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

End-Scheme Incentives Report

Annex B: Role 2 - Market development and transactions

May 2025

NESO
National Energy System Operator

Contents

B.1 Activity Updates

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

Role 2 Activities

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

Demand Flexibility Service (DFS) (design, engagement and development)

Why are we undertaking this activity?

The Demand Flexibility Service (DFS) was introduced during the winter of 22/23 as part of the winter contingency toolkit. Its initial objective was to act as an enhanced action, to access additional megawatts (MW) during times of high national demand, particularly on days when the system could have been placed under stress. The DFS is a pioneering initiative and has enabled households and businesses to join a flexibility market with lower entry barriers than established markets. In addition, as a merit based margin tool in 24/25 it has demonstrated it can be competitive versus other actions we may use to balance the system.

What have we achieved by the end of BP2?

The DFS initially launched in November 2022 as an enhanced action, due to the risks and uncertainties for winter 2022/23. The Early Winter Outlook report we published in June 2024 showed that margins were expected to be adequate and within the reliability standard, so we no longer had the same operational need for DFS as in previous years. We wanted to ensure that a route to market continued to exist for volume already participating and harness the value of demand side flexibility. Due to this, the main change for DFS in the past 12 months has been the transition from an enhanced action to a merit-based margin service for peak demand and the ability for the DFS to stack with other services as detailed below.

We presented our proposals for change to industry via a webinar on 11 June 2024.

These were:

- Change from an enhanced action service to a merit-based margin tool.
- Unlock the ability to stack with Capacity Market and Distribution Network Operator (DNO) Flexibility Services
- Unit meter points can only be in one DFS Unit
- Remove day-ahead dispatch option and keep within-day only bringing operations closer to real time.

- No planned testing and the removal of a Guaranteed Acceptance Price (GAP).
- Remove requirement for asset meters to be associated to Half-Hourly Settled (HHS) boundary meters.
- Introduce performance incentives.
- Introduce enhanced automation through Application Programming Interface (API's).

We incorporated these changes and two further elements into the service design that was approved by Ofgem in November 2024. The additional elements were allowing providers to submit MWs to one decimal place both for capacity and service bids; and moving the validation of the Unit Meter Point schedule from 11am to 9am to allow new MPAN's to participate from the day they were submitted. Alongside the service approval we worked with Ofgem to secure a multi-year derogation from the requirements of Article 6(4) of the retained regulation giving confidence to the market in the service for the medium term.

As of 31 March 2025 we have 29 registered providers with over 1.8 million MPANS. As DFS is now a year round service we are hopeful that these numbers will continue to increase, and we are still engaging with industry and interested parties to help them understand the benefits of participation. We have seen a range of bid prices with the lowest accepted bid price 0f £59/MWh and the highest bid accepted at £1,290/MWh. The expected consumer benefit up to the end of March is almost £500,000.

How did our approach maximise outcomes?

We engaged with stakeholders through various channels including webinars, drop-in sessions, bilateral meetings, questionnaires, and formal consultations. Initially, we ran a questionnaire and received 38 responses from the industry. Following this, we conducted over 50 hours of calls and meetings on a bilateral basis to further explore ideas and feedback.

This engagement helped us shape the service design, leading into the EBR Article 18 Consultation. We received a total of 34 consultation responses and implemented several changes in the service design based on the feedback received as outlined above.

We updated and published detailed material and guidance documents to support the service design and provide up-to-date information. These include the Participation Guidance Document, DFS Market Guidance, and API Schema document.

Response and Reserve (D4.3.3, D4.3.4, D4.3.6)

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

Our RIIO-2 plan covered the implementation and ongoing development of a suite of response and reserve products to meet the needs of the changing electricity system.

What have we achieved by the end of BP2?

Future developments to frequency response services (D4.3.6): A number of changes to frequency response services were implemented or progressed in 2024-25 in response to service provider feedback. We have refreshed and carried out updates to our frequency response services (Dynamic Containment, Dynamic Regulation and Dynamic Moderation). The primary service design change introduced was the removal of the maximum ramp rate restriction. Providers argued that this inhibited efficient allocation of asset capacity across markets when participating in dynamic response. Following an in-depth system risk assessment, we concluded that, on balance, this change was in the consumer interest.

We also developed tools and processes to enable us to more systematically monitor provider compliance with the service terms, including state of energy management, baseline and metering submission. These tools provide us with the capability to penalise providers for a range of non-compliance with the service terms enhancing the operation a robust service that fosters competition.

We have progressed service design and industry engagement for an optional and instructible dynamic response product that will form the foundation of the Mandatory Frequency Response (MFR) replacement solution. In addition, we have progressed service design and industry engagement for locational procurement of response and reserve products.

In April 2024 we introduced the first iteration of our Balancing Reserve Service securing regulating reserves from the market. In December 2024 we launched the Quick Reserve (QR) phase 1 service (Balancing Mechanism (BM) only). The Quick Reserve service aims to achieve potential cost efficiencies in system balancing by procuring firm fast reserve capacity rather than relying on optional services such as Optional Fast Reserve ("OFR") and Spin Generation and Pump Storage Contracts.

In 2025 there will be further reforms to QR with the delivery of Quick Reserve phase 2 service (BM and Non-BM). We expect the service will be delivered in the summer of 2025. The phased delivery of the QR service was created by considering the need to provide near-term value and savings to end-consumers while acknowledging the time needed to make changes to our systems. Due to IT system lead times, we were unable to launch the Quick Reserve market to non-BM parties until 2025. However, we identified an opportunity to bring forward consumer value and deliver the service to BM parties in winter 2024, utilising our existing BM systems in combination with the new Open Balancing Platform (OBP) multi-dispatch.

We have also finalised the service design and carried out industry engagement to support the launch of our new Slow Reserve service planned to go live in summer 2025. This will replace our current Short Term Operating Reserve Service (STOR) service which is used to secure our largest loss on the system. We have also developed and shared a detailed transition plan with the industry, inviting input on the phasing out of both the Fast Reserve and STOR service as we move to procure our new product suite.

How did our approach maximise outcomes?

Future developments to frequency response services: Extensive industry engagement through face-to-face roadshows in London and Edinburgh, interactive webinars and many bilateral provider meetings, in addition to formal consultation, provided a deep insight into remaining challenges of operating in the dynamic response markets. When considering changes, we ran robust processes to consider options and evidence, including quantitative evidence submitted by service providers, and reach decisions using standard criteria.

The improved quality of our submissions and the appropriateness of our stakeholder engagement early in the change process were both noted by Ofgem. Industry stakeholders have also consistently stated their appreciation for our in-depth engagement and responsiveness to feedback.

Throughout the Reserve reform process, we engaged with providers early in the design phase. As well as service specific webinars, in the second half of 2024 we held several monthly Reserve webinars which allowed us to provide information to Industry and also ran a 'call for input' process on early design proposals. This was valuable input that fed directly into the final service design:

"Content has been helpful to gain an overall picture with the phase 2 QR and SR phase developments" - *Provider*

"The session was well run and very informative slides. We also appreciate the proactiveness of having this process, it helps providers like ourselves structure our development roadmaps accordingly and ahead of time." - *Provider*

This early engagement has also allowed us to ensure we have robust submissions to Ofgem and has informed the supporting documentation for our EBR Article 18 process. Each submission has been accompanied by a full Service and Procurement design plus additional documents. "really good EBR submission and quality supporting documents" – *OFGEM*.

In support of the launch of each service we have held a series of weekly drop-in sessions prior to go live. In gathering feedback from these sessions, we have identified the need to start earlier engagement, for phase 2 of Quick Reserve due to go live later in 2025 IT integration drop-in sessions are already planned and will be starting shortly.

"very helpful sessions and it was good to cover points as we entered different stages of preparedness for QR" – *Provider* “the sessions are helpful for preparing for the product launch.” – *Provider*

Enduring Auction Capability (EAC) (D4.3.5)

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

Continue to expand functionality on the auction side and IS integration to enhance automation and bidding efficiencies. Progress moving all relevant newly formed services onto the setup. Develop roadmap for the addition of any new services. Ensure continuous improvement of the capability and ongoing customer support and engagement to meet customer expectations.

What have we achieved by the end of BP2?

The Enduring Auction Capability (EAC) has continued to deliver and procure our Response and Reserve services. The benefit of moving these services to the EAC was calculated to be £67m per year over a period of two years and five months, giving a total of £162m. This has provided consumer and market value and we have successfully developed the EAC tool to bring forward these benefits over the course of RIIO-2.

We continued to expand functionality with the addition of Balancing Reserve and Quick Reserve as well as IT integration to enhance automation and bidding efficiencies. Response and Quick Reserve is a co-optimised auction with more services to be added to this timeframe. By the end of 2025 we will have added Slow Reserve to the EAC and a fully co-optimised auction for all services (Response, Quick Reserve, Slow Reserve and Balancing Reserve). We have developed our roadmap for the evolution of existing services beyond this period to set ourselves up for success. This will ensure continuous improvement of the capability and ongoing customer support and engagement to meet customer expectations. This has meant more flexibility for providers in procuring our services and utilising their assets to maximise their throughput.

We also completed the Day 1 NESO activities (e.g. re-branding).

How did our approach maximise outcomes?

We engaged with stakeholders through industry consultation, drop-in sessions and mock auctions to help stakeholders better understand how the EAC system operates with the new Balancing Reserve (BR) and Quick Reserve (QR) services.

We updated and provided detailed materials, including the market design report and an Application Program Interface (API) guide. These resources offered clear, up-to-date information on the EAC design and technical specifications.

We continue to engage with the industry to introduce more services to the EAC.

We regularly run simulations to test hypotheses or provide counterfactuals based on real situations to continually refine and improve our procurement.

Reactive Power (D4.6.2)

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

To establish a Long Term reactive market based on the learning from Voltage Pathfinders (now called Network Services Procurement) and be ready to launch the tender when the system needs are identified, so that the Long Term market will replace pathfinders to run the procurement process if required depending on the system needs

To confirm whether the Mid Term Reactive market will be implemented as proposed initially from Reactive Market innovation project. In addition to Long and Mid Term markets development, to plan and further explore whether there is any additional value for having a Short Term market in place.

What have we achieved by the end of BP2?

Following our update last year, the Long Term reactive power market has been designed and is available for us to use when requirements are identified and a tender through this market is the appropriate strategy. The Long Term market is the succession to Voltage Pathfinders and will now form part of the Reactive Power Market as part of the Network Services programme. The design of the Long Term market is based on the Voltage Pathfinders procurement approach and market design project output. We have completed the system studies and identified system needs for locational voltage services across GB from 2029 onwards. As the Long Term market is confirmed as an option to meet these needs, we are now running the tender as the first dedicated Long Term market under the network services programme

In addition to the Long Term market, as of March 2025 we have now completed our market design work for the Mid Term reactive power market, reviewing the outstanding market design questions with industry. We have decided to proceed with the implementation of the Mid Term market as part of the overall Reactive Power Market. The Mid Term market will provide a route to market to access voltage services closer to real-time, leveraging voltage services from existing assets based on their additional capability over & above the requirements of Grid Code through an open, transparent and competitive market. We are now working on the detailed requirements and criteria as part of this market, and more information will be shared with industry in the near future.

We have started an innovation funded project to review the current methodology of Obligatory Reactive Power Service (ORPS), which is used to calculate a fixed rate to pay the utilisation of reactive power as an obligatory service. The methodology hasn't been reviewed since it was initiated hence might not fit for the need now and future. The output may also have an impact on the potential value of a short-term reactive market if it proposes a change, so the daily market review will be continued after the conclusion of this innovation project expected in Aug 2025.

The project related information can be found here: Alternative approaches to the ORPS methodology.

How did our approach maximise outcomes?

We have been engaging with industry through different ways including webinar, bilateral discussions, Requests For Information (RFI), publication through our webpage etc, to enable enough opportunities for industry to feedback, comment and work with us on the reactive market development.

We have been working with industry together to develop the market, we shared the market design proposal at each critical stage, and encouraged industry to comment, question or suggest different views.
All of that feedback was captured and analysed to feed into our final recommendation.

The ORPS review innovation project has also adopted the proactive engagement approach with external stakeholders, the WP2 and WP3 was designed specifically to discuss with other TSOs and different service providers to help us fully understand the issue, cause and potential options for the project. We have completed the discussion with five TSOs and eight providers across 11 technologies.

Single Markets Platform (SMP) (A4.4)

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

Continued development of SMP to facilitate new market inclusion and an improved user experience delivered through regular releases and supported by ongoing industry engagement. The inclusion of the Balancing Mechanism registration process is a key target in delivering a digital first approach to a complex legacy process.

What have we achieved by the end of BP2?

SMP has had another strong year of delivery onto the production system. We have continued to deploy regularly and have again delivered 12 releases across the performance year.

Of particular note is the recent migration of the Balancing Mechanism registration process to SMP. This is specifically in support of participation in the Balancing Mechanism which represents an expansion to our previous work that focused on day-ahead Balancing Services markets. This is a complex legacy process that will benefit from being in SMP to facilitate greater levels of user visibility, access to our APIs to better facilitate registration of embedded Balancing Mechanism Unit (BMUs), and ongoing enhancement to the process and user experience over time.

High level SMP delivery over the last 12 months is best segmented across the following categories: -

New service adoption – Balancing Mechanism Unit Registration process, Quick Reserve onboarding, Slow Reserve onboarding

Existing service enhancements – Demand Flexibility Services (DFS), Regional Development Programme (RDP)

Functionality enhancements – API enhancements, user dashboards, Customer Identity and Access Management (CIAM)

NESO system integrations – integrations with Open Balancing Programme (OBP), Digital Engagement Platform (DEP), Settlements (STAR), Forecasting (PEF)

DNO market interactions – DNO reporting (initial stages of primacy / risk of conflict reporting), EAC (Auction) outcome conflict report, provision of SMP sandbox and API support for Flexibility Markets Unlocked (FMU) project

Other – NESO rebranding for Day 1, application of new design system

The work delivered in support of DNO market integration differs to what was originally envisioned based on the ongoing DESNZ and Ofgem industry consultations. SMP has fed into all consultations and the specific work detailed above sets us up well in this space for the future.

How did our approach maximise outcomes?

SMP operates as a genuinely agile project with regular deployments, industry engagement and a value-based approach to backlog refinement and re-prioritisation. Whilst SMP has largely met the milestone targets set in the BP2 plan, these were written prior to our foundational release in 2022, so assessing performance through this lens underestimates the value delivered for users. We continue to regularly engage with users through monthly 'Show and Listen' webinars to share what's coming up and to also seek direction on what is of most important to users. We also canvas opinions from users in our monthly drop-in surgeries and through the account management relationships; such interaction directly resulted in the enhancements to our "Related Entity" process and APIs. The design of the BM Registration process on SMP was also influenced by direct user feedback.

Facilitating Market Access for Whole Electricity Flexibility, and Service Coordination between markets

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

Under AWEF, there are 3 Role 2 deliverables: 4.5.3, 4.5.4 and 4.5.5. We have successfully delivered Deliverable 4.5.3 by developing and publishing the Enabling Demand side Flexibility in our Markets Report (EDSF). Continuous improvements are being delivered to our markets to facilitate market access for distributed flexibility, aligning with the direction outlined by EDSF (Deliverable 4.5.4). Currently the only outstanding deliverable is the 4.5.5 which focuses on providing locational data for all flexibility service providers to facilitate Distribution System Operator (DSO) awareness. The delay in achieving this milestone is due to external factors, primarily dependencies on ongoing work by Ofgem / DESNZ on Industry Asset Registers. While awaiting Ofgem's decision on Flexibility Market Asset Registration (FMAR), Single Market Platform (SMP) has leveraged lessons from the proof of concept work to deliver initial Distribution Network Operator (DNO) reporting functionality in Q3. This work supports teams to understand risk of conflicts in the pre-qualification stage. Additionally, we actively responded to Ofgem's Flexibility Market Asset Registration (FMAR) consultation and are feeding into DESNZ's AAR (Automatic Asset Registration), CAR (Central Asset Registration) and FMU (Flexibility Markets Unlocked) programmes.

EMR (A5)

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

EMR BAU delivery – We implemented a number of key regulatory changes to the Contracts for difference (CfD) and Capacity Market (CM) regimes in time and successfully ran both schemes, including prequalification and auction processes for a record number of applications. We have also proactively raised a number of issues and improvements to the CM Rules and CfD Allocation Framework, which will reduce ambiguity and improve robustness of the schemes.

Capacity Market Portal - The updated Capacity Market Portal delivery plan for BP2 agreed with the industry and Ofgem set clear success expectations that the Capacity Market processes, including any required regulatory changes, would operate in the new CM portal for the Prequalification 2024 round with clear evidence of improved customer satisfaction and experience in using the portal and supporting guidance.

What have we achieved by the end of BP2?

EMR Delivery Body Function

Contracts for difference (CfD)

The CfD scheme is the government's main mechanism for supporting new low carbon electricity generation projects in GB. As the EMR Delivery Body, we are responsible for the prequalification, disputes and auction processes of the CfD scheme.

Allocation Round (AR) 5 and 6

During the BP2 period, we successfully delivered AR5 and AR6.

AR5 was the first annual round (a change from running rounds every two years) and a total of 95 projects were successful, representing ~3.7GW at a cost of ~£228m (2012 price). This included three geothermal projects being awarded CfD contracts for the first time, a record number of tidal stream projects (11 projects), and significant quantities of new solar and onshore wind generation. A record low number of disputes were raised to Ofgem, who upheld all our decisions.

In AR6, a total of 131 contracts were awarded, securing ~9.6GW of renewable capacity for a cost of £1.3bn (2012 prices). This significantly higher cost than AR5, was due to changes to the administrative strike price for each technology, a dedicated pot for offshore wind and an uplifted budget, following our valuation of eligible applications.

Although EMR DB received a record number of 216 applicants in AR6, the prequalification, dispute and auction processes went smoothly. The customer satisfaction survey score remained strong of 8.4/10, received from 47 respondents.

Following closure of AR6, we recommended several improvements to the Allocation Framework to reduce ambiguity for both us and applicants. Some of the proposed changes were to address the rules ambiguity which led to Ofgem's overturn decision for the two disputes.

Capacity Market (CM)

The CM is the government's main mechanism for ensuring security of supply. It is a technology neutral scheme that procures capacity through two Auctions -the T-1 and the T-4. As the EMR DB, we are responsible for the prequalification, disputes, auction and ongoing management of awarded agreements.

Auctions 2023-2024 and 2024-25

During the BP2 period, we successfully delivered two CM rounds – prequalification opened in July 2023 for the February 2024 auctions and in July 2024 for the March 2025 auctions. Both rounds had over 1,000 applications with the 2024 round having 20% more applications than 2023.

In 2023, Ofgem upheld the EMR DB's decision on two of the Tier 2 disputes raised with them and overturned one which was due to ambiguity in the CM Rules. We have been working with Ofgem on a change to clarify the intent of the Rules associated with the overturned rejection.

On 20 February 2024, the EMR DB ran the T-1 Auction and on 27 February 2024, the T-4 Auction, securing 7.6 GW and 42.8 GW respectively. The Auction Monitor Reports for both auctions confirmed that they were run in accordance with the CM Rules and Regulations.

During the 2024 prequalification process, to enhance delivery assurance and as agreed with Ofgem and DESNZ, we more stringently applied the CM Rules and rejected all applications that were non-compliant in any way. During the Tier 1 disputes process, we were able to overturn almost all of the disputes, following receipt of addition information or correction of errors, with only 13 being upheld. All 13 applicants raised Tier 2 disputes to Ofgem, with Ofgem upholding our decision on all of the disputes.

Due to a more competitive auction, the T-1 clearing price (£20/kw/yr) is the lowest since 2021 and T-4 was cleared at £60/kw/yr, £5 reduction on 2023 record high T-4 price (£65/kw/year) ending an upwards trend for the last 5 years but still sending a strong signal to the industry for new capacity. DEZNZ have published the Auction Monitor Reports for both auctions, confirming that they were run in accordance with the CM Rules and Regulations.

Despite the increase in applicants and initial rejections, we are pleased to have received an average customer satisfaction score of 8.3/10 from 93 responses, a record high score, reflecting an enhanced customer services we delivered to the industry.

CM and CfD policy and regulatory changes

During BP2 period, the EMR team have been working with government, Ofgem and industry to identify, assess and implement policy, rule and process changes to further develop the CM and CfD mechanisms. This includes not only incremental improvements but also medium to long term reforms to ensure the schemes remain fit for purpose.

In particular, we have been supporting DESNZ with shaping the detailed design and implementation of the proposals that they consulted on CM to ensure the mechanism evolves in light of the energy landscape changes. We have proactively raised a large number of issues and gaps with the CM Rules and Regulations with DESNZ and Ofgem and are working with them to identity changes that will improve participants' delivery assurance and value for money for end consumers.

We also continue to a be an active participant of the CM Advisory Group (CMAG), which is the expert group established by Ofgem to develop, assess and recommend changes to the Rules. Now the backlog of changes has been cleared, most changes raised are intended to tweak the Rules to benefit a specific technology and situation. As the EMR DB, we have been using our expertise to challenge proposals and shape the design to ensure Ofgem has sufficient information to reach decisions, including on their most recent consultation published in January 2025.

For CfD, in preparation for AR7, we have been supporting DESNZ with developing changes to the Regulations and Allocation Framework, including to implement proposals to enable repowered onshore wind projects to enter and extended the phased CfD policy to floating offshore wind projects. Following further engagement with stakeholders and publication of the Clean Power 2030 Action Plan, DESNZ has issued a second late consultation on further changes. We are currently assessing the feasibility of implementing these additional changes and having ongoing dialogue with DESNZ on this as well as raising suggestions to address uncertainties faced by investors in AR7.

EMR Modelling & Capacity Adequacy

We have continued to develop and undertake modelling to provide recommendations to Government on the Capacity Market. The 2024 Electricity Report (ECR) was submitted to Government in line with our obligations and published in July 2024. The Secretary of State accepted our recommendation on the target capacity for the T-4 auction for delivery in 2028/29. The Secretary of State set a slightly lower target (0.3 GW lower) for the T-1 auction for delivery in 2025/26. We continue to welcome scrutiny from DESNZ's Panel of Technical Experts (PTE) on our modelling, who continue to recognise our open approach to engagement with them in their published report.

We have continued to deliver the modelling enhancements that seek to improve different elements of our modelling. A highlight for this year was the work we completed to implement changes to de-rating factors for limited duration storage technologies. We ran a consultation in April 2024 and published our response in July 2024 alongside the 2024 ECR setting out the changes that would take effect from the subsequent auctions.

In 2024-25 we have continued to develop our work on longer-term resource adequacy for the 2030s. We have continued to engage with stakeholders as we develop our modelling, most notably through an expect group that we established to support this activity. We published two reports in mid-2024 providing further insight on adequacy metrics and demand-side response (DSR) assumptions. These topics were chosen based on feedback from stakeholders during round table discussions in spring 2023. In March 2025 we published a third report on the modelling approach for Resource Adequacy in the 2030s, which you can access here.

We had intended to publish our next 2030s resource adequacy study in 2024, following the study we published with AFRY in December 2022. This was delayed due to our work on CP30 for two main reasons. Firstly, we reallocated resources to undertake adequacy modelling for the CP30 pathways that highlighted the need and role for unabated gas generation. Secondly, we wanted to wait for the outcome of the CP30 work before undertaking the 2030s resource adequacy study to ensure coherence and consistency for stakeholders. Modelling for the adequacy study is now well underway, and we intend to publish this study in late spring / summer 2025, shortly after the BP2 period.

Capacity Market Portal - Following successful implementation in Q1 FY25, delivery milestones transitioned to continuous improvements driven by customer feedback and delivery of regulatory/rule changes.

The new portal and integrated guidance have enabled a 20% increase in prequalification applications, leading to increased competitiveness in auctions. The T-4 and T-1 auctions run in March 2025 cleared at lower prices for consumers than equivalent auctions in 2024.

Customer surveys and verbatim feedback confirmed high customer satisfaction with the ease of use, transaction performance, the integrated guidance, and in specific new features for managing applications and capacity agreements.

Improvements were designed from feedback received and prioritised with the dedicated Capacity Market User Group. Portal improvements have been implemented in Q3 and Q4 of FY25.

Following the REMA Autumn update, an options assessment was completed in Q4 on development of a new Contracts for Difference (CfD) portal. Given focus on delivery of Clean Power 2030 objectives in Allocation Rounds 7 and 8. The assessment concluded that investment should be prioritised in implementing changes required for AR7 and AR8 and in focused improvements to strengthen reliability, stability and scalability in FY26 in the current CfD portal rather than in a full delivery project to develop a new CfD portal or bring functionality into the Capacity Market Portal.

How did our approach maximise outcomes?

Capacity Market Portal – The EMR Delivery Body continued our engagement with the dedicated Customer User Group to support review, challenge and prioritisation of features being delivered. Regular progress newsletters were provided to all users, with further updates and webinars delivered to support transition to the new portal.

A new website and a dedicated guidance site were implemented to provide clear sources for customers to track progress and access supporting material.

Customer feedback was gained throughout the portal delivery, during user requirement playback and demonstrations, via a dedicated customer familiarisation phase and with a full user survey conducted after the Prequalification application round. Customers were asked to rate overall experience, the new guidance site, and the performance of the new portal, with median scores received up to 8/10.

Feedback received was used as a key input in delivery of our continuous improvement plans implemented for Q3 and Q4.

EMR Modelling & Capacity Adequacy

We have continued to engage with stakeholders as we develop and deliver our modelling. For our work on the ECR, this includes engaging with DESNZ PTE through a regular series of discussions covering both the modelling improvements and delivery of the ECR itself. The PTE make recommendations in their annual report, that often lead to development projects that are reported in the subsequent ECR.

This year we also ran a consultation to change the method to calculate de-rating factors for limited duration storage technologies in the Capacity Market. We received 15 written responses and published our response setting out how we had reflected stakeholder feedback in the changes that were subsequently made.

We established an expert group to support our work on longer-term resource adequacy covering the 2030s. We have also continued to engage with academia and expert international groups to ensure that we are using the latest available techniques in our modelling.

Codes (A6 / A21)

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

Develop code and charging arrangements that are fit for the future.

We continue to progress code and framework changes to deliver the BP2 Schedule and beyond. Key highlights include management via the codes of, connections reform, market-wide half hourly settlement, technical and charging changes. We have also made signification progress in the development of the Interconnector Framework. To deliver all this change successfully and at pace, we have engaged extensively with industry, ensuring delivery of the BP2 schedule and prioritised code modifications.

What have we achieved by the end of BP2?

Code Governance – Managing Code Changes

The NESO Code Administrator has worked with industry, Panels, and Ofgem to support code change with 256 workgroup meetings taking place and 30 Final Modification Reports submitted to Ofgem across the codes and standards we administer. These are the Connection and Use of System Code (CUSC), the Grid Code (GC), the System Operator – Transmission Owner Code (STC), and the Security & Quality of Supply Standard (SQSS) (from April 2024 up to and inclusive of 12 March 2025).

The Digitalised Code Management (DCM) project has delivered the technology capability to make industry codes accessible and consumable for customers, transforming the customer experience for the Code Management process through digitalisation of the Grid Code and provision of enhanced navigation capabilities. The Minimum Viable Product (MVP) of the Digitalised Grid Code was successfully released in June 2024 to internal and external users, and there have been several releases since then with additional enhanced features being added iteratively post go-live. Enhancements have included a GenAI tool and, in February, the release of a digital Modification proposal form, as well as changes in response to user feedback.

Connections Reform Code Changes

We have supported industry through the management of several Urgent Connections Reform modifications. In April 2024, we raised urgent code modifications to implement Connections Reform (CMP434, CMP435 and CM095). In February 2025, Ofgem published their minded-to position to approve the Modifications. In 2025, we raised a second suite of modifications to further improve the Connections process. These changes aim to improve the connection process for smaller Distributed Generation (CMP446) and to incentivise the timely removal of unviable projects from the connections queue by introducing a Progression Commitment Fee ("PCF") (CMP448). We also raised two STCP Mods to facilitate Connection Reform, PM0142 and PM0143.

These were agreed to be material STCPs and were submitted to Ofgem for approval in February 2025.

Charging and Market Wide Half-Hourly Settlement (MHHS) Code Changes

We have progressed several charging modifications prioritised by industry, including CMP444, which proposes to introduce a Cap and Floor to TNUoS charges. This modification aims to increase investor certainty in new generation investment required to meet Clean Power 2030 without undermining locational signals. CMP444 is currently out for Code Administrator Consultation, and on track for an Ofgem decision in time for the AR7 CfD round, and for implementation in April 2026.

We have also supported industry-raised code modifications, including providing subject matter expertise and guidance to the proposers of CMP441 (Reducing the credit risk of supplying non-embedded hydrogen Electrolysers) and CMP445 (Pro-rating first year TNUoS for Generators); providing analysis to several workgroups, including to the urgent modification CMP432 (Improve "Locational Onshore Security Factor" for TNUoS Wider Tariffs) and high priority modifications CMP440 (Re-introduction of Demand

TNUoS locational signals by removal of the zero price floor) and CMP423 (Generation Weighted Reference Node); and facilitating industry change through involvement at all CUSC workgroups.

We continue to support the MHHS programme, delivering the urgent modification CMP430 (Adjustments to TNUoS Charging from 2025 to support the MHHS Programme) which was approved in September 2024, as well as supporting MHHS through participation in the Design Advisory Group (DAG), Programme Steering Group (PSG) and several workgroups.

Technical Code Changes

We continue to drive forward technical code changes, including GC0117, GC0166, and GC0159. In February 2025, Ofgem issued their minded-to position on GC0117, which aims to improve Transparency and Consistency of Large, Medium and Small Power Stations across GB. In late 2024, the Code changes in respect of Competitively Appointed Transmission Licensees (including GC0159) were submitted to Ofgem for approval. GC0166, which seeks to introduce new parameters that will allow the better use of Electricity Storage Modules within the Balancing Mechanism, is currently in the workgroup stage and is well advanced. In February 2024, Ofgem approved the code changes for the Electricity System Restoration Standard (ESRS) and we are currently working with the industry to ensure compliance for 31 December 2026.

There has also been much work from the Technical Codes and Code Governance perspective to ensure the introduction of the NESO arrangements, including GSR033, to integrate the SQSS governance framework into the SQSS main document. We are also engaging in other initiatives such as code simplification, the wider Energy Code Reform work, Offshore HND (Holistic Network Design) work and the Offshore Hybrid Asset (OHA) work.

The Digitalised Whole System Technical Code (dWSTC) Steering Group oversees the Alignment, Simplification and Rationalisation (ASR) and Digitalisation workstreams. GC0164 (Simplification of Operating Code No.2) is progressing, with the modification being considered at workgroup following Code Administrator Consultation (CAC) responses. This modification has been a test case for Code simplification and has shown that rationalisation of technical Code sections will be difficult to deliver using open governance and voluntary Industry resource. GC0179 (Rationalising Balancing Code No.4 (BC4) and Balancing Code No.5 (BC5)) was submitted to the Grid Code Administrator in March 2025.

Balancing and Settlement Code (BSC) Changes

We have continued to drive forward BSC changes, including participation in BSC workgroups, BSC Panel, BSC Issue Groups and driving forward our proposals such as P462. P462 aims to reduce consumer cost potentially caused by the interaction between the Balancing Mechanism (BM) and support mechanism arrangements. This Modification aims to ensure a level playing field in BM.

Role in Europe

Interconnector Framework

We have made significant progress in the development of the Interconnector Framework. This aims to encourage consistency for interconnectors operating in GB markets and aid transparency of the ways in which the interconnectors operate and work with us.

Industry feedback identified two key themes for the interconnector framework: harmonization of existing frameworks and increased transparency. To address these, we created a new area on our website dedicated to interconnectors which currently collates existing information on interconnectors to make it more accessible. This dedicated interconnector webpage serves as a centralised hub for all relevant information. It aims to enhance transparency regarding interconnector operations and obligations. It streamlines the process of finding and utilising information. It facilitates better communication and collaboration between ourselves and industry stakeholders by providing a platform for sharing updates, feedback, and best practices. Recognising that stakeholders have diverse interests and varying levels of expertise, the webpage is designed to appeal to both new and experienced stakeholders, ensuring that everyone is brought along on the journey.

We also repurposed the Joint European Stakeholder Group (JESG) to encourage industry collaboration on harmonisation, future policy development and transparency requirements.

How did our approach maximise outcomes?

Code Governance – Managing Code Changes

Through delivering the suite of Urgent Connection Reform modification workstreams (Implementing Connections Reform, Application of Gate 2 Criteria to existing contracted background and increasing the lower threshold in England and Wales for Evaluation of Transmission Impact Assessment (TIA)), the team facilitated 73 Workgroup meetings, whilst receiving and reviewing 294 consultation responses. We introduced new ways of working to simplify and streamline processes.

We are now integrating these improvements into routine modifications (e.g. updated clarity on standard slides) or using them for more complex modifications to ensure that Workgroup discussion is kept on track (e.g. query and action log differentiation).

The Code Governance Team has worked closely with the CUSC Panel, navigating their prioritisation decisions and ensuring feedback from the Workgroup hiatus was acted on. A Panel member now attends the 'Transmission Charging Methodologies Forum' (TCMF) to explain next steps and inform industry of how they can feed directly into the Panel decision making process.

To ensure quality and consistency of modifications from proposal to Final Modification Reporting, the report templates have been reviewed and improved to reduce queries and drive consistencies. Additionally, training has focused on sharing best practices between team members

As part of developing the Digitalised Grid Code platform we engaged with industry to understand how we can improve the user experience. We issued a survey to industry in November 2024. The Digitalised Grid Code has gone through User Acceptance Testing and has regularly sought feedback from users, to inform improvements for future releases.

Connections Reform Code Changes

We undertook extensive engagement with industry before raising the Connections Reform modifications to maximise efficiency and ensure stakeholder views were heard and considered. For example, prior to raising CMP448: Progression Commitment Fee ("PCF"), we presented the initial proposal at the 'Transmission Charging Methodologies Forum' (TCMF). We then published a 'Call for Input' to gather wider feedback from stakeholders across the energy sector. We received 132 responses from the 'Call for Input'. This provided us with insight on the potential impact that the initial proposal could have on stakeholders. It helped us to understand and evaluate its interactions with wider connection reforms and the combined effect on developers. It also allowed us to assess proposal options and refine the proposal using the evidence gathered. The proactive approach has helped build consensus for the PCF needs case - as well as key design principles - and proceed through workgroups at pace.

We also substantially improved engagement with the DNOs prior to raising the suite of Connections Reform modifications and throughout the modification process. We have multiple weekly calls with the DNOs and utilise the ENA Strategic Connections Group (SCG) to discuss the connections modifications. The ENA and DNOs also attended (and continue to attend) Connections Reform workgroup meetings to enable full involvement in the end-to-end process. In addition, we have gone further and set up the Connections Reform Implementation hub. This is across all networks (ENA, INA, DNOs, IDNOs and TOs) and ensures that we have a joined-up approach to connections reform implementation. This has resulted in multiple weekly workshops in the run up to connections reform and includes DNO/IDNO specific workshops focusing on the distribution related impacts of connections reform.

In developing the new and revised STC Procedures (STCP) to facilitate Connection Reform, we worked collaboratively with TOs and OFTOs via a series of regular meetings, to ensure that impacted stakeholder concerns and views were considered.

Charging and MHHS Code Changes

We continue to chair the Transmission Charging Methodologies Forum (TCMF). We have continuously improved TCMF during the year, actively seeking and listening to industry suggestions, and gaining positive feedback on improvements – including more transparent Connections data, signposting CUSC Panel members and how they represent industry, allowing more time for complex topics, etc.

We acted quickly to develop the CMP444 proposal. We engaged with Ofgem and Industry (via TCMF and several bilateral meetings with industry parties) before raising the CMP444 modification, which incorporated a lot of industry's feedback, particularly around which elements of TNUoS the cap applied to. We worked proactively with Ofgem, DESNZ and workgroup members to coordinate and perform analysis of all the CMP444 original and alternative proposals – showcasing the trade-offs between options. This analysis provides stakeholders with clarity on their potential costs ahead of Allocation Round 7 and enables a collective understanding of the impacts of the proposal on CfD and CM auctions. We also worked with Ofgem/DESNZ to ensure that the proposal takes account of future REMA reforms, particularly to ensure implementation of the cap and floor does not overlap with implementation of REMA.

We engaged extensively with industry on CMP430, supporting the Market Wide Half-Hourly (MHHS) programme. We used forums such as TCMF, MHHS governance groups and TNUoS Taskforce to inform industry of changes and seek wider feedback on the proposal and solution. We used this feedback and workgroup feedback to change the solution as the modification progressed, showcasing agility and adaptability in our approach. We were mindful in how we designed the solution, ensuring it was compatible with the MHHS migration timetable and any potential delays to MHHS implementation. This avoided the need for future changes to the solution.

<u>Technical Code Changes</u>

We work extensively with internal and external stakeholders in the development of Technical Code Mods. We make use of the Grid Code Development Forum (GCDF, chaired by NESO) to seek feedback from stakeholders on the potential impact of Mods, prior to formally raising them. GCDF is a well-attended forum, and the stakeholder feedback and discussion generally improve the quality of Mod proposals. During Modifications, we support options analysis where required (e.g. for GC0117).

Our Technical Codes change team is also working on several strategic topics to develop solutions, including Grid Forming and Ramping, prior to raising formal Mods. The Grid Forming expert group that we are hosting has been well attended by industry stakeholders, with around 60-70 industry stakeholders regularly attending, providing a forum for all interested parties to share ideas and work. This work will feed into drafting the solution later this year.

GC0164 (Simplification of Operating Code No.2) has involved extensive stakeholder engagement, including 12 workgroup meetings, 2 industry surveys, 70 bilateral stakeholder meetings, and 20 industry forum presentations. Stakeholder input has been critical, both in terms of considering the principles of simplification, and supporting with the re-drafting to ensure requirements were not altered while text and presentation of material was simplified.

<u>Balancing and Settlement Code (BSC) Changes</u>

We continue to engage with industry on BSC related activity. For P462, we proactively engaged with BSC Panel, Elexon, Ofgem, government, workgroup members and industry to develop an independent Cost Benefit Analysis (CBA) which aims to assess the wider impacts of the modification. This detailed analysis will support progression of the code modification and inform workgroup deliberations, taking on board industry feedback throughout the process.

Role in Europe

<u>Interconnector Framework</u>

Before launching the Interconnector Framework in March 2025, we carried out a series of engagements including the completion of a Request For Information (RFI), an industry webinar and internal workshops. This enabled feedback to be gathered on operational and commercial issues that interconnectors identified and whether an interconnector framework could potentially resolve these issues.

In January 2025, we launched a consultation to gather further industry feedback on proposed plans for the NESO Interconnector Framework. The feedback received shaped the purpose and design of the framework.

Before we repurposed JESG, we launched a consultation on the revised terms of reference and invited stakeholders to bring forward topic areas for discussion, ensuring the forum was fit for industry needs.

Charging including STAR (Settlements and Revenue) (A6)

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

Continue to develop a faster, more flexible and configurable system with improved functionality for system maintenance, regulatory priorities, customer enhancements and functional backlog management. The Settlements and Revenue (STAR) system will replace CAB for billing, and ASB for Settlements, and allow us to better respond to evolving market conditions.

Of particular note are two specific projects that should be starting to be implemented: Market Half-Hourly Settlement (MHHS) and Changes resulting from the Transmission Network Use of System (TNUoS) reform Taskforce.

Balancing Services Use of System (BSUoS) reporting and capability is covered under RRE 2E Accuracy of Forecasts for Charge Setting - BSUoS

What have we achieved by the end of BP2?

STAR BSUoS daily billing was successfully implemented in November 2024, which was the last major billing stream to be migrated. This allowed the CAB legacy billing system to be decommissioned in December 2024. Further STAR releases happened in March 2025 for TNUoS generator reconciliation (to be billed April 2025) and TNUoS final demand reconciliation (to be billed Sep 2025).

Changes to the industry timeline for MHHS delivery have moved the consequential STAR system changes out of BP2. Additionally, the TNUoS taskforce modifications are still in progress and therefore this has been moved out of BP2 as well.

For Settlements, Firm Frequency Response (FFR) was successfully implemented in Q2 FY25. There has been further technical go lives of Ancillary Services achieved for Mandatory Frequency Response (MFR), Reactive & Balancing Reserve across Q3 FY25 and Q4 FY25 respectively.

Hydro development has been deprioritised to enable new Ancillary Services (Quick Reserve & Slow Reserve) to be delivered in STAR, a Change Request has been raised to move Hydro to BP3.

The STAR system has delivered the benefits expected, significant increase in stability, capability and controls, and adaptable to future changes in the charging methodologies.

How did our approach maximise outcomes?

Ahead of each STAR revenue billing release, we have consulted with customers on the system changes and guidance documents for the file formats of the reports the system sends to customers. Where changes have been needed following a release, we have provided options to customers and selected the most popular and least impactful to industry.

A parallel run has been completed for each STAR Settlement release enabling validation to existing Settlement outputs and payment calculations. We have provided guidance to customers on any file or calculation changes as part of the Settlement release process. Following each successful release, we conduct a 'lessons learnt' process to ascertain what has gone well and what can be changed to improve efficiency of the release programme.

Net Zero Market Reform (NZMR) / REMA (A20)

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

Trusted Partner to DESNZ, Ofgem and the wider industry in this space.

What have we achieved by the end of BP2?

During the last year of BP2, we have continued in our role as formal delivery partner for the Review of Electricity Market Arrangements (REMA) together with DESNZ and Ofgem, reflecting our status as 'Trusted Partner' to both organisations.

In this period, we have led the REMA workstream looking into dispatch reform and played an advisory role in other workstreams.

We have worked within the REMA programme, researching and informing on:

- Dispatch options for reform
- Investment options for reform (Contracts for Difference, Capacity Market)
- Potential zonal designs and processes
- Interactions between cross-border trading arrangements and GB market design
- Trading and market strategy

Potential implementation implications of REMA options for NESO and industry

How did our approach maximise outcomes?

During this performance year, the REMA team focused on providing evidence based, impartial advice that incorporated industry feedback where possible. In July 2024, we conducted the Dispatch Options webinar, enabling industry to provide their views to inform the next phase of work. During the webinar we ran interactive breakout sessions where discussion was encouraged. After the webinar, we published a summary of the discussions and the Q&A. This webinar was followed by a targeted Q&A session for interconnector developers in September 2024, focusing on the interactions between dispatch design and cross-border trading.

The insight gathered from our engagement with stakeholders has been used to inform the programme, specifically by listening to and acting on the following stakeholder feedback:

- Concerns were raised for the need to properly account for how dynamic the renewables-based system will be.
    - We were careful to reflect the beneficial role of intraday trading under self-dispatch.
- Stakeholders were concerned on the role of liquidity in improving balancing mechanism outcomes.
    - As a solution to the 'inter-temporal constraints' challenge we raised in our Case for Change, this led us to model wider balancing mechanism access which would improve liquidity.
    - Throughout our dispatch work, concerns were raised around how central dispatch could be made to work with efficient and seamless cross-border trading.
    - We have taken significant steps to illustrate this to ensure a holistic approach.
    - On the cross-border elements of REMA, we have worked closely with Interconnector Owners, Operators, EU Transmission System Operator's (TSO) and EU groups.

  - The feedback from these groups has fed into the analysis and conversations happening internally as well as with DESNZ and Ofgem.
- On the implementation of market reforms, we have engaged with international stakeholders.
- This information has helped us to glean insights and best practices from similar market reform programmes.

An emphasised point of feedback we received during the July engagement was the need to conduct quantitative analysis to further understand the trade-offs involved. We have since commissioned FTI Consulting to model the different dispatch options, and in November 2024 we held a Request for Input seeking to get industry input on the key assumptions and methodology of the assessment.

This year has also seen the REMA team strengthen our internal governance and stakeholder management arrangements. A number of discussion and approval forums have been established, seeking to ensure all our REMA work receives the right level of visibility and feedback from across the business. Integrating both external and internal feedback has enabled the REMA team to guarantee the robustness of its advice, delivering consumer value and accounting for the needs of market participants.

EU and cross-border activity (A21)

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

Significant strategic improvements in interconnector and cross-border planning, assessment and development across NESO, including those of DESNZ and Ofgem and re-establishing EU relationships, to achieve the full potential of GB interconnection, while maintaining a secure and operable system.

What have we achieved by the end of BP2?

Strategic improvements to cross border arrangements

We have realised significant improvements across NESO in how GB interconnection is planned, assessed and developed through a reformed strategic approach, encompassing the objectives of NESO, DESNZ & Ofgem.

These improvements largely stemmed from the NESO Future of Interconnectors (FIC) innovation project, delivered in 2023. This project provided a better understanding of how interconnector behaviour could evolve in the transition to a net-zero system and how they could contribute to the key aspects of GB system operation. The project identified the key challenges to be solved to maximise the full capabilities and value of GB interconnection. This analysis led to the development of a cross-border case for change prioritising the key areas for improvement based on their urgency and potential contribution to GB's energy trilemma. From this, we have been able to strategically focus on the identified key areas for improvement and the steps required to achieve these improvements. We plan to share this with Ofgem later in 2025.

The following major improvements already achieved because of this strategy are listed below, with the most significant being the analysis of the different REMA dispatch options and the effects on cross-border arrangements:

- Assessment of the different Review of Electricity Market Arrangements (REMA) dispatch options and the effects on cross-border arrangements. This was carried out in coordination with FTI consulting and assessed the impacts of different REMA dispatch options on the current and future cross-border arrangements. We analysed how changes to cross-border arrangements would create market efficiencies under the different REMA dispatch options. The results have been presented to DESNZ and Ofgem in modules from November 2024 – February 2025, followed by detailed presentations, discussions and communications to address clarifications. This has subsequently helped to inform DESNZ's progress and decision-making on the different REMA dispatch options. The outcomes of this work will be published to the wider industry later in 2025.
- Alignment of DESNZ, NESO and Ofgem's strategies and objectives for future GB interconnection. This has been achieved through the creation of a tripartite working group which continues to develop these objectives and clarify the desired future for GB interconnection and cross-border arrangements.
- Clarity and alignment across NESO on how future GB interconnection are assessed and modelled in the Strategic Energy Planning (SEP) workstreams, including all available technologies (i.e., standard Point-to-Point interconnectors, Non-Standard Interconnectors [NSI], and Multi-Purpose Interconnectors [MPI]). This has encompassed alignment with the government's ambition for future interconnection.
- Development of an assessment of the possibilities and impacts of different GB-EU market coupling mechanisms, including the impacts on GB system operation.
- Development of new operational interconnector arrangements and improved efficiencies of existing operational tools have resulted in more accurate, efficient and reliable interconnector operations. This has included the design, creation and implementation of new System Operator-to-System Operator (SO-SO) Trading mechanisms, the redesign and streamlining of existing SO-SO Trading mechanisms, the move of operational data exchanges from email to IT system-to-system-based processes, and the improvement of market and operational arrangements relating to the compensation of capacity restrictions by NESO.

The cross-border workstreams have engaged with industry customers and stakeholders in various forums to obtain insights and provide transparency on cross-border opportunities and challenges wherever possible. We continue to ensure the aims of NESO, and the wider industry, maximise the potential of GB interconnection and cross-border arrangements.

Engagement with the EU

With our expanded remit as NESO we have reinforced existing electricity relationships, as well as built relationships across new energy vectors. In support of UK Government, we have engaged with EU Commission's Director General on Energy to explain its new responsibilities.

We have continued to engage with EU TSOs with which we share an interconnector and fostered new bilateral EU TSO relations with others. We also joined the Renewables Grid Initiative – a forum of European TSOs and civil society organisations committed to the decarbonisation of grids across Europe.

In spite of positive engagement, the working arrangement framework for GB Transmission Owners to engage with ENTSO-E was only approved by the Specialised Committee on Energy in November 2024 and is in the process of being executed by relevant parties. The Trade and Cooperation (TCA) Working Arrangements Memorandum of Understanding allows joint EU/GB cooperation groups to be established. Prior to this approval, in the interim we initiated informal engagement between ENTSO-E and EU TSOs in key areas such as North Sea Cooperation (including Offshore and MPIs), interconnector ramping limits, operational harmonisation and interconnector flow control tools.

We have been active in supporting offshore collaboration in the North Sea as part of the Offshore Transmission System Operator Coordination (OTC) group and has actively supported DESNZ in its engagement with the North Sea Energy Community (NSEC).

We have established the UK TSO TCA Coordination Group which we also currently Chair. This group ensures there is a venue for all classes of UK TSO to agree single positions for the negotiation of TCA topics, including our participation in the Multi Region Loose Volume Coupling (MRLVC) working groups, with the EU. The group also allows collective TSO-wide EU horizon scanning to occur.

How did our approach maximise outcomes?

The development of the strategic approach to GB interconnection, stemming from the Future of Interconnectors project and followed by the case for change and subsequent prioritisation of key challenges to be solved, as described above, provided a clear focus on where improvements could be made including which were the highest priority and would have the most significant impact.

This has already resulted in improvements to the operation, planning and ambitions of GB interconnection and are visible in numerous areas across the industry. Two examples of this are:

i. We have been able to better align the interconnector assumptions in Strategic Energy Planning (SEP) workstreams with those of DESNZ and Ofgem to ensure any potential conflicts and contradictions are identified early and any changes incorporated as required. This was achieved by NESO clarifying the processes and aims of SEP workstreams with various DESNZ teams who are not directly involved in the SEP decisions and identified areas of misalignment both within and between the 3 organisations. The result is there will be fewer delays and complications later in the SEP deliverables.

ii. We also undertook an analysis to understand if and where there were gaps in the UK & EU's knowledge of how interconnector operations are managed in GB. This led to our recent interconnectors focus session at the Operational Transparency Forum (OTF) on 5th March 2025. This session focused on the operational tools we use on the GB interconnectors and gave a forum for industry participants to ask questions on these areas and clarify where interconnectors fit in the GB system balancing actions.

Industry Engagement

Given the impact of these improvements on wider industry parties, we have communicated these improvements openly and transparently wherever possible to ensure industry parties have a voice and are included throughout. This communication has taken place through specialised focused forums (e.g. AFRY's working group on the assessment of a GB Enhanced National market design and subsequent report), industry steering groups and forums (e.g. the Joint European Steering Group and the GB Interconnector Forum), NESO-led webinars on specific topics (e.g. Assessment of the different REMA dispatch options and the effects on cross-border arrangements) and bilateral clarification meetings with DESNZ, Ofgem, interconnector owners and operators, EU Transmission System Operators, EU Regulators, EU ministries, consultants and other industry parties as required.

More specifically regarding engagement with ENTSO-E, once it became apparent that the wider EU/ UK political landscape would not permit formal, wider re-engagement between ENTSO-E and NESO within BP2 timescales, we established regular, informal engagement with ENTSO-E's Intra-Synchronous Area working group. This allowed an open communication channel to ensure the exchange of information on topics such as system security, system operation and efficient cross-border market arrangements with EU Transmission System Owners
as one.

Overall, this has led to greatly improved relationships with GB and EU industry parties through increased levels of transparency, trust and engagement across all areas relating to interconnection and cross-border arrangements.

B.2 Delivery Schedule Status

Deliverable Progress

For Role 2, the BP2 Delivery Schedule received an ambition grading of 4/5, providing us 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 2 – 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 2 (Market development and transactions), the latest BP2 RIIO-2 deliverables tracker lists **47 deliverables** in total, which is made up of **133 milestones**.

- **All 133** of these milestones were due to be completed by March 2025 or earlier
- Of those:
  - **0** are delayed in order to deliver an improved outcome for consumers
  - **25** are delayed due to reasons outside NESO's control
- Of the remaining 108**:**
  - **104** (96%) are now complete
  - **4** (4%) are delayed due to NESO related delays

The results for the **133** milestones due to be completed by March 2025 or earlier are illustrated below:

Role 2 – Milestone status by deliverable

For milestones due by March 2025 or earlier

			Delayed...		
Ref	Deliverable name (shortened)	Complete	Consumer Benefits	External reasons	Internal reasons
D13.1	Published Future Energy Scenarios (FES), Winter Ou...	2			
D13.5.3	Enhance our energy modelling to reflect stakeholde...	1			
D15.8.1	Develop policy areas to accelerate whole electrici...	6			
D15.8.3	Enabling whole electricity system operational serv...	4			1
D20.1	Net Zero Market Reform programme	1			
D21.1	Cross-border strategy development	2			
D21.1.1	Strategic Engagement with EU	2			
D21.2.1	Continued facilitation of EU driven code changes i...	4			1
D21.2.2	Implementation of the TCA	3		3	
D21.2.3	Enhancing interconnector operations and access to ...	1			
D4.1	We manage an end-to-end process to ensure that bal...	1			
D4.1.1	Frequency management strategy	1		1	
D4.2.1	Regular and specific metrics and publications acro...	2			
D4.2.2	Regular and specific metrics, and publications for...	1			
D4.3.3	New reserve products - development and introductio...	1			1
D4.3.4	Delivering an efficient frequency market	1			
D4.3.5	Auction capability	1			
D4.3.6	Future developments to frequency response services	4			
D4.4.1	A market platform through which market participant...	5			
D4.4.2	Common standards, including interoperable systems,...	2		2	
D4.5.3	Reforming markets to facilitate future growth of D...	2			
D4.5.4	Facilitating market access for Distributed Flexibi...	2			
D4.5.5	Ensure co-ordination of markets across the whole e...	1		1	
D4.6.1	Development of competitive approaches to procureme...	2			
D4.6.2	Development of competitive approaches to procureme...	2			
D4.6.3	Maximise participation in ancillary services	1			
D4.6.4	Local Constraints Market reform	2			
D5.1.1	Continuation of Electricity Market Reform (EMR) De...	8			
D5.1.2	Continuation of EMR Delivery Body obligations:We ...	4			
D5.2	Deliver an enhanced platform for EMR	1			
D5.2	Developing the EMR platform	3			
D5.3	Use of enhanced modelling and more granular data s...	4			
D5.4	Building our long-term security of supply modellin...	3		1	
D6.1	Continued facilitation of industry changes to the ...	2			
D6.1.1	Enable major net zero programmes - Offshore Coordi...			1	
D6.1.2	Enable major net zero programmes - Onshore Competi...	1			
D6.1.3	Enable zero carbon operation - System Restoration	3			
D6.1.4	Enable zero carbon operation - Stability	1			
D6.1.5	Lead charging reform	2			
D6.1.6	Support Market Wide Half Hourly Settlement	1		1	
D6.3	Continued managing, collecting and disbursing char...	4			
D6.3.1	Market half-hourly settlement	2		5	
D6.3.2	TNUoS reform			8	
D6.4	Change from a code administrator to a code manager...			2	
D6.5	Develop a single technical code for distribution a...	2			
D6.7	Enhanced delivery of the recommendation from the B...	1			
D6.8	Implementation of digital solutions	1			1
D6.9	Whole electricity system framework assessment	4			
	TOTAL - Role 2	**104**	-	**25**	**4**

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 2. 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
Exploring the economic benefits of co-optimising procurement of energy, response and reserve	The project is looking at the potential benefits of co-optimising the procurement of energy and ancillary services like reserve and response. The benefits arise from removing the imperfect opportunity cost estimation under sequential procurement which leads to inefficient allocation of resources and higher prices.	The final qualitative report outlines the benefits of co-optimisation, its potential utility in the future GB regime, and highlights international comparisons and successes. The draft partner report provides the economic theory and design considerations for co-optimisation, focusing on bidding product design, locational considerations, and reserve scarcity pricing. Our work has assessed the potential cost savings and market improvements of co-optimisation, examining changes in a zonal versus national market. We plan to use these findings to engage with the industry on REMA options and inform future implementation studies in GB, with the report to be published in Q3 FY2025/26 alongside a study on central scheduling benefits.	D4.3.3	Complete	RIIO-2

Regional Dynamic Reserve Setting	This project will further the Dynamic Reserve Setting (DRS) work by building explainable, risk-based dynamic models for reserve that generate predictions at finer spatial resolutions. Using these models, we will have access to accurate, risk-based predictions of reserve requirements at different locations and can then make more informed decisions to maximise its usage and minimise costs.	Regional datasets and geographical information required for building the model have been identified and processed, with some data issues resolved using alternative sources. Currently, the delivery partner is working on feature selection for the regional model, with plans to start training and validating the initial model, with an interim report expected in Q1 FY2025/26.	D4.1.1	Delivery	RIIO-2
Impact of climate change on power systems	The project aims to identify the best available meteorological data to model power systems at a range of time horizons, from two weeks ahead through to 2035.	We have found limitations in the current datasets we use for weather and climate data. As a result, we recommend using alternative datasets that offer better insights into the probability of extreme weather events affecting energy supply. Our case studies show how using ensembles from decadal predictions can improve assessments of electricity and gas supply security. These case studies have also revealed additional areas for	D5.3	Delivery	RIIO-2

		further development. We will disseminate the findings at a stakeholder meeting and determine the steps required to incorporate the recommended changes into the NESO operational models in Q1 FY2025/26			
Market Signals for the Electrification of Heating	This project will look to understand how flexibility market signals can encourage electrification of heating, and the adoption of flexible heating practices from domestic consumers and their homes. This project aims to understand what market signals we should develop to encourage electrified heating, flexibility practices and understand where these sit in the wider context of market signals for domestic consumers.	The project has modelled various scenarios for electrified heating up to 2050, considering factors like heating technology mix, operational characteristics, housing variations, and key cost drivers. Electrified heating shows significant load growth, and small changes in modelling assumptions can lead to substantial shifts in system costs. Despite limited real-world data and uncertainty about future heating mixes and load profiles, unlocking flexibility in electrified heating will result in considerable system savings across all scenarios. The final phase of the project will present recommendations to NESO, regulators, policymakers, and the wider industry to accelerate the flexibility of electrified heating.	D4.5.5	Delivery	RIIO-2
Quantitative assessment	This project will provide a	The project has finished the main	D5.1.1	Delivery	RIIO-2

of self and central scheduling	qualitative overview of different scheduling approaches and quantitatively estimate the impact of self vs central scheduling under national and zonal pricing. The project will also test whether improvements to the balancing mechanism or strengthening balancing incentives market participants face may impact the case to move to central scheduling.	tasks for assessing self-dispatch versus central dispatch under national and zonal designs. We are now conducting sensitivity analyses, which we expect to complete shortly. The final report will be published by the end of 2025, along with another Innovation project on the benefits of co-optimisation.			
Compatibility assessment of dispatch options with GB cross-border markets	This project aims to qualitatively evaluate the impact of potential reforms in scheduling and dispatch and wholesale market locational granularity on GB cross-border market arrangements both from the perspective of current cross-border arrangements and what could be implemented in the future.	The project began in August 2024 and completed in January 2025. The partner provided a comprehensive qualitative assessment of all market design options and their implications for cross-border market arrangements. This report included comparisons between different market design options and process diagrams to aid understanding. The results are part of our assessment of various dispatch options for DESNZ's second phase of the Review of Electricity	D5.1.1	Complete	RIIO-2

		Market Arrangements (REMA).			
CrowdFlex (SIF)	CrowdFlex is a multi-year SIF project designed to realise the potential that domestic flexibility can play in addressing decarbonisation by modelling how domestic flexibility can be used in network operations, improving coordination across the network and reducing stress on the system.	The CrowdFlex project has successfully completed its summer 2024 large-scale consumer trials, and the winter 24/25 trials are underway and will complete by the end of April 2025. Electricity customers are being incentivised to use energy flexibly and data from the trials is being gathered to build models of domestic flexibility. Customer surveys took place after the summer trials and midway through the winter trials with 3,600 and 10,800 customers taking part respectively. Trial data is being analysed and is starting to reveal some interesting learnings about consumer behaviour and a better understanding of how to best use domestic flexibility for grid operations.	N/A	Delivery	RIIO-2

B.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 **1869** stakeholders.

Role 2

For Role 2, the following question was asked:

> *'Considering Market Development and Transactions, which includes key activities such as Market Design, Balancing Services, Electricity Market Reform (EMR) and Industry Codes and Charging. 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.

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

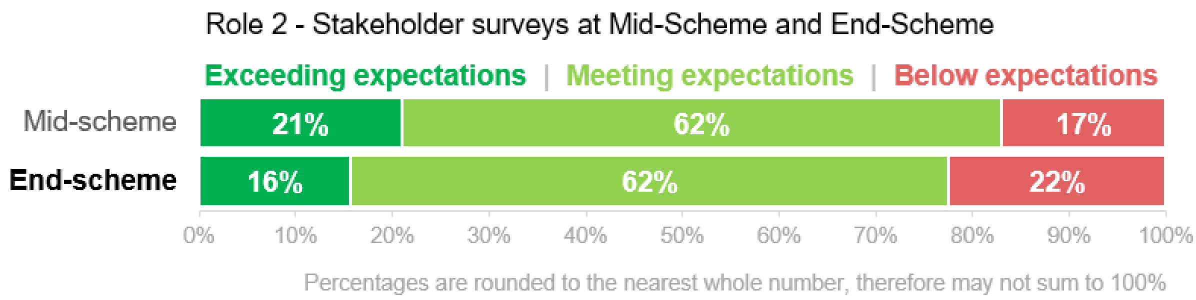
ii. If they rated NESO as meeting expectations, they were asked what NESO needed to do to exceed their expectations.

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

For Role 2, we contacted **534** stakeholders, and received **89** responses to this question, which were distributed as follows:

- **16%** exceeding expectations
- **62%** meeting expectations
- **22%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 2
"Exceeding Expectations" **14** stakeholders scored us as "exceeding expectations". Feedback on what we have done to exceed stakeholder expectations in Role 2 included:	• **Positive stakeholder interactions with staff** – Several responders spoke warmly about the interactions they had with Role 2 staff, and the communications our teams provided. The Codes team are highlighted as "helpful and efficient, despite their high workload". Another responder praised the "competent staff who are great to deal with". • **Effective management of change** – A couple of responders commented we have effectively managed change in the sector. • **Other positives highlighted in the responses included:** - Completion of Voltage 2026 tender and other ancillary service tenders. - Active development and transparency of the whole process and status of each market. - Overhaul of Electricity Market Reform (EMR) Capacity Market portal. - Provision of reminders ahead of delivery of changes and offer deep dive sessions. Also, very open to feedback. - Continuously putting in new revenue streams such as batteries.
"Meeting Expectations" **55** stakeholders scored us as "meeting expectations". Feedback on what we need to do to exceed stakeholder expectations in Role 2 included:	• **Improve engagement with stakeholders** – Several responders said they would like to see improved stakeholder engagement. We should share more information on changes, including providing information sooner. Another indicated they would like more proactive engagement from NESO. One expressed "frustration at having to wait

	long periods of time for NESO colleagues to respond on time critical queries". • **Go further in performance monitoring** – Stakeholders raised concerns about the performance monitoring of new reserve and response services. One response stated, "Issues lack of clear guidance, and inadequate enforcement of penalties". Another stakeholder suggested we need better monitoring of service performance across all developed services. • **Faster and more efficient delivery** – A number of responses highlight delays and the speed of our delivery. For example, one stated "NESO sometimes delays sending data". Others reference delays to projects, delays to Code Modifications and one states we "need to progress more, more quickly." • **Other feedback suggested we:** - Need to build experience and knowledge of the team. - Take action to address reserve services which have "been rocky". - Ensure our systems can deal with granularity of data required. - Should seek improvements to Single Markets Platform (SMP) as it is "very particular to work with". - Should develop frameworks to improve conflict management of transmission and distribution services, and establish primacy rules to enable participation from various providers. - Consider capabilities of existing conventional assets before launching services only.
"Below Expectations" **20** stakeholders scored us as "below expectations". In response to being asked what we need to do to meet their expectation, we received the following feedback:	• **Make faster progress on market reform** - A number of stakeholders indicated they feel we need to go further on market reform. Comments include "Market Reform is slow and the process just isn't working", "Connection applications in the queue aren't being processed", "everything feels at a standstill and not progressing" and "the approach has been pretty long winded". • **Improve communications and engagement with stakeholders** – Stakeholder responses highlighted

	the need for quicker communication and issue resolution, better customer listening, faster provision of information, and simpler, user-friendly guidance. Points of concern include difficulties caused by multiple use of communication channels, the lack of a centralised location for planned changes, and delays, errors, and the need for us to share information on missed deadlines as soon as possible. • **Adjust the Code Modifications process** - Several responders have commented on how we process code modifications. For example, one suggested we should do more to progress industry code modifications, and not just the ones NESO want. Another highlighted they feel the Code Modification Process feels "very biased and merely to rubber stamp what is already Ofgem's view. (see CMP 444, and CMP 434)." • **Other feedback suggested we:** - Need to do more to show independence from Ofgem / Government. - Place too much emphasis on nodal / regional pricing. - Provide greater transparency needed on balancing services - Need to reduce errors in settlement on balancing services.

Capacity Market and Contracts for Difference Survey

Under the NESO Performance Arrangements, we are required to carry out and report on Customer and Stakeholder Satisfaction Surveys at least once in every Regulatory Year to assess Customer and Stakeholder Satisfaction with our Capacity Market (CM) and Contracts for Difference (CfD) activities.

Our Contracts for Difference Allocation Round 6 (AR6) Customer Satisfaction Survey Results were published here in December 2024, with an overall satisfaction score of 8.4/10 for AR6.

Our Capacity Market Customer Satisfaction Survey Results were published here in April 2025, with an overall satisfaction score of 8.3/10.

Please see the reports for full details of the questions asked, the results and the actions we will take to build on the responses.

B.4 Metric Performance

Table: Summary of metrics for Role 2

Metric			Full year 2023-24			Full year 2024-25			BP2
			Benchmark	Actual	Status	Benchmark	Actual	Status	Status
2Ai	Phase-out of non-competitive balancing services	FR & Reserve	25%	22%	●	20%	17%	●	●
		Reactive	90%	97%	●	90%	96%	●	●
		Constraints	65%	62%	●	55%	9%	●	●
2X	Day-ahead Procurement		55%	68%	●	80%	82%	●	●

Below expectations ● Meeting expectations ● Exceeding expectations ●

Metric 2Ai Phase-out of non-competitive balancing services

This metric measures the percentage of services procured by NESO that are procured on a non-competitive basis. For the purpose of this metric, we consider a 'non-competitive' service to be either a bilateral contract or a service with significant barriers to entry. It excludes SO-SO trades, which are trades made between system operators of connected countries. These are used to determine the direction of electricity flow over interconnectors. The volumes reported in this metric are those delivered within the time period.

There are benchmarks for the following categories: Frequency Response (FR) and Reserve, Reactive Power, and Constraints.
Benchmarks are set based on NESO's current and projected procurement for each of these services:

Category	Benchmark	Assumptions applied in BP2 benchmark
FR and Reserve	Year 1: 25% Year 2: 20%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the benchmark • Reserve will continue to be procured competitively until the implementation of new reserve services
Reactive power	Year 1: 90% Year 2: 90%	• Historical data was analysed from the previous reporting period (BP1) and no uplift applied for the benchmark • Understanding of opportunities for competitive procurement of Reactive Power have been further developed through 2024 as part of the development of the Reactive Power Market. • There will continue to be specific regional requirements, and these will be procured through market mechanisms where feasible.
Constraints	Year 1: 65% Year 2: 55%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the benchmark • B6 Commercial Intertrip service was the first Constraint service to be delivered competitively. More will be delivered through market mechanisms in BP2, such as Constraint Management Intertrip Service (EC5 CMIS) and Local Constraint Market (LCM).

The non-competitive percentage is calculated on a volume basis, which is measured in MWs, with the exception of Reactive Power which is measured in MVAr.

These expectations are set for the current suite of products and may be revised if new products are introduced.

Category	Services procured competitively	Services procured non-competitively
Frequency Response	• Static FFR (Firm Frequency Response) • Dynamic Containment Low and High • Dynamic Moderation Low and High • Dynamic Regulation Low and High	• Mandatory Frequency Response (Primary, Secondary and High) • Fast Start
Reserve	• Day-Ahead STOR (Short Term Operating Reserve) • Balancing Reserve • Quick Reserve BM only Phase 1	• Long Term STOR (ended April 2025) • Optional Fast Reserve • Super SEL (Stable Export Limit) (Footroom)
Reactive Power	• Mersey Reactive Power Pathfinder • Pennines Pathfinder • Stability Pathfinder • Mid-term Stability Market • Voltage 2026 contracts (Contract award Sept/Oct 2024)	• Reactive • Mandatory Reactive Lead & Lag • Stability Reactive Lead & Lag • Reactive Sync Comp, Comp Lead and Comp Lag
Constraints	• B6 & EC5 Constraint Management Intertrip Service	• Strike Price

Overall performance – All services

H2 2024-25 performance

Figure: Percentage of volume procured non-competitively vs benchmark

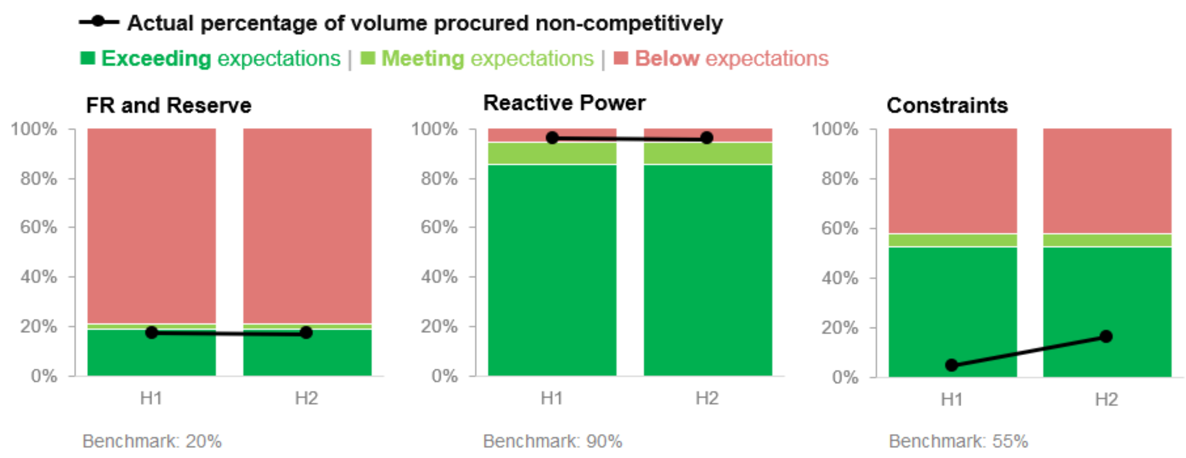
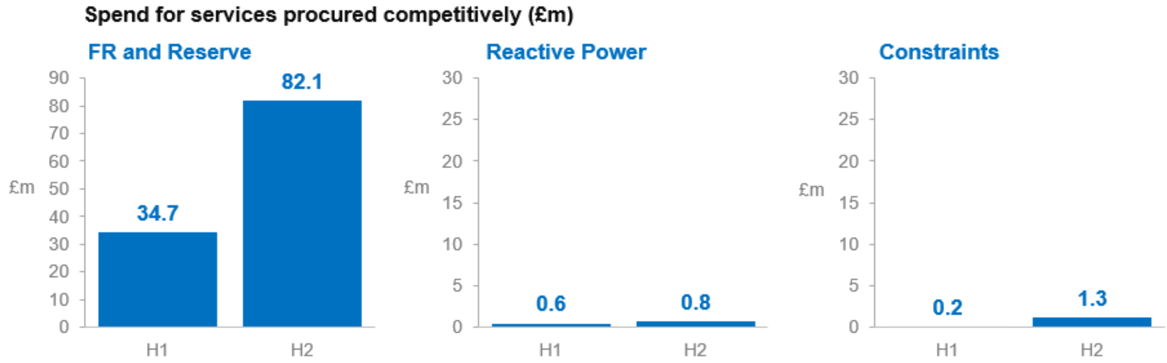


Figure: Six-Monthly competitive spend by service



SO-SO trades made during H2

Historically SO-SO Trades were available to us across the IFA & IFA2, Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, and so we can no longer use this service. EWIC, Greenlink & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. We do not trade via third Parties and therefore only have access to CBB. SO-SO trades are also available with Energinet via the Viking Link Interconnector.

Trades for H1 total £0m consisting of 0 trades on 0 interconnectors.

Trades for H2 total £0.62m consisting of 6 trades on 3 interconnectors.

1. Frequency Response and Reserve

H2 2024-25 performance

Table: Frequency Response and Reserve percentage of services procured on a non-competitive basis, and spend.

Frequency Response & Reserve		Unit	H1	H2	Full Year
Volume	Total volume procured	GWh	33,899	34,232	68,131
	Volume procured non-competitively	GWh	5,995	5,917	11,912
	Percentage of volume procured non-competitively	%	18%	17%	17%
	Year 2 benchmark	%	**20%**	**20%**	**20%**

	Status	n/a	●	●	●
Spend	Total spend	£m	81.4	126.5	207.9
	Spend for volume procured competitively	£m	34.7	82.1	116.8
	Spend for volume procured non-competitively	£m	46.7	44.4	91.1

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 is 20%

Supporting information

For the Full year, 17% of Frequency Response and Reserve volume was procured non-competitively, which is within 5% of the benchmark of 20%, and therefore exceeding expectations.

With the growth in response and reserve competitive markets, including the launch of Balancing Reserve in March 2024, followed by Quick Reserve Phase1 in December 2024, we are able to procure more of our requirements at day-ahead so have less reliance on non-day-ahead procured services. As more reserve services are introduced to day-ahead procurement we expect to see further reductions in the Frequency Response and Reserve volumes that are procured non-competitively. For Long Term STOR, we were committed to the legacy ~ 400MW volume of contracts which expired in April 2025. This volume has now been replaced by volumes procured at day-ahead through our day-ahead reserve products.

2. Reactive Power

H2 2024-25 performance

Table: Reactive Power percentage of services procured on a non-competitive basis and spend.

Reactive Power		Unit	H1	H2	Full Year
Volume	Total volume procured	GVARh	28,883	26,862	55,745
	Volume procured non-competitively	GVARh	27,829	25,814	53,643
	Percentage of volume procured non-competitively	%	**96%**	**96%**	**96%**
	Year 2 benchmark	%	**90%**	**90%**	**90%**
	Status	n/a	●	●	●
Spend*	Total spend	£m	112.9	120.6	233.6
	Spend for volume procured competitively	£m	0.6	0.8	1.4
	Spend for volume procured non-competitively	£m	112.4	119.8	232.2

*Rounding: Spend figures in £m are rounded to the nearest 1 decimal place, therefore Total spend may differ slightly from the sum of competitive and non-competitive spend.

Performance benchmarks:
- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 remains at 90%

Supporting information

For the full year, 96% of Reactive Power volume was procured non-competitively, which is more than 5% higher than the benchmark of 90% and therefore below expectations. The benchmark was established late in the BP1 period, on the expectation that by BP2 we would have a Reactive Market in place.

The Reactive Power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the Balancing Mechanism (BM).

The long-term Mersey Pathfinder awarded two contracts to meet a need in this region: the Peak Gen shunt reactor service went live in Q1 2022-23 and the Zenobe Battery live in Q4 2022-23. In January 2022 we also awarded contracts to meet reactive needs in the Pennines region. Three NGET reactors were commissioned in Summer 2024 and already delivering consumer value, with the remaining service online in 2026 which will decrease the percentage of reactive power services procured and utilised through non-competitive means.

In October 2023 we launched a third long-term pathfinder style tender "Voltage 2026" to award further contracts to meet reactive power absorption requirements in London and Northern England. We have awarded four contracts to deliver services for 10 years, with the first service due to deliver the end of 2025, with the remaining services from 2026

Furthermore, in March 2025 we launched the Long-term 2029 tender for Network Services, initiating the procurement process for stability, reactive power and restoration services from 2029. An expression of interest was launched on 24 March and further promoted in the Operational Transparency Forum. This also marks the first time we have simultaneously launched a Y-4 tender for both stability and reactive power but also took the opportunity to co-procure restoration services.

A Reactive power market is being established based on the initial market design recommendation from the NIA "Future of Reactive Power" project in 2022. We completed our work on the design of the long-term reactive power market and the Long-term 2029 tender was launched. Implementing the long-term market will drive locational investment and enable greater competition in the delivery of reactive power service provision.

We have now completed our work with industry, which included a webinar and voluntary Request for Information (RFI) and are recommending implementation of the mid-term Reactive Power Market. As our system studies identify future needs for locational voltage services across GB, we will continue to develop our approach for how best to meet these requirements. Once a requirement for mid-term procurement is identified, further information will be provided to industry. Work on the short-term reactive power market is on hold pending the outcome of the ORPS review.

3. Constraints

H2 2024-25 performance

Table: Constraints percentage of services procured on a non-competitive basis and spend.

Constraints		Unit	H1	H2	Full Year
Volume	Total volume procured	GWh	22	139	161
	Volume procured non-competitively	GWh	1	22	23
	Percentage of volume procured non-competitively	%	2%	15%	9%
	Year 2 benchmark	%	**55%**	**55%**	**55%**
	Status	n/a	●	●	●
Spend	Total spend	£m	0.17	4.61	4.78
	Spend for volume procured competitively	£m	0.16	1.31	1.47
	Spend for volume procured non-competitively	£m	0.02	3.30	3.32

Performance benchmarks:

- ● **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- ● **Meeting expectations:** within ±5% of the annual procurement benchmark
- ● **Below expectations:** 5 or more higher than the annual procurement benchmark

The benchmark for Year 2 is 55%

Supporting information

During H2 the Intertrip service had high utilisation with arming instructions for the EC5 boundary and the B6 boundary, due to network conditions in these areas, such as high wind through this period of H2.

A Strike Price contract was procured in H2 (contract started 11 October 2024 until 28 November 2024 and subsequently extended to 12 December 2024), where it was identified that there was a need to manage forecast constraint costs and volumes, arising from asset health, planned outages and forecast system conditions. This was a zonal requirement in the East Anglia/North London area and a specific service provider was identified during network studies.

Metric 2X Day-ahead procurement

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

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

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

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

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

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

Non-day-ahead: Mandatory Frequency Response, Long Term STOR

Services newly introduced during BP2 should only be included in this metric if they displace those procured earlier than day-ahead.

Q4 2024-25 performance

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

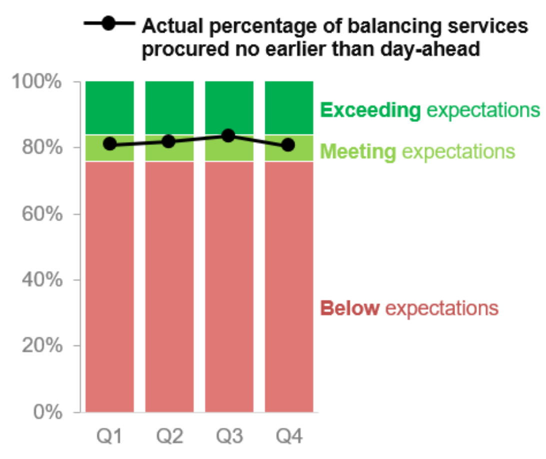


Table: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4	Full Year
Volume of balancing services procured (average per procurement period)	MW	3996	4081	4433	4762	17273
Volume procured no earlier than day-ahead	MW	3231	3341	3705	3831	14108
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	81%	82%	84%	80%	82%
Benchmark	%	80%	80%	80%	80%	80%
Status	n/a	●	●	●	●	●

Performance benchmarks:

● **Exceeding expectations:** 5% or more higher than annual day-ahead procurement benchmark
● **Meeting expectations:** within ±5% of the annual day-ahead procurement benchmark
● **Below expectations:** 5% or more lower than the annual day-ahead procurement benchmark

Please note, we have made a small correction to the calculation used previously on this metric. This does not have a material impact on the figures. The overall figure for 2024-25 changes from 81.3% to 81.7%. None of the RAGS change for any of the quarters in 2023-24 or 2024-25.

Supporting information

For the full year, 81.7% of balancing services volume was procured no earlier than day-ahead, slightly above the benchmark of 80%, and meeting expectations.

The increase in MWs procured over the final period is in line with the winter period where requirement is slightly higher.

Balancing reserve was launched earlier in the year and is beginning to mature into a fully established reserve service. BM Quick Reserve service went live in December which created a co-opted auction with response services, whilst the market familiarises with co-opted auction this may have initially impacted the MW volumes procured across these services.

The launch of Non BM Quick reserve and Slow reserve services in 2025 should result in a percentage increase going forward.

The overall STOR MW requirement has remained static, with several Longterm assets entering the day ahead service supplementing the overall requirement.

B.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 our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 2 are:

- Build the future balancing service and wholesale markets (A4)
- Transform access to the Capacity Market (CM) (A5)
- Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025 (A6.5), Digitalisation of Codes (A6.8)
- Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges (A6.6) and Fixed BSUoS tariff setting (A6.7)

In this section, we provide a progress update for each of the activities for which we originally provided a CBA, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence (RRE), 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 2021 nor progress made towards yet to be completed milestones.

We also provide a specific case study on **DFS**, which was not covered by the original CBA document.

The Panel will also consider NESO's RREs as part of the Quality of Outputs criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the NESO PAGD guidance. For Role 2, the items of RRE reported at mid-year are:

- 2Aii. Balancing services procured in a non-competitive manner
- 2D. EMR Demand Forecasting Accuracy
- 2E. Accuracy of Forecasts for Charge Setting (TNUoS)
- 2E. Accuracy of Forecasts for Charge Setting – BSUoS

CBA: Build the future balancing service markets (A4)

BP2 Latest view of gross benefits compared to BP2

We now estimate gross benefits of £330m over the RIIO-2 period, which is an increase of £231m compared to the BP2 figure of £99m.

		Estimated gross benefits during the 2021-26 RIIO-2 period (£m)		
Area		**BP2 Plan view**	**Latest forecast view**	**Variance**
1.	More liquid response and reserve market	72	259	**+187**
2.	Buying the optimal volume of response	27	70	**+43**
Total		**99**	**330**	**+231**

The original BP2 benefits figures for this CBA were created based on high level assumptions. Therefore for this end-scheme view, we have taken a new approach based on the calculated benefit of a number of individual market changes we have made.

The updated calculation shows higher benefits than estimated at BP2, due to the benefits realised from the transition to the Enduring Auction Capability (EAC) platform. This has features such as co-optimisation of auction products, splitting of bids across multiple products and negative price clearing. The combination of these with an increase in market liquidity and bringing more products into the co-optimisation has greatly reduced the cost of procuring balancing services.

Summary of progress in 2024-25

We have made a number of beneficial changes to our reserve and response markets so far under RIIO-2. We have transitioned to a new set of frequency response and reserve products that we are able to procure at a day-ahead stage which will provide high quality grid stability into the future.

During 2024, we continued to see benefits from the EAC platform and its use in the day-ahead procurement of frequency response and reserve. There has been a steady increase in auction participation which allowed for increases in requirements for all dynamic services without a marked increase in the clearing prices in these markets.

We also launched two new reserve services: Balancing Reserve (BR) and Quick Reserve (QR) phase 1. As with our new frequency response products, these will serve as our primary way of procuring reserve services.

Balancing Reserve was launched in March 2024 on to the EAC auction platform as a singular auction that is run ahead of the day-ahead wholesale energy market. This brings benefit to NESO and consumers as reserve is held less in long-term contracts and can be competitively tendered. The timing of the auction which runs before the wholesale electricity market also means that we can choose to buy reserve capacity ahead of real-time which can reduce exposure to high prices during times of stress.

The auction is run for both a positive (PBR) and negative (NBR) product, however we do not currently value negative Balancing Reserve and is not actively being procured.

Quick Reserve phase 1 was launched onto the EAC platform in December 2024 and is included in the same auction as the response product suite. This has allowed the co-optimisation algorithm to optimise across more products and between reserve and response providers. Quick Reserve is a faster acting service than Balancing Reserve and it intended to be a replacement for optional fast reserve (OFR) and spin-gen and spin-pump. It is also procured in both positive (PQR) and negative (NQR) products. Quick Reserve phase 2 which will allow additional benefits with the inclusion of non-Balancing Mechanism units to participate, will go live in June 2025.

Combined status by milestone for relevant deliverables (Activity A4)

Status	**Count**	**%**
Complete	**31**	86%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**4**	11%
Delayed - Internal Reasons	**1**	3%
Total	**36**	**100%**

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

Supporting evidence

Type	Measure	Rationale and status
Qualitative evidence	-	The expansion and development of the new Frequency Response and Reserve product suites has enabled us to secure larger loss volumes than it ever has previously. In March 2024, a trip of ~2GW on the electricity system was managed to well within operational limits because of the response provided from the response product suite. Since its inception, the EAC platform continues to attract good participation. The increased liquidity has meant that we have increased the baseline target requirements for all dynamic services and have secured a record high of 1643 MW for Dynamic Containment High. The new services suite is also allowing us to develop towards a system capable of running in lower-carbon, lower-inertia conditions. The minimum inertia level at which the grid will run has been lowered from 140 GVA.s to 120 GVA.s. This reflects increased confidence in the new products and their ability to be procured through the EAC platform.
Metric	2X Percentage of balancing services procured at no earlier than day-ahead	2024-25 view: Meeting expectations with 82% of balancing services procured at no earlier than day-ahead, compared to the benchmark of 80%. Procuring closer to real time enables providers a better view over the markets and alternative revenue streams, and they are not locked into month-long contracts. This also allows us to buy more optimal volumes of response and reserve due to more accurate forecasts.

Metric	2Ai Phase-out of non-competitive balancing services	Latest view: • Frequency Response and Reserve are exceeding expectations (17% procured non-competitively vs benchmark of 20%) • Reactive Power is below expectations (90% procured non-competitively vs benchmark of 90%) • Constraints is exceeding expectations (9% procured non-competitively vs benchmark of 55%) The greater volume of reserve and response that are exposed to competitive markets should enable NESO to fulfil more of our system security obligations at a lower price.

Detail: Calculation of monetary benefit

The original BP2 benefits figures for this CBA were created based on high level assumptions. For the Latest view we have taken a new approach based on the calculated benefit of a number of individual market changes we have made.

For details of the original BP2 assumptions, please see our CBA A4 update from the BP2 Mid Scheme Report 2023-24 Evidence Chapters pp126-129.

1. More liquid response and reserve market

Latest approach

Assumptions	Latest forecast view
(a) Volume-weighted cost of buying response on the EAC platform compared to the previous EPEX platform	The benefit calculation compares the weighted volume cost of procuring frequency response services in the following two periods: • The last year before the move to the EAC platform (November 2022 – November 2023) • The first year after the move to the EAC platform (November 2023 – November 2024) This benefit was calculated to be £67.0m / year for 2 years and 5 months, giving a total of £161.9m.
(b) Volume-weighted cost of buying Balancing Reserve	The benefit calculation assesses any savings that have arrived compared to regulating reserve for the creation of reserve capacity as well as the savings in utilisation of reserve units. The analysis covers the period from March 2024 to October 2024

	(7.5 months) and annual savings are derived and extrapolated from this: • Savings in creation of capacity: £9.8m • Losses from utilisation payments: £0.3m This benefit in total was calculated to be £15.2m / year for 2 years and 0.5 months (£31m)
(c) Volume-weighted cost of buying Quick Reserve compared to Optional Fast Reserve and Hydro Spin-Gen	The benefit calculation assesses the cost benefit from introducing Quick Reserve into the co-optimised auction with the dynamic services for BM participants only against contracting Optional Fast Reserve and Spin-Gen and Spin-Pump. It includes the associated increased costs arising in the other co-optimised markets. The analysis includes a four-scenario approach, using NESO requirements and bidding price behaviour to give a range of benefit outcomes. The value quoted here is for the lowest benefit outcome. This was calculated at £49.9m / year for 1 year and 4 months (£66.5m)
Calculation	£161.9m (a) + £31.0m (b) + £66.5m (c)
Gross benefits	£259.5m

2. Buying the optimal volume of response

Latest approach

Assumptions	**Latest forecast view** - no change from Mid-Scheme view
(x) Volume weighted cost of procuring static FFR in a day-ahead auction compared to the month-ahead auction	Benefit based on a comparison of the volume-weighted cost of procuring static FFR at a day-ahead basis in the following time periods: • The 12 months before the service began being procured (April 2022 – March 2023) • The first 12 months in which the service was procured (April 2023 – March 2024) This was calculated to be £5.2m (£1.3 million/year for four years).
(y) Volume weighted cost of	Benefit based on the decrease in costs (volume weighted) of procuring Dynamic Containment Low

procuring post-fault frequency response as dynamic containment	in the period November 2021 to October 2022 and November 2022 to October 2023. This was calculated to be £49.9m (£12.5m for four years).
(z) Volume weighted cost of procuring pre-fault frequency response as dynamic regulation and moderation compared to legacy products	Benefit based on comparison of procuring pre-fault frequency response through legacy Dynamic Firm Frequency Response service (dFFR) and through Dynamic Moderation and Dynamic Regulation. Comparison is based on the final 10 month period immediately prior to dFFR being phased out (January 2023 to October 2023). The benefit was calculated to be £15m (£5 million/year for three years).
Gross benefit	£70.1m
Calculation	£5.2m (x) + £49.9m (y) + £15m (z)

CBA: Transform access to the Capacity Market and Contracts for Difference (A5)

BP2 End-Scheme view of gross benefits compared to BP2

We now estimate gross benefits of £257.2m over the RIIO-2 period, which is an increase of £182.5m compared to the BP2 figure of £74.7m.

	Estimated gross benefits during the 2021-26 RIIO-2 period (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
1. Enhanced Modelling Capability	68.2	251.3	+183.1
2. Reduced Barriers to Entry and Cost of Participation	6.5	5.9	-0.6
Total	**74.7**	**257.2**	**182.5**

*Figures are rounded to the nearest £0.1m, therefore small differences may arise in totals.

For Enhanced Modelling Capability, the only assumption that has changed since BP2 is the clearing price, which has been updated with actuals for 2022-23, 2023-24 and 2024-25 and a new forecast for 2025-26. This has increased the benefit by £257.2m.

For Reduced Barriers to Entry and Cost of Participation, the benefit has reduced from £6.5m to £5.9m to reflect the Capacity Market Portal go-live being delayed until Q1 2024-25.

Summary of progress in 2024-25

1. Enhanced Modelling Capability

We have met all of the milestones for enhanced modelling capability in this period. This includes delivery of the annual Electricity Capacity Report to DESNZ and a set of development projects that seek to improve the modelling. Development projects have been completed in line with a well-established joint-prioritisation process involving DESNZ and Ofgem. Details of the development projects are reported each year in the Electricity Capacity Report. This year's projects included changes to de-rating factors for limited duration storage to better reflect their contribution to security of supply. These changes were implemented following industry consultation in spring 2024. The development projects have sought to enhance our modelling capability such that it remains robust for a changing energy system. This enhanced capability has underpinned our recommendations on the required capacity to secure – recommendations that have continued to withstand scrutiny from DESNZ' Panel of Technical Experts and be accepted by DESNZ.

For more detail please see our activity update for EMR here.

2. Reduced Barriers to Entry and Cost of Participation

The Capacity Market Portal is the key enabler for both NESO and the Capacity Market participants to comply with the Capacity Market Rules and Regulations. The new system is expected to deliver efficiency for all parties involved through its more user-friendly, agile and modernised functionalities and design logics.

We achieved delivery of all the milestones against the new baselined delivery plan in 2024/25 supported by the industry and Ofgem, which included implementation of the Capacity Market Portal in June 2024. As such the benefits are expected to deliver from 2024-25 onwards with about £3m per annum.

Combined status by milestone for relevant deliverables (Activity A5)

Status	Count	%
Complete	**23**	96%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**1**	4%
Delayed - Internal Reasons	**-**	-
Total	**24**	**100%**

Note that although the one delayed milestone, ‘Production of capacity adequacy study’, is part of Activity A5, it does not inform this CBA.

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

Supporting evidence

1. Enhanced Modelling Capability

Type	Measure	Rationale and status
Qualitative evidence	n/a	The enhanced modelling capability has underpinned our recommendations on the required capacity to secure through the Capacity Market. Our recommendations have withstood scrutiny from DESNZ’ Panel of Technical Experts (PTE), who have supported our recommendations that were accepted by DESNZ. The PTE have reported on our “open

		and constructive process of engagement"[1] and have found no conflict of interest concern[2] in us producing our recommendations.
RRE	RRE 2D Demand Forecasting Accuracy	Delivery year 2024-25: Absolute percentage error of 5.6% for T-1 (below expectations), and 2.9% for T-4 (exceeding expectations).

2. Reduced Barriers to Entry and Cost of Participation

Type	Measure	Rationale and status
Qualitative evidence	Customer Satisfaction Survey	Following the implementation of the Capacity Market (CM) Portal and the first operational round of Prequalification Applications, a customer satisfaction survey was run to validate the expected efficiency delivered for participants and gain insights on their overall experience. The results are available on the Delivery Body website here however, the overall results summary are: • Survey completed by 36 customers representing 32 separate organisations • Responders represented approximately 50% of active CM agreement capacity. • Responders rated the median performance of the new CM portal as a score of 8 out of 10. • Responders rated the median performance of the new dedicated

[1] Panel of Technical Experts: Report on the National Grid ESO Electricity Capacity Report 2023 (publishing.service.gov.uk) paragraph 12

[2] Panel of Technical Experts: Report on the National Grid ESO Electricity Capacity Report 2023 (publishing.service.gov.uk) paragraph 23

		knowledge site integrated with the CM Portal as a score of 8 out of 10. • Responders rated the median performance of their overall experience satisfaction in using the CM portal as a score of 7.5 out of 10. Responders provided their overall feedback on areas of positive experience, as well as areas recommended for improvements. The Delivery Body is acting on the recommended areas for improvement, with support from our dedicated customer user group to prioritise areas to drive further improved customer experience.

Detail: Calculation of monetary benefit

1. Enhanced Modelling Capability

Assumptions	BP2 Plan view	Latest forecast view
(a) Clearing price of the Capacity Market	£17.045/kW per year based on the average of six T-4 auctions held to date.	2022-23: £63.5/kW (Actual) 2023-24: £65.0/kW (Actual) 2024-25: £60.0/kW (Actual) 2025-26: £62.8/kW per year (Average of the last 3 years)
(b) Annual consumer savings as a result of our actions.	The equivalent of purchasing an additional 1 GW of capacity.	No change to high level assumption
(c) Number of years of benefits during RIIO-2	Benefits delivered from year two of RIIO-2, therefore four years of benefit. This allows a year for implementation of this activity, given auction timings, when improved analysis will feed into recommendations to procure capacity.	Modelling improvements delivered in year one of BP2, therefore four years of benefit still applies.

Calculation	= 17.045 (a) x 1,000,000 (b) x 4 (c)	= (63.5 + 65.0 + 60.0 + 62.8) (a) x 1,000,000 (b)
Gross benefits	£68.2m	£251.3m

2. Reduced Barriers to Entry and Cost of Participation

Assumptions	**BP2 Plan view**	**Latest forecast view**
(a) Number of companies on CM register	1,122. The approximate number of companies registered on the Capacity Market Portal.	There are 2,327 registered companies in the Capacity Market Portal, including companies migrated from the legacy portal to retain historical data e.g. previous unsubmitted applications or expired agreements
(b) Percentage of registered companies that interact with the Capacity Market	50%. We have assumed that around 50% of registered companies are active at either T1 or T4 auctions, based on historical observations.	The new Capacity Market Portal offers better data analytics on system usage. We are reflecting on the analysis in updating this metric to reflect the actual profile of active companies, instead of using an estimated percentage. This provides a more accurate basis for benefit calculation. The data shows that 770 registered companies have participated in the CM since the portal launched in June 2024. Of these, 474 engaged in the Prequalification process, 296 managed live agreement obligations, and 740 were involved in both Prequalification and obligation management.
(c) Number of weeks of FTE weeks of time that	2 FTE weeks. We have assumed that Capacity Market	No change

our actions save for each Capacity Market company	companies' FTE requirements mirror our own	
(d) Cost of one FTE week	£1,923. Based on one FTE at £100,000 divided by 52.	No change
(e) Number of years of benefits during RIIO-2	Benefits delivered from year three of RIIO-2, therefore three years of benefit. This allows a year for implementation of the activity, given auction timings.	Reduced from three years' benefit to two, to reflect the delayed go live of the Capacity Market Portal, with full functional go-live in Q1 2024-25.
Calculation	= 1,122 (a) x 50% (b) x 2 (c) x £1.923 (d) x 3 (e)	=770(b) x 2(c) x 1,923(d) x 2 (e) Note that as explained above, we now know the number of companies interacting with the Capacity Market, therefore the calculation is updated so that (a) is removed, and (b) becomes the actual number of companies interacting, rather than a percentage estimate.
Gross benefits	£6.5m	£5.9m

CBA: Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025 (A6.5), Digitalisation of Codes (A6.8)

BP2 End-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £40 million over RIIO-2. For this 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 A6.5 and A6.8 will deliver.

		Estimated gross benefits during the 2021-26 RIIO-2 period (£m)	
Area		**BP2 Plan view**	**Latest view**
A6.5	Reducing Barriers to Entry through Digitalising the Grid Code	40	We have provided a written update for end-scheme. The current view is still consistent with the original high level assumptions.
A6.8	Digitalisation of codes*	0	
Total		**40**	

For background on this CBA please see our previous update BP2 Mid Scheme Report 2023-24 Evidence Chapters page 133.

There has not been a budget agreed for BP3 for Digitalisation of codes, we are however working through the remainder of the budget from BP2 with a possible sanction request for additional budget. This is to continue with the workflow digital process.

Summary of progress in 2024-25

The Digitalisation process for the minimum viable project phase went live in April 2024 and can be viewed here. The digital platform allows for a simpler search functionality, detailed glossary as well as linkable sections and individual section downloads. We have consulted with stakeholders through a steering group and workshops to discuss feedback on the live digital platform as well as discuss future enhancements and upcoming releases. The benefits of the features detailed above were for the users of the Grid Code. These features were designed to reduce the amount of time spent searching a 1000 page legal document, reduce customer queries, and reduce barriers to entry. We are yet to complete a customer satisfaction survey however we would hope that our service scores would improve following the launch of the digital platform.

Key updates from April 2024 to March 2025:

- Release 1 went live on 8 May 2024. This was where the Grid Code was digitalised and benefited from features such as a glossary, search function and enhanced code navigation. On 17 May 2024, Release 2 gave us some small enhancements and fixes of Release 1 defects.

- We signed a new contract with IBM in August 2024 to agree the discovery of Release 5 and the scope of Releases 3 and 4. The project then continued with Release 3 in September and Release 4 in February 2025, where the digitalisation of the first stage of the internal journey (proposal form) was launched.
- The second stage of the process is to digitalise our internal workflow used by Code Governance to manage the process of code change. This end to end process is currently very manual, relying on the use of word documents, copy and paste, emails, folders, manual version control and isolated project management tools to manage the process. The aim of the digital platform is to have an end to end workflow that is in one place, is interactive, and has an editor tool designed to allow for sophisticated version control management of the implementation process. This element of the digital platform is the most crucial part to reduce the risk of errors to the code as we eliminate the manual human element from the process.
- The implementation of the process will result in a reduced workload for Code Governance, improved communication, simpler industry forms and the elimination of the need for multiple offline documents and a lengthy review process. The editor tool improves the ability to update/implement the changes into the code, especially when drafting multiple changes from different mods coincidingly.

Combined status by milestone for relevant deliverables (Activities A6.5 and A6.8)

Status	Count	%
Complete	3	75%
Delayed – Consumer Benefit	-	-
Delayed – External Reasons	1	25%
Delayed - Internal Reasons	-	-
Total	**4**	**100%**

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

Calculation of monetary benefit	The original BP2 benefits case for the digitalisation of the code element was conducted at a very high level. It is challenging to calculate a meaningful number as the benefits are industry time saved spread across multiple companies. For the internal workflow digitalisation, the aim is to reduce the risk and compliance issues that can come with complex code changes simultaneously, rather than a £m benefit In line with the rationale we shared in the Mid-Scheme Report we haven't updated the benefits calculation. We believe the known benefits are consistent with the original proposal but are still very much anecdotal based on customer feedback.

CBA: Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges (A6.6) and Fixed BSUoS tariff setting (A6.7)

BP2 End-Scheme view of gross benefits compared to BP2

We continue to estimate an NPV of £68m over the five-year RIIO-2 period, in line with the original BP2 figure of £68m.

		Estimated NPV during the 2021-26 RIIO-2 period (£m)		
Area		**BP2 Plan view**	**Latest forecast view**	**Variance**
A6.6	Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges	68	68	-
A6.7	Fixed BSUoS tariff setting	-	-	-
Total		**68**	**68**	**-**

Industry, Ofgem and NESO agreed that the introduction of fixed BSUoS for final demand would result in a reduction of risk premia. With BSUoS costs of £2.9bn in 2024-25, even a very conservative estimate of 1% reduction in suppliers' risk premia would provide a £29m consumer benefit for the first year of operation alone. Therefore, we can assume that we are on track to deliver the overall benefits.

Following implementation of CMP308 and CMP361/361, we raised another modification CMP408 (followed by CMP415 for the non-charging elements) to reduce cashflow risk, and the resulting risk of a tariff reset. These modifications have now been approved and implemented with the new timeline for notice and tariff periods starting in December 2025.

This benefit cannot be tracked as it relies on reduced risk premia from suppliers which is not data that is available to us. There is no indication to suggest that the benefits have not been realised, so until there is evidence to suggest otherwise, we are comfortable that we are on track to deliver £68m.

For more detailed background on this CBA please refer to our BP2 Mid Scheme Report 2023-24 Evidence Chapters, pp135-139.

Summary of progress in 2024-25

Fixed BSUoS was implemented in April 2023. Fixed Tariff 1 (April 2023 – September 2023), Fixed Tariff 2 (October 2023 – March 2024) and Fixed Tariff 3 (April 2024 - September 2024) have concluded. Fixed Tariffs 4, 5 and 6 have been set. To date, no tariff resets have been required.

The cash position at the end of Fixed Tariff 3 was £421m. We are currently (as of 12 March 2025) forecasting a cash position at the end of Fixed Tariff 4 at £323m, Fixed Tariff 5 at £59m and Fixed Tariff 6 at £129m.

The positive cash position at the end of Fixed Period 4 is in line with suppliers reducing their risk premia, as this reduces the risk of a tariff reset.

It should be noted that the current forecasted positive cash position at the end of Fixed Tariff 5 was originally forecast as negative when Fixed Tariff 6 was set (end of December 2024). Due to this, we changed the method slightly of how forecast over and under recoveries fed into Fixed Tariff 6, compared to previous tariffs. It was felt that it would reduce the risk of a tariff reset by recovering the forecast under recovery position sooner and allow us to begin the new methodology when setting Fixed Tariffs 7&8 in a neutral cash position.

Since setting Fixed Tariff 6, forecast balancing costs and wholesale costs have both seen overall reductions, hence we are now forecasting to finish Fixed Tariffs 5 and 6 in a positive cash position.

As stated in the section above, CMP408 and CMP415 are now implemented and will reduce the notice period. This will enable more accurate tariffs to be set than is available presently.

Combined status by milestone for relevant deliverables
(D6.7 only (Enhanced delivery of the recommendation from the BSUoS taskforce around reducing the volatility of BSUoS forecasting). D6.6 was 100% complete at the end of the BP1 period)

Status	Count	%
Complete	1	100%
Delayed – Consumer Benefit	-	-
Delayed – External Reasons	-	-
Delayed - Internal Reasons	-	-
Total	**1**	**100%**

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

Supporting evidence

As the original benefits figure was based on a high level calculation (shown further below), here we present a range of further evidence to demonstrate our performance in relation to delivering the benefits.

A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges.
(The benefits of A6.7 are already accounted for in the original A6.6 benefits case, so A6.7 has no additional financial benefits.)

Type	Measure	Rationale and status
Qualitative evidence	-	In our BP2 Mid-Scheme Report (p138) we also provided a flow chart setting out how benefits result from activities A6.6 and A6.7. This helped to drive the indicators below to help us understand if we are on track or not.
Performance Indicator	No. times reset in period / once fixed	Zero within Fixed Tariff 1 (Apr 23 – Sep 23), Fixed Tariff 2 (Oct 23 – Mar 24), Fixed Tariff 3 (Apr 24 – Sep 24) and Fixed Tariff 4 (Oct 24 – Mar 25) No tariff resets would maximise the benefit.
Performance Indicator	Forecast cash position	Fixed Tariff1: £350m, FT2 £854m, FT3: £421m, FT4: £312m; FT5:-£91m; FT6: -£9m A positive cash position is indicative of benefit being delivered.
RRE 2E	BSUoS month ahead forecast % error	Average month ahead forecast error (Absolute Percentage Error) of 22% for 2023-24 and 22% for 2024-25. A small error shows the accuracy of the BSUoS forecasting methodology. Ideally this would be close to zero, as prolonged forecasting error may increase the risk of under-recovery and a tariff reset.
Performance Indicator	Forecast Revenue vs Cost report	Weekly published report shows at daily granularity the current and forecast cash position for Fixed Tariffs. (available here under 'Current BSUoS Data') This ensures that industry can inform their forward contracts and pricing, by identifying potential impacts on future fixed tariffs, and early indication of any risk of tariff rest.
Performance Indicator	Communicating new tariffs by deadline (current 9 month ahead)	All tariffs have been published on time. This ensures that industry can use the information released in tariffs in their own contracts and pricing.

Performance Indicator	Communicating draft tariffs by deadline (current 18 month ahead)	All draft tariffs have been published on time. This ensures that industry can use this information to inform their forward contracts and pricing.

Detail: Calculation of monetary benefit

For consistency with the original BP2 benefits case, below we have also updated the high level calculation produced by Frontier Economics and LCP.

A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges.

(The benefits of A6.7 are already accounted for in the original A6.6 benefits case, so A6.7 has no additional financial benefits.)

Assumptions	BP2 Plan view	Latest forecast view
Code modification proposals for BSUoS reform	BP2 focussed on the CMP308 NPV using the Consumer Transformation FES as a basis, recognising that this gives a conservative estimate of the total NPV. To obtain an estimate of the NPV across the RIIO-2 period, we have annuitised the benefits from the analysis commissioned by Ofgem.	These modifications have now been implemented. We have also implemented the decision from CM408 and CMP415 to make amendments to the notice and fixed period/ Please note that CMP420 was withdrawn by the proposer.
BSUoS price setting	If we did not undertake A6.6 and A6.7, the BSUoS arrangements would remain unchanged and the BSUoS price would continue to be set after balancing actions are taken.	No change from BP2 view
Benefits methodology:	Our five-year NPV estimate is now based on analysis commissioned by Ofgem for CMP308.	No change from BP2 view
Implementation date for BSUoS reform	We assume benefits begin from April 2023, the estimated	Implemented in April 2023 as assumed.

	implementation date of BSUoS reform.	
NESO will finance any new arrangements	Taking on the additional cost of managing the risk premia will require financing for us to manage this risk.	The working capital facility is currently still in place.
Risk premia	Frontier Economics and LCP risk premia assumption	Even a very conservative estimate of a 1% reduction in risk premia would result in £29m of benefit in the first year alone (2023-24), with two more years of RIIO-2 remaining.
Benefit over the five-year RIIO-2 period (£m)	£68m (RIIO-2 NPV)	More than or equal to £68m

Consumer benefit case study for Role 2

Activity	Demand Flexibility Service (DFS)
Key RIIO-2 Deliverables	Not in BP2 plan
How does this activity deliver consumer benefit?	DFS has this year moved to an in-merit service where it is assessed against other positive margin options that we have available and is instructed if it is more economic than those options. This aims to deliver consumer benefit through reduced Balancing Costs. There is also a secondary benefit that the service is typically a lower carbon option than typical peak generation options to provide margin. It also directly rewards participating consumers for their demand reduction (through their DFS providers), enabling them to participate directly in balancing the system Longer term, the additional volume created by this service in the market effectively creates additional supply into the market, which should add competitive pressure to reduce scarcity pricing, leading to overall lower balancing costs.
Is the consumer benefit mainly this year or in future years?	This year the service moved from a seasonal, winter service which ended each year to an enduring service. This means that benefits will continue to accrue, although as the service was started in November 2024, there is the potential for benefits to increase over a full year's operation and if participation grows.
Calculation of monetary benefit to consumers	Our initial estimates for benefits against the cost of our alternative options at the time of procurement are: December: £38,300, January: £357,900, February: £52,600 The increased saving in January was driven in particular by 8 January, where alternative costs were particularly high due to lower-than-average market surplus of generation. We are working on an enhanced benefit methodology to track DFS benefit going forwards as part of our Balancing Costs analysis. While these savings are for all consumers, a significant proportion of our procurement spend (e.g. approximately 80% for one domestic supplier, but this offering varies amongst providers) is passed through to participating consumers. Our spend over those 3 months was ~£1M, so we believe there is a further direct benefit in the region of £800k to participating domestic, industrial and commercial consumers
Assumptions made in calculating	At the point of issuing a DFS requirement, we assess our positive margin requirement and the cost of alternative options to create margin such as interconnector trades or taking Offers in the BM. If any DFS bids are more

monetary benefit	economic than the alternative options, then we will accept the bids that will deliver benefit against these alternatives. Our initial savings calculation is based on the cost of DFS compared to the forecast cost of the alternative options procuring the same volume at the forecast price. Direct participating benefit assumes 80% of procurement cost is passed to consumers.
How benefit is realised in the consumer bill	DFS reduces trading or Balancing Mechanism Actions, therefore leading to lower Balancing costs which is seen on all consumer bills through a reduction in BSUoS spend charged to suppliers.
Non-monetary benefits	DFS is a lower carbon alternative to many conventional peak generation options, as we are seeing demand reductions or domestic export of battery volume. Therefore we expect this to lead to a lower carbon cost of operating the network, however we cannot quantify this as we only have access to meter readings and not the data behind how each meter achieved the reduction procured.
Assumptions made in calculating non-monetary benefit	Qualitative benefit outlined, no calculations.

Regularly Reported Evidence

Table: Summary of RREs for Role 2

Most RREs don't have performance benchmarks, with the exception of 2D which is reported annually.

2024-25

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2Aii	Balancing services procured in a non-competitive manner	n/a	H1: Spend: **£140m** Volume **33.0 TWH** and **27.8 TVARH**						H2: Spend: £**152m** Volume **32.9 TWH** and **25.8 TVARH**					
2D	RRE 2D EMR Demand Forecasting Accuracy	%	T-1 forecast accuracy of **5.6%:** = below expectations T-4 forecast accuracy of **2.9%:** = exceeding expectations											
2E	Accuracy of Forecasts for Charge Setting (TNUoS)	%	Actual total TNUoS revenue for 2024-25 is within **0.28%** of the budget											
	Accuracy of Forecasts for Charge Setting (BSUoS)	%	**16%**	**19%**	**12%**	**47%**	**32%**	**22%**	**11%**	**21%**	**20%**	**22%**	**3%**	**1%**

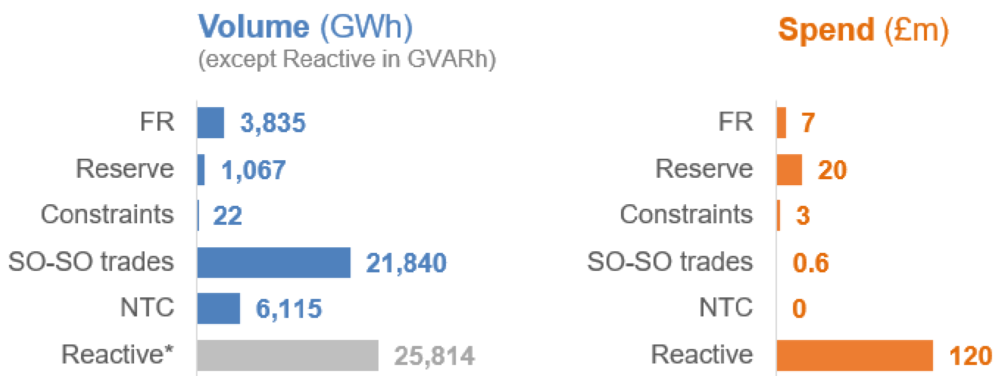
RRE 2Aii Balancing services procured in a non-competitive manner

This Regularly Reported Evidence (RRE) measures the volume and spend for non-competitive services for contracts. For the purpose of this metric, we have included volumes where the decision to instruct non-competitive services is made after 31 March 2023, even if the contract terms were signed before (e.g. Mandatory Frequency Response). Figures are reported in GWh/GVARh for the contracted month, which is calculated as the contracted volume in MW multiplied by the number of contracted hours.

Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded. However, all SO-SO trades and NTC application, as well as any other non-competitively procured services with contract award after this date, are included.

H2 2024-25 performance

Figure: Volume and spend for non-competitive services for contracts



*Reactive volume is measured in GVARh and is not directly comparable to the other services measured in GWh but is included in the graph with this caveat.

Table: Volume and spend for non-competitive services

	Service	Unit	H1	H2	Full Year
VOLUME	Frequency Response****	GWh	3,433	3,835	7,268
	Reserve****	GWh	1,451	1,067	2,517
	Constraints***	GWh	1	22	23
	SO-SO trades	GWh	21,960	21,840	43,800
	Net Transfer Capacity (NTC)	GWh	6,149	6,115	12,264
	Total Volume in GWH	GWh	**32,993**	**32,878**	**65,871**

	Reactive (in GVARh)	GVARh	27,829	25,814	53,643
SPEND	Frequency Response	£m	7	7	14
	Reserve -	£m	22	20	42
	Constraints	£m	0	3	3
	SO-SO trades *	£m	0	0.6	0.6
	Net Transfer Capacity (NTC)**	£m	0	0	0
	Reactive	£m	112	120	232
	Total spend	£m	**140**	**152**	**292**

*SO-SO trades, trade volumes and costs for services provided to NESO by another country's system operator have been included. Services provided by NESO to another country's System Operator are excluded.

**NTC cost was updated for Q1 to show payments to provider only – this logic to be used going forward

***For Q2 - Super SEL category has moved from Constraints to Reserve

****Total non-competitive procurement for Frequency Response and Reserve in RRE 2Aii will not align with volume stated in Metric 2Ai. This is because Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded from RRE 2Aii as per the agreed methodology.

Supporting information

Frequency Response

The volume of non-competitive services procured in Frequency Response is Mandatory Frequency Response (MFR). MFR is used as an element of our response holding that can be instructed within operational timescales. We are actively considering alternatives to the current MFR service to reduce this volume in future and have continued to engage with stakeholders on this.

Reserve

This volume of non-competitive Reserve is made up of the intra-day Optional Fast Reserve product, where prices for the service can be updated by providers per Settlement Period close to real-time. The Optional Fast Reserve product will be phased out with the introduction of the new day-ahead procured reserve products as they are introduced through 2024 and 2025.

Optional Fast Reserve is used for short-term frequency management outside contracted fast reserve windows e.g., periods where wind may have dropped unexpectedly, or demand has increased more than anticipated. Note that day-ahead procured STOR is to replace the largest loss and thus utilisation should always be quite low.

Super SEL, which is now included as a Reserve service, is an active but optional contract that a number of generators can provide as a backup to other solutions.

Constraints

High winds and network conditions in H2 meant significant amount of Arming instructions of the B6 and EC5 Constraint Management Intertrip Service.

SO-SO Trades

Historically SO-SO Trades were available to us across the IFA & IFA2, Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, and so we can no longer use this service.

EWIC, Greenlink & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. We do not trade via third Parties and therefore only have access to CBB.

SO-SO trades are also available with Energinet via the Viking Link Interconnector.

Net Transfer Capacity (NTC)

A capacity management process is used to ensure secure system operation for both Interconnectors and onshore TSOs. This process can result in the reduction in capacity through the application of a Net Transfer Capacity (NTC) and this reduction is defined as a non-frequency ancillary service.

Standard Licence Condition C28 requires that we procure non-frequency balancing services using market-based procedures. NTC is not procured through market-based procedures and therefore requires a derogation from this requirement. The procurement of NTC cannot be market-based due to technical parameters and the fact that alternative actions are not sufficient or economically efficient.

On 28 September 2023, Ofgem granted us a derogation against C28 for NTCs until 30 September 2026. This follows a request we sent to Ofgem to extend this derogation in August. They also approved our revised NTC Commercial Consultation Methodology, which applies from 1 October 2023. This gives our Control Room certainty that they can use this vital tool when required for system security over the coming years.

NTCs are our only way of guaranteeing system security in real time. As a result, they are as near to real-time calculated values as the market structure allows. Any restrictions are based on the forecast system conditions for that particular real-time period and are reflective of the limits of GB system security.

RRE 2D EMR Demand Forecasting Accuracy

April 2024 – March 2025 Performance

This Regularly Reported Evidence (RRE) measures the accuracy of NESO's peak national demand forecast. This forecasting is done as part of NESO's role as Electricity Market Reform (EMR) Delivery Body (DB). We aim to optimise the volume of capacity procured in the Capacity Market through more accurate forecasts of peak demand, which are used by the Secretary of State to determine the volume of capacity to procure.

The RRE measures the absolute percentage difference between our forecast and outturn of peak National Demand [3]. For outturn peak National Demand, we used Peak Average Cold Spell (ACS) i.e., peak weather corrected National Demand, as this is the most effective measurable proxy. This percentage gives a value greater than, or equal to, zero, and indicates how accurate the peak demand forecasts are. The closer to zero the percentage, the more accurate the forecast.

Over forecasting leads to unnecessary capacity being procured, which increases the cost to consumers. Under forecasting leads to either more capacity needing to be procured later (potentially at a greater cost) or risks security of supply.

All forecasts that outturn post 1 April 2023 will be assessed against this measure.

For 2024-25, the accuracy of two forecasts will be measured as follows:

- The T-1 forecast made in 2023-24, for delivery in 2024-25
- The T-4 forecast made in 2020-21, for delivery in 2024-25

Forecast accuracy is the absolute difference between forecast ACS Peak National Demand and outturn ACS Peak National Demand, given as a percentage of the outturn ACS Peak National Demand.

Table: One-year view of peak demand forecast accuracy

Auction	Forecast made in	Delivery Year	Forecast	Actual	Forecast accuracy	Status
T-1	2023-24	2024-25	42.3 GW	44.8 GW	5.6 %	●
T-4	2020-21	2024-25	43.5 GW	44.8 GW	2.9 %	●

Please note that accuracy figures and accompanying narrative for delivery year 2023-24 were included in the Mid-Scheme incentives report.

[3] National Demand as defined in the Grid Code

Performance benchmarks (2024-25)	T-1	T-4
• **Exceeding expectations**	<2%	<4%
• **Meeting expectations**	2%	4%
• **Below expectations**	>2%	>4%

Supporting information

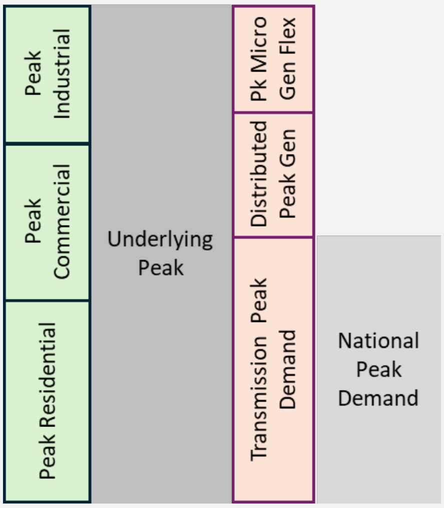
2024-25 performance

- Our 2020-21 peak demand forecast accuracy for T-4 is exceeding expectations
- Our 2023-24 peak demand forecast accuracy for T-1 is below expectations

T-1 Forecasting Accuracy Overview

ACS Peak Demand Forecasts:

- In 2023/24 (FES 2024), the forecast for the 2024/25 underlying winter peak demand was 58.0 GW.
- This forecast was revised in 2024/25 to 58.3 GW, a difference of only 0.3 GW.
- When accounting for contributions from distributed generation, storage output, demand-side response (DSR), and micro-generation, the difference between T-1 forecast and out-turn on the delivery year is 2.5 GW, with the outturn demands being higher than forecast. This is due to an overestimation of distributed generation and storage at peak moving demand away from the transmission system.



Impact of Generation, Storage, and Peak Avoidance:

- In FES 2024, distributed generation, storage output, demand-side response (DSR), and micro-generation reduced underlying demand by 15.7 GW, resulting in a peak national demand forecast of 42.3 GW.
- In 2024/25, these contributions were revised down by 2.2 GW to 13.5 GW due to:
  - A 0.5 GW reduction in distributed generation capacity at peak.
  - A 1 GW reduction in distributed battery output at peak.
  - A 0.4 GW reduction in estimated DSR after accounting for embedded generation.

  - Ongoing uncertainty about the behaviour of embedded generation at peak, impacting DSR forecasts and adjustments for double-counted generation.

FES 2025 Adjustments:

- **Battery Load Factors (LFs):**
  - Revised down LFs for distribution (Dx) batteries at peak.
  - This increases the peak demand seen on the transmission system.
- **Reasons for Adjustment:**
  - Changes in battery dispatch patterns: more stratified and over a longer period (3:30 PM to 7 PM) due to low margins and high prices.
  - Increased awareness of the removal of the Triad incentive led to batteries discharging more gradually across high-price windows (rather than all within the same time period), with an average duration of about 1.5 hours.
  - Winter 2024/25 had a sustained period of low margins and high prices. Analysis of this period provided insights into the limited discharge duration of batteries and changes in revenue streams post-Triad.
- **Result:**
  - Adjusted load factors down, assuming:
    - Batteries can engage at multiple periods throughout a winter peak evening.
    - The starting times for battery dispatch will be spread out across a longer period.

T-4 Accuracy Forecasting Overview

ACS Peak Demand Forecasts:

- In the 2020/21 forecast (FES 2021), the predicted underlying peak demand for the winter of 2024/25 was 58.5 GW. This represented a difference of +0.2 GW compared to the latest 2024/25 estimates.
- When considering factors like distributed generation, storage output, demand-side response (DSR), and micro-generation, the forecast error compared to the actual winter ACS out-turn was 1.3 GW.

Impact of Generation, Storage, and Peak Avoidance:

- According to FES 2021, distributed generation, storage output, DSR, and micro-generation collectively reduced the underlying demand by 15.0 GW. This led to a national peak demand forecast of 43.5 GW.
- Forecasts for distributed battery capacity were considerably lower in comparison to those in FES 2025. Consequently, the forecast impact of battery output at peak times was much less significant.

- The inclusion of a triad avoidance forecast in the FES 2021 analysis contributed to shifting an additional 1.4 GW of demand away from the transmission system peak demand in the form of peak avoidance and embedded generation.

Our long-term demand forecasting analysis feeds into a range of processes, including the Future Energy Scenarios (FES), Electricity Market Reform (EMR), the Electricity Ten Year Statement (ETYS), Regional Energy Strategic Plan (RESP) as well as gas security of supply and network planning processes.

Since 2018-19 (the first year of making forecasts included in this report), we have pursued a number of initiatives which have led to improvements in our long-term demand forecasting process. However, as the forecasts made this year relate to future years, the effect of these improvements will not yet have been realised in the accuracy figures reported this year.

We have focussed on increasing the transparency of our work to our key stakeholders, setting up challenge and review sessions where they have had the opportunity to comment on our modelling inputs, and then giving an early view of our outputs. A Topic Table Talks event specific to demand modelling gave an opportunity for a wider group of stakeholders to dive into topics such as Heat, Transport, Industrial and Commercial demand, and we were able to use the feedback we received to set the inputs for our modelling.

We have also rolled out new, improved tools which have streamlined our processes, allowing our analysts to focus on value-adding activities rather than manipulating data. These tools have included new models for Industrial and Commercial, an improved Heat model, and improved visualisation of the data within our Transport model. These improvements have been delivered by colleagues within NESO.

However, despite these new tools, the changing nature of the energy system means that we still experience some challenges within our forecasting process. For example, although we were aware of the removal of the Triad incentive, it was difficult to forecast how Industrial and Commercial demands would respond to this: we had not foreseen that there would be a further impact in the second winter following its removal.

Another challenge is the behaviour of emerging technologies such as batteries. The number of batteries connected to the system has increased significantly since the T-4 forecast was made. We had previously modelled the majority of batteries to be discharging at the time of peak demand, however we now understand that battery discharge is more likely to be spread out over a longer period. This improved understanding has fed into our FES 2025 forecasts.

And finally, predicting the behaviour of distributed generation at peak times can be challenging. To reduce uncertainty in our modelling, we plan to improve our method of determining total consumer metered demand, based on net sales and measured half hour generation throughout the winter. By enhancing the availability and quality of consumer demand data, we can create a half-hourly metered demand profile for GB. This means we will no longer benchmark total consumer demand against the sum of transmission and distributed generation. Instead, we will use deductive methods to ensure our forecasts for distributed generation more accurately reflect the generation needed to meet metered demand, considering the uncertainty for each type of generation technology.

The table below sets out improvements and challenges which occurred during the past financial year (2024/25)

Improvement / challenge	Category	Description
Improvement	**Stakeholder engagement**	• For the first time we held a demand-specific stakeholder event which took place earlier in the year than the main stakeholder event, giving stakeholders an improved opportunity to shape the inputs to our demand analysis before modelling started • We introduced Input Challenge and Review sessions, giving key stakeholders such as Ofgem, DESNZ and the energy networks the opportunity to comment on our modelling inputs ahead of modelling taking place. This streamlined our analytical processes, and provided more transparency for our stakeholders. This was in addition to the Output Challenge and Review sessions, which we had run in previous years. • For FES 2025, we have engaged with 2,609 stakeholders across all of our events (including the 2024 live launch), representing a total of 802 organisations. This compares to 2,203 stakeholders for the previous cycle
Improvement	**Input data quality**	• We commissioned consultancy reports to better understand the behaviour of Data Centres, a key driver of increasing electricity demand, and used the learnings from these to inform our analysis • We improved our understanding of battery behaviour at times of peak demand, leading to an improved methodology for our modelling • We introduced a new detailed dispatch breakdown to represent demand shifting and different assumed appetites for dispatch volume - DSR volume is now split into 6 categories for dispatch, allowing for more granular modelling • CLASS resources are now better integrated into the peak capacity calculation

		• Smart metering uptake forecasts now vary across the pathways, based on data from Ofgem and stakeholder feedback from metering agents • Archetype study from Demand Flexibility Service information integrated into existing forecasts for customer engagement • Capacity Market component information added as a data source with support from Elexon metering team - primarily used for early period of forecast to help avoid double counting generation. • We have improved our estimates of peak losses. We now incorporate daily losses from Elexon settlement data for winter. • We used the outputs of recent innovation projects to improve our modelling of electrified heating profiles. As more heating systems are electrified, this becomes more important in the context of modelling peak electricity demand • We have also improved our understanding of electric vehicle charging behaviour. As more electric vehicles are sold, this is also becoming a more important factor influencing electricity demands • We worked closely with DESNZ to understand areas where our respective electricity forecasts differ. This resulted in some updates to modelling inputs where we felt that we could learn from the approach taken by DESNZ. • We have leveraged improved subject matter knowledge within new functions in NESO to validate the inputs to and results of our modelling
Improvement	**Analytical tools**	• We have made significant improvements to our Heat model, improving accuracy and usability • We have rolled out new models for Industrial and Commercial, which use modern cloud-based platforms consistent with our overall digitalisation strategy • We are working with other teams in NESO to transition our data to the Data and Analytics Platform

		• We have improved our modelling of uncertainty around peak demands, acting on feedback provided by the Panel of Technical Experts • We have increased the use of tools such as PowerBI and Power Automate within the team to streamline and visualise our processes.
Challenges	**Market behaviour**	• The energy system is changing at pace, and past behaviour cannot always be relied upon to predict the future • Over the past few years, there has been a significant increase in embedded battery capacity. In recent years, we have also observed a change in battery behaviour at peak. • The removal of the triad incentive has led to a change in market participant behaviour. However, the change in behaviour was not fully seen until the second year without the incentive. • It is challenging to reduce uncertainty when predicting the behaviour of embedded generation at peak. Over/under forecasting the contribution of this generation inadvertently effects the accuracy of National Peak Demand.

RRE 2E Accuracy of forecasts for Charge Setting – TNUoS and BSUoS

April 2024 – March 2025 Performance

This Regularly Reported Evidence (RRE) shows the accuracy of Transmission Network Use of System (TNUoS) and Balancing Services Use of System (BSUoS) forecasts used to set industry charges against the actual outturn charges.

1. Accuracy of Forecasts for Charge Setting - TNUoS (reported annually)

The TNUoS tariff setting methodology describes how much of the total required revenue should be collected from Suppliers and Generators, which requires a wide range of tariffs to be calculated. These tariffs aim to reflect the costs of how, when and where Suppliers and Generators use the transmission system. Final TNUoS tariffs are set by 31 January for the next charging year commencing 1 April, and out-turn revenue is known by the end of April following the charging year.

Customer type	Liable for	Detail
Suppliers	TNUoS Demand charges	The Non Half-Hourly (NHH) demand tariff is charged for consumption between 4pm-7pm for every day of the charging year, and the Half-Hourly (HH) demand tariffs are applied to import or export over Triads (the three periods of highest net GB system demand). The TDR demand charges are based on site counts or unmetered supply volume per day as provided by the DNOs (except for TRN1 to TRN4 bands which are determined by NESO).
Generators	TNUoS Generation charges	All Generators are liable for the Wider TNUoS Generation tariff. They may also be required to pay onshore local circuit and onshore local substations tariffs depending on where they connect to the transmission system. Offshore local tariffs are also created following asset transfer of the offshore transmission system, which are then charged to offshore generators.

The charging bases used to calculate TNUoS tariffs are the inputs that can be responsible for significant variance between budget and actual TNUoS revenue. The TDR demand tariffs require an assumed demand charging base for each of the 22 charging bands. The locational demand tariffs require an assumed demand charging base for each of the 14 demand zones and for each type of demand (NHH, HH gross demand and HH embedded export). The generation charging base is the best view of the amount of Transmission Entry Capacity (TEC) contracted by Generators for the charging year.

Table: Forecast vs. outturn TNUoS Performance

TNUoS Charging	Forecast £m	Actual £m	Variance £m	Variance %
NHH Demand	70.65	70.35	-0.30	-0.42%
HH Demand	22.18	22.18	-	0.00%
TDR Demand	3,037	3,028	-9	-0.29%
Generation	1,017	1,015	-2	-0.22%
TOTAL	**4,147**	**4,135**	**-11**	-0.28%

For each charge type, the **Forecast** is what we aim to collect for each tariff and **Actual** is how much we collected.

Actuals are based on the final available settlement metering.

Figures rounded to the nearest £m, therefore totals may differ slightly from the sum of the four components.

Supporting information

Several events can impact out-turn TNUoS revenue once TNUoS tariffs have been set 14 months earlier, for 2024-25 demand volumes continue to be suppressed below those seen prior to the start of the war in Ukraine and resulting higher energy prices. Generation revenue may be impacted by unforeseen delays to stations connecting to the transmission system or delays in the transfer of an offshore transmission system.

TNUoS charge	Explanation of variance
TDR Demand	We continue to see some data refinement from customers and DNOs throughout 2024/25 charging year. There have been large shifts between LVNo Mic and LV bands the removal of non-final demand and de-energised sites as customers have queried data with their DNOs. A charging base of 11.73bn site count days was assumed at tariff setting compared to 11.67bn site count days outturn (-0.46%) with revenue down £9m at outturn (-0.4%). Of note there has been a large decrease in the high value EHV bands (£-17m) as customers have sought to have them re-banded by DNOs. LV bands also experienced an increase (+£13m). This correction of data prompted by suppliers was not anticipated whilst

	setting tariffs. It is expected based on prior 6 months that TDR site counts are now stabilising.
NHH Demand	A charging base of 22.98TWh was assumed at tariff setting for 2024-25. Actual 2024-25 out-turn NHH demand is 0.1% higher at 23.1TWh.
HH Demand	**HH Gross Demand:** A charging base of 17.2GW was assumed at tariff setting for 2024-25. Actual 2024-25 out-turn HH demand is 8.3% higher at 18.7 GW. **HH Embedded Export** A charging base of 7.31GW was assumed at tariff setting for 2024-25. Actual 2024-25 out-turn for EE demand is 19.17% higher at 8.7GW. This resulted in outturn credits paid for 2024/25 exports (£26m), 35.6% higher than budget at tariff setting (£19.24m).
Generation	The amount of Transmission Entry Capacity (TEC) assumed at 2024-25 tariff setting was 82.9GW compared to actual TEC invoiced of 74.9GW. The delay of asset transfer for several offshore transmission systems means that offshore tariffs could not be introduced and charged to offshore Generators as early as anticipated when Final tariffs were set leading to a reduction of £27m. Combined with a lower-than-expected number of new connections, this means that in 2024-25 overall TNUoS Generation revenue is 2.6% less than budget.

2. Accuracy of Forecasts for Charge Setting – BSUoS

April 2024 – March 2025 Performance

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

The BSUoS charge (£/MWh) is now based upon a fixed tariff. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) are forecast for six-monthly tariffs and set 9 months ahead of the chargeable tariff period. For 2024/25, Fixed Tariff 3 (April 24 – September 24) was published in June 2023. Fixed Tariff 4 (October 24 – March 2025) was published in December 2023.

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

Q4 2024-25 performance

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

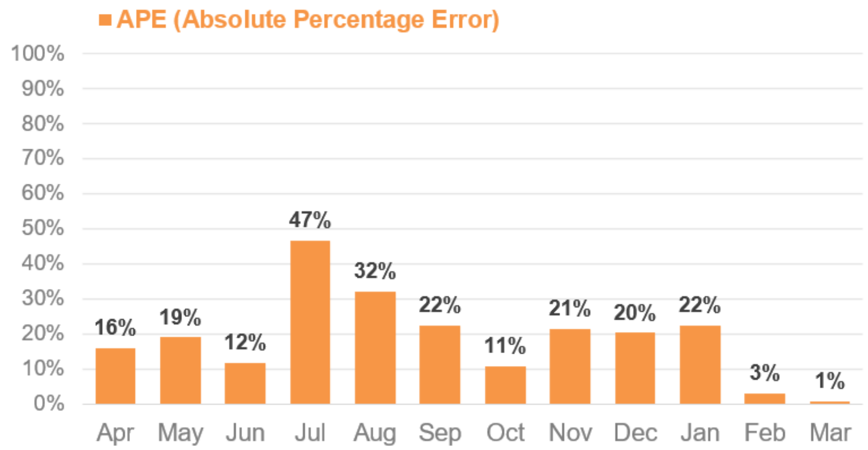


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	11.5	8.5	12.7	8.0	16.5	10.4	14.4	11.5	15.0	9.8	13.5	13.5
Month-ahead forecast (£ / MWh)	9.7	10.2	11.2	11.7	11.2	12.7	15.9	13.9	12.0	12.0	13.9	13.6
APE (Absolute Percentage Error)[4]	**16.0**	**19.0**	**11.8**	**46.6**	**32.1**	**22.4**	**10.7**	**21.3**	**20.3**	**22.3**	**3.0**	**0.6**

Supporting information

Q4 Performance:

The average monthly Absolute Percentage Error for Q4 has decreased since Q3 (8.6% vs 17.4%).

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

Costs:

Costs out turned below our month ahead forecasts across the quarter, with the largest variance from our January 2025 forecast.

January balancing costs out turned at the 25th percentile of our month ahead forecast, predominantly due to constraint costs out turning £43m below our forecast. Wind outturn for January was lower than December 2024 and December 2025, resulting in the proportion of demand met by renewables outturning 4% below our month ahead forecast. We have previously found that a higher proportion of renewables tends to drive higher constraint costs.

Balancing costs for February and March both out turned just under the 50th percentile of our month ahead forecasts.

For February, constraint costs were £33m above our month ahead forecast, however this was offset by lower energy imbalance and other costs.

For March, constraint costs out turned in line with our month ahead forecast.

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

Volumes:

Across Q4, our average monthly volume forecasting error was 1.8%. The largest variance was in January, with very low temperatures and lower wind levels and levels of distributed embedded generation resulting in higher than forecast demand.

BP2 Performance summary 2024-25

The average monthly absolute percentage error has decreased since last year (18.8% vs 22%)

The 2024-25 charging year is the second year that BSUoS has been based on a six-monthly fixed tariff, set 9 months in advance of the tariff period. Fixed Tariff 3 (April 24 – September 24) was published in June 2023, and Fixed Tariff 4 (October 2024 – March 2025) was published in December 2023.

As costs and revenue for BSUoS are now disconnected, there is the potential for over or under-recovery of revenue throughout the year, and therefore continual monitoring of our BSUoS forecasting performance will support the fixed BSUoS methodology.

Two key drivers of our BSUoS forecasting are wholesale electricity prices and the renewable proportion of demand met by renewable generation. Therefore, although our average monthly APE has decreased since last year changes in these drivers can result in higher percentage errors. This is most clearly seen in July, which saw a 16% decrease in wholesale energy prices between our forecast at the beginning of June and the proportion of demand being met by renewables out turning 10% below our forecast, resulting in July out turning at the 15th percentile of our month-ahead forecast.

2024-25 is also the second charging year where BSUoS has been charged on final demand only. BSUoS chargeable volume is forecast using a simple linear regression using the NESO national demand data as the explanatory variable. Having a full year of actual BSUoS settlement data has enabled us to re-estimate the relationship between BSUoS chargeable volume and national demand.

There have also been some forecast methodology updates across 2024/25. In late 2023, an innovation project was concluded, which had set out to investigate whether Machine Learning techniques could be employed to improve our forecast of balancing costs. Of all the variables tested, the ones with the best predictive power for forecasting the components of balancing costs were found to be the ones used within our forecasting model; renewable generation as a proportion of demand and wholesale electricity prices. However, it was found an alternative modelling package provided a theoretical improvement in accuracy compared to the existing model. This was implemented from our May 2024 forecast, and we continue to monitor the performance of our forecasts.

Additionally, in our July 2024 we reviewed and updated several data sources for the BSUoS forecast, including the latest Network Option Assessment (NOA), which updated the upper and lower balancing cost risk range, and updated our renewable growth assumptions, resulting in an increase in our long term constraint forecasts (18 months ahead).

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