

August 2026

Monthly Balancing Cost Report

Analysis of balancing costs and drivers

Monthly Balancing Costs Report – August 2026

Executive Summary

The total balancing cost for August was £242m, which is £24m (~9%) below the benchmark of £266m.

Despite wind output remaining similar to July at 4TWh, August saw more variable weather. Early-month unsettled conditions in the north of GB led to wind curtailment and thermal constraint actions in Scotland, while July's high pressure continued in southern GB, bringing low wind levels and tighter margins. These contrasting conditions resulted in the month's highest daily costs on 7th and 8th August at £19.5m and £19.2m. All other daily costs in August remained below £15m.

August saw a reduction in the exceptionally high embedded solar generation of July, which had reduced daytime transmission system demand and increased the requirement to offer on synchronous generation to manage voltage and inertia. As a result, voltage costs were almost half those of July and inertia costs reduced by 65% from July.

An Electricity Margin Notice was issued by NESO on the evening of 11th August for the period 17:00–22:00 on Wednesday 12th August 2026, the date of the eclipse. The EMN was revised in the morning to cover only 18:00–20:00 and then cancelled just before 1pm. With daytime solar forecast to decrease earlier in the evening than usual, lower solar generation was expected over the evening demand peak. Total balancing costs for the 12th amounted to £10.6m.

August constraint costs decreased by £54m from July. Lower requirement for wind curtailment drove a reduction in constraint costs in Scotland by £22.9m. Meanwhile the earlier-mentioned reduction in requirement for voltage and system inertia management during the daytime meant that August saw a reduction of £19m in England & Wales constraint costs, mostly attributable to the reduced spend on voltage. Compared to August 2025, the absolute volume of constraint actions decreased by 317GWh, however the effect of higher gas prices meant that the lower volume did not materialise as a significantly lower cost, with a total constraint cost decrease of £4.5m (–2.6%) from last year's total.

Non-constraint costs decreased in August to £74m from £79m in July. While there was a slight increase in Reactive spend, this was outweighed by lower costs for Response, Reserve and Restoration. Average Response clearing prices for Dynamic Moderation (DM) and Dynamic Containment (DC) increased slightly between July and August, while the price of Dynamic

Regulation (DR) continued a sharp drop seen last month and, at £1.73/MWh, reached its lowest price since March 2025.

Both NBP gas and DA power prices were higher in August compared to July. Gas prices trended consistently upwards as the month progressed, from 141.23p/therm on 1st August to 164p/therm on 31st August, with a noticeable step up between the 10th and 11th in reaction to supply concerns, with Norway extending a partial outage at the Ormen Lange field, as well as the number of vessel transits falling through the Strait of Hormuz. Day-ahead power prices varied more throughout the month in response to changing weather conditions. A period of lower pricing (£87.98–£112.89/MWh) between the 5–9th August was driven by the highest wind outturn of the month on the 5th and some higher wind days continuing until the 9th. With margins tightened due to heatwave conditions and low wind, alongside the step up in gas prices from the 11th, the highest DA power prices of the month occurred on the 13th, 14th and 17th August.

The volume weighted average (VWA) price of bids in August was £42.43/MWh, which is less expensive than July's price of £16.47/MWh (a positive bid price reflects a net payment to NESO). The positive bid price reflects a greater proportion of the total monthly bid volume taken on fuel types other than wind, a continuation of the trend since June. Wind bids accounted for 33% of total bid volume in August, the lowest percentage all year. Meanwhile CCGT bid volume saw its highest percentage all year at 22%. The volume weighted average (VWA) price of offers, which has been climbing since April, increased from £173.94/MWh in July to £193.77/MWh in August, in line with increasing gas prices. CCGT units accounted for 63% of Offer volume this month, the highest all year. Carbon prices also saw a slight increase this month, from £68.7/ton to £69.84/ton.

Total Balancing Costs (£m) and Balancing Volume (GWh) monthly vs previous year



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Table: 2026–27 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
Unconstrained Wind Penetration	0.21	0.15	0.18	0.15	0.14								0.17
Day Ahead APX (£/MWh)	82.5	104.8	100.2	106.7	127.1								104.3
Benchmark*	299	262	278	257	266								1362
Outturn balancing costs¹	307	239	319	301	242								1408

Previous months' outturn balancing costs are updated every month with reconciled values. Benchmark and outturn balancing costs are rounded to the nearest £m.

For more information on our balancing costs benchmark please see our [monthly incentives reporting](#).

What is NESO doing to help reduce Balancing Costs?

NESO is continually identifying opportunities to minimise balancing costs. We are working closely with DESNZ, Ofgem and industry to explore, develop and assess cost saving initiatives and enhance existing services from our [Balancing Cost Strategy](#) to support lower costs.

Thermal constraints currently make up the largest share of balancing costs (~60%). The Government's Summer 2025 Review of the Electricity Market Arrangements (REMA) set out the decision to move forward with RNP. Through this programme, we're working with DESNZ and Ofgem to prioritise and progress constraint management initiatives with the greatest potential for cost reduction, while ruling out less effective options. We are also working closely with Network Operators and other industry participants to optimise outage placement and drive improvements to the overall planning process – enabling system access for vital reinforcement work, whilst driving down the cost of thermal constraints.

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

As part of the Balancing Cost Strategy, we are also progressing initiatives to further reduce non-thermal constraint costs through strategies to manage voltage and inertia. Between April 2025 and March 2026, we delivered £536m in savings across key initiatives. These savings are calculated by comparing the cost of actions taken through these initiatives with known counterfactuals (which in most cases is taking equivalent actions in the BM). This includes £128m from Network Services, £207m from trading actions, and £164m from reduced inertia requirements under FRCR. £37m in further savings have also been delivered through DFS and Balancing Reserve.

For further details on ongoing work to reduce balancing costs please see our latest [Annual Balancing Cost Report](#).

NESO Operational Transparency Forum: 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. 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](#).

If you would like to find out more about balancing costs and our initiatives, visit the balancing costs website [here](#); or click on the links below:

- [Annual Report](#)
- [Portfolio](#)
- [Performance Reporting](#)

System and Market Conditions

Market trends

Gas prices trended consistently upwards as the month progressed, from 141.23p/therm on the 1st August to 164p/therm on the 31st. The increase was steady but with a noticeable jump between the 10th and 11th in reaction to supply concerns, with Norway extending a partial outage at the Ormen Lange field, as well as the number of vessel transits falling through the Strait of Hormuz. Lower confidence in supply continued throughout the rest of the month driving a continued increase in gas prices. Overall, the average gas price this month was 150.69p/therm, which is 18% higher than July's average price of 127.69p/therm, and 90% higher than the August 2025 price of 79.28p/therm.

By comparison, day-ahead power prices varied more across the month in response to changing weather conditions. A period of lower pricing (£87.98-£112.89/MWh) between the 5-9th August was driven by the highest wind outturn of the month on the 5th and some higher wind days continuing to the 9th. However, in the middle of the month DA power prices rose sharply, from

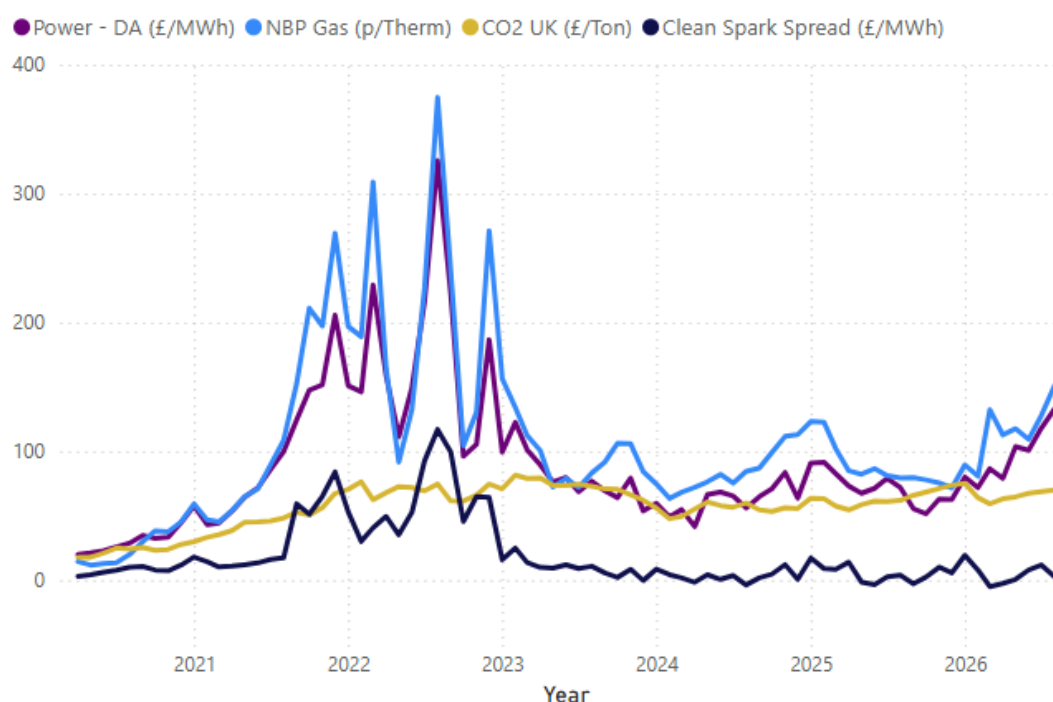
£133.38/MWh to £150.14/MWh between the 12th and 13th. Prices then largely remained higher for the second half of the month, with the peak price of £152.39/MWh falling on the 17th. Overall, the average DA power price this month was £132.72/MWh, which is 12.5% higher than July's average price of £117.96/MWh, and 85% higher than the August 2025 price of £71.75/MWh.

The mid-month power price increase was driven by very low wind levels between the 13th and 17th, increasing the grid's reliance on gas-fired generation, which met the earlier-described gas price increase that had occurred on the 11th. Further to this, heatwave conditions were experienced from 10th–14th August, with records suggesting 13th August was the 5th hottest day on record for the UK. With margins tightened due to heatwave conditions and low wind, alongside a step up in gas prices, the highest power prices of the month occurred on the 13th, 14th and 17th.

The volume weighted average (VWA) price of bids in August was £42.43/MWh, which is less expensive than July's price of £16.47/MWh. The positive bid price reflects a greater proportion of monthly bid volume taken on fuel types other than wind, a continuation of the trend since June. Wind bids accounted for 33% of total bid volume in August, the lowest percentage all year. Meanwhile CCGT bid volume saw its highest percentage all year at 22%. The volume weighted average (VWA) price of offers, which has been climbing since April, increased from £173.94/MWh in July to £193.77/MWh in August, in line with increasing gas prices. CCGT units accounted for 63% of Offer volume this month, the highest all year.

Carbon prices saw a slight increase this month from £68.7/ton to £69.84/ton.

Day Ahead Market Trends (2020-2026)



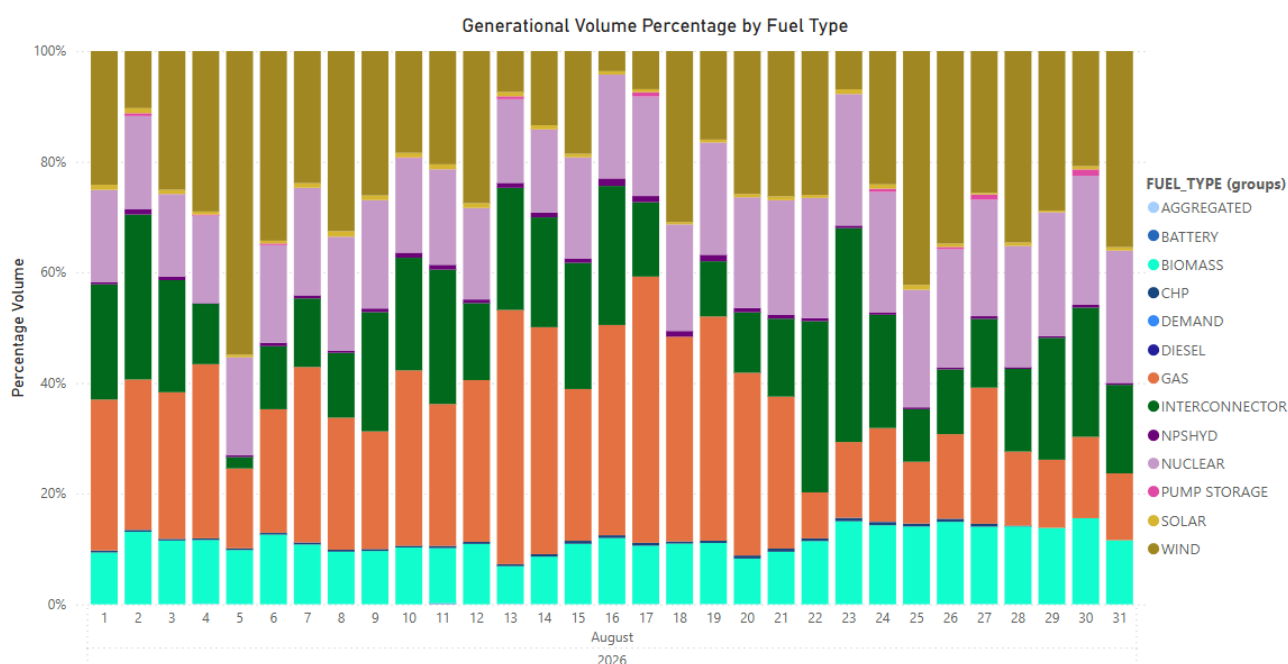
DA BL: Day Ahead Baseload

NBP DA: National Balancing Point Day Ahead

Generation Mix

August saw a fairly even split between gas generation (26%) and wind generation (24%) in the total generation mix. Following this was nuclear at 19% and interconnectors at 17%. Only 5th August had wind accounting for over 50% of daily generation, which compares to 2 days in July and 4 days in June. There were no days in August where gas accounted for over 50% of generation, though there were some low wind days between the 13th & 17th where gas and interconnector representation increased.

On 23rd August, only 7% of generation came from wind and only 13% came from gas. This day saw the highest representation of interconnectors (39%) and second-highest representation of nuclear (24%) and biomass (15%). 23rd August saw the second highest daily spend on Reserve this month (£1.7m), followed by the 17th and 13th, also low wind days.



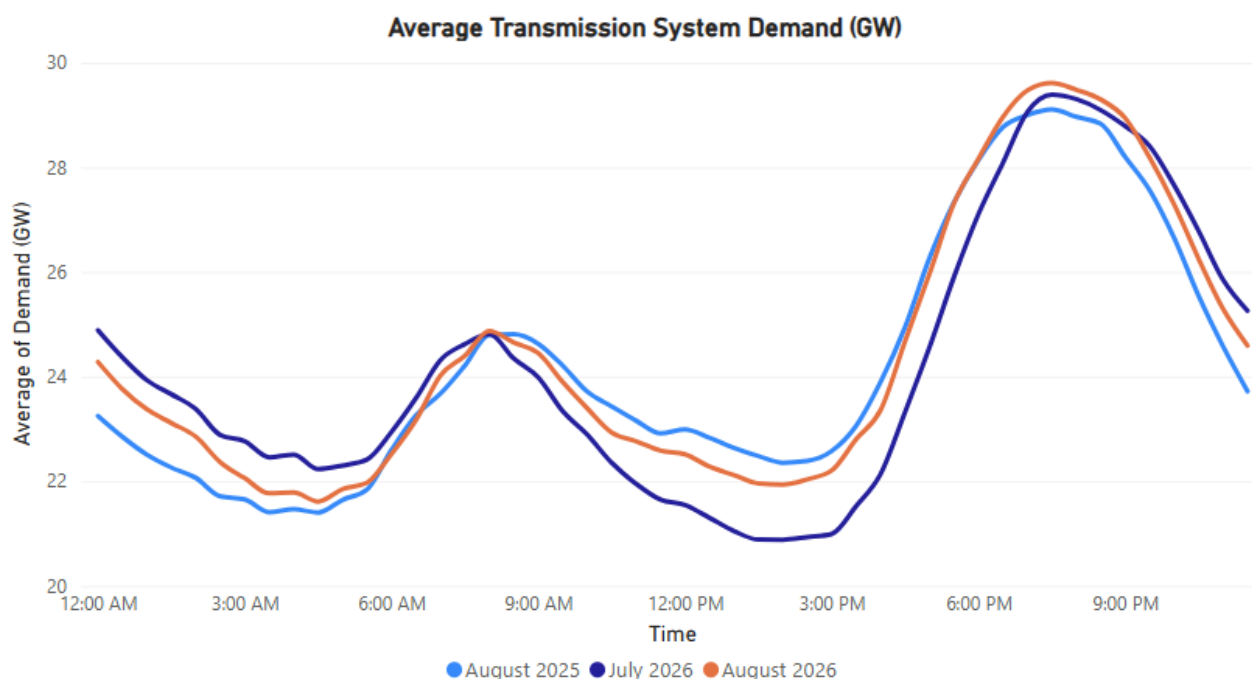
*Generation mix includes exports from interconnectors.

Transmission System Demand

The average Transmission System Demand (TSD) in August 2026 was higher than the average in July during daylight hours, specifically from the morning demand peak (08:00) through to the evening demand peak (19:30). The lower daytime demand in July had been driven by high embedded solar generation lowering demand on the transmission system. While embedded solar contribution had still been high in August (daily average 3.6GW), it dropped towards the end of the month and did not reach the same daily highs as July (daily average 4.5GW).

With the post-peak drop in demand throughout the evening periods, the average TSD for August became increasingly lower than that of July during the nighttime, reaching its lowest point at 04:30. Lower overnight demand in August was likely influenced by lower overnight temperatures materialising as a lower cooling demand.

Compared to August last year, demand was generally lower during the daytime, with embedded solar capacity having increased from 21GW at the end of August 2025 to 24GW at the end of August 2026, allowing a greater embedded contribution during daylight hours. August sunshine was also above average for the UK this year. In the lead up to the evening peak, demand levels in August 2026 were similar to those in August 2025 but, at the very top of the peak (19.30), they were higher by ~0.5GW. Demand then remained higher than the previous year overnight, which follows the general trend of increasing overnight demand over recent years.



Wind Outturn

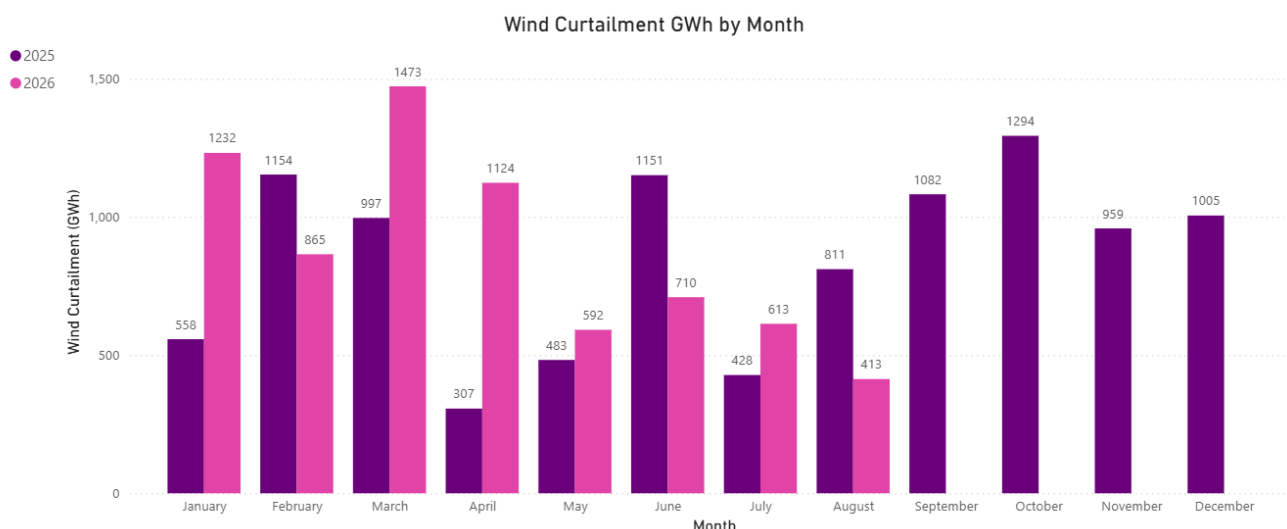
While wind outturn remained similar to July's outturn at 4TWh, August saw more varied weather conditions affecting the system. Throughout the first half of August the south of GB saw July's high-pressure system continue, with high daytime temperatures, significant sunshine and low rain, until the second half of the month became more unsettled, with occasionally heavy rainfall and thunderstorms.

Meanwhile, the northern half of GB saw unsettled conditions for most of the month, with low pressure bringing occasional thunderstorms, lower temperatures and more cloud than in the south.

Overall wind outturn in August was 3.96 TWh, slightly lower than July's outturn of 4.01 TWh, and a little lower than the outturn in August 2025 of 4.44 TWh. Locationally, wind outturn was marginally lower than July in England and Wales (2.39 TWh in August compared to 2.54 TWh in July), and slightly higher in Scotland (1.57 TWh in August compared to 1.46 TWh in July).

Wind curtailment in August this year was 413 GWh, which is nearly half that of August last year (811 GWh), with August 2025 having experienced Storm Floris at the beginning of the month. It was also 200 GWh lower than July 2026, with the volume of wind curtailment in August this year more representative of July last year (428 GWh).

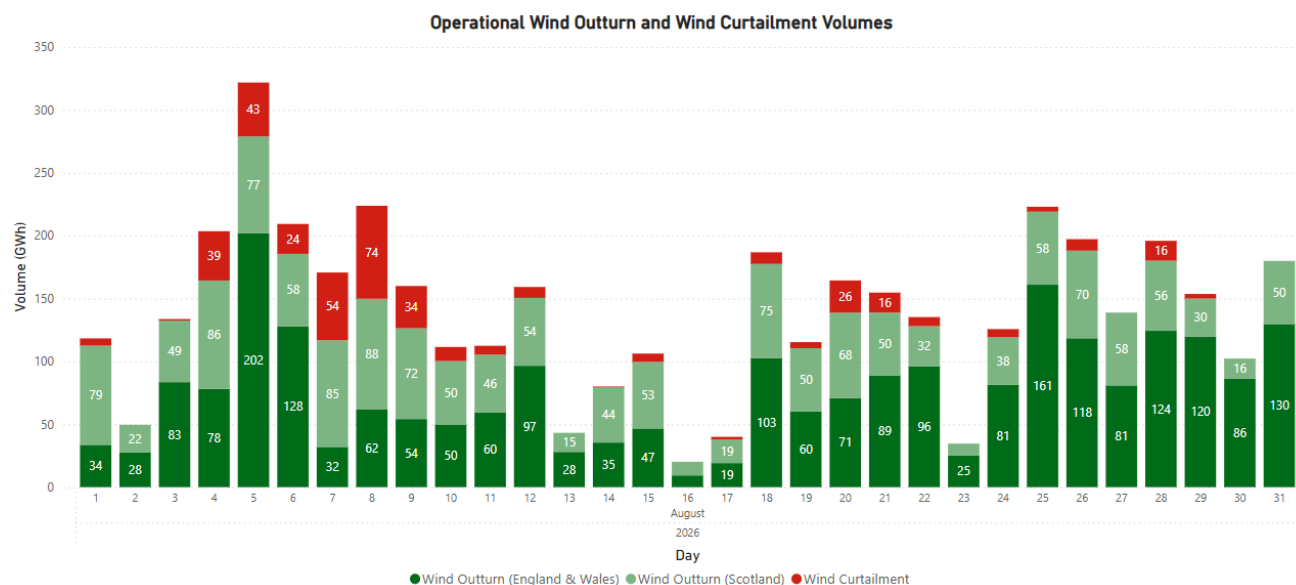
The percentage curtailment in August was 9.4%, compared to 13.3% in July and 15.5% in August 2025.



Despite 5th August having the largest hypothetical wind outturn this month at 321.8 GWh, the chart below shows that the greatest volume of curtailment occurred on the second-highest wind outturn day, which was 8th August. The 8th saw a total hypothetical outturn of 223.7 GWh (98 GWh lower than the 5th), but curtailment of 74GWh (31 GWh higher than the 5th). The 7th also had higher curtailment volumes than the 5th and was the highest costing day this month. The primary difference was that the 5th had a large wind outturn in England & Wales (202GWh), whereas the 7th & 8th saw greater outturns in Scotland, where the network experiences greater congestion around the areas of wind generation, leading to a greater need for curtailment.

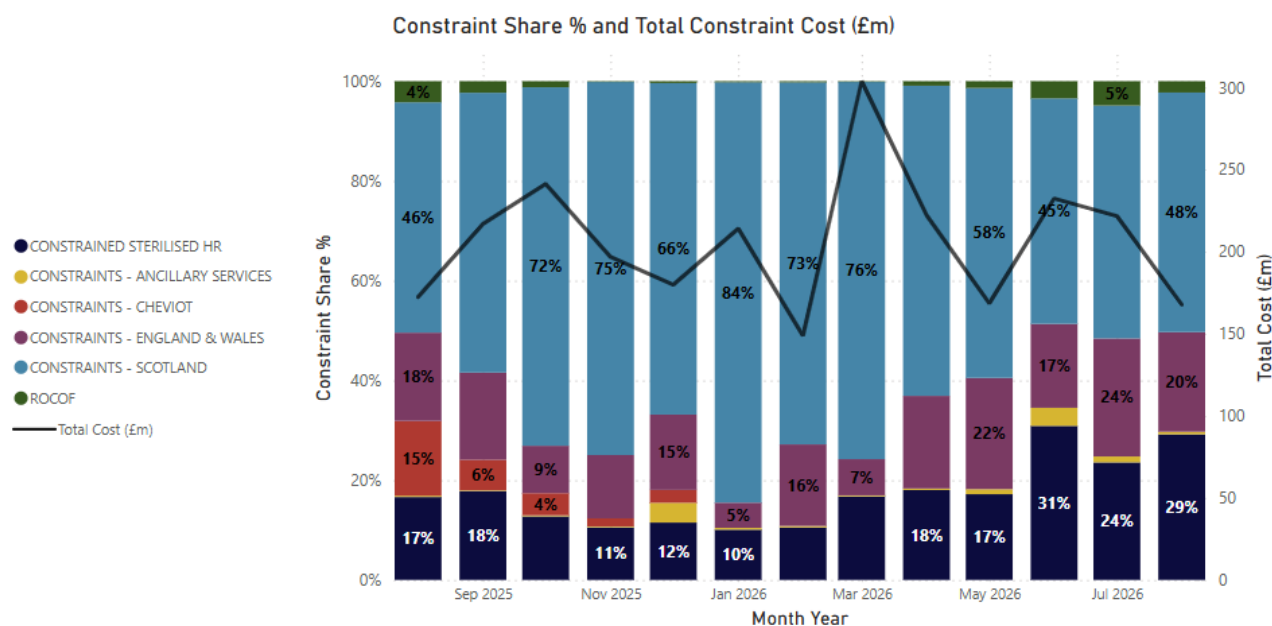
There were several days of very low wind outturn this month (2nd, 13th, 16th, 17th and 23rd). Of these only the 17th experienced some curtailment. Towards the end of the month there were 3

further days that, despite higher levels of wind on the system, required no curtailment (27th, 30th, 31st).



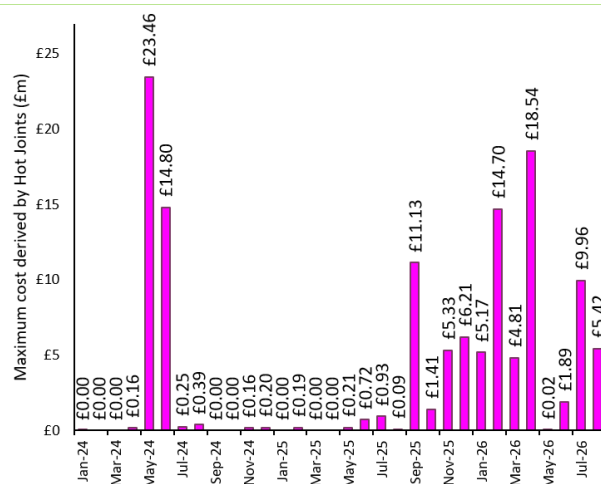
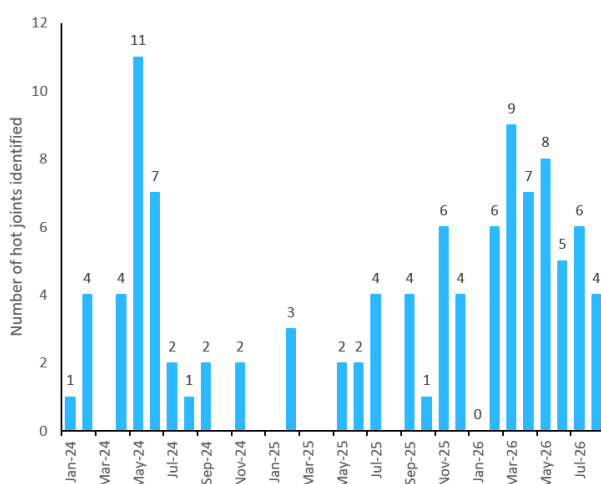
Constraints

Constraint costs decreased from £221.7m in July to £172.2m in August, a decrease of £54m. The largest decrease came from Scottish constraints at –£22.9m, but there was also a significant decrease in England & Wales constraints at –£19m.



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 July 2026, four hot joints were identified. The maximum cost is estimated in £5.42 million.



Daily Costs Trends

August balancing costs were £242m, a decrease of £58.7m from July, but a slight increase of £2.6m from August 2025. Two days in August had a total cost above £15m (7th and 8th at c.£19m each). There were a further 6 days above £10m (4th, 5th, 6th, 9th, 12th, 20th), which overall meant 5 fewer high-costing days than July. The daily average cost decreased to £7.8m, down from £9.7m in July – a decrease of 20%.

The highest cost day was Friday 7th August at £19.5m, which is over £6m lower than July's highest costing day of £25.7m. Just under 98% of costs on 7th August were attributed to constraints, which included a spend of £13.4m managing thermal constraints in Scotland and £4.6m on constrained sterilised headroom.

As mentioned earlier in this report, weather conditions in GB were split by a north-south divide in the first half of the month. So, despite low wind outturn in England/Wales, there was a high wind outturn in Scotland and actions were required to manage thermal constraints in Scotland throughout the day. With very low wind outturn in England & Wales (32 GWh compared to 202 GWh on the highest wind day of 5th August), margins were expected to be tight for the evening demand peak. Constrained wind, as well as gas units limited behind constraints, meant seeking maximum volumes on interconnector trades, which were required for margin as well as an import constraint in the south, tightened by a planned outage taken the day before.

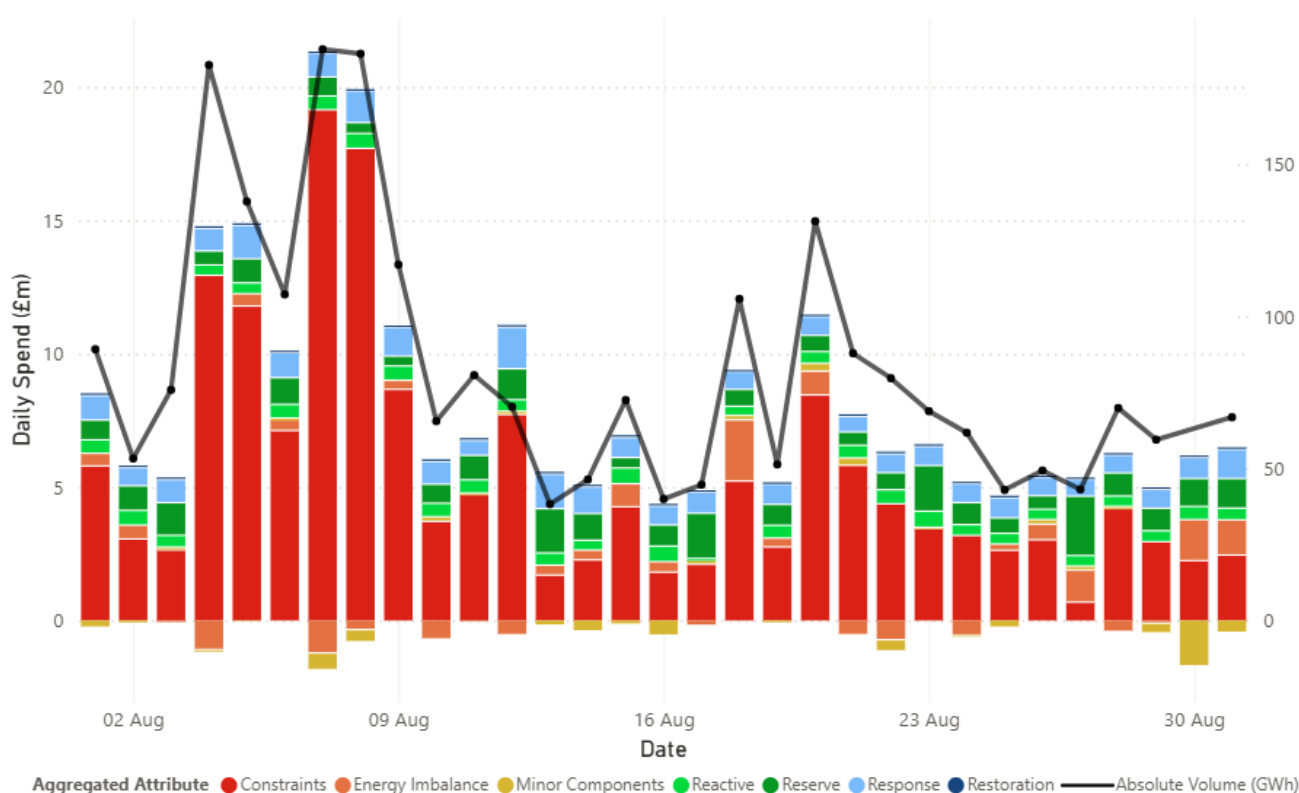
Wind in Scotland was constrained by planned outages, while a faulted circuit was additionally constraining some generation in the north of England. The faulted circuit returned to service in the evening; this did not allow material time for scheduling but did increase flexibility options over the evening demand peak.

Conditions the next day were similar and, as seen in the section on wind outturn, there were higher levels of wind curtailment required on the 8th (54 GWh on 7th compared to 74 GWh on 8th). However, the 8th was a Saturday which meant lower demand levels, and there was also a greater wind outturn in England & Wales (62GWh), which meant lower stress on system margins and the daily cost was slightly lower (£19.2m).

The lowest cost day occurred on Sunday 16th August, with a total cost of £3.9m. 16th August was the lowest wind outturn day at 20.2 GWh and no wind curtailment was taken. Being a Sunday, the 16th was one of the lower demand days in August, and therefore margins remained healthy despite the lack of wind on the system.

A final date of note was Wednesday 12th August, the date of the eclipse. With daytime solar levels forecast to decrease earlier in the evening than usual and therefore lower solar generation expected over the evening demand peak, an EMN had been issued for the period 17:00–22:00. The highest response costs occurred on this date (£1.6m) and there were some of the higher reserve costs too (£1.2m). Total balancing costs for the 12th amounted to £10.6m.

Daily Cost and Volume by Action Type



High-Cost Day

The highest cost day of the month was the **7th August 2026**.

Breakdown of Cost and Volume

- Total cost: £19.5m
- Total Absolute Volume: 187.8 GWh

Balancing Costs detailed breakdown

Comparison Between August 2026, July 2026 and August 2025			
Constraint Non-Constraint Group	Latest Month Total	Month Change	Year Change
Constraints	£167.73	-£53.95	-£4.52
CONSTRAINED STERILISED HR	£48.95	-£3.28	£20.34
CONSTRAINTS - ANCILLARY SERVICES	£0.88	-£1.76	£0.42
CONSTRAINTS - CHEVIOT*	£0.00	£0.00	-£25.83
CONSTRAINTS - ENGLAND & WALES	£33.49	-£18.99	£3.00
CONSTRAINTS - SCOTLAND	£80.57	-£22.92	£1.04
ROCOF	£3.83	-£7.01	-£3.48
Non-constraints	£74.28	-£4.70	£7.11
ENERGY IMBALANCE	£6.47	£0.27	£7.13
FAST RESERVE	£7.21	-£0.08	-£0.21
MINOR COMPONENTS	-£3.97	-£0.64	-£2.58
NEGATIVE RESERVE	-£0.02	-£0.21	-£0.42
OPERATING RESERVE	£12.66	-£1.07	£2.27
OTHER RESERVE	£2.19	£0.22	£1.22
REACTIVE	£14.09	£1.38	£0.59
RESPONSE	£26.39	-£1.51	£4.65
RESTORATION	£3.30	-£3.31	-£0.23
STOR**	£5.97	£0.25	-£0.31
Total	£242.00	-£58.65	£2.59

*As of 2026 Cheviot constraint costs are now included under Scotland constraint costs

**NESO has now ceased procurement of the STOR service. The figures show here are the total of Balancing and Quick Reserve, as well as DFS/Demand Turn Up

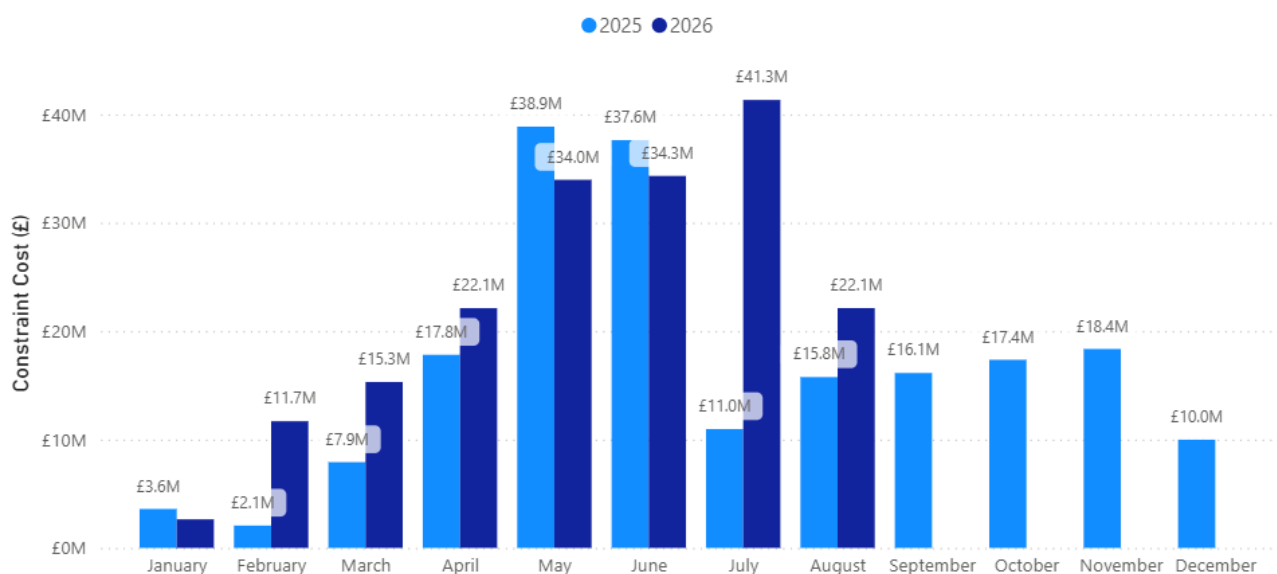
As shown in the table above, since last month, constraint costs and non-constraint costs decreased by £54m and £4.7m respectively, which results in an overall decrease in costs of £59m compared to July 2026.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£22.9m Constraint – England & Wales: -£19m Constraint Sterilised Headroom: -£3.3m Overall constraint costs decreased by £54m, with August experiencing the lowest absolute volume of constraint actions required this year. Compared to July, a lower requirement for wind curtailment drove a reduction in costs in Scotland, while less requirement for voltage and system inertia management reduced constraint costs in England & Wales.	Constraints – Scotland & Cheviot: -£24.8m Constraints – England & Wales: +£3m Constraints Sterilised Headroom: +£20.3m Despite lower constraint costs in Scotland compared to August 2025, the difference was almost made up by the sum of the higher England/Wales and sterilised headroom costs, leading to a total constraint cost reduction of £2.9m since last year. The absolute volume of constraint actions decreased by 317GWh from last year (-14%), however the effect of higher gas prices meant the lower volume did not materialise as a significantly lower cost (-2.6%). England/Wales voltage constraints are often managed by offers on gas units and sterilised headroom tends to mean accessing flexible generation such as gas, which is where costs have increased since last year.

Voltage – Monthly system cost of synchronisation actions for voltage control across 2025 and 2026:

In August, the system synchronisation costs for voltage (what it costs to the system, which factors in energy replacement and headroom among others) were £22.1m, representing a decrease of approximately £19.2m compared to July 2026, but £6.4m higher than August 2025.



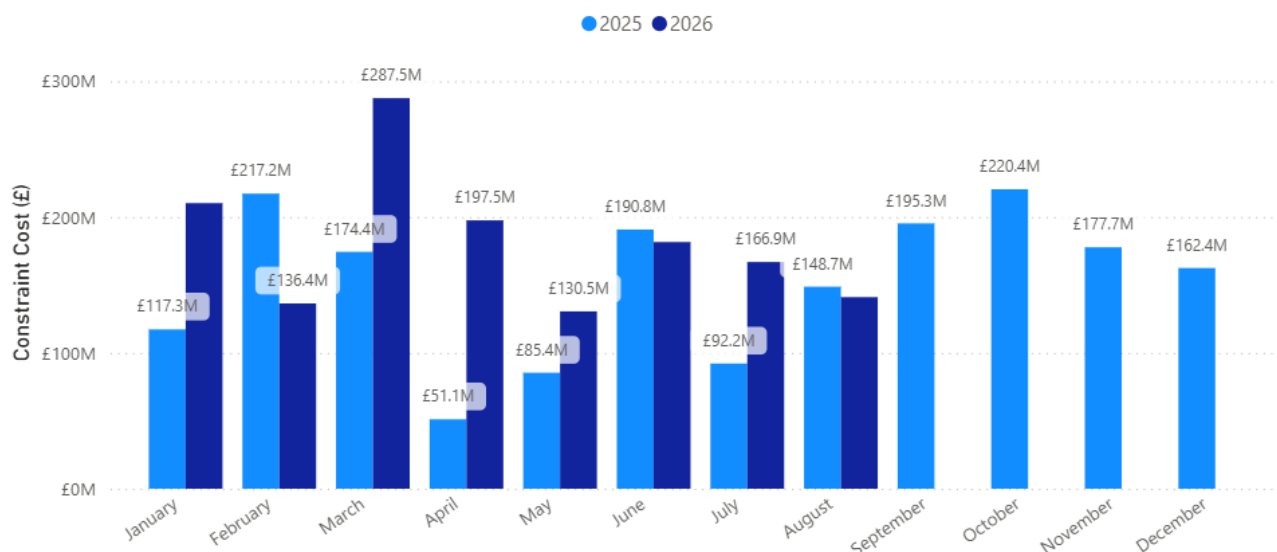
Voltage spending is usually higher overnight: lower demand means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism. Most voltage costs arise from the South-West region of Great Britain, where the system relies on Combined Cycle Gas Turbines (CCGTs) for voltage management; however, the system's operational condition and outages in other areas also influence the system spending.

The significant drop in voltage costs since July was because July had seen a large daytime requirement for voltage management, as well as overnight, which had been driven by high levels of embedded solar output reducing system demand and the number of synchronous generators self-dispatching; this led to many occasions where voltage units were run throughout the whole day. With lower solar output, August saw a return to previous levels of daytime synchronisations and the net volume of voltage actions therefore decreased by 40% from July, which resulted in a 46% decrease in costs.

In comparison, voltage spending this August increased by 40% from August last year. There was a slightly higher volume of voltage actions required due to some lower daytime demand, but the percentage increase in absolute volume (14%) was less than the cost increase. Given a strong reliance on CCGTs to provide voltage management actions, the higher voltage costs this year were consequently also driven by the elevated gas prices resulting from the US-Iran conflict.

Thermal – Monthly system cost of actions for thermal management across 2025 and 2026:

In August, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £141m, reflecting a decrease in costs of £25.9m compared to July (£166.9m). Thermal constraint costs were close to August last year (£148.7m).

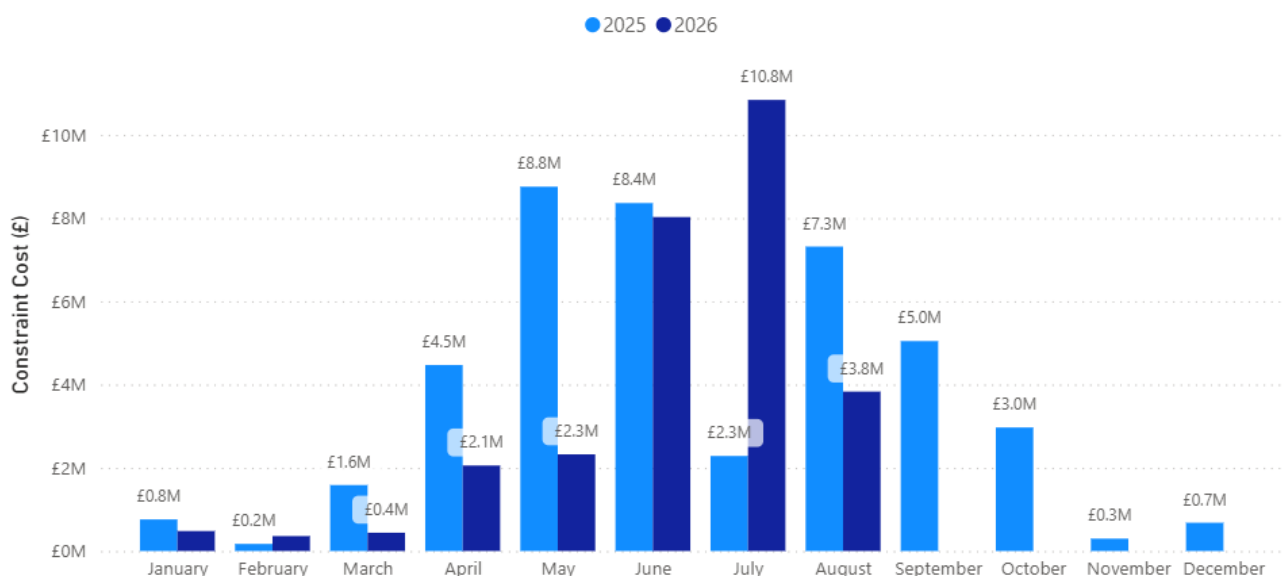


With wind curtailment volumes having steadily decreased since June, August also continued an associated downwards trend in thermal constraint costs since June. The absolute volume of thermal constraint actions in August 2026 was 881GWh, which represents the lowest volume since July 2025.

Despite similar costs between August 2026 and August 2025, wind curtailment in August 2026 was almost half that of August 2025. The lack of cost saving from the reduced volumes of wind curtailment can be attributed to the growing cost of turn up actions. With gas prices having almost doubled since last year, the energy from wind curtailed in Scotland, which is often replaced by energy sourced from flexible CCGT units or interconnectors in the south, was costlier to replace this year.

Inertia / ROCOF – Monthly system cost of actions for inertia management across 2025 and 2026:

In August, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £3.8m, which was a decrease of £7m from July (£10.8m) and approximately half the cost of August last year (£7.3m).



Regarding the large drop in costs since last month, inertia expenditure had been high in July for similar reasons to the increased spending on voltage constraints. High renewable solar generation and low demand had displaced synchronous generation from the grid and therefore additional actions were required in the Balancing Mechanism to gain the inertia requirement that these units provide in order to comply with the Security and Quality of Supply Standard (SQSS) limits.

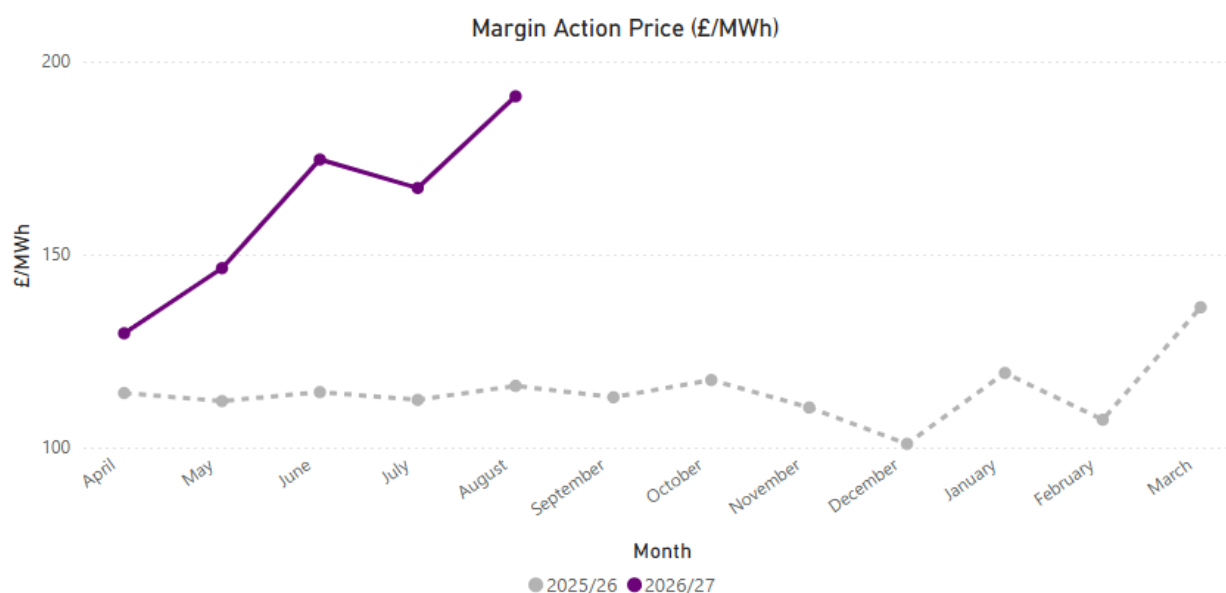
Lower spend on inertia this August compared to last accompanies a much lower volume of actions. August 2025 had the largest monthly volume of actions taken to manage system inertia that year, whereas this year June and July have seen higher volumes required than August.

Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£1.4m Reactive costs have increased on last month. Higher spending tended to occur on the dates with the lowest average transmission system demand.	+£0.6m Reactive costs have slightly increased on last year with lower transmission system demand levels experienced on average this year compared to last year.

Reserve Costs/Volumes

Reserve prices increased from £167.2/MWh in July to £191/MWh in August, which is a return to the upwards trend observed over the past financial year in line with gas prices increasing.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: -£1.1m Fast Reserve: -£0.1m There was a 19 GWh increase in the volume of operating reserve compared to July, though the overall cost decreased. A 7 GWh decrease in the volume of fast reserve since July 2026 materialised as a slightly lower cost.	Operating Reserve: +£2.3m Fast Reserve: -£5.2m There was a 24 GWh decrease in the volume of operating reserve compared to last year, though the cost was higher due to price increases. A 12 GWh decrease in the volume of fast reserve did however lead to lower costs than last year.

The highest costing date for Reserve was 27th August at £2.2m, where higher reserve costs were encountered over the evening demand peak.

Response Costs/Volumes

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

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£1.5m	+£4.7m

There was a 6.5 GWh decrease in the absolute volume of actions compared to July, meaning August saw a return to similar volumes to June.

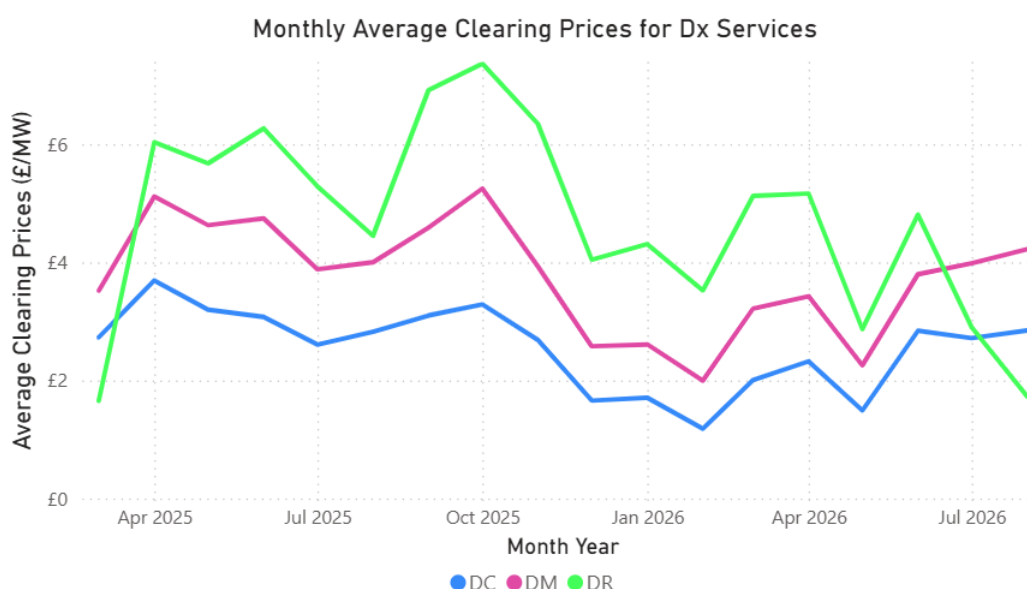
The volume of actions taken for response decreased by 72 GWh compared to August 2025.

Comparison Between August 2026, July 2026 and August 2025

Service	Monthly Variance	Yearly Variance
DC	£0.1	£0.0
DM	£0.2	£0.2
DR	-£1.2	-£2.7

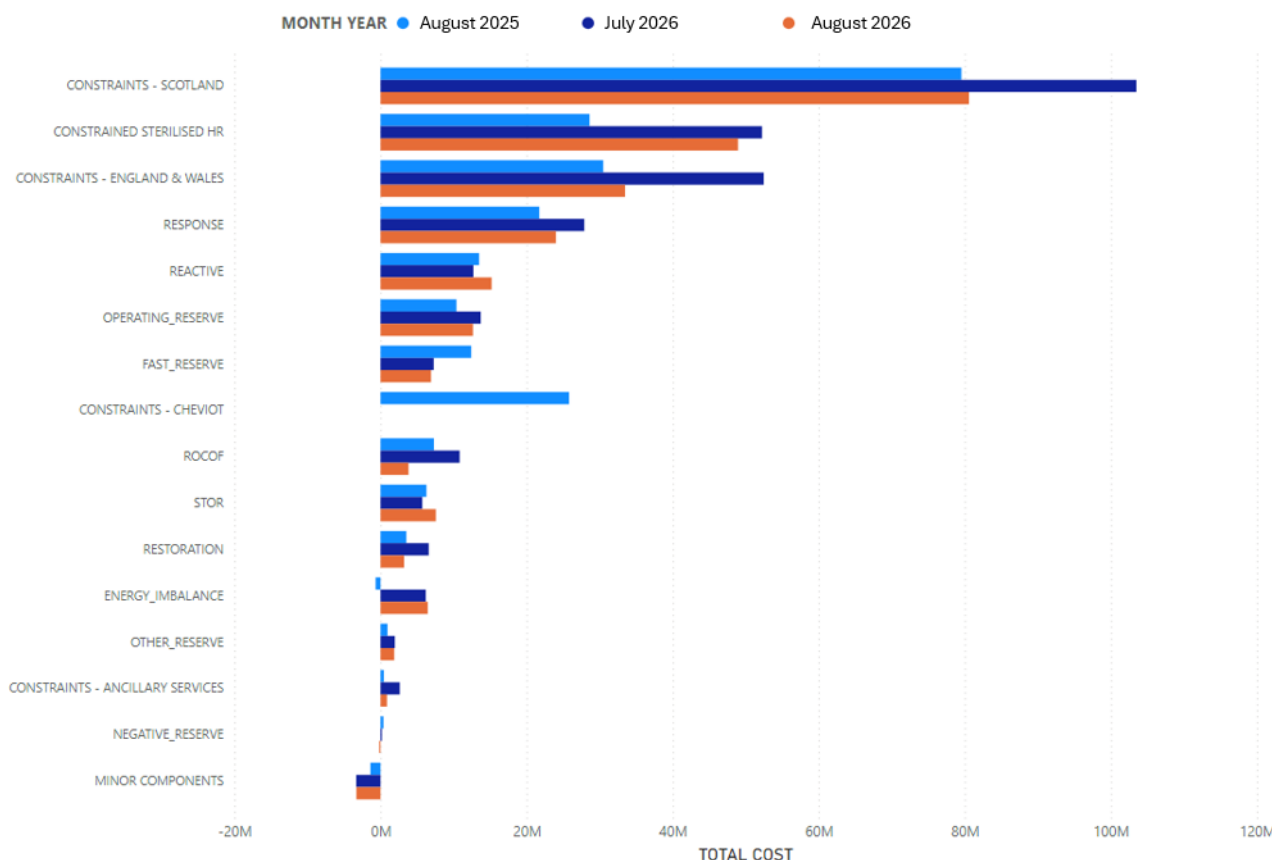
Average clearing prices for Dynamic Moderation (DM) and Dynamic Containment (DC) increased slightly between July and August, at £4.22/MWh and £2.85/MWh respectively. Meanwhile, the average clearing price for Dynamic Regulation (DR) continued the sharp drop seen last month and, at £1.73/MWh, reached its lowest price since March 2025. DRL has seen more offered volume competing against the firm requirement, leading to more competitive pricing.

Compared to August last year, average DC prices cleared at almost the same price as a year ago, DM prices increased very slightly and DR experienced a significant decrease in average clearing price.



Comparison breakdown

The graph below provides a breakdown of cost components compared to the previous month and previous year.



Cost Savings

Outage Optimisation

The total savings from outage optimisation were approximately £16m in August 2026. This is a decrease of £89m relative to July 2026 (£105m). The most valuable action was the deferral of a shunt reactor outage in the Yorkshire and the Humber region, avoiding the need of additional voltage units in the system during a concurrent outage in the area. The expected savings delivered from this action are estimated in £10.8 million.

Trading

The Trading team were able to make a total saving of £26.7m in August through trading actions as opposed to alternative BM actions, representing a 27% increase on the previous month and the highest trading savings seen since November 2025. Trading for constraints made up the greatest

share of savings in August, largely down to trading for constraints in South East England, with wind bids as the alternative BM price. The increased trading for constraints also meant we observed the second highest number of trades taken against Emergency Instruction / Emergency Assistance in the last year. There was an increase in voltage trading as well, reflecting the lower demand and summer conditions on the system. The day with the greatest trading savings was on 31 August at £2.4m with the greatest savings being made for managing constraints in South East England. The day with the greatest spend on trades was 18 August at a cost of £2.7m with the greatest component being for margin.

From Friday 24th July, NESO have started to use DA NTC restrictions more regularly, which we expect to impact trading savings in the future. These are used to help guarantee the security of the GB system, should available intraday options not provide this certainty. For further information please see our notice at the OTF [here](#) (slide 12).

Network Services

We are using Network Services 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 £34m in savings across 2026/27 to date (April 2026 – June 2026).



Further information

For further information please see our [balancing costs website](#).

Appendix

Types of constraint costs

Voltage Synchronisation Costs

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.

Inertia Costs

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.

Thermal Constraint Costs

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 most of the system constraints, accounting for a significant percentage of system actions.

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