NESO RIIO-2 Business Plan 2 (2023-25)

End-Scheme Incentives Report

Annex A: Role 1 - Control Centre Operations

May 2025

NESO
National Energy System Operator

Contents

A.1 Activity Updates

See below an overview of Activity updates for Role 1 over the second year of the Business Plan 2 period. This incorporates evidence covering Plan Delivery, Stakeholder Evidence and Quality of Outputs.

Role 1 Activities

BP2 delivery schedule activity/deliverable reference shown in brackets where relevant

Forecasting (D1.1.7)

What did we define as success for the end of BP2?

Continue to provide timely and accurate possible forecasting data to industry.

Continue with the development of the forecasting platform for integration with NESO's strategic platforms, Data and Analytics Platform (DAP), and Open balancing platform (OBP).

Forecasting product/model improvement (as possible).

What have we achieved by the end of BP2?

We delivered our updated core Forecasting Platform on Azure (PEF v2), along with its new generation Wind Forecasting product. While the delivery was later than intended, the product was released into Production in early November 2024. This new capability unleashed a significant improvement in wind forecasting performance, which has been maintained since. This new platform has allowed us to rebuild its wind High Speed Shutdown model, which was utilised successfully during Storm Éowyn.

We also delivered a new web-based suite of Wind Forecast User Interfaces (UIs) for Distributed Energy Resource (ENCC) Operations. This UI offers enhanced situational awareness and a far richer user-experience for control room and business users.

More recently, we undertook a series of model-validations to facilitate the migration of legacy forecast products (National Demand Machine Learning, Grid Supply Point Demand and National Solar).

We constructed a set of Solar Balancing Mechanism Units (BMU) models on the new platform, providing BMU-resolution solar forecasts for the new portfolio of industrial-scale solar farms.

We acknowledge that Metric 1B - Demand Forecasting Accuracy performance has been below standard and there are known reasons for this. In February 2025 we presented a comprehensive 1B/1C Improvement Plan to Ofgem, detailing the current challenges and planned solutions.

Our forecasting team has made strong progress and utilisation of its Advanced Analytics Environment (AAE) which is hosted on the Data Analytics Platform. The AAE has allowed the development of an updated prototype version of its National Demand ML model, which is using AI (Artificial Intelligence) capability, while facilitating expanded data science support to wider business functions.

Energy Forecasting has continued to support the Balancing Programme and facilitate the Forecasting forum, a request from this forum resulted in additional data being published on the NESO data portal. We have also supported the Operational Transparency Forum (OTF) with a deep-dive analysis of INDO (Initial National Demand Outturn).

Energy Forecasting has remained a healthy focus of external customers and stakeholders. We continue to offer support for extensive customer queries on our published datasets, both on Balancing Mechanism Reporting Service (BMRS) and Data Portal. We have also responded to customers' data requests and published additional new datasets.

How did our approach maximise outcomes?

Accepting that we had a suite of legacy forecasting products and tools, and that the delivery of the new generation Wind Forecasting product was in flight, we initially focused on the immediate improvement of Metric 1C - Wind Forecasting Accuracy.

We identified and prioritised a series of required data and model-upgrades for the planned Most Viable Product (MVP) release, along with a list of improvements to be delivered at later dates. Prior to its release, we evaluated the model to ensure that it would perform as expected.

In the preparation of the new Wind User-Interface, we collated internal user-requirements and executed an Agile delivery plan.

We have identified the major contributing factors to the poor performance of Metric 1B and focused on those areas.

We listened and responded to customer needs, preparing and publishing additional forecast-related datasets on the Data Portal.

Skip Rates (Dispatch Transparency)

Why are we undertaking this activity?

NESO has an obligation to operate a safe, reliable and efficient system. With the rapid acceleration of renewable energy sources, the volume and complexity of balancing actions taken by our control teams has increased significantly. We have demonstrated our commitment to battery assets and other flexible providers through regular engagement with industry, however, we recognise that our operational systems, processes and tools have not always kept up with the pace of this rapid transition. We need to do more to unlock these new technologies and reduce skip rates across all asset types.

What have we achieved by the end of BP2?

We have continued to engage with customers to explain how we make dispatch decisions and to respond to queries. We recognised that we needed to do more to manage skip rates, and, in October 2024, we accelerated our activities to define, measure, and address skip rates.

We commissioned LCP Delta to conduct a historic review of skip rates and develop a new methodology for their calculation. Building on from this, we established a common definition for skip rates (All Balancing Mechanism (BM) and Post System Action (PSA)), which align with the LCP Delta methodology. In December 2024, we started publishing a daily data set for skip rates for every settlement period for Bids and Offers. This data is presented in our weekly Operational Transparency Forum. Alongside this, we have published a delivery roadmap and skip rate methodology, outlining how we are defining, refining, measuring and addressing skips. We also started delivering initiatives to drive efficiency and transparency in our dispatch decisions.

We held two CEO roundtables (10 October & 3 December) with Battery senior leaders to discuss progress with our actions. This was supplemented by an in-person Battery Forum event on 4 December, which provided a platform for discussion and collaboration, and supported LCP Delta with a webinar about their methodology. Our customer engagement has continued with a Battery Storage and Skip Rate webinar on 27 February. The webinar provided updates on the roadmap and progress with actions to address skips rates. We also facilitated a skip rate data surgery on 12 March and hosted customers at our Control Centre.

We have established a Skip Rate Programme to coordinate all our activities to address skip rates across the BP3 period.

How did our approach maximise outcomes?

By listening to our customers, especially battery energy storage systems (BESS) we recognised that we need to do more to address their concerns. This resulted in us creating an accelerated programme to define and measure skip rates.

Recognising the complexity and breadth of activities impacting skip rates, we have created a single programme to track the activities addressing improvements. In addition, we have taken ownership for reducing the skip rate number, building a more robust methodology by finding ways to remove limitations and investigating additional root causes.

Managing the system (Frequency / voltage events, security of supply) (A1.1)

What did we define as success for the end of BP2?

No reportable voltage and frequency excursion events within the National Electricity Transmission System (NETS) based on the C17 reporting criteria statement.

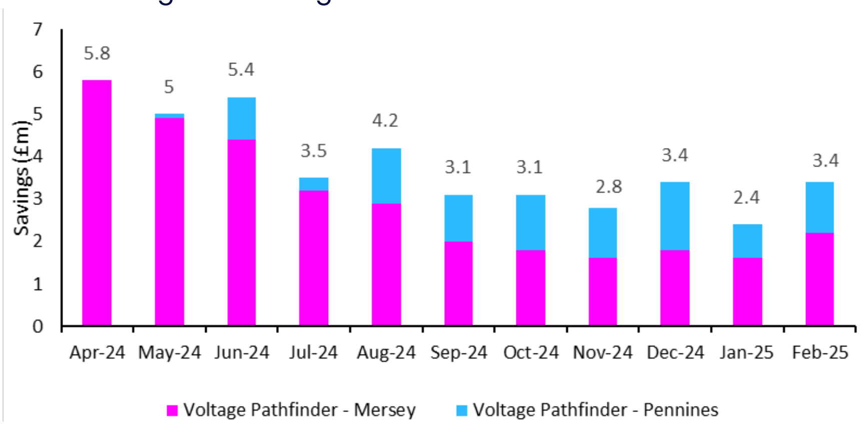
The power system is highly dynamic and variable, requiring the management of numerous factors.

Voltage

In tracking costs for balancing services, we regularly monitor the savings delivered by voltage pathfinders. These savings have demonstrated realised benefits higher than the initial Cost-Benefit Analysis (CBA) figures when the schemes were initially designed. Voltage pathfinders are not a silver bullet for solving voltage problems in the system, but they have proven particularly useful in reducing operational costs in voltage management by decreasing reliance on Balancing Mechanism Units (BMUs).

Please note that savings delivered by Stability Pathfinder Phase 1 are not included here, although they provide voltage regulation in addition to inertia and short-circuit level support.

Figure 1: Voltage Pathfinders Realised Benefits



However, we continue to face several challenges in managing system voltage. This relates to changes to the generation mix and flows on the transmission system and changes to demand taken by Distribution Network Operators (DNOs) (the reactive power demand is falling by circa 500 MVAr per annum). The increased unavailability of Reactive Compensation Equipment also exacerbates these challenges.

Frequency

The Frequency Risk and Control Report (FRCR) 2023 recommended to reduce the minimum inertia requirement from 140 GVA.s to 120 GVA.s. The policy was approved by Ofgem on the 9 June 2023 and the first phase of inertia reduction to 130 GVA.s was successfully implemented on 28 February 2024. Phase 2 of further reduction of minimum inertia requirement down to 120 GVA.s was implemented on 19 June 2024. By end of BP2 post implementing the reduced minimum inertia policy, there has been no reportable frequency excursion events according to the C17 reporting criteria. The total saving from inertia requirement reduction is well above the FRCR 2024 projection.

Stability

We have an obligation to operate a safe, reliable and efficient system. With the rapid acceleration of Renewable Energy Sources (RES) and the penetration of Inverter-Based Resources (IBR) into power systems, Sub-Synchronous Oscillation (SSO) has begun to emerge. This poses extra challenges to the secure and reliable operation of these system.

The impact of this new risk, associated with the SSO events in operating the GB system, requires managing. It is one of the main challenges with other System Operators worldwide. A high IBR penetration system is currently under active research in the area of detection, prediction, source location, simulation, mitigations etc.

NESO aims to pursue practical approaches in the fields of SSO detection, oscillation source location, SSO-related Electro Magnetic Transient (EMT) simulation in collaboration with the industry and academia.

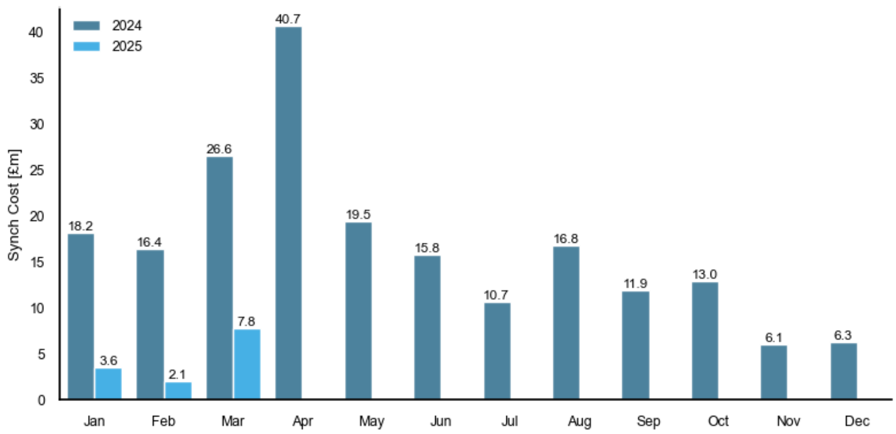
What have we achieved by the end of BP2?

During the 2023-25, there were no reportable Voltage and Frequency excursions within the NETS.

Voltage

NESO has significantly reduced the spending on voltage management during 2024 and into 2025, after reaching significant peaks in 2023.

Figure 1. System cost of synchronisation actions for voltage management



This primarily depends on the operational conditions of the system (e.g., identification of voltage control circuits, BMUs scheduled, demand, etc.), but also on various initiatives undertaken by NESO, particularly focused on the procurement of network services. These initiatives include:

- Economic assets commissioned through voltage pathfinders, including those located in Mersey (a 38 MVAr battery at Capenhurst and a 200 MVAr reactor in Frodsham) and Pennines (reactors at Bradford West – 100 MVAr, Stocksbridge – 200 MVAr, and Stalybridge – 200 MVAr).

- Stability assets commissioned through stability pathfinders. Twelve synchronous compensators received contracts through Phase 1, providing roughly 12.3 GVA.s of inertia to the system, in addition to 1.06 GVAr of absorption and 950 MVAr of injection capacity.

Additionally, the commissioning of the Greenlink interconnector at the end of 2025 has provided the system with additional compensation capacity, allowing for further reductions in voltage management spending.

Moreover, during the BP2 period, NESO requested the installation of new shunt reactors in the South West of England, particularly in Taunton (200 MVAr) and Melksham (200 MVAr). This is an area where voltage management has been particularly challenging. It is expected that the compensation equipment will be available by mid-2025 (Melksham) and early 2026 (Taunton).

Frequency

Since implementing the lower minimum inertia policy that was recommended in FRCR 2023 policy, there was no reportable frequency events in the GB system. This is where the system frequency excursions outside statutory limits, i.e. a range of 49.5 Hz to 50.5 Hz, for 60 seconds or more. There was no increasing trend observed in frequency events based on Grid Code – OC3 reporting criteria. During those frequency events, the system and response services performed as expected. The events were not initiated, caused or related to the lower system inertia policy.

Balancing cost saving

Between February 2024 and January 2025, the estimated balancing cost savings from lowering the minimum inertia requirement from 140 GVA.s to 120 GVA.s totalled over £200 million. That figure is well above the FRCR 2024 projection.

System events

NETS experienced two simultaneous events within the BP2 period. The low frequency event on 22 December 2023 was caused by cascading trips within 10 seconds with the total loss of ~1.7 GW. On 14 March 2025 a significant loss of infeed of ~1.9 GW occurred. It was initiated by the cascading trip of three generating units at one power station. During both frequency events, the system behaved as expected. Simultaneous events were not securable events according to the FRCR policy; however the system frequency was well contained based on the system conditions and the response service holding at the time the events occurred. Both events did not breach the Security & Quality of Supply Standard (SQSS) frequency statutory limit as frequency excursion was within 49.2 Hz and returned to 49.5 Hz in less than 60 seconds.

Tools

We have delivered our new Frequency and Time Error (FATE) replacement product, which has reduced the risk associated with the previous FATE product.

Stability

The number of SSO events recorded has been increasing since 2020. A lot of progress has been made since 2021 in areas such as EMT modelling, monitoring, compliance and post-event analysis spaces through collaborative working across the Transmission Owners (TOs) and NESO. The root cause of most have been identified and rectified. Despite the progress made, the recent reoccurrence of SSO events indicates the need for further collaboration across the transmission organisations to accelerate progress and assess current approaches.

SSO taskforce

We formed an SSO taskforce in September 2024, continuing from the previous SO chaired working group. The SSO taskforce has been created to build on the past work, accelerate the progress and facilitate sharing learnings. The taskforce will be a vehicle through which TOs, NESO and potentially other stakeholders collaborate closely with minimum organisations boundaries to achieve the taskforce purpose.

The taskforce is working on revising our SSO assessment guidance for Inverter Based Resources (IBR). We will issue a second version based on this work and other feedback from stakeholders. The taskforce has reviewed the SSO post-event investigation process and implemented amendments to improve the overall procedure.

Further workstreams could be launched later this year to investigate other areas, including short-term operational mitigation actions and event replication.

Estimated timeline to issue final recommendations from the ongoing SSO taskforce workstreams is Q2 2025. The outcome will be shared with Ofgem.

The taskforce had a meeting with Ofgem in February 2025 to update the latest progress on the SSO and a further session was held with Ofgem in March 2025 to discuss the recent SSO cases and actions taken to address the issue. A further meeting is scheduled in September 2025 to communicate the progress with Ofgem.

Under the wider industry engagement, we updated the industry in February 2025 compliance seminar on the SSO management. In March 2025, SSO taskforce organised a panel session on SSO during the IET AC/DC conference.

In May 2024 we published the Sub-synchronous oscillations in GB report, which covered the current state and plans for future management of SSO events.

We are engaging with international organisations and bodies such as International System Operator Network (ISON) and Global Power System Transformation (G-PST) to expedite the progress in SSO related works. We are supporting research works and innovations projects in the field of oscillation source location.

We arranged a six-month secondment with one of the System Operators (AEMO - Australian Energy Market Operator) with high IBR penetration. This enabled us to exchange experience and knowledge on how to manage SSO
on the NETS.

How did our approach maximise outcomes?

Voltage

In March 2023, NESO conducted a public consultation, resulting in the addition of a section detailing the Availability and Unavailability of Reactive Compensation Equipment for onshore Transmission Owners to the National Electricity Transmission System Performance Report (C17, changed to E7 from October 2024). This enhancement promotes greater transparency and aids in identifying areas requiring improvement.

Assets procured through the Pennine Voltage Pathfinder have been commissioned at various sites in West Yorkshire and Greater Manchester (NGET reactors), contributing to cost reductions in voltage management in the North of England. NESO have also continued to roll out procurement of reactive power services in the longer term through the 2026 Voltage Pathfinder tender.

Markets for reactive power continue to be developed, with the Long-term Reactive Power Market (Y-4) being the successor to the Pathfinders, and the Mid-term Reactive Power Market (Y-1) providing a route to access voltage services from existing assets. Work to develop a short-term day ahead (D-1) market is also continuing.

Aligned with the Reactive Power Market work, NESO are also working with an innovation partner and industry on potential reforms to the Obligatory Reactive Power Service (ORPS).

We are also actively engaging with DNOs to limit and/or reduce the transfer of reactive power from distribution to transmission. This has been a big driver of voltage challenges seen on the network and influencing the behaviour of DNO reactive power demand could have a significant impact on voltage management.

Frequency

We have always conducted industry engagement along with FRCR policy development and implementation. We organised multiple webinars to support the industry's understanding of FRCR framework, detailed data and methodology, and the proposed policy during its consultation. We notified the industry 5 days prior to the commencing of the lower minimum inertia level. We have had regular meetings with the SQSS Panel and Ofgem engineering team. To improve transparency, we briefed key frequency events, system performance review after implementing the lower inertia requirement on the Operational Transparency Forum (OTF) in a timely fashion.

Stability

We collaborated with the industry to expedite findings and develop more robust solutions concerning SSO.

Based on lessons learned from past SSO events, a more efficient process is being developed and tested in conjunction with TOs for SSO investigation.

There has been significant progress in the ability to analyse SSO risk using a wider area EMT model.

Industry engagement has been conducted through compliance seminars, the Grid Code Development Forum, and IET conferences.

We listened and responded to customer feedback on the SSO assessment guidance, developing and revising the new version of the guidance to streamline the process.

Tools

The SSO monitoring capability has been significantly improved by adopting a new SSO alarm system (Oscillation Guard Pro) in the control room. Efforts are underway with TOs to further increase Phasor Measurement Unit (PMU) deployment across the wider GB system to provide a more comprehensive view of system conditions.

Advanced tools for oscillation tracing are being developed both internally and in collaboration with academia through innovation projects.

Stability Pathfinders

Services procured through the stability pathfinder tenders have commissioned in the last few years. These are predominantly synchronous compensators, which provide inertia and short circuit level, though notably a battery using a grid forming control has also commissioned, making use of inverter connected energy storage to provide similar stability services.

Balancing Programme (A1.2)

What did we define as success for the end of BP2?

The programme delivery remains on its Roadmap plan. The programme has delivered four releases to the Control Centre (with interim releases).

The Open Balancing Platform (OBP) is the primary balancing system in the Control Centre.

Industry and Ofgem have received regular updates and quarterly "We said, we did, we will do" reports aligned to Programme Increments. Confidence in the delivery is maintained.

Ancillary Services Dispatch Platform (ASDP) is preparing to be decommissioned.

Integration of the Inertia monitoring tools within the network control tool to provide a single window for all situational awareness tools

Ongoing tool development as required to implement additional pathfinders.

What have we achieved by the end of BP2?

The Balancing Programme is transforming our control centre's balancing and forecasting capabilities through continuous delivery of the Open Balancing Platform (OBP), the Platform for Energy Forecasting (PEF) and the Real Time Predictor (RTP) whilst maintaining and delivering high value functional changes on our legacy systems.

In FY25, we delivered 22 OBP releases, totalling 2070 changes with minimal outage time. In addition, we delivered:

- 13 PEF releases
- 7 BM releases
- 4 ASDP releases

Through these releases, key capabilities delivered include BM Quick Reserve (OBP) and enhancements to bulk dispatch and a new fast dispatch capability which have improved dispatch efficiency making OBP the primary tool for battery dispatch. New key forecasting capabilities for wind, national demand and close to real time minute-by-minute predictions have also been delivered improving forecasting accuracy. In ASDP we have delivered changes for dynamic response and regional development programmes and MW dispatch.

Throughout FY25, we have continued to be agile with our prioritisation of activities of our balancing programme products at both an individual (micro) product level and from an overarching (macro) level. You can read more about upcoming deliverables on the roadmaps here.

In the early part of 2024-25, we accelerated the delivery of non-Balancing Mechanism (BM) Application Program Interfaces (APIs) within OBP to allow for external testing of Quick Reserve and Slow Reserve in April 2025. This was accelerated from Q2 FY26 to Q4 FY25. This supports efficient delivery of new market products aimed at reducing balancing costs whilst ensuring security of supply.

We have managed the interdependencies across our products whilst introducing multiple changes and new initiatives in response to customers, including:

- Accelerated skip rates activities in Q3 FY 2025 in response to customers.
- Delivered new temporary parameters and improvements to the Legacy Dispatch Algorithm to provide dispatch advice for batteries. This will be in place until the implementation of the full solution for the GC0166 modification for Limited Duration Assets.
- Introduced a dispatch efficiency monitor tool into the control room. This provides real-time dispatch efficiency feedback to engineers and enabling the reporting of skip rate data on the NESO website.
- Developed features in VERGIL (VERsatile Graphical Instruction Logger) to enhance visibility and navigation for managing constraints will improve the automatic extension of manually created bid-offer acceptances (BOAs).
- Deploying several improvements to the OBP algorithm to resolve outstanding rounding issues resulting in an increase in the use of these assets when in cost merit order.

To implement the deliverables above, key resources, primarily legacy system expert resources, have had reduced capacity to support the transition of capabilities from legacy systems to OBP. This has had a knock-on impact to the delivery of EDT/EDL which we had previously accelerated (albeit the sequence of deliverables to enable EDT/EDL migration has not changed).

Delivering the new initiatives set out above has required reconfiguration of the roadmap. To deliver skip rate activities in a timely manner, we had to delay a BM release to receive Ancillary Services instructions from OBP, this has no impact on customers as it does not change business processes or efficiency, just how internal technology data exchanges are executed.

We have made significant strides in our Real-Time Prediction (RTP) investment. We successfully delivered a product strategy and roadmap, adopted NESO's design-led delivery approach, and implemented Minimal Viable Predictor (MVP) capabilities within the Critical National Infrastructure (CNI) environment. We delivered the foundation of new real-time prediction capability in BP2. This will enable incremental delivery of functional and enhanced capabilities in BP3 and realise expected benefits of ~£43m per annum from April 2026. Four new microservices for Real-Time Prediction were delivered onto the Open Balancing Platform.

The combined impact of the above developments has resulted in a significant increase in instructions for batteries and small BMUs. Comparing the daily average of the quarter from October – December 2023 to the quarter 1 January - 31 March 2025, the dispatch volume of batteries and small BMUs has increased by 425% and by 31% respectively. The number of corresponding instructions increased by 1347% for batteries and 72% for small BMUs.

The programme is anticipated to generate a carbon cost saving of £110m across the whole RIIO 2 Period when compared to the RIIO 1 Baseline. This figure is calculated from the annual carbon price, total generation, carbon intensity and the estimated value realised by year for the programme.

Maintaining and delivering high value changes for existing products is crucial to meet obligations and balance safety, security, and value for money. Key improvements included upgrades for handling increased data traffic, streamlining processes for validating data and optimisation of screens.

Through these changes, we have focused on performance and resilience, accommodating growth in BMUs and data submissions. That growth, which has an impact on performance, is detailed as follows:

- Number of instructible BM units have increased from 779 to 848, from March 2024 to March 2025, an increase of 9%.
- Number of MEL/MIL submissions over EDT & EDL have increased from 401,390 per day in March 2024 to 422,166 per day in March 2025, an increase of 5%.

We completed the final Ancillary Services Dispatch Platform (ASDP) release with new capabilities. We will continue to maintain the platform but will be migrating the capabilities into OBP ahead of its retirement in Q4 FY26.

The strategic review of Platform Energy Forecasting (PEF) in the first year of BP2 led to a reprioritisation of the PEF roadmap to accelerate commitments and deliver value. The strategic review highlighted the following focus areas:

- Development of a Wind Power generation forecasting product on Azure PEF.
- Migration of all existing forecasting products on the Oracle Cloud Infrastructure (OCI) to new Azure Infrastructure.
- New PEF Interfaces to OBP & Offline transmission analysis tool (OLTA).
- Decommissioning of the legacy Energy forecasting system (EFS).

By the end of BP2, we delivered in accordance with our strategy and plan, providing significantly more accurate wind forecasts exceeding expectations for the 1C metric (Nov 2024 - Feb 2025: 3.97% mean percentage error against an annual target of 4.68) through delivery of the new wind product on the new Azure PEF platform, both going live in November 2024.

The remaining forecasting models and core capabilities were successfully migrated from Oracle Cloud Infrastructure PEF to the Azure PEF platform. APIs have been deployed to share forecasting data with the wider business.

In addition, new visualisation and analysis tools, decoupled from EFS have been deployed for both the energy forecasting and control room teams providing enhanced situational awareness as well as insight and evidence for model accuracy improvement opportunities.

These activities have gradually decoupled our tools and processes from EFS and provided increased accuracy and resilience to support decision making, delivering value to both the business and end consumer, while working towards the eventual decommissioning of EFS during BP3.

We have continued to take opportunities that develop our Inertia Monitoring tools, including working closely with the National Physical Laboratory on understanding inertia accuracy, and with our suppliers on options to improve Inertia Forecasting techniques. Integration with our network control tool has been realigned to match the changed delivery plan in Network Control (A1.2)

How did our approach maximise outcomes?

Stakeholder collaboration and feedback continue to be central to the development and evolution of the Balancing and Forecasting Transformation roadmaps.

We have had significant engagement in FY25:

- Two in-person events – 117 customers from 66 organisations.
- Three webinars - 227 customers from 113 organisations.
- Over 55 relationship management meetings with 31 organisations.
- Four focus groups (3x Technology & 1x Forecasting) – 88 customers from 51 organisations.
- Regular content in NESO ‘Energising Progress’ newsletter including webinar and event content which reaches over 5,199 people.
- Query management through our Balancing Programme inbox.

You can view all the content and recordings from our previous events, webinars, and focus groups here.

Through this engagement we have been able to respond directly to customer feedback, delivering impactful change:

Customer said…	We did…
NESO need to improve dispatch efficiency and reduce skip rates	The programme has been able to adapt to incorporate additional scope to the release schedule to address stakeholder feedback and concerns regarding skip rates, as outlined in the "what we have achieved" section above. Several of our upcoming releases in BP3 including constraint management & optimisation within a constraint are expected to support improved dispatch efficiency.
Greater Industry input into shaping the Balancing Programme's future delivery & prioritisation process	The Balancing Programme's 'Beyond 25' engagement is aimed at ensuring our future balancing and forecasting transformation roadmap aligns with customer expectations and priorities, whilst enabling a decarbonised energy system and delivering consumer value. We have hosted several interactive 'Beyond 2025' engagement sessions between June 2024 and March 2025 to generate ideas for future capabilities and engagement will continue throughout 2025.
Improved transparency around the benefit and impact of the Balancing Programme's delivery	Regular updates of utilisation statistics for batteries and small BMUs demonstrating how the Programme is supporting increased market participation and use of flexible technology. We have expanded our benefit metric reporting for external engagements to include how the programme is enabling a reduction in CO_2 emissions, and adapting to new requirements, innovation & services – we will continue to build on this throughout BP3.
Improved contact points in the Balancing Programme would be useful between events / focus groups	Following our June event, we introduced relationship managers within the Programme and are now also meeting our customers individually on a regular basis. We have held >55 customer meetings in FY25 enabling us to deliver updates on Balancing Programme focus and priorities and provide the opportunity for customers to highlight any questions and pain points, with time to explore these in more detail.
Receive content in advance of events & increased accessibility to content from in-person events	We now share slide content ahead of our events / webinars, and record key messaging from our in-person events and publish this on our website; all webinars and focus groups are also recorded.
More information on specific topics	At our webinars/events, we have covered constraint management, national optimisation, OBP wind deliverable and

	the impact & benefits of our roadmap for BP3, as well as a session exploring a day in the life of a Control Room engineer.

The following shows details of engagements to date with content available here;

Engagement Activity	Balancing Programme Area	Delivery Mechanism	Date
Beyond 25 session	Balancing Programme	In person	June 2024
Beyond 25 playback	Balancing Programme	Webinar	September 2024
Technology Stakeholder Group	Technology	Webinar	October 2024
Forecasting Stakeholder Group	Forecasting	Webinar	October 2024
Initial review of potential future capabilities	Balancing Programme	In person	November 2024`
Capabilities survey	Balancing Programme	Online Survey	November 2024 – December 2024
Follow up from November Balancing Programme event	Balancing Programme	Webinar	January 2025
Progress Updates	Balancing Programme	Webinar	March 2025
Share & validate draft roadmap	Balancing Programme	In person	June 2025 (planned)
Endorse roadmap to support RIIO-3 submissions	Balancing Programme	In person	June 2025 (planned)

To enable delivery for our customers, as quality of technology deliveries was a key prior concern, we have continued to evolve our strategic approach to delivery and implement new ways of working for the development of the Open Balancing Platform (OBP) and our future products. These focus on improving the flow of work, enabling continuous delivery through a user centric process. The delivery of the roadmap is informed through long range planning and predictability in squad delivery. Functionality has been implemented in OBP through agile delivery and bi-weekly releases.

The Open Balancing Platform and Ways of Workings have been recognised externally with the team receiving the following industry awards:

- Product of the Year at the Energy Storage Awards 2024
- Best DevOps Team 2024 at the DevOps Excellence Awards 2024
- Best Use of Cloud-Native Technology at the DevOps Excellence Awards 2025
- DevOps Project of the Year at the DevOps Excellence Awards 2025

Our strategic review of PEF, completed in April 2024 prioritised our roadmap to optimise benefits for stakeholders. First, we delivered the new Wind product, followed by new interfaces and richer visualisation in the control room. Finally, towards the end of BP2 we completed migration of all models to Azure. As with OBP, adopting an agile way of working, the PEF team delivers against its commitments with 2-week cadence, including ongoing engagement with stakeholders and continually striving for better outcomes. The Balancing Programme working with the Energy Forecasting team continue to facilitate the Forecasting stakeholder working group. We have delivered additional transparency, following requests from this forum, by publishing additional datasets on the NESO data portal.

Network Control (A1.3)

What did we define as success for the end of BP2?

Transition of infrastructure to new Data Centres, along with integration with Data Analytics Platform (DAP) and Balancing systems.

Successful integration of offline and online Network Models.

Electricity National Control Centre (ENCC) Operator Console implemented.

What have we achieved by the end of BP2?

Network Control Management System (NCMS)

The transition of infrastructure has been more complex than anticipated. We have experienced delays internally, and working with our vendor, as we navigate our new design. We have been able to stand up parts of the estate, which has allowed the team to begin delivery of the new NCMS suite. We have also progressed from testing in cloud-based environments, to testing on our vendor on-premises system.

We have worked closely with our vendor on the key product developments that are required for our NCMS suite. This includes intelligent alarm processing and the first visualisations of our future Look Ahead process, with work on these being completed in March 2025. These are now being made available for full testing.

We have successfully installed workstations into our office environment to function as a test and simulation facility. We scheduled an upgrade to our Control Training Unit to have the same functionality in time for user training.

We have trialled an integration layer from our vendor to connect the NCMS suite with DAP and the enterprise estate. This proof-of-concept was successful, and we have started full implementation of this modern method for managing information flow. We have also completed integration work between our NCMS suite and Open Balancing Platform (OBP) products ready for operational Go-Live.

Real-Time Analytic Capabilities

We delivered a suite of real-time analytical capabilities including:

- A voltage stability assessment tool that provides continuous monitoring of voltage stability margins.
- An enhanced constraint calculation tool that allows operators to dynamically assess system constraints across multiple stability domains.

These capabilities mark a step-change in network control by moving from static, offline assessments to real-time, dynamic stability management. This has enhanced the efficiency of system operation, reduced costs and improving security of supply.

We completed the requirements definition, design, and implementation strategy for the unification of online and offline model environments. This has laid the groundwork for a consistent, single-source-of-truth network model across operational and planning timescales.

We completed a full design and procured hardware to transition our real-time analysis tools to our new datacentre. This will unlock new training and simulation capability and significantly increased computational power.

ENCC Operator Console

Our ENCC Operator Console developments remain in procurement phase. They have faced delays caused by a more complex than expected design phase and a delay to the procurement process. This is because we sought to engage more suppliers in the interest of facilitating a fully competitive process. The overall impact of these delays will be minimal as delivery timelines remain strongly aligned to the latest NCMS and OBP delivery plans.

In response to oscillation events starting to occur on the network, we worked with a supplier to develop a prototype oscillation monitoring system ahead of the delivery of Phasor Measurement Units (PMUs) by the Transmission Owners. In December 2024, following the successful trial and building on monitoring devices provided for inertia monitoring, we extended this service to cover the whole GB network to provide awareness of the occurrences of sub-synchronous oscillations.

How did our approach maximise outcomes?

During the BP2 period we reviewed the latest product roadmap from our vendor and pivoted our NCMS architecture towards their latest modular platform.

To help mitigate delays in the delivery plan for NCMS, we have deployed vendor resources regularly on-site at NESO offices. This face-to-face working arrangement has helped accelerate environment deployment activities. We continue to hold face-to-face planning sessions quarterly with our vendor.

We have jointly developed a series of Working Groups with National Grid Electricity Transmission (NGET). The aim of these groups is to discuss and manage the complex changeover process from our existing shared Integrated Energy Management System (IEMS) product to separate NCMS and Supervisory Control and Data Acquisition (SCADA) products.

Our ENCC Operator Console project team have been engaging other Transmission System Operators (TSOs), suppliers and research institutes, such as EPRI. These interactions enabled us to gain valuable insight into developments around the world. This has included site visits across Europe to witness technologies that have been deployed.

We have utilised Innovation funding such as Network Innovation Allowance (NIA) to advance our understanding of new areas.

Data and Analytics Platform (DAP) (A1.4)

What did we define as success for the end of BP2?

Continued evolution of DAP in line with medallion architecture.

Continued ingestion of NESO data onto the platform, along with consolidation of legacy systems and grey IT.

Proactive engagement with industry on all types of potential IT system solutions.

Demonstrably acting on stakeholder feedback, and any burdens imposed on stakeholders, to inform future IT development. evidence through "you said, we did".

Positive feedback from members of the Technology Advisory Council (TAC), evidenced through survey results.

What have we achieved by the end of BP2?

Over the last twelve months, we have continued to enhance the capabilities of the NESO data platform.

We successfully established a scalable data platform, that enables enterprise-wide data lifecycle management to be established and integrated within NESO applications and processes. This includes:

Data Catalogue and Inventory, Data Quality, Data Serve Application Programming Interfaces (APIs), Data Protection and Management controls, GDPR and Personally identifiable information (PII) data management, automated and bulk ingestion, and near real-time ingestion. This has expanded our ability to server diverse data demands.

We successfully established over 50 data source connections (both internal and external) and ingested over 180 datasets to conformed gold standard (Medallion). This enabled delivery of BP2 committed programmes and business outcomes and enabled the ingestion of a base data for future analytics and modelling activities.

We established the NESO Advanced Analytics Environment, supported by DAP data for the Data Science community. This has been used to deliver key AI and analytics models such as Skip Rate Monitoring, Dynamic Reserve Setting and Ancillary Reserve Services Buy-Order.

We are ensuring that our data ecosystem provides the ability for interoperable energy data for NESO outcomes. Created patterns and connectors to enable the flow of data within the Data and Analytics Platform from multiple sources as and when required.

The complexity of NESO's separation from National Grid and complete infrastructure and data separation coupled with other key BP2 transformation deliverables has resulted in changes to expected deadlines for the consolidation of legacy system replacement and grey-IT. Progress has been made to capture the requirements and establish a delivery plan, however, completion of the activities have been moved into BP3 timeframes, allowing the completion of the separation activities and alignment to key dependency technology transformation roadmaps.

We hold quarterly Technology Advisory Council (TAC) Digital and Data Strategy subgroup meetings and bring various topics for discussion to gain industry and academic perspectives on our data strategy. Examples include:

In July 2024, our approach for the DAP operating model and ingestion was presented. Advice received has been integrated into our process. This included structuring our demand prioritisation process for data ingestion to ensure a streamlined procedure and aligning to proven business value.

In January 2025, we presented our approach for Data Catalogue and received positive feedback. The group advised that we should ensure the number of data sets utilised for similar purposes, and we are incorporating that advice into our process.

We also attend and facilitate the TAC main group. In March 2025 we presented an overview of the data programme, which included discussion on DAP. Feedback was positive, and the group advised that we would only be successful if adoption is driven across the organisation by calling out the use cases and the benefits they bring. Additionally, it was suggested to have strong ties to the analytic community. They suggested a feature store be created (packaged data products suggested by users). This will be considered in the design for the user experience for DAP in BP3.

In addition to our regular forums, we regularly consult technology companies such as Microsoft and Databricks as well as IT consultancies such as Accenture and EY who have assured us that our approach for technology is sound and industry leading.

We have not conducted formal surveys with TAC members but feedback from sessions on the data strategy and direction of the DAP platform has been positive. Examples of this positive feedback has been recorded in our minutes. TAC meeting minutes can be found on our website here.

How did our approach maximise outcomes?

To maximise outcomes, the DAP programme engages with established NESO governance and process forums, including Programme Management Board (PMB), Quarterly Business Reviews, and Technical Assurance Forums.

Implementation of a data operating model, as well as attending or establishing appropriate forums, ensured that the DAP investment, remained aligned and committed to supporting the delivery of NESO priority programmes and outcomes.

Our programme of stakeholder engagement and user feedback has enabled the DAP product to scale the foundations of the enterprise data lifecycle platform.

We have engaged with forums such as:

- Data Council (DC) – The NESO Data Council provides ongoing support, management, and oversight for our data related initiatives. The ultimate purpose for the Data Council is to improve data quality and integrity across NESO. Its key responsibility is to ensure compliance with data protection regulations.
- Technical Design Authority (TDA) – The NESO Technical Design Authority provides technical assurance and evaluation on the proposed architectural designs. The ultimate process is to ensure that the chosen approach aligns with the enterprise-wide technology design.
- Data Product Demand Forum (DPDF) – The DPDF ensures that the solutions continuously meet business needs by efficiently capturing, evaluating, prioritising, and implementing demand. This process enables the alignment of platform's capabilities with strategic business goals and maximise the outcome value.

Methodologies and Processes – Best Practice

1. DAP follows Agile methodology for its delivery which is based on DevSecOps principles.
2. User Experience follows a customer centric design thinking methodology. Iterative approach to problem-solving that involves understanding users, challenging assumptions, redefining problems, and creating innovative solutions through prototyping and testing.

The Data Products team follow a Product Management methodology to manage the process of building, developing, and managing data products from concept to launch, ensuring alignment with business goals and customer needs.

Accelerating Whole Electricity Flexibility (AWEF) - Operational coordination with DER and DNOs

Please note that our Accelerating Whole Electricity Flexibility (AWEF) activities span across the three roles. We provide end-scheme updates on AWEF activities in each of the three roles, which complement a deep dive session we held with Ofgem in February 2025.

AWEF is a holistic industry wide programme, structured as three areas of work:

- Facilitating market access for whole electricity flexibility
- Improving DER visibility
- Service co-ordination between markets.

All are reinforced by a fourth supporting function under Role 1 of facilitating Distribution System Operator (DSOs) transition, which in addition to this support, focused on the following areas:

Facilitating market access for whole electricity flexibility	Development of Regional Development Programmes (RDP) within control room operations.
	Development of Local Constraint Market (LCM) functionality, within control room operations.
Improving Distributed Energy Resource (DER visibility)	Increase DER visibility in real time.
Service co-ordination between markets	Increased operational liaison, including risk of conflict reporting.
Facilitating DSO	Ensuring real world performance, by for example meeting with Distribution Network Operator (DNO) control centre staff.

Further development in this area will be underpinned by progression in the following areas:

Implementation and governance

- Ongoing work with industry through the Primacy rules Technical Working Group under the Electricity Network Association (ENA) to agree and standardise required data exchanges and process flows. This will build on recommendations shared with Ofgem which will transitioning into the Market Facilitator role.
- Commencement of IT design for implementation within our systems.

System design and data provision

As we move to the implementation stage, a number of dependent pre-requisites need to be met by both NESO and DNO's:

- Visibility of assets to both NESO and DNO's of those providing distribution, transmission, and system services
- Data sharing mechanisms enabled in sufficient accuracy and timing
- DNO curtailment forecasting at day-ahead stage
- Further discussions with DNOs to ensure AMN systems do not unwind actions taken.
- NESO day ahead forecasting and data exchange of service requirements at both asset and settlement period level (impacting Single Markets Platform (SMP), Enduring Auction Capability (EAC), & Open Balancing Platform (OBP)).

Balancing Costs Strategy (A1.6)

What did we define as success for the end of BP2?

Regular reporting of progress on delivery to stakeholders.

Feedback from stakeholders recognises that NESO is taking actions that will deliver or support current or future delivery of meaningful reductions in Balancing Costs.

What have we achieved by the end of BP2?

Throughout BP2, we have enhanced our reporting and analytics on Balancing Costs, promoted initiatives that will deliver the most significant savings and developed new methodologies to calculate the savings generated by certain initiatives.

Reporting and Analytics

- We developed a comprehensive and technical monthly reporting method in our Metric 1A reporting that explains the dynamics in the market and the system that have resulted in certain cost outcomes. It provides narrative and information on specific actions we have taken each month to promote savings.
- Having developed our reporting and analytical capabilities for Balancing Costs, we have brought our seasonal analysis (Summer and Winter Reports) of Balancing Costs in-house (this reporting was previously outsourced to external consultants LCP). This has enhanced our internal understanding and capabilities, allowing for better direction internally on prioritising initiative that influence Balancing Costs. It also allows us to provide expert guidance to the public and industry on cost outcomes throughout the year. This has evolved over BP2 to provide great technical, but understandable insights on balancing costs. These insights have received very positive feedback through public forums such as the OTF.
- In May 2024, we published our first ever yearly Balancing Costs report the report provides analysis on the cost landscape, and our best projections of future balancing costs. This information helps us, the government, and the industry in guiding activities and identify key points of significant change in the cost landscape.

Industry Engagement

- We provided timely responses to questions and queries from the public and industry regarding Balancing Costs via the OTF, balancing costs. box and balancing cost forums.
- We held several education sessions with the government and industry that were open to the public to present our analysis outlined above. This included the yearly balancing costs report. This provided direction and strategy to the industry on how we can keep costs low.
- We developed a monthly forum (the Balancing Cost Trilateral) to discuss new initiatives and challenges on Balancing Costs with Ofgem and DESNZ. This will help us prioritise work and provide needed context around the benefits or difficulties around certain trends and initiatives.

Cost Initiatives

- Over the course of BP2, we delivered many initiatives that reduce Balancing Costs, in line with our Balancing Costs Portfolio. These include the Network Services Procurement projects, that help us manage voltage, stability, thermal constraints at lower costs, the dynamics adjustment of stability requirements in our FRCR publication, PN Inaccuracy work, outage optimisation, trading, commissioning of new generators and interconnectors (such as Greenlink and Viking Link), amongst many others. We have calculated at least £1.3bn in savings over BP2 from just four specific initiatives in our Balancing Costs Strategy including FRCR, Trading activities, and Network Procurement Services"
- We also developed methodologies to calculate the realised savings from some of these initiatives. These savings get reported through our Metric 1A reporting each month, with external publication where possible. We will continue to develop these into BP3.

The analysis and insights we have been able to develop have allowed us to engage and provide better reporting that we initially anticipated over BP2. This includes projecting future balancing costs and developing a cost savings analysis.

How did our approach maximise outcomes?

Our approach was to recruit a team of experts on Balancing Costs. These experts understand the data and how to utilise data insights to inform the industry and NESO on trends, opportunities, and challenges. This approach was effective in achieving our BP2 objectives as it provided a centralised point not just within NESO, but within the industry to discuss the topic of Balancing Costs and what we are doing to reduce them.

This approach was different to previous business plans. Cost expertise was at risk of being siloed between different parts of the organisation without any specific team providing direction and input on how best reduce Balancing Costs more holistically. Having a dedicated team has allowed us to have a stronger voice to promote the initiatives and actions we believe will have the best impact on consumer's bills.

Training (A2)

What did we define as success for the end of BP2?

- Improved decision making
- Reduced resource costs
- Decreased training costs
- Workforce development

What have we achieved by the end of BP2?

By the end of BP2, the organisation achieved improved decision-making through enhanced training and simulation capabilities. This investment allowed employees to better understand and respond to various scenarios, leading to more informed and effective decisions.

However, while workforce management has improved, reductions in overtime and training costs have not yet been fully realised. This indicates that although the workforce is better managed, the expected financial benefits from reduced overtime and training expenses have not materialised. This is primarily due to the challenges around recruiting from within the GB Energy industry.

Challenges in recruitment for Power System Engineers are exacerbated due to new security vetting requirements, which complicate the hiring of higher-skilled positions. These stringent requirements have made it difficult to attract and onboard highly skilled professionals, impacting the recent recruitment campaigns.

Despite these challenges, previous campaigns have enabled System Operations to be able to increase in full-time employees. Workforce integration has improved through training and authorisation, resulting in reduced overtime. The growth in full-time staff has helped reduce the reliance on overtime, as the workforce becomes more cohesive and efficient.

We have also presented a revised roadmap for future training simulator capabilities against the latest delivery plans for Balancing Programme (A1.2) and Network Control (A1.3) to ensure alignment.

How did our approach maximise outcomes?

Our approach maximised outcomes by focusing on several key areas:

- **Enhanced Training and Simulation Capabilities**: By investing in advanced training and simulation tools, we were able to improve decision-making processes within the organisation. This allowed employees to better understand and respond to various scenarios, leading to more informed and effective decisions.
- **Workforce Integration**: Despite challenges in recruitment due to new security vetting requirements, we successfully increased the number of full-time employees.

This helped reduce overtime as the workforce became more integrated and efficient.

Collaboration Across Departments: The Automated Rota project for workforce development involved collaboration between various departments, including business change, IT, and operations. This cross-functional teamwork ensured that different perspectives were considered, leading to more comprehensive and effective solutions.

Restoration (A3)

What did we define as success for the end of BP2?

Success was defined as demonstrating progress toward the implementation of and compliance with the Electricity System Restoration Standard (ESRS) which is effective from December 2026. This included maintaining and validating restoration plans, publication of requirements and the approved Assurance Framework, contribution of new technologies into the restoration strategy and significant progress toward the implementation of the Restoration Decision Support tool.

What have we achieved by the end of BP2?

In 2024/25 we drove forward a number of the initiatives required for the industry to be compliant with the ESRS standard by December 2026.

Following consultation with industry and approval from Ofgem, we published the ESRS assurance framework in September 2024. This clearly sets out the requirements, programme of works for NESO and actions across industry to achieve the standards.

As well as internal training for restoration, we have continued to work with Distribution Network Operators (DNOs), Transmission Operators (TOs) and restoration providers to maintain and improve restoration plans. We have supported the industry to ensure the successful implementation of the code and licence modifications required to achieve the standard.

We are undertaking monitoring of industry readiness and have implemented a cost recovery process ready for any claims for 72 hrs resilience.

We have increased our portfolio of restoration providers contracting for future capability with wind and Distributed Energy Resource (DER). This capability will become available through 25/26, and we will continue with tenders for further providers.

To ensure we can fully understand restoration timescales, we have enhanced our restoration modelling. This is in response to audit feedback and to give further confidence of the assumptions that we model.

We are developing a Restoration Decision Support Tool (RDST) to support the decision making of Control Centre engineers in a national power outage scenario by giving real-time visibility of the time expected to restore the network. Full requirements for this tool have been developed, and decision was taken to strategically align the tool to the development of Network Control Management System (NCMS). Due to this realignment build of RDST has not yet begun, however planning is underway with the developer to ensure critical phases are delivered ahead of the Dec 2026 requirements for ESRS.

We committed to delivering 3 additional Inter Control Centre Communications Protocol (ICCP) to give visibility of restoration progress on DNO Networks. These links have been delayed due to a change in provider, however, are on track for delivery by Autumn of 2025. We are working with DNOs to ensure delivery is complete ahead of the ESRS implementation date.

Overall, whilst we recognise the work required from NESO and the wider Industry to achieve ESRS compliance by Dec 2026, we are committed to achieving this standard in the required timeframe.

How did our approach maximise outcomes?

Compliance with the timescales set out in the ESRS is dependent on various industry stakeholders delivering changes to their systems and processes. We established and continue to drive forward a cross industry steering group and working groups to ensure work is prioritised and risks managed. In addition to the working groups, we have worked closely with TOs and DNOs to ensure robust plans are in place for restoration and the new standards. We have been transparent with risks and progress and consulted industry to seek views through our annual assurance consultation and framework.

Transparency (including OTF) (A17)

What did we define as success for the end of BP2?

Positive customer and stakeholder feedback is a key indicator of success for all Transparency Deliverables.

ESO Transparency Roadmap published and informed by stakeholder feedback ensuring we provide clarity on information that we share and future developments.

Proactively driving transparency in ESO decision-making through identification, prioritisation and publication of more datasets and insight communicated through the “Skip Rates” work. Ensuring transparency of decision making will be further enhanced which supports stakeholders to be better able to operate their assets through improved understanding of the operational decisions that we make.

Continued growth in the Open Data Catalogue and greater automation in Open Data requests enabled through DEP and DAP enhanced by the publication of the NESO Data Sharing Approach.

Operational Transparency Forum continues to drive stakeholder engagement and maintain transparency of operational issues and decisions.

Continued positive stakeholder feedback received.

What have we achieved by the end of BP2?

Teams across NESO continue to focus on improving the quality and content of engagement with energy industry stakeholders by developing new approaches to sharing information about NESO activities and future developments. For example: both the Balancing Programme and Markets Forum have used different ways of delivering content and engaging with customers.

We have continued to publish the Transparency Roadmap regularly and have seen the contents of this roadmap develop over the period of RIIO-2. This breadth of content demonstrates the commitment to greater transparency in our engagement, events, publications and ongoing activities. We recognise the importance of continuing to enhance transparency to ensure we remain open and collaborative with the wider energy industry and engage them fully across all aspects of NESO. However, we do need to consider whether the roadmap is the best way to share this content as industry has not significantly engaged with the current publications (less than 100 views between January 2024 and March 2025).

The NESO Data Sharing Approach now provides industry with a clear process to request publication of additional datasets beyond those provided on the Data Portal. Please see the following Data Transparency section for details.

Formerly, we provided ad hoc explanations of operational decision making and share datasets on Dispatch Transparency. We have now improved this process, by creating a dedicated team to lead on engaging stakeholders around our decision making. The dedicated team have collaborated with stakeholders to develop a new approach to understanding and reducing “skip rates”. This work is providing greater insight into our operational decision making. For further details, see the “Skip Rates” section on page 6.

The Operational Transparency Forum continues to provide industry with a weekly update of regular operational content while also delivering deep dives in a wide range of focus topics and allowing customers to receive answers to their questions. There are currently over 2000 registered participants from across the energy industry and beyond.

Reviewing 2024/25, we did lack some content for the forum during the earlier part of the year while teams across the organisation were preparing for NESO Day One. This led to a reduction in the number of focus topic presentations, and a related decline in the number of attendees. Only the Balancing Reserve presentation attracted an industry audience of over two hundred (216). Preparations for NESO also delayed the implementation of improvement opportunities identified from the December 2023 survey responses.

Following NESO Day One, improvements were finally embedded into the OTF in Q3 2024/25 and the weekly attendance continues to trend upwards. Across Q3 and Q4 only two of the weekly events achieved less than 200 industry attendees.

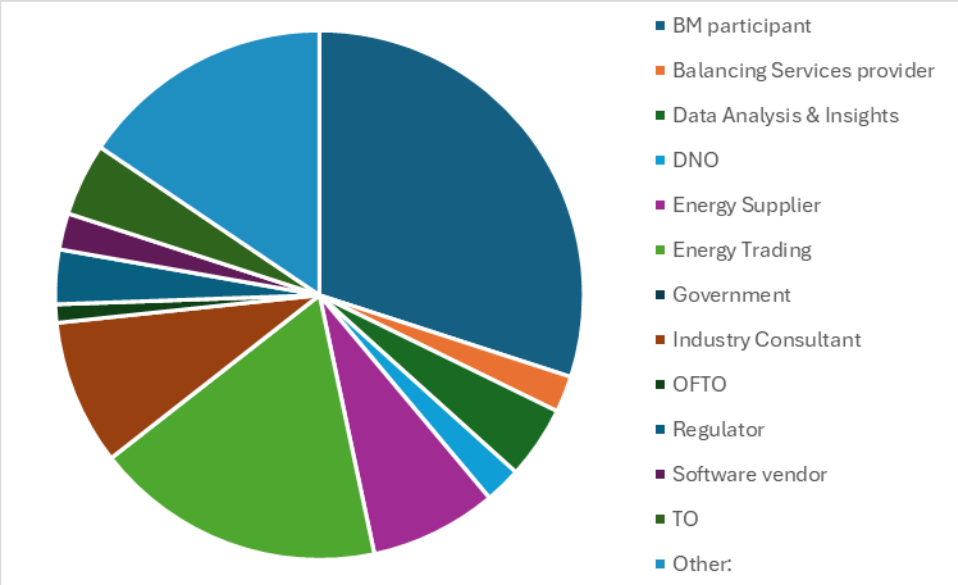
Industry attendance was particularly high for:

- 322 on 15 January: Overview of 8 January Operational Activity
- 264 on 8 January: NESO response to recent BSAD queries
  and on 22 January: Initial National Demand Outturn (INDO)
- 262 on 5 March: Interconnector Special refreshed

The increasing attendance reflects the improving quality of the forum content. We have presented 40 deep dives and focus topics in 2024/25 (compared to 27 in the previous year). These were mostly in the second half of the year, and included several topics specifically requested through the survey or directly at the OTF.

In January 2025 we conducted a further survey of participants which received 91 responses (previous survey received 40) representing a very wide range of energy industry participants.

Q1: What type of customer or organisation do you represent?



This demonstrates the considerable breadth of industry interest in the content of the OTF.

Regular content and the focus topics/deep dives scores are comparable with the previous year and the majority of the over 200 comments received were positive, showing how highly the industry values the forum and their willingness to provide constructive contributions towards maintaining and improving the events.

In the previous survey we received feedback for other NESO engagement activities. Therefore, in January 2025 we specifically asked:

> *"Q11: We understand that the OTF and other forums facilitated by NESO are primarily geared towards technical and operational attendees*
>
> *Are there additional forms of engagement you would like to see from us that could enhance your understanding and experience of NESO operations?"*

We heard our customers and stakeholders are interested to know more about NESO activities through a variety of channels including LinkedIn and podcasts. There were also requests for "teach ins" and similar content (including "bite size") to provide more background understanding for the operational content in the forum. We will be exploring these suggestions with industry as part of our customer activities during the next year.

We plan to provide a summary of the survey responses and our initial responses in Q1 2025/26.

How did our approach maximise outcomes?

At the Operational Transparency Forum we remain focused on understanding and meeting the expectations of our participants. Following a detailed survey about the OTF in December 2023 we used the feedback from the 40 respondents to identify and implement changes to better meet the needs of our audience (see details above). The final update on the survey was published on the OTF webpage in January 2025.

Transparency (Data)

Why are we undertaking this activity?

It is critical that NESO makes as much of its data open and transparent as possible, to adhere to Ofgem Data Best Practice where data is presumed open and to enable shared energy system objectives. At the same time, we must ensure we only share data that does not pose security concerns.

What have we achieved by the end of BP2?

We implemented a data sharing function as part of our Day One setup. The function offers a data sharing service to both internal and external parties, enabling requests to be triaged for potential sharing, both in a non-public manner as well as on our Open Data Portal should the data be classed as open or public. Additionally, we have started a proactive programme of work to review critical data for addition to our data porta

Content about our Data Sharing Approach has been made available on our website to enable customers to understand our approach as well as request data sharing via our open data portal.

How did our approach maximise outcomes?

We relied on industry best practice on data sharing triage, relying on ENA's Data Triage Playbook and creating a Data Sharing Policy for NESO. The policy has been widely communicated internally so that colleagues understand the importance of having their data assessed for external data sharing.

When requests are received for data to be added to the Data Portal via the Operational Transparency Forum, these are promptly triaged and made available whenever possible.

Market Monitoring (A18)

What did we define as success for the end of BP2?

Robust and established process which allows us to fulfil our licence and legal obligations of detecting and reporting suspicious behaviour.

The continuous submission of detailed Suspicious Transaction Reports (STRs) to Ofgem, in line with Ofgem's expectations. Extensive monitoring of all services and product groups, developing additional monitoring processes where applicable.

What have we achieved by the end of BP2?

We have continually developed and improved robust and fuel-specific methodologies for assessing reasonableness of bid and offer prices and monitoring of dynamic and physical parameters. This includes tailored alerts and procedures for the updated Transmission Constraint Licence Condition (TCLC) Guidance and the newly introduced Inflexible Offers Licence Condition (IOLC). These models have been refined using Ofgem feedback ongoing. Our tools and analysis have been used to support the Ofgem market conduct team in recovering over £38million to the consumer redress fund over the last year.

We have also used the analytical capabilities of the team to support a proposed BSC modification P462 to cost benefit stage.

An additional key deliverable has been a guidance note on the Physical Notification Accuracy of wind and the enduring process for surveillance and referral to Ofgem. This project has significantly reduced a consumer cost from directional physical notification errors which have improved significantly between financial years (see our Role 1 case study on 'Improving Information Inaccuracy to reduce wind PN inaccuracy'). This Physical Notification (PN) accuracy work was above our BP2 delivery plan.

How did our approach maximise outcomes?

As a ringfenced team, we balance the openness and transparency expected of NESO with Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) obligations of keeping the state of an investigation private. Over the last year, we have undertaken much greater market transparency with the Wind Physical Notification work being a representative of this learning process. We have substantially increased our challenge of data quality and behaviours directly with customers, resulting in quick amendments and identification of wider system issues.

Following our engagement with the Wind Advisory Group in April 2023 on data accuracy issues, we initiated discussions on options for improvement with Ofgem and the Wind Advisory Group (WAG) in November 2023. This was followed by the publication of an open letter in May 2024, establishing our intent, and the commencement of a consultation in June 2024. We acknowledge that the initial three-week consultation period was insufficient for all parties; therefore, we undertook an additional six months of one-on-one engagements and collaboration with both the market and Ofgem. This included an extended consultation period and republished guidance note. As a result, the monitoring period went live on 1 March 2025. Although this means the monitoring period started later than initially planned, it has already prompted industry changes and realised significant benefits prior to any enforcement actions. For more detailed information on improvements, please refer to our Role 1 case study on 'Improving Information Inaccuracy to reduce wind PN inaccuracy'.

Our engagement on the guidance note landed well with stakeholders. For example, we received verbal feedback from EDF regulation that "We can see you have really listened to us" following this revised guidance note. This was despite us retaining the high standards of accuracy requested in the initial guidance note.

We have also moved towards longer and more comprehensive analyses. We continue to work with Ofgem and take feedback to make the Person Professionally Arranging Transactions (PPAT) function deliver what is most useful for supporting market improvements.

Demand Flexibility Service (DFS) (Operational aspects under Role 1)

Why are we undertaking this activity?

The Winter Outlook for 2024-25 indicated that margins were more comfortable than previous years and well within the reliability standard. Therefore, there was no need for an "enhanced action" service. However, we wanted to retain the strong levels of engagement from previous years. In addition, our learnings from the competitive tests performed previously suggested that Demand Flexibility Service (DFS) would be able to compete with alternative margin actions available to NESO.

Therefore, DFS was re-developed for Winter 2024-25 and beyond as an in-merit service. The purpose was to provide access to demand flexibility over the peak hours competing on a level playing field with our regular margin options of interconnector trading or Balancing Mechanism actions.

What have we achieved by the end of BP2?

As with previous years the service incentivised consumers, both domestic and industrial and commercial (I&C), to voluntarily adjust their electricity usage. As the service was designed to compete commercially and minimise costs for consumers, there was no testing commitment or Guaranteed Acceptance Price (GAP) in the service design. However, we retained the right to re-introduce these if required.

Building on the learnings from last years' service using different timescales, we have only allowed the service to be initiated within day. This is because we saw no significant reduction in volumes when called during the within day windows last year compared to day-ahead. Initially we are also just using DFS for the evening peak as this will deliver the greatest benefit, this will be assessed as the service continues.

As of 31 March, we have 29 Registered Providers and in excess of 1.8 million Meter Point Administration Numbers (MPANs). We have procured volume on 45 occasions with almost 200MWs procured on several occasions. The lowest accepted bid was at £59/MWh and the highest was £1,290/MWh. The expected consumer benefit up to the end of March is almost £500,000.

How did our approach maximise outcomes?

To run the service effectively, a three-way dialogue was created between Balancing Services, Trading, and the Control Room. This dialogue assessed DFS effectively against alternatives and ensured value for the consumer. The process was designed to align closely with the existing process for interconnector trading to minimise disruption and provide room for growth of the service. We ran training sessions to ensure that everyone is aware of their roles in the process. We also run review sessions every four to six weeks to identify improvements in co-ordination.

The smooth integration of the new service into our BAU has enabled us to look at further evolution of the service. Options such as demand turn up and locational procurement are now under consideration.

A.2 Delivery Schedule Status

Deliverable progress

For Role 1, the BP2 Delivery Schedule received an ambition grading of 4/5, providing NESO with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The NESO Performance Arrangements Governance Document (PAGD) states that the Performance Panel should consider that NESO has outperformed the Plan Delivery criterion if NESO has successfully delivered the key components of a 4- or 5-graded delivery schedule.

Role 1 – Progress of our deliverables

Our BP2 RIIO-2 deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

The statuses are defined as follows:

Complete	Milestone has been delivered
Delayed – consumer benefits	Delayed or de-prioritised to maximise consumer benefits
Delayed – external reasons	Delayed due to factors outside our control (e.g., BREXIT, Covid, Ofgem)
Delayed – internal reasons	Delayed due to factors within our control and/or that we're accountable for

For Role 1 (Control Centre Operations), the latest BP2 RIIO-2 deliverables tracker lists **52 deliverables** in total, which is made up of **140 milestones**.

- All **140** of these milestones were due to be completed by March 2025 or earlier
- Of those:
  - **6** are delayed in order to deliver an improved outcome for consumers
  - **6** are delayed due to reasons outside NESO's control
- Of the remaining **128:**
  - **107** (84%) are now complete
  - **21** (16%) are delayed due to NESO related delays

The results for the **140** milestones due to be completed by March 2025 or earlier are illustrated below:

Role 1 – Milestone status by deliverable For milestones due by March 2025 or earlier

			Delayed...		
Ref	Deliverable name (shortened)	Complete	Consumer Benefits	External reasons	Internal reasons
D1.1.1	Balance Great Britain's (GB) demand for energy wit...	1			
D1.1.2	Maintain security of supply in real time and the a...	1			
D1.1.3	Maintain the integrity of the transmission network...	1			
D1.1.4	Support development of new methodology under Trade...			2	
D1.1.5	Upgraded legacy balancing and situational awarenes...	2			
D1.1.6	Assessment of future operability challenges commun...	2			
D1.1.7	Produce and publish detailed forecasts and analysi...	2			1
D1.1.8	Trading solutions to deliver a safe, secure and ec...	2			
D1.2.1	(Now known as 'Future of Balancing') Enhanced bala...	2	3		1
D1.2.2	Develop inertia monitoring capabilities and other ...	1			1
D1.3.1	Develop and deliver new real-time situational awar...	2	1	2	2
D1.3.2	Enhanced network modelling capabilities with onlin...	3			1
D1.3.3	Upgraded Control Centre video walls and operator c...	3			4
D1.4.1	Creation of a data and analytics platform that wil...	2			2
D1.4.2	Continue to facilitate meetings of the Technology ...	8			
D1.5.1	Increased DER visibility in real-time operations	6			
D1.5.2	Whole electricity system operational service coord...	4			
D1.5.3	Development of RDP and LCM functionality into real...	2			
D1.5.4	Increased operational liaison	3			
D1.6.1	Constraint boundary optimisation	1			
D1.6.2	An agile programme of strategic and tactical Balan...	4			
D1.6.3	Stakeholder Engagement on Minimising Balancing Cos	2			
D17.3	Transparency Roadmap	4			
D17.6	ESO Operational Transparency Forum (OTF)	1			
D17.7	Proactively driving transparency in ESO decision-m...	1			
D17.8	Digital Engagement Platform (DEP) continued phased..	1			
D17.9	Open Data Catalogue	1			
D18.1.1	Daily analysis of Market activity and transaction ...	1			
D18.1.2	Detection of suspicious behaviour and submission o...	1			
D18.1.3	Undertake independent review of our Market Monitor...	1			
D19.1.1	Data and Analytics (D&A) Operating Model	1			
D2.1.1	Develop and drive control centre strategic resourc...	2			
D2.1.2	Incident analysis and investigations of abnormal e...	1			
D2.1.3	Monitoring and reporting of system performance to ...	1			
D2.1.4	Guidance on operational policies for use in the co...	1			
D2.2.1	Development of new modules and (based on feedback)	4			3
D2.2.2	Enhanced training and simulation with DNOs and wid...	2			2
D2.3.1	Upgrades to current simulators, including annual s...	1	2		1
D2.3.2	New training methods and platforms, including onli...	4			1
D2.4.1	Personalised updates and automated shift logins to...	3			1
D2.4.2	Content and infrastructure for personalised traini...	6			1
D3.1.1	Control Centre has fully tested skills, processes,...	1			
D3.1.2	Restoration plans for GB with the necessary stakeh...	1			
D3.1.3	Engage and collaborate with industry to plan and d...	1			
D3.1.4	Advice and oversight of Restoration and restoratio...	1			
D3.1.5	Fully competitive Restoration procurement process...	2			
D3.2.1	Facilitate and compile, on behalf of the GB indust...	2			
D3.2.2	Validate restoration timelines for GB using the as...	1			
D3.2.3	Maintain obligations and requirements against the ...	4			
D3.2.4	Restoration decision making support tool designed ...			2	
D3.3.1	Trial case studies based on different technology t...	1			
D3.3.2	Subject to industry adoption, Distributed ReStart ...	2			
	TOTAL - Role 1	**107**	**6**	**6**	**21**

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 1. Some of these projects are funded as part of the RIIO-2 price control and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. The references in the table below provide links to additional information about each project.

Innovation project name	Description	Progress update	Deliverables supported	Status	Funding
Solar Nowcasting	Research and develop the use of machine learning & satellite images to nowcast PV at Grid Supply Point (GSP) level.	A limited set of Numerical Weather Predictions (NWP) ensemble data has been obtained, and a processing pipeline has been developed and put into operation to enable the utilisation of NWP ensembles for inference. The analysis of the resulting data is currently in progress, along with the investigation of suitable visualisation methods. Additionally, efforts are being made to acquire further data to support the second phase of this project.	D1.1.7	Delivery	RIIO-2
Co-Optimisation of Energy and Frequency-containment services	Develop mathematical modelling techniques to achieve co-optimisation of energy and frequency services, to enhance the efficiency and security of the operation for the future electricity system.	Our findings discovered that holding response regionally, especially in areas with lower inertia, was more beneficial for frequency response, and this could result in lower costs.	D1.2.1	Complete	RIIO-2

Causational analysis of balancing costs	This project will deliver a method to quantify the probability that certain conditions will lead to high balancing costs, and a detailed causal and statistical analysis for the most impactful factors identified. If successful, the methodology will support the production of a prototype tool.	We have performed an in-depth analysis of wholesale prices and successfully quantified the effects of seasonality, demand, wind penetration, time of day, and other factors on wholesale prices to specifically understand the impact of wind. Additionally, we are already obtaining results regarding flows and limits across certain boundaries and their specific impact on thermal constraint costs. The project will continue to expand its scope to include these other influences, aiming to provide a more comprehensive perspective.	D1.1.3	Delivery	RIIO-2
3MD Market Monitoring Model Development	Explore machine learning methods to identify types of possible market manipulation in the balancing mechanism (BM), applying core principles set out in REMIT legislation and other market rules.	As part of the project scope, anomaly-based detection models were developed and integrated into daily NESO processes. This includes monitoring the price levels of BM units and establishing a new process to evaluate cases against the Inflexible Offer Licence Condition (IOLC). Consequently, several cases have been identified and escalated to Ofgem, prompting more detailed investigations into the behaviours of market participants.	D18.1.1	Complete	RIIO-2
REVEAL	Designing a single environment and developing	Having defined a vision and assessed the technical and regulatory feasibility in Phases 1	D1.2.1	Delivery	RIIO-2

a Proof of Concept to enable Balancing Trial Capabilities to expedite learnings for unknown elements, such as EV operation.

and 2, Phase 3 saw two technical solutions designed for ongoing consideration - the Live Trial Environment and the Trial Management Platform.

Additionally, other learnings will be integrated to enhance the maturity of our capabilities and feedback into existing business processes.

In Phase 4, the REVEAL team delivered the REVEAL Live Trial Environment Proof of Concept (POC). Replicating data sent to and from the Control Room by sharing Electronic Dispatch Logging (EDL), Electronic Data Transfer (EDT), and Operational Metering Data successfully across a site-to-site Virtual Private Network (VPN).

Following Phase 4.5, a 12-week work package to migrate the POC to the NESO tenant, REVEAL will look to deliver a backlog of capabilities to establish a robust MVP with true trialling capability and increase accessibility to market participants.

A.3 Stakeholder Evidence

Our incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of NESO's plan delivery. To demonstrate performance against this criterion, at the six-month, mid-scheme and end-scheme stages we report on our stakeholder satisfaction survey results.

Stakeholder Surveys

NESO has commissioned surveys from market research company BMG. These surveys measure satisfaction for each NESO Role. For this report we also ask one question on stakeholder satisfaction on NESO's performance establishing its new organisation and roles. The survey is targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with NESO's services. In total we contacted **1,869** stakeholders.

Role 1

For Role 1, the following question was asked:

> *'Considering Control Centre Operations, which includes key activities such as real-time system operation, system restoration, balancing mechanism review and provision of data and forecasting. Overall, from your experience in these areas over the last 6 months, how would you rate NESO's performance?'*

Survey participants were given the options of rating NESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

If they rated NESO as below expectations, they were asked what NESO needed to do to meet their expectations.

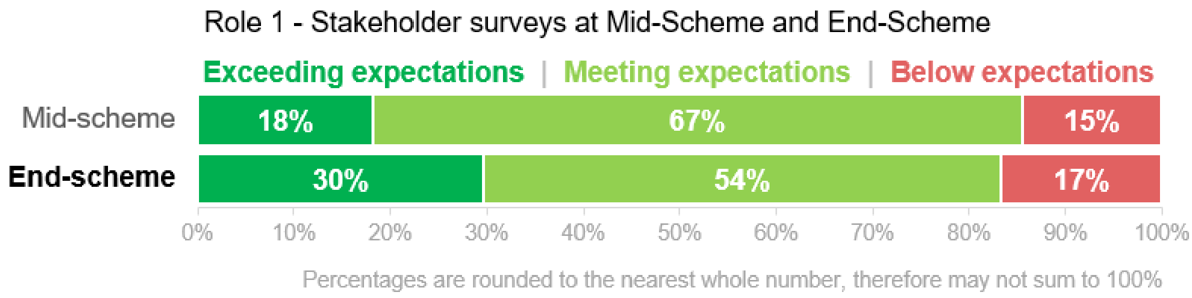
If they rated NESO as meeting expectations, they were asked what NESO needed to do to exceed their expectations.

If they rated NESO as exceeding expectations, they were asked what NESO did that exceeded their expectations.

For Role 1, we contacted **356** stakeholders, and received **54** responses to this question, which were distributed as follows:

- **30%** exceeding expectations
- **54%** meeting expectations
- **17%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 1
"Exceeding Expectations" **16** stakeholders scored us as "exceeding expectations". Feedback on what we have done to exceed stakeholder expectations in Role 1 included:	• **Good customer service and stakeholder interactions delivered by Control Room** – Several responders highlighted positive interactions with the control room staff, finding them knowledgeable and very supportive in interactions. One response expanded, stating "Control Centre Operations are a really good team to work with work/engage with and support us in any way they can". • **Effective engagement through the Balancing Programme** – Several responders call out positive engagement from the Balancing Programme team. They suggested the team have been "excellent to work with" and their methods for engagement including Stakeholder Focus Groups, one-on-one engagement, relationship and accessibility of Balancing Programme events are a "fantastic model for engagement". • **Transparency of operations** – The way we approach transparency and Operational Transparency Forum (OTF) events are called out as a positive vehicle for the sharing of data. One stakeholder specifically references Skip Rates data and deep dives in the OTF as highlights. • **Efficient delivery** – The output from the Control Room teams is called out as an example of good delivery by a few stakeholders. One states that Control Room Staff "work under difficult circumstances and continue to deliver".

"Meeting Expectations" **29** stakeholders scored us as "meeting expectations". Feedback on what we need to do to exceed stakeholder expectations in Role 1 included:	• **Increase visibility and transparency of data shared –**Some stakeholders suggested we need to go further in the visibility and transparency of data. More data on decision making, effective forecasting data, and data on skip rates, are all areas we could improve. • **Enhance and evolve our processes –** Several responses stated we need to go further to evolve our processes, and "move away from legacy actions, systems and mindset". One suggested Grid-Code, and control systems built for Coal, Gas and Nuclear, are areas we should look to modernise. Another responder said we need to "simplify myriad system interfaces", and another stated we should seek to improve digitalisation of data exchange. • **Increase collaboration with wider industry –** Some responses stated we could work more closely with our stakeholders. For example, joint procurement with Distribution Network Operators (DNOs) was suggested to reduce costs and we should engage on how Interconnectors could support meeting future flexibility challenges. • **Other feedback suggested that we:** - Need to meet deadlines for releases or be more realistic when planning. - Must continue to address work on Skip Rates. - Improve the speed of our responses and interactions. - Make quicker progress in balancing improvements. - Can be very electric biased which has continued since becoming NESO.

“Below Expectations” **9** stakeholders scored us as “below expectations”. In response to being asked what we need to do to meet their expectations, we received the following feedback:	• **Need to make more progress on Skip Rates –** Several stakeholders expressed concerns about Skip Rates, emphasising the need for more efforts to reduce “bad Skips”. One responder highlighted that Skip Rates are too high due to a discrepancy between the Control Room's definition of a Skip and the industry's definition - this “lack of clarity makes consistent progress tracking challenging”. The responder cited decisions made in the Balancing Mechanism (BM) in January 2025 as an example. Additionally, another stakeholder requested that we provide backlogged data for Skip Rates. • **Steps should be taken to address issues raised –** A few responses highlight issues and mistakes made. One stakeholder identified concerns that process issues seem to have arisen on multiple occasions due to human error. They stated the issue has been raised, but “it may then reoccur”. They recommended that training/processes need to ensure the root cause of issues is identified and then mitigated. • **Other feedback suggested we:** - Need to do more for forward planning and working to the plan. - Transmission Status Certificate (TSC) management is a massive concern that requires urgent action to address the late submission and quality of TSCs. - Must do more to unlock flexibility via battery units. - Provide better and fairer treatment of different asset classes.

A.4 Metric Performance

Table: Summary of metrics for Role 1

		2023-24 Total			2024-25 Total			**BP2 Overall**
Metric	Unit	Benchmark	Actual	Status	Benchmark	Actual	Status	Status
1A Balancing Costs	£m	2,703	2,444	●	2,721	2,697	●	●
1B Demand Forecasting	MW	594	602	●	591	646	●	●
1C Wind Generation Forecasting *Using new methodology*	%	4.6%	5.7%	●	4.7%	4.4%	●	●
1D Short Notice Changes to Planned Outages	#	1 - 2.5	1.7	●	1 - 2.5	0.9	●	●

Below expectations ●

Meeting expectations ●

Exceeding expectations ●

Metric 1A Balancing cost management

April 2023 to March 2025 Performance

This metric measures NESO's outturn balancing costs (including Electricity System Restoration costs) against a balancing cost benchmark.

A new benchmark was introduced for BP2. Analysis has shown that the two most significant measurable external drivers of balancing costs are wholesale price and outturn wind generation. The new benchmark was derived using the historical relationships between those two drivers and balancing costs:

- The benchmark was created using monthly data from the preceding 3 years.
- A straight-line relationship has been established between historic constraint costs, outturn wind generation and the historic wholesale day ahead price of electricity.
- A straight-line relationship has been established between historic non-constraint costs and the historic wholesale day ahead price of electricity.
- Ex-post actual data input into the equation created by the historic relationships to create the monthly benchmarks.

The formulas used 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.

March 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

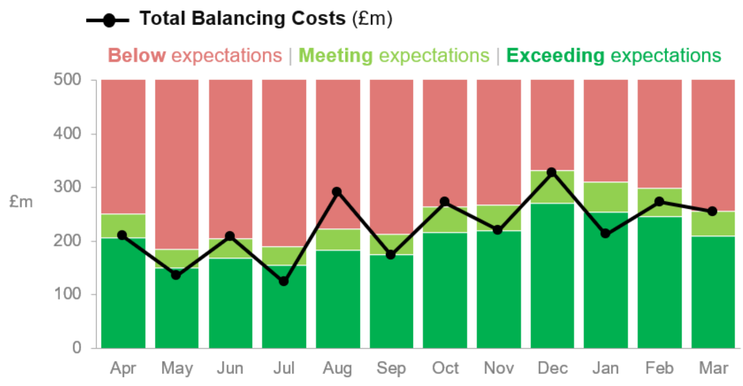


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	6.3	3.2	3.9	3.5	5.1	4.2	5.7	5.3	7.9	6.1	6.4	5.3	57.6
Average Day Ahead Baseload (£/MWh)	59	72	76	71	62	76	88	103	99	127	107	91	n/a
Benchmark	228	167	187	173	203	194	239	243	301	282	272	232	2721
Outturn balancing costs[1]	**209**	**135**	**208**	**123**	**291**	**173**	**272**	**220**	**327**	**212**	**273**	**254**	**2697**
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

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.

Performance benchmarks:

- ● **Exceeding expectations:** 10% lower than the annual balancing cost benchmark
- ● **Meeting expectations:** within ±10% of the annual balancing cost benchmark
- ● **Below expectations:** 10% higher than the annual balancing cost benchmark

Supporting information

Overall performance

BP2 Performance summary 2024-25

Balancing costs in 2024-25 are meeting expectations. The total balancing costs were £2,697m, which is £23m (1%) below the annual benchmark of £2,720m. Overall, there were four months that exceeded expectations and three months that fell below expectations. The three below expectation months (June, August, October) were linked to higher than expected constraint costs, and notably, high costs in June and August were linked to particularly high wind outturn in Scotland. Although the benchmark accounts for overall GB wind output, significantly more of these months' wind generation output was in Scotland, which has a bigger impact on constraints, and is not accounted for in the benchmark. 2024-25 has also seen Scottish constraints impacted by long-term planned outages, which exacerbate the operational cost in the region, particularly at times of high wind outturn. We are currently pursuing a range of measures to reduce thermal constraint including the continuation and expansion of our Constraint Management Intertrip Service (CMIS), network outage optimisation, and Constraints Collaboration Project.

[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.

Although thermal constraints have contributed to high costs in some months, 2024-25 has seen cost reductions across other balancing cost components. This has been supported by cost savings delivered through several key balancing cost initiatives including our Network Service Procurement (NSP)projects. We provide details of some of these in the table below. Additional benefits have been provided through inertia requirement reductions (reducing from 130 GVA.s to 120 GVA.s. from 19 June 2025) which has reduced the volume of actions required to manage system stability and consequently support cost reductions. Furthermore, the commissioning of the Greenlink interconnector on 30 January 2025 has provided access to an additional reactive capacity in the South-West (South-West England and South-Wales), supporting lower spending on voltage constraints in addition to our voltage NSPs.

Table: Summary of £1.3bn savings during BP2 from balancing cost initiatives

	Approximate savings during BP2 (£m)			
Initiative	2023/2024	2024/2025	TOTAL	Explanation of savings
Trading	458	266	724	We carry out mainly short term intraday trades for three key purposes: to balance the system where there is a foreseen energy requirement; to ensure system security where there may be a constraint; and to meet forecast NESO balancing requirements at minimum cost. The trading team have a licence obligation to conduct trades to balance the system in the most economical way, replacing more expensive BM actions. The savings due to trading are determined by the difference between trading actions and alternative BM actions.
Network Service Procurement (NSP)	157	161	318	Savings are derived from the procurement of non-energy services through Network Service Procurement (NSP) projects. Voltage and stability pathfinders generate savings by displacing generation, usually thermal, that is regularly required for voltage and inertia requirements. This is achieved through the commissioning of reactive compensation equipment and synchronous compensators/grid forming technologies via competitive tenders. The savings are calculated under counterfactual scenarios. That is, the cost the system would have incurred

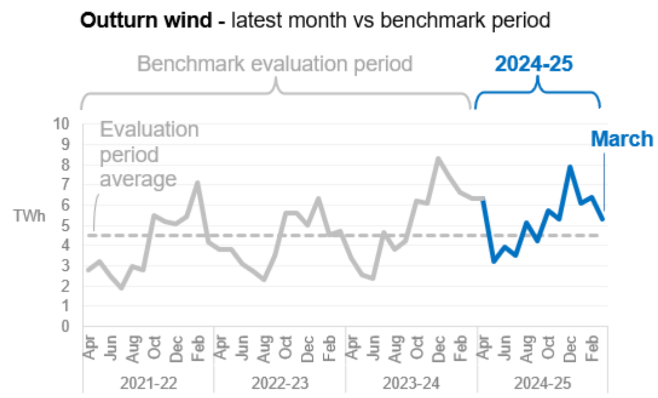
				for these services if the NSP had not been deployed.
Frequency Risk and Control methodology (FRCR)	3	235	238	FRCR savings are associated with reductions in the minimum inertia requirement of the system. Inertia is usually supplied by synchronous units, most often through Combined Cycle Gas Turbines (CCGTs). Lower requirements mean that fewer inertia units need to be running at a certain point of time. The savings are related then to the avoided cost of procuring those units in the Balancing Mechanism (BM) when there is a shortfall in market outturn inertia.
Demand Flexibility Service (DFS) (Winter 2024/25)	-	0.48	0.48	DFS was introduced during the winter of 2022/23 as part of the winter contingency toolkit. In 2024, DFS was transitioned from an enhanced action service to an in-merit based margin tool and the service went live on 27 November 2024. Since going live, the cost of accessing volume through DFS has reduced significantly and often provides a cheaper alternative to equivalent actions in the BM. DFS is only procured where it demonstrates economic value against alternative actions at the time of assessment.
TOTAL	**618**	**663**	**1,280**	

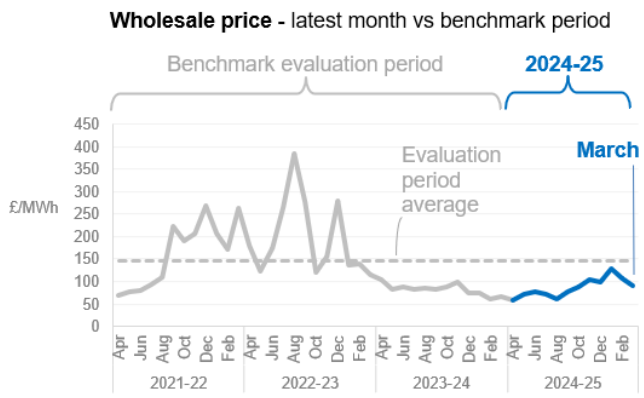
This month's benchmark

The March benchmark of £232m is £40m lower than February 2025 and reflects:

- An **outturn wind** figure of 5.3 TWh that is higher than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 4.5 TWh) but lower than last month's figure (6.4 TWh).
- An average monthly **wholesale price** (Day Ahead Baseload) that has decreased compared to February 2025 but remains elevated compared to the previous year. However, it remains lower than the evaluation period average.

Lower wholesale prices and wind outturn both supported the decrease in the benchmark for March.





Variable	March 2025	February 2025	March 2024
Average Wholesale Price (£/MWh)	91	+15	-26
Total Wind Outturn (TWh)	5.3	+1.1	+1.0
Benchmark (£m)	232	+40	+9
Performance			

*The first three rows show the outturn measures for this month and difference in the previous month and same month last year, while the bottom row outlines outturn performance for each month.

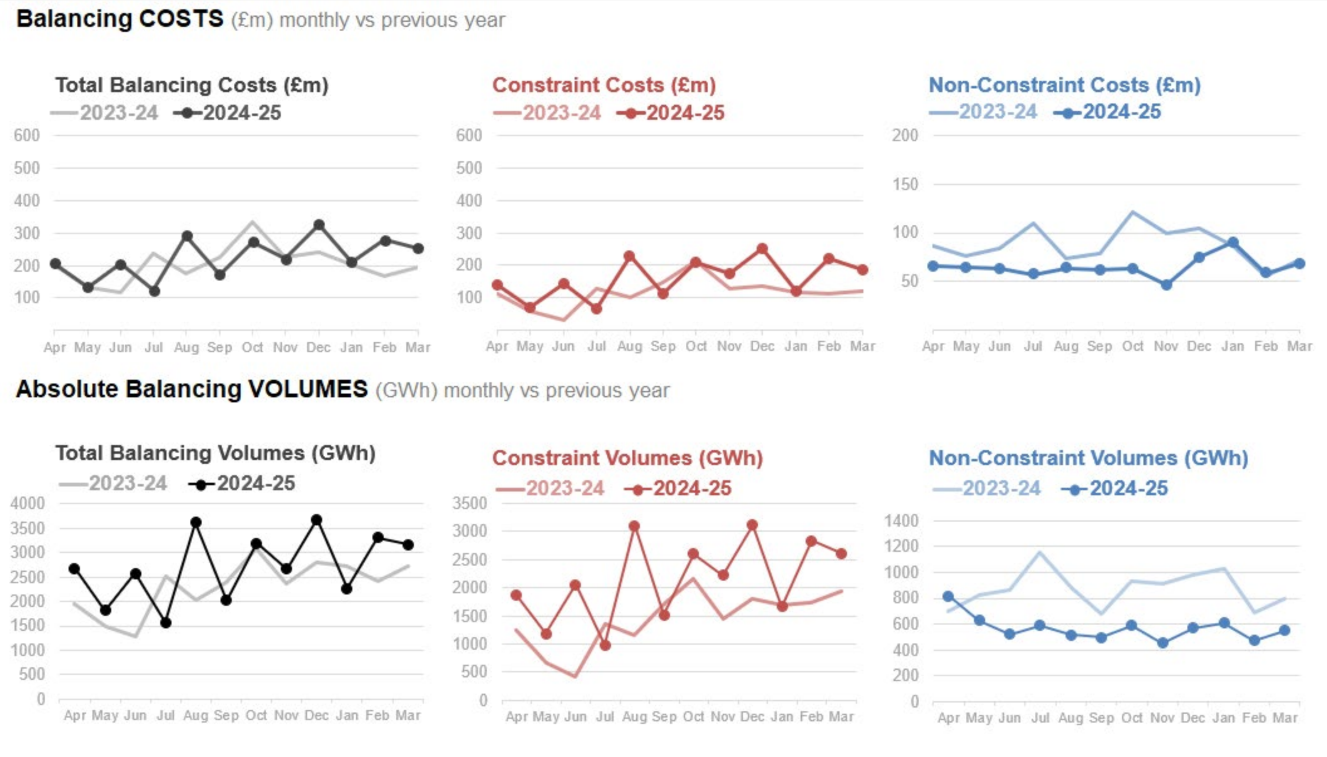
Balancing Costs - Overview

The total balancing costs for March were £254m, which is £21m (9%) above the benchmark of £232m. As the variance is within 10%, performance is meeting expectations.

March saw predominantly settled weather for much of the month, which contributed to a reduction in costs compared to February. Despite this, thermal constraints in Scotland continued to dominate costs in March which, although decreasing £12.0m compared to February, were up £76.5m compared to March 2023. This is due to high curtailment volumes required to manage transfer limits in Scotland (B4, B5, B6) and Cheviot (B7). These costs, as has been common in recent months, have been exacerbated by multi-stage reinforcement works in the Scottish boundaries (taken as planned outages). Restrictions on the Western Link also contributed to higher costs for constraints.

Overall constraint costs reduced by £34.9m compared to the previous month but were up £64.4m on March 2024. Non-constraint costs increased £10.0m compared to February but fell £7.1m relative to last year.

Average wholesale power prices were down £15/MWh compared to February 2025 but were higher by £26/MWh relative to March 2024. The volume-weighted average price for bids is £2.6/MWh, which is a slight increase on last month's price of £0.7/MWh. The volume weighted average price for offers decreased by £10.6/MWh (from £138.4/MWh to £127.8/MWh), in line with the monthly decrease in average wholesale price.

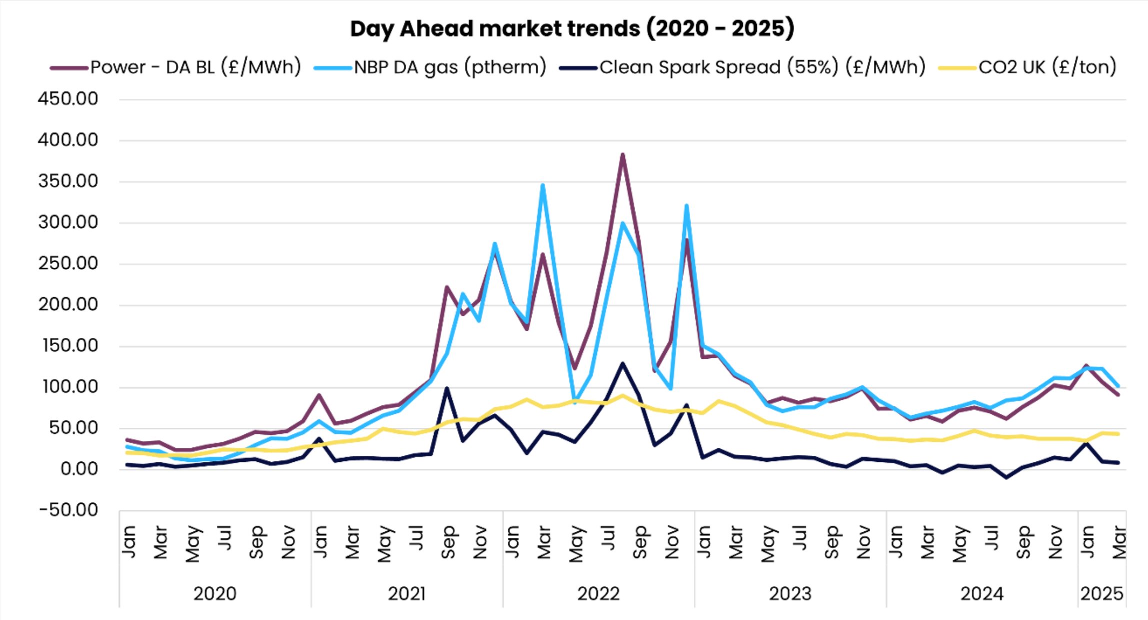


*Please note that the charts above now show <u>absolute volume</u> rather than net volume.

System and Market Conditions

Market trends

Power and gas prices have decreased compared to February, with a subsequent drop in the Clean Spark Spread Price. The CO_2 price has also decreased slightly compared to its February level. On comparison to last year, power and gas prices were significantly higher than in the same time period last year, with the CO_2 price also being slightly higher than it was in March 2024. This drop in power prices was down to reduced demand linked to mild weather, bar some colder spells towards the middle of the month, with above average temperatures seen in the latter half of the month.



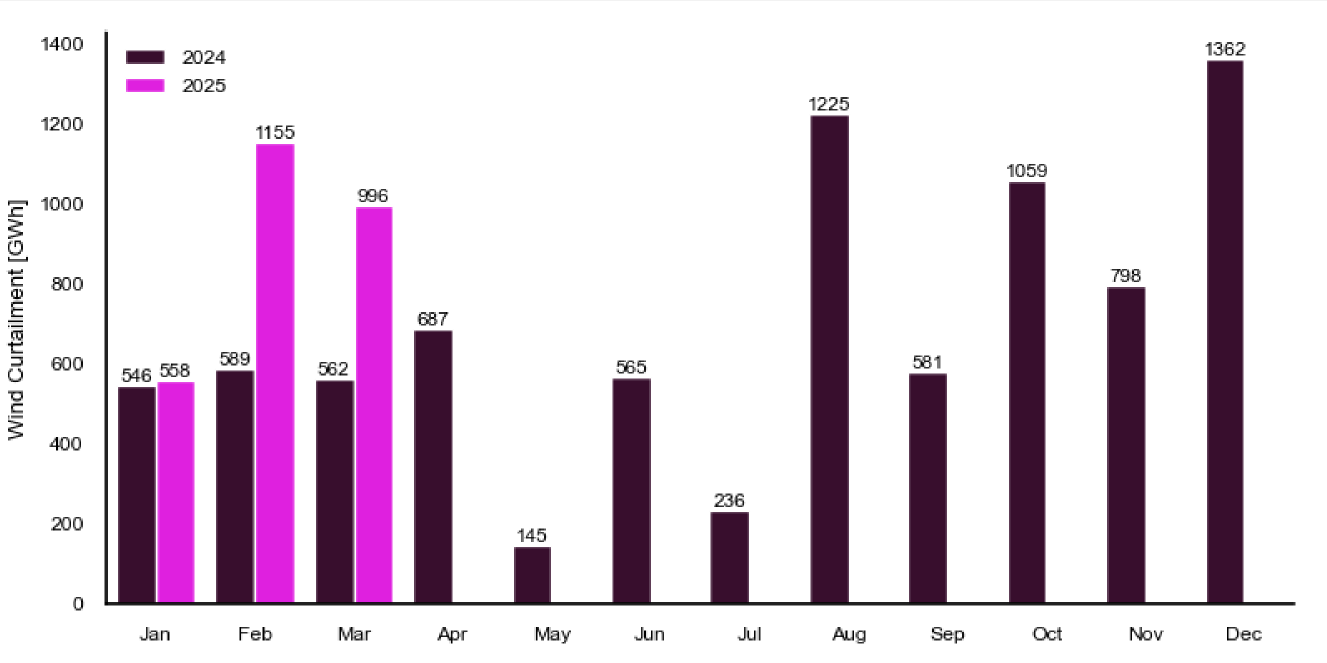
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Wind Outturn

March saw predominantly settled weather and was the sunniest March on record, with record solar generation outturn which contributed to low demand. High winds were observed at the beginning of the month, particularly between the 4th and 5th.

Overall wind outturn decreased compared to the previous month, from 6.4 TWh in February to 5.3 TWh in March. Wind generation in England and Wales contributed approximately 43% of the total, while Scottish wind accounted for the remaining 57%. This represents a shift from February's contributions of 62% in England and Wales and 38% in Scotland.

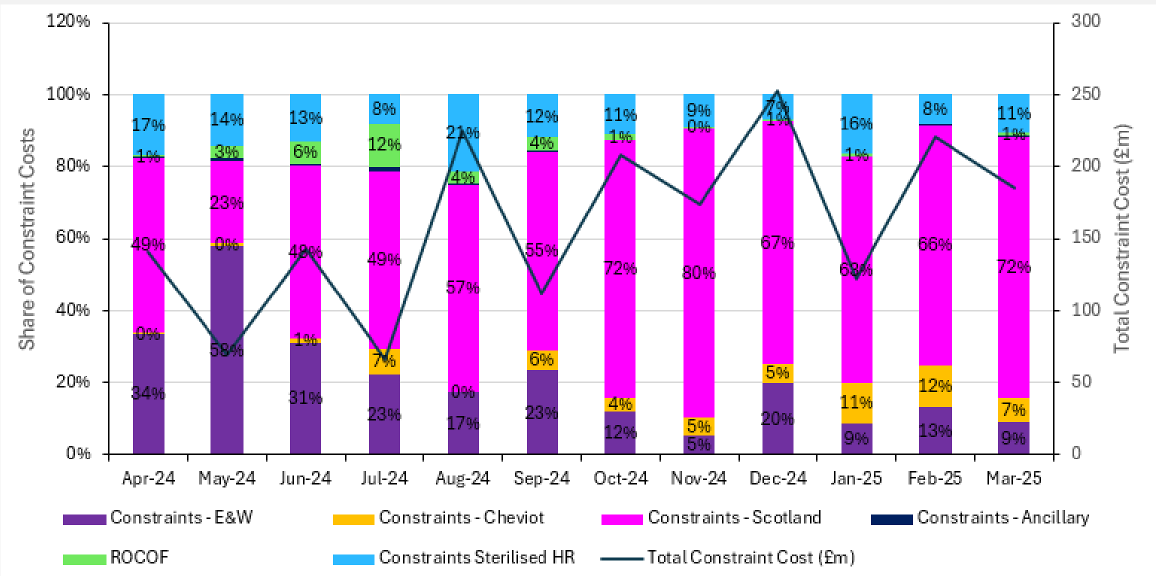
The volume of wind curtailment decreased from 1,155 GWh in February to 996 GWh in March. However, it remains significantly high compared to the same period last year and is the second highest recorded in 2025



The highest wind curtailment for the month was seen on the 5 March at 105 GWh, representing 26% of the hypothetical outturn of that day. This was also the highest cost day of the month.

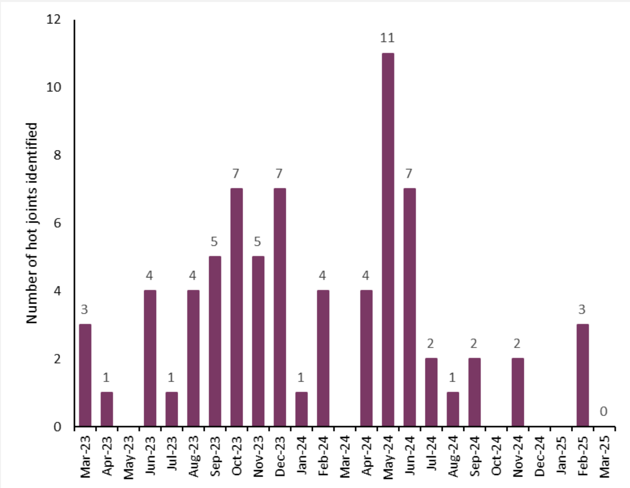
Constraints

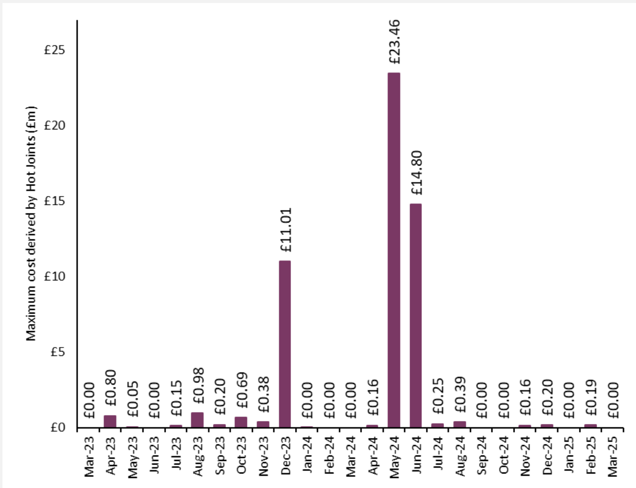
Constraint costs in March decreased by £34.9m compared to February 2025. Cost decreases were observed across most components, with only ROCOF and Constraints Sterilised HR having slight increases. Scottish constraint costs remained high, despite dropping by £12.0m compared to last month, they were still £76.5m higher than last March. Scottish constraints still formed the largest proportion of costs at 72% (up from 66% in February). This was partly due to a reduction of constraint costs in England and Wales (a decrease of £12.2m from February). High constraint costs were linked to high wind outturn and network constraints. It is anticipated that Scottish constraints will continue to represent a significant portion of the costs in 2025 due to various outages that are facilitating work to enhance the transfer capacity of Scottish boundaries. This work is expected to provide significant cost benefits over the long-term.



Network Availability

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. Currently, the methodology includes only hot joints identified in England and Wales, as such occurrences in Scotland are particularly rare. However, we are in the process of including Hot Joints identified by the Scottish Transmission Owners. No hot joints were identified in March in England and Wales.





March 2025 detailed breakdown

Balancing Costs variance (£m): March 2025 vs February 2025

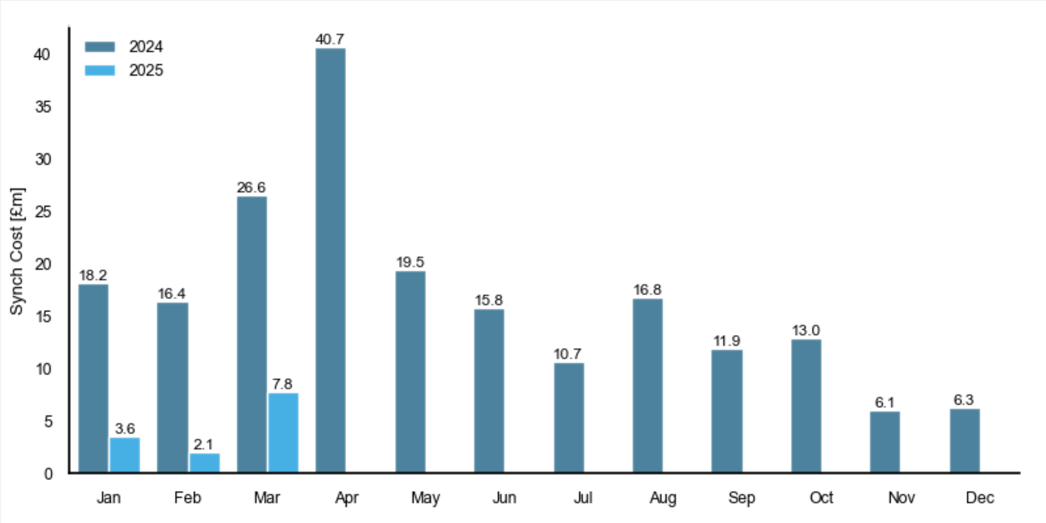
		(a) Feb-25	(b) Mar-25	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	-8.7	-8.6	0.1	
	Operating Reserve	4.6	6.3	1.7	
	STOR	6.7	7.9	1.2	
	Negative Reserve	0.4	0.5	0.0	
	Fast Reserve	18.1	20.1	2.0	
	Response	20.6	24.5	3.9	
	Other Reserve	2.6	2.6	(0.0)	
	Reactive	11.2	15.1	3.9	
	Restoration	2.4	2.9	0.4	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	0.8	-2.5	(3.2)	
Constraint Costs	Constraints - E&W	29.1	16.9	(12.2)	
	Constraints - Cheviot	25.9	12.4	(13.4)	
	Constraints - Scotland	146.3	134.3	(12.0)	
	Constraints - Ancillary	0.8	0.2	(0.6)	
	ROCOF	0.2	1.6	1.4	
	Constraints Sterilised HR	18.0	19.8	1.8	
Totals	Non-Constraint Costs - TOTAL	58.8	68.7	10.0	
	Constraint Costs - TOTAL	220.2	185.3	(34.9)	
	Total Balancing Costs	**279.0**	**254.0**	(25.0)	

As shown in the totals from the table above, constraint costs decreased by £34.9m and non-constraint costs increased by £10.0m, resulting in an overall decrease in balancing costs of £25.0m compared to February 2025.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£25.4m **Constraint – England & Wales: -£12.2m** **Constraint Sterilised Headroom: +£1.8m** Constraint costs decreased by £34.9m in March, coinciding with a 122 GWh decrease in the absolute volume of actions. Wind outturn has reduced in March which has acted to lower the volume of actions to manage constraints. **ROCOF: +£1.4m** In March, 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. An increase of 59 GWh in the volume of actions was observed during this period.	**Constraints – Scotland & Cheviot: +£79.7m** **Constraints – England & Wales: -£16.3m** **Constraints Sterilised Headroom: -£0.4m** Constraint costs have increased by £64.1m compared to last year. Although wind outturn is down on March last year there are a larger number of outages impacting the network in Scotland which are reducing the limits of some key boundaries and increasing the need for constraint management. **ROCOF: +£1.4m** The expenditure on ROCOF tends to be marginal in the system. The implementation of the FRCR requirement reduction (140 GVAs to 120 GVAs) across February to June 2024 is contributing to reduced inertia volumes and costs compared to the previous year. Additionally, 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 minimal 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 March, the system synchronisation costs (what it costs to the system, which factors in energy replacement, headroom among others) amounted to £7.8m, which is lower than the same period in 2024 (£26.6m).

Additional factors driving lower voltage management costs include:

- Commissioning of Greenlink interconnector (converter station +/- 172MVAr), providing additional voltage support in South Wales.
- Economic assets commissioned through voltage pathfinders. This includes the ones allocated in Mersey (a 38 MVAr battery at Capenhurst and a 200 MVAr reactor in Frodsham) and Pennines (reactors at Bradford West – 100 MVAr, Stocksbridge – 200 MVAr and Stalybride – 200 MVAr).
- Stability assets commissioned through stability pathfinders. Twelve synchronous compensators received contracts through Phase 1, providing roughly 12.3 GVA.s of inertia to the system, in addition to 1.06 GVAr of absorption and 950 MVAr of injection capacity.

Reactive Costs/Volumes

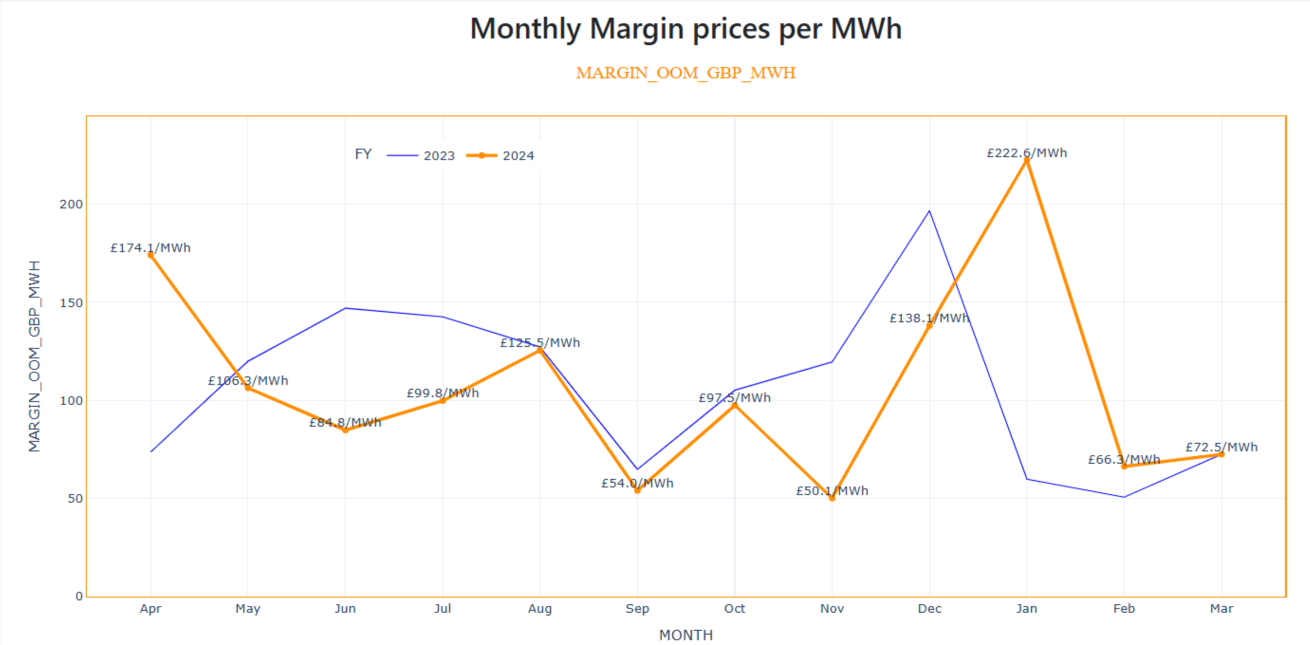
The volume-weighted average price for reactive power was £4.8/MVAr in March 2025.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£3.9m The volume-weighted average price increased from £4.5/MVAr to £4.8/MVAr compared to last month.	**+£3.2m** The volume-weighted average price increased from £3.7/MVAr to £4.8/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 £72.5/MWh in March from £66.3/MWh in February 2025.This is aligned with an increase in absolute volume of actions taken over March and comes despite the slight month on month fall in wholesale price.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£1.7m **Fast Reserve: +£2.0m** There was a 28 GWh increase in the volume of Operating Reserve required to secure the system compared to February.	**Operating Reserve: -£4.9m** **Fast Reserve: +£5.5m** The introduction of the Balancing Reserve service in March has the potential to decrease reserve prices in the BM contributing to lower costs than last 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
+£3.9m There was a 4.5 GWh increase in the volume of actions compared to February. Higher costs were also linked to higher clearing prices for response services.	**+£9.9m** The volume of actions taken for response increased 25.1 GWh compared to March 2024, although clearing prices were higher.

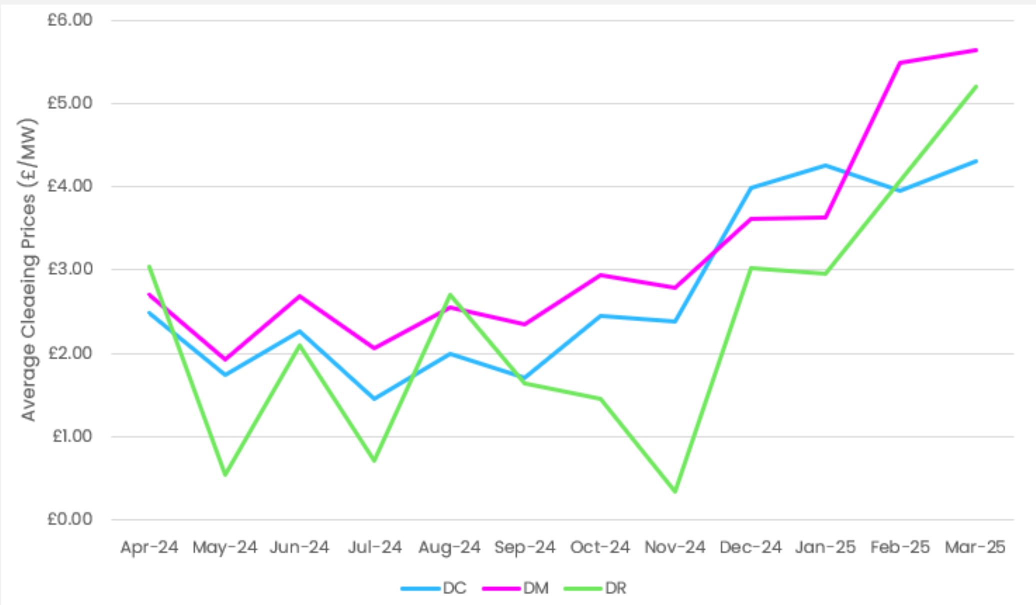
Dynamic Services Average Clearing Prices: March 2025 vs February 2025

		(a) Mar-25	(b) Feb-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	4.3	4.0	0.3	
	DM	5.6	5.5	0.2	
	DR	5.2	4.1	1.1	

Dynamic Services Average Clearing Prices: March 2025 vs March 2024

		(a) Mar-25	(b) Mar-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	4.3	1.9	2.4	
	DM	5.6	2.0	3.7	
	DR	5.2	1.2	4.0	

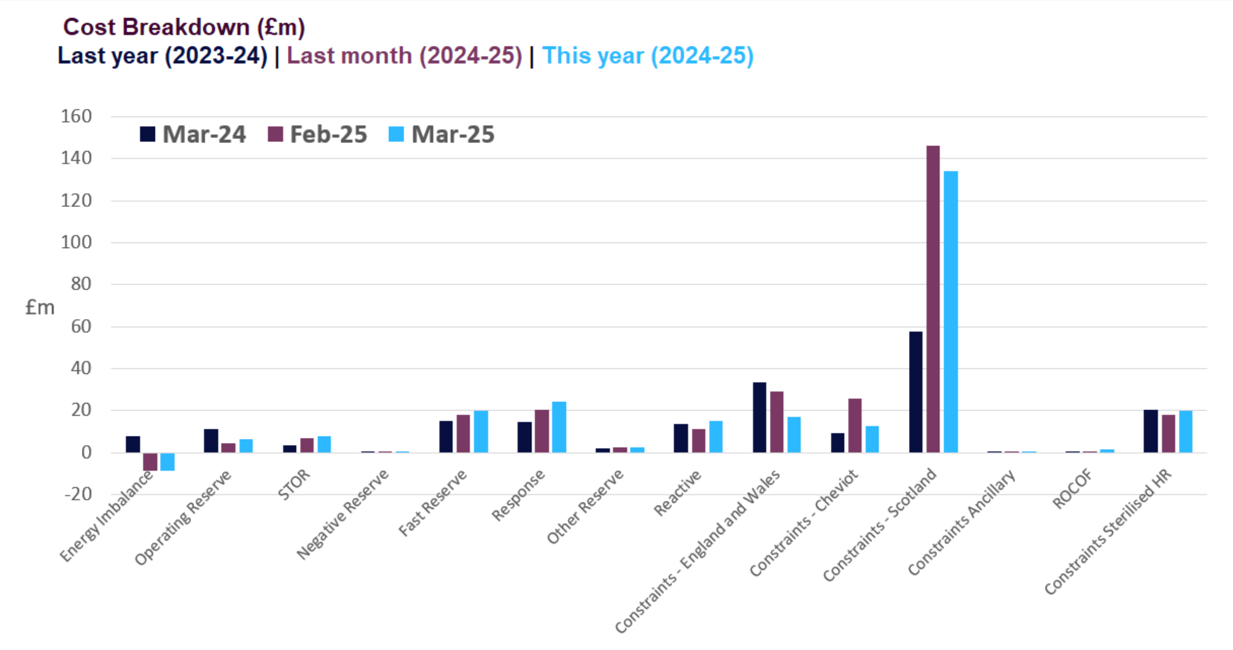
Average clearing prices for DC, DM and DR increased in March compared to February 2025 and March 2024. The largest monthly price rise was seen by DR which saw an increase in average procurement volumes. The increase in DC, DM, and DR prices in February 2025 compared to March 2024 is primarily due to higher system requirements. In March 2024, the firm requirement was 150 MW for DM and 330 MW for DR. By February 2025, these requirements had risen to 300 MW and 480 MW respectively, effectively doubling the need for DM and significantly increasing the demand for DR. This higher demand pushed prices up, even though wholesale actually decreased. Meanwhile, DC volumes remained almost unchanged.



Comparison breakdown

Constraint costs were down by £34.9m compared to the previous month, this is due to a decrease in both England and Wales (£12.2m decrease) and Scotland & Cheviot (£25.4m decrease). Constraint costs are also up on last year, by £64.1m largely down to high costs from Scottish constraints, with constraint volumes being 349GWh higher than March 2024. Non-constraints costs increased by £10.0m from last month, largely driven by increases in most categories (especially reactive and response) and smaller increases in others, however non constraint costs were £3.7m lower than March last year.

Thermal constraints currently dominate constraint costs. We are progressing several initiatives to reduce thermal constraint volumes/costs including the Constraints Collaboration Project and Constraint Management Intertrip Service. The ongoing Review of Electricity Market Arrangements (REMA) is also considering options that could alleviate thermal constraints over the long term such as zonal pricing. Network Service Procurement projects for voltage and stability are also helping to provide solutions for network management at lowest cost.



March 2025 - Cost savings

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £48 million in March. This represents an increase of around £23 million compared to February, where savings were £25 million. The most valuable action taken was the optimisation of the running arrangements at Waltham Cross substation (3-way split) which reduced the impact of outages within the area. This increased the transfer capacity of a constraint in the South-East by 2090 MW. The estimated cost savings for this action are close to £6 million.

Cost Savings – Trading

The Trading team were able to make a total saving of £9.3m in March through trading actions as opposed to alternative BM actions, representing a 15% increase on the previous month. The increase in savings this month has been reflected by increased margin trades, largely for upwards margin. Margin trades were mainly required for periods of low wind or outages on the system. There were also trades for thermal constraints as well, with many being against Emergency Instruction. The day with the greatest trading savings was the 22 March, at a cost of £1.5m with the greatest component being for Downwards Regulation. The day with the greatest spend on trades was on 5 March at a cost of £1.7m with the greatest component being for margin.

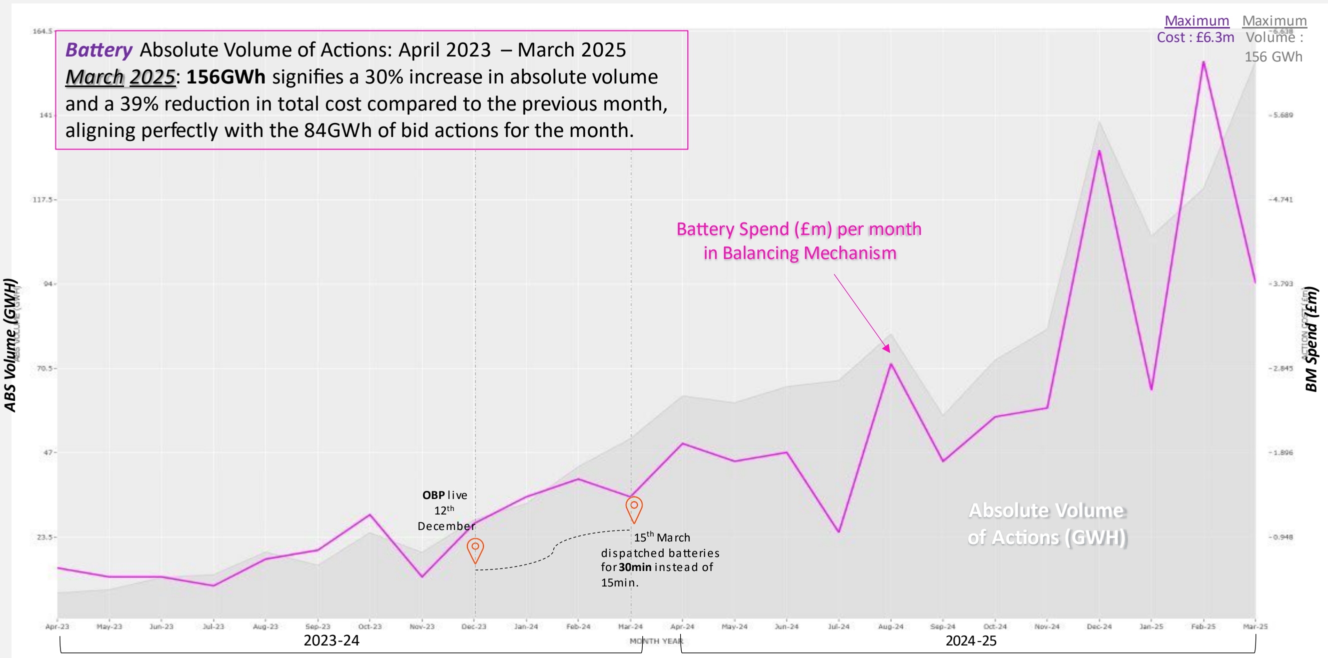
Cost Savings – Network Services Procurement (NSP)

We are using Network Services Procurement (NSP) 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 £316m in savings since April 2023.

Notable events in March 2025

Monthly Absolute Volume of actions and spend for Batteries in the Balancing Mechanism

April 2023 to March 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 has increased compared to the previous month, February 2025, while costs have fallen. Battery dispatch increased to a new record absolute volume, at 156 GWh, illustrating our commitment to maximising the flexibility of energy offered by battery storage and small BMUs over the last year. Most of the spend for batteries was related to margin and minor components.

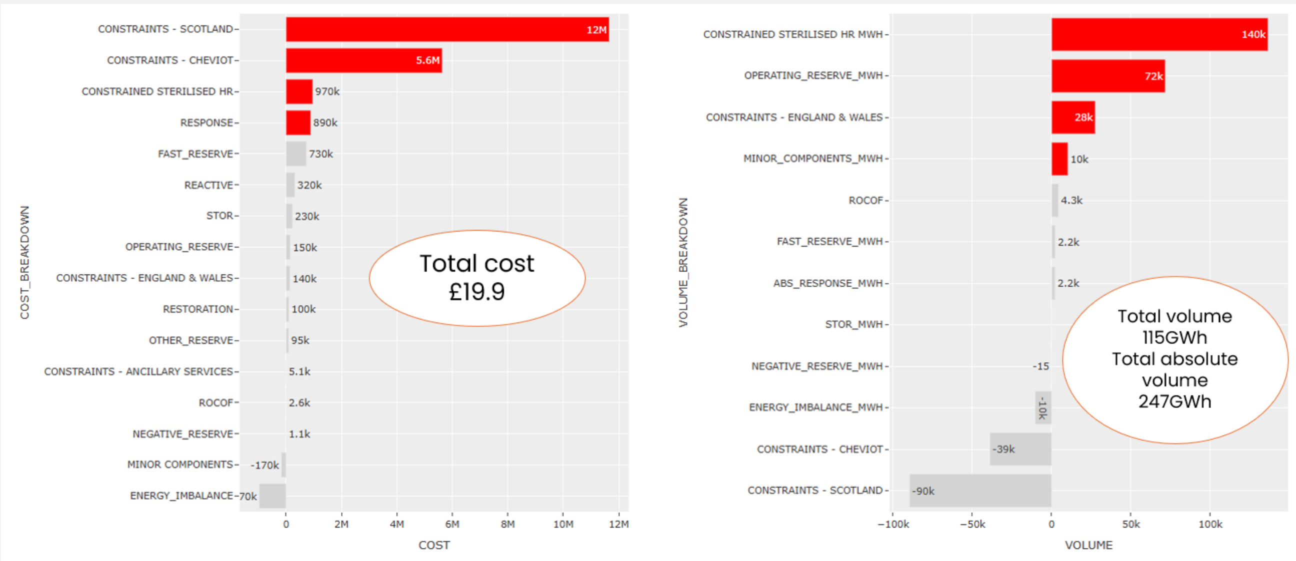
DAILY CASE STUDIES

Daily Costs Trends

March's balancing costs were £254m which is £19m lower than the previous month. Three days were recorded with costs above £15m (4, 5, 28) with an additional twelve having a daily total cost over £10m (2, 3, 4, 5, 6, 10, 11, 12, 21, 27, 28, 29). The daily average fell by £1.6m compared to February 2025 (£9.8m to £8.2m).

The lowest cost day was observed on 18 March, with a total balancing cost of approximately £2.3m. The 18 saw increased solar generation on the system, with a record of 12.2GW set (which has been beaten since during April). This contributed to low demand during the day. The highest cost day was 5 March, with a total spend of £19.9m. This day saw the highest volume of wind curtailment during the month, with actions to manage Scottish constraints making up around 60% of the total costs. This was brought about by windy conditions in Scotland.

High-Cost Day – 5 March 2025



March 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.

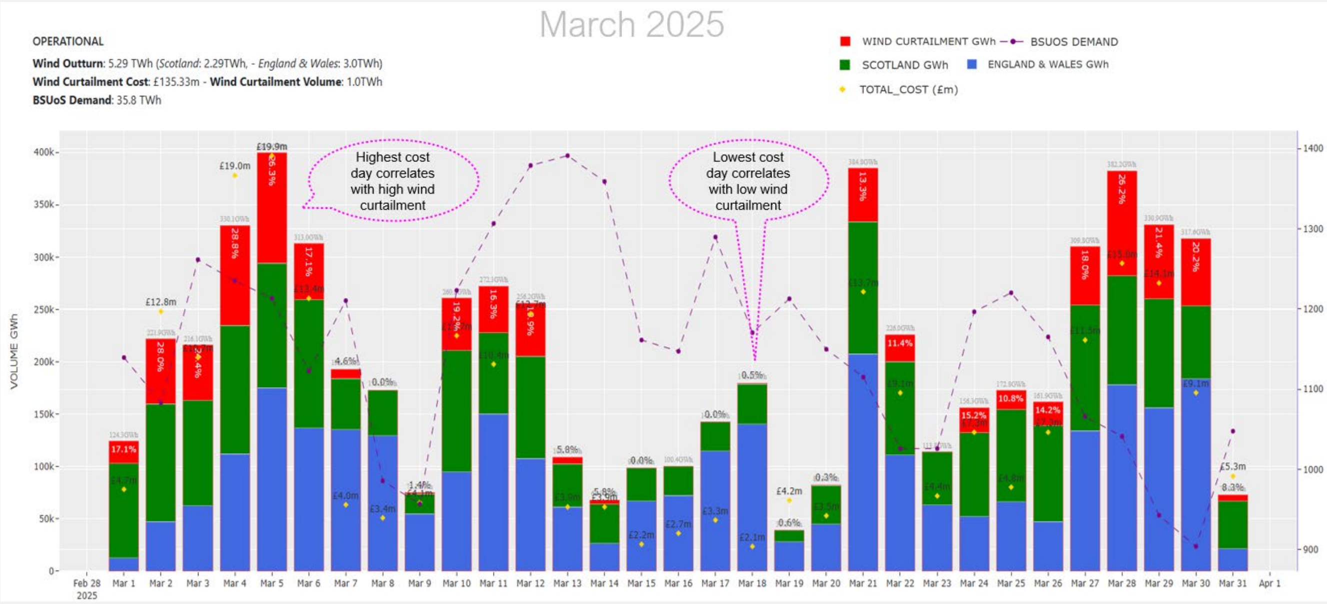
KEY: **Blue bars:** Wind generation in England and Wales

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.

Metric 1B Demand forecasting accuracy

This 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. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

A 5% improvement in historical 5-year average performance is required to exceed expectations, whilst coming within ±5% of that value is required to meet expectations.

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.

Performance will be assessed against the annual benchmark, but monthly benchmarks are also provided as a guide. The NESO will report against these each month to provide transparency of its performance through the year.

March 2024-25 performance

Figure: 2024-25 Monthly absolute MW error vs Indicative Benchmark

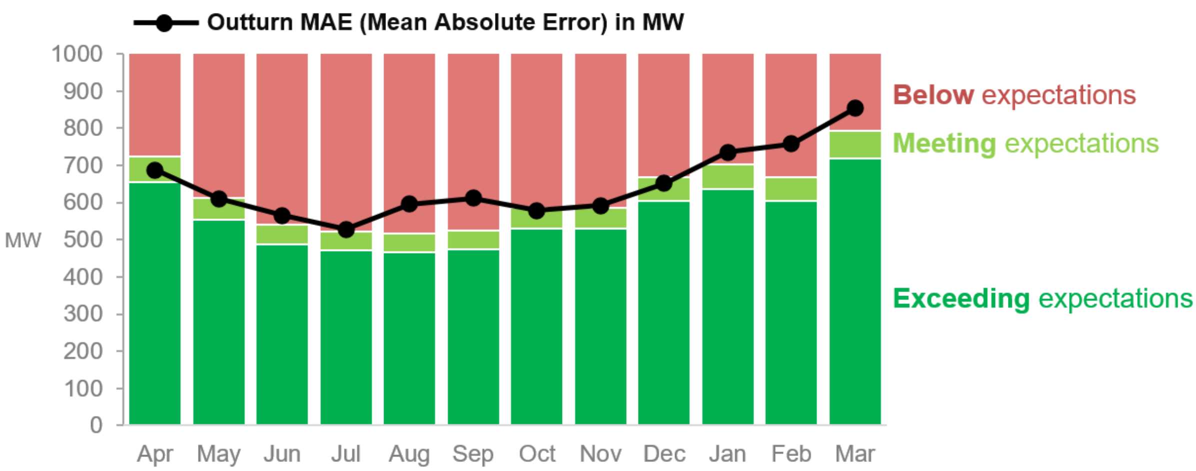


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	690	584	514	496	491	500	559	557	635	669	637	756
Absolute error (MW)	**687**	**610**	**565**	**528**	**596**	**612**	**578**	**591**	**652**	**735**	**758**	**853**
Status	●	●	●	●	●	●	●	●	●	●	●	●

[2] Demand | BMRS (bmreports.com)

Performance benchmarks:

- **Exceeding expectations:** >5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** >5% higher than 95% of average value for previous 5 years

Supporting information

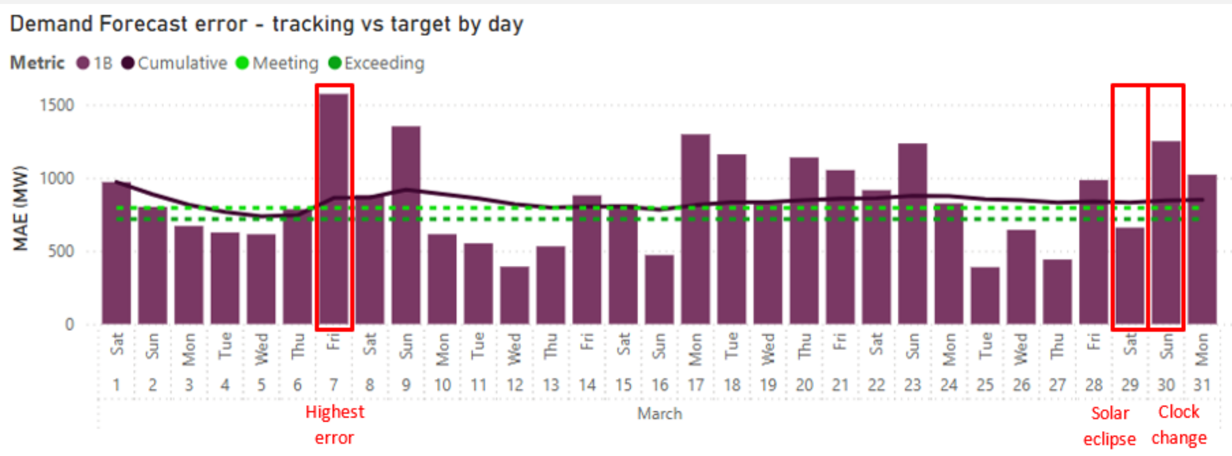
In March 2025, the mean absolute error (MAE) of our day ahead demand forecast was 853 MW compared to the indicative benchmark of 756 MW. The 5% range around this benchmark extends 794 MW, meaning our performance failed to meet expectations for March.

The Met Office reported that England experienced the sunniest March in their 116yr records. Solar forecasting is a known challenge and was the prime contributor to the demand errors this month.

Sustained sunshine led to record Solar PV production levels, with minimum weekday demands occasionally occurring during the afternoon. The sunny but cooler conditions presented almost perfect solar panel conditions and as a result, led to a new Solar PV production record of 12.7GW on 18 March.

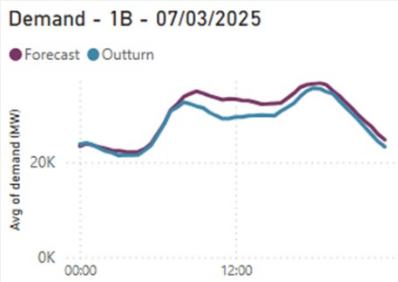
March also brought the first significant solar eclipse (partial) since 2022, during the morning of Saturday 29 March. While the effects on demand can be observed in the chart below, the impact was lower as a result of the approaching weather front, which coincided with the tail end of the eclipse.

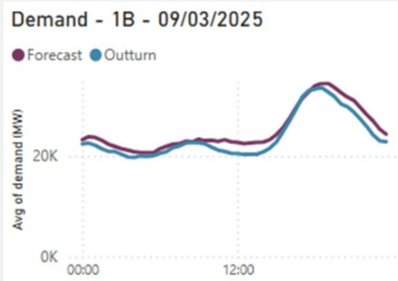
The largest demand forecast error this month was 4.9 GW on 17 March, settlement period 27. Demand peaked at 40GW on 13 March, while the high solar production produced an extremely low minimum demand of 14.5GW on 30 March, settlement period 26.

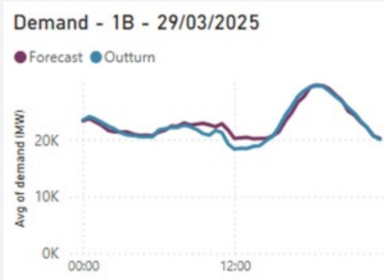


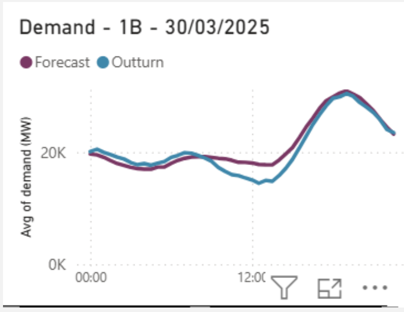
Days with largest errors:

Partial solar eclipse









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

Error greater than	Number of SPs	% out of the SPs in the month (1486)
1000 MW	443	30%
1500 MW	275	19%
2000 MW	161	11%
2500 MW	76	5%
3000 MW	37	2%

The days with largest MAE were 7 and 9 March.

Day	Error (MAE)	Major causal factors
7 Mar	1573	Solar/weather and profiling
9 Mar	1352	Contributions from solar/profiling and other factors not identified by our models

Missed / late publications

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

Triads

Triads run between November and February (inclusive) each year, and thus did not affect March.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 2-7, 10-14, 17-19, 25, 26, 28 and 31 March, with an accumulated total of 1958MWh procured. These will nominally affect the national demand outturns but are not included in the day ahead forecast.

BP2 Performance Summary 2024-25

The forecasting of National Demand has remained challenging, for reasons outlined in the *Metric 1B/1C Improvement Plan* that we shared with Ofgem recently. While our forecasting performance has largely remained in close proximity to the forecasting targets, the yearly performance has been undermined by a few poor months. We have released a new National Demand AI prototype model, which is currently being validated and will be released into production at the earliest opportunity.

Solar errors appear to be the dominant factor with National Demand forecasts and we have been working hard to address this. In the last quarter, we have built a set of prototype solar (National Solar & BMU Solar) models and validation will commence shortly.

Metric 1C Wind forecasting accuracy

This 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).
- 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.

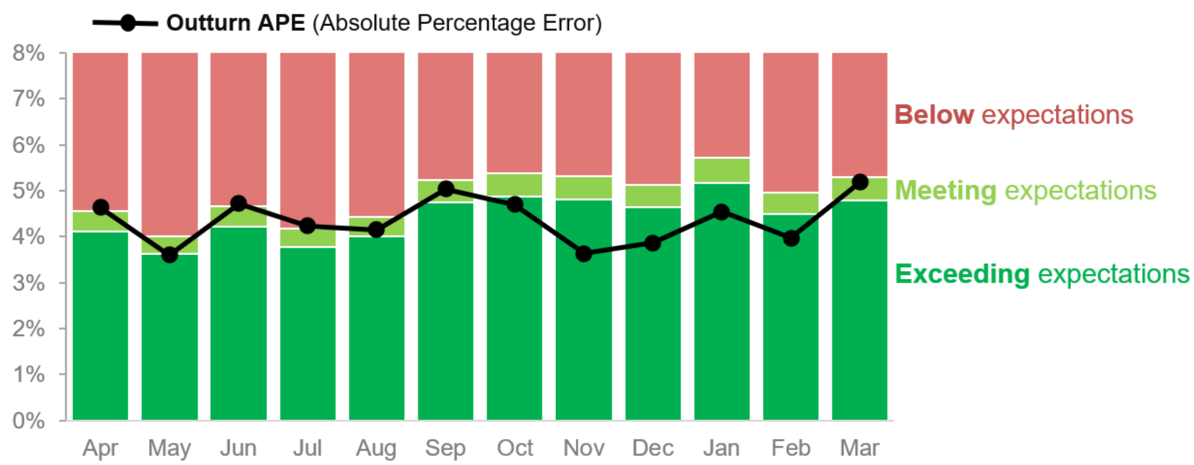
Sites deemed to have withdrawn availability are those that:

- 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.

The benchmarks are drawn from analysis of historical errors of the five years preceding the performance year. A 5% improvement in performance is expected on the 5-year historical average, with a range of ±5% used to set the benchmark for meeting expectations.

March 2024-25 performance

Figure: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmark



Change to methodology from 18-Month Report onwards

In line with the NESO Performance Arrangements Governance Document, from the 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). This approach applies to the figures reported for the whole of 2024.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.34	3.82	4.45	3.98	4.22	4.99	5.13	5.07	4.89	5.44	4.73	5.05
APE (%)	**4.64**	**3.60**	**4.72**	**4.24**	**4.15**	**5.04**	**4.70**	**3.63**	**3.86**	**4.40**	**3.97**	**5.19**
Status	●	●	●	●	●	●	●	●	●	●	●	●

ESORI view of BMU Wind Generation Forecast APE (Previous Method)

Below, we report the APE% and benchmark based on the method described in The Electricity System Operator Reporting and Incentives (ESORI) Arrangements: Guidance Document. This applied prior to the transition to NESO on 1 October 2024, up to and including the figures reported in August 2024. This view includes sites that have redeclared to zero and does not incorporate Initial Settlement Runs (+16 Working Days).

A performance status is shown in the table below, however for the figures reported for September 2024 onwards, this is for information only and is not part of the 2024-25 incentives assessment.

Table: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmarks (ESORI method)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.32	3.85	4.43	4.02	4.19	4.98	5.13	5.02	4.93	5.46	4.74	5.09
APE (%)	**5.14**	**3.61**	**4.89**	**4.30**	**4.60**	**4.98**	**4.77**	**3.51**	**3.83**	**4.50**	**4.05**	**5.28**
Status	●	●	●	●	●	●	●	●	●	●	●	●

Performance benchmarks:

- **Exceeding expectations:** < 5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** > 5% higher than 95% of average value for previous 5 years.

Supporting information

In March 2025, the mean absolute percentage error (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 5.20% against the corresponding monthly benchmark of 5.05%. The 5% range around this benchmark extends from 4.80% to 5.30%, meaning our performance met expectations for March.

The mean absolute percentage error for the original 1C metric was 5.30%, compared to the monthly benchmark of 5.09%. The 5% range around this benchmark extends from 4.84% to 5.34%. meaning performance on this metric also met expectations.

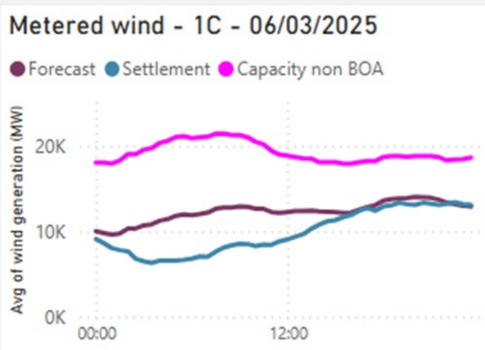
The Met Office reports that March saw predominantly settled, non-impactful weather, mostly dominated by high pressure systems. This month's performance was largely influenced by two extraordinary days on 6th and 8th March. Errors on 6 March were due to wind speed forecast errors, which improved significantly as time progressed. Errors on 8 March were affected by Settlement Metering errors, which NESO expect to self-correct in due course.

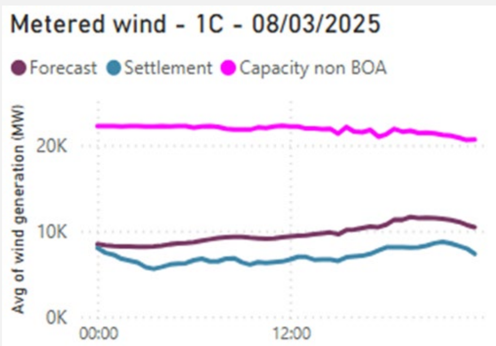
March 30 also saw a period of sustained negative day-ahead energy prices (9 consecutive hours from 6am-3pm) where units with a Contract for Difference (CfD) often redeclare to 0.

The largest wind forecast error this month was 5.3 GW on 6 March, settlement period 12.

The day with largest APE (12.2%) was 6 March, while wind generation peaked at 15.0GW on 21 March.

Largest errors





Details of largest error

Day	Error (APE)	Major causal factors
6 Mar	12.2	Day ahead wind speed forecast errors over the first half of the day
8 Mar	11.97	Wind forecast errors in addition to settlement metering errors yet to be corrected in Elexon settlement runs

Missed / late publications

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

BP2 Performance Summary 2024-25

Following the sustained tactical efforts in 2023/24, wind forecasting performance improved during the first half of 2024-25. Although released later than anticipated, the successful launch of the new strategic Platform for Energy Forecasting (Wind R5) product in November 2024 has recovered the yearly wind performance to exceed expectations.

The new platform has also provided the foundation to create new demand and solar models, using common datasets and repeatable technology.

Metric 1D Short Notice Changes to Planned Outages

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

Q4 2024-25 performance

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

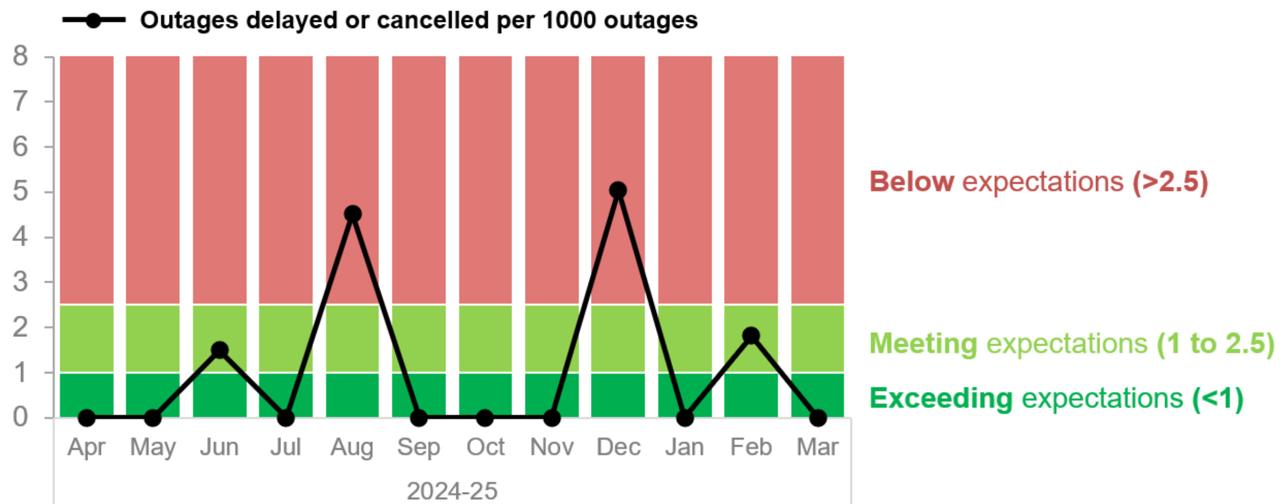


Table: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	673	614	670	784	665	729	738	730	397	552	550	766	7868
Outages delayed/cancelled due to NESO process failure	0	0	1	0	3	0	0	0	2	0	1	0	7
Number of outages delayed or cancelled per 1000 outages	0	0	1.49	0	4.51	0	0	0	5.04	0	1.81	0	0.89
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Performance benchmarks:

- **Exceeding expectations:** Fewer than 1 outage delayed or cancelled per 1000 outage
- **Meeting expectations:** 1-2.5 outages delayed or cancelled per 1000 outages
- **Below expectations:** More than 2.5 outages delayed or cancelled per 1000 outages

Supporting information

We successfully released 552 outages in January and 766 outages in March with zero delays or cancellations due to a NESO process failure.

For February, we successfully released 550 outages. There was one delay or cancellation due to a NESO process failure. The number of stoppages or delays per 1000 outages for February was 1.81, which is within the 'Meets Expectations' target of less than 2.5 delays or cancellations per 1000 outages. The cumulative number of stoppages or delays per 1000 outages is 0.89 which is 'Exceeds Expectation' target of less than 1.00. The single event is summarised below:

The single delay was caused by a routine live trip that would have resulted in a substation being exposed to additional risk due to interaction with another outage. It was decided the postpone the trip test by several days to allow the other planned outage at the site to return to service, and it would mitigate any additional risk to the demand connected there. An Operational Learning Note (OLN) is being written to investigate and capture an improvement to the assessment of trip tests to ensure consistency across the control room and planning departments

BP2 Performance Summary 2024-25

We successfully released a total of 7868 outages in 2024/25 with 7 delays or cancellations being caused by a NESO process failure. This gives an overall score of 0.89 per 1000 outages and 'Exceeds Expectations'. Out of the 7 delays or cancellations, 6 of the events have been followed up with an Operational Learning Note (OLN) shared with preventative actions. There is one OLN in progress which will be shared with the wider business once completed.

Overall, the 2024/25 performance improved compared to 2023/24 where a total of 7470 outages were released with 13 delays or cancellations caused by NESO, giving a cumulative score of 1.74 per 1000 outages. Therefore, NESO successfully released an additional 398 outages in 2024/25 and had 6 fewer delays or cancellations.

A.5 Quality of Outputs

The fourth evaluation criterion for the NESO incentive scheme is Quality of Outputs, where the Performance Panel will consider the actual benefits NESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing BP2, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the BP2 RIIO-2 Business Plan. This was an update from BP1. The relevant CBAs for Role 1 are:

- Control centre architecture and systems (A1)
- Control centre training and simulation (A2)
- Restoration (A3)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit. Deliverable activity statuses reflect the delivery of RIIO-2 milestones and do not recognise either work completed prior to April 2023 nor progress made towards yet to be completed milestones.

We also provide a specific case study on our Improving Information Inaccuracy to reduce wind PN inaccuracy which was not covered by the original CBA document.

The Panel will also consider NESO's Regularly Reported Evidence (RRE) as part of the Quality of Outputs criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the PAGD guidance. For Role 1, the items of RRE reported at the end of the year are:

- 1E. Transparency of operational decision making
- 1F. Zero Carbon Operability (ZCO) indicator
- 1G. Carbon intensity of ESO actions
- 1H. Constraints cost savings from collaboration with TOs
- 1I. Security of Supply reporting
- 1J. CNI outages

CBA: Control centre architecture and systems (A1)

BP2 End-Scheme view of gross benefits compared to BP2

We now estimate gross benefits of £360m over the RIIO-2 period, which is a decrease of £62m compared to the BP2 plan figure of £422m.

However, additional benefits from PEF that were not assumed in the original CBA are now expected to deliver an additional £698m during RIIO-2.

Area	Estimated gross benefits during the 2021-26 RIIO-2 period (£m)		
	BP2 Plan Views	**BP2 End-Scheme view**	**Variance**
1. **Reduced CO_2 emissions** - reduced environmental damage from our control centre residual balancing actions.	226	190	-36
2. **Improved situational awareness** - estimated 5% improvement in managing constraints from enhanced situational awareness tools.	108	113	+5
3. **Utilising flexible technology** - lowering consumer bills through unlocking the benefits of greater flexibility.	80	53	-27
4. **Greater interconnection** - upgrading our tools to better handle greater levels of interconnection.	6	3	-3
5. **Reduced BM outage downtime** - reduced Balancing Mechanism outage downtime.	2	2	0
Total	**422**	**360**	**-62**
Additional benefits: - **Platform for Energy Forecasting** (PEF)	n/a	698	+698

The main drivers of the change in the benefits are as follows:

- **Reduced CO2 emissions** - A new methodology is used to calculate the benefit, and the methodology uses the carbon intensity outturn values (vs historic baseline) and outturn carbon costs (vs predicted carbon costs from 2021).
- **Improved Situational Awareness** – the benefit has increased, due to outturn of constraint costs being higher than forecasted.
- **Utilising Flexible Technology** and **Greater Interconnection** – the benefit has reduced due to a change in our assessment of NCMS value delivered by year.
- **Reduced BM Outage Downtime** – the planned benefit has not changed compared to the BP2 plan.

Additional benefits (PEF):

- **Platform for Energy Forecasting (PEF)** benefits were not documented in the original CBA despite the existence of the investment at that time. PEF has implemented several developments which added significant additional value by improving situational awareness in the evolving market, so we added these into the CBA at BP1 end of scheme.
- For BP2 mid-scheme we agreed with Ofgem that benefits that were not included in the original CBA could be reported, but the £m benefits should be kept separate from the CBA total and included as an 'annex' to the CBA. We have continued that approach for this BP2 End-Scheme Report.

Summary of progress in 2024-25

In 2024-25, we delivered 28 Open Balancing Programme (OBP) releases, totalling over 2,000 changes with minimal outage time. For the PEF product we had 13 releases and we also had 7 releases across existing balancing products.

This table details the key releases from the programme (by quarter):

Quarter	Release
Apr – Jun 2024	Voided Instruction Improvements
Apr – Jun 2024	Battery Fast Dispatch
Jul – Sep 2024	Enhanced Fast Dispatch
Oct – Dec 2024	Dispatch Efficiency Monitor
Jul – Sep 2024	Interface from the Single Markets Platform (SMP)
Jul – Sep 2024	Interface from integrated energy management system (IEMS) for metering

Oct – Dec 2024	Legacy Dispatch Enhancements
Oct – Dec 2024	VERGIL Improvements
Oct – Dec 2024	Dispatch Efficiency Monitor
Oct – Dec 2024	BM Quick Reserve
Oct – Dec 2024	R5 Wind – New PEF Platform
Oct – Dec 2024	OBP Interface to the Data Analytics Platform (DAP)
Jan – Mar 2025	Oracle Cloud Infrastructure (OCI) to Azure Migration

Combined status by milestone for relevant deliverables
(Activity A1)

Status	Count	%
Complete	**54**	73%
Delayed – Consumer Benefit	**4**	5%
Delayed – External Reasons	**4**	5%
Delayed - Internal Reasons	**12**	16%
Total	**74**	100%

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence, further detail and benefit calculations

1. Reduced CO_2 emissions

The table below details the breakdown of the 'Reduction in CO2 Emissions' benefit into financial years, split between the Balancing Programme and NCMS. These figures can be extracted in part from the Carbon Intensity figures available on the NESO data portal: Historic GB Generation Mix | National Energy System Operator

The benefits for the Balancing Programme and NCMS are determined as the difference between the carbon cost for each financial year of RIIO 2 vs the RIIO 1 Baseline of £285M. The Carbon cost is calculated as:

Yearly Generation x Carbon Intensity x Carbon Price x 2.5%

where 2.5% is the attributed amount of the Carbon Benefit to NESO major projects.

An additional Programme Value Realised % is then applied when calculating the benefit figure. This % represents the % of value realised of the total by the programme for each financial year.

Source	Financial Year			
	22-23	23-24	24-25	25-26
Yearly Generation GWh	287k	275k	283k	283k
Carbon Intensity gCO2/kWH	178	146	125	125
Carbon Price £/T	£249	£253	£257	£257
Calculated Carbon Cost	£318M	£254M	£227M	£227M
RIIO 1 Baseline Cost	£285M			
Balancing Programme % of Value Realised	1%	15%	80%	100%
Balancing Programme Benefit	-£327k	£4.69m	£46.7m	£58.4m
NCMS % of Value Realised	1%	15%	30%	100%
NCMS Benefit	-£327k	£4.69m	£17.5m	£58.4m
Yearly Total (Balancing Programme + NCMS Benefit)	-£654k	£9.38m	£64.2m	£116.8m
Full Total	**£189.7m**			

2. Improved situational awareness

The original forecast of constraint costs was £660m in the original CBA for 23-24, Outturn constraint costs for 24-25 is £1.5bn. In addition, total constraint forecasts in original CBA were £4.7bn compared to current view of £6.9bn. With this and the change in our % calculations for when NCMS will deliver value, the result is a net increase in the improved situational awareness benefit of £5m.

3. Utilising flexible technology:

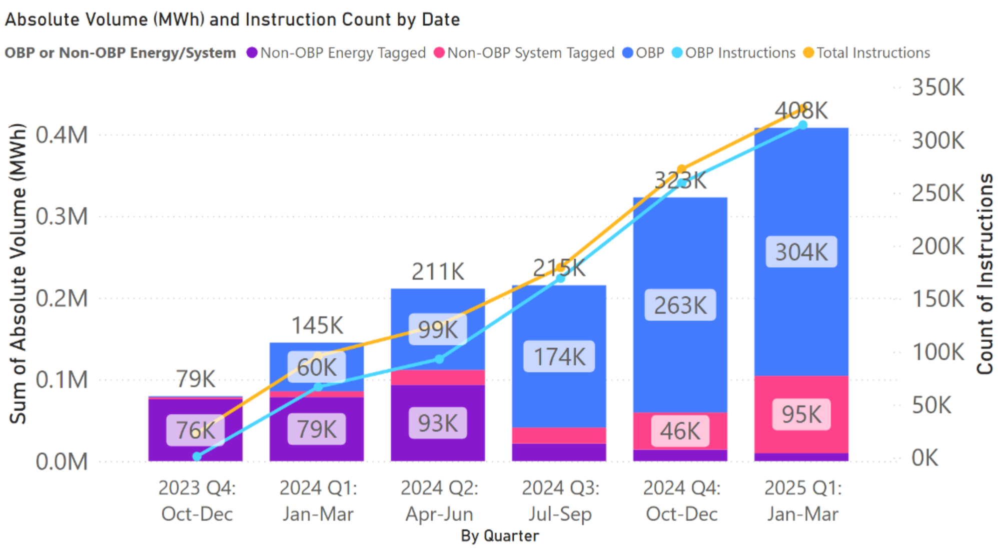
The Utilising Flexible Technology benefit has been reduced due to a change in our assessment of NCMS value delivered by year.

Measuring the direct impact of the deliveries in all the benefits areas is complex and the collective set of impacts across all NESO deliverables is difficult to unpick. 'Utilising Flexible Technology' is one area where it is easier to measure and see the change, and attribute directly to IT deliverables within A1. We can do this by measuring the instructed volumes in the BM for flexible technologies which are contained within the battery and small BM unit zone.

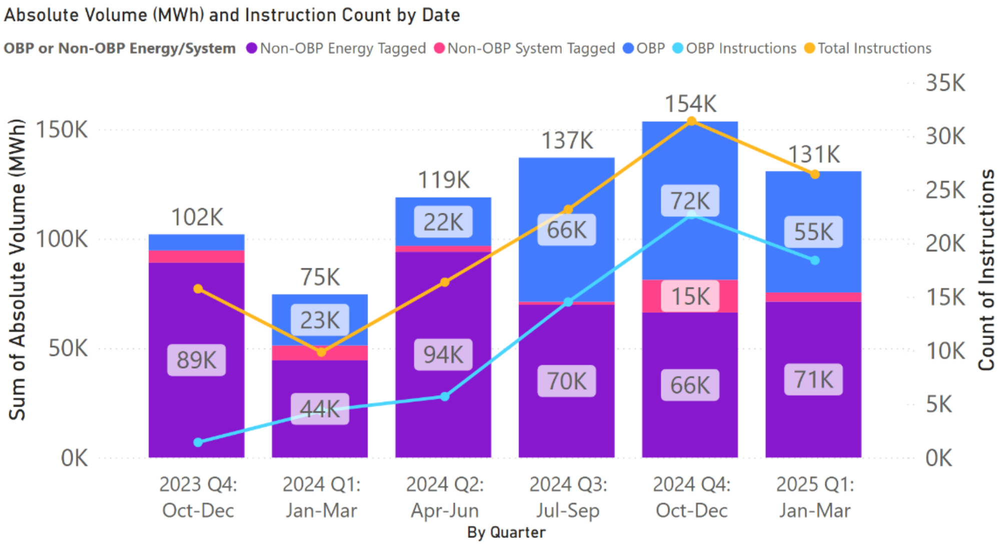
Type	Measure	Rationale and status
Lead indicator	Small BM Unit Dispatch	Increase in average daily dispatch volume of 31% comparing Oct-Dec 2023 and Jan-Mar 2025
Addition al indicator	Small BM Unit Dispatch	Increase in average daily dispatch instruction count of 72% comparing Oct-Dec 2023 and Jan-Mar 2025
Lead indicator	Battery Zone Unit Dispatch	Increase in average daily dispatch volume of 425% comparing Oct-Dec 2023 and Jan-Mar 2025
Addition al indicator	Battery Zone Unit Dispatch	Increase in average daily dispatch instruction count of 1347% comparing Oct-Dec 2023 and Jan-Mar 2025

Graphs to see the increase of utilisation are shared below. On these charts, the boxes represent the quarterly volume (split by OBP, Non-OBP System, Non-OBP Energy) and the lines represent the count of instructions (OBP and total).

Battery Utilisation



Small BMU Utilisation



4. Greater Interconnection

Greater Interconnection has been reduced due to a change in our assessment of NCMS value delivered by year.

5. Reduced Outage Downtime:

The Downtime CBA value is subject to an assumption that two hours of downtime incurs an estimated £700,000 cost to the market.

There have been 2.75 hours of unplanned downtime in the RIIO 2 period so far compared to 9 hours of unplanned downtime In RIIO 1. This means there is a 6.25 hour saving in RIIO 2, incurring a saving of approximately £2m.

Additional benefits

As outlined above, there are additional benefits which have been created which were not included in the original BP2 CBA.

Platform for Energy Forecasting (PEF)

For PEF we now forecast a benefit of £696m over the RIIO-2 period. This is because of an improvement in the accuracy of demand forecasts (Mean Absolute Error) as a direct result of the improved PEF functionality. This benefit breaks down as follows:

Assumption		Financial Year					
		21-22	22-23	23-24	24-25	25-26	Comments
Day-Ahead Price, £/MWh		200	200	80	87	87	Based on Bloomberg data
Actual (A) / Forecast (F)		A	A	A	A	F	Outturn (Actual) or Forecast
National Demand + Solar + Embedded Wind	Forecast Improvement (MW)	100	100	119	119	119	Improvement in Mean Absolute Error of demand forecast
	Estimated Balancing Costs Savings (£m)	175.2	175.2	83.4	90.7	90.7	24/7 benefits. Price x Improvement x 365 x 24
Grid Supply Point	Forecast Improvement (MW)		100	100	100	100	Improvement in Mean Absolute Error of demand forecast
	Phased Delivery		30%	70%	100%	100%	Percentage of benefits realised (phased PEF implementation)
	Estimated Balancing Costs Savings (£m)		17.5	16.4	23.4	23.4	8 hours per day benefits. Price x Improvement x 365 x 8
Total Yearly Savings (£m)		175.2	192.7	99.7	114.1	114.1	
Total Savings (£m)		**695.8**					**Sum across RIIO-2 Period**

CBA: Control centre training and simulation (A2)

BP2 End-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £32 million over RIIO-2. For this BP2 End-Scheme update, we have not updated the BP2 gross benefits calculation, but instead provide an update on progress along with qualitative evidence of the benefits that A2 will deliver.

		Estimated gross benefits during the 2021-26 RIIO-2 period (£m)	
Area		**BP2 Plan view**	**Latest view**
1.	**Improved decision making:** Better training and simulation capability, combined with better tools.	25.9	We have provided a written update for End-Scheme.
2.	**Reduced resource costs:** New workforce and change management tools, updated shift patterns and working arrangements will create efficiencies and increase staff retention.	4.9	
3.	**Decreased training costs:** Our enhanced training and simulator proposals mean that new starters will have more knowledge and can be trained quicker.	1.3	
Total		**32.0**	

In summary, whilst 'Improved decision making' will still be delivered in RIIO-2, there is a delay to the benefits being realised.

We continue to see less than the total BP2 benefits for 'reduced resource costs' and 'decreased training costs'.

Summary of progress in 2024-25

1. Improved decision making	With the initial roll out and subsequent releases of the Open Balancing Platform we have been able to use the CTU to train the Control Room shift teams on the tools. This has resulted in a good integration of the new tools and an increase in the dispatch of battery generation and small BMUs.

	One of the building blocks to the Future Training Simulator is the tool set from investment 110 (Network Control Management System). We had originally planned for this to be delivered in 2023-24 but we now expect this to be completed in Q1 FY26. This is primarily due to delays with the vendor. It does not affect the critical delivery of the investment as we require the NCMS simulator from June 2025 in order to begin 'Train the Trainer' Training ahead of full roll out of the training in the following months. Requirement gathering for the overall end-to-end training simulator has begun. We have realigned the plan against the OBP and NCMS timelines. We now expect to complete this by August 2025. Our work will continue to align the training simulators of NCMS and OBP which will now extend beyond the RIIO-2 period.
2. Reduced resource costs	We have seen some substantial benefits from improved workforce management and recruitment, however in terms of overtime and training costs, these are yet to be realised. The increase in full-time employees (from 121 at the start of 2024-25 to 132 at the end of the year) over the past year has initiated a positive shift in the organization, despite the initial challenges associated with recruitment and training. The additional 11 FTE is made up of 6 balancing engineers and 5 assistant transmission engineers. The balancing engineers are required to support the changing landscape of energy dispatch with an initial focus on management of skip rates, and the transmission engineers were due to vacancies caused by attrition. The temporary rise in overtime was a necessary phase, but with the workforce now better integrated and more skilled, overtime is on the decline. By continuing to invest in employee development and strategic workforce planning, the organization is well-positioned to achieve sustained growth and success. The Automated Rota System has continued to improve the administration accuracy of managing shift rotas, annual leave, training and meetings for operational staff. In addition, Phase 3 has been delivered, which has enabled the electronic storage of all training

	documentation to be associated directly to the employee's file stored on the management system. Our external review of shift pattern in July 2024 concluded that the current shift patterns remained the preferred option. We have increased the number of flexible workers in the control room from 6 in 2023 to 16 in 2024. Our attrition rate (percentage of authorised staff leaving the ENCC or NESO has fallen from 14.3% in 2023 calendar year to 7.2% in 2024.
3. Decreased training costs	We continue to see the recruitment challenges we outlined in last year's CBA update. In addition, due to additional checks, from November 2024 all ENCC recruits require National Security Vetting (NSV) which adds to the already challenging position on recruitment. We trained 15 new candidates in 2024-25 and expect to train 11 in 2025-26. This gives a total of 56 new candidates over five years in line with last year's CBA. However the last two recruitment campaigns for Senior Power System Engineers, which require a higher skill/experience level have proved to be unsuccessful. This aligns with our comments in last year's CBA update about having to pay more to attract staff to our roles. Because of the shortfall in the market the last two years we're recruiting more graduates and higher apprentices to mitigate the challenges with recruitment and the future expect attrition. We are behind on the 'Enhanced Training Material' activity with universities and colleges due to changes in personnel and the creation of NESO. However, our partnership with Loughborough College has been formalised. Loughborough College is now our apprenticeship provider for our L4 HNC and L5 HND qualification for Power System Engineering. They currently have a cohort of 20 NESO students who joined in September 2024 and we are looking to onboard a further 20 in September 2025. In 2023-24 we formed a University Steering Group headed up by our Chief Engineer. This was paused

	during the transition to NESO but we are now restarting the group, with the first meeting in April 2025. Relationships also continue with Brunel and Manchester University. Over the BP2 period we have had 4 Industrial Placement students in 2022, 12 in 2023 and 6 in 2024. We have approval for 8 positions in 2025 and are in the process of recruiting. We had 18 graduates in 2022, 27 in 2023 and 16 in 2024. We have approval for 29 in 2025 and are in the process of recruiting. In terms of apprentices, we had 12 in 2022. In 2023 we had none, due to transitioning our placement schemes out of National Grid and transforming them as we became NESO. In 2024 we had 20 and we have approval for 20 and are in the process of recruiting. We also take an annual intake of 8 Power Academy Scholars (Power System Engineer Summer Internship). Training Simulation environments were not delivered in 2024-25 as expected. They are now expected to be delivered by the end of calendar year 2025. For details of the delay please refer to the RIIO-2 Deliverables Tracker.

Combined status by milestone for relevant activities (Activity A2)

Status	Count	%
Complete	**25**	81%
Delayed – Consumer Benefit	**2**	6%
Delayed – External Reasons	**-**	-
Delayed - Internal Reasons	**9**	25%
Continuous	**-**	-
Total	**36**	100%

For detailed commentary on all of the above milestones, please see the RIIO-2 Deliverables Tracker.

Detail: Calculation of monetary benefit	The original BP2 benefits figures for this project were calculated based on broad assumptions. For BP2 End-Scheme, rather than generating an updated high-level estimate that may not provide an accurate representation, we provide the written update above for each element, setting out progress to date and qualitative impacts on benefits. Full details of the original BP2 calculation can be found in our CBA A2 update from the BP2 Mid Scheme Report 2023-24 Evidence Chapters pp60-62

CBA: Restoration (A3)

BP2 End-Scheme view of gross benefits compared to BP2

We estimate gross benefits of £13.1m over the RIIO-2 period, in line with the BP2 figure.

	Estimated gross benefits during the 2021-26 RIIO-2 period (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
1. Carbon savings	8.5	**8.5**	**-**
2. Benefits from Distributed ReStart NIC project	4.6	**4.6**	**-**
Total	**13.1**	**13.1**	**-**

A high-level CBA was carried out ahead of the Distributed ReStart innovations project, which underpins the estimated gross benefit during RIIO-2 as stated above. We are on track to implement the recommendations from the Distributed ReStart project and in line with the assumptions made, we will start to see the benefits from 2025-26 which is when the first batch of contracted Distributed Energy Resources (DERs) will start providing Restoration Services.

Supporting evidence

Type	Measure	Rationale and status
Lead indicator	Restoration Service Contracts	In Q2 2024 NESO awarded twenty Restoration Service Contracts to generators in the Northern GB region, including Scotland. NESO are currently in the process of tendering in the Southwest & Midlands regions. The Northern GB tender increases the number of Restoration Service Contractors on the network from Q3 2025.
Driver	Total contract costs, £m	The total cost for the Northern tender, covering 4 regions (Scotland South, Scotland North, NE & NW) over the span of five years is £232 million. Although this aligns with the previous tender spend from traditional generators, we anticipate that the expenditure on DERs will decrease over time.

Driver	Reduction in restoration services emissions, tCO_2e*	The benefits will be realised in 2025-26 when the Restoration Services go live.

Detail: Calculation of monetary benefit

The assumptions below remain unchanged from the A3 CBA in our BP2 Mid-Scheme Report.

Carbon savings

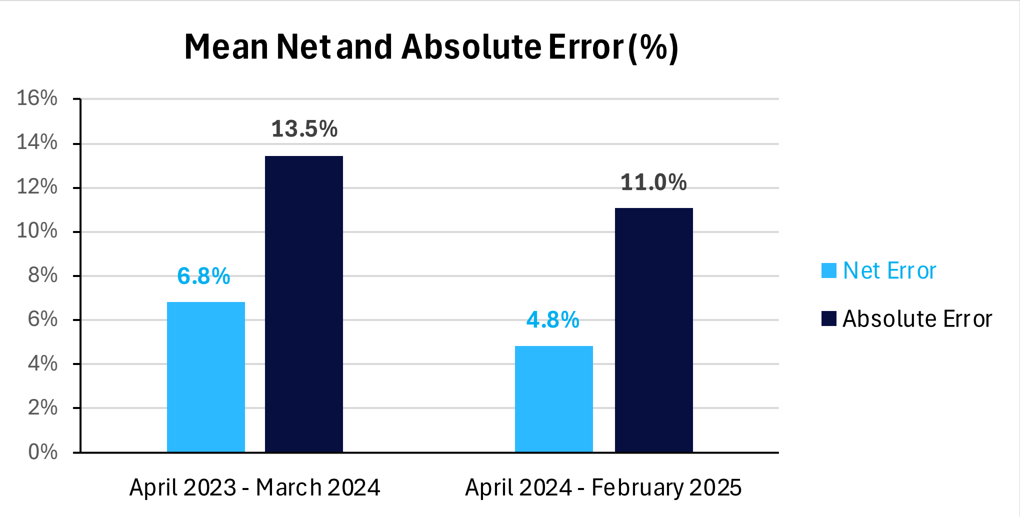
Assumptions	BP2 Plan view	Latest forecast view
(a) CO_2 reduction to 2050	We estimate the Distributed ReStart NIC project will lead to a reduction of 810,000 tonnes of CO_2 by 2050. This is through low carbon DER taking part in restoration services, leading to reduced carbon emissions from large generators. Source: Black Start from Distributed Energy Resources - Bid document to Ofgem	Assumption is still valid
(b) Phasing of CO_2 benefits	We assume this reduction is allocated evenly from 2025-26 when the implementation of the project recommendations will start delivering benefits. This means one year of benefit during the RIIO-2 period, which is $1/25^{th}$ of the total benefit (i.e. one year out of 25).	Assumption is still valid
(c) Carbon price	Average carbon price of £264 per t/CO_2e in 2025-26, based on BEIS Updated Short-Term Traded Carbon Values April 2019	This is in line with the published carbon values
Calculation	810,000 (a) x 1/25 (b) x £264 (c)	Assumption is still valid
Gross benefits	£8.55m	£8.55m

2. Benefits from Distributed ReStart NIC project

Assumptions	BP2 Plan view	Latest forecast view
(a) £m benefit to 2050	The net present value of implementing the recommendations of the Distributed ReStart NIC project is £115 million to 2050. This is due to increased competition in restoration services and reduced costs from the use of some large generators. Cost savings will be passed on to consumers through reduced BSUoS charges. Source: Black Start from Distributed Energy Resources - Bid document to Ofgem	Assumption is still valid
(b) Phasing of benefits	We assume this saving is allocated evenly from 2025, when the implementation of the project recommendations will start delivering benefits. This means one year of benefit (2025-26) during the RIIO-2 period, which is 1/25th of the total benefit (i.e. one year out of 25).	Assumption is still valid
Calculation	£115 (a) x 1/25 (b)	Assumption is still valid
Gross benefits	£4.6m	£4.6m

Consumer benefit case study for Role 1

Activity	Improving information inaccuracy to reduce wind PN inaccuracy
Role	Role 1
Key RIIO-2 Deliverables	A1.6 Minimising Balancing Costs
What is this activity and how does it deliver consumer benefit?	Since October 2023, NESO (formally ESO) undertook work to determine and quantify the scale and types of information inaccuracy in data submitted to the ENCC, with the main focus of this work being the inaccuracy of Final Physical Notifications (FPNs) submitted by wind BMUs. After engagement with Ofgem, DESNZ and wider industry (through the Wind Advisory Group and OTF), NESO published an initial guidance note in August 2024 setting thresholds for Good Industry Practice against which wind market participants would be judged. Following publication, several participants shared reservations about the information provided, including feedback about the benchmark and the wording surrounding extenuating circumstances. As a result NESO decided to delay the start of the monitoring period originally planned for November 2024, and launched a consultation in December for further feedback. The revised guidance note was published in February 2025. The monitoring period began on 1 March 2025, with market participants being provided with net and absolute error data. In the coming months, individual wind BMUs will be monitored against the net and absolute thresholds set by NESO. In the event of failure to improve performance at the end of the six-month monitoring period, a formal notice will be issued to the respective wind unit and Ofgem. For this benefits case study we have calculated the non-monetary benefit for the April 2023 – March 2024 and April 2024 – February 2025 period. This was to match the RIIO reporting schedule, but also to encompass the most recent data on wind accuracy, as published up to February 2025 (at time of submission).
Is the consumer benefit mainly this year or in future years?	Consumer benefit has been seen over the course of the year with an improvement to both the net error and the absolute error of submitted PNs, which leads to improved data quality in the ENCC and thus a reduction in extraneous BOAs submitted. With the publication of Clean Power 2030, there is an expectation to have between 43 – 51 GW of offshore wind and ~27GW of onshore wind connected to the grid by 2030. FPN accuracy will therefore become more significant in the coming years as more and more wind generation capacity connects to the electricity network.

Calculation of monetary benefit to consumers	We have not estimated the monetary impact of PN inaccuracy, please see below for the non-monetary benefits.
Assumptions made in calculating monetary benefit	Not applicable.
How benefit is realised in the consumer benefit	Increasing the accuracy of FPNs from wind BMUs reduces the need for additional Bid Offer Acceptances (BOAs), which helps reduce the total BSUoS bill. This benefit is then passed back to the consumer through their supplier to impact their energy bills.
Non-monetary benefits	Reducing the inaccuracy of FPNs submitted increases the quality of data available to the ENCC, allowing them to make more accurate and economical decisions. This can range from improved forecasting of wind generation to helping reduce the risk of overloading wires. Looking at the graph below there has been improvement in the mean net and absolute error, with ~2% drop in net error and a ~2.5% drop in absolute error, between the two time periods.  We would expect these errors to decrease further following the start of the monitoring period on 1 March 2025, and upon closer engagement with any market participant who is having difficulties meeting the thresholds set out in the revised Guidance Note. However as outlined further in the Guidance Note, it is not the expectation of NESO that the thresholds can or will be achieved every month, with NESO understanding that there may be occasional months where the thresholds are not achieved.

	These percentages were calculated from the *Supporting Data on PN inaccuracies* files on the Balancing Costs webpage.
Comments on non-monetary benefit calculations	The following comments provide further context to our analysis: • Errors in FPN accuracy broadly remain consistent between periods immediately either side of a period where a wind BMU has been curtailed, and other periods where the unit is generating at its PN. • This analysis also includes settlement periods where wind BMUs have been issued a BOA, which affects the value of the Expected Output *(outlined further in the Guidance Note).*

Regularly Reported Evidence performance for Role 1

Table: Summary of RREs for Role 1 for 2024-25

Role 1 RREs don't have performance benchmarks.

2024-25

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
1E	Transparency of Operational Decision Making	%	91	91	92	96	94	91	93	93	95	91	95	94
1F	Zero Carbon Operability indicator	%	Q1: 92%			Q2: 89%			Q3: 89%			Q4: 94%		
1G	Carbon intensity of ESO actions	gCO_2 /kWh	11.9	3.9	12.3	6.3	15.0	6.7	10.9	7.7	13.9	3.9	9.1	8.9
1H	Constraints cost savings from collaboration with TOs	£m	Q1: £210m			Q2: £809m			Q3: £381m			Q4: £146m		
1I	Security of Supply	#	-	-	1	-	-	-	1	-	-	-	-	-
1J	CNI Outages - Planned	#	-	-	-	1	1	-	-	-	1	-	-	1
	CNI Outages - Unplanned	#	-	-	-	-	-	-	-	-	-	-	-	-

RRE 1E Transparency of operational decision making

This Regularly Reported Evidence (RRE) shows the percentage of balancing actions taken outside of the merit order in the Balancing Mechanism each month.

We publish the Dispatch Transparency dataset on our Data Portal every week on a Wednesday. This dataset details all the actions taken in the Balancing Mechanism (BM) for the previous week (Monday to Sunday). Categories and reason groups are allocated to each action to provide additional insight into why actions have been taken and ultimately derive the percentage of balancing actions taken outside of merit order in the BM.

Categories are applied to all actions where these are taken in merit order (Merit) or an electrical parameter drives that requirement. Reason groups are identified for any remaining actions where applicable. Additional information on these categories and reason groups can be found on our Data Portal in the Dispatch Transparency Methodology.

Categories include: System, Geometry, Loss Risk, Unit Commitment, Response, Merit

Reason groups include: Frequency, Flexibility, Incomplete, Zonal Management

The aim of this evidence is to highlight the efficient dispatch currently taking place within the BM while providing significant insight as to why actions are taken in the BM. Understanding the reasons behind actions being taken out of pure economic order allows us to focus our development and improvement work to ensure we are always making the best decisions and communicating this effectively to our customers and stakeholders.

We have been publishing the Dispatch Transparency dataset since March 2021, and it has sparked many conversations amongst market participants. As we continue to publish this dataset for BP2 we will also be providing additional narrative to help build trust by explaining:

- actions we are taking to increase understanding of the NESO's operational decision making
- insight into the reasons why actions are taken outside of merit order in the Balancing Mechanism
- activity planned and taken by the NESO to address and reduce the need for actions to be taken out of merit order.

March 2024-25 performance

Figure: 2024-25 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

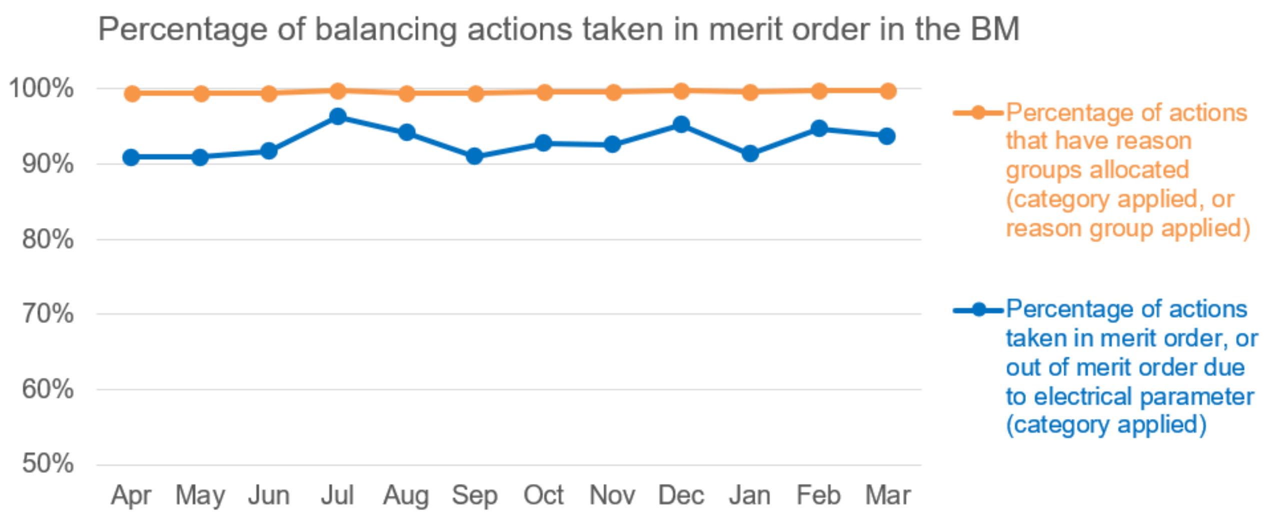


Table: Percentage of balancing actions taken outside of merit order in the BM

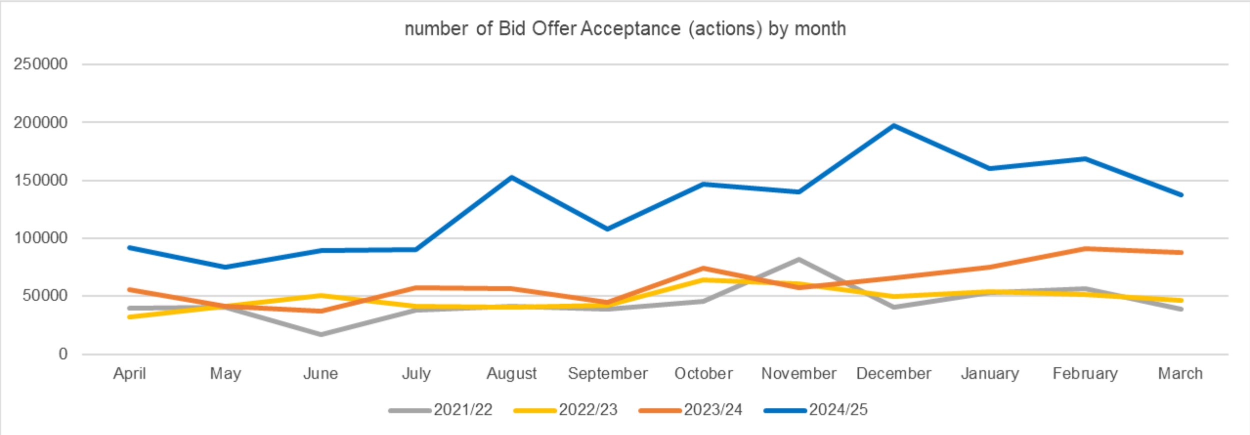
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	90.9%	90.9%	91.7%	96.3%	94.2%	91.0%	92.8%	92.6%	95.3%	91.4%	94.7%	93.8%
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.4%	99.5%	99.4%	99.8%	99.5%	99.4%	99.6%	99.7%	99.8%	99.6%	99.8%	99.8%
Percentage of actions with no category applied or reason group identified	0.6%	0.5%	0.6%	0.2%	0.5%	0.6%	0.4%	0.3%	0.2%	0.4%	0.2%	0.2%

Supporting information

March performance

This month 93.8% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 6.0% of actions were allocated to reason groups for the purposes of our analysis, and the percentage of actions with no category applied or reason group identified remained in line with previous months.

During March, there were 137,210 BOAs (Bid Offer Acceptances) and of these, only 276 remain with no category or reason group identified, which is 0.2% of the total.

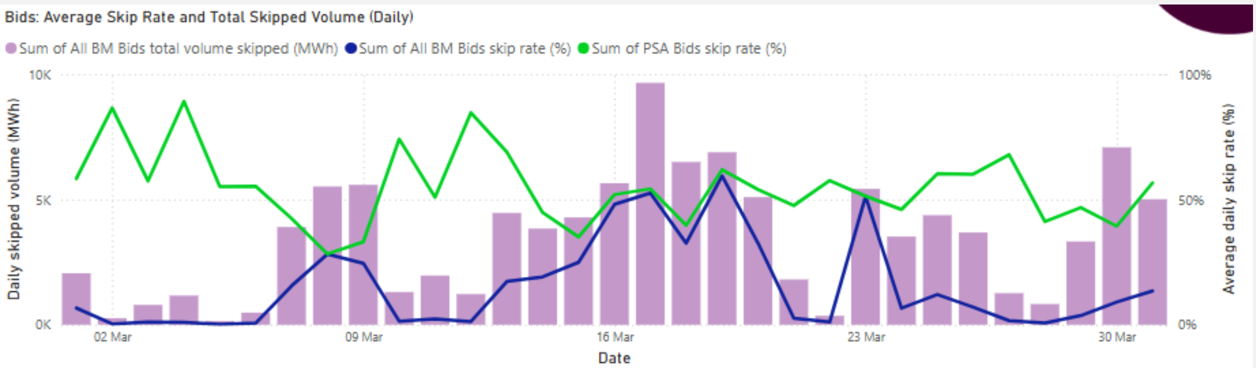


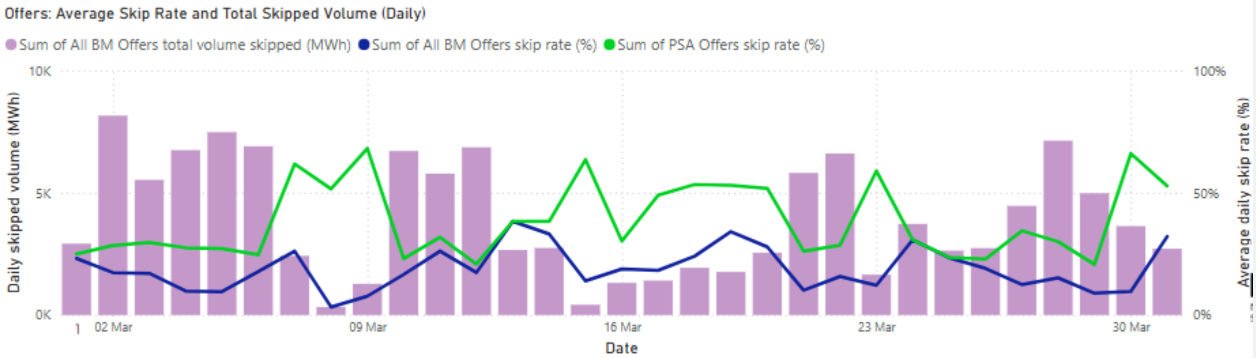
Other activities

This is a summary of the average monthly skip rates for the two agreed definitions (All Balancing Mechanism & Post System Actions):

Monthly Average	Offers - All BM	Offers - PSA	Bids - All BM	Bids - PSA
January	18%	34%	11%	53%
February	15%	33%	5%	49%
March	15%	29%	7%	47%

The graphs below show daily skip rates and skipped volume for bids and offers in March.





BP2 Performance Summary 2024-25

For 2024-25, 93.2% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 6.4% of actions were allocated to reason groups for the purposes of our analysis. Over the year there were 1,452,131 BOAs and of these 5,749 remain with no category or reason group identified, which is 0.4% of the total.

RRE 1F Zero Carbon Operability Indicator

This Regularly Reported Evidence (RRE) 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 RRE, 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. As this RRE 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 RRE 1F and RRE 1G differs.

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

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

Part 1 – Defining the maximum ZCO limit for BP2

Below we define the approximate maximum ZCO limit - using a reasonable approximation of likely operating conditions - the system can accommodate at the start and end of BP2, explaining which deliverables are critical to increasing the limit.

Table: Forecast maximum ZCO% after our operational actions

BP2 2023-25	Maximum ZCO limit	Calculation and rationale
Start of BP2 (Q1 2023-24)	**90% - 95%**	The maximum ZCO% achieved prior to the start of BP2 was 90%, set in January 2023. New frequency products and voltage and stability pathfinders are the main projects delivering increased ZCO% during the early part of BP2. The methodology for calculating ZCO% is consistent with BP1 and our continued delivery of projects and programmes increases the opportunity to operate the system at higher ZCO%.
End of BP2 (Q4 2024-25)	**95% - 100%**	We expect that our remaining projects, products and programmes will enable us to operate at 100% ZCO in 2025. Our operational strategy is set to deliver some key projects which will increase the maximum ZCO% over the BP2 period. These key deliverables are the deployment of our full suite of response and reserve products, voltage and stability pathfinders, further reduction of minimum inertia requirement via the Frequency Risk and Control methodology (FRCR), and improved tools for monitoring system inertia. These deliverables are either enabling zero carbon providers of ancillary services or increasing the window in which we can operate the system securely.

Part 2 – 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: Q4 maximum zero carbon generation percentage by month (2024-25)

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	92.3%	94.7%	15 Apr SP29
May	83.4%	93.8%	12 May SP28
June	86.1%	88.6%	4 Jun SP28
July	86.7%	92.7%	4 July SP33
August	89.2%	95.0%	21 Aug SP24
September	84.6%	91.1%	30 Sep SP3
October	85.1%	94.4%	13 Oct SP3
November	84.6%	94.1%	23 Nov SP44
December	89.4%	95.7%	23 Dec SP4
January	88.7%	94.8%	1 Jan SP21
February	86.6%	95.6%	23 Feb SP25
March	93.5%	99.7%	30 Mar SP20

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

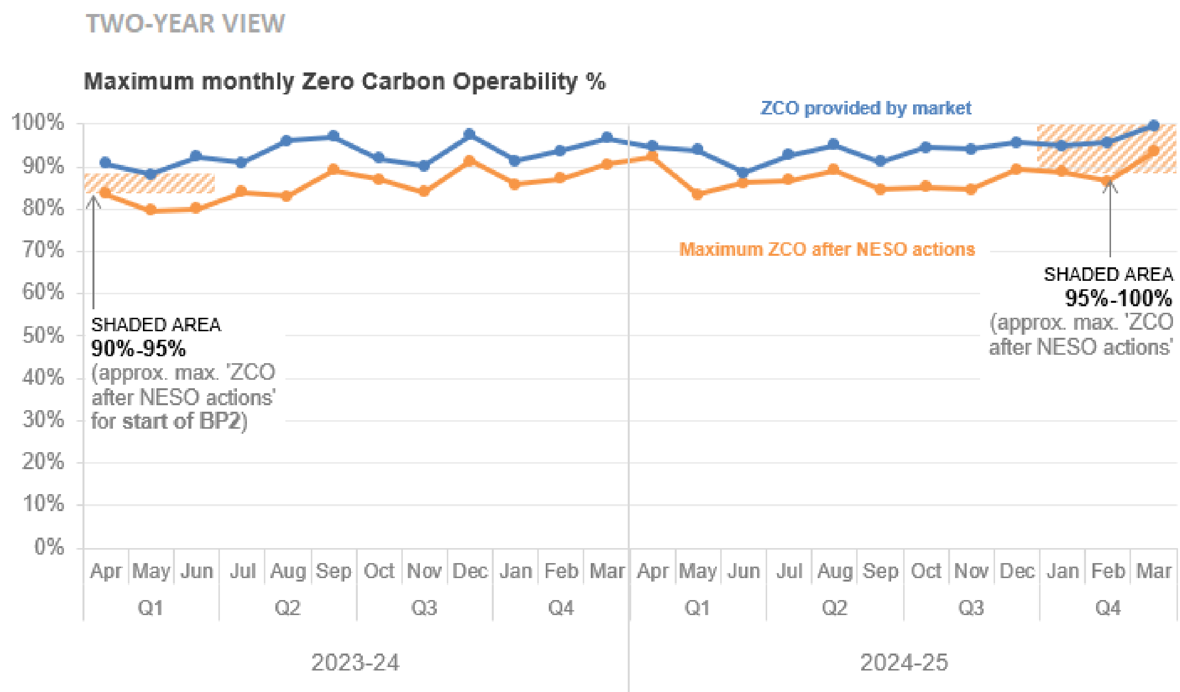
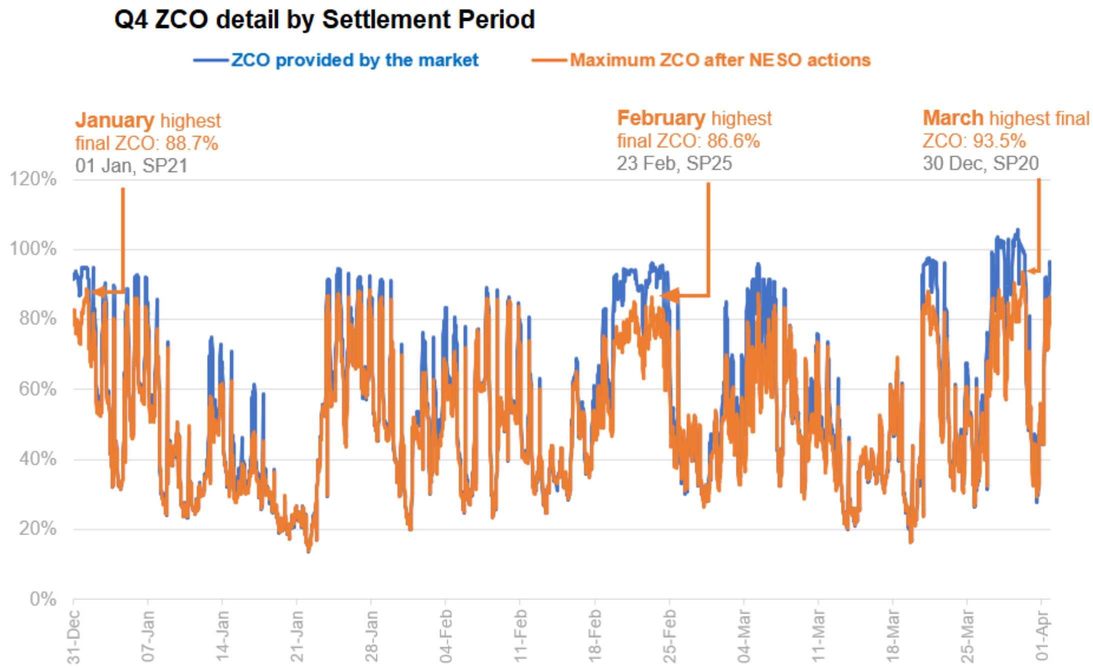


Figure: Q4 2024-25 ZCO by Settlement Period, before and after NESO operational actions



Supporting information

In Q4 2024-25, the monthly average highest ZCO was 88.1% which is 0.9% higher than the 2024-2025 monthly average of 87.2%

In January the highest ZCO% performance for a single settlement period was 88.7%, a 2.9% increase on the same position 12 months ago. On 1 January there were amber weather warnings across the country and a number of cable faults on multiple assets resulted in an increase to NESO actions to stabilise system frequency.

In February the highest ZCO% performance for a single settlement period reduced slightly to 86.6%. On 23 February, a number of asset faults required NESO intervention. There were also yellow weather warnings across the UK relating to rain levels. Balancing actions were taken to manage these constraints.

In March the highest ZCO% performance for a single settlement period increased to 93.5%. On 30 March there was high levels of solar generation, coupled with wind constraints this required actions by NESO to maintain system inertia to statutory levels.

Highest final ZCO by month vs previous year

Quarter	Month	2023/24	2024/25	Difference
Q1	April	83.6%	92.2%	+8.6%
	May	79.6%	83.4%	+3.8%
	June	79.9%	86.1%	+6.2%
Q2	July	83.9%	86.7%	+2.8%
	August	82.9%	89.2%	+6.3%
	September	89.1%	84.6%	-4.5%
Q3	October	86.8%	85.1%	-1.7%
	November	84.0%	84.6%	+0.6%
	December	91.3%	89.4%	-1.9%
Q4	January	85.8%	88.7%	+2.9%
	February	87.1%	86.6%	-0.5%
	March	90.5%	93.5%	+3.0%

BP2 Performance Summary 2024-25

On 30 March 2025 a new zero carbon operation record was achieved of 93.5%, this is an increase to the previous record set in April 2024 of 92%.

In 2025 we are aiming to be capable of operating at least 1 settlement period with 100% Zero Carbon Generation. To support this, successfully delivered projects throughout BP2 include:

- **FRCR 2024** – minimum inertia requirement moved to 120GVAs in April 2024.
- **Quick Reserve** – became operational on 3 Dec 2024, this new service is part of the suite of services to improve the existing response services, replacing Fast Reserve.
- **Balancing Reserve** – allowing us to procure Regulating Reserve on a firm basis at day ahead. This went live in March 2024.

- **Pennine Pathfinder** – offering voltage support by removing the need for the DRAXX voltage machine in most circumstances.
- **Stability Pathfinder 2** - 2 of the projects have gone live.

Ongoing projects due throughout 2025 that should enable a capability within the 95%-100% ZCO range include:.

- **FRCR 2025** – minimum inertia requirement moving to 102GVAs.
- **Stability Pathfinder** – additional project due to go live.

On 15 April 2024 when 92.3% ZCO was achieved the market provided 94.7% ZCO.

Over the course of 2024 – 2025 on the days when highest ZCO levels were achieved the market provided an average of 94.12% ZCO. An average of 87.15% was achieved following NESO intervention.

Highest Market Delivered ZCO period in 2024/25

According to available data the market was delivering higher than 65% zero carbon generation from 08:30 on Thursday 27 March 2025 until 17:30 on Sunday 30 March 2025. The peak was 97.8% on 29 March 2025 at 19:30.

- These days had favourable forecast conditions for wind and solar generation during the day. However, actions by the control room were required to manage shortfalls in generation when the observed wind or solar was less than forecast and to cover generation losses in addition to other actions to manage system requirements.
- We have operated the system at increasing levels of zero carbon generation over this reporting period, and have operated at higher percentages for longer periods. The remaining projects planned for delivery should provide the capability to operate a 100% zero carbon system - if the market delivers and wider conditions allow.
- The next highest zero carbon percentage day is Friday 21 March 2025 which peaked at 97.5% at 13:00.
- On this occasion the observed wind exceeded the forecast and similar actions were taken to secure system conditions.

RRE 1G Carbon intensity of NESO actions

This Regularly Reported Evidence (RRE) 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 RRE 1F (Zero Carbon Operability Indicator) and 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. More information about NESO's operability challenges is provided in the Operability Strategy Report.

March 2024-25 performance

Figure: 2024-25 Average monthly gCO2/kWh of actions taken by NESO (vs 2023-24)

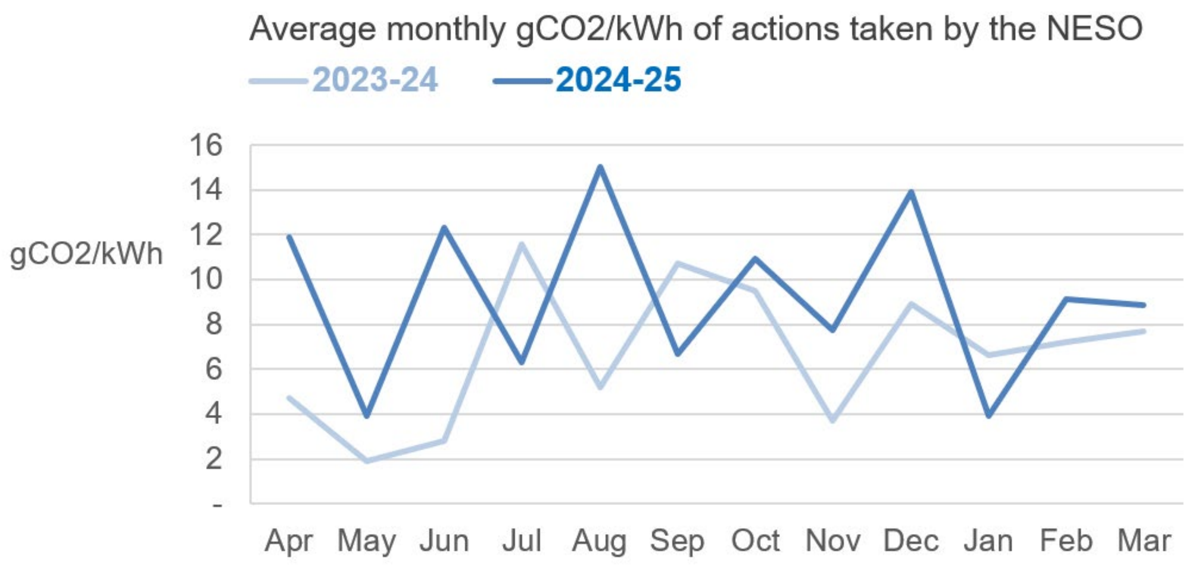


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	11.87	3.93	12.31	6.33	15.02	6.69	10.92	7.74	13.92	3.91	9.13	8.87

Supporting information

In March, the average monthly carbon intensity from NESO actions was 8.87g/CO2/kWh. This is 0.26g/CO2/kWh lower than February and 0.35g/CO2/kWh lower than the 2024-2025 YTD monthly average of 9.22g/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 54.57g/CO2/kWh which took place on 21 March at 1500. This is 6.89g/CO2/kWh higher than February's highest difference of 47.68g/CO2/kWh.

On 21 March North Hyde substations remained shut following a fire. Additional gas and pumped storage units were run to secure upward margins and inertia.

BP2 Performance Summary 2024-25

The average monthly g/CO2/kWh of actions taken by NESO has ranged from 3.91g/CO2/kWh to 15.02g/CO2/kWh across 2024-2025 with a monthly and quarterly average of 9.22g/CO2/kWh.

Last quarter the average carbon intensity from NESO actions fell below the average to 7.3g/CO2/kWh.

Intervention has taken place following uncontrollable incidents including multiple red and amber weather warnings.

Over the first six months of 2024-2025 there were three months with a monthly action over 11g/CO2/kWh. In the last six month this has occurred on one occasion.

Over the complete duration of BP2 there has been a slight trend increase to the average monthly g/CO2/kWh of actions taken by NESO. These are consistent with the provided marked provisions vs NESO actions.

RRE 1H Constraints Cost Savings from Collaboration with TOs

April 2024 to March 2025 Performance

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 Regularly Reported Evidence (RRE) 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 for RRE 1H:

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[3] 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 this RRE 1H.

   iii. For RRE 1H, 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.

[3] 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.

Figure: Estimated £m savings in avoided constraints costs (ODI-F) – 2024-25

(Estimated savings in GWh are also shown for context)

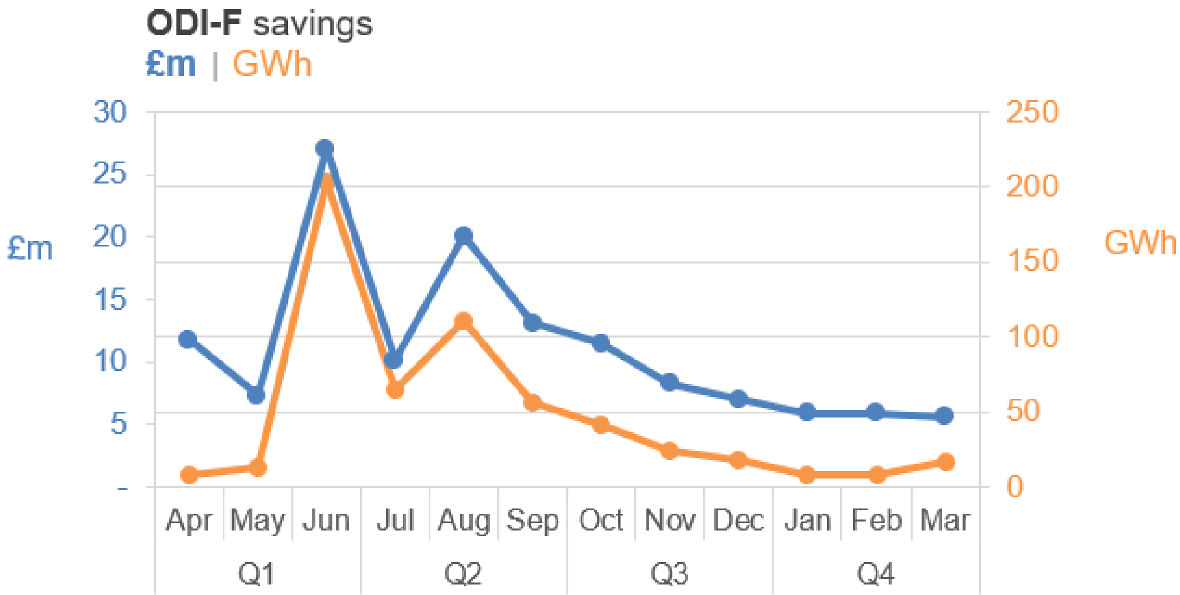


Figure: Estimated £m savings in avoided constraints costs (Other)

(Estimated savings in GWh are also shown for context)

*Note **vertical axes scales** differ from the ODI-F graph above.*

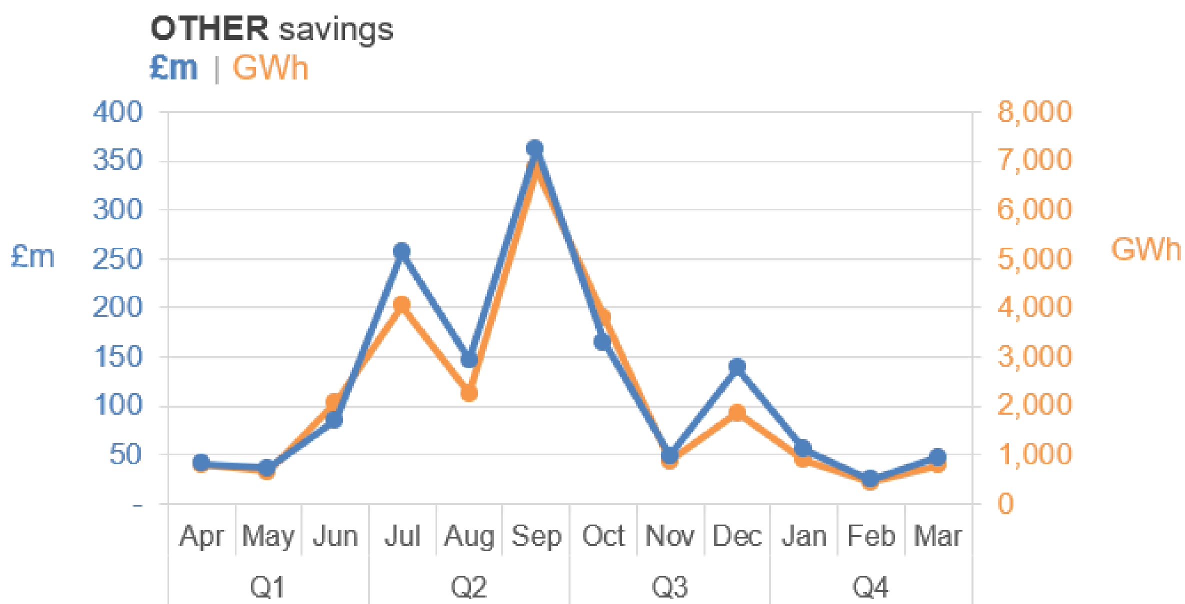


Table: Monthly estimated £m savings in avoided constraints costs (2024-25)

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	11.8	41.3	8.4	810.1
May	7.3	36.6	13.0	661.3
Jun	27.1	85.4	204.2	2,078.8
Jul	10.1	256.2	65.2	4,037.8
Aug	20.1	147.0	111.2	2,244.1
Sep	13.1	362.3	56.4	6,841.2
Oct	11.5	165.5	41.4	3,803.9
Nov	8.3	49.8	24.6	883.9
Dec	7.0	139.0	17.8	1,860.2
Jan	5.9	55.6	8.4	902.9
Feb	5.9	25.1	8.4	453.1
Mar	5.6	47.9	17.2	789.7
YTD	**133.8**	**1,411.7**	**576.2**	**25,366.9**

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 29 approved enhanced service provisions from TO's through STCP 11.4 that provided constraint cost savings this year. Some of these provisions are highlighted below:

- In January and February, NGET, SHET, SPT, and NAP provided three enhancement services due to these being year-round enhancements. The services included the Western Link Run Back scheme, Tongland protection, and a bypass on a 132kV circuit connecting Aberdeenshire and Angus in Scotland. These services facilitated the management of constraint boundaries, outage placement, and pre and post fault network loading. Over January and February, these three services resulted in a saving of **16.4 GWh** of energy and an outturn cost of **£11.8 million** to the end consumer.

- In March, National Grid Electricity Transmission (NGET) and Network Access Planning (NAP) 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 maintenance and minor construction works on a circuit linking Tyne and Wear County with Northumberland. As a result, these enhancements saved **8 GWh** of energy and resulted in an outturn cost of **£1.02 million** for the end consumer.

During the 2024-2025 financial year, NAP has achieved approximately **£133.8 million** in constraint cost savings through STCP 11.4 with the release of **576.2 GWh** of additional capacity.

Please be advised that figures for previous quarters have been updated following comprehensive reviews at the end of the 2024-2025 financial year, as detailed in the attached table of figures later in this section. Three enhancements were utilised throughout the year: the West Link Run Back scheme, Tongland Quad booster, and the Kintore–Tealing 275kV outage bypass. These enhancements were implemented consistently over the 12 months.

Financial savings have been precisely calculated for the 2024-2025 year based on actual costs incurred. No forecast savings are included in this section. GWh outturn savings are proportionately derived from the forecast GWh values and the actual outturn cost savings.

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 **43 instances this quarter, and 250 instances in the past 12 months,** where the actions of the National Electricity 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 Operators (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 January, NAP received two outage requests from Scottish Power Transmission (SPT) and Scottish Hydro Electric Transmission Limited (SHETL) for circuits connecting Perth and Kinross to Kincardineshire to facilitate overhead line works. These outages were scheduled at different times, which would reduce the B4 boundary capability. To minimize the impact of these outages on the B4 boundary, NAP coordinated with both SPT and SHETL to align these outages. This action resulted in saving 441.6 GWh of energy worth approximately £33.1 million.
- In March, NAP received a request from NGET to initiate maintenance work on a 400kV substation located in North Lincolnshire. To accommodate this outage, NAP and NGET agreed to reconfigure the substation to enhance the EC1 boundary capability. This

revised configuration resulted in a savings of approximately **407 GWh**, valued at **£30.5 million.**

- In March, NAP received an outage request from National Grid Electricity Distribution (NGED) concerning a 132kV substation in Somerset for system protection-related works. These works posed a risk of tripping for 900 MW of generation connected to a 400kV NGET substation in Cornwall. Consequently, NAP coordinated with NGED to reconfigure the interconnection between two 132kV substations in Somerset. This measure resulted in saving approximately **243 GWh** of energy for end consumers, equating to roughly **£8.7 million.**

This section of the report encompasses actions monitored up until the conclusion of the 2024-25 financial year. There was a notable increase in CVOs during Quarter 4, primarily attributed to an excessive number of value opportunities arising from the rapid escalation in outages as the new plan year commenced, thereby presenting more opportunities to optimise the plan.

Some of the aforementioned customer value opportunities in the **fourth quarter** are part of the **250 instances** recorded over the past 12 months. Collectively, these represent a total of **25.4 TWh (approximately £1.41 billion)** in generation capacity for the 2024-25 financial year. This surplus capacity, if otherwise restricted, would have resulted in additional costs being transferred 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. When 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.

BP2 Performance Summary 2024-25

Network Access Planning (NAP) continued to deliver significant value to end consumers through ongoing collaborations with Transmission Owners (TOs) under the 11-4 framework. This partnership facilitated system access for various system works, resulting in outturn energy savings of **576 GWh**, equivalent to approximately **£134 million.**

Furthermore, the customer value opportunities metric (Other Savings) employed by NAP during planning timescales aimed to optimize system access by establishing secure and economical methods, led to additional savings of **25 TWh**, which translates to approximately **£1.4 billion**, benefitting end consumers.

RRE 1I Security of Supply

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

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

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

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

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

March 2024-25 performance

Table: Frequency and voltage excursions (2024-25)

	2024-25											
	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)	-	-	-	-	-	-	-	-	-	-	-	-
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	-	-	1	-	-	-	1	-	-	-	-	-
Voltage Excursions defined as per	-	-	-	-	-	-	-	-	-	-	-	-

Transmission Performance Report[4]												

Supporting information

March performance

There were no reportable voltage or frequency excursion in March 2025.

BP2 Performance Summary 2024-25

Throughout 2024-25 there were no reportable voltage or frequency excursions that breached the statutory limits. However there were two frequency events.

On 24 June 2024 @18:32, there was one frequency event. An interconnector tripped while importing 1000MW to GB. The frequency reached a maximum deviation of 49.661Hz and returned to the operational limit 49.8Hz within 5 minutes and 50Hz within 15 minutes.

On 8 October 2024 @8:48, there is one frequency event. An interconnector tripped while importing 1424MW to GB. The frequency reached a maximum deviation of 49.594Hz and returned to the operational limit 49.8Hz within 5 minutes and 50Hz within 15 minutes.

[4] https://www.neso.energy/industry-information/industry-data-and-reports/system-performance-reports

RRE 1J CNI Outages

This Regularly Reported Evidence (RRE) 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.

March 2024-25 performance

Table: 2024-25 Unplanned CNI System Outages (Number and length of each outage)

	2024-25											
Unplanned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	-	-	-	-	-	-	-	-	-	-	-	-
Integrated Energy Management System (IEMS)	-	-	-	-	-	-	-	-	-	-	-	-

Table: 2024-25 Planned CNI System Outages (Number and length of each outage)

	2024-25											
Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	-	-	-	1 outage 265 mins	1 outage 203 mins	-	-	-	1 outage 205 mins	-	-	1 outage 205 mins
Integrated Energy Management System (IEMS)	-	-	-	-	-	-	-	-	-	-	-	-

Supporting information

March performance

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

This change took place on 11 March, and was planned in advance, in collaboration with our control rooms to ensure it did not introduce a conflict with other known periods of high activity. Notifications are posted to the industry, via BMRA, at 7 days prior and 1 day prior.

On the day of the outage, our control rooms are again consulted to confirm that conditions remain suitable to proceed with the change or, if required, whether the change must be rescheduled.

Additionally, on the day, notifications are posted to the industry, via BMRA, when the outage is due to start, and when it is complete.

There were no other planned outages during March.

BP2 Performance Summary 2024-25

Throughout the year there have been four planned outages to our CNI systems. In all cases, the outages occurred on our BM system, and were required in order to deploy a software release of changes and, in some cases, enhancements to the production systems.

Any such planned outages were communicated, in advance, to the market via BMRS and email notifications, in line with our obligations to report these events. Additionally, we have worked closely with Elexon throughout, highlighting the known impact upon any of their systems that utilise data from BM.

Each change impacted the key BM Suite components used for scheduling and dispatch of generation. As part of these outages, we were also able to plan and complete maintenance and configuration tasks, where required, to enable the continued focus on resilience of the system.

There were no other planned outages during the period.

There were no unplanned outages during period.

We believe we have performed well over the period, avoiding any unnecessary planned outages, and not encountering any unplanned outages.

System monitoring improvements have been implemented to the systems throughout the period, to include monitoring of new changes & low-level incidents to increase the capability to identify and resolve system issues.

A continued schedule of regular maintenance activities has remained in place throughout the period, aiding ongoing system availability.

National Energy System Operator
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

box.soincentives.electricity@neso.energy

www.neso.energy

NESO
National Energy
System Operator