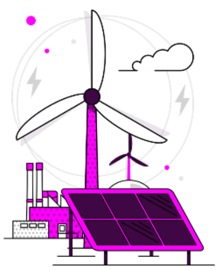
23 July 2025

Quarterly (Q1) Incentives June 2025 Report

Business Plan 3 (2025-26)

NESO
National Energy System Operator

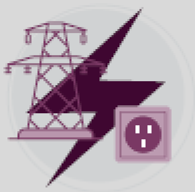
Contents



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

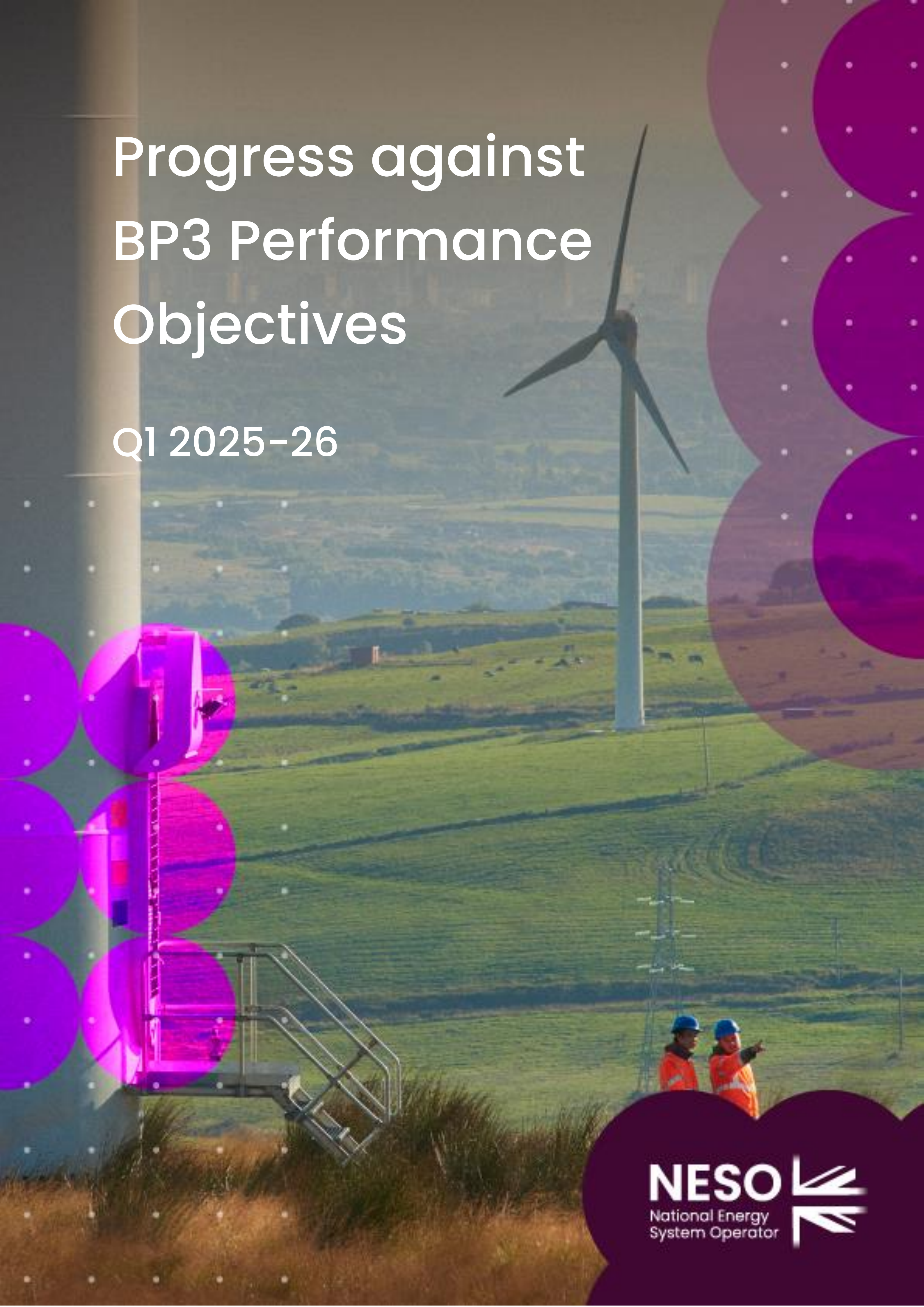
Following our BP2 submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The objective of the CMF is to provide visibility of our BP2 Digital, Data and Technology (DD&T) delivery progress and cost management, and the value being delivered across the DD&T investment portfolio. 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.

Progress against BP3 Performance Objectives

Q1 2025-26



NESO
National Energy System Operator

Performance Objectives Summary

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.

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.

The below table shows the status for each Performance Objective as at the end of the previous quarter. This is followed by more detailed updates for each Performance Objective including progress updates for their associated Success Measures.

Performance Objective	End-Q1 25/26 Status	Status change
Strategic Whole Energy Plans	🟡	n/a
Enhanced Sector Digitalisation and Data Sharing	🟡	n/a
Fit-for-Purpose Markets	🟡	n/a
Secure and Resilient Energy Systems	🟡	n/a
Operating the Electricity System	🟡	n/a
Connections Reform	🔴	n/a
Clean Power 2030 Implementation	🟢	n/a
Separated NESO Systems, Processes and Services	🟡	n/a

🟢 On track / no risk

🟡 At risk

🔴 Significant challenges

Performance Objective	Status	Status change
Strategic Whole Energy Plans We'll establish our capabilities, and the foundations and methodologies to deliver national and regional strategic whole energy plans.		n/a (since last quarter)

Summary of progress this quarter in delivering this PO outcome
SWEP is progressing with two success measures completed in the last quarter relating to the publishing of the SSEP methodology and the first quarterly regional forums being convened. The draft CSNP methodology was published, including hydrogen and is now in consultation. The refresh of the tCSNP methodology is currently off-track due to delays with inputs and we are in discussions with Ofgem regarding an extension to the deadline.

Progress on Success Measures this quarter
Submit the first SSEP pathways document to the UK Energy Secretary by the end of 2025. The SSEP methodology was approved and published in May, with progress made on modelling and pathway development. Challenges have caused some delays, but the pathway options report is expected to be submitted by December 2025.
Publish the Transitional Centralised Strategic Network Plan 2 Refresh Methodology (tCSNP2) report by 31 January 2026. The refresh of the tCSNP report is currently off track due to delayed inputs from the Future Energy Scenarios (FES) processes. The delay has arisen due to dependencies on both internal processes and late data from external third parties. Discussions are currently ongoing with Ofgem to agree a new proposed delivery date, and this will also take the opportunity to align with wider developments such as the outputs of Connection Reform and SSEP.
Publish the approved strategic energy planning methodologies within the specified timelines: SSEP methodology by May 2025; CSNP methodology by September 2025. The SSEP methodology was published on 15 May 2025 following approval from the Secretary of State for Energy Security and Net Zero and Ofgem. The CSNP methodology is progressing well, with the draft methodology published on 30 June 2025 and the consultation closing on 1 August 2025. Submission to Ofgem is on track for the 30 September 2025 deadline, ensuring alignment with national and regional plans and stakeholder feedback.
Publish the RESP methodology consultation by November 2025. We have agreed the approach to the RESP methodology with Ofgem and shared an outline of the proposed structure/content. We have also mobilised technical Working

Groups and appointed a technical partner to help us through the methodology design work which is now underway.
Publish RESP inputs to Electricity Distribution-3 price control as agreed with Ofgem by March 2026. Detailed design work has focused on pathways, planning assumptions, strategic investment need, and regional context, supported by stakeholder engagement and regional forums. Key consultation planned for September 2025 to enable completion in early 2026.
Publish the Gas Options Advice Document (GOAD) by 31 December 2025. The project is progressing well despite facing challenges with internal resources and delivery timescales. We are on track with the GOAD and hydrogen network planning, with significant achievements in data acquisition, methodology approval, and stakeholder engagement.
Establish hydrogen network planning activities by 30 March 2026, including, where relevant, proposals to extend the 2026 Gas Network Capability Needs Report (GNCNR) to cover hydrogen network requirements. We are progressing well with hydrogen network planning, having published the high-level methodology as part of the whole system CSNP consultation, and will continue to refine the methodology based on stakeholder feedback. This integration demonstrates our commitment to a whole-system approach, optimising energy network infrastructure costs across electricity, gas, and hydrogen.
Build capability and establish regional teams with at least five full-time equivalents (FTEs) per RESP region by December 2025. Convene the first quarterly Regional Forum for each region by May 2025, to support transitional RESP and RESP development. The initial target of 5 FTE per region by the end of December 2025 will provide a minimal level of resource to achieve regional presence and drive initial delivery/forums whilst also embedding initial core capabilities into the team. 9 of the 11 regions/nations (81%) have already achieved this targeted figure of 5 FTE with the remaining regions on target for the end of December 2025. The first conventions took place on 11 April 2025. Total attendance at the first round of quarterly forums was 1,263, and one of the key lessons captured was to enable more stakeholders input into those forums.
Progress on additional Ofgem expectations
No updates for Q1
Progress towards PO not captured by the Success Measure reporting above
No updates for Q1

Performance Objective	Status	Status change
Enhanced Sector Digitalisation and Data Sharing By working with the energy sector, we'll develop an aligned and interoperable digital ecosystem driving industry digitalisation collaboration utilising innovation, underpinned by transparent data sharing and access.		n/a (since last quarter)

Summary of progress this quarter in delivering this PO outcome
We have made significant progress in several key areas, particularly in the Data Sharing Infrastructure (DSI) development. The DSI pilot and Minimum Viable Product (MVP) are on track with risks around procurement and the MVP use case. The sector digitalisation plan is set for delivery in August without issues. Plans include reviewing processes to enhance data throughput and exploring promotional activities with Corporate Affairs.

Progress on Success Measures this quarter
Publish a sector digitalisation plan study by the end of April 2025. *Note: As agreed with Ofgem the date for this success measure has moved from April 2025 to July 2025.* The publication is planned to be delivered in August. There are no identified risks to plan. Review copies were shared with Ofgem, DESNZ, Elexon, DCC, RECCo and experts including the Royal Academy of Engineering. Feedback is being incorporated into the plan.
Establish Data Sharing Infrastructure (DSI) for the industry, with Minimum Viable Product (MVP) readiness by the end of September 2025. *Note: As agreed with Ofgem the date for this success measure has moved from September 2025 to March 2026.* The DSI pilot has been successfully completed, and MVP development is underway with revisions based on pilot insights. All plans are on track for March 2026 with two risks identified, procurement framework and the need to clarify the exact MVP use case to be delivered.
Fully implement the interim Data Sharing Infrastructure (DSI) Coordinator role (subject to consultation outcomes) by the end of 2025. The DSI pilot was successfully completed, and the MVP development is on track with no identified risks. Recruitment for the interim DSI team is ongoing, ensuring systems are in place by the end of 2025.

Improve the Open Data Portal by increasing the availability of shareable energy data and embedding a more comprehensive data catalogue for greater transparency. The Open Data Portal is on track to incorporate new data catalogue capabilities for better user experience by end of 2025.
Increase distributed energy resources (DER) visibility through improved registration and forecasting. Efforts to improve distributed energy resources (DER) visibility through registration and forecasting continue, though there are deliverability risks.
Progress on additional Ofgem expectations
No updates for Q1
Progress towards PO not captured by the Success Measure reporting above
No updates for Q1

Performance Objective	Status	Status change
Fit-for-Purpose Markets We'll 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.		n/a (since last quarter)

Summary of progress this quarter in delivering this PO outcome
The performance objective is currently at an amber status with mixed progress against the success measures. The early competition success measure is off track. The programme is suffering unexpected delays in identifying a qualifying onshore project, this is due to factors largely outside of NESO's control. Market engagement and regulatory milestones have progressed but timelines must be revised to reflect the ongoing project identification challenges. Shortly after the end of Q1, we received ministerial decision that the UK would retain national wholesale pricing rather than zonal. The government has committed to publish a Reformed National Pricing Delivery Plan later this year. We will support the creation of this delivery plan and will need to consider the impact on current programmes of work.

Progress on Success Measures this quarter
Report the volume of services procured competitively. The proposed targets for BP3 are: Constraints: 100%, Frequency Response and Reserve: 90%, Reactive: 5% Q1 Performance: Constraints: 100% Frequency Response and Reserve: 85.4% Reactive: 4.2% For Q1, constraints competitive procurement % was in line with the full-year target (100%). Whilst Frequency Response & Reserve and Reactive were slightly below the full-year targets, the % are an improvement compared to BP2 (82.5% and 3.8% respectively). We expect to continue to see improvement through BP3.
Deliver quality analysis required for the REMA programme to reach a successful conclusion and move into the implementation phase. We will evidence engagement with a broad range of customers and clearly demonstrate how their feedback has been fully considered in our work. During Q1, NESO teams continued to provide analysis to the REMA programme on a range of relevant topics including market design and implementation preparation.

On 10 July 2025 DESNZ announced their decision on REMA to retain a single national wholesale price with subsequent reforms to existing arrangements. The NESO REMA Programme is considering the broader impact and will re-plan accordingly.
Deliver against the Markets Roadmap to be published in April 2025. • **Improved capability to manage frequency, and a level playing field for response providers.** • **New and improved procurement processes for ancillary services, such as stability and reactive power.** • **Deliver the actions needed to support the objectives of our Enabling Demand Side Flexibility report, including the Routes to Market Review (as per the planned timeline).** The 2025 Electricity Markets Roadmap was successfully published in April 2025, detailing our market design principles and plans for NESO markets. Good progress has been made in market development work for day ahead reactive power and stability markets, static recovery, the Demand Flexibility Service, locational procurement of response and reserve, and instructible dynamic response. There is currently a delay in the go-live of Quick Reserve Phase 2 compared to our original plan. A revised go-live is targeted for the end of August to allow time for resolution and market participant onboarding.
Publish the first draft Gas Future Markets Plan for consultation and review. We will also lead and set the direction of the Future of Gas Steering Group and Forums which will support in providing a review done with effective industry engagement. We continue to engage relevant gas market participants via the Gas Advisory Council (GAC), which has prioritised five projects for the Gas Future Markets Plan. At the most recent GAC, three projects were approved to proceed, while two require further detail. Regular bilateral meetings with key stakeholders have been established, including to ensure clarity around project scope and NESO's role.
Engage with decision-makers and customers across energy vectors to move towards greater whole energy market coordination, collaborating to assess and prioritise our activities. Evidence engagement with a broad range of customers and clearly demonstrate how their feedback has been fully considered in our work to develop proposals in areas where there is benefit from improved whole energy market design coordination. The Whole Energy Market Strategy was published during July 2025, offering an independent view of cross-vector market interactions and opportunities for greater coordination. We are now moving into the next phase of this work, continuing to collaborate with a broad range of stakeholders to further develop the work.

As Code Administrator for the CUSC, Grid Code, STC and SQSS, NESO will ensure that these codes are administered in an independent, fair manner in accordance with CaCOP standards. Positive feedback from our Independent Panel Chair, Panel Members and industry in relation to our performance as Code Administrator. The Connection and Use of System Code (CUSC) and System Operator – Transmission Owner STC (code) modifications for connection reform were implemented as per the Authority decision letters, and industry and NESO are actioning the required changes.
First Early Competition pre-qualification launched by the end of 2025 and Invitation to Tender launched by the end of March 2026. Deadlines met with sufficient market interest to run an effective procurement event. This success measure is currently off track due to delays in identifying a qualifying onshore project, driven by the timing of the tCSNP2 refresh and Ofgem's new guidelines. Whilst market engagement and regulatory milestones have progressed, the first tender timeline must be revised to reflect the ongoing project identification challenges.
Implement Capacity Market and Contracts for Difference regimes for CP30 and operate the markets effectively. • **Implement system and process guidance changes required to enable CP30 and wider policy objectives in line with DESNZ and Ofgem consultation decisions ready for the CM and CfD rounds opening summer 2025.** • **Provide support for CM and CfD customers enabling participation in the schemes through maintaining guidance, offering points of contact and in running industry webinars.** • **Deliver continuous improvements to CM and CfD systems and processes against prioritised customer enhancements.** We are on track to open the Capacity Market 2025 round and Contracts for Differences (CfD) Allocation Round 7 in August 2025.
Progress work to enable the realisation of the demand side flexibility required to achieve CP30, including through NESO markets. The programme of work for NESO to enable more demand-side flexibility in NESO's markets was outlined in our report published in December 2024. This requires a range of activities across NESO and beyond. We are currently setting up the internal programme management required for delivery. NESO has worked with DESNZ and Ofgem to develop a joint roadmap, which is due to be published shortly.
Progress on additional Ofgem expectations
Evidence how market reform has resulted in greater market compliance with NESO's Market Design Framework, shown through an update of the 2023 assessment by a competent third party or equivalent.

No updates for Q1 **Evidence how NESO has proactively engaged with the Market Facilitator ahead of its launch, such that development of market rules and delivery of benefits is enabled as soon as possible from go-live (and earlier where relevant). NESO should also continue to work with the Open Networks programme, delivering on actions where relevant.** NESO has been engaging regularly with Elexon and Ofgem on the workings and establishment of the Market Facilitator. We have provided input through Elexon's governance consultation and will respond to Ofgem and Elexon's consultation on licence changes and the flexibility market rules through 2025. **Evidence how NESO has engaged proactively in the identification of GB rule changes (including relevant industry codes and standards) and has worked to affect change positively to the benefit of the GB consumer.** No updates for Q1
Progress towards PO not captured by the Success Measure reporting above
No updates for Q1

Performance Objective	Status	Status change
Secure and Resilient Energy Systems We'll improve whole energy system emergency preparedness and resilience. We will ensure we are on track to have the capabilities and requirements in place and facilitate industry readiness to meet the Electricity System Restoration Standard.		n/a (since last quarter)

Summary of progress this quarter in delivering this PO outcome

This Performance Objective tracks amber with no tangible risks to delivery.

The Summer Outlook report and Summer Readiness reports have been successfully published at the end of April as planned. The Electricity Capacity Report (ECR) has been submitted to DESNZ and Ofgem and is due to be published in July in line with BP3 timelines.

An extension to the first Energy Resilience Assessment which was due at the end of June has been approved to 27 July to reflect the learnings from the North Hyde investigation.

Due to the extent of dependencies, the success measure relating to the target of delivery of 95% capability and arrangements to meet new ESRS by December 2026 has some risks. We are collaborating closely with Ofgem and the Distribution Network Operators to identify and implement the necessary actions to realign this project with its intended timeline.

All other success measures are currently on track.

Progress on Success Measures this quarter

Deliver 95% of capability and arrangements to meet the Electricity System Restoration Standard to restore 100% of Great Britain's electricity demand within five days.

Several initiatives are underway to meet the restoration standard. Key deliverables include the Restoration Decision Support Tool (RDST) and ICCP links, will assist in meeting network restoration. Phase one of the RDST is expected to be delivered in March 2026, aiding control room decisions. Enhancements to ICCP links are needed for secure communication.

Additional key actions are being implemented to ensure the standard of restoring 60% demand in 24 hours is met and these actions are being implemented via Ofgem and DNOs. They include speeding up demand block loading, improving power island stability, and expanding distribution restoration zones.

Produce the first Energy Resilience Assessment by 30 June 2025. We will evidence engagement with a broad range of customers and clearly demonstrate how their feedback has been fully considered in our work.

An application was approved by Ofgem on 27 June 2025 to extend the deadline for the Energy Resilience Assessment report from 30 June 2025 to 27 July 2025. Delivery is on track

based on the new deadline with 90% of sprints completed. Some risks to deliverability have been identified however these are being managed.
Publish the electricity Summer and Winter Outlook Reports by 30 April 2025 and 31 October 2025. We will evidence collaboration with industry partners, including National Gas, which prepares the *Gas Winter Outlook*, to ensure there are 'no surprises'. The Summer Outlook Report was published in line with expected timelines (30 April 2025). The Winter Outlook Report is due by 31 October 2025. This report is on track and currently being compiled and reviewed.
Submit to DESNZ and Ofgem the Summer and Winter Readiness Reports by 30 April 2025 and 31 October 2025. The Summer Readiness Report was submitted in line with expected timelines (30 April 2025). The Winter Readiness Report is due by 31 October 2025. This report is on track. Stakeholder engagement planning and survey question preparation is currently underway.
Publish the Gas Supply Security Report by 31 October 2025. Recommendations of the *Gas Supply Security Report* will be evidence-based, considering the impact on the whole energy system, and will be adopted by the government and Ofgem. The drafting of the updated methodology report is complete, and further engagement with DESNZ, Ofgem and National Gas is underway.
Submit the Electricity Capacity Report to DESNZ by 1 June 2025. Recommendations in the Electricity Capacity Report are adopted by government. DESNZ's Panel of Technical Experts remark positively on the quality of the modelling in their published report. The ECR Report has been submitted to DESNZ and Ofgem and is due to be published in July.
Deliver the programme to look at the longer-term resilience of our control operations. We are currently assessing options on how to ensure and safeguard operations alternative and back up operations are being considered. Due to the sensitive nature of this programme, we will not be providing detailed information for security reasons. However, we will work closely with Ofgem to ensure effective outcomes and efficient spending on this project.
Progress on additional Ofgem expectations
Establish the capability to fully meet Parts A, Energy risk and threat advice, and B, Post-event and post-emergency analysis, of our Energy resilience and resilience reporting licence condition obligations. **Provide the Emergency Processes Assessment to Ofgem and DESNZ by 1 December in line with our licence obligation.**

Continue to work on medium-term adequacy modelling, building on the developments made in BP2 including: - **the Electricity Capacity Report and the annual cycle of development projects to enhance the modelling; and** - **adequacy modelling, including assessment of the 2030s, looking beyond the time horizon set out in CP2030 which now includes a new, dedicated assessment of gas supply security to be produced by 31 October each year.** No updates for Q1
Progress towards PO not captured by the Success Measure reporting above
No updates for Q1

Performance Objective	Status	Status change
Operating the Electricity System 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		n/a (since last quarter)

Summary of progress this quarter in delivering this PO outcome

We continue to operate the electricity system safely and efficiently while progressing towards zero-carbon operation by end-2025. Progress in the FRCR project means there is a potential operational window identified for December. Ofgem approval is pending on inertia levels.

The Balancing Cost Strategy and Annual Report was published in June, enhancing transparency, though skip rate reduction remains challenging. Daily publication of detailed skip rate datasets, including new technology-specific metrics, supports future analysis, and methodology development for constraint-driven skips is underway. Overall the Dispatch Transparency Programme roadmap delivery is on track and risks being actively managed.

The Balancing Programme is progressing well, with key deliverables such as the National Optimiser and real-time prediction system on track. Forecasting capability has been strengthened through the delivery of the Restoration Demand Forecast and ongoing system audits. While frequency performance remains stable, voltage events are under review following a June excursion, with a Post Event Report due on 18 July. Overall, the programme is progressing across all fronts with areas of active risk management and strong delivery momentum.

Progress on Success Measures this quarter

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).

Progress against this success measure has improved over the last month driven by progress in the Frequency Risk and Control Report (FRCR) project. This project is crucial for achieving zero carbon operations.

In Q1, the monthly average highest ZCO was 89.0% which is 0.9% higher than the previous quarter's average of 88.1%. Please see the Reported Metrics section of this report for more information related the Zero Carbon Operability Indicator and Carbon intensity of NESO actions metrics.

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. Opportunities are continually being identified to enhance understanding and accessibility of balancing costs. The Balancing Cost Strategy was successfully published on 12 June 2025 along with the Balancing Costs Report. Further details are available in the previous incentives report. In Q1, balancing costs totalled £691m. Please see the Reported Metrics section of this report and previous incentives reports for further updates related to the Balancing Costs metric.
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. **Share Platform for Energy Forecasting (PEF) and skip rate data, as well as issuing data associated with other strategic platform energy releases.** **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 5-stage post system action methodology and any updated methodology agreed with industry.** See the Reported Metrics section for updates related to the Skip Rates metric. We are progressing on track against our programme roadmap and have adjusted the timing of methodology refinements following stakeholder feedback. Whilst the trend for skip rates currently remains relatively flat, we are progressing our root cause analysis work to identify causal factors. We continue to improve transparency with expanding the data sets we publish, now including skip rates by technology type and engaging stakeholders through drop in sessions and the Operational Transparency Forum (OTF). Methodology development for constraint-driven skips is underway but remains in early stages. Work to define a target for skip rates will commence later in the Autumn.
In BP3, we will deliver new products and capabilities in accordance with our Balancing Programme, following our industry-agreed roadmap. The Balancing Programme is on track to deliver against our BP3 plan. The roadmap is challenging but on track to deliver all high level BP3 outcomes in FY26.
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).

Enhanced forecasting capability is key to enabling secure and economic balancing decisions through the energy transition. We will develop and publish our Forecasting Strategy for consultation by October 2025, followed by a corresponding delivery plan by February 2026. We will implement any initiatives specified in our delivery plan that are due within BP3. See the Reported Metrics section for updates related to the Wind and Demand Forecasting metrics. We have successfully delivered a new Restoration Demand Forecast capability, while also initiating external customer engagement for the development of our Forecasting Strategy. We are continuing with a wider systems audit, with an aim to improve our Grid Supply Point (GSP) forecasts used in the Network Access Planning & Electricity National Control Centre (ENCC) functions.
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 11). There were no frequency or voltage excursions in April and May. On 19 June there was one one frequency excursion below 49.7Hz lasting 66 seconds. On 29 June there was one voltage excursion. The excursion occurred in the Southwest of England lasting for longer than 2 hours. A Post Event Report (PER) is expected on 18 July.. Please see the Reported Metrics (Security of Supply) section of this report for further information related to these events.
Progress on additional Ofgem expectations
Progress against additional expectations related to skip rates covered above.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q1

Performance Objective	Status	Status change
Connections Reform 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.		n/a (since last quarter)

Summary of progress this quarter in delivering this PO outcome
Connections Reform is broadly on track at the end of Q1, in terms of delivery but significant challenges are anticipated. Since the end of Q1 there have been technical issues with the Connections Reform evidence portal which are affecting stakeholders, applicants, and our ongoing programme work. We remain dedicated to addressing these challenges and ensuring that all parties who wish to submit evidence are able to do so. The Executive Leadership Team, together with our committed staff, are diligently addressing concerns in a timely manner to ensure the programme remains aligned with its objectives and delivers as intended. At time of publication of this report, we have confirmed that the Connections Reform Evidence Submission Window will be extended by at least five working days beyond the original deadline day of 29th July 2025. More information will follow in next quarter's update.

Progress on Success Measures this quarter
100% of the projects that enter the Gate 2 to Whole Queue process will have connection offers by the end of December 2025. Preparation and planning on the success measure continued at pace, ahead of the submission window opening (9 July 2025) and ahead of the process to reduce and reorder the connections queue ("Gate 2 to Whole Queue"). Please refer to update provided for overall Performance Objective with regards to technical challenges faced since Q1, which may impact on the timely delivery of this Performance Objective. More information will follow in next quarter's update.
During the connection reform process, achieve effective customer engagement through transparent and clear communication. **Provide enhanced support for customers via the Connections Reform Hub, hosting industry webinars, and using a range of other communication and outreach channels.** Customer engagement is underway, with support teams established and regular updates provided via industry webinars and a broad suite of guidance documents. Since identification of the technical issues referred to with regards the overall Performance Objective, we have published an Open Letter and communicated several times a week to customers via webinars. Connections Reform statement issued to customers - 2050714

By March 2026 provide revised connection offers aligned with the new methodologies approved by Ofgem. These offers will reflect the technological and locational mix required to deliver a queue of projects capable of supporting the government's Clean Power 2030 Action Plan. Only those who meet specific readiness and strategic alignment criteria will progress beyond Gate 2 and be eligible for a confirmed connection date, with others receiving a provisional Gate 1 offer. Please refer to update provided for overall Performance Objective with regards to technical challenges faced since Q1, which may impact on the timely delivery of this Performance Objective. More information will follow in next quarter's update.
By March 2026 design an approach to accelerate strategic demand projects leading to improved connection times. To include identifying and consulting on amendments to connection methodologies to support strategic demand identified by government. Preparation and planning on-going, including several workshops with Government, Ofgem and network companies to identify a range of possible options for further consideration
Invest further into a fully customer-centric Connections Portal. Please refer to update provided for overall Performance Objective with regards to technical challenges faced since Q1, which may impact on the timely delivery of this Performance Objective. More information will follow in next quarter's update.
Progress on additional Ofgem expectations
No updates for Q1
Progress towards PO not captured by the Success Measure reporting above
No updates for Q1

Performance Objective	Status	Status change
Clean Power 2030 Implementation 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 CP2030 action plan.	●	n/a (since last quarter)

Summary of progress this quarter in delivering this PO outcome
The NESO 2030 Delivery Plan was published and the new transmission network operator tracker was successfully used for Q2 data reporting by Transmission Operators to DESNZ and Ofgem.

Progress on Success Measures this quarter
Consult upon and publish our comprehensive 2030 NESO delivery plan in April 2025. This will be a clear and concise publication with evidence of collaboration with and alignment to DESNZ Clean Power Team and Mission Control's objectives. The NESO Clean Power Implementation Plan was published on 17 June 2025.
Establish ways of working with DESNZ Clean Power Team and Mission Control. We will provide timely responses to reactive requests from DESNZ through Mission Control who are planning to run "policy sprints" which would focus resolving an issue in a short 6-12 week time horizon. Clean Power 2030 Advisory Commission Meetings are suspended until the re-election of new commissioners.
Produce a stakeholder engagement plan that enables NESO publications to clearly and concisely demonstrate evidence of engagement with a broad range of customers on CP30 and how their feedback has been considered. The stakeholder engagement approach has been approved. Work is ongoing to build trust and transparency with the relevant NESO stakeholders.
Develop a strategic approach to System Access Planning with TOs and wider stakeholders by the end of June 2025 with delivery following by the end of March 2026. There is significant complexity in relation to delivery is driven by the number of stakeholders and the scale of industry challenges. The development of a strategic approach was completed by the end of June 2025 and the programme commences in July.

Publish the updated Operability Strategy Report in December 2025 incorporating the full detail of the Clean Power Action Plan. Operability Strategy is impacted by a number of different areas. This is a live document that will be consulted upon and amended on a regular basis. Work is ongoing with publication of the annual plan due in December.
Working with DESNZ, Ofgem and TOs, develop and implement by June 2025 a new dashboard system that provides a single version of the truth against which to track progress of transmission network projects required to meet CP30 and, where necessary, facilitates mitigation of project risks. The new tracker was successfully used for Q2 reporting to DESNZ and Ofgem, with minor issues identified and scheduled for resolution in the July release.
Work with stakeholders to produce a set of integrated dashboards to track and review the delivery of the supply side projects required to meet CP30 targets. Development underway to allow the Transmission Operator tracker to be used to record connections and network projects.
Progress on additional Ofgem expectations
Long Duration Energy Storage - establishment of capabilities to support cost-benefit analysis work No updates for Q1
Progress towards PO not captured by the Success Measure reporting above
No updates for Q1

Performance Objective	Status	Status change
Separated NESO Systems, Processes and Services We'll transition remaining systems, process and services from National Grid to NESO ownership to enhance our capabilities and establish our autonomy and full independence.		n/a (since last quarter)

Summary of progress this quarter in delivering this PO outcome

We are progressing on schedule and within budget for the Transitional Service Agreement (TSA) exit plan. We have just completed the rebase lining of our exit plan with National Grid. Progress to July includes migration of all users to NESO M365. We have also concluded several strategically significant procurement events.

We have revised our networks plans, due to delays with circuit delivery from our network provider Verizon. This impacted our overall separation plan; however, we are still confident that we can achieve separation by September 2026.

Progress on Success Measures this quarter

Exit 60% of services from the Transition Service Agreements (TSA) by the end of March 2026.

We remain on track to achieve exiting 60% of services by the end of March 2026.

Transition physical and cyber security from National Grid. Establishing the strategic Security Operations Centre (SOC), Security Information and Event Management (SIEM), Digital Forensics, and Threat Intelligence capabilities by March 2026.

The Cyber Security transition remains on track to meet the exit date, however this is at risk due to external delays from our supplier in the setup and delivery of the Networks with escalations in place to manage progress.

While physical security is progressing, overall end date delivery has been impacted by the National Grid to NESO network separation moving the plan to the right, but we remain on track to exit.

Deliver foundational services, including:

- **physical separation of the NESO network from National Grid by December 2025**
- **migration of all users and devices to NESO infrastructure by January 2026**
- **migration of digital platforms and the majority of applications to NESO by March 2026**

We remain on track to achieve physical separation of the NESO network from National Grid by December 2025. NESO device rollout remains on track for January 2026. We also remain on track for digital platforms and the majority of NESO applications are to be migrated by March 2026.

Build systems and data for people-related functions, including the implementation of People, Payroll, Finance, and Procurement SaaS platforms. Elevate remains on track against agreed plan. We have just completed our design phase, and we are currently in delivery.
Progress on additional Ofgem expectations
No updates for Q1
Progress towards PO not captured by the Success Measure reporting above
No updates for Q1

Reported Metrics

Summary of Reported Metrics

The table below summarises our Reported Metrics for June 2025:

	Reported Metric	Performance
1	**Balancing Costs**	**£324m**
2	**Demand Forecasting**	Forecasting error of **616MW**
3	**Wind Generation Forecasting**	Forecasting error of **5.36%**
4	**Skip Rates**	Post System Action (PSA) Offers: **33%** Bids: **51%** Combined: **40%**
5	**Carbon intensity of NESO actions**	**21.53 gCO_2/kWh** of actions taken by the NESO
6	**Security of Supply**	**1** instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. **0** voltage excursions
7	**CNI Outages**	**0** planned and **0** unplanned system outages
8	**Short Notice Changes to Planned Outages**	Q1: (June) **1.24** delays or cancellations per 1000 outages due to a NESO process failure. April & May **0** delays or cancellations per 1000 outages due to a NESO process failure.
9	**Zero Carbon Operability Indicator**	Q1: Highest ZCO% of **89.60%** after NESO operational actions
10	**Constraints Cost Savings from Collaboration with TOs**	Q1: **£220m**
11	**Day-ahead procurement**	**87%** balancing services procured at no earlier than the day-ahead stage
12	**Accuracy of Forecasts for Charge Setting - BSUoS**	Q1: Month ahead BSUoS forecasting accuracy (absolute percentage error) of; April: **15%** May: **5%** June: **37%**

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.

June 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

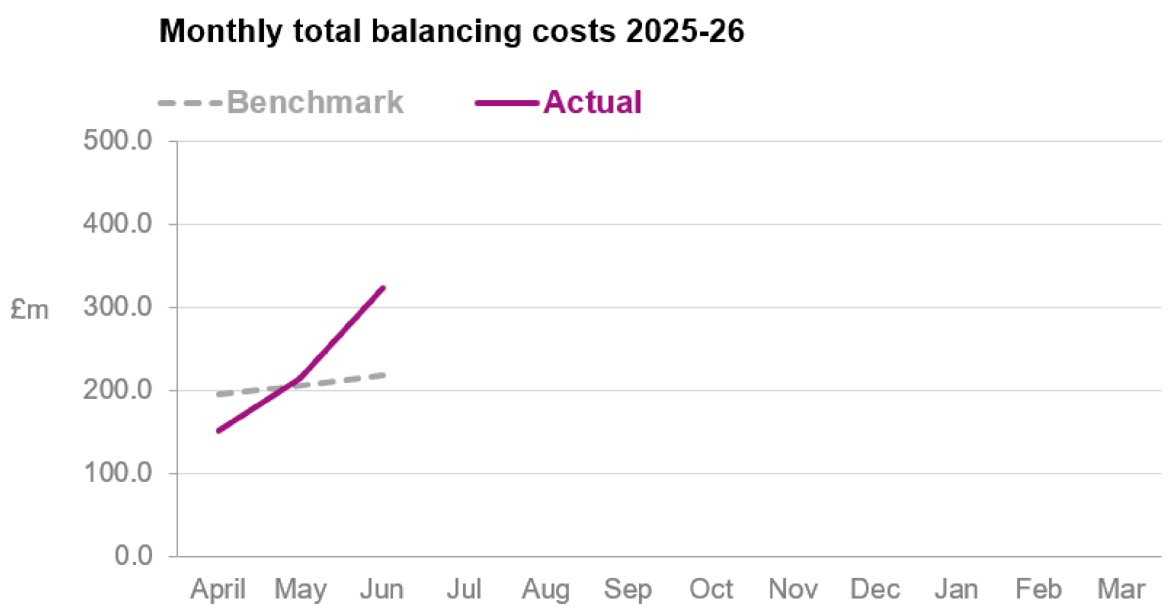


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

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										14.2
Average Day Ahead Baseload (£/MWh)	81	77	73										n/a
Benchmark*	195	206	219										620
Outturn balancing costs[1]	**152**	**215**	**324**										**691**

[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

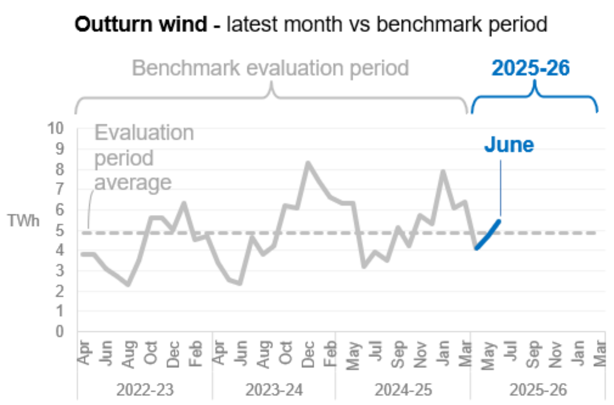
BALANCING COSTS METRIC & PERFORMANCE

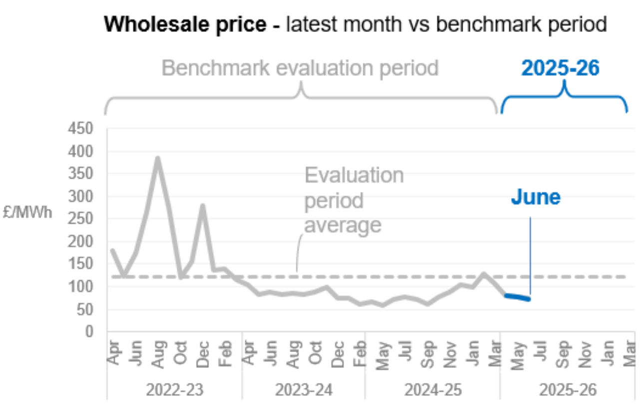
This month's benchmark

The June benchmark of £219m is £13m higher than May 2025 and reflects:

- An **outturn wind** figure of 5.4 TWh that is above than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 4.9 TWh) and is higher than May 2025's figure (4.7 TWh).
- An average monthly **wholesale price** (Day Ahead Baseload) that has decreased compared to May 2025 and is lower than the previous year. However, it remains lower than the evaluation period average.

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





Variable	June 2025	May 2025	June 2024
Average Wholesale Price (£/MWh)	73	-4	-3
Total Wind Outturn (TWh)	5.4	+0.7	+1.5
Benchmark (£m)	219	+13	+32

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

Balancing Costs - Overview

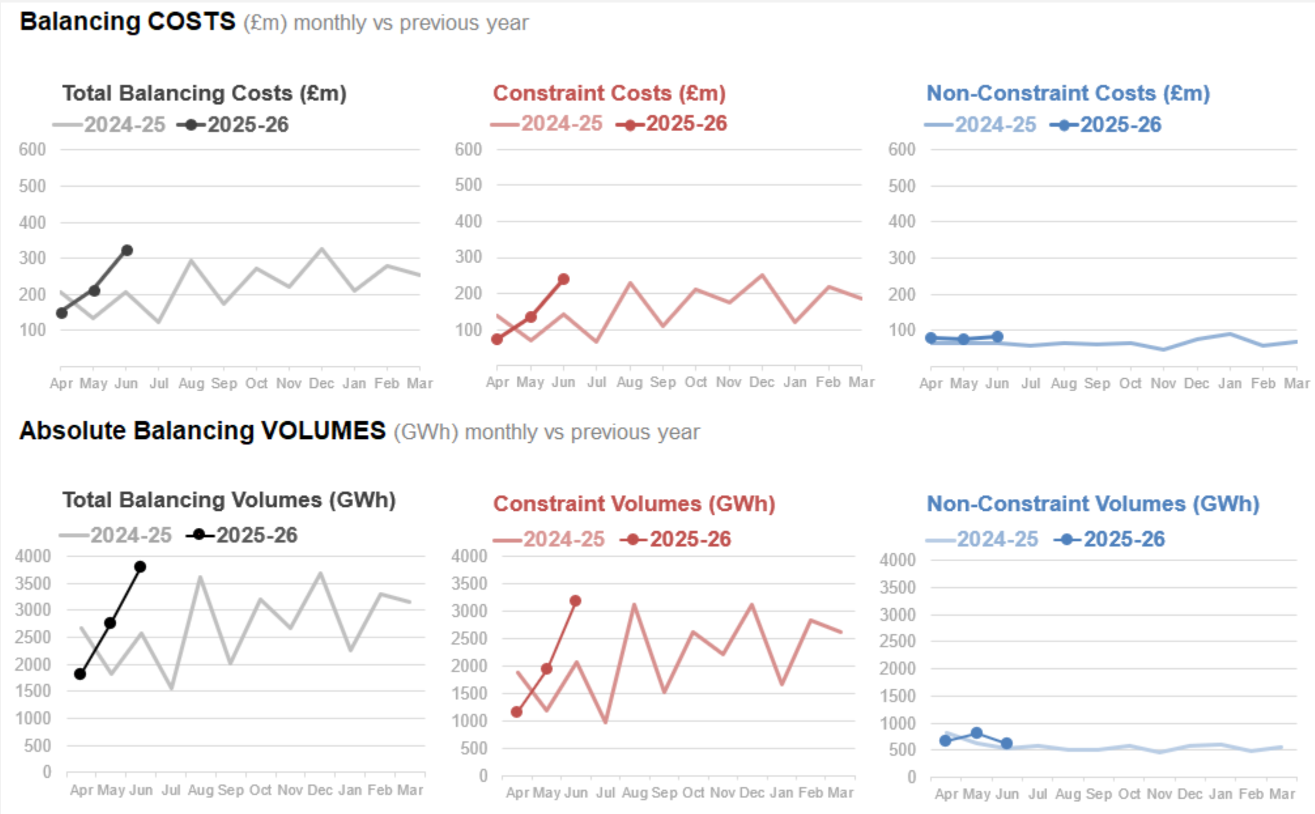
The total balancing cost for June was £324m, which is £105m (~48%) above the benchmark.

Wind outturn in June increased up from the previous month to 5.4TWh which was very high for the time of year. June's wind outturn was the highest recorded June wind outturn over the last seven years, and around 1.5TWh higher than the second highest outturn (June 2024 at 3.9TWh). High wind curtailment was seen particularly at the beginning and towards the end of the month, leading to the volume of wind curtailment for June only being slightly less than the maximum volume seen so far this year. Costs across most constraint categories increased, with substantial increases seen in England & Wales and Scotland. Overall this meant that Scottish constraints had an increased proportion of overall constraint costs compared with last month.

There are still ongoing outages across Scotland which took place during the month, further influencing constraint costs in the region, especially during days with high wind outturn. Lower demand during daylight hours and high wind outturn additionally led to further redispatch actions by NESO for voltage and inertia management.

Voltage and inertia costs stayed close to the record high levels from last month, at £37.6m and £8.0m respectively. The main driver for voltage costs staying high was the low daytime demand periods seen in June, which while not as low as May, still meant we have to dispatch synchronous generators to provide reactive power support which drives up these costs compared to when they would typically self-dispatch. High inertia spending is also linked to the increased procurement by NESO for synchronous generators when we see low demand periods and high wind outturn.

Average wholesale prices were down by £4/MWh from May 2025 and £3/MWh from June 2024. The volume weighted average (VWA) price of bids was £-21.2/MWh, which is significantly more expensive than last month's price of £0.6/MWh. The VWA price for offers has increased from £122.8/MWh to £129.2/MWh. Non-constraint costs have increased by £4.6m, despite the absolute volume of non-constraint actions decreasing by 188GWh.

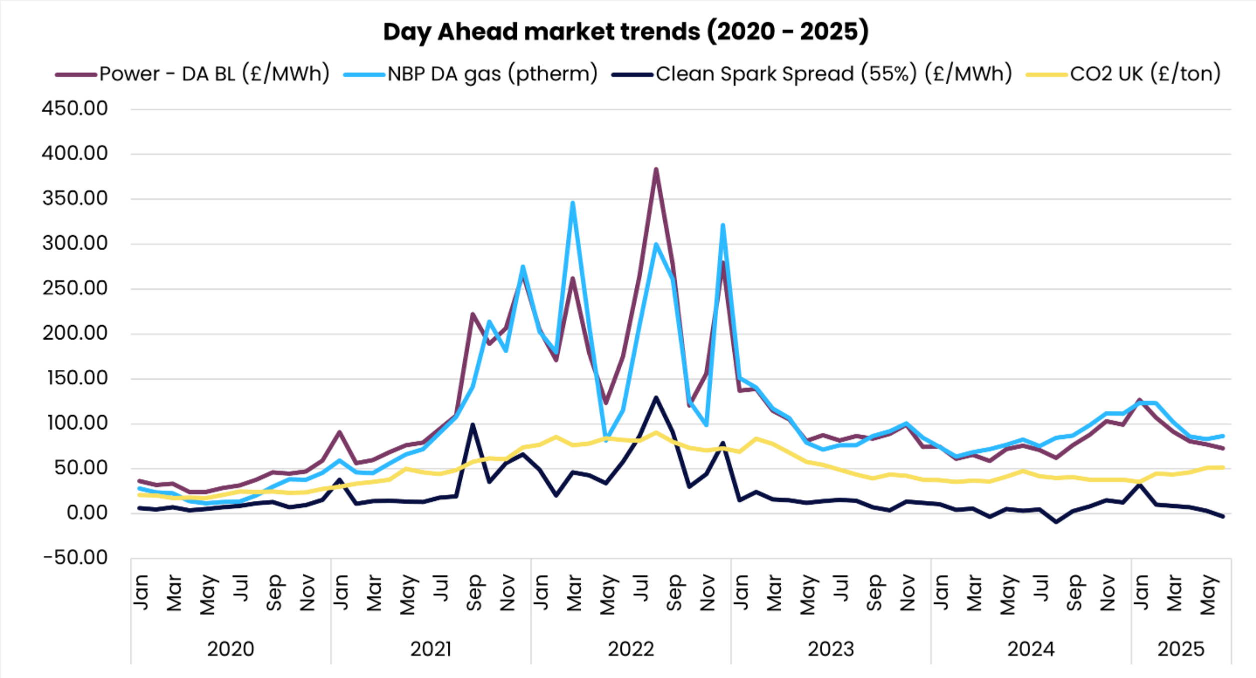


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

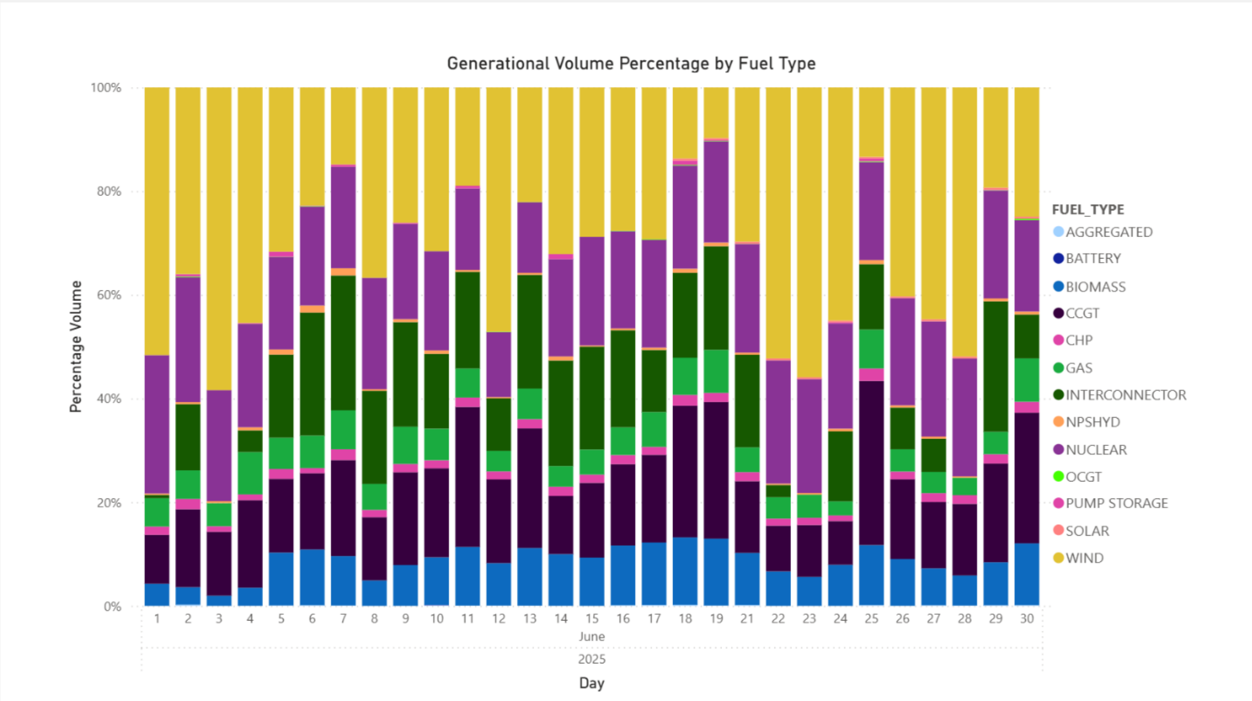
Market trends

Power prices continued to trend downwards in June 2025 reaching a low of £73.01/MWh this year, with a subsequent drop in the Clean Spark Spread Price down to -£3.26/MWh. However, Gas prices rose slightly in June, reaching 86.22p/therm, the highest price since March and CO_2 prices has a slight increase as well. Gas prices rose slightly due to geopolitical tensions during the month, however high wind and solar generation helped reduce gas demand. Power and Gas prices were comparable to June 2024, with power prices being lower this year while gas prices were higher.



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

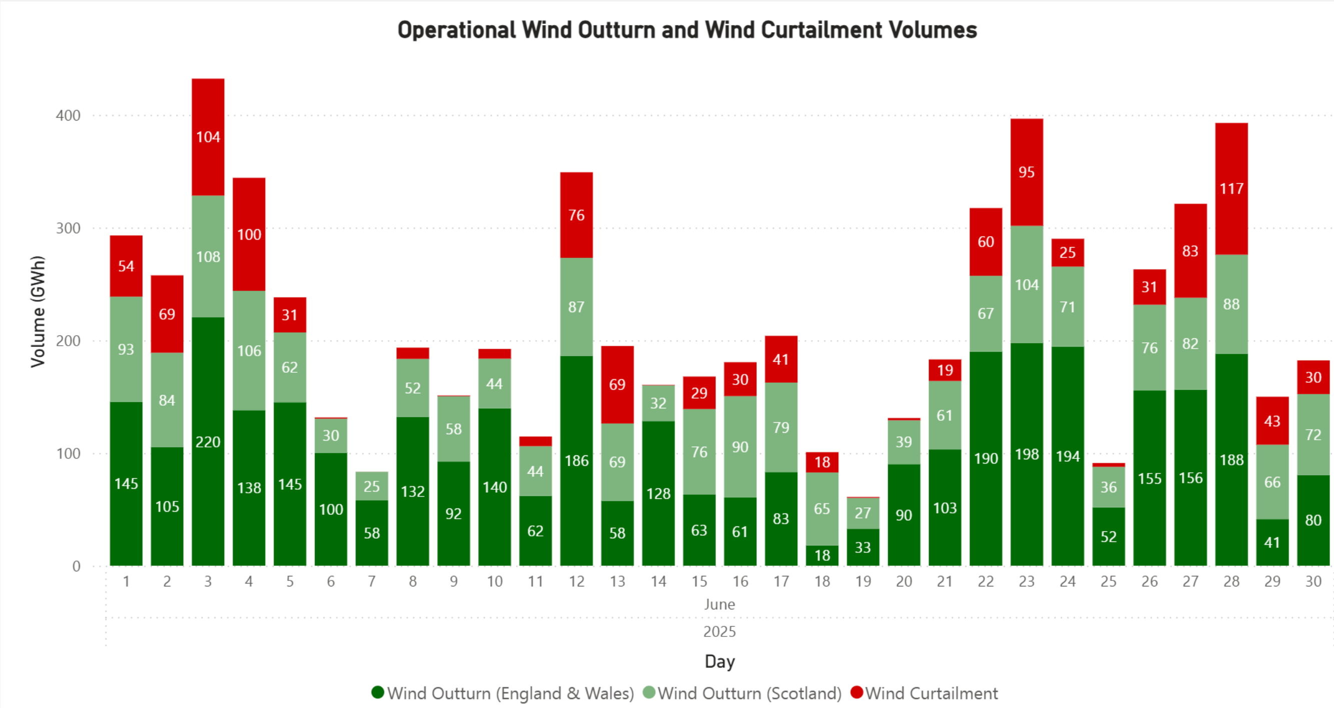
Generation and demand*



*Generation mix includes exports from interconnectors.

In June we saw that wind made up the largest share of the generation mix at 32.7%, which was higher than the 27.2% we saw in May, corresponding with a month on month increase in the absolute volume of nearly 650GWh. CCGT saw a slight decrease of around 1.5% as a share of the generation mix.

4 June was the day with the highest balancing costs at £19.2m and also had the third highest wind curtailment volume of the month at 100GWh. Constraint costs in Scotland contributed to a sizable proportion of the costs, with Scotland seeing the second highest wind outturn of the month. As a result, NESO re-dispatched BMUs for both voltage support and energy/inertia management, which contributed to the high costs for both across the month.

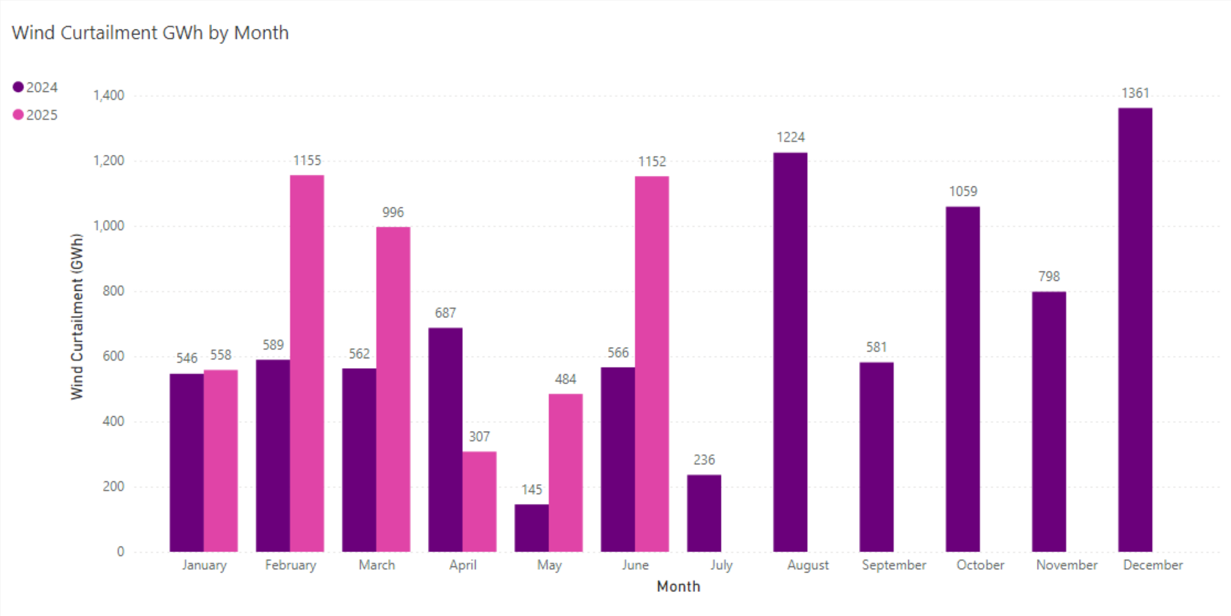


Wind Outturn

June started off with some unsettled weather in the first week, with some windy conditions before a rise in temperatures and settled conditions took hold. There were some thunderstorms during the middle of the month before temperatures rose once again, followed by more thunderstorms and warmer temperatures.

Overall wind outturn in June was up from the previous month and same time last year, with 5.4TWh total, compared to 4.7TWh in May 2025 and 3.9TWh in June 2024. This was significantly higher than expected for the time of year with the wind outturn in June being the highest recorded June wind outturn for the last seven years and considerably higher than the second highest recorded wind outturn in June 2024. The wind outturn in June was mostly influenced by high wind outturn in the beginning and in the latter half of the month.

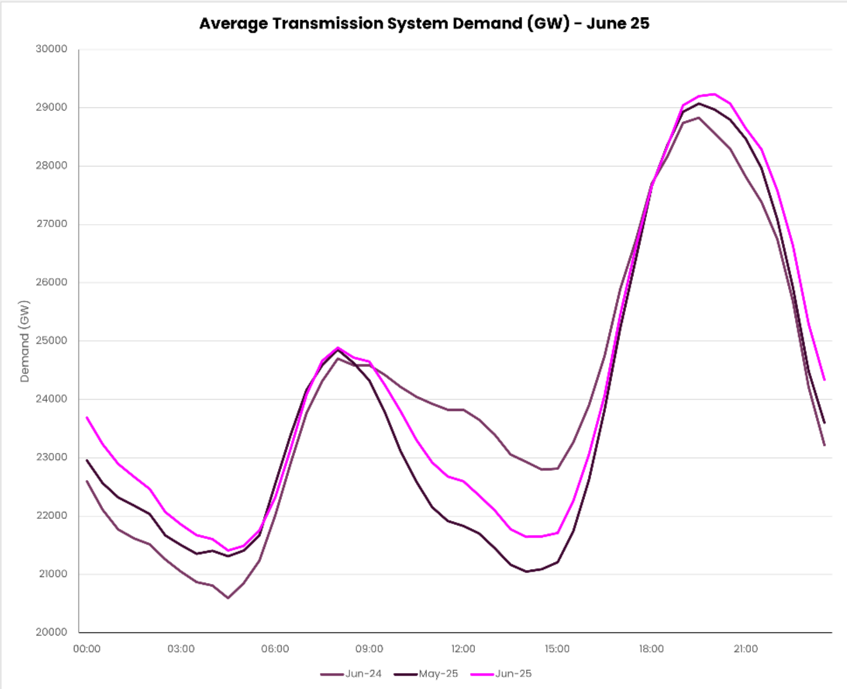
Total curtailment in June was up from May, at around 1152 GWh compared to 484GWh in May, which is very close to the record curtailment seen so far this year in February. This is partly down to a few days with high curtailment as shown on the graph with the high wind outturn at the beginning and end of the month.



The day with the highest volume of wind curtailment occurred on 28 June with 117GWh which aligns with the second highest cost day of the month.

Transmission System Demand

In June the average Transmission System Demand (TSD) was generally higher than the previous month, particularly outside of peak times, either during the middle of the day or overnight. Comparing June to the same period in 2024, the average TSD was notably lower during the middle of the day but was higher during the overnight period. There was significantly higher average TSD in June 2025 compared to June 2024 during the early morning, with average TSD being an average of around 800MW higher between midnight – 7am.

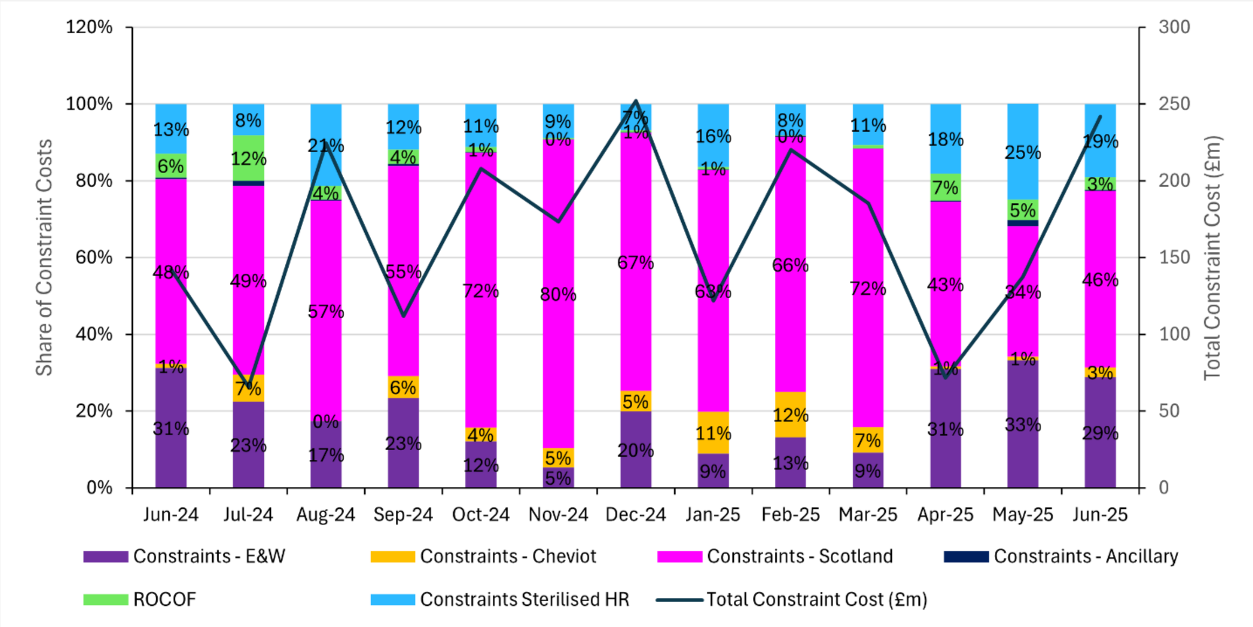


Constraints

Constraint costs in June increased from £136.1m to £241.9m, an increase of £105.8m from the previous month. Most constraint cost categories saw a substantial increase in cost in June, except for inertia, where there was a slight increase, and Constraints - Ancillary which saw a small decrease.

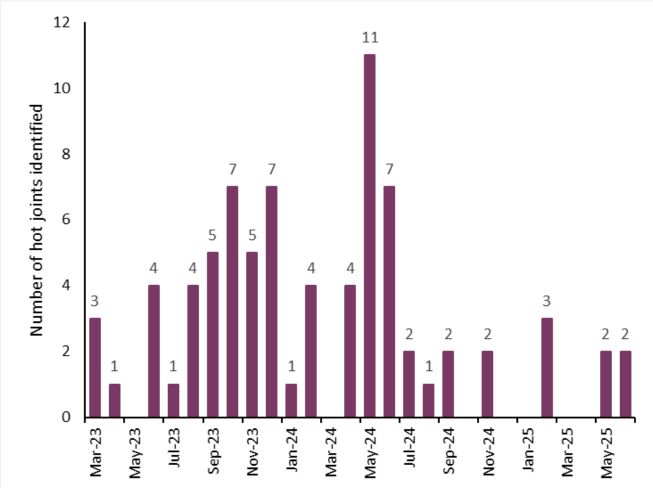
As a proportion of total constraint costs, the main increase was in Scottish constraints which increased from 34% to 46% this month, while Constrained Sterilised HR and Constraints – England & Wales saw their share decrease to 19% and 29% respectively.

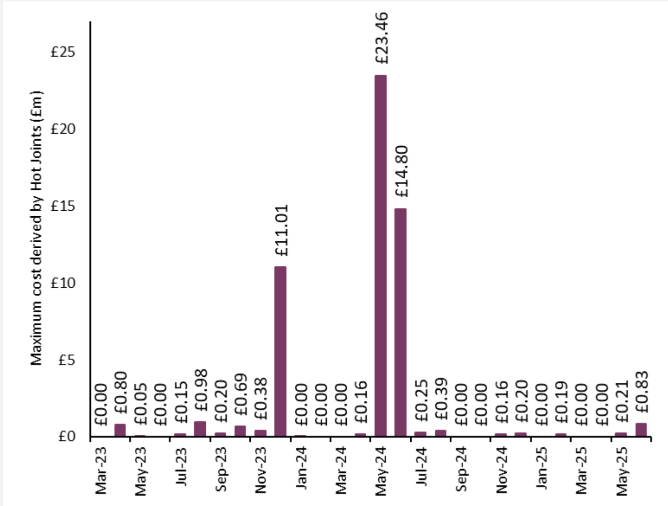
June was a very high month for wind curtailment with over double the volume curtailed of both May 2025 and June 2024. This is largely down to the wind outturn being around 750GWh higher than last month, and almost 1.5TWh higher than June last year, with Scotland having significantly higher wind outturn in June than in previous years. Other factors include the low demand seen during the daytime, and ongoing outages in Scotland.



Network Availability

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. Two hot joints were identified in June, one in Drax 400 kV and another in Elstree 275 kV. The cost impact remained low with a maximum estimated value of £830k.





BALANCING COSTS DETAILED BREAKDOWN

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

		(a) May-25	(b) Jun-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	2.5	9.2	6.7	
	Operating Reserve	16.5	21.2	4.8	
	STOR	3.8	4.1	0.3	
	Negative Reserve	0.3	0.9	0.6	
	Fast Reserve	10.6	10.4	(0.2)	
	Response	21.9	23.9	1.9	
	Other Reserve	0.7	0.4	(0.3)	
	Reactive	13.4	10.1	(3.3)	
	Restoration	5.3	3.6	(1.7)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	2.2	-2.1	(4.3)	
Constraint Costs	Constraints - E&W	45.8	69.9	24.1	
	Constraints - Cheviot	1.3	6.1	4.8	
	Constraints - Scotland	46.6	111.2	64.6	
	Constraints - Ancillary	0.8	0.5	(0.3)	
	ROCOF	7.3	8.0	0.7	
	Constraints Sterilised HR	34.3	46.2	11.8	
Totals	Non-Constraint Costs - TOTAL	77.1	81.7	4.6	
	Constraint Costs - TOTAL	136.1	241.9	105.8	
	Total Balancing Costs	**213.2**	**323.6**	**110.4**	

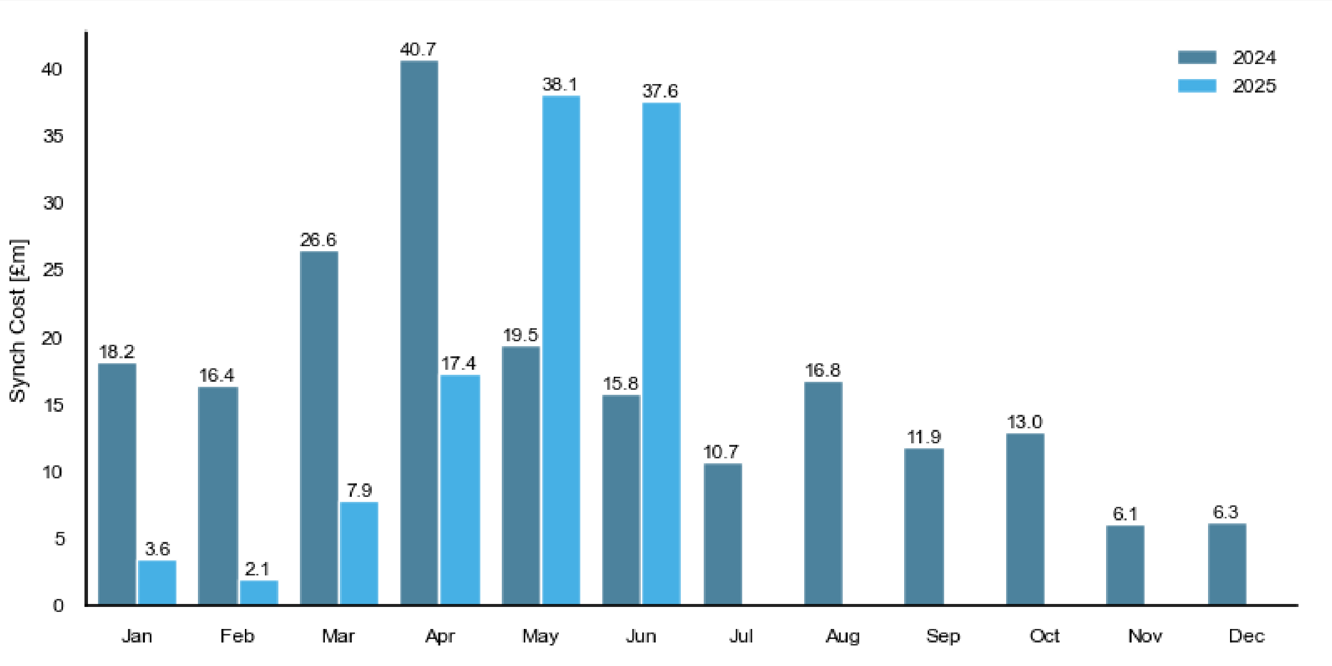
As shown in the totals from the table above, constraint costs increased by £105.8m and non-constraint costs increased by £4.6m which results in the overall increase in costs of £110.4m compared to May 2025.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£69.4m **Constraint – England & Wales: +£24.1m** **Constraint Sterilised Headroom: +£11.8m** Constraint costs increased by £105.8m in June, coinciding with a 1.2 TWh increase in the absolute volume of actions. Wind outturn increased in June and was abnormally high for the time of year which is responsible for the increase in the volume of actions to manage constraints, alongside periods of low demand and ongoing outages in Scotland. **ROCOF: +£0.7m** In June, the system's outturn inertia (including market-provided, stability assets, and synchronous plants used for voltage support) resulted in higher volumes to meet the minimum inertia requirements of the system. High wind outturn in June contributed to increased inertia regulation as non-synchronous generation met a larger proportion of the self-dispatched generation mix.	**Constraints – Scotland & Cheviot: +£47.3m** **Constraints – England & Wales: +£25.5m** **Constraints Sterilised Headroom: +£27.7m** Constraint costs have increased by £99.6m compared to last year. Wind outturn is roughly 1.5TWh higher than in June 2024 which corresponds with a substantial increase in the volume of actions. **ROCOF: -£0.8m** There was slight decrease in inertia spend compared to June 2024. 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 June, the system synchronisation costs (what it costs to the system, which factors in energy replacement, headroom among others) amounted to £37.6m, the second highest spend so far in 2025, and an increase of £21.8m on the same period in 2024.

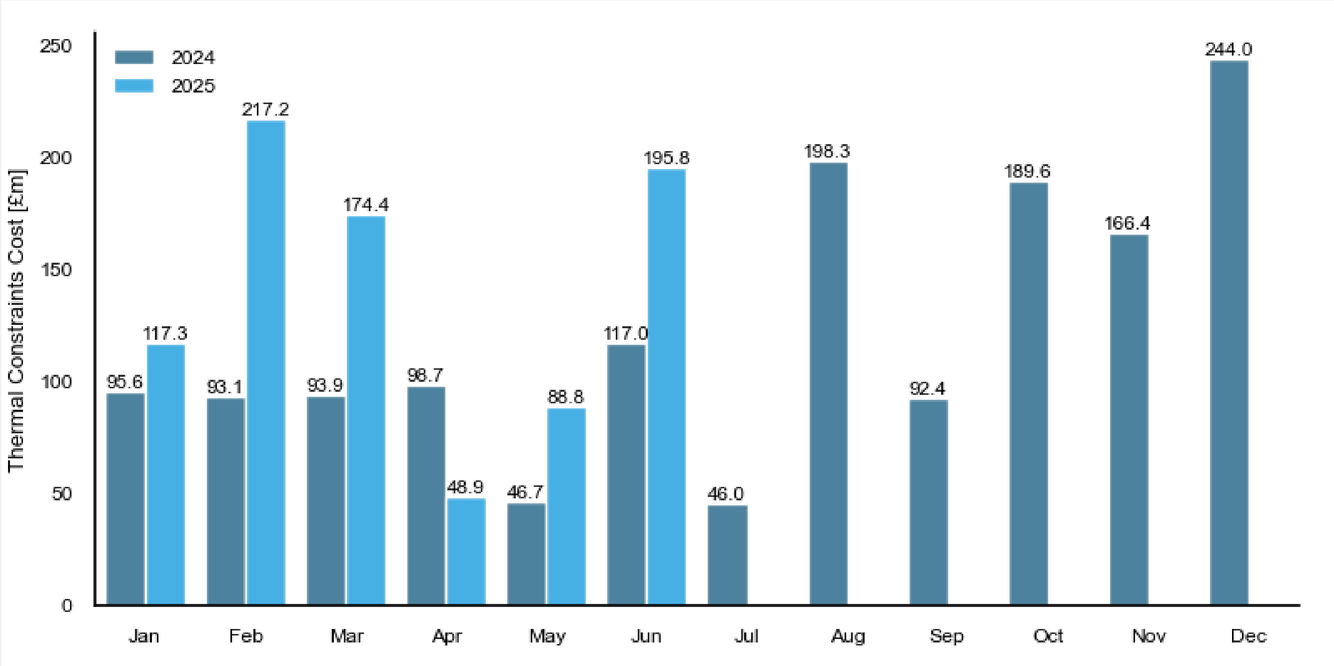


Higher voltage costs have been driven by periods of low demand. This means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism.

An outage in the south of England caused restrictions on the import and export limits of IFA, particularly associated with the risk of Transient Over Voltage (short-duration, high-amplitude voltage increases due to events on the system). These conditions were managed through trades and Intraday Transfer Limit restrictions.

There has also been an increase in voltage trading over the month to help manage voltage levels in the South East. Work is ongoing to minimise voltage costs through the implementation of initiatives such as voltage pathfinders, stability pathfinders (which provide not only inertia but also voltage support), and the commissioning of assets as Greenlink interconnector in South Wales.

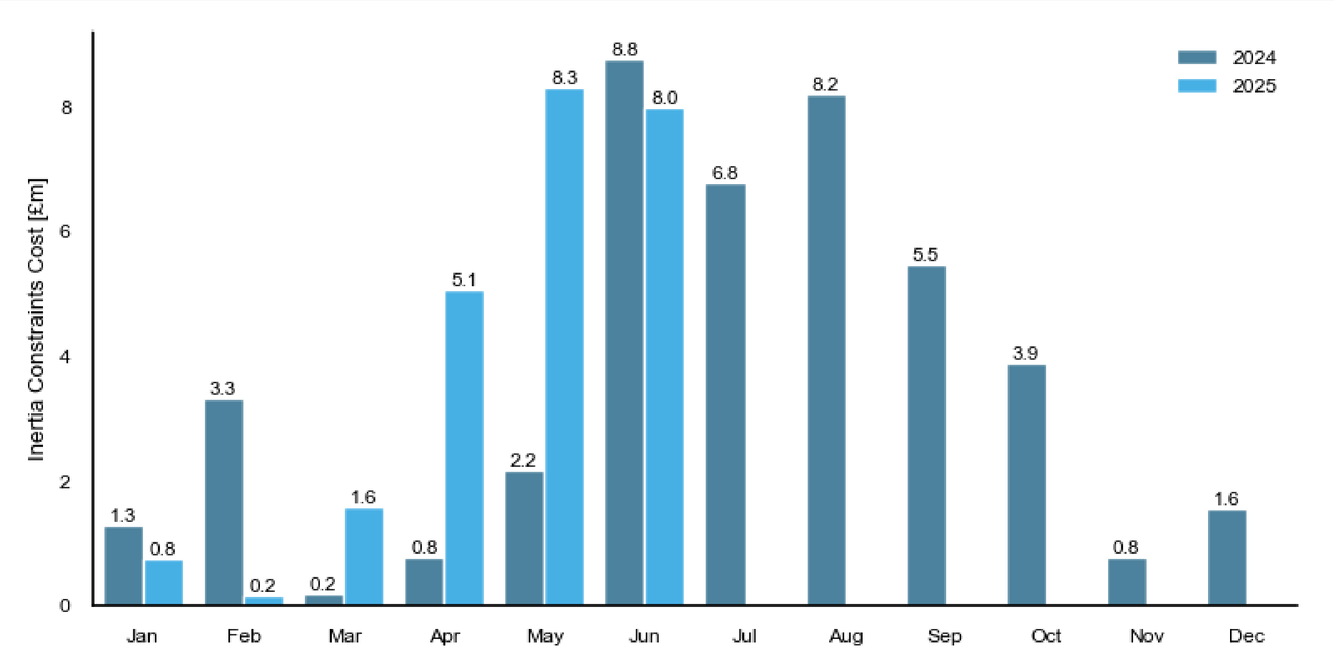
Thermal – Monthly system cost of actions for thermal management across 2024 and 2025: Thermal constraints are associated with operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, 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 lion's share of the system constraints, accounting for a significant percentage of system actions. In June, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £195.8m, reflecting a rise in costs compared to the previous month (£88.8m) and the same period last year (£117.0m).



There was a significant increase in wind curtailment in June, from 484GWh in May to 1.1TWh in June, largely down to a significant increase in wind outturn. Ongoing planned outages in Scotland are also continuing to impact constraints in the Scottish region. Higher wind outturn consequently drove increase operational costs related to managing these constraint boundaries during June.

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 June, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £8.0m, which is slightly lower than the maximum inertia cost seen so far this year. These costs are also lower compared to the same period in 2024 (£8.8m).



The expenditure on inertia dropped slightly in June, but stayed significantly elevated compared to previous months in the year. This is mainly due to operational conditions related to periods of low demand, partly due to the high levels of embedded generation on the system and higher wind outturn than usual for the time of year. This results in a lower number of synchronous units providing inertia regulation as most of the demand is met by non-synchronous generation. This forces NESO to procure inertia through the Balancing Mechanism.

Reactive Costs/Volumes

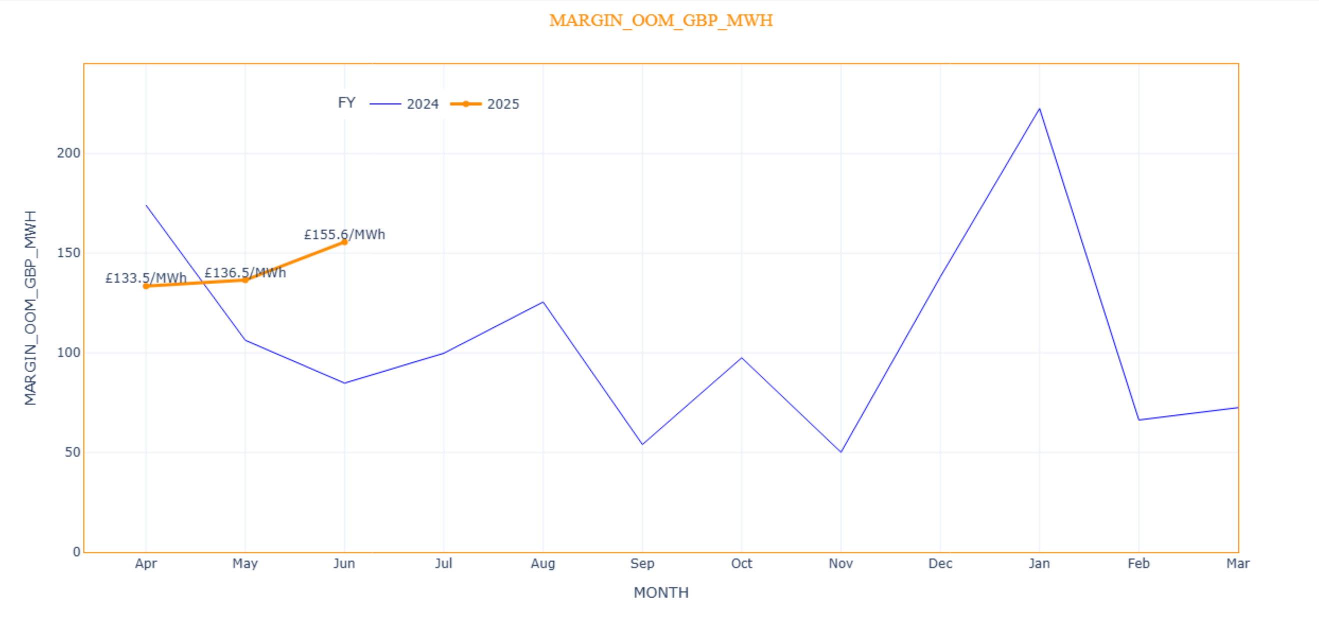
The volume-weighted average price for reactive power was £3.8/MVAr in June 2025.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£3.3m The volume-weighted average price decreased to £3.8/MVAr down from £4.3/MVAr in May.	**-£0.6m** The volume-weighted average price increased from £3.5/MVAr to £3.8/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 increased to £155.6/MWh in June from £136.5/MWh in May 2025. This increase corresponds to the absolute volume of reserve actions taken in June doubling from May coupled with a similar wholesale price.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£4.8m **Fast Reserve: -£0.2m** There was a 510 GWh increase in the absolute volume of reserve required to secure the system compared to May.	**Operating Reserve: +£15.2m** **Fast Reserve: -£5.4m** There was a 457 GWh increase in the absolute volume of reserve required to secure the system compared to June 2024. Volume weighted reserve prices were higher year-on-year.

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
+£1.9m There was a 41 GWh decrease in the absolute volume of actions compared to May but clearing prices for most Dynamic Services were higher than the previous month.	**+£8.8m** The volume of actions taken for response increased 44 GWh compared to June 2024. Clearing prices were also higher year-on-year across all Dynamic Services.

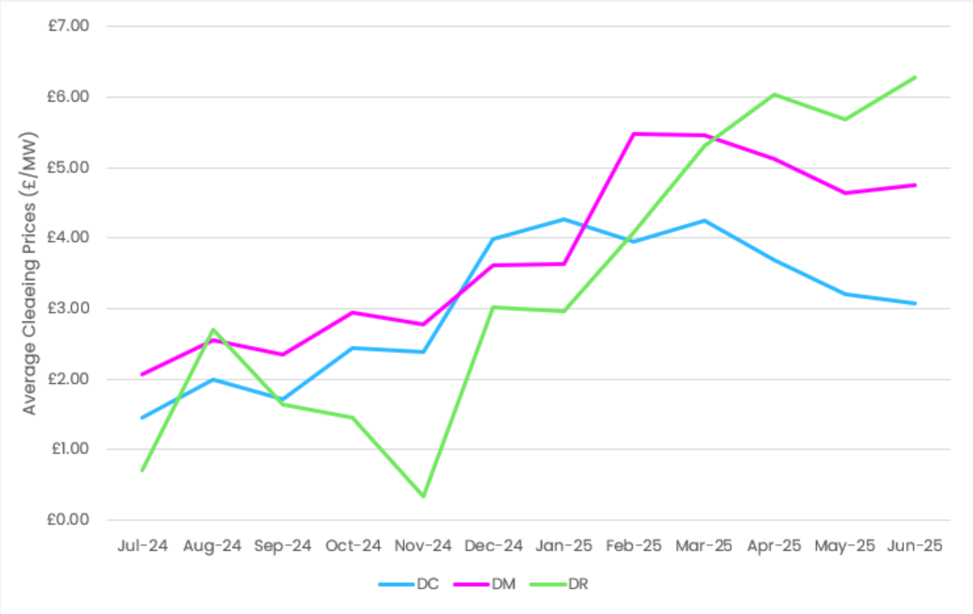
Dynamic Services Average Clearing Prices: June 2025 vs May 2025

		(a) Jun-25	(b) May-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	3.1	3.2	(0.1)	
	DM	4.7	4.6	0.1	
	DR	6.3	5.7	0.6	

Dynamic Services Average Clearing Prices: June 2025 vs June 2024

		(a) Jun-25	(b) Jun-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 up for DM and DR in June compared to the previous month, however there was a slight decrease in DC. This is in line with a slight increase in wholesale prices and spreads. However, all three services saw an increase in average clearing prices to June last year, corresponding with the increase in wholesale price.



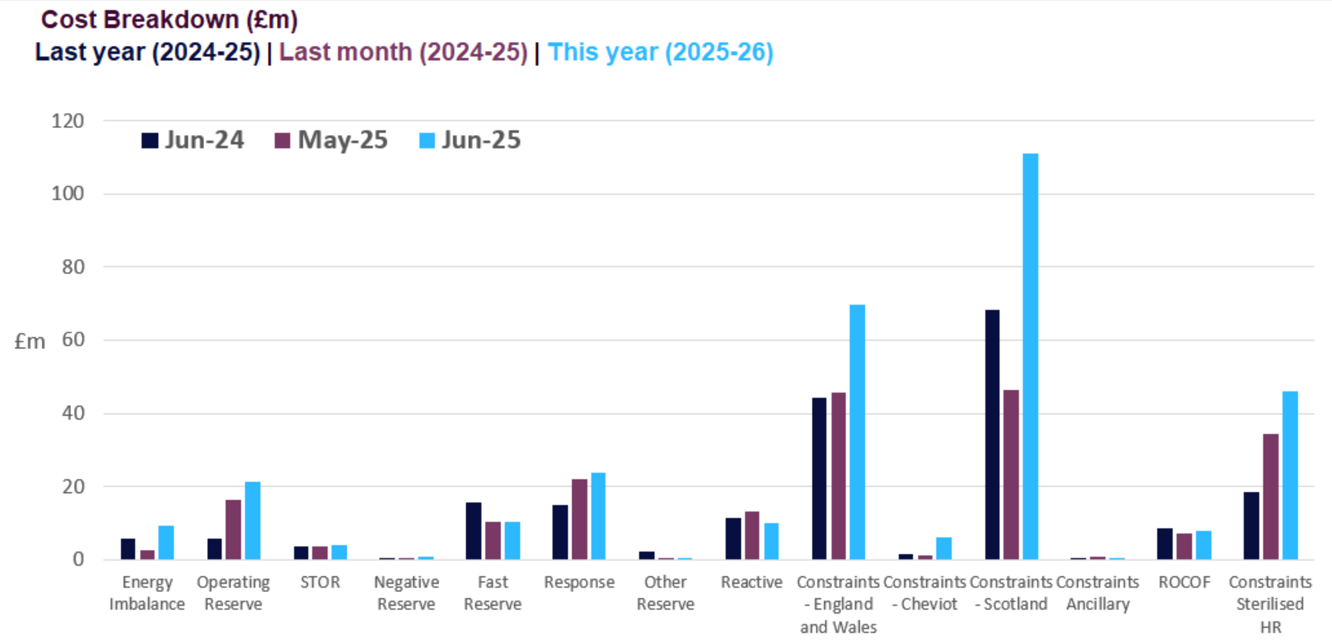
Comparison breakdown

Constraint costs were up by £105.8m compared to the previous month, this is largely down to a significant increase in costs across most constraint categories compared with May 2025. This is largely due to high wind outturn seen in June, with particularly high volumes of wind curtailment seen at the beginning and end of the month, coupled with elevated voltage and inertia management levels, similar to May, and ongoing outages in Scotland. The most significant increase was in Scottish constraints which were up from £46.6m in May to £111.2m in June, an increase of £64.6m.

Constraint costs were also up by £99.6m on June 2024, with the largest increase of £42.8m being from Scottish constraints. However, there were also sizable increases in constraint costs on last year in both England & Wales constraints and Constraint Sterilised HR, with a rise of £25.5m and £27.7m respectively. The main factor for this increase is a significant rise in wind outturn of almost 1.5TWh year on year.

Thermal constraints were significantly higher in June, being a substantial increase on both May and the previous June. There was a slight drop in Constraints – Ancillary Services, the only cost component to see a decrease between May and June.

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 £81m in June 2025. This represents an increase of around £58m compared to May, where savings were £23m. The most valuable action was the use of additional transformation capacity at a 275kV substation in London to improve a constraint in the South-East, which was affected by an unplanned extension of an ongoing outage in the same area. The estimated cost savings for this action was roughly £15.5m.

Cost Savings – Trading

The Trading team were able to make a total saving of £10.2m in June through trading actions as opposed to alternative BM actions, representing a 60% decrease on the previous month. Trading savings were lower in June largely down to the Transient Over Voltage issues seen on IFA, meaning that large number of trades were done for Emergency Instruction / Emergency Assistance. Sell trades were also taken for margin during tight periods because of lower demand due to warmer weather and substantial renewable generation. Voltage trades were also required most evenings due to high winds. The greatest daily trading savings was £2.34m on 2 June with the greatest component being for managing voltage in the South East. The day with the greatest spend on trades was on 30 June at a cost of £9.4m with the greatest component being for managing the LE1 constraint.

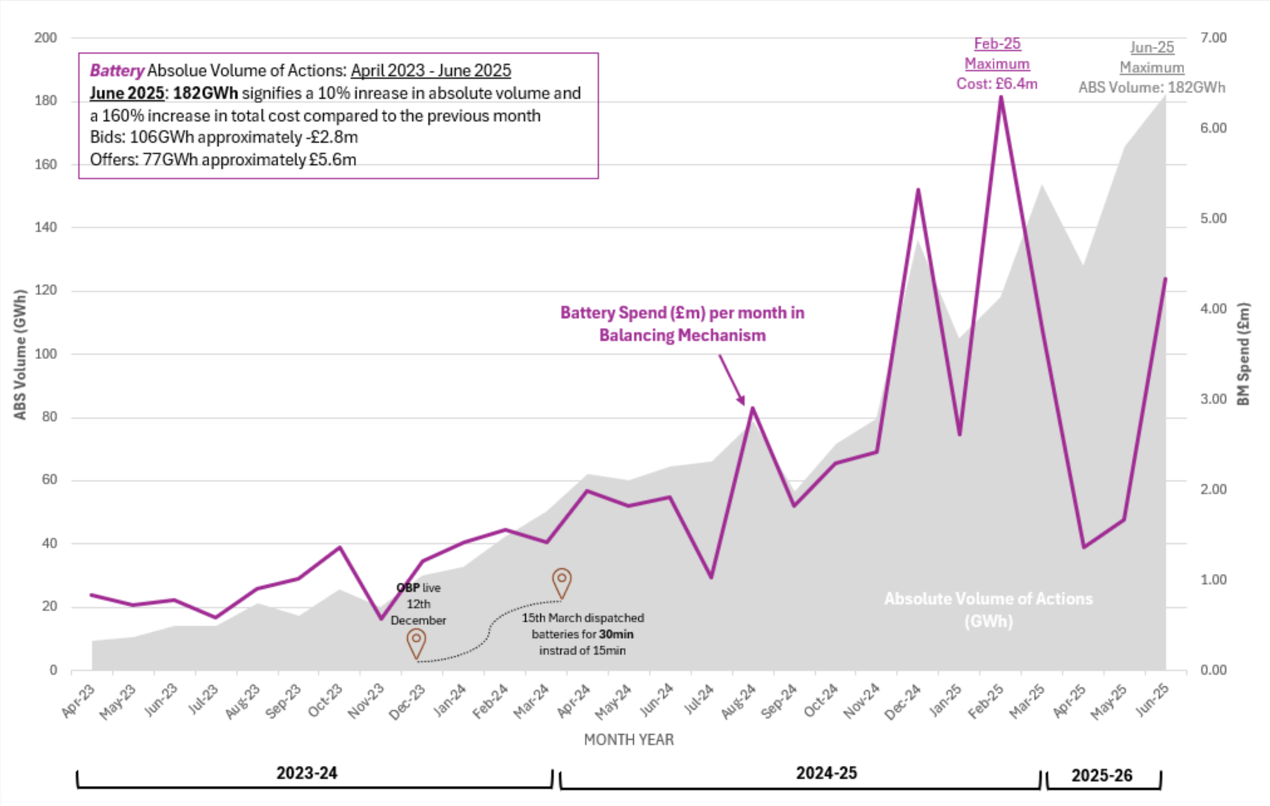
Cost Savings – Network Services (NS)

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 £26.3m in savings in the first two months of 2025/26.

NOTABLE EVENTS

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

June 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.

The total absolute volume of actions and the total cost has increased compared to the previous month, May 2025. The absolute volume of battery dispatch has nearly tripled compared to June 2024, demonstrating our dedication to enhancing the flexibility of energy provided by battery storage and small BMUs over the last year.

DAILY CASE STUDIES

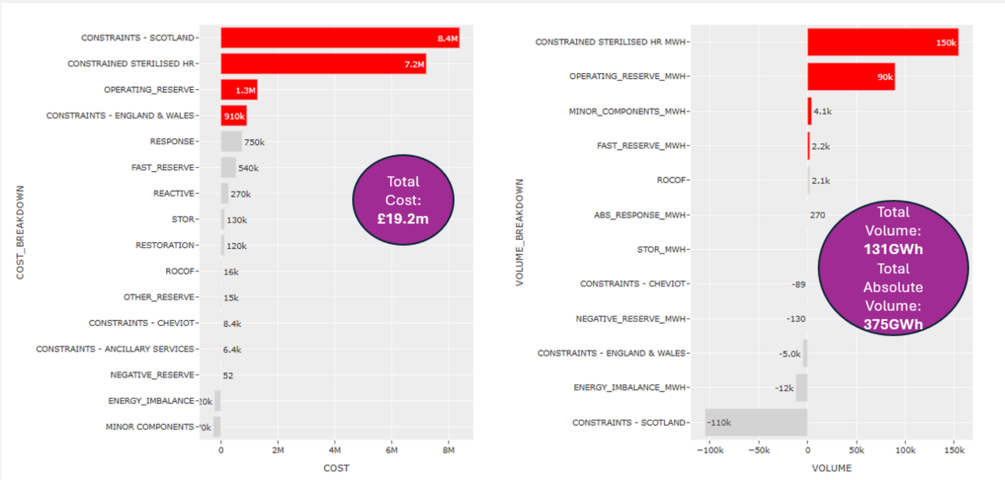
Daily Costs Trends

June's balancing costs were £324m which is £110m higher than the previous month. We had nine days above £15m total costs (2, 3, 4, 12, 13, 23, 27, 28, 30 June) with the highest cost day of the month being 4 June. There were a further five days with costs above £10m which were the 1, 15, 17, 22 and 29 June. The daily average increase by £3.9m from £6.9m in May to £10.8m in June.

The highest cost day on 4 June had a total cost of approximately £19.2m and was also the day with the highest absolute volume of actions over the month. This was largely down to NESO having to bid off significant volumes of wind across the day and offer on replacement energy for both voltage support and energy/inertia management.

The lowest cost day was on 20 June at a cost of approximately £3.5m, partly down to a low percentage of wind curtailment. No trading took place on the day.

High-Cost Day – 4 June 2025



June 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.

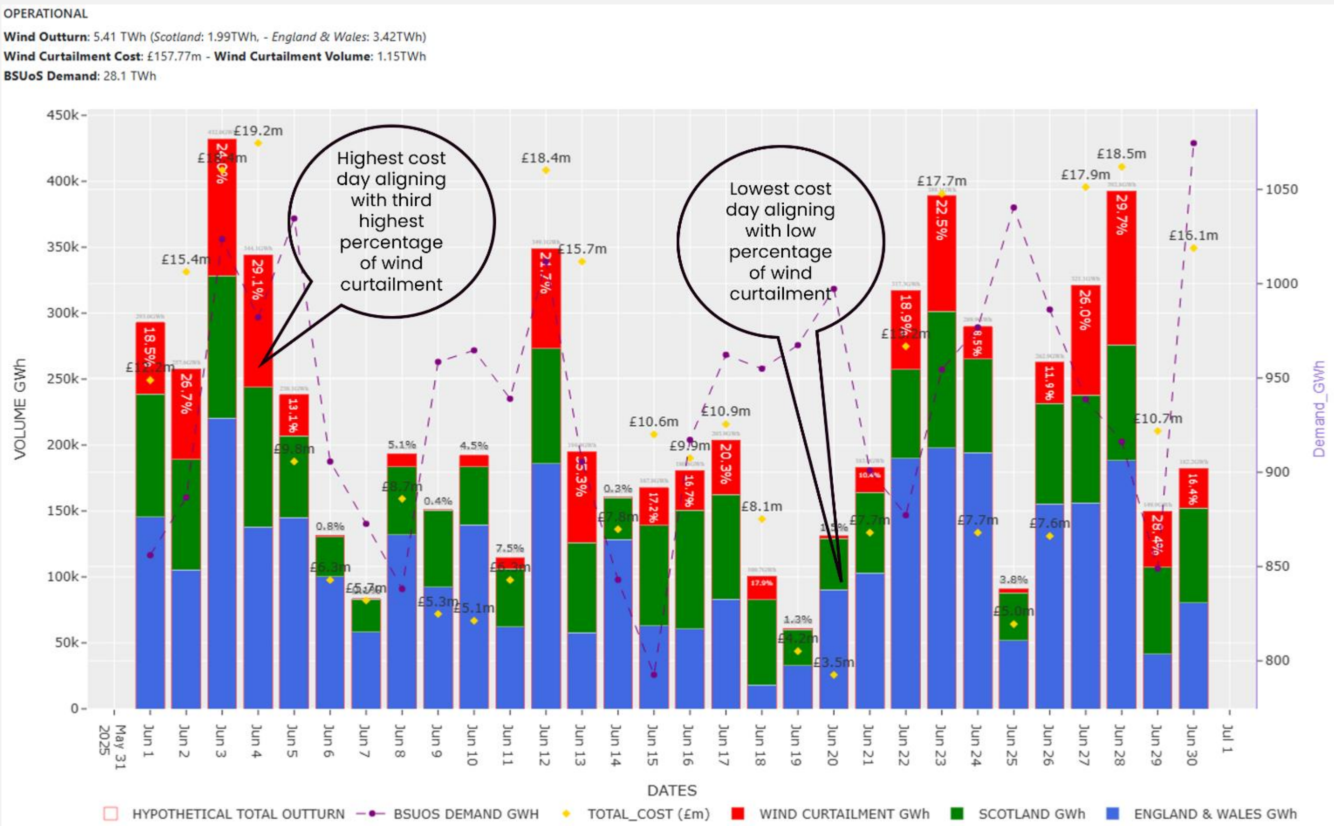
KEY: **Blue bars:** Wind generation in England and Wales

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).

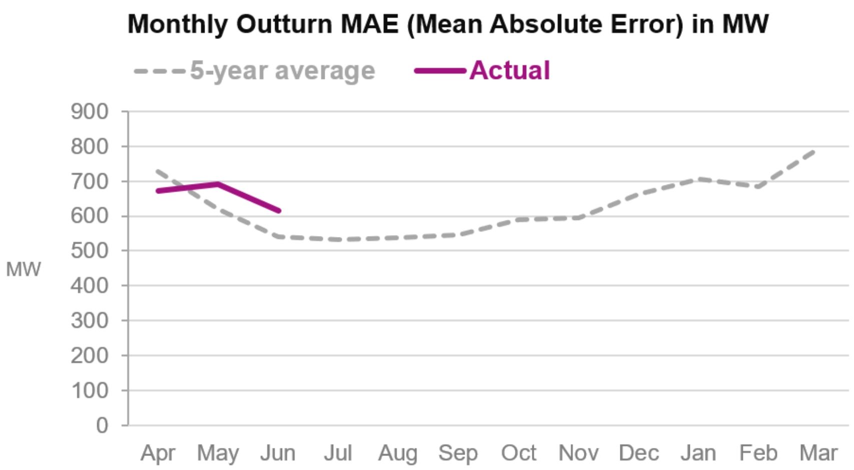
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each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

June 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**									

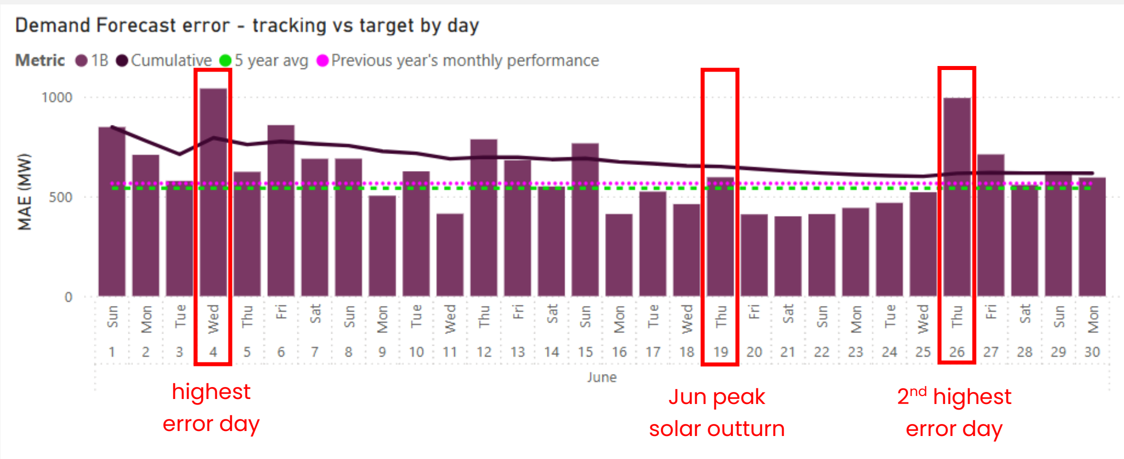
*Ofgem will no longer use a benchmark to assess our performance against this Metric however we will continue to report the previous 5-year average and last year's outturn as an indicator.

Supporting information

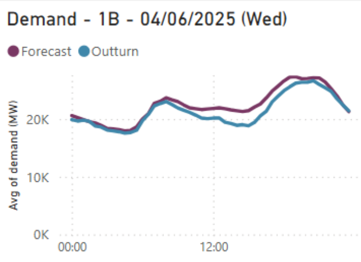
In June 2025, forecasting error averaged 616MW, an increase on the previous 5-year average of 541MW of 75MW (13.9%).

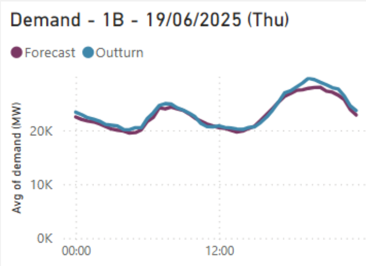
A very warm and sunny June continued the trend of record-breaking weather this year. This was England's warmest June on record.

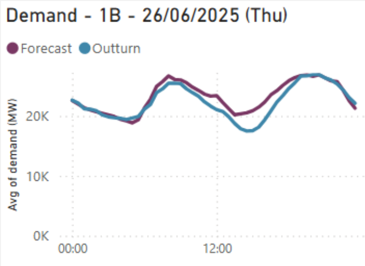
Solar forecasting errors remained the largest contributor to national demand errors, with the unseasonal sustained good weather compounding the reduced performance. New solar models are currently being tested and validated, to minimise such effects.



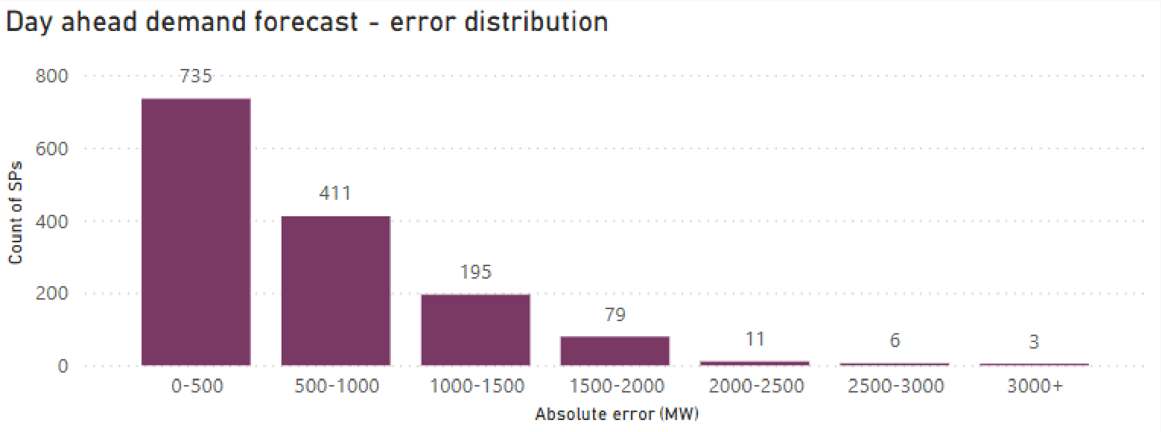
Days of Interest:



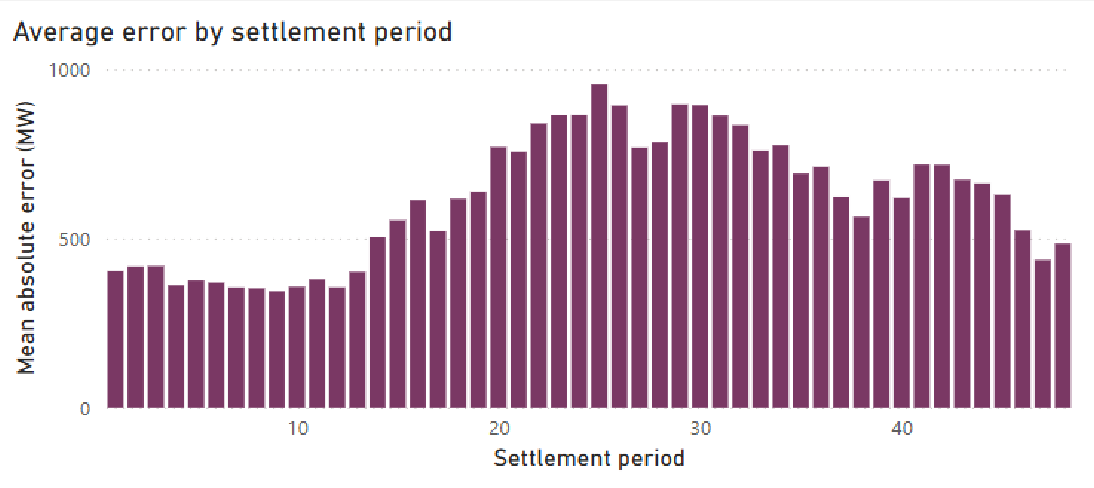




The distribution of settlement periods by error size is shown below:



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



The days with largest MAE were 4 Jun and 26 Jun.

Day	Error (MAE)	Major causal factors
4	1041	Solar forecasting errors and other factors not captured in models
26	994	Solar forecasting errors

Missed / late publications

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

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 4, 5, 10, 13, 17, 23-27 and 30 June, with an accumulated total of 783MWh 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.

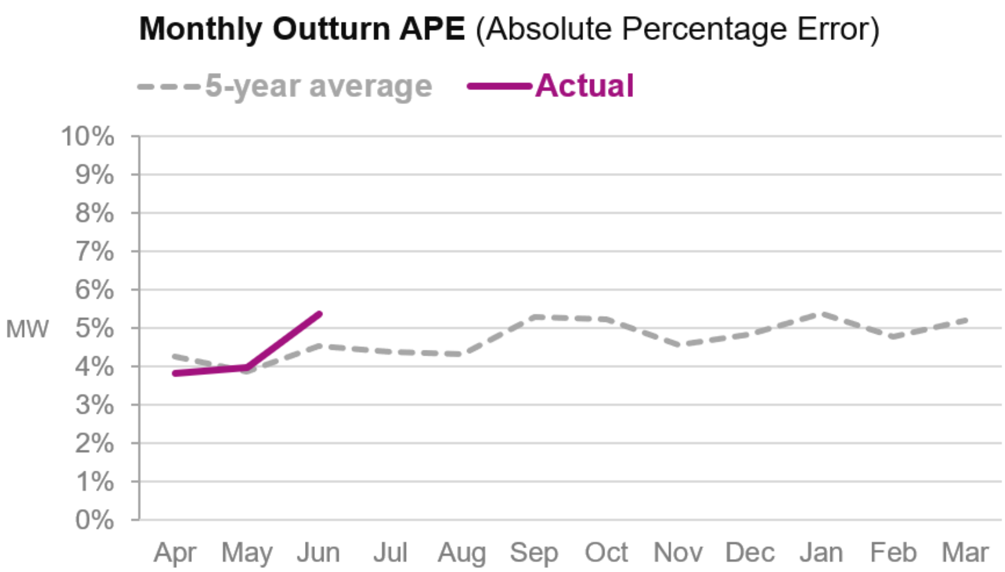
Sites deemed to have withdrawn availability are those that:

- 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.

June 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 (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**	**5.48**									

*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 June 2025, BMU wind forecasting error averaged 5.48%, an increase on the 5-year average of 4.53%.

While June normally has stable lower winds, this year it was more varied.

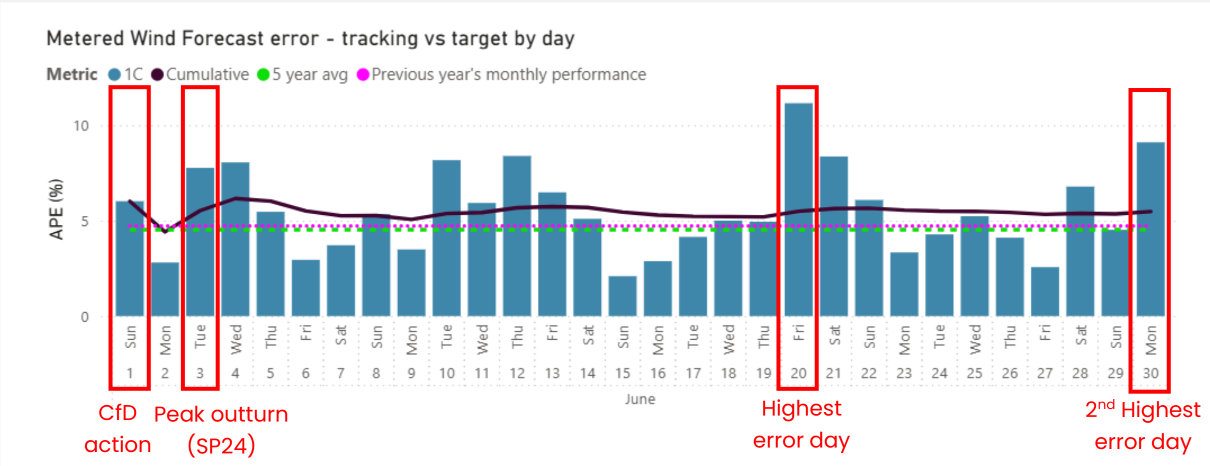
NESO has experienced some front-end data processing issues this quarter, which has resulted in the late processing of weather forecasts and a deterioration of the Day Ahead forecast performance. Within-Day forecast accuracy continues to offer significantly improved values, with performance close below 4% consistently being achieved at 6hr lead time.

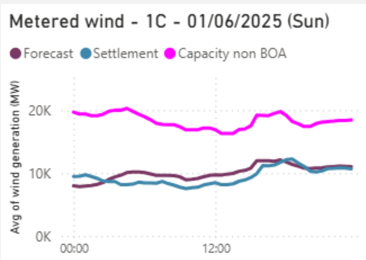
Contracts for Difference (CfD) activity occurred on 1 & 23 June. This curtailment effect is naturally compensated for in the daily performance record.

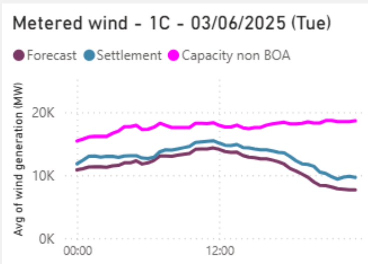
Note: metric performance for April and May has been recalculated with updated settlement data, which in this case has caused a slight decrease in reported accuracy.

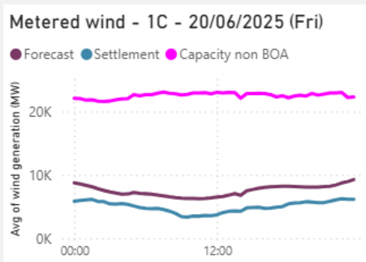
Wind generation peaked at 15.5GW on 3 June, SP24.
Wind forecast absolute error peaked at 3.8GW on 10 June, SP2.

Days of Interest:

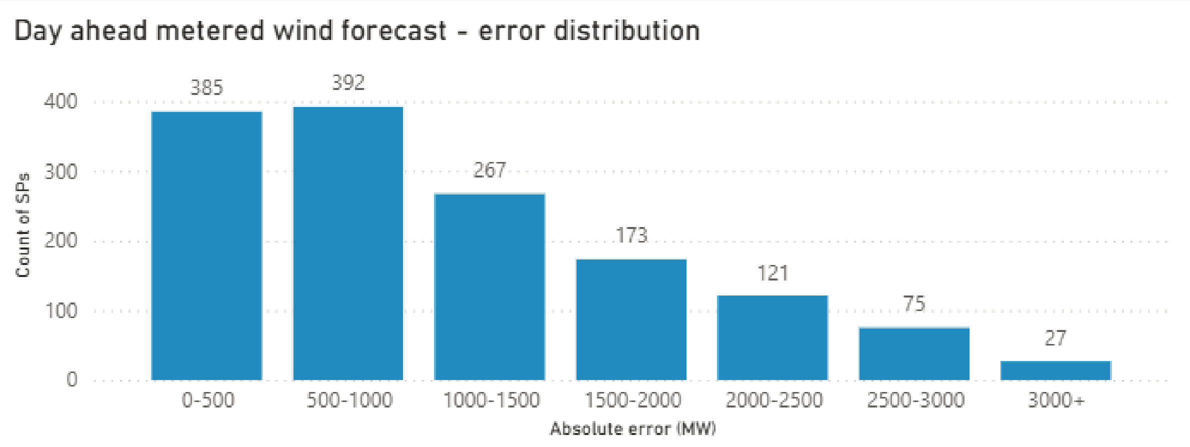








The distribution of settlement periods by error size is summarised below:



Details of largest error

Day	Error (APE)	Major causal factors
20	11.16	Wind speed forecast errors at day-ahead stage
30	9.11	Wind speed forecast errors at day-ahead stage
12	8.39	Wind speed forecast errors at day-ahead stage

Missed / late publications

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

4. Skip Rates

Performance Objective

Operating the Electricity System

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.

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

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									
Offers – in merit Energy volume	148	205	356									
Offers – All in merit volume (System & Energy)	504	901	1052									
Bids – Skipped volume	150	154	118									
Bids – in merit Energy volume	336	352	234									
Bids – All in merit volume (System & Energy)	815	995	1576									

Supporting information

The Offer skip rate has reduced slightly from May (35%) to June (33%). The Offer skipped offer volume was significantly higher in June compared to May due to a higher volume of energy actions in June. The Bid skip rate has increased from 44% in May to 51% in June but the skipped volume has reduced. The higher skip rate is due to a larger volume of total and system actions, resulting in fewer energy only volume, the denominator of the skip rate calculation. The combined bid and offer skip rate has reduced slightly from 44% in April to 40% in May and June.

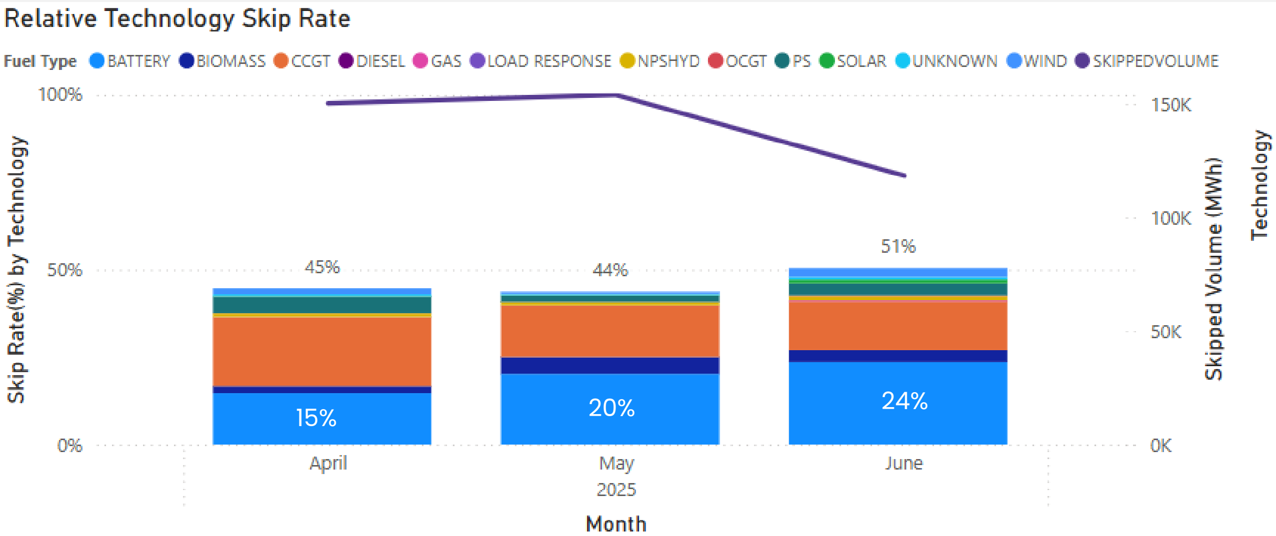
The definition of Post System Action (PSA) Skip Rate and the methodology to calculate skip rates were developed with LCP Delta and shared with industry in December 2024. We are currently reporting the PSA skip rate numbers for both bids and offers calculated at stage 5, which represents the actions available 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.

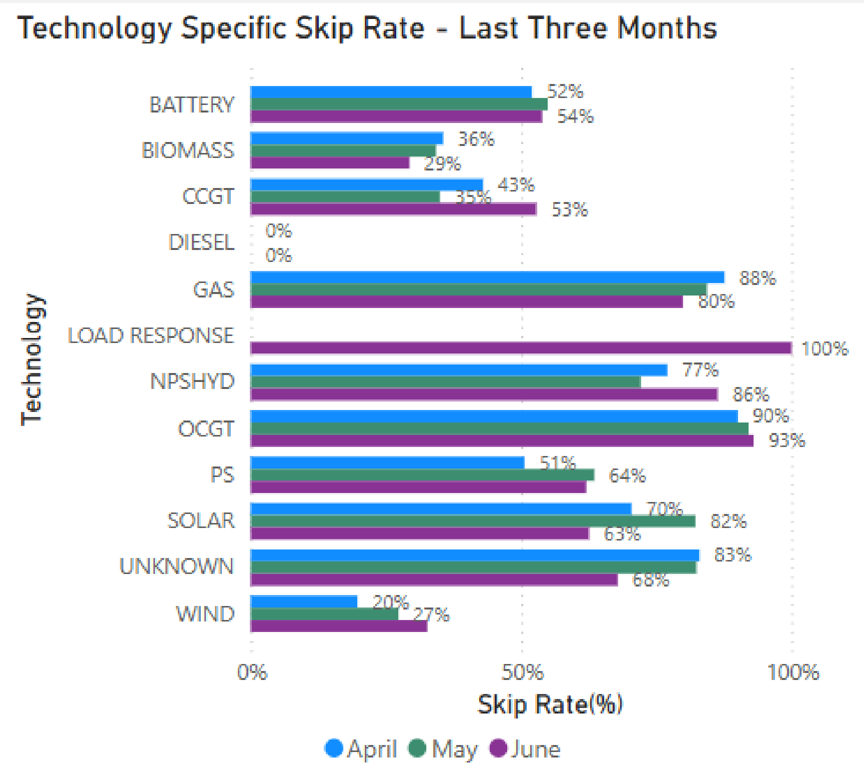
We have expanded this metric to include the skip rate by technology type, using two calculation methods. The left graphs show the Relative Technology skip rate, which shows how different technology types contribute to the overall skip rate. The right graphs show the Technology Specific skip rate for each technology type for the last 3 months. Both calculation methods are based on the PSA skip rate definition.

We have also shared these graphs in the weekly Operational Transparency Forum to increase transparency as this was a key area of interest for stakeholders. We began publishing a dedicated dataset with skip rate by technology type from early July.

Bids

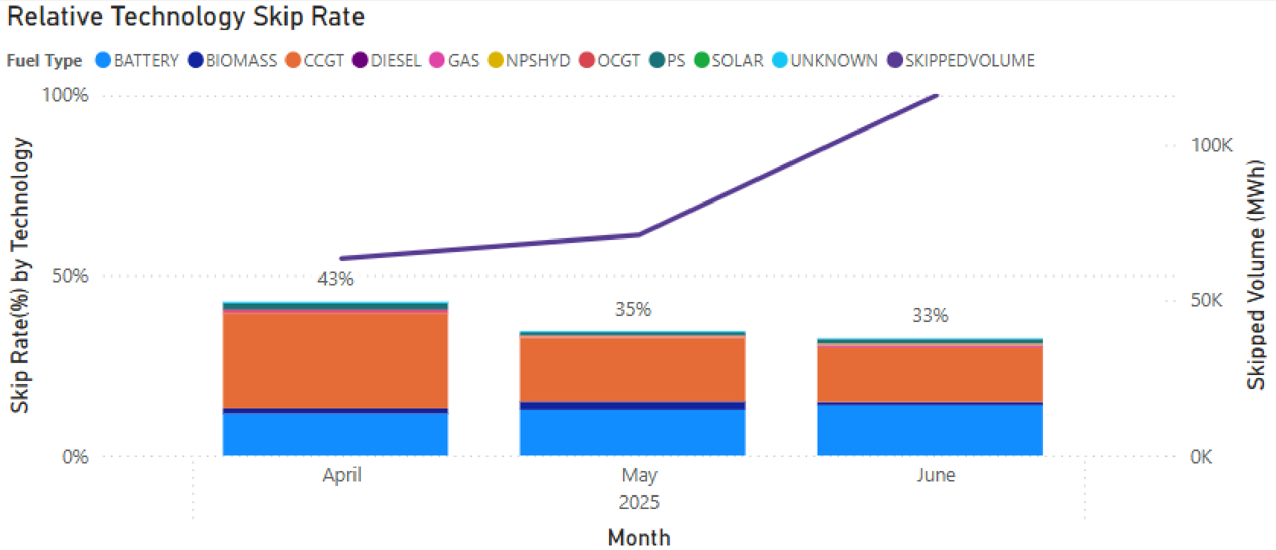
Throughout Q1 batteries have been accounting for an increasing proportion of bid skipped volume – 15% in April compared to 24% in June. However, when looking at the Technology Specific skip rate has remained constant (52-55%). This shows that the increased proportion of battery skips is due to a reduction in total skipped volume, rather than an increase in battery skip rate.

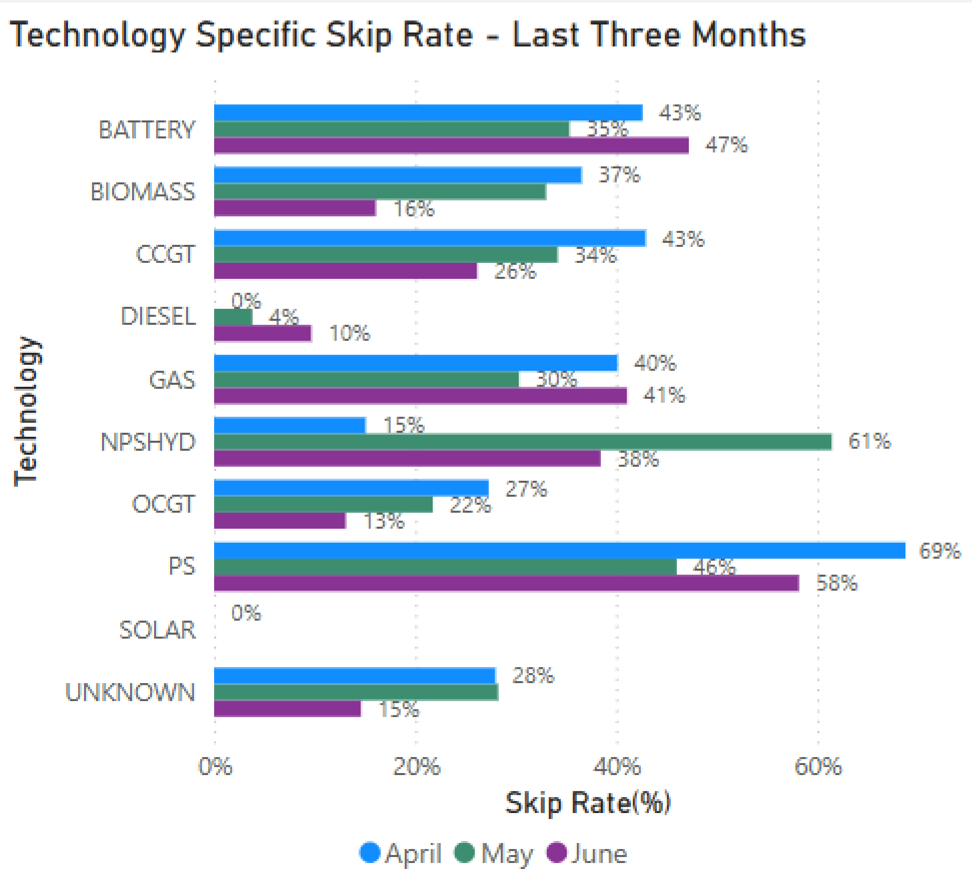




Offers

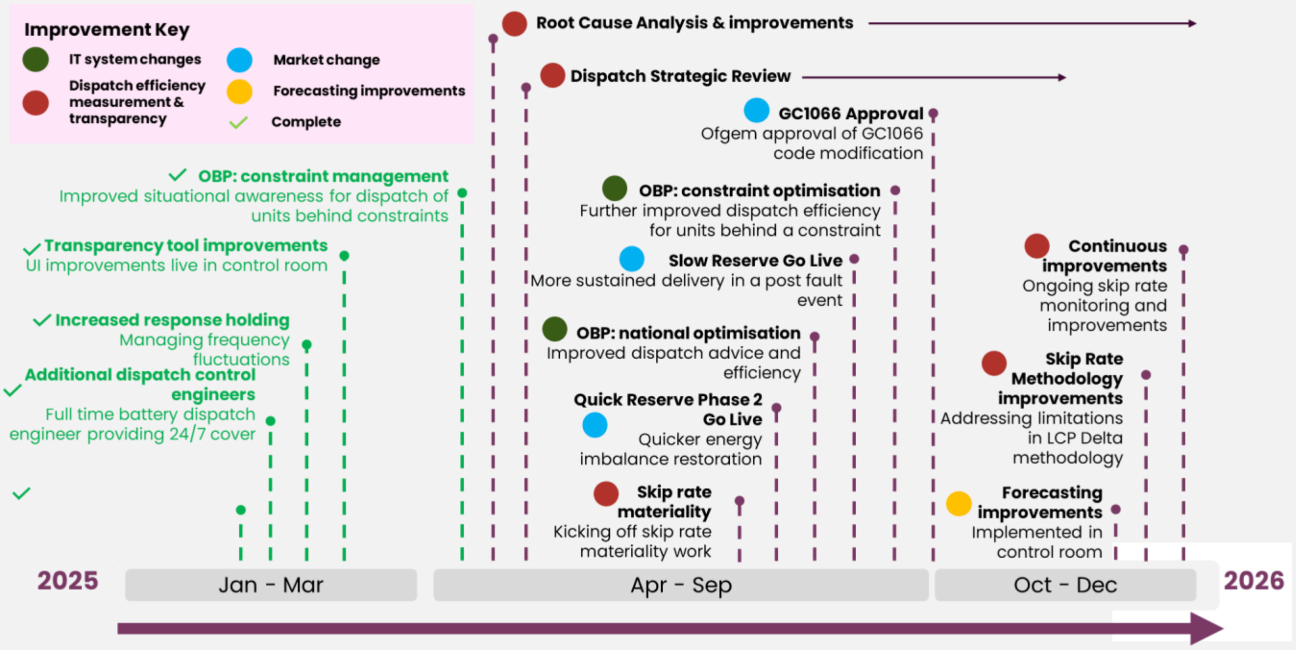
The Offer skip rate has reduced between April (43%) and June (33%) but the skipped volume has increased. The increase in skipped volume aligns with an overall increased volume of energy offers in June.





Note: In these graphs 'Gas' refers to gas reciprocating units, which are typically small, aggregated units.

We have updated our roadmap below to reflect progress so far this year.



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.

June 2025-26 performance

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

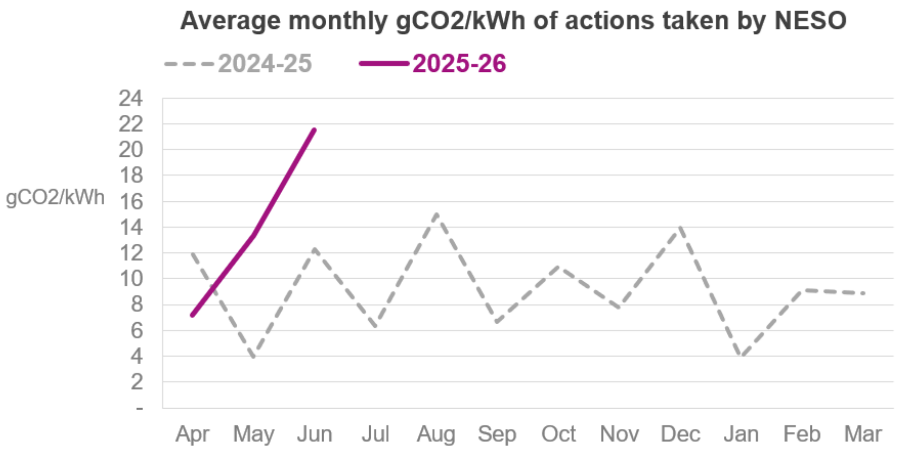


Table: Average monthly gCO2/kWh of actions taken by NESO

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

Supporting information

In June 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 reporting figures.

In June, the average monthly carbon intensity from NESO actions was 21.53g/CO2/kWh based upon ZCO definition (excluding biomass). This is 8.17g/CO2/kWh higher than May and increases the YTD average to 14.02g/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 82.7g/CO2/kWh which took place on 12 June at 23.30. This is 8.37g/CO2/kWh higher than the highest point in May 2025 which took place on 3 May at 1230.

On 12 June there was a yellow MET office waring for thunderstorms and transmission connected wind was high requiring NESO intervention to manage constraints. There was also NESO intervention required to manage unexpected increased demand and transient overvoltage issues on the South coast.

6. Security of Supply

Performance Objective

Operating the Electricity System

Success Measure

As the electricity system in Great Britain evolves, we will transform the capabilities of our people, processes and systems and continue to deliver economic and efficient real-time operation of the electricity transmission system, as measured through the Security of Supply reporting evidence (BP2: RRE 1I).

This Reported Metric shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz for more than 60 seconds, and where voltages are outside statutory limits. On a monthly basis we report instances where:

- The frequency is more than ± 0.5Hz away from 50 Hz for more than 60 seconds
- The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds.
- There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

For context, the **Frequency Risk and Control Report** defines the appropriate balance between cost and risk, and sets out tabulated risks of frequency deviation as below, where ‘f’ represents frequency:

Deviation (Hz)	Duration	Likelihood
$f > 50.5$	Any	1-in-1100 years
$49.2 \leq f < 49.5$	up to 60 seconds	2 times per year
$48.8 < f < 49.2$	Any	1-in-22 years
$47.75 < f \leq 48.8$	Any	1-in-270 years

At the end of the year, we will report on frequency deviations with respect to the above limits and communicate any plans for future changes to the methodology.

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

Supporting information

There was one frequency excursion below 49.7Hz on the 19/06/2025 lasting 66sec.

The frequency dropped following a circuit trip in 400kV. Coincident with the fault, 675MW from an interconnector importing were lost, and 191MW of solar generation was lost.

During the early morning on 29/06/2025, the transmission network in the Southwest of England was operated outside the permissible voltage range of the Security and Quality of Supply Standard (SQSS) and the declared rating of the assets owned by National Grid Electricity Transmission (NGET).

The voltage excursion occurred in the Southwest of England lasting for longer than 2 hours. The voltage control during low demand periods in that region is highly dependent on the reactive power absorption from local generators. Following the start of the de-synchronization sequence of these generators, there were no further options to control voltage in the area to avoid operating outside the permissible voltage limits.

[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.

June 2025-26 performance

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

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

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

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

Supporting information

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

8. Short Notice Changes to Planned Outages

Performance Objective

N/A

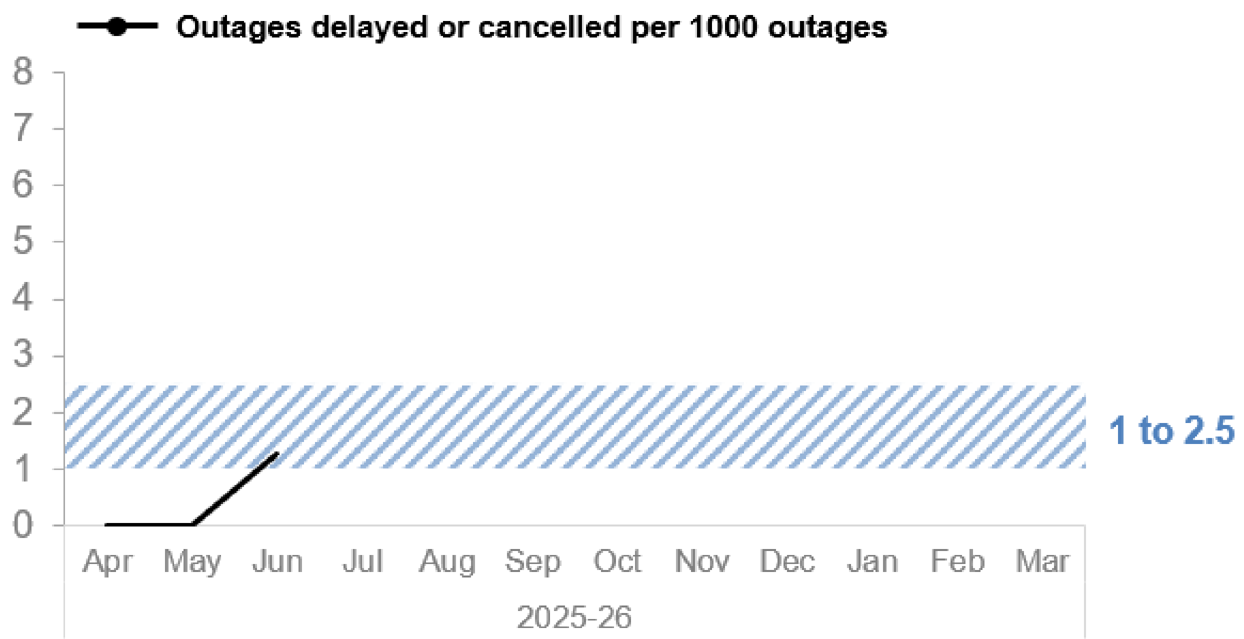
Success Measure

N/A

This Reported metric measures the number of short notice outages delayed by > 1 hour or cancelled, per 1000 outages, due to NESO process failure.

Q1 2024-25 performance

Figure: 2024-25 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages



We have included the BP2 “meeting expectations” benchmark (1 to 2.5) threshold in the graph above for comparability purposes. Note that as per the PAGD, Ofgem will not assess our performance against this metric as below/meets/exceeds.

Table: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	727	750	804										2281
Outages delayed/cancelled due to NESO process failure	0	0	1										1
Number of outages delayed or cancelled per 1000 outages	0	0	1.24										0.44

Supporting information

We successfully released 727 outages in April, 750 outages in May and 804 outages in June. Across these three months there was one delay or cancellation due to a NESO process failure that occurred in June. The number of stoppages or delays per 1000 outages in June was 1.24 while the cumulative number of stoppages or delays per 1000 outages in Q1 is 0.44.

The single delay was caused by the overlap of a planned outage that interacted with a several other network outages and an unplanned outage on the network. This overlap of outages presented a risk where several Grid Supply Points (GSPs) would be exposed to a single circuit fault disconnecting them. This demand at risk was not properly identified within planning timescales due to human error and consequently this was not flagged up to the Transmission Owner (TO). The NESO control room identified this overnight prior to the outage being released. Subsequently, the outage was deferred to a later date where the network risk could be mitigated when other planned outages were complete. An Operational Learning Note (OLN) has been written to capture the sequence of events that led to this being missed and several preventative actions identified.

9. Zero Carbon Operability Indicator

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 provides transparency on progress against our zero-carbon operability ambition by measuring the proportion of zero carbon transmission connected generation that the system can accommodate.

For this Reported Metric, each generation type is defined as whether it is zero carbon or not. Zero carbon generation includes hydropower, nuclear, solar, wind, battery and pumped storage technologies. The power generation sources included in the Government's Clean Power 2030 Action Plan (CPAP) include Biomass in the ZCO metric as zero carbon generation. Biomass is yet to be added into these calculations until agreed. As this Reported Metric relates to NESO's ambition to be able to operate a zero carbon transmission system by 2025, only transmission connected generation is included and interconnectors are excluded (as EU generation is out of scope of our zero carbon operability ambition). Note that the generation mix measured by this Reported Metric Zero Carbon Operability Indicator (BP2: RRE 1F) and the Carbon Intensity of NESO Actions (BP2: RRE 1G).

The Zero Carbon Operability (ZCO) indicator is defined as:

$$ZCO(\%) = \frac{(Zero\ carbon\ transmission\ connected\ generation)}{(Total\ transmission\ connected\ generation)} \times 100$$

Regular reporting on actual ZCO

Every quarter we report the ZCO provided by the market versus the ZCO following NESO actions. This is presented at a monthly granularity.

The table below is calculated according to the formula for ZCO for each settlement period for every day over the reporting period. ZCO is a percentage of the zero-carbon transmission generation (hydropower, nuclear, solar, wind, battery, and pumped storage technologies) divided by the total transmission generation. Two figures are calculated: one represents the system conditions before NESO interventions are enacted, the other is after. This indicator measures progress against our zero-carbon operability ambition by showing the proportion of zero carbon transmission generation that the system can accommodate.

For each month, the settlement period that has the highest ZCO figure after our operational actions were enacted is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum ZCO that the market provided over the month. For example, the maximum ZCO provided by the market in Q2 2023-24 was 98% on 28 September 2023, settlement period 8. However, for that period the final ZCO dropped to 80% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month.

The graphs further below show the underlying data by settlement period and highlight when the maximum monthly values occurred.

Table: Q1 maximum zero carbon generation percentage by month (2025-26)

Month	**Highest ZCO% in the month** (after NESO operational actions)	**ZCO% provided by the market** (during the same day and settlement period)	**Date / Settlement Period**
April	89.14%	95.31%	2 April SP33
May	88.30%	96.98%	29 May SP27
June	89.60%	96.96%	3 June SP26
July			
August			
Sept			
Oct			
Nov			
Dec			
Jan			
Feb			
March			

Note that the values can change between reporting cycles as the settlement data is updated by Elexon.

Figure: Maximum monthly ZCO% after NESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – two-year view

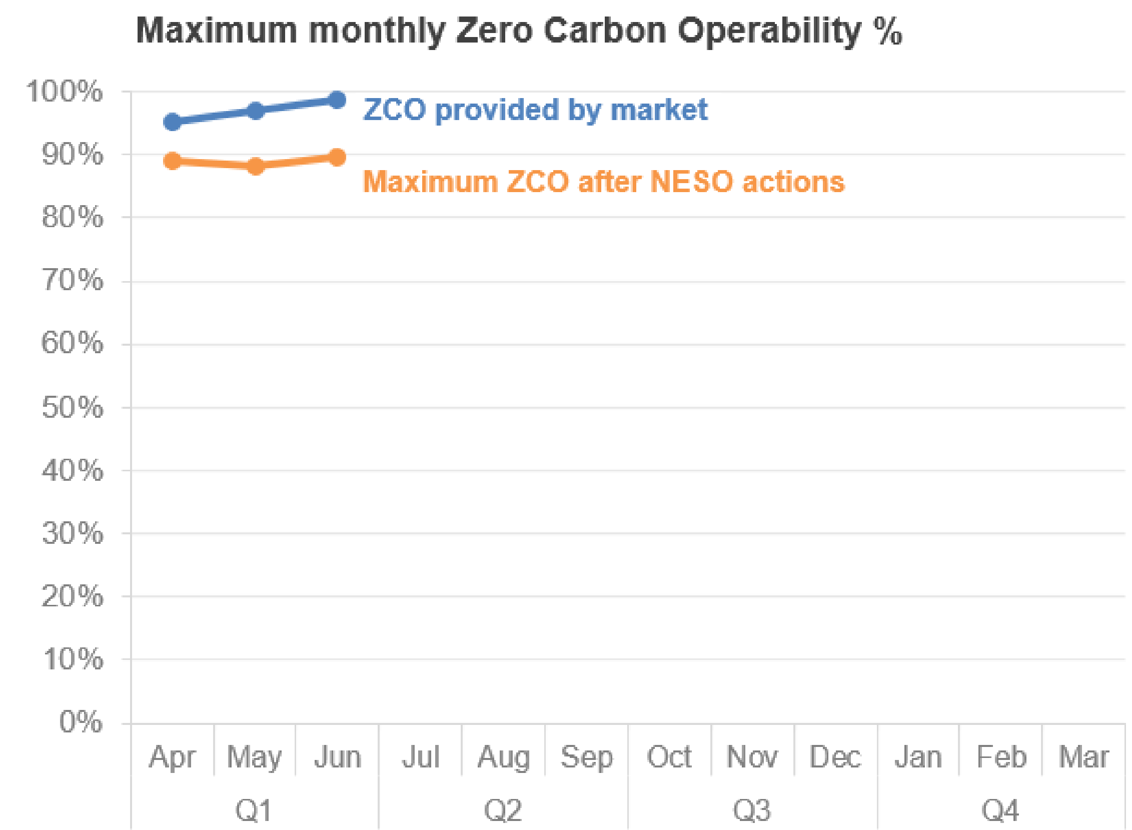
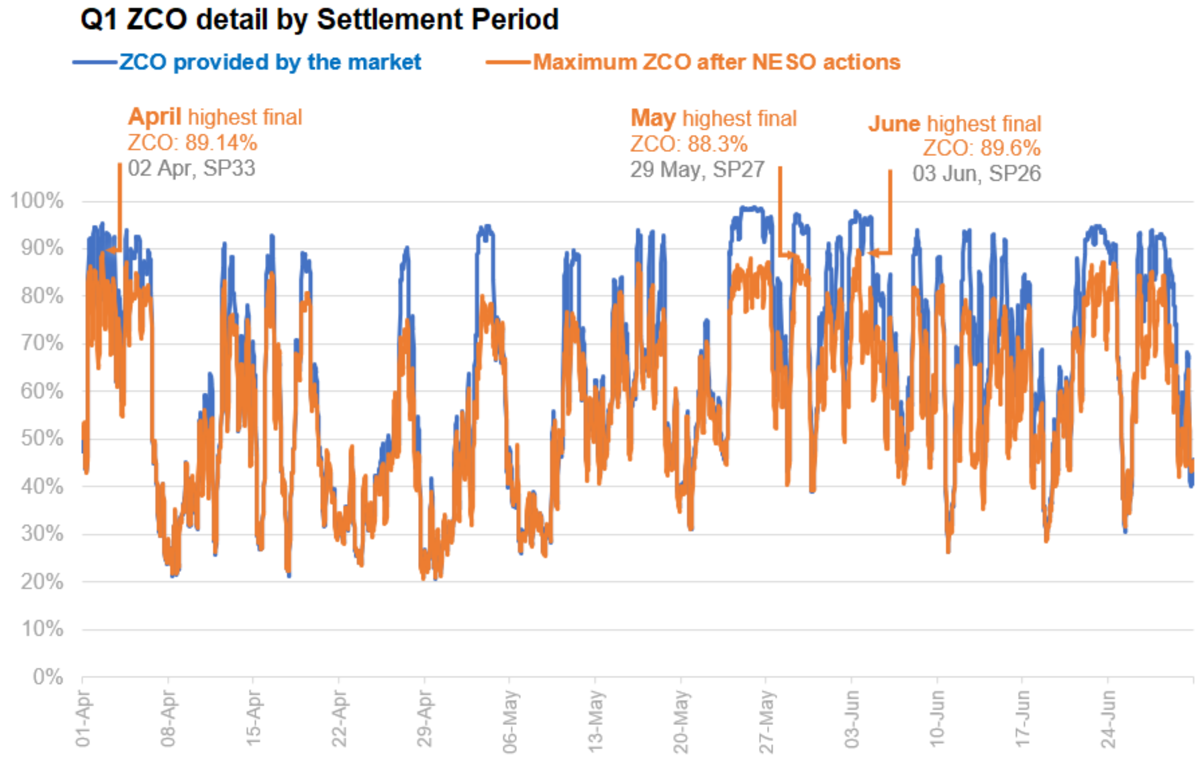


Figure: Q1 2025-26 ZCO by Settlement Period, before and after NESO operational actions



Supporting information

In Q1 2025-26, the monthly average highest ZCO was 89.0% which is 0.9% higher than last quarter's average of 88.1%

In April the highest ZCO% performance for a single settlement period was 89.1%, a 3.1% decrease on the same position 12 months ago when the ZCO record of 92.2% was reached.

On 2 April unrestricted transmission connected wind levels were high and restrictions were required to manage constraints in Scotland.

On 29 May unrestricted transmission connected wind levels were high again. NESO intervention was required to manage losses on the interconnector hourly gates throughout the afternoon leading to dynamic scheduling and despatch decisions being made.

On 3 June unrestricted transmission connected wind levels were volatile rising to 20GW then dropping to 12GW throughout the day. Managing large amounts of fluctuating wind that coincided with peak solar generation required increased NESO intervention.

Overall this quarter demonstrates a positive trend in the monthly average ZCO% with NESO intervention required to manage high levels of transmission connected wind.

Highest final ZCO by month vs previous year

Quarter	Month	2024/25	2025/26	Difference
Q1	April	92.2%	89.1%	-3.1%
	May	83.4%	88.3%	+4.9%
	June	86.1%	89.6%	+3.5%
Q2	July	86.7%		
	August	89.2%		
	September	84.6%		
Q3	October	85.1%		
	November	84.6%		
	December	89.4%		
Q4	January	88.7%		
	February	86.6%		
	March	93.5%		

10. Constraints Cost Savings from Collaboration with TOs

Performance Objective

N/A

Success Measure

N/A

The Transmission Operators (TOs) need access to their assets to upgrade, fix and maintain the equipment. TOs request this access from NESO, and we then plan and coordinate this access. We look for ways to minimise the impact of outages on energy flow and reduce the length of time generation is unable to export power onto the network.

This Reported Metric measures the estimated £m avoided constraints costs through NESO-TO collaboration.

There are two ways NESO can work with the TOs to minimise constraint costs. We will report on both:

1. ODI-F savings: Actions taken through the System Operator: Transmission Owner (SO:TO) Optimisation ODI-F

    i. Output Delivery Incentives (ODIs) are incentives that form part of the TOs' RIIO-2 framework. They are designed to encourage licensees to deliver outputs and service quality that consumers and wider stakeholders want to see. These ODIs may be financial (ODI-F) or reputational (ODI-R).

    ii. One of these ODIs, the SO:TO Optimisation ODI-F, is a new two-year trial incentive to encourage the Electricity Transmission Owners (TOs) to provide solutions to NESO to help reduce constraint costs according to the STCP 11-4[4] procedures. NESO must assess the eligibility of the solutions that the TOs put forward in line with STCP 11-4, and must deliver the solutions in order for them to be included as part of the SO:TO Optimisation ODI-F and for this metric.

[4] The STCP 11-4 'Enhanced Service Provision' procedure describes the processes associated with NESO buying a service from a TO where this service will have been identified as having a positive impact in assisting NESO in minimising costs on the GB Transmission network.

iii. For this metric, where constraint savings are delivered through the SO:TO Optimisation ODI-F, the savings are calculated in line with the methodology for that incentive.

2. Other savings: Actions taken separate from the SO-TO Optimisation ODI-F

i. NESO also carries out other activities to optimise outages. In these cases, the assumptions used for estimating savings will be stated in the supporting information.

Figure: Estimated £m savings in avoided constraints costs (ODI-F) – 2025-26

(Estimated savings in GWh are also shown for context)

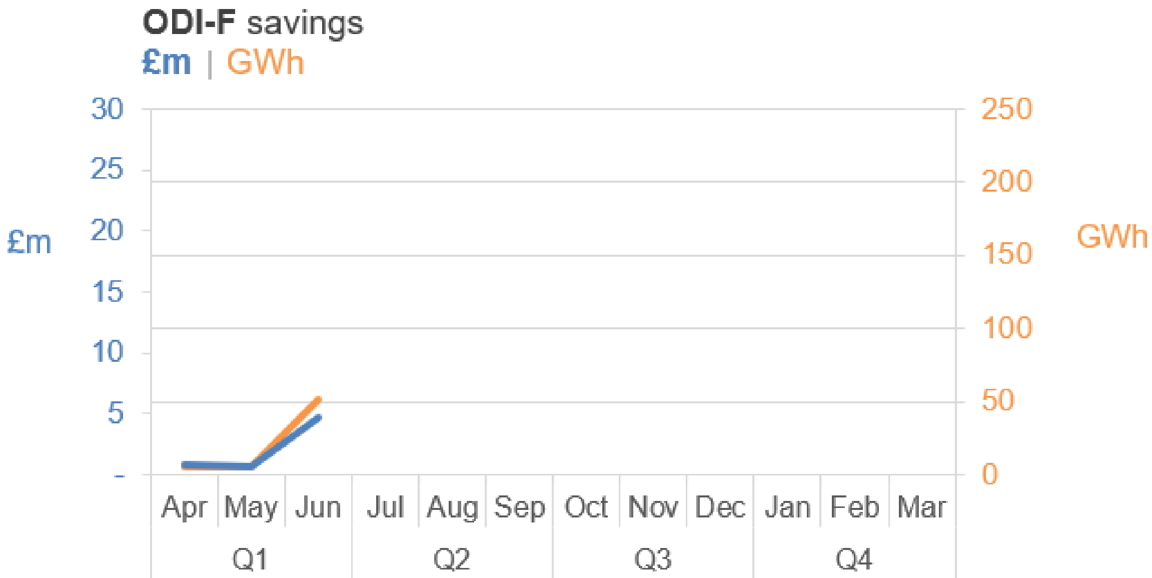


Figure: Estimated £m savings in avoided constraints costs (Other)

(Estimated savings in GWh are also shown for context)
*Note **vertical axes scales** differ from the ODI-F graph above.*

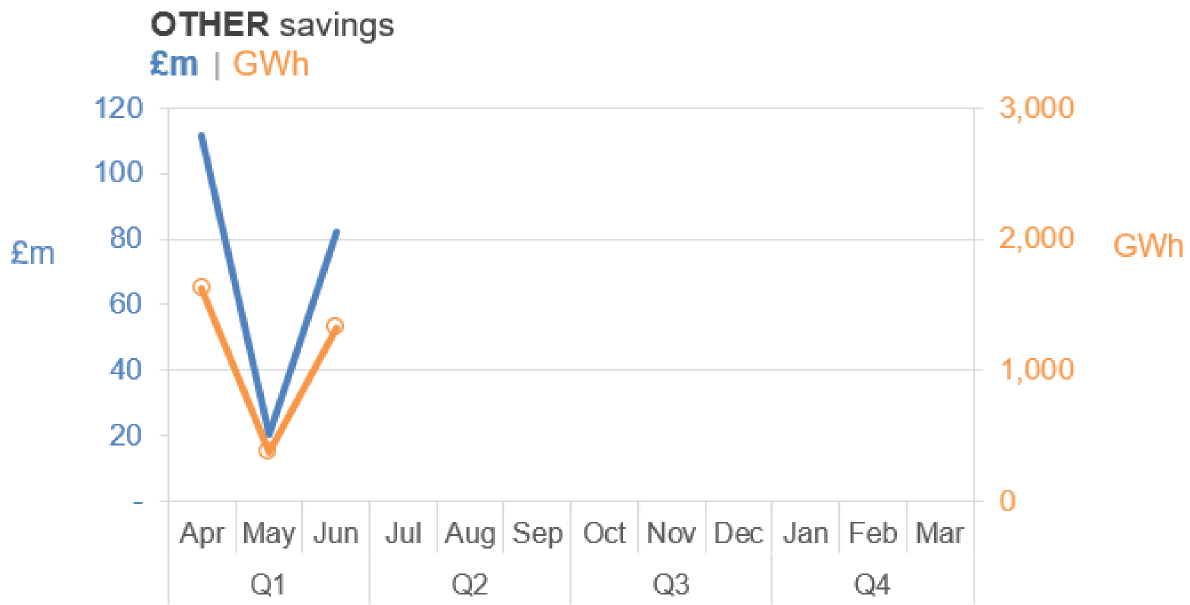


Table: Monthly estimated £m savings in avoided constraints costs (2025-26)

	ODI-F savings	**Other** savings	**ODI-F** savings	**Other** savings
	£m	£m	GWh	GWh
Apr	0.8	111.8	5.8	1628.5
May	0.6	20.3	5.3	376.0
Jun	4.7	82.0	51.8	1327.7
Jul				
Aug				
Sep				
Oct				
Nov				
Dec				
Jan				
Feb				
Mar				
YTD	**6.1**	**214.1**	**62.9**	**3332.2**

Note that figures from previous quarters may change as some savings are updated retrospectively with costs that were not available at the time that the activities were carried out.

Prices of £36 per MWh are used for conventional generation and £75 per MWh for renewable generation.

Supporting information

ODI-F (STCP 11-4) Constraint Cost Savings

The Network Access Planning (NAP) team has progressed and completed 3 approved enhanced service provisions from TO's through STCP 11.4 that provide constraint cost savings this quarter. Some of these provisions are highlighted below:

- In April, National Grid Electricity Transmission (NGET) and Network Access Planning agreed upon enhancements based on static and dynamic weather conditions for two circuits connecting North Tyneside to Northumberland and South Tyneside. These improvements were implemented to facilitate NGET routine maintenance works on a circuit linking Tyne and Wear County with Northumberland. As a result, these enhancements saved **5.78 GWh** of energy and resulted in an outturn cost of **£0.75 million** for the end consumer.

- In May, National Grid Electricity Transmission (NGET) and Network Access Planning agreed upon enhancements based on dynamic weather conditions for a circuit connecting Preston in Lancashire County to Kirkby in Merseyside Northwest of England. These improvements were implemented to facilitate repair to a damaged pedal disconnector on a circuit linking Preston County to Metropolitan Borough of Knowsley. As a result, these enhancements saved **5.26 GWh** of energy and resulted in an outturn cost of **£0.56 million** for the end consumer.

- In June, National Grid Electricity Transmission (NGET) and Network Access Planning agreed upon enhancements based on dynamic weather conditions for two circuits connecting Hartlepool in Durham County to West Boldon in the county of Tyne & Wear, NorthEast England. The improvements were implemented to facilitate NGET routine maintenance on the circuit linking Offerton in Tyne & Wear County to Hawthorn Pitt in Durham County. As a result, these enhancements saved **51.8 GWh** of energy and resulted in an outturn cost of **£4.7 million** for the end customer.

In Q1 2025-26 financial year, NAP has achieved **£6.0 million** in constraint cost savings through STCP 11-4 with the release of **62.8 GWh** of additional capacity. This is because only started and completed enhancements have been reported. There are several ongoing enhancements which will be included in the next quarterly reports once they have successfully completed.

Other Savings (Customer Value Opportunities (CVO)):

The Network Access Planning team has demonstrated significant progress over the past three months. In collaboration with our stakeholders, Transmission Owners (Tos) and Distribution Network Operators (DNOs), we have identified and documented **51 instances this quarter,** where the actions of the National Energy System Operator (NESO) have directly contributed to adding value for end consumers. Additionally, NESO's innovative approaches have successfully facilitated increased generation capacity for connected customers. Such actions include adjusting outage dates, segmenting outages, minimizing return to service times, acquiring enhanced ratings from Transmission Owners (TOs), re-evaluating system capacity, identifying and facilitating opportunity outages, synchronizing outages with customer maintenance schedules and generator shutdowns, proposing and implementing alternative solutions for prolonged outages that impact customers, among others. Some examples of these instances include:

- In April, NAP received a system access request from National Grid Electricity Transmission (NGET) on the circuits connecting Waltham Cross in Hertfordshire to Haringey Borough in Greater London for 3 months, needed as part of the Hackney Waltham Cross Upgrade Scheme to uprate the circuits to 400kV. However, due to this request boundary LE1 will be constrained heavily. To minimize the impact, NAP and NGET agreed to reconfigure the substation located in Hertfordshire to enhance the LE1 boundary. This action resulted in saving **1.16 TWh** of energy worth approximately **£86.9 million**.

- In May, NAP received a system access request from Scottish Power Transmission on the circuit connecting Busby to Neilston in East Renfrewshire in the west of central Lowlands of Scotland, needed for replacement of a Supergrid Transformer. However, due to this request the capability of the Western Link High voltage direct current circuit connecting Ayrshire region in Scotland to North Wales will be reduced by 350MW thereby impacting boundary B6, B6a and B7. To minimize this impact, NAP agreed with SPT to provide enhanced ratings on the circuits connecting Lambhill to Windyhill in the north of Glasgow, East Kilbride to Strathaven in South Lanarkshire and Neilston in East Renfrewshire to East Kilbride in South Lanarkshire to remove the limitation on the Western Link High Voltage Direct Current circuit for the duration of the outage. This action resulted in saving **0.07 TWh** of energy worth approximately **£5.25 million**.

- In June, NAP received a system access request from NGET for a circuit connecting Harker in Cumbria County to Hutton in East Yorkshire for replacement of a Printed Circuit Board. However, this outage would clash with a planned outage on the Western Link High Voltage Direct Current Bipole circuit connecting Ayrshire region in Scotland to North Wales, thereby impacting the boundary B6a. To minimize the impact of this outage, NAP proposed to NGET to place the outage for a different date in Mid-June. This action resulted in saving **0.05 TWh** of energy worth approximately **£4 million**.

The customer value opportunities, along with others, collectively amount to an additional **3.33 TWh (approximately £214 million)** of generation capacity across Q1 in the 2025/2026 financial year. The surplus capacity would have otherwise been restricted, incurring costs to the end consumer.

The £/MWh figure for savings is calculated per outage. Savings for conventional generation are calculated using £36 per MWh, while renewable generation uses £75 per MWh. Where a full commercial cost-benefit analysis is available, those figures are used instead. Due to the high price per MWh in fully costed CVOs and the increase in renewable generation on the network, the average price per MWh is approximately £65.

11. Day-ahead procurement

Performance Objective

N/A

Success Measure

N/A

This Reported Metric measures the percentage of balancing services procured at no earlier than the day-ahead stage, i.e. those procured at day-ahead or closer to real time. We report on total contracted volumes (mandatory and tendered) in megawatts (MWs). Expectations are set for all relevant services that are currently procured by NESO and may be revised if new products are introduced.

Benchmarks are set based on expected product expirations, and expectations for new procurement volumes:

Note that in line with the terms of a derogation from the requirements of Article 6(9) of the Electricity Regulation, NESO is required to procure at least 30% of services no earlier than day-ahead stage.

Whilst NESO set out the daily requirements for day-ahead procurement, when these requirements are not met through competitive day-ahead tendering the outstanding requirement could be met through other means such as bi lateral agreements and mandatory markets.

The following services are included in the figures for this metric:

Day-ahead: Short-Term Operating Reserve (STOR), Dynamic Containment, Dynamic Moderation, Dynamic Regulation, Static Firm Frequency Response, Quick reserve

Non-day-ahead: Mandatory Frequency Response only. Previously, this also included Long Term STOR, however since April 2025, this service is no longer procured..

Services newly introduced during BP2 should only be included in this metric if they displace those procured earlier than day-ahead. This is the reason why Balancing Reserve figures are not included in the Volume details by service table in page 61.

Q1 2025-26 performance

Figure: Quarterly percentage of balancing services procured at no earlier than day-ahead

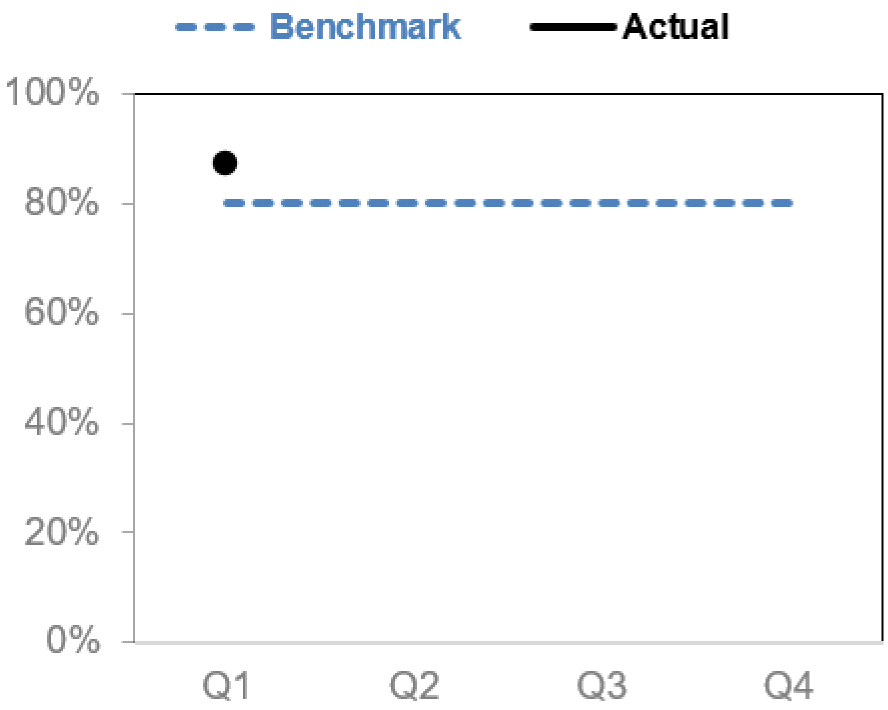


Table: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4	YTD
Volume of balancing services procured (average per procurement period)	MW	5266				
Volume procured no earlier than day-ahead (average per procurement period)	MW	4595				
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	87%				
Benchmark*	%	80%				

* For consistency with previous RIIO-2 incentives reporting, we have included a view of a benchmark based on the BP2 methodology. We are evaluating how we report differently going forward instead of the historical benchmarks. We will consider how new services

and those retired will impact any aggregations. For this quarter, we will however continue to refer to the benchmark indicated in BP2, as there aren't any significant changes from the previous period and therefore some continuity is possible. Note that as per the PAGD, Ofgem will not assess our performance against this metric as below/meets/exceeds.

Volume details by service

Type	Service	Unit	Q1	Q2	Q3	Q4	YTD
Day-ahead	DC	MW	1275				
	DM	MW	294				
	DR	MW	448				
	Static FFR	MW	202				
	STOR	MW	1751				
	BR	MW	N/A				
	QR	MW	625				
	Total	MW	4595				
Non Day-ahead	MFR	MW	671				
	STOR long-term	MW	N/A				
	Total	MW	671				
All	Grand Total	MW	5266				

Supporting information

In the previous year, we reported 81.7% of balancing services volume was procured no earlier than day-ahead, slightly above the benchmark of 80%. In this quarter, the percentage has increased to 87%. However, we are evaluating how best to report the trends from this quarter onwards.

With the growth in response and reserve competitive markets, we can procure more of our requirements at day-ahead so have less reliance on non-day ahead procured services. As more reserve services such as Quick and Slow Reserve are introduced to day-ahead procurement and historic non-competitively procured services like Long-Term STOR retiring this year, we expect to see a steady rise to more competitively procured day-ahead volumes being utilised.

12. Accuracy of Forecasts for Charge Setting - BSUoS

Performance Objective

N/A

Success Measure

N/A

This Reported Metric shows the accuracy of Balancing Services Use of System (BSUoS) forecasts used to set industry charges against the actual outturn charges.

The BSUoS charge (£/MWh) is now based upon a fixed tariff. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) are forecast for six-monthly tariffs and set 9 months ahead of the chargeable tariff period. For 2025/26, Fixed Tariff 5 (April 25 – September 25) was published in June 2024. Fixed Tariff 6 (October 25 – March 2026) was published in December 2024.

We continue to forecast balancing costs monthly and measure our performance against this forecast. It remains an important metric to support the fixed tariff methodology by being the main component of the fixed BSUoS tariff. The BSUoS cost forecast (costs rather than what is charged against the fixed tariff) is probabilistic and therefore produces percentile values. The published forecast for each month is based on the central value of the BSUoS cost forecast (50th percentile). If the outturn BSUoS costs are below the 50th percentile of the cost forecast, then the actual costs for that month would be lower than the forecast predicted, provided the actual volume is at or above the estimate (and vice versa).

Q1 2025-26 performance

Figure: 2024-25 Monthly BSUoS forecasting performance (Absolute Percentage Error)

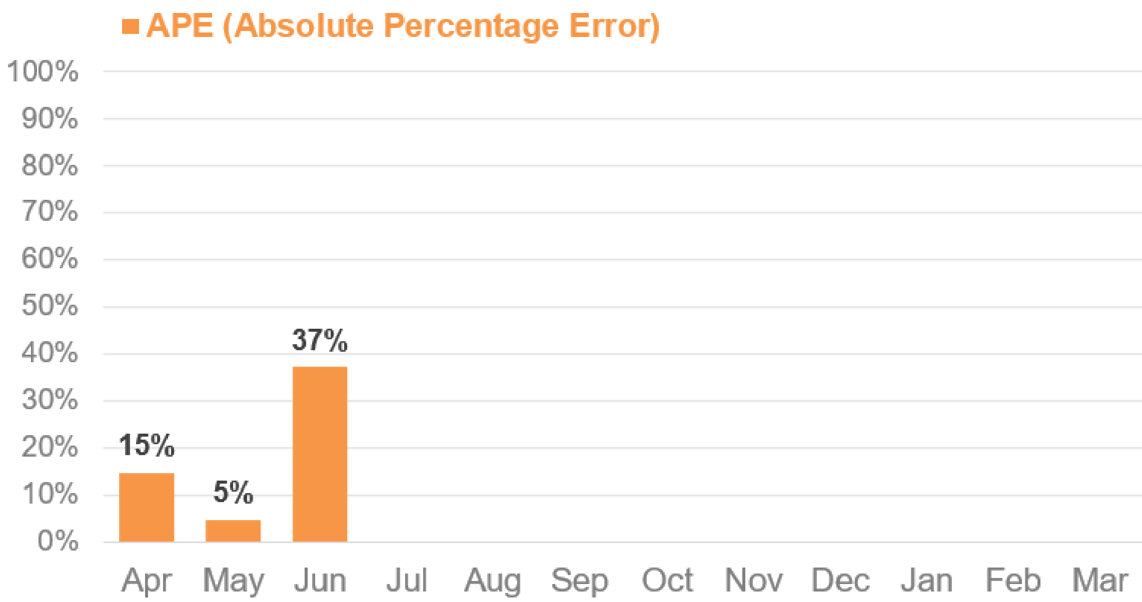


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	9.53	13.02	18.54									
Month-ahead forecast (£ / MWh)	11.15	12.46	13.52									
APE (Absolute Percentage Error)[5]	14.5	4.5	37.1									

Supporting information

Q1 Performance:

The average monthly Absolute Percentage Error for Q1 is 18.7%, with higher than month ahead forecasts for both May and June.

The BSUoS forecast is probabilistic and tries to find patterns in recent history. It also uses two key drivers in forecasting expected costs; wholesale market prices and the proportion of demand met by renewables.

[5] Monthly APE% figures may change with updated settlements data at the end of each month. Therefore, subsequent settlement runs may impact the end of year outturn.

Costs:

Total balancing costs across the quarter outturned above our month ahead forecast across the quarter, with the largest variance from our June 2025 forecast.

In April, balancing costs outturned just below the 25th percentile of our month ahead forecast. Wholesale market prices were 6% lower than those used within the balancing cost model, and constraints were £51m lower than forecast.

In May, balancing costs outturned at the 55th percentile of our month ahead forecast, £7m above our forecast. Wholesale market prices outturned 8% lower than those modelled, with the proportion of demand met by renewables 8% higher than forecast.

June balancing costs outturned at the 95th percentile of our month ahead forecast, predominantly due to constraint costs outturning £90m above our forecast. Wind outturn for June was higher than anticipated, with 53% of demand being met by renewable generation against a forecast 35%. We have found previously that a higher proportion of renewables tends to correlate to higher constraint costs.

The high outturn from June will impact our future forecasts through our persistence model, which uses previous forecasting errors to adjust the near term of our forecasts.

We are also continuing to monitor the performance of the balancing cost forecast, and the distribution of the outturn percentiles compared to forecast.

Volumes:

Chargeable BSUoS volume is forecast using a linear regression model based on the National Demand forecast, and historic actual BSUoS volumes.

Across Q1 our average monthly volume forecasting error was 2.8%, with the largest variance in April, with volumes outturning below forecast, with high solar production reducing demand across the month.

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