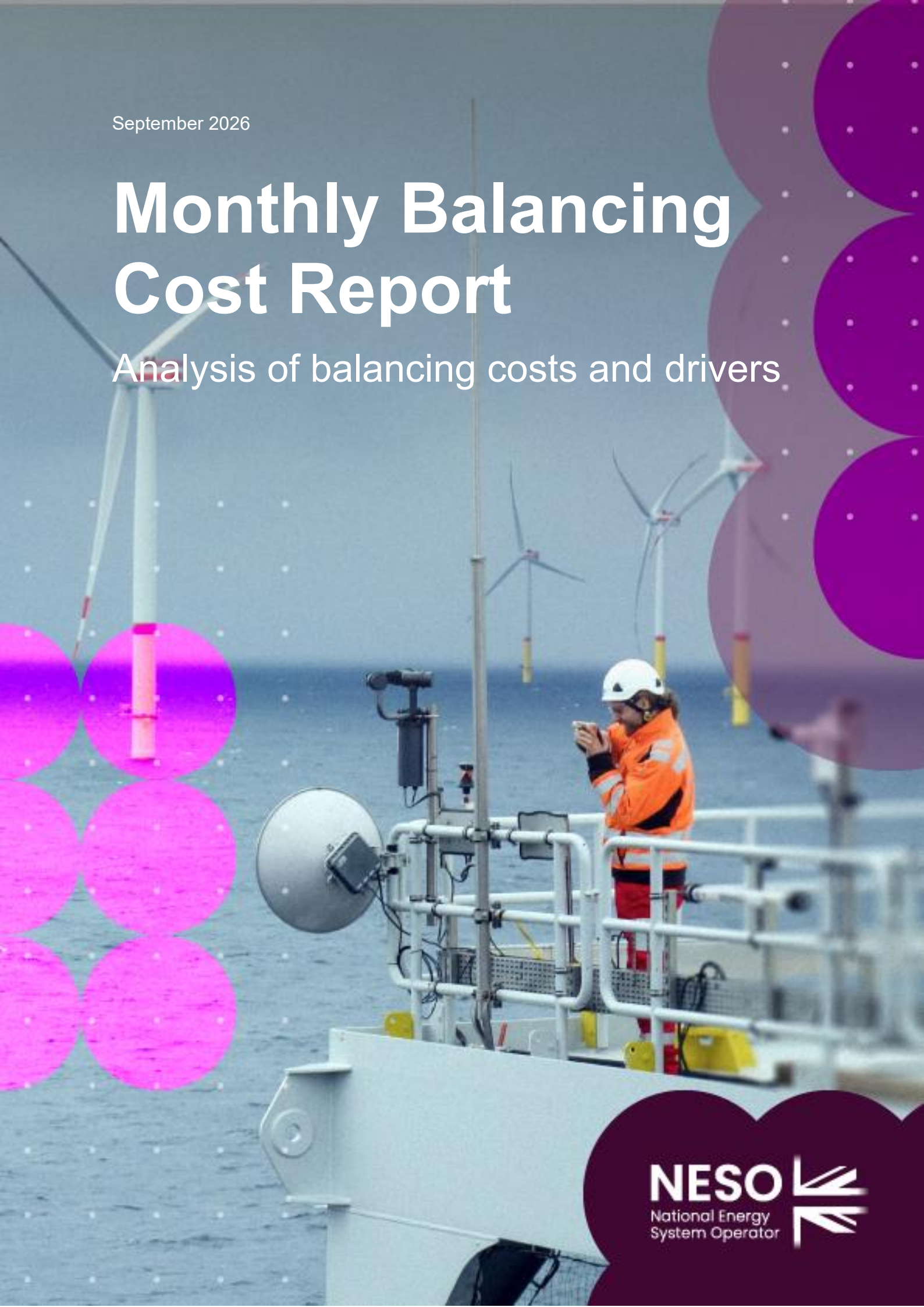
September 2026

Monthly Balancing Cost Report

Analysis of balancing costs and drivers



NESO
National Energy System Operator

Monthly Balancing Costs Report – September 2026

Executive Summary

The total balancing cost for September was £553m, which is £98m (~22%) above the benchmark of £455m. Although September balancing costs were £98m above the £455m benchmark, the benchmark captured most of the cost impact associated with the month's unusually high wind, low demand and elevated wholesale prices. The remaining variance was largely associated with network outages and reduced transfer capability, which are not directly represented in the benchmark model and amplified the effects of high wind and low demand.

September was the highest costing month on record, slightly higher than the record set in November 2021 (£542m). Unlike November 2021, when exceptionally high gas and power prices were the main driver, September 2026 was primarily characterised by record balancing-action volumes, alongside higher replacement-energy costs due to inflated electricity and gas prices amid ongoing market volatility.

September costs were driven by:

- **Higher redispatch volumes.** Sustained high wind generation, combined with low demand, transmission outages and multiple active thermal constraints, significantly increased redispatch requirements. Wind accounted for 39% of the generation mix, reaching 67% on 19 September, while a record 1.8 TWh of wind was constrained off during the month. High wind availability in Scotland coincided with reduced network transfer capability, including transmission outages associated with reinforcement work. This limited how much electricity could be moved to demand further south, requiring more wind to be curtailed and replacement generation to be increased elsewhere.
- **More expensive redispatch actions.** Gas and power prices were 136% higher year on year, increasing the cost of replacing curtailed wind. On several high-cost days, low day-ahead and within-day power prices reduced incentives for gas generation to run ahead of real time, requiring volumes to be turned up later through the Balancing Mechanism at significantly higher offer prices. The volume-weighted average offer price increased to £211.97/MWh, while the average bid price fell to -£3.14/MWh, reflecting the high volume of wind curtailment. The negative bid price here reflects a net payment from NESO to generators.

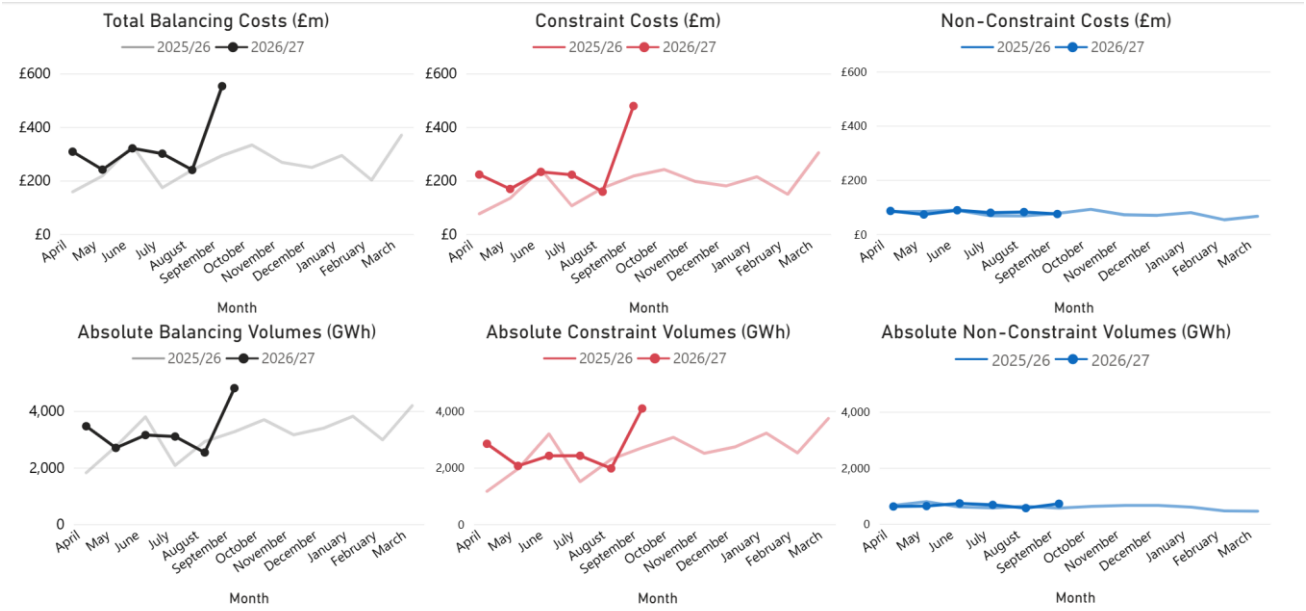
- **The combined volume and price effects were sustained across the month**. Daily balancing costs averaged £18.0m, compared with £7.7m in August, with 17 days above £15m and six above £30m. Constraint costs increased by £326m compared with August and accounted for much of the increase in overall balancing costs. The repeated occurrence of high-cost days shows that September's increase was not driven by a single event, but by the sustained combination of high wind, network limitations and expensive replacement energy.

These system conditions also affected:

- **Trades:** There was an increase spend on trades in September to £48.6m compared to £18.1m in August, to help manage constraints on the system.
- **Constraint Sterilised Headroom:** Costs increased as network constraints limited access to available generation headroom, reducing the flexibility available to balance the system.

Non-constraint costs were relatively flat month on month with a slight drop in costs from £81m to £74m. With almost all categories of non-constraints dropping except operating reserve. This is due to the increase in reserve costs driven by increased gas prices, high weather volatility and reduced flexibility.

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	0.25							0.18
Day Ahead APX (£/MWh)	82.5	104.8	100.2	106.7	132.7	134.9							109.3
Benchmark*	299	262	278	257	266	455							1817
Outturn balancing costs[1]	**307**	**239**	**319**	**301**	**242**	**553**							**1961**

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.

[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.

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.

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 £891m 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 £356m through work with TOs to increase network capability, £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

Day ahead prices

Day ahead power prices remained elevated and highly volatile throughout September, reaching their highest levels since 2023 at £133.94/MWh. Prices fell sharply on the 5th September (£64.84/MWh) and 20th September (£22.22/MWh), reflecting periods when strong wind and solar generation were sufficient to meet much of system demand. However, renewable output declined later in the day, increasing reliance of thermal generation to meet evening demand and contributing to intraday price volatility. Despite these periods of lower prices, wholesale power prices remained supported by elevated gas prices and reduced nuclear availability.

Gas prices

Gas prices increased significantly during September, averaging 189.93 p/therm compared with 150.69 p/therm in August, continuing the upward trend observed since June. Prices were 136% higher year on year, increasing the cost of replacing curtailed wind. On several high-cost days, low day-ahead and within-day prices reduced incentives for gas generation to run ahead of real time, requiring volumes to be turned up later through the Balancing Mechanism, often at significantly higher offer prices.

Market prices remained supported by ongoing supply concerns, including continued outages and maintenance affecting Norwegian gas exports to Europe. At the same time, extensive nuclear outages removed around some capacity from the GB system at certain points in the month, increasing reliance on gas-fired generation. Additional support came from heat-related nuclear curtailments in France, which reduced export availability and contributed to tighter power market conditions.

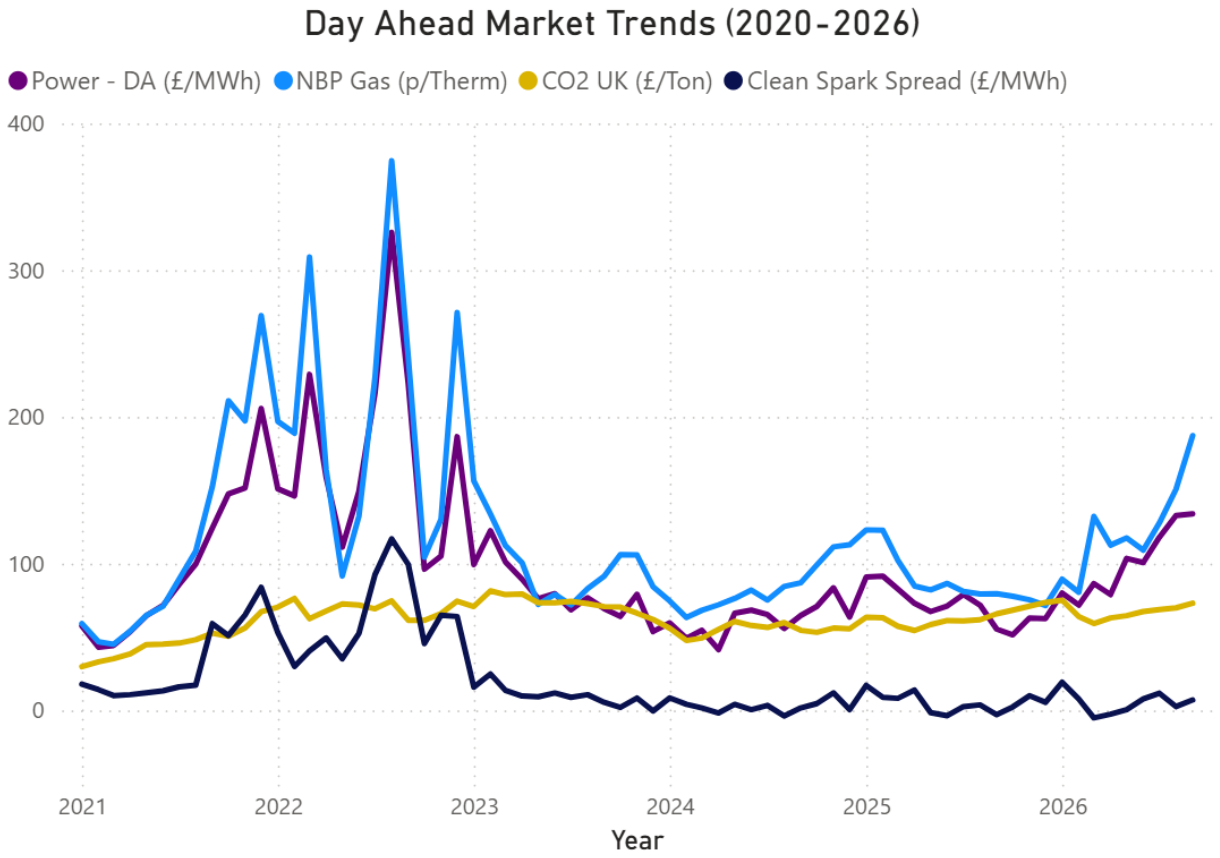
VWA bid/offer prices

The volume weighted average (VWA) bid price in September was -£3.14/MWh, compared with £42.43/MWh in August. This reflects the significantly higher volume of wind generation curtailed during the month, with wind bids accounting for 75% of total bid volumes. The increase in renewable curtailment marked a reversal of the trend observed in August and was consistent with the high levels of wind generation observed throughout September.

The volume weighted average (VWA) offer price increased to £211.97/MWh, continuing the upward trend observed throughout 2026 and standing 75% above September 2025 (£120.76/MWh). Higher gas prices increased the cost of replacement energy, while gas-fired units accounted for 50% of total offer volumes, reflecting the volume of replacement energy required across the month.

Carbon prices

Carbon prices increased from £69.84/t to £73.04/t during September. Despite strong renewable generation during parts of the month, elevated gas and power prices and reduced nuclear availability increased the expected reliance gas generation, providing support to carbon prices.



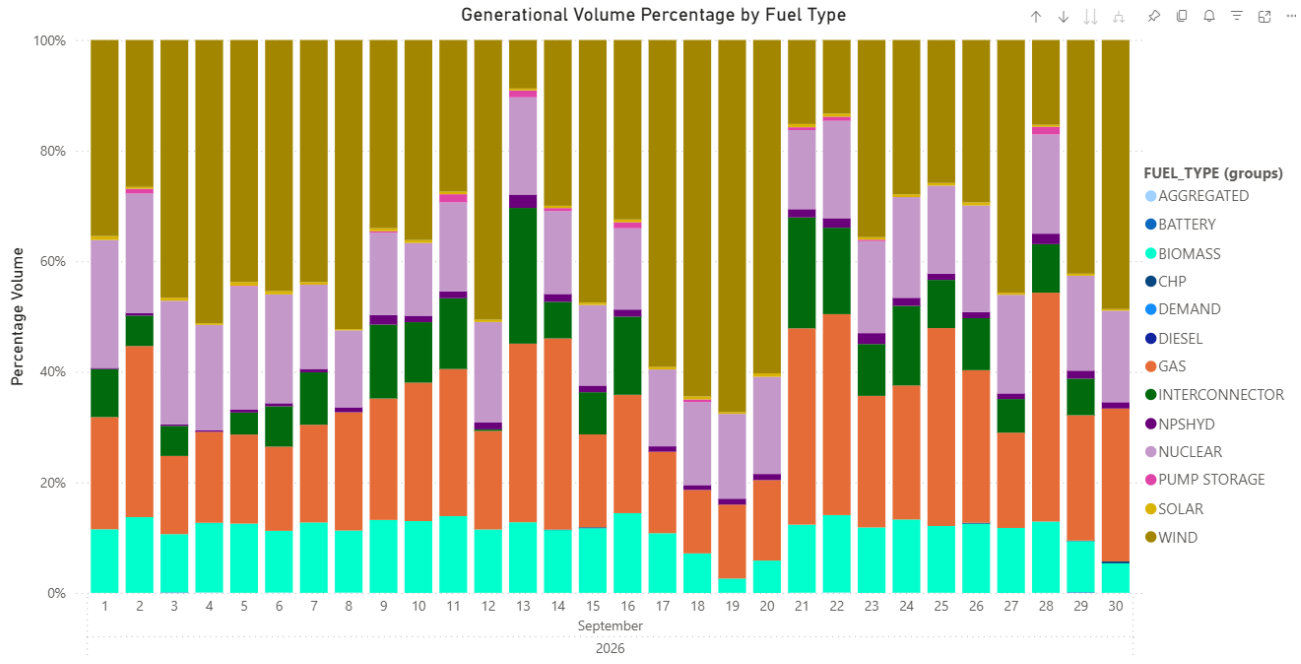
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation Mix

Wind generation increased to 39% of the total generation mix in September compared to 24% in August. This contributed to a reduction in reliance on gas-fired generation, which fell slightly month on month from 26% to 23% of the generation mix. Nuclear generation decreased from 19% to 17% because of outages across several units, while the contribution from interconnectors fell significantly from 17% to 8%, partly reflecting restrictions on interconnector trading.

Despite periods of lower renewable output, September was characterised by strong wind generation. Wind accounted for just 9% of generation on 13 September, the lowest level recorded during the month, before increasing to a monthly high of 67% on 19 September. Gas generation displayed the opposite trend, with lower contributions during periods of high wind output and increasing to around 36% on 22 September when wind generation weakened. The 19 September

recorded both the highest proportion of wind generation and the lowest proportion of biomass generation during the month.

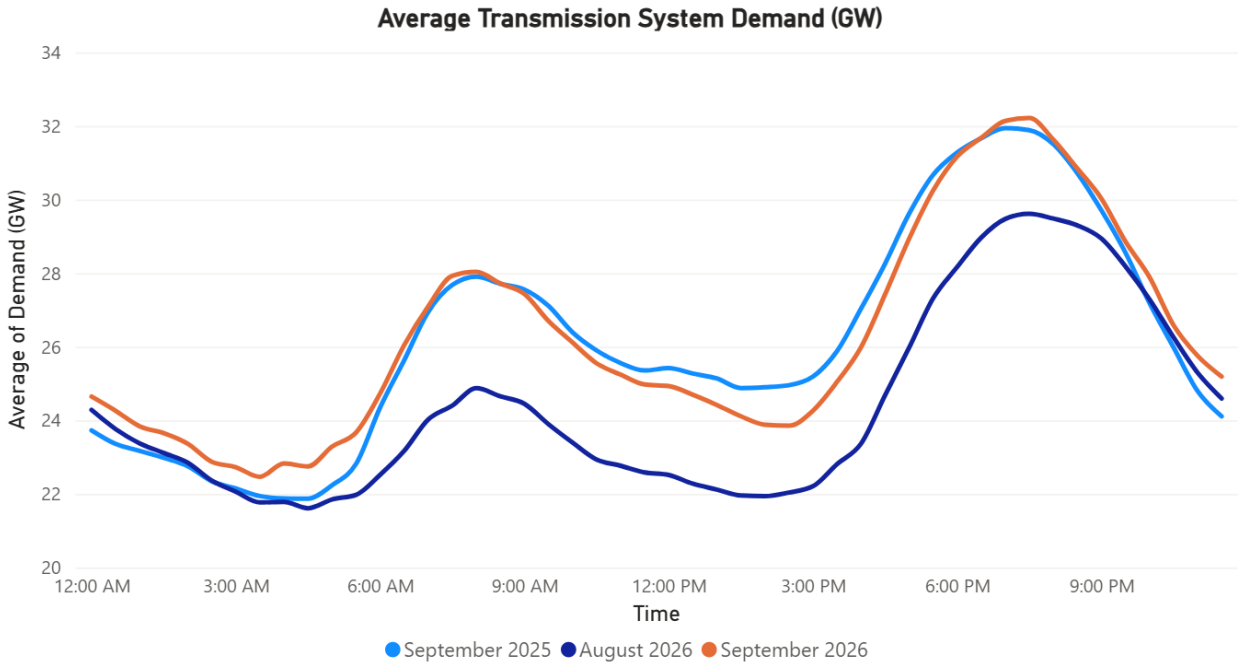


*Generation mix includes exports from interconnectors.

Transmission System Demand

Average Transmission System Demand (TSD) in September 2026 was higher than in August across all hours of the day. This was driven by lower temperatures, less daylight hours and a significant reduction in embedded solar generation, which fell from an estimated 5.4GW in August to 1.8GW in September. The increase in demand was most pronounced during the morning and evening peak periods, while overnight demand remained closer to August levels.

Compared with September 2025, demand was lower during daylight hours (09:00-18:00) but higher overnight and during the morning peak. Average demand ranged from a minimum of 22.5GW to a peak of 32.2GW during the month. September experienced above-average temperatures, resulting in lower-than-typical demand on the transmission system.



Wind Generation

Hypothetical wind outturn increased from 7.4 TWh in September 2025 to 7.9 TWh this September, reflecting the high level of wind available to the system. However, a significant proportion of this generation could not be accommodated due to network constraints, contributing to record levels of wind curtailment during the month.

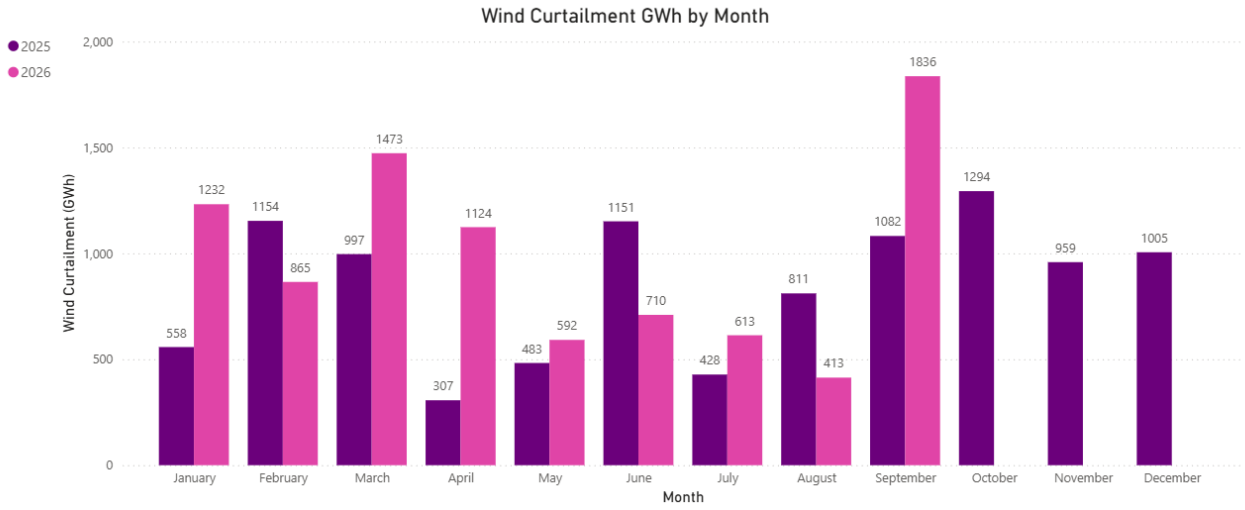
Actual wind generation totalled 6.1 TWh, compared with 6.4 TWh in September 2025, but increased compared with August. Generation reached 3.8 TWh in England and Wales and 2.2 TWh in Scotland. Wnd conditions varied considerably throughout the month, with several periods of particularly strong generation. Daily wind outturn reached 290 GWh on 4 September, 330 GWh on both 17 and 18 September, and peaked at 350 GWh on 19 September. Hypothetical wind outturn also reached its monthly peak of 481 GWh on 19 September.

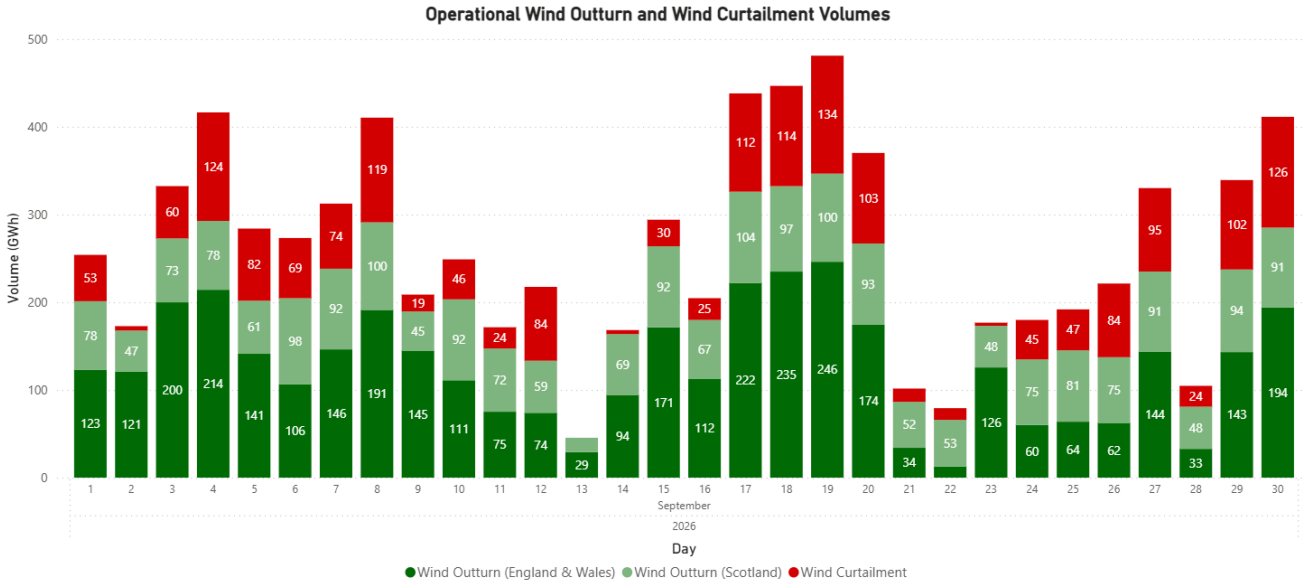
The combination of high available wind and restricted network capacity resulted in record wind curtailment of 1.8 TWh, an increase of 1.4 TWh compared with August. Transmission outages reduced transfer capability across parts of the network, amplifying the impact of high wind generation where power could not be transferred further South. Around 97% of curtailed wind volume was in Scotland, compared with just 0.7% in England and Wales, highlighting the concentration of the curtailment challenge in Scotland.

There were eight days with more than 100 GWh of wind curtailment: 4, 8, 17, 18, 19, 20, 29 and 30 September. The highest occurred on 19 September, when 134 GWh was curtailed alongside the month's highest hypothetical wind outturn of 481 GWh. Conversely, periods of lower wind saw

considerably less curtailment, with none recorded on 13 September and less than 5 GWh on 2, 14 and 23 September.

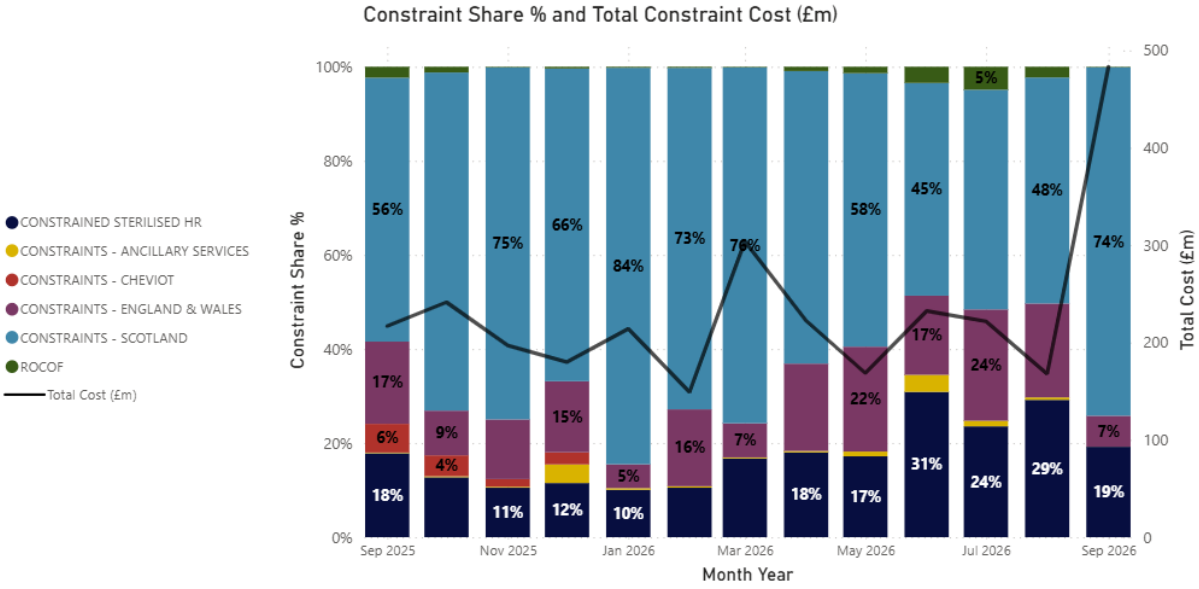
Towards the end of the month, conditions shifted from periods of high wind and significant curtailment to tighter operational margins during periods of lower wind. NESO issued a precautionary Electricity Margin Notice on 28 September covering the evening peak, driven by forecast low wind generation and reduced operational margins associated with transmission constraints. The notice was subsequently cancelled with no impact on customer supplies.





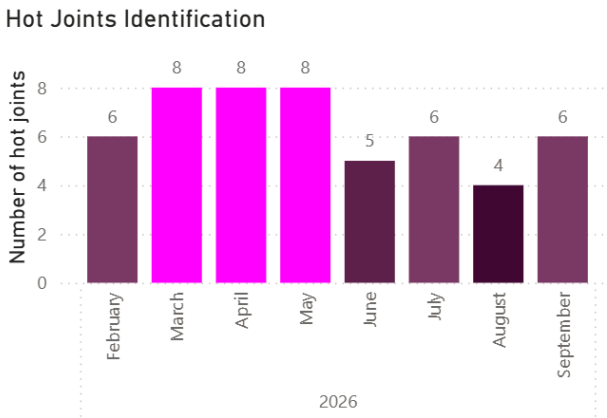
Constraints

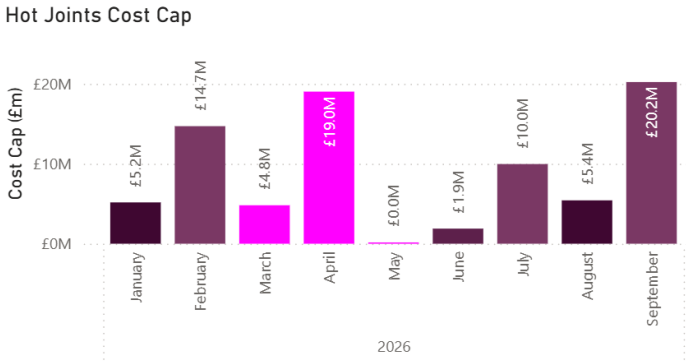
Constraint costs increased from £158.2m in August to £478.4m in September, an increase of £320.2m. The largest increase came from Scottish constraints at £261.9m although there was a small decrease in from constraint costs in England & Wales at £2.0m.



Network Availability

Hot joints refer to transmission equipment that tends to overheat during normal operational conditions. Transmission Owners are responsible for notifying NESO of any service reductions associated with this equipment. Hot joints in the system have both operational and economic





impacts. In September 2026, six hot joints were identified. The maximum cost is estimated in £20.2m .

Daily Costs Trends

September balancing costs totalled £553m, making it the highest costing month on record, greater than November 2021 which reached £542m. Average daily balancing costs were £18.42m, significantly higher than August's average of £7.7m. There were a large number of high cost days in September with 17 days during the month with balancing costs exceeding £15m, of which six exceeded £30m. In contrast, only nine days recorded costs below £10m.

The month's most expensive days were largely driven by periods of strong wind generation coinciding with active transmission constraints. This resulted in significant volumes of Scottish wind generation being curtailed and replaced by more expensive generation located in the South. Multiple network outages, thermal constraints, voltage requirements and power flow restrictions further limited system flexibility, while high gas prices increased the cost of replacement energy.

30th September – Highest Cost Day

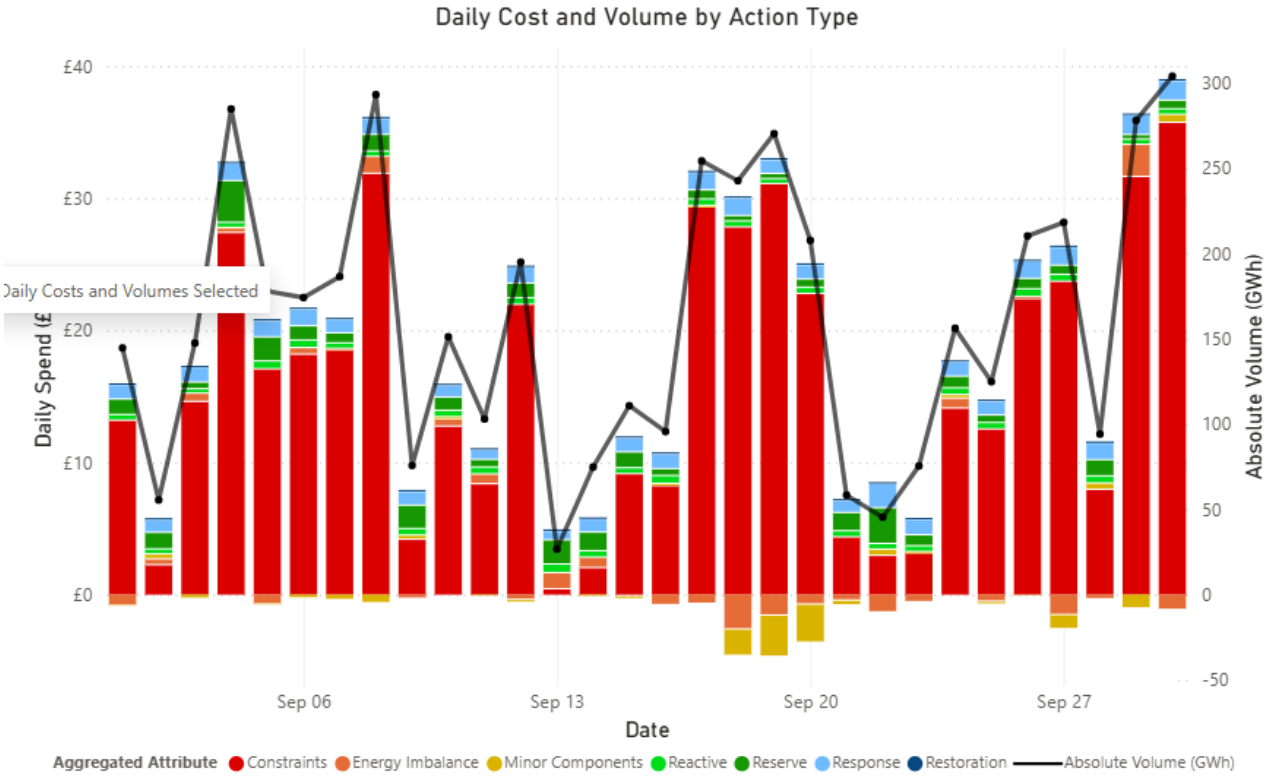
The highest-cost day of the month was 30 September, with balancing costs of approximately £38m, of which £36m related to constraint management. Around 86% of constraint costs were associated with thermal constraints in Scotland. High wind generation required substantial volumes of wind to be curtailed and replaced with expensive gas generation, while significant interconnector trades were required to manage constraints in England and Wales. The 30th saw the highest volume of actions for September reflecting how the high costs this month were driven by high volumes of action taken. Several plant issues during the evening peak, including unit trips and synchronisation difficulties, reduced operational flexibility and increased redispatch costs. Around £4.1m was spent on interconnector buy trades to manage constraints further increased costs.

8th September – Second Highest Cost Day

Costs on 8 September reached approximately £36m. With multiple constraints active on the system access to flexible generation was limited while a circuit trip in Scotland increased operational complexity. Interconnectors buy trades were required to help manage constraints as well as synchronising gas units in the South which needed to remain online overnight to provide replacement energy and voltage support. With high offer prices these factors combined to increase balancing costs despite high wind generation levels.

29th September – Third Highest Cost Day

Balancing costs reached approximately £35m on 29 September. Demand increased more rapidly than forecast while battery flexibility was restricted by several active network constraints. Several plant issues, including a generating unit trip, further reduced operational flexibility and created an additional generation shortfall, increasing the volume of costly balancing actions required.



High-Cost Day

The highest cost day of the month was the **30th September 2026.**

Breakdown of Cost and Volume

- Total cost: £38m
- Total Absolute Volume: 304 GWh

Balancing Costs detailed breakdown

Comparison Between September 2026, August 2026 and September 2025

Constraint Non-Constraint Group	Latest Month Total	Month Change	Year Change
Constraints	**£478.40**	**£320.18**	**£261.55**
CONSTRAINED STERILISED HR	£103.47	£54.51	£64.81
CONSTRAINTS - ANCILLARY SERVICES	£0.39	£9.01	£0.04
CONSTRAINTS - CHEVIOT	£0.00	£0.00	-£13.24
CONSTRAINTS - ENGLAND & WALES	£31.53	-£1.96	-£6.36
CONSTRAINTS - SCOTLAND	£342.43	£261.86	£220.76
ROCOF	£0.59	-£3.24	-£4.46
Non-constraints	**£74.12**	**-£7.23**	**-£2.24**
ENERGY IMBALANCE	-£3.18	-£9.65	-£2.05
FAST RESERVE	£5.72	-£2.11	-£8.28
MINOR COMPONENTS	-£9.33	-£7.01	-£9.48
NEGATIVE RESERVE	£0.83	£0.85	£0.24
OPERATING RESERVE	£18.11	£5.45	£8.50
OTHER RESERVE	£1.58	-£0.25	£0.24
REACTIVE	£14.39	-£0.94	£3.13
RESPONSE	£34.95	£6.13	£11.07
RESTORATION	£4.80	£0.29	-£3.81
STOR	£6.24	£0.01	-£1.79
Total	**£552.52**	**£312.95**	**£259.31**

*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, constraint costs increased by £320.2m since last month and non-constraint costs decreased by £7.2m. This results in an overall increase in costs of £313.0 compared with August 2026. Constraint costs increased by £261.6m compared with last year, reaching a record high of £478.4m. Constraint volumes hit a record high this month reaching 4088GWh, reflecting that a large driver of this month's costs were from curtailment.

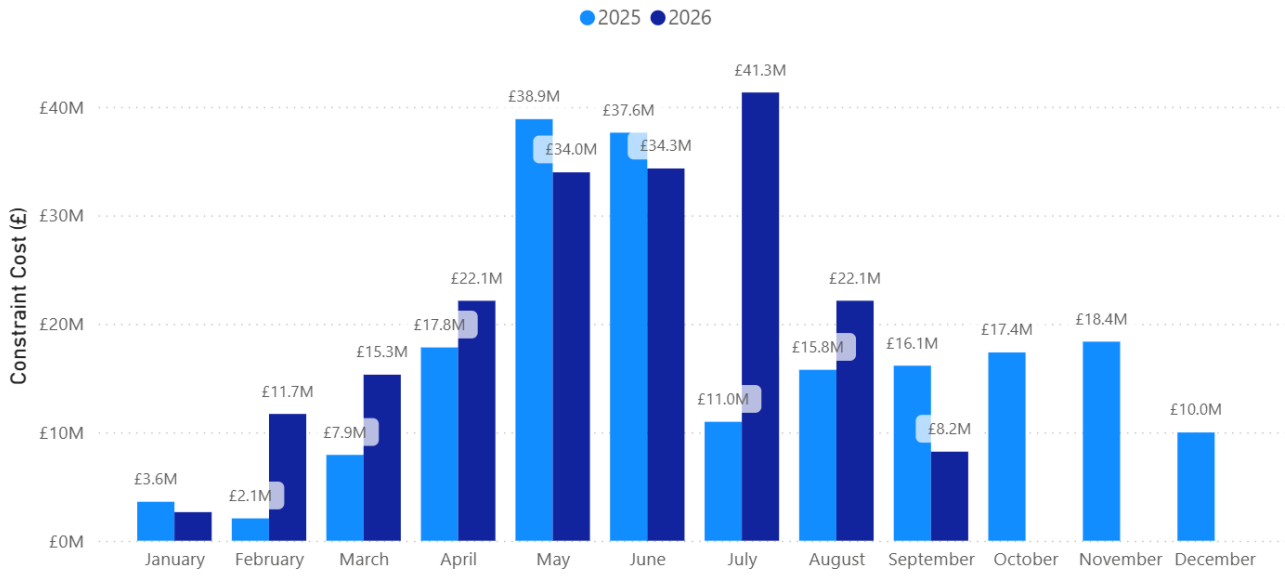
Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: £261.86m **Constraint – England & Wales: -£1.96m**	**Constraints – Scotland & Cheviot: -£220.76m**

Constraint Sterilised Headroom: £54.51m **Constraint volumes: 2116GWh** Constraint costs reached a record high in September due to a combination of high wind and low demand coinciding with restricted network capability, with higher energy prices increasing the cost of the actions required	**Constraints – England & Wales: £6.36m** **Constraints Sterilised Headroom: £64.81m** **Constraints volumes: 1384.26GWh** Compared with last year constraint costs were significantly higher. September 2026 was the highest on record at £478m. The absolute volume of constraint actions was also at a record high 4088GWh.

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

In September, the system synchronisation costs for voltage (what it costs to the system, which factors in energy replacement and headroom among others) were £8.2m, representing a decrease of approximately £13.9m compared to August 2026, and £7.9m lower than September 2025.

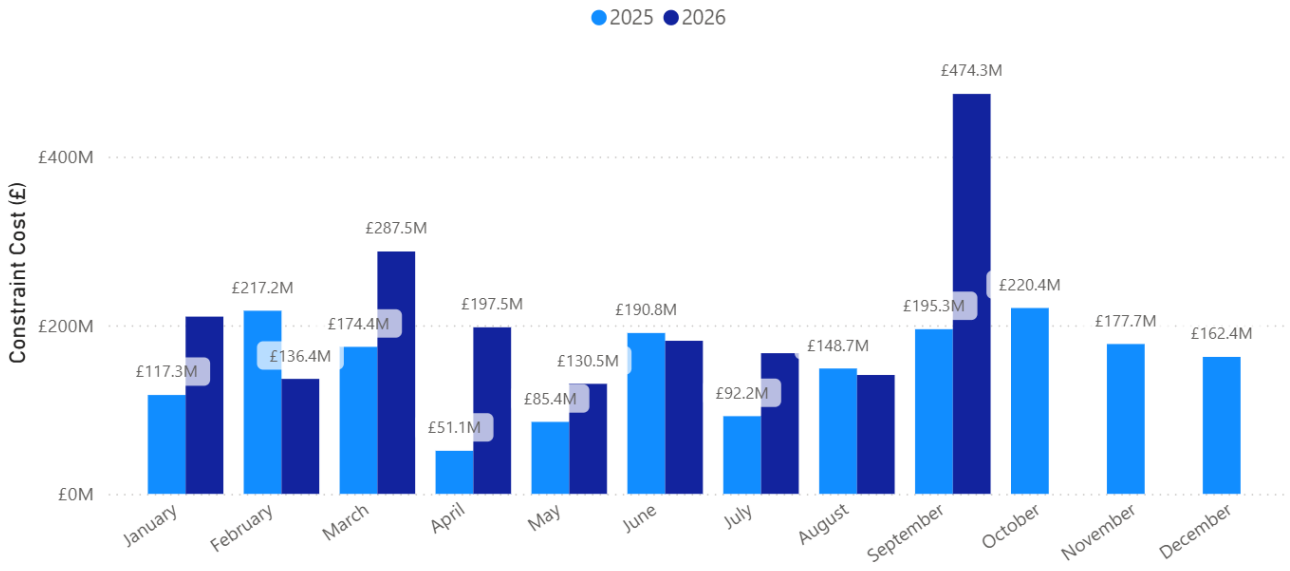


Voltage spending is usually higher overnight: lower demand means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism. Most voltage costs arise from the South-West region of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

Voltage costs reduced during September despite several voltage support requirements remaining across the network. Several voltage support assets and network reinforcements became available during the month, reducing the need to run generation solely for voltage purposes. Where voltage support units were required, they often also provided replacement energy, inertia or constraint management services, meaning that a greater proportion of balancing costs was attributed to these wider system requirements rather than voltage support alone.

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

In September, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £474.3m, reflecting an increase in costs of £333.3m compared to August (£141.0m). Thermal constraint costs hit a record high, overtaking the highest costing month in November 2021.



With wind curtailment volumes reaching record levels in September at 1.8TWh, a corresponding increase in thermal constraint costs was expected. The absolute volume of thermal constraint actions reached 2,372GWh, the highest level on record, making this the largest driver of balancing costs during the month.

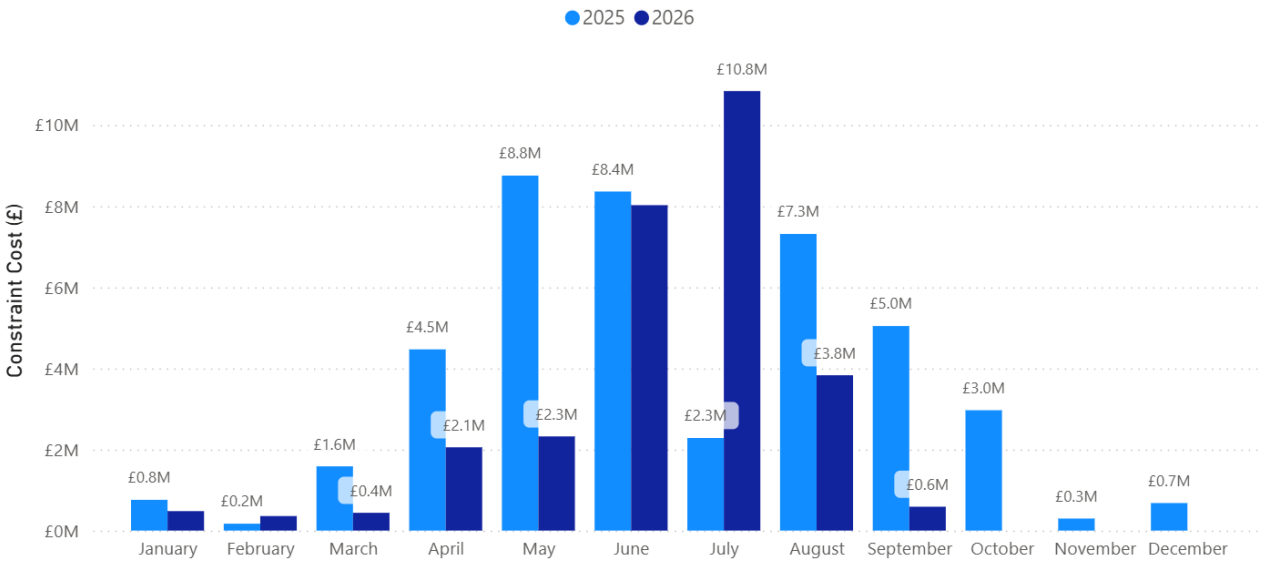
Thermal constraints in England and Wales only accounted for £29.6m. The largest rise was in Scotland which reached £444.7m. The increase in costs was primarily driven by sustained periods of high wind output, which resulted in large volumes of Scottish wind generation being constrained off and replaced by expensive gas generation elsewhere on the network. This was

due to ongoing outages in Scotland for reinforcement work which combined with high wind resulted in multiple active transmission constraints and therefore reduced network capability. As a result, significant volumes of expensive gas units were required to provide replacement energy and maintain system security.

Elevated gas prices further increased the cost of replacement energy, while interconnector trading and margin actions were required on several days to support system operation. Together, these factors resulted in thermal constraint costs reaching record levels during the month.

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

In September, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £0.6m, which was a decrease of £3.2m from August (£3.8m).



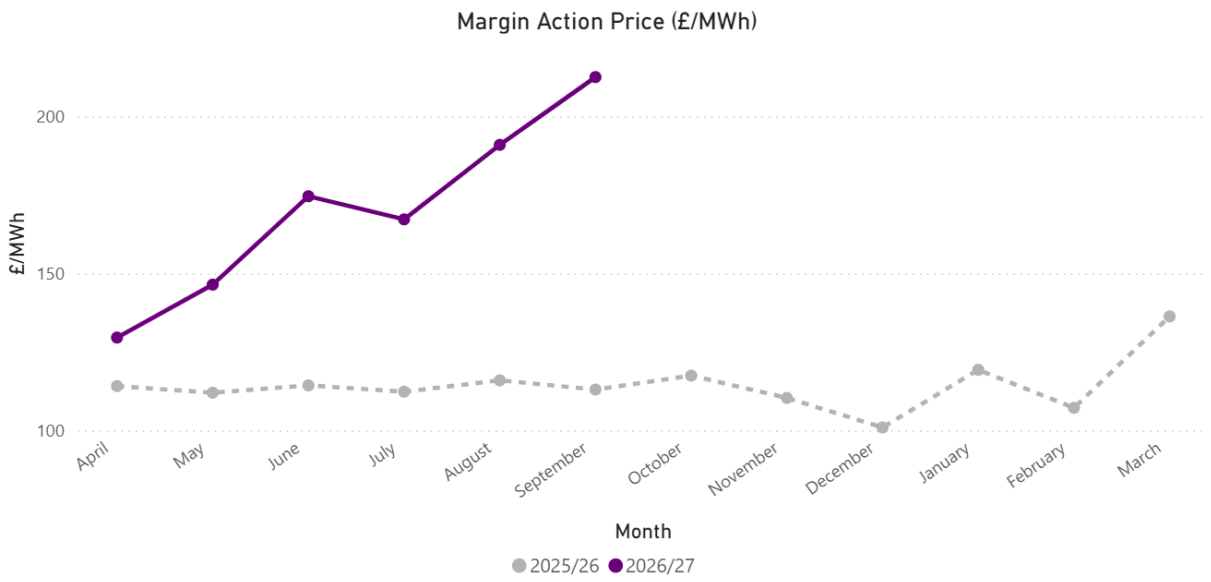
Inertia costs decreased during September despite overall balancing costs reaching an elevated level. The month was dominated by thermal constraint management and the replacement of curtailed wind generation, which required large volumes of gas generation to remain synchronised. As these units were already online for energy, margin and constraint management purposes, they provided inertia as a by-product of their operations, reducing the need for dedicated inertia actions. The availability of synchronous compensators and other stability supporting assets also helped meet system stability requirements without requiring additional inertia-specific interventions.

Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£0.9m Reactive costs have decreased on last month coinciding with higher transmission demand compared with August.	**£3.1m** Reactive costs have increased on last year.

Reserve Costs/Volumes

Reserve prices increased from £191/MWh in August to £213/MWh in September, which is a return to the upwards trend observed over the past financial year in line with gas prices increasing. This sharp rise is due to tight system conditions, volatile weather conditions and reduced flexibility on the system. With less spare generation available relative to demand and increased uncertainty of available generation reserve prices increase to their highest prices since January 2023.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year

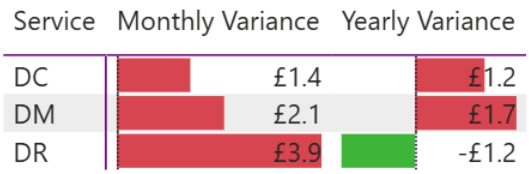
Operating Reserve: £5.4m **Fast Reserve: -£2.1m** There was an 888 GWh increase in the volume of operating reserve compared to August, due to tighter system conditions and reduced operational flexibility. Additional generation, batteries and interconnector support were frequently required to provide upward reserve particularly during evening peak. However fast reserve decreased due to generators being online to provide reserve capability. Despite a decrease in cost for fast reserve there was increase in volume for fast reserve of 19GWh.	**Operating Reserve: £8.4** **Fast Reserve: -£8.3m** There was a 776 GWh increase in the volume of operating reserve compared to last year, and a 0.23GWh decrease of volume for fast reserve.

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
£6.1m There was a 9.8 GWh decrease in the absolute volume of actions compared to August. Despite a reduction in volume we spent more on response due to increase is power prices.	**£11.0m** The volume of actions taken for response decreased by 35 GWh compared to September 2025, but due to an increase in power prices spending on response increased.

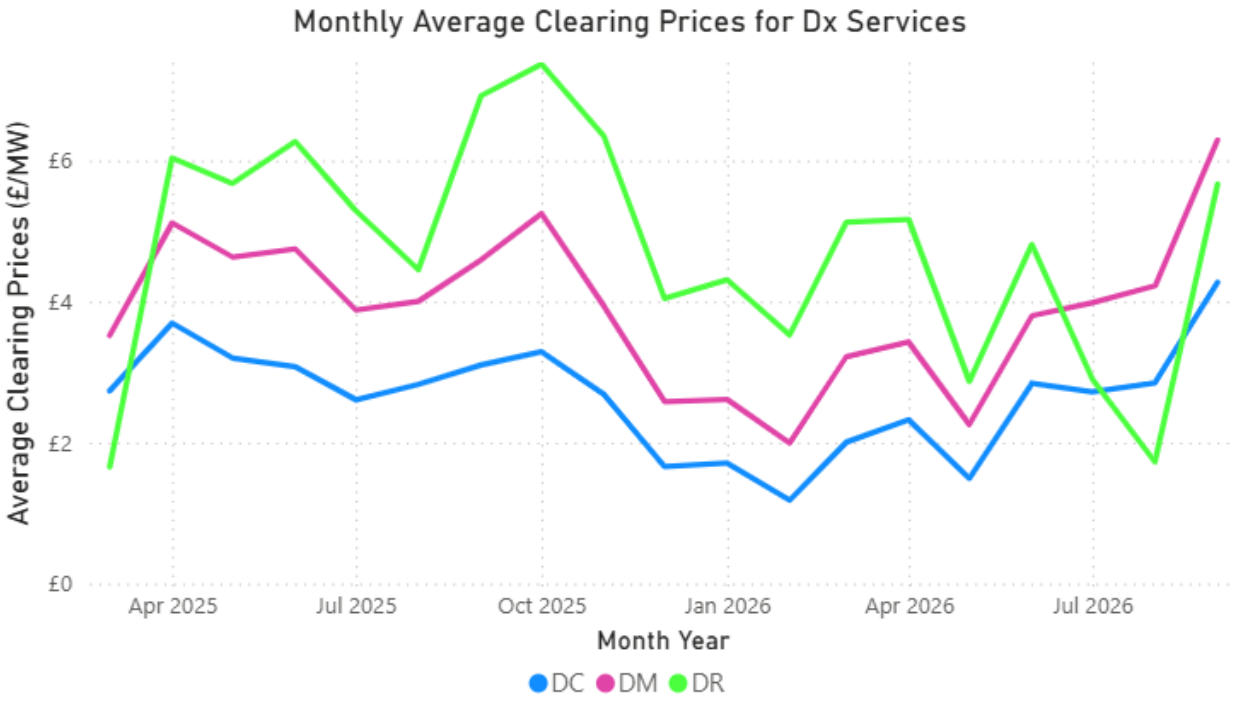
Comparison Between September 2026, August 2026 and September 2025



Average clearing prices for Dynamic Moderation (DM), Dynamic Containment (DC) and Dynamic Regulation (DR) increased between August and September, to £6.29/MWh, £4.27/MWh and £5.67/MWh respectively. With the largest rise coming from DR.

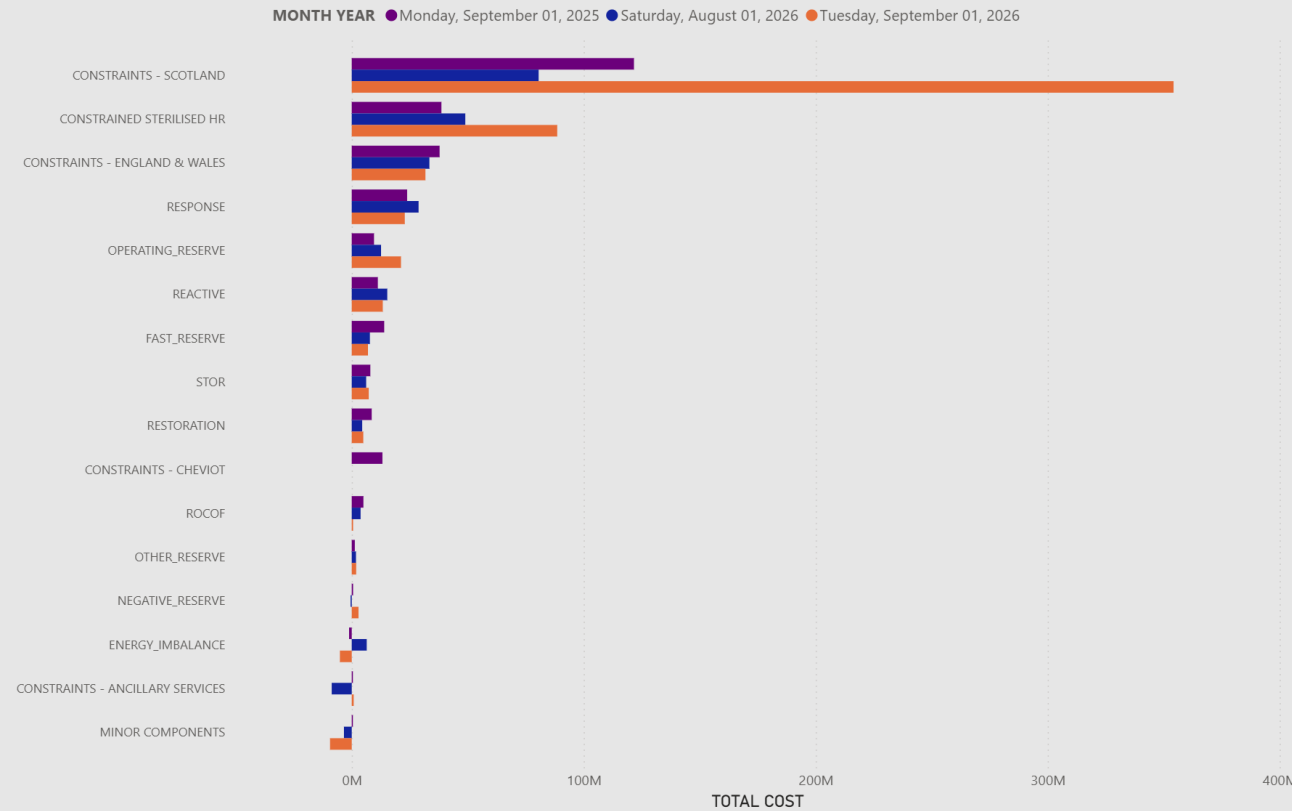
Compared to September last year, the average DC and DM prices have gone up whereas DR experienced a decrease in clearing price.

Dynamic clearing costs increased due to the tight system conditions, high day ahead and power prices and high market volatility in September led to higher DR, DC and DM prices.



Comparison breakdown

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



Cost Savings

Trading

The Trading team were able to make a total saving of £18.4m in September through trading actions as opposed to alternative BM actions, representing a 31% decrease on the previous month, though represents the third highest savings recorded in 2026. Trading for margin made up the greatest share of savings in September. Tight margins and the need to manage constraints in southeast England often resulted in NESO requesting additional volume from other TSOs above the 1500MW interconnector restriction limit, and contributed to the highest volume of buy trades observed since February 2025. There was also an increase in voltage trading, largely due to a circuit outage in the southwest requiring additional trading actions to operate the network securely, resulting in the highest monthly voltage savings observed in the last 12 months at just under £5m. The day with the greatest trading savings was on 10 September at £2.4m with the greatest savings being made for actions taken to manage margin. The day with the greatest spend on trades was 28 September at a cost of £4.6m, with the greatest component also 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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