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

End-Scheme Incentives Report

Annex C: Role 3 - System insight, planning and network development

May 2025

NESO
National Energy System Operator

Contents

C.1 Activity Updates

See below an overview of Activity updates for Role 3 over the second year of the Business Plan 2 period. This incorporates evidence covering Plan Delivery, Stakeholder Evidence and Quality of Outputs.

Role 3 Activities

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

Network Development (A7)

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

(A7.1) Continuing the enhancements to the ETYS publication by communicating additional System needs (year round thermal & voltage) and recognising the substantial changes likely from the Network Planning Review

(A7.2) Continuation of the existing process, reflecting the need to discuss the future of Interconnector Analysis given Ofgem's Interconnector Policy Review decision, and recognising the substantial changes likely from the Network Planning Review.

(A7.3) Analysis is produced to the standard required by the TOs and Ofgem.

What have we achieved by the end of BP2?

During this period, we have made significant enhancements to our publications, further building on our commitment to deliver comprehensive and insightful analyses. The ETYS was published in February 2025, (as agreed with Ofgem to accommodate changes within the broader strategic planning landscape). This edition continued the enhancements introduced in ETYS 2023, offering core content publication earlier to provide stakeholders with more time to review system needs before conducting the Cost Benefit Analysis. The publication features year-round thermal analysis and our voltage screening results, reflecting our dedication to expanding our understanding of system needs. Additionally, it includes several key data points within the ETYS appendices.

In the realm of interconnection analysis, we have advanced our future approach, which encompasses the Centralised Strategic Network Plan and its interactions with other strategic plans like the Spatial Strategic Plan. A significant achievement in this area was our analysis for Ofgem, supporting the Interconnector Cap & Floor Window 3.

Throughout the period, we have consistently produced high-quality analyses to support insight and decision-making processes. This includes delivering several impact assessments for the Transmission Owners, ensuring they meet the required standards of quality.

How did our approach maximise outcomes?

Our approach to developing and producing the ETYS, along with our strategies for future network planning, interconnector analysis, and other related topics, is designed to maximise outcomes by focusing on delivering high-quality analysis. This ensures that decisions are made to effectively contribute towards achieving net zero, enhancing consumer benefits, and maintaining security of supply.

Key to maximising outcomes is our collaboration with various partners and stakeholders. By engaging in meaningful conversations, we ensure a comprehensive understanding of the key questions our analysis aims to address. This collaborative approach – including reasonable challenge - helps in scoping the analysis to ensure it is pragmatic, practical, robust, and beneficial.

Moreover, we have significantly enhanced our analytical capabilities by adopting advanced tools. For instance, we now utilise Plexos as our primary tool for the economic analysis of network investments. This advancement enables us to conduct detailed studies of various options, thereby supporting informed decision-making and optimising outcomes.

Network Services Procurement (Pathfinders) (A8.1)

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

Relevant milestones achieved for planned projects.

The specific milestones for the end of BP2 related to Constraint Management Intertrip Service (CMIS) and are set out in the BP2 delivery schedule.

In addition, we set out a number of deliverables that are reflected under Role 2 relating to Network Services Procurement. These centre on implementing new markets for stability and voltage services which build on learnings from Pathfinders and the output of respective innovation projects.

What have we achieved by the end of BP2?

In addition to the BP2 milestones, we have also delivered a number of tenders across Network Services to secure the capability required to operate a zero-carbon electricity system.

<u>Voltage</u>

The tender for Voltage 2026 concluded in December 2024, awarding contracts to four solutions to provide reactive power absorption services across two regions in England (London and North England). These contracts are forecast to deliver £318M of benefit over the 10 year contract period from 2026 out to 2036.

To support competition and reduce barriers to entry for this tender, we sought to reserve a connection bay for potential projects to connect into. This, with the support of NGET, was possible and helped to mitigate some of the delivery risks for projects as they had certainty that a connection bay would be available for them following contract award to enable them to deliver their Voltage 2026 contract.

A number of improvements were made to the contract terms as part of the Voltage 2026 tender. These were based on lessons learnt from previous Network Services/Pathfinder tenders and considering approaches in other areas e.g. EMR, Connections. Examples of these include a restructure of the contractual milestones that successful projects would have to meet, and report progress on between contract award and service delivery, which can cover a period of up to 3 years. The changes ensure that we have greater oversight of the progress of projects to mitigate the impact of any delays.

<u>Stability</u>

The first Mid-term (Y-1) Stability Market tender for Year 1 2025/26 concluded in November 2024 with five synchronous condenser solutions contracted to provide 5GVA.s of inertia capability to the GB network.

This is a significant milestone in the implementation of a new market, following our efforts with industry since 2021 to consider options for the design of a stability market.

These first set of contracts are forecast to deliver consumer savings in excess of £47m throughout the delivery year (October 2025 to September 2026) compared to alternatives in the balancing mechanism.

For the second tender, launched in January 2025, we took on learnings about the capability and functionality of grid forming units and revised the payment mechanism for these units to reflect how they deliver the service to lower costs for consumers. In addition, acting on feedback from market participants, we have reviewed the approach for liquidated damages that would be payable where contracted units are delayed in meeting their start date. This is to seek to a balance between incentivising project to deliver on time against avoiding unduly burdening with increased barriers or costs.

The first two units contracted under Stability Phase 2 entered into service and are providing crucial stability capability at locations in Scotland. These units are in addition to the 12 units already live under Phase 1 meaning over 13GVA.s of inertia is now being provided from zero-carbon assets.

<u>Constraints</u>

A tender for an 'enduring' intertrip service was carried out in 24-25 to enable us to manage constraints in the East Anglia (EC5) region out to 2030 and beyond. The current 'interim' service is configured for deload capability where units ramp down over 10 seconds following a fault. This capability, while useful, limits the instances where the scheme can be armed as following a fault, power may sometimes need to be taken off the system within 200ms to secure the system.

As a result, the new 'enduring' service, which is due to begin in Q2 2026, will provide this enhanced trip speed through the upgrade of the current intertrip scheme by NGET. To enable NGET to carry out the works required, the 'interim' service has been extended to Q2 2026 to bridge the gap. Following the upgrade, this should result in increased usage of the service which in turn will deliver greater consumer savings in constraint costs.

The tender was open to all forms of technologies in the area of need to increase competition and enable innovative solutions to come forward. The tender has resulted in the selection of a mix of offshore wind, CCGT and interconnector assets that can be used to manage constraints in the region at costs far lower than in the balancing mechanism.

In Scotland, we have been exploring the optimal solution for a Constraint Management Intertrip Service in the B2 & B4 boundary areas (North and Central Scotland), so as to manage the increased constraints in this region that are forecasted until 2030 and beyond, primarily due to network upgrades and outages taking place in this region. It is estimated that this would not be delivered until mid-2027 due to the work that the Transmission Owners would need to carry out as part of any intertrip solution. Given that a solution for these boundary areas could also incorporate the existing B6 scheme (Southern Scotland) as part of a wider solution with an upgraded tripping scheme, the decision was taken by us to extend the current B6 2024-2026 contracts for a further 12 months, taking them to September 2027. This allows the time to finalise future Constraint Management solutions across the B2, B4, and B6 regions in the next 12 months. It is expected that the 12-month B6 contract extensions will deliver approximately £8m of savings benefit to the consumer during that time period.

How did our approach maximise outcomes?

Across all elements of Network Services, we have sought to regularly engage with the wider market through a number of channels to ensure that timely and relevant information is made available. Examples of these include dedicated web page where documents can be accessed and the use of our NESO newsletters to publicise key updates.

Furthermore, webinars are held at different points of a projects journey, e.g. during the Expression of Interest and Invitation to Tender stages, on specific topics such as the technical and commercial aspects of services being procured to provide detailed information as well as to invite opportunities for parties to ask questions to us.

In addition to this, to enable our markets to become regular and repeatable, we continually seek to learn and identify improvements that can be implemented for future tenders. As part of this, individual calls have been offered to all interested parties to allow mutual sharing of feedback on the tender process, and sharing of ideas on how the markets can evolve to enable competition and delivery of consumer value.

Internally, there is sharing of information and learnings between the Network Services team and colleagues developing Early Competition on approaches to procurement, market insight and learnings from previous Network Services/Pathfinder tenders.

The governance of Network Services is formed of a Steering Committee that provides oversight of all projects, with key decisions and approvals made by the committee.

Membership is made up of relevant positions from across NESO, representing technical, operational, markets and procurement areas to ensure all views are considered.

At various stages throughout a project's lifecycle, key decisions may be required that are taken to the committee. Examples include defining the rules for tender eligibility, changes to the payment mechanism for a service etc. A number of options would be reviewed by the relevant project to consider the impact on system operability, ability to meet tender requirements, market liquidity etc, to ensure that any changes that are made allow NESO to meet its objectives. Where possible, we would also seek views from bidders through the consultation stage of a project before a final recommendation is made to the committee for a decision.

Network Competition / Early competition (A8.4)

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

Launch the first Early Competition tender.

What have we achieved by the end of BP2?

The main achievement has been the support to Ofgem and DESNZ that has culminated in laying of the Onshore Tender Regulations[1] in April 2025 that enable the appointment of CATOs. There has also been significant progress in all the of the supporting elements that support the implementation of onshore early competition e.g. code modifications, TO licence changes etc., as described below.

A lot of progress has been made since the February 2024 when we published our Early Competition Implementation Update. The update included our proposals on policy matters such as the alignment of early competition with the proposals under the CSNP, as well as detailing the methodology around the use of Cost Benefit Analysis (CBA) in the identification of projects. These updates gained approval from Ofgem via their decision on policy updates to Early Competition in onshore electricity transmission networks in June 2024[2].

We have completed the Competitively Appointed Transmission Owner (CATO) code modifications that enable competition that Ofgem have recently approved. We have finalised and submitted the early competition commercial model details that form the CATO's commercial framework and anticipate Ofgem's publishing their decision later this year. We have also been heavily involved in supporting Ofgem's licence changes for the TOs and the development of changes required for NESO licence that all enable competition. Significant support and advise has been provided to Ofgem and DESNZ on the Tender Regulations that are now laid to appoint a CATO.

[1] The Electricity (Early-Model Competitive Tenders for Onshore Transmission Licences) Regulations 2025

[2] https://www.ofgem.gov.uk/decision/decision-early-competition-onshore-electricity-transmission-networks-policy-update

Subsequently, we have met our obligations in line with enabling the launch of the first early competition tender by virtue of the activities above and by making a formal request in November 2024 for its first competitive tender, in line with agreed timescales with Ofgem and DESNZ.

The project selected was a sub-section of WCN2, a new high voltage transmission line from south-west Scotland to north-west England that forms part of the Beyond 2030 refresh network plan. This request was then consulted on by Ofgem[3]. Ofgem's decision following their consultation[4] was published on 4 April 2025. Ofgem have made the decision that for now, not to accept WCN2 as a qualifying project for early competition. Ofgem's decision is based on the overall needs case as described in their consultation.

Notwithstanding all the above, we will have been unable to achieve the final milestone for BP2.

Given we have completed all elements of the required steps to launch a tender which are within our control[5], we are work on identifying further projects for competition in order to deliver value for consumers.

How did our approach maximise outcomes?

In developing the model and policies around Early Competition, we undertook significant stakeholder and industry engagement to formulate and develop its proposals, which has continued with NESO as its proposals develop. This has been achieved through bilateral meetings with incumbent TO's and potential bidders for early competition projects, as well as various webinars throughout the year[6].There have also been initial discussions with Citizens Advise and Consumer Scotland around the plan to introduce early competition.

The identification of the first project required interdepartmental working with close collaboration between the early competition teams as well as network planning and customer connection teams. This work fed into the project identification process and will be developed upon as we identify more projects for competition. Furthermore, the network competition team utilised lessons learnt, and processes developed under network services procurement to further refine processes where similar mechanisms can be used across different competitive processes.

In addition, NESO early competition teams have been working in collaboration with Ofgem and DEZNZ in the development of code modifications, licence changes, and legislation to enable competition.

[3] https://www.ofgem.gov.uk/consultation/onshore-electricity-transmission-early-competition-first-project
[4] Onshore electricity transmission early competition: first project | Ofgem
[5] Decision on the Electricity (Early-Model Competitive Tenders for Onshore Transmission Licences) Regulations 2025 | Ofgem
[6] https://www.neso.energy/about/our-projects/early-competition/events-and-webinars

Future Energy Scenarios (FES) / Energy Insights (A.13)

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

The key target for the end of BP2 was consistent annual delivery of FES and related insight publications, including a well-informed and widely supported reports, outlining key actions to achieve net zero. We aimed to provide additional regional insights to feed into downstream processes alongside agreement of feedback loops with regional stakeholders. We also targeted ongoing updates to pan-European and country-level electricity and energy demand models, as well as the adaptation of models to meet stakeholder feedback and evolving needs.

What have we achieved by the end of BP2?

We published our Future Energy Scenarios: Pathways to Net Zero (FES) 2024 analysis with the launch events taking place week commencing on 15 July. The FES 2024 launch saw over five thousand stakeholders engage either in-person, online or on catch-up. We hosted an in-person panel event, followed by four deep-dive webinars.

Our FES 2024 key messages, changes we made to move from scenarios to pathways, our refreshed framework, and the improved accessibility of our publication, were very well received by stakeholders.

For FES 2024 we implemented new models for electricity and hydrogen supply capacity modelling. For FES 2025, these models are being brought together to provide greater whole system modelling capability. Alongside this we have introduced new demand models for industrial and commercial sectors and significantly improved our heat modelling capabilities. Our tools for Gas Demand Statements have been modernised, enhancing their flexibility and resilience, and the outputs will be utilised by gas-focused teams across NESO to ensure consistency.

Our regional building blocks data fed into downstream processes such as the transitional Centralised Strategic Network Plan and the Electricity Capacity Report, and other regulated activities such as the Distribution FES (DFES) and RIIO3 activities carried out by electricity and gas network operators. The significant work required in moving from scenarios to pathways and developing proposals for Strategic Energy Planning, including RESP, resulted in reduced regional commentary within the main FES publication, but this did not impact the level of granular data available within our data workbook.

In the first quarter of 2025, we have published a new FES methodology document for FES 2025, a new requirement for us, alongside a summary of stakeholder feedback and how this is shaping our modelling for 2025.

How did our approach maximise outcomes?

Our approach to modelling development is based on a combination of stakeholder feedback, customer needs, and our own expert insights and research. Looking at the whole energy system helps to understand how different parts connect and affect each other, and enables us to produce data and insight that is relevant and useful.

We have introduced additional challenge and review sessions with gas and electricity network operators, government and the regulator with an increased focus on our inputs and assumptions. Changes to our FES 2024 pathways were made as a direct result of these sessions, particularly around hydrogen.

By providing additional opportunities for feedback and further detail around assumptions, through the introduction of new supporting documents (such as our Assumptions Log) and a focussed webinar we have improved the transparency of our process. We continue to welcome feedback on how we can further improve.

Winter & Summer Outlook (A13.1)

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

The key target for the end of BP2 was consistent annual delivery of the seasonal Outlook reports and accompanying datasets. We aimed to produce a clear and transparent assessment of the electricity security of supply outlook for each season to inform the energy industry and support effective preparation.

What have we achieved by the end of BP2?

We published our Summer Outlook on 15 April 2024 and our Winter Outlook on 8 October 2024. In addition, we published an Early View of Winter, alongside the Winter Review and Consultation on 5 June 2024. The Winter Outlook was published alongside the National Gas Winter Outlook at an Ofgem hosted launch event. Alongside the industry launch, the underlying analysis in both the Summer and Winter Outlook were presented at various industry events, as well as the Operational Transparency Forum (OTF).

For the 2024 seasonal outlook documents we made several structural changes to the reports. We sought to more clearly structure our Winter Outlook around two key metrics of adequacy in order distinguish more clearly between the De-rated Margin, and corresponding Loss of Load Expectation (LOLE), and the Operational Surplus. Alongside our adequacy metrics we sought to enhance our seasonal outlook reports through deeper assessment of current signals in interconnected power markets, and the sensitivity of security of supply to developments in global energy markets.

Stakeholder feedback, internal expert insights and research projects continue to inform our adequacy modelling and operational analysis. We seek to refresh the structure and content of each report to ensure that changes to the electricity system, and in the wider market context, are reflected in the analysis and highlighted in the messaging.

How did our approach maximise outcomes?

The underlying analysis in our Summer and Winter Outlook publications is used to support our close and continued engagement with Government, Ofgem and National Gas. This engagement provides opportunity for challenge and review of our assumptions and enables coordinated assessment of emerging risks and any necessary steps that would be required to build resilience. Our analysis is also used to support security of supply dialogues with neighbouring TSOs and wider seasonal preparations.

To ensure that our publications continue to improve, and contain information necessary to support industry planning, we seek feedback through various channels. Comment and suggested improvements are sought during presentations to various industry groups, via the Operational Transparency Forum (OTF) and through the consultation contained in the Winter Review report. We seek to supplement the main report with a data workbook which contains underlying assumptions and model outputs and welcome feedback and comment on our analysis.

Bridging the Gap (FES) (A13.4)

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

Success was defined as delivering a well-informed and widely supported report outlining key actions to be taken in the near term to achieve net zero. This was originally intended to be delivered through our Bridging the Gap (BtG) initiative. Over the course of BP2, we made a strategic decision to retire the standalone BtG activity and instead deliver on this ambition through NESO's wider energy insight function. By embedding the BtG principles into a more structured and integrated model, we aimed to improve the reach, policy relevance and long-term sustainability of this energy insight work.

What have we achieved by the end of BP2?

We achieved the intent of the original Bridging the Gap milestone through the delivery of the energy insights function as NESO. One notable example of an energy insight delivered during six-month period from the formation of NESO to the end of BP3 is delivery of the Clean Power 2030 (CP30) report. This report was informed by stakeholder input and underpinned by rigorous analysis on how to deliver a clean, secure and operable power system by 2030. CP30 provided whole-system advice on how to deliver a clean, secure, and operable power system by 2030. This work built upon established stakeholder engagement processes from both FES and BtG.

CP30 engaged 318 stakeholders from across the energy industry, government, and civil society, using a structured approach that included bilateral meetings, stakeholder forums, engagement events, and public feedback submissions. Throughout the process, interim analysis was published openly on our website, enabling stakeholders to provide real-time input and challenge assumptions. This iterative process directly shaped key decisions, including the consolidation from three pathways to two, the refinement of technology deployment limits, and the clarification of institutional roles required to enable delivery. Stakeholder feedback was incorporated into the final report, reflecting widespread concerns that achieving clean power by 2030 required urgent, coordinated action from Government, Ofgem, and NESO.

Compared to previous BtG work, CP30 represented a significant increase in scale, analytical depth, and cross-government alignment. Its outputs have directly influenced the Government's Clean Power 2030 Action Plan, which adopted NESO's advice as a foundation for its policy and regulatory roadmap. The programme has also shaped ongoing NESO workstreams, including FES 2024, whole-system planning, and operability analysis.

How did our approach maximise outcomes?

Our approach maximised outcomes by embedding early engagement, transparency, and open challenge within a structured, policy-driven advisory model. Building on engagement models developed in FES and BtG, we established a continuous feedback process that combined structured stakeholder forums, bilateral engagement, and open consultation windows. This ensured that CP30 evolved in response to real-time input and remained aligned with stakeholder expectations.

A recurring theme from stakeholder engagement was the urgency of action needed to enable clean power delivery. Many participants stressed that progress would only be possible if Government, Ofgem, and we acted decisively to accelerate planning reform, streamline connections, and improve investment certainty. These messages were explicitly incorporated into the final report, shaping the enabler framework and ensuring that proposed pathways reflected not just technical feasibility but policy, regulatory, and commercial reality.

Stakeholder feedback directly influenced core analytical decisions. Concerns over offshore wind deployment realism led to adjustments in assumed build-out rates and a refinement of pathway structures. Diverging views on the role of hydrogen for power generation resulted in a more nuanced approach to dispatchable capacity requirements. Feedback from local authorities, developers, and civil society organisations led to greater emphasis on institutional roles, planning reform, and consumer impact considerations.

Internally, we strengthened governance by integrating CP30 into our whole-system planning functions, ensuring alignment with FES and wider energy system modelling efforts. By structuring our engagement, refining our assumptions in real time, and publishing transparent interim analysis, CP30 delivered a more credible, actionable, and widely supported pathway for achieving clean power by 2030.

Connections (A.14)

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

The ongoing management of connection contracts and Grid Code compliant connections, both with positive feedback from customers.

Delivery of a further enhanced customer experience of connections, considering specific support for smaller parties and those connected at distribution level. This includes well-attended whole electricity system connection seminars, improved systems and data and successful delivery of regulatory and policy change influenced by customer engagement.

Facilitate delivery of the Connections Portal, moving into Phase 2 developments.

Connections Reform – progression and delivery of tactical initiatives and wider, long-term transformation:

- Five-Point Plan
- Connections Action Plan
- Connections Reform Phase 2 and 3

What have we achieved by the end of BP2?

Summary

Our estimates suggest that Transmission and Distribution projects in the transmission queue and waiting to connect could reach 800 GW by the middle of this year without further intervention. Despite action through our Five Point Plan making incremental improvements, we can only make the transformative change required through the radical actions set out within our 'TMO4+ reform package, which was approved by Ofgem shortly after the end of BP2. On 15 April 2025, Ofgem published their decision to approve the suite of industry code modifications, Connections Methodologies and Licence Changes.

Ahead of this, we brought forward Connections Reform Programme plans, and in the second year of BP2, we increased the pace and scale of connections reform activity, building on tactical initiatives to develop detailed reform proposals in collaboration with customers and networks.

Connections Reform

We have made significant progress in delivering a transformation of connections during Phase 3 of Connections Reform. At the start of the second year of BP2, we published our intention to go further and faster with our reform proposals, setting out how we would take forward 'TMO4+', applying Gate 2 criteria to projects in the existing queue, as well as to new projects applying for existing connections. In mid-2024 we further extended the proposed TMO4+ arrangements to ensure 'strategic alignment' between the connections queue and strategic energy plans published by Government.

We raised the relevant Code Modifications in April 2024 to propose the regulatory framework required to deliver connections reform. These modifications were all progressed under urgent arrangements and in December 2024, CMP434 'Implementing Connections Reform', CMP435 'Application of Gate 2 Criteria to existing contracted background' and CM095 'Implementing Connections Reform' were submitted to Ofgem, with their decision to approve being published in April 2025. The industry Code Modification process involved an unprecedented number of Workgroup meetings (over 50), for Code Modifications granted urgency, across a five-month period. More than 60 representatives from industry were involved with shaping the final proposals and alternatives through Workgroups and wider industry input were obtained through the Workgroup Consultation, and finally the Code Administrator Consultation.

Since December, we have raised two additional Connection and Use of System Code (CUSC) Modifications which have also been granted Urgent status. These are CMP446 'Increasing the lower threshold in England and Wales for Evaluation of Transmission Impact Assessment' and CMP448: Introducing a Progression Commitment Fee to the Gate 2 Connections Queue | National Energy System Operator. The Final Modification Report for CMP446 was submitted to Ofgem at the end of March and, if approved, will facilitate the timely connection of distribution projects that have minimal impact on the transmission network in England and Wales. CMP448 proposes to introduce a new fee payable by those in Gate 2 on termination or reduction in capacity, ensuring the connections queue is comprised of committed and viable projects. This Modification is in train and if approved, will complement wider TMO4+ reforms, which the urgent timeline aligns to.

We have developed and consulted with stakeholders on three connections' methodologies: Gate 2 Criteria Methodology, Project Designation Methodology and Connections Network Design Methodology. These are new and detailed documents, complementing the industry code proposed solutions by setting out the 'rules' for how NESO and the network companies will implement Connections Reform. We have taken this innovative approach to ensure the reformed arrangements are agile and can be reviewed and updated at least annually. The methodologies allow us to respond rapidly and flexibly to any new policy development, whilst at the same time providing visibility and transparency to industry and encouraging feedback through consultation. We submitted the three methodologies to Ofgem for decision in December 2024 and these were approved in April 2025. Collectively, the methodologies ensure that the reformed connections process:

i) prioritises and supports delivery of 'ready' projects that are progressing towards completion; and
ii) aligns the reformed queue with government strategic energy plans (firstly CP30, then Strategic Spatial Energy Planning (SSEP) in due course) to ensure efficient transition towards net zero by 2050 whilst promoting growth and investment.

In addition to the code changes and methodology creation required to deliver reform, we have supported the licence changes led by Ofgem. We have input informally and formally into two consultations to ensure that the wider regulatory framework supports the successful implementation of connections reform.

The suite of final proposals for connections reform have been delivered to the same timescales as originally planned within BP2 before the introduction of the 'strategic alignment' element to reform.

Connections Action Plan

- Letter of Authority (LoA)

In accordance with the Connection Action Plan to raise entry requirements, we successfully implemented CUSC Modification CMP427 in Q1 2024, introducing the LoA requirement for new directly connected applications. An 11.65% reduction in applications was observed from April to December when comparing the same periods between 2023 and 2024, highlighting the LoA's potential impact in deterring speculative applications from entering the queue. While a 252% increase in applications was noted in January when comparing January 2024 to January 2025, this was largely driven by the applications pause implemented in January 2025.

- Detailed reporting of connections data

We have developed our reporting of detailed connections data to support policy development, process implementation and decision making. This is through regular submissions, such as the monthly connections data books to Ofgem and the Connections Delivery Board (CDB), and specific publications. In December 2024, we published our Connections Reform Data Impact Assessment, providing detail on the potential impact of connection reform proposals on the connections queue.

Connections – Five Point Plan

Before the end of 2024, we implemented Queue Management milestones in all customer agreements with a post-November 2025 connection date, supporting improved project progress. We have actively monitored customer agreements with a pre-November 2025 connection date to ensure continued project progress and implementation of Queue Management milestones.

All second step offers from the two-step process were issued in May 2024, reflecting improved Construction Planning Assumptions (CPAs) from the Transmission Works Review (TWR).

Further overall benefits from the new methodologies to improve background CPAs under the TWR were impacted by the very large increase in new applications received across this period.

In relation to accelerated non-firm offers for storage, over 5 GW of projects have signed offers in England and Wales and we have also rolled out this policy in SSEN-T's region with 1.9 GW of offers being sent so far.

Management of Connection Offers

To manage the increasing number of contracts and bridge the gap between the current connections offer process and the upcoming connections reform, we have proactively introduced two initiatives. Following decision and communication issued by Ofgem in August 2024, any new directly connected transmission application has received a

Transitional Offer. Subject to implementation of Connections Reform, Transitional projects will be able to apply for a Gate 2 offer providing the project meets the required criteria to receive an updated offer. Secondly, we have introduced a pause in applications, further to Ofgem's decision in January 2025, and this creates a stable platform for the Gate 2 to Whole Queue (G2tWQ) process whilst also providing clarity to customers through distinct pauses and deadlines ahead of the new process. We have communicated both of these arrangements to customers through multiple channels.

We have worked with DNOs directly, and collectively through the ENA's Strategic Connections Group, to develop technical limits and reallocation of capacity at Grid Supply Points where Distributed Energy Resources (DER) will benefit and issued revised Bilateral Connection Agreements to DNOs that enable accelerated connection offers where network capabilities allow.

<u>Connections Portal</u>

We have continued to develop the Connections Portal across the second year of BP2 to make ongoing improvements to customer connection journeys, whilst also enhancing supporting data management processes and rebranding when we became NESO. From a customer perspective, we have introduced Offers and E- Signing to allow customers to sign offers digitally. Customers can now also view sections of the portal more quickly and efficiently through the addition of filters to applications, pre-applications, projects and queries. We have introduced Consultant access to the Portal and Salesforce which now allows consultants to manage applications and projects for developers. In addition to customer-facing improvements, we have migrated the existing Security system into Salesforce, mitigating data risk and have automated the sending of data to our TO partners via an API.

How did our approach maximise outcomes?

<u>Connections Reform</u>

The addition of strategic alignment into the connections' methodologies required fast and efficient work with NESO and DESNZ teams developing CP30. Strategic alignment relates to ensuring projects align with the pathways within Government's CP30 Plan as well as a future proofed approach that can support delivery of SSEP. We reviewed a range of different options for whether/how to do strategic alignment and worked with a wide range of external industry stakeholders through industry groups, bilateral meetings and formal consultations. We listened to and acted on stakeholder feedback, making key amendments to methodologies, e.g. the introduction of 'protections' for more well-developed projects so that they will be included in the new queue. We have received considerable interest in our reform of connections from abroad and we have tested our proposals against arrangements from other countries.

We have held regular and extensive engagement with industry, both at transmission and distribution levels, on our journey to develop the detailed design and associated framework changes. We have provided monthly updates at connections forums, delivered regular bespoke seminars and webinars on reform, created and shared FAQ documents and held bilateral meetings with customers. We continued to run the monthly Connections Policy Advisory Group (CPAG) until the end of 2024, with industry to seek steer on reform and also have taken a wide range of proposals of the Connections Delivery Board (CDB) for information and steer.

Following feedback from industry on our initial proposal on a 'financial instrument' concept through the standard code change forum in October 2024, we took a different approach and conducted a call for input in November 2024 before raising a revised and refined CUSC Modification Proposal in February 2025. The call for input received 132 responses which identified common themes and issues we which looked to address in the CMP448 Proposed Solution raised.

At the end of 2024, in collaboration with all networks, we established the Connections Reform Implementation Hub which created a new way of working in partnership with network companies. The Implementation Hub includes a senior-level steerco which has identified various focussed workstreams to develop the detailed processes and systems that will underpin our interactions and the people and systems that support these, with the connections customer at the forefront of our considerations. Outputs will be required for Spring 2025. This has resulted in multiple weekly workshops in the run up to implementation of connections reform and includes DNO/IDNO specific workshops focusing on the distribution related impacts of connections reform.

Holistic Approach to Transmission and Distribution

Our proposed frameworks for delivery of connections reform take a holistic approach to transmission and distribution customers. Sections of the connections methodologies are about the roles and responsibilities of DNOs/iDNOs and provide transparency on the implications for embedded customers. We have held joint seminars and webinars with networks to ensure messages to customers are transparent and consistent. We have continued to engage with and play an active role in the meetings under the ENA's Strategic Connections Group (SCG), communicating regularly on the impact from Code Modifications during development and working collaboratively to find appropriate solutions for embedded customers.

The Implementation Hub has been actively considering reform proposals for connections at transmission and distribution and was established on a whole electricity system foundation. Through some of the process workstreams, we have aligned implementation processes and shared best practice between NESO and networks.

System Operability Framework

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

Complete; Our operability strategy ensures future system operability. It will improve network safety and reliability by ensuring that future operational challenges can be addressed securely. It will drive lower bills by changing the way we operate and seek better solutions, tested through innovation projects where relevant, SOF publications work together with the Operability Strategy Report to provide clear requirements to stakeholders. Plans and associated frameworks / funding arrangements are in place to facilitate operability outcomes.

What have we achieved by the end of BP2?

During the BP2 period, we delivered two Operability Strategy Reports (OSR). The first was delivered on time and focused on the final areas needed to achieve our zero carbon ambition in 2025. The second OSR was postponed as a result of the Clean Power Plan work and was to enable us to ensure the OSR integrates with the Clean Power 2030 framework. The 2025 OSR begins to encompass our whole system role by exploring some whole system impacts on electricity system operability. The 2025 OSR, in conjunction with the electricity Markets Roadmap, also goes a long way to meeting the Government's clean power action to deliver an Operability Strategy.

Elsewhere in System Operability, in May 2024 we published a report into the current state and future plans for sub-synchronous oscillations, following events in summer 2023. Since the report we have progressed a code modification to acquire Electromagnetic Transient (EMT) models from assets connected to the grid prior to September 2022. This will enable us to transition from models for a system dominated by synchronous machines to one dominated by inverter-based resources. It has also led to us form an industry work group to develop a code modification which would mandate grid-forming technology on certain asset types, which support the transition to a clean power electricity system.

How did our approach maximise outcomes?

Following the publication of the 2024 Operability Strategy Report (OSR), we ran an industry webinar in January 2024. It was well received with a score of 4/5 and 90% of respondents 'learnt something new'.

We engaged with industry in Q2 2024 getting feedback on the previous OSR and views on the next OSR. In response to the feedback, the 2025 OSR was developed to move away from chapters covering each of the seven operability areas, and to a scenario based report, similar to Bridging the Gap: a Day in the Life from 2022. We also included a section on Stability Phenomena, and developed the publications map into an interactive version; both in response to feedback.

The decision to postpone the 2025 OSR was taken in early September. This allowed us to incorporate data and analysis from our Clean Power 2030 (CP30) advice into the illustrative examples and highlight where the CP30 enablers would help overcome the future operability challenges.

Throughout the investigation into sub-synchronous oscillations we collaborated with Transmission Owners and Users. We consulted with research partners to explore novel approaches to investigate sub-synchronous oscillations. We also sought operational experience from international system operators in Ireland, USA, Australia and Finland to share experience and incorporate their knowledge into the post-event investigation. We presented our experience in public venues such as the Operational Transparency Forum and The Global Power System Transformation Consortium.

DER Visibility

Please note that our 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.

The TIDE (Transformation to Integrate Distributed Energy) programme has committed to delivering agreed BP2 milestones in its journey to delivering greater DER & CER visibility and access. Of the seven key milestones (Table 1), we delivered six across three phases: Phase 1, Phase 2 and Phase 3 Alpha, up until March 2025.

Table 1: TIDE (DER Visibility) Programme BP2 milestones and delivery status

Phase	Role	Deliverable	Commentary	Status
1	3	D15.8.2	Complete project scoping with external stakeholders to enable operational visibility of DER	Complete
	1	D1.5.1	Increased DER Visibility in real-time operations.	Complete
	1	D1.5.4	Operational coordination and liaison	Complete
2	3	D15.8.2	Initiate IT discovery phase to understand impacts on required changes to systems and define change strategy	Complete
	3	D15.8.2	Complete IT discovery phase and identify costs of implementation	Complete
3 Alpha	3	D15.8.2	Commencement of requirements and design phase to develop detailed IT solution to enable DER visibility	Complete
	3	D15.8.2	Commence building the storage and transfer capability to utilise bigger volumes of data associated with a larger number of operational metering data points	Milestone drafted in 2023 pre programme launch and is no longer applicable to the TIDE programme. The TIDE programme has communicated this with both the NESO Regulatory team and Ofgem directly with acknowledgement that milestones set as

				conceptual targets pre programme initiation may not be valid by close of the period.

Since commencing BP2 in April 2023, we have:

- ✓ Recruited and established a core delivery team
- ✓ Collaborated with industry to draft a vision, design principles, and roadmap
- ✓ Captured and prioritised ~200 industry use cases and ~c200 data points to underpin this Vision
- ✓ Considered how advancement of DER & CER visibility & access was meeting real-time operations requirements
- ✓ Conducted NESO business, technology & policy impact assessments to determine the detailed activities required within NESO to achieve the vision and uses cases
- ✓ Agreed DNO Impact Assessment approaches with DNOs
- ✓ Progressed the quantitative benefits assessment for the detailed scope of the TIDE Programme
- ✓ Commenced NESO solutioning with DD&T and NESO business teams, allowing TIDE to progress delivery of use cases from BP3 period onwards
- ✓ Progressed three innovation projects (DERIVE, Cascade, Fractal Flow) to identify solutions to future-facing use cases and commenced the alpha phase of Fractal Flow during which we defined requirements and then trialled a minimum viable product (MVP) based on those requirements. With Fractal Flow, we can provide analytical insights to NESO control Room Operators via an engine used to reduce uncertainty in forecasts of demand and service availability at the GSP level.
- ✓ Advanced demonstrator projects to derisk delivery, such as accessing smart meter data via Smart DCC, establish data governance process for CER/DER data, and agreeing harmonisation and prioritisation of NESO – DNO Operational Data.

Achieving DER & CER Visibility & Access requires much more than the TIDE programme. During BP2 we have collaborated with multiple NESO initiatives to support delivery of other key BP2 outcomes to delivery additional value, such as:

- Supporting definition of bilateral connections agreement through assuring NESO-DNO data sharing agreements
- Supporting NESO's regional development programmes' creation of regional NESO-DNO solutions such as MW Dispatch and GSP Technical Limits
- Informing the definition of key programmes related to DERs & CERs including Primacy, the Enabling Demand-side Flexibility Programme, the Operational Metering Standards Review.

In BP3, we will work with industry to develop and agree an industry transformation roadmap. In parallel, we will explore opportunities to deliver benefits early through achievement of priority NESO use cases, targeting modelling & forecasting, real-time operations, outage planning & procurement use cases. To support our work with industry partners to agree an industry transformation roadmap, we require Ofgem to provide NESO with a formal mandate to own delivery of TIDE as an industry transformation programme. This will also need to entail establishing an industry delivery structure, collaboration agreement, and governance for the delivery of the roadmap and plan.

Regional Development Programmes (RDPs) (A15.5)

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

Whole system dispatch capabilities delivered via Generation Export Management Scheme (GEMS) and Scottish Power Distribution Active Network Management (SPD ANM) integration solution, establishment of Grid Supply Point (GSP) Technical Limits and processes.

IT implementation complete to deliver operability solution for managing battery storage in the Midlands and East Anglia. Service enhancements have been delivered to ensure efficient constraint management tools.

Enduring process developed and established with consumer benefits identified from initial outputs.

Basic functionality required by the RDP is under development.

What have we achieved by the end of BP2?

In the BP2 period, we collectively decided with our partners and stakeholders to cease activity on the GEMS project deliveries. Our project partner encountered several impassable technical issues, cyber security concerns, and concerns over the implications for a transmission company of full compliance with Balancing and Settlement Code (BSC) (BM dispatch rules), making it impossible to proceed with the original GEMS design. After an extensive options assessment, we, along with our partner Scottish Power Energy Networks (SPEN), decided to adopt the Open Balancing Programme (OBP) as the way forward to achieve the original intention of GEMS dispatch automation. This represented a more streamlined, lower-risk, and scalable solution delivery to meet the project's needs.

We decided to repurpose and redefine our approach to the remaining RDPs to maximise consumer benefit. Under RDPs 3&4, we enhanced the MW Dispatch functionality and service delivered as an MVP under RDPs 1&2, while delivering the battery storage solutions initially scoped in the RDP plans as part of RDP 5. This RDP will also deliver GSP Technical Limits functionality and changes to the wider GB network. Within BP2, for RDP 3&4, we have delivered a series of technical and process enhancements to the MW Dispatch service in the NGED and UKPN regions. This has aligned business processes for MW Dispatch-enabled DNOs and internally within NESO, addressing previous misalignments due to different timelines under RDP 1&2. We have automated several business and technical processes, such as the exchange and processing of unavailability data from DNO to NGED, and the registration of DERs for the MW Dispatch service. Additionally, we collaborated with the NESO Control Room and IT teams to provide a more flexible approach to dispatch instructions, allowing management at both GSP and Constraint boundary levels.

All the above changes within the MW Dispatch service will ensure a scalable and enduring solution as the volume of DERs and associated MW capacity increases in the relevant DNO regions, supporting our drive to Net Zero and decarbonisation. As part of transitioning MW Dispatch to BAU, the RDP/MW Dispatch project team is working closely with the operational and readiness teams to ensure a smooth transition and successful adoption of the service within all operational teams.

Finally, in addition to our original plans for delivery, we are working with both NGED and UKPN to extend the current 'ahead of time' unavailability reporting data exchanges from DNO to NESO beyond the current MW Dispatch-related GSPs and registered DERs. This extension will include all DERs and GSPs within the DNO licence areas. This will enable our Network Access Planning teams to make more informed and effective outage planning and system access decisions, while also laying the foundations for wider data exchange to support our DER Visibility programme.

RDP 5 – The minimum viable product (MVP) GSP Technical Limit (TL) infrastructure was successfully delivered for NGED enabling/accelerating DER connections without the need for reinforcement. We have also documented the end-to-end process for the required IT infrastructure to enable GSP Technical Limits that will provide clarity to internal and external parties when deploying GSP TLs at other DNO sites in the future.

RDP 6 –The complexity of the Scottish transmission network, presence of Load Management Schemes, and other control schemes that were deployed historically have presented significant challenges and conflicts associated with the deployment of a MW Dispatch solution under RDP 6. We worked with SPD to validate the estimated benefit that can be realised from deploying this solution and concluded that approximately 50MW of DER capacity will be available under the MWD scheme, presenting little value for consumers. This is compounded by the recent approval of a parallel 132kV network reinforcement that will increase capacity and reduce constraint costs.

The anticipated approval of GC117 also greatly reduces the reach of the MWD parties, as all future Generators (inclusive of DERs) with a capacity ≥10MW will be classified as Large Power Stations and therefore will be part of the Balancing Mechanism and available for NESO to instruct directly.

How did our approach maximise outcomes?

As we approached the end of BP2 we wanted to deliver the best value for end consumers whilst also supporting key objectives such as the Connections 5 Point Plan.

Therefore, upon reviewing the original scope for RDP 3 and 4 and considering challenges in the Connections space, we decided to being the previous NESO concept of a GSP Technical Limit project under the RDP umbrella and deliver it as RDP 5. This would also support the objectives for Midlands and East Anglia battery storage.

This also allowed us to repurpose RDPs 3 and 4 to deliver the enhancements detailed above, ensuring a robust, scalable, and enduring solution for MW Dispatch to support the planned DER capacity increases.

In our work with DNOs on RDP 3 and 4 to deliver MW Dispatch enhancements, we opted for simultaneous IT technical delivery wherever possible. While this made coordination more challenging by aligning three parties' schedules instead of two, it increased efficiency and cost-effectiveness by undertaking IT changes only once, reducing development, project management, and testing costs.

RDP 5 (GSP Technical Limits) - Our collaborative approach with all DNOs and TOs over the RIIO 2 period produced GSP Technical Limits commercial solution. This product has enabled accelerated DER connections without the need for reinforcement, while ensuring the appropriate rules and controls in place to protect SQSS. By the end of FY25/26 we anticipate GSP TLs to be established at 3 DNOs with the remainder to follow to align with the DER Technical Limit connection offers. We have also documented the end-to-end process to provide clarity to stakeholders and streamline future GSP Technical Limit deployments as required.

RDP 6 (SPD MWD) – Noting the complexity and associated challenges associated with RDP 6 detailed above, we worked diligently with SPD to confirm that the long-term consumer benefit outweighed the cost of implementation in the Dumfries and Galloway area. It was concluded that there was minimal value in deploying the MWD solution in the Dumfries and Galloway area. We will continue to work with SPD to determine if another area of the network could provide a more sustainable consumer benefit.

Network Access Planning (NAP) (A.16)

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

Planning and Outage Data Exchange (PODE)

Ongoing eNAMS improvements releases taking into account stakeholder feedback. Expansion of our existing MWD data sharing methodology across existing MW Dispatch enabled DNOs and scoping of future strategic outage planning changes to be developed beyond BP2.

System Operation:

Provision of time ahead outage plans to support security and resilience of electricity system. Build whole electricity system and carbon intensity considerations into our NAP processes. Investigate opportunities and implement solutions for process automation to drive efficiency and consistency.

What have we achieved by the end of BP2?

PODE:

We delivered a series of eNAMS functionality and code change releases to provide improved business processes and user experience. Scoping and design of expansion of MW Dispatch unavailability reporting to non-MW Dispatch relevant DERs and GSPs. Commencement of cross NESO / DNO data exchanges to provide more detailed and granular information to drive more effective and efficient outage decisions. Future strategic changes scoped via NESO / DNO collaboration in readiness for post BP2 development and delivery.

System Operation:

All time ahead outage plans and processes in place and contributing to system security and robustness. Consistent processes and procedures in place, along with the introduction of some automation developed via stakeholder engagement, solution design and Sandbox environment development with users trained and aware of new developments.

How did our approach maximise outcomes?

We have continued to work collaboratively and constructively with all industry partners to drive forward our key BP2 deliverables and objectives. In particular, we have worked closely with both NGED and UKPN to drive forward our PODE data sharing aspirations ensuring effective and joined up governance and decision making via regular updates and formal governance processes. We have also worked with both SSEN and UKPN to agree a series of proposed strategic outage planning improvements and changes for potential roll out and implementation to wider industry.

Centralised Strategic Network Plan (CSNP) (A22.1)

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

Start the transition of existing network planning activities to the enduring Centralised Strategic Network Planning Process.

What have we achieved by the end of BP2?

Development of the CSNP methodology, in collaboration with Ofgem and other key stakeholders continued throughout this period with:

- the commencement of the working groups to scope the detail of the net methodology;
- the publication of the CSNP high level principles document for consultation in December 2024;
- continuation of the working groups and detailed design working toward the final methodology;
- the publication of a summary of the consultation responses in March 2024.

Revised completion dates were agreed with Ofgem (and set out in licence conditions), due to interactions with other spatial plans and connection reforms. Consultation on draft methodology will be published by end of June 2025.

How did our approach maximise outcomes?

Our approach to maximising outcomes in developing the Centralised Strategic Network Plan (CSNP) methodology centred around comprehensive stakeholder engagement. This was achieved through a multi-faceted strategy that included:

Bilateral Meetings: We conducted one-on-one meetings with key stakeholders to facilitate in-depth discussions and gather specific feedback. This personalised approach helped us understand individual stakeholder perspectives and incorporate them into the CSNP development process.

Focused Working Group Sessions: By organising targeted working group sessions, we were able to delve into specialised topics. These sessions provided a platform for stakeholders with common interests to collaborate and contribute their expertise, ensuring that the methodology was robust and well-informed.

External Consultation Document: We issued a detailed consultation document alongside the Strategic Spatial Energy Plan (SSEP) and transitional Centralised Strategic Network Plan (tCSNP) methodologies. This synchronised release allowed us to clearly communicate how these plans interconnect, providing stakeholders with a comprehensive understanding of the broader strategic context.

To enhance engagement further, we hosted an external webinar. This event provided stakeholders with an opportunity to learn more about the CSNP methodology and interact directly with the NESO team. During the webinar, participants could ask questions and clarify any uncertainties, fostering a transparent and open dialogue.

The response to our consultation was significant, with over 50 submissions from a diverse range of stakeholders. This high level of engagement has enriched the CSNP with a wide array of insights and perspectives. The feedback received was instrumental in highlighting the importance of stakeholder involvement and offered valuable guidance on structuring future engagements.

Overall, our approach ensured that the CSNP methodology is being developed with comprehensive input from stakeholders, maximising its effectiveness and alignment with broader energy transition goals. By fostering an inclusive and interactive process, we were able to build a methodology that is both strategic and responsive to stakeholder needs.

Offshore Coordination (A22.2)

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

Work progressed in line with Offshore Transmission Network Review project board timelines.

What have we achieved by the end of BP2?

Over the BP2 period we have been undertaking the Holistic Network Design Follow Up exercise (HNDFUE) which included strategic designs the offshore connections for Crown Estate Scotland's Innovation and Target Oil and Gas (INTOG) and The Crown Estate's Celtic Sea Leasing Rounds. These are the final two exercises which close out the HNDFUE by completing the work asked of us under the Offshore Transmission Network Review (OTNR). The completion of these design recommendations totals over 53GW across 34 different projects of offshore wind across HND, HNDFUE, Celtic Sea and INTOG.

We've also been supporting the TOs and developers in their detailed network design by evaluating design refinements to our holistic network design through a process called Impact Assessment.

These exercises which make up 'HNDFUE' evaluate design options which bring power onto the transmission network in a way that which would optimise cost, mitigate deliverability and operability challenges, and minimise environment and community impacts.

A total of 13 seabed leases were granted by CES in the North Sea, following this we assessed each individual project to determine what projects to include in scope of our Holistic Network Design Follow Up Exercise (HNDFUE). Considerations for incorporation considered, progress to date, connection agreements and route to market amongst other project variables. A total of 3 developers across 7 INTOG projects were selected to be considered for coordination – alongside an interconnector. The interconnector NorthConnect opted in to the design exercise to allow potential continuation of work that had already been completed to date with another in scope developer (CENOS).

We carried out a design exercise to recommend how to connect the in scope projects to the onshore electricity network. The recommended design considered all four design objectives detailed in our Terms of Reference (ToR) which includes total cost, deliverability and operability, community impact and environmental impact. All four design objectives were considered throughout the design process on an equal footing whilst engaging with a broad range of stakeholders. We published our recommended design on 12 December 2024.

The Celtic Sea recommended design connects up to 3GW in two locations in South Wales and up to 1.5GW into the Southwest of England. Similarly to INTOG a number of shortlisted designs were assessed against our four design objectives. The Celtic Sea design is unique to other network design exercises previously undertaken as developers have yet to bid for the opportunity to develop in the three areas of seabed identifies by The Crown Estate for this leasing round.

Since the beginning of the Holistic Network Design and Follow Up Exercise we have worked closely with both The Crown Estate and The Crown Estate Scotland on the next rounds of offshore wind development, with the completion of the HNDFUE this is no different. We have developed a new process, Strategic Offshore Design Analysis (SODA) which aims to identify interface points where power from new offshore wind or interconnector projects might come onshore in anticipation of The Crown Estate announcing future leasing for offshore wind. This will feed into our Strategic Spatial Energy Plan, and enable us to undertake an offshore design exercise to inform the Centralised Strategic Network Plan and ultimately flow into the new reformed connections process. This longer term vision allows us to better account for network credible solutions within the SSEP and the CSNP. As SSEP and CSNP will ultimately inform the new connections process for capacity beyond 2035 we anticipate that this new strategic approach will ultimately reduce the need for additional ad-hoc analysis to refine the connections of individual projects in the future.

How did our approach maximise outcomes?

Working on the Celtic Sea designs prior to the leasing announcement takes a new approach on the connections queue by ringfencing the 4.5GW in advance so we can process efficiently with the connection contract process when the seabed Agreement for Lease are awarded by TCE. Whilst developing the Celtic Sea recommendation for the first time we also set up the Community Forum where we invited local authority representatives to provide feedback throughout the design process and included them as part of the wider Celtic Sea Workshops where they inputted across the detail of our recommendations.

Regarding INTOG whilst the leasing round included 12 different projects, we only included six in scope of the design process as detailed above. This was to ensure we were coordinating effectively and not holding back projects which were already well progressed. Also following extensive engagement with both NorthConnect and Cenos, deciding to include the interconnector in scope of the design exercise meant favourable outcomes for stakeholders and maximisation of work already progressed to date.

C.2 Delivery Schedule Status

Deliverable progress

For Role 3, 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 3 – 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 3 (System insight, planning and network development), the latest BP2 RIIO-2 deliverables tracker lists **62 deliverables** in total, which is made up of **221 milestones**.

- All **221** of these milestones were due to be completed by March 2025 or earlier
- Of those:
  - **1** is delayed in order to deliver an improved outcome for consumers
  - **12** are delayed due to reasons outside NESO's control
- Of the remaining **208**:
  - **205** (99%) are now complete
  - **3** (1%) are delayed due to NESO related delays

The results for the **221** milestones due to be completed by March 2025 or earlier are illustrated below:

Role 3 – Milestone status by deliverable

For milestones due by March 2025 or earlier

Ref	Deliverable name (shortened)	Complete	Delayed... Consumer Benefits	Delayed... External reasons	Delayed... Internal reasons
D11.1	Improved identification of when is the most economical	2			
D11.2	Improved identification of network needs	1			1
D11.3	Improved assessment of voltage requirements, and abi	1			1
D11.4	Improved assessment of stability requirements across	2			
D12.2	Potential solutions identified and direction established	2			
D12.3	Key changes to SQSS made or in progress	2			
D13.1	Published Future Energy Scenarios (FES), Winter Outlo	4			
D13.2	Update pan-European and country level electricity and e	1			
D13.2.1	Provide whole system regional insights	2		1	
D13.3	Shared insights on future energy expectations and requi	8			
D13.4	Bridging the Gap - produce evidence-based recommen	1			
D14.1.1	Managing an increasing volume of connection offers for	1			
D14.1.2	Contract management of connection agreements	1			
D14.2.1	Compliance monitoring of new connections in accordan	1			
D14.3.1	Establish dedicated Distributed Energy Resource (DER	6			
D14.3.3	Whole electricity system connection seminars on an on	8			
D14.3.4	Improving Systems and Data	8			
D14.3.5	Improving our internal processes	1			
D14.3.6	Proposing future policy and code improvements	2			
D14.4.1	Implement first phase of the ESO connections portal, in	2			
D14.4.2	Phase 2 of the connections portal concluded	8			
D14.5.1	Five Point Plan	5			
D14.5.2	Connections Reform Phase 2	3			
D14.5.3	Connections Action Plan - ESO delivery	6			
D14.5.4	Connections Reform Phase 3	5		2	
D15.1.1	System Operability Framework (SOF) documentation to	8			
D15.1.2	Innovation projects developing new operability solutions	2			
D15.2.1	Updates to customer offers and agreements – provide t	2			
D15.3.1	Changes to business procedures and processes follow	2			
D15.4.1	Data transfers between network organisations in accor	2			
D15.4.2	Technical modelling for use across the ESO – ongoing	8			
D15.4.3	Automation of data exchange mechanism and preparati	2			
D15.5.2	RDP2 of RIIO-2 (MW dispatch, South East, UKPN)	1			
D15.5.3	RDP3 of RIIO-2 (wider rollout & enhancements, WPD)	5			
D15.5.4	RDP4 of RIIO-2 (wider roll out & enhancements UKPN)	5			
D15.5.5	Deliver GB rollout of functionality developed through initi	4			
D15.5.6	RDP5 of RIIO-2	4			
D15.5.7	RDP6 of RIIO-2	1		2	1
D15.6.2	Further Grid Code modification implementation (arising,	5			
D15.6.6	Deliver major upgrades to our offline modelling tools, wl	2			
D15.6.7	Deeper Outage Planning go live in Offline Network Mode	2			
D15.6.8	Development & ongoing maintenance of EMT Capabiliti	6			
D15.6.9	Co-simulation analysis innovation project	2			
D15.7.1	Commence System State Targeted Monitoring and Con	1			
D15.8.2	Enabling whole electricity flexibility service provision thro	5			
D15.9.5	Provide Early engagement with stakeholders on implem	1			
D16.1.1	Year ahead regional outage programmes developed in	2			
D16.1.2	Detailed week and day ahead operational documentatio	2			
D16.2.1	Great Britain (GB) wide NAP process goes live including	7		1	
D16.3.3	Finalise new processes in readiness for approval of co	1		1	
D16.3.4	Deeper access planning go-live – frameworks, process	1	1		
D16.4.1	Scoping exercise concluded for delivery of enhancemen	3			
D16.4.2	Delivery of enhancements to outage notifications, to stir	3			
D16.5.1	Agreed future platform for any automation and create sa	8			
D16.5.2	Scope future automation development	8			
D7.1	Electricity Ten Year Statement (ETYS)	2			
D7.2	NOA Annual Report	3			
D7.3	Large Onshore Transmission Projects (LOTI) (previousl	8			
D8.1	Rollout of Network Services Procurement (NPS) approa	2			
D8.4	Early Competition	1		4	
N/A	Network Planning Review			1	
N/A	Offshore Coordination	1			
	TOTAL - Role 3	**205**	**1**	**12**	**3**

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 3. 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
Stability Requirements Calculation Toward NetZero (STARTZ)	This project will review the current methods of calculating system stability needs and implement automation and machine learning to calculate system stability needs for the GB network at a granular level.	The STARTZ project aims to develop an automatic solution for analysing extensive system data to determine future stability requirements. Since April 2024, the project team has overcome challenges in data sharing, model adjustments, and team changes, making significant progress in data validation, ETYS model setup, algorithm development, automation tool creation, and report preparation. The next phase will focus on calculating system stability needs, benchmarking, and finalising the report, with a handover workshop planned. The project is expected to be completed by mid-2025.	D11.4	Delivery	RIIO-2
Strength to Connect	The project is investigating improved metrics to assess the system strength and will be used to propose bespoke metrics for use in the small signal	Building on the success of developing the Impedance Margin Ratio metric for small signal stability, the project is now focused on creating a metric to assess system strength in the large signal stability domain. This new metric will	D15.2.1, D15.3.1	Delivery	RIIO-2

	stability domain and the large signal stability domain.	evaluate the ability of inverter-based resources to stay connected after severe network disturbances. The project is set to be completed in Q1 FY2025/26, and its findings will be used to update the network operability policy and guidance.			
Consumer Building Blocks (Phase 2)	This project will build on existing consumer building blocks to combine learnings from the first and second Demand Flexibility Service (DFS) and create a more granular set of archetypes for different electrified heating types with a large and recent dataset.	We surveyed domestic consumers who took part in the Demand Flexibility Service over winter 2023/24 and the evaluation report is due in Q1 FY2025/26. The low carbon heat archetypes work is focused on producing a set of heating profiles that consider different low carbon technologies, building characteristics, as well as consumer type and heating behaviour. The partner is developing a draft modelling tool based on building physics principles which calculates different heating demand profiles based on input thermal resistances, heat capacity, outdoor temperature, solar gains, and heater power. Work is ongoing to enhance the tool's capability to model the behaviour of different low carbon technologies.	D13.2.1	Delivery	RIIO-2
Automated Sub Synchronous	Ability to investigate a wider pool of	The project completed in March 2024, resulting in a Python-	D15.6.8	Complete	RIIO-2

Oscillation Identification	future scenarios for potential Sub Synchronous Oscillation (SSO) threats and develop an advanced tool useful for both planning and connections studies for NESO, TO and customers.	based automation tool designed to screen potential SSO scenarios from a large pool of network operating conditions. Since May 2024, the operability innovation team has extensively used the tool for frequency scanning of user electromagnetic transient (EMT) models for potential SSO issues, providing valuable insights. The DD&T team is now working on productionising the tool for deployment in a cloud environment and incorporating potential enhancements.			
RealSim: RealTime PhasorEMT Simulations	Investigating when and where to use phasor mode and EMT mode simulations for a given system condition and provide real-time simulation of the grid in that region for system stability & security and identification of stability risks.	The RealSim project concluded successfully in January 2025, delivering electromagnetic transient (EMT) and real-time simulation modelling and analysis of the South Coast GB network's stability, focusing on HVDC interconnections and wind farm capacity. Using PSCAD for EMT and Hypersim for real-time execution, the analysis resulted in a control solution designed, tested, and validated to maintain frequency stability in scenarios involving the loss of large interconnector flows. The proposed 'cooperative' control system allows	D15.6.8, D15.6.9	Complete	RIIO-2

		remaining interconnectors and existing wind farms to adjust their output, enhancing the region's frequency response. This approach ensures frequency stability as more inverter-based resources connect to the network and provides a framework for using real-time modelling to investigate system stability across the GB network.			
Powering Wales Renewably (SIF Beta)	Through delivery of a digital twin of the whole Welsh energy transmission and distribution systems, this project will provide a digital common interface to accelerate the integration of renewable generation, by enhancing locational visibility of system challenges and whole energy system status.	Following the successful delivery of a Proof of Concept in the Alpha phase, the Powering Wales Renewably (PWR) project has successfully applied for and obtained SIF funding for the final Beta phase, which started in January 2025. PWR has engaged key stakeholders across the project partner consortium to prioritise requirements, and development has begun on the first key delivery of the foundation use case, which is due later this year.	N/A	Delivery	RIIO-2
Neural BB	The project seeks, as a proof of concept, to use machine learning to create a surrogate model from a" black box" model of an	The most recent research developments in neural network (NN) modelling of generators and networks have been studied, leading to the development of a	D15.1.2	Delivery	RIIO-2

	AC/DC converter. The black box model and the surrogate are to be of the type used in power system computer aided design (PSCAD), a type of electromagnetic transient (EMT) simulation software.	methodology for training NN generator models. This methodology was improved after testing in isolation with different network conditions. The current work focuses on enhancing the NN model by testing various code libraries and developing its integration with PSCAD as a custom module in parallel.			
FastPress Alpha+	This project builds on the use of Artificial Intelligence to inform improved National Transmission System (NTS) network planning decisions, namely, to optimise the configuration of network assets to ensure sufficient pressure at NTS offtakes.	The project began with a discovery phase aimed at identifying innovative AI solutions applicable to both current work (focused on solving gas network scenarios) and future work (looking at the resilience and structure of the network). The feasibility and impact of these solutions were evaluated to propose a Proof of Concept (PoC). The project has now been accepted to continue into its Alpha+ phase, where the PoC will be further investigated and gradually transitioned into usable software for analysts.	D15.1.2	Delivery	RIIO-2
Virtual Energy System – Data Sharing Infrastructure Pilot	Digitalisation and data sharing are critical enablers to the achievement of net zero. This project is developing a	The DSI Pilot project has progressed through design and development in sandbox environments and is now planned to enter a period of trials with network partners. The development and	N/A	Delivery	RIIO-2

	Pilot for the Data Sharing Infrastructure (DSI), by bringing together expertise from NESO, project partners and the National Digital Twin Programme. The project will develop the initial DSI capabilities and demonstrate how it can support scalable data sharing through an outage planning use case. The pilot is an important phase in developing the wider objective of the Virtual ES and will leverage expertise from previous project stages to create and demonstrate the technology.	trials will support the definition of requirements and scope for the Minimum Viable Product (MVP) which has been described in NESO RIIO-2 Business Plan 3.			
Network Security in a Quantum Future (SIF Alpha)	This project supports the creation of an innovative risk management tool to assess the quantum threat to the energy network, mapping it to a diverse range of energy system assets, and enabling prioritisation of	This project has made significant progress since its launch in October 2024. The architecture for the Quantum-Aware Risk Management Tool (Q-ARM) is complete, with basic functionality in development. The Quantum Threat Tracker (QTT) has completed its architecture design report and is now in the initial implementation phase.	N/A	Delivery	RIIO-2

	appropriate mitigations.	Additionally, two test cases for the Energy System Specification and Product Ownership have been developed. The project is on track to conclude in April 2025.

C.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 3

For Role 3, the following question was asked:

> *'Considering System insight, planning and network development, which includes key activities such as Connections and Network access planning, Strategy and Insight (e.g. FES) and long-term Network development. Overall, from your experience in these areas over the last 6 months, how would you rate NESO's performance?'*

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

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

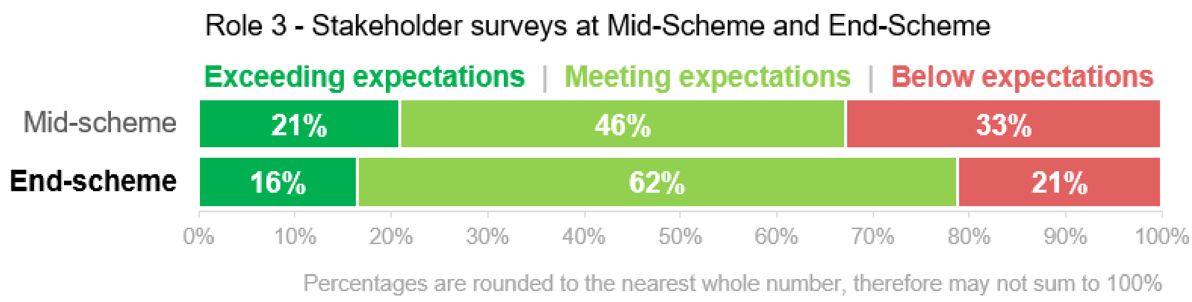
If they rated NESO as meeting expectations, they were asked what NESO needed to do to exceed their expectations.

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

For Role 3, we contacted **997** stakeholders, and received **146** responses to this question, which were distributed as follows:

- **16%** exceeding expectations
- **62%** meeting expectations
- **21%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 3
“Exceeding Expectations” **24** stakeholders scored us as “exceeding expectations”. Feedback on what we have done to exceed stakeholder expectations in Role 3 included:	• **Good communications and engagement from team** – Many responses praised our communication and engagement. “Excellent” communication materials are called out as a highlight. Another stakeholder stated, “the team are efficient, professional and friendly”. Other responses commended our engagement with other industry actors and engagement with specific forums and networks. • **Good level of experience and subject knowledge –** Responders highlighted our experience and subject knowledge, including excellent level of technical expertise. Other responses referred to our “clear foresight and wider implication awareness” along with “deep market expertise, ability to challenge assumptions and understanding of international best practice”. • **The Future Energy Scenarios (FES) team continues to impress –** Responses highlight good engagement on FES and found the team open and responsive to feedback. One stakeholder stated they are “looking forward to the 2025 FES Pathways and highly rated the early engagement through the Demand in-person event”. • **Effective collaboration with Transmission Owners (TOs)** – Partnership working with TOs was praised in responses. One praised our “clear Holistic Network Design (HND), CP30 objectives and support to initiate wider transmission works with TOs”. Another stakeholder highlighted we successfully “supported difficult TO outage combinations which carried higher network security risks, and extensive generation constraint

	costs". Another commended us working with the TOs to deliver the 2025 Consultation Report on the new outage planning initiatives. • Another stakeholder added they were "impressed with the consideration of deployed AI technology"
"Meeting Expectations" **91** stakeholders scored us as "meeting expectations". Feedback on what we need to do to exceed stakeholder expectations in Role 3 included:	• **Improve transparency and sharing of data and learning** - Stakeholders suggested there is a need for enhanced transparency and better sharing of data, including "more accurate information on upgrades and decision-making processes". They emphasised the importance of providing clearer scheduling information and presenting data in a more digestible format. Additionally, stakeholders suggested we should improve how we incorporate feedback from consultations and the clarity of network planning assumptions. • **Build on positive delivery from NESO teams overall** — Stakeholders feel our delivery has been good, but we can build on from it. For example, one stated "engagement has been positive and transparent, although quicker and more agile decision-making is needed to exceed expectations". Another response built on this "System insight and planning score highly, with regular updates from our account manager. Network development has seen uncertainty due to connection reform, but meeting expectations is a success amid these challenges". • **Faster and more timely communications** – Some responders stated we need to do more to address delays in responding, last minute outage cancellations and the reasons why. A couple of responses highlight they feel that communications and engagement in the Scotland area can improve. • **Go further on network development** – Several stakeholders expressed concerns regarding the prolonged process of network development. One also noted that "the current reform does not effectively address efficient management of the network, such as managing constraints". Additionally, another stakeholder said they "expect improvements in the approach to how the

	buildings sector evolves in line with network development". • **Other feedback suggested we:** - Need to do more to show independence from Ofgem and Government. - Must ensure that we understand the impacts on all customers, not just those directly connecting to the transmission system - Should implement clearer timelines and industry understanding of the overall process for activities across the various work streams.
"Below Expectations" **31** 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:	• **More transparency and better engagement with the market** – Some stakeholders suggested they would like greater transparency in the FES process and better engagement with the market. Some feel communication about contractual impacts and project changes should be more proactive rather than reactive. • **Improvements to the quality of data shared** – Several responders highlighted the need for improved data quality and delivery. They cited errors in the FES data workbook, unrealistic pathways, and inadequate communication on reinforcement and upgrades at Grid Supply Points (GSPs). They also raised concerns about the secrecy of historical outage data among Transmission System Operators (TSOs). • **Frustrations from Connections customers –** A couple of stakeholders expressed significant frustration with the handling of the connections reform process. They are concerned about the lack of transparency regarding grid connection costs, extended delays in connection offers, and the lack of protection for assets under construction. One response stated, "there is a need for NESO to improve communication and responsiveness to customer issues". • **Other feedback suggested we:** - Need to address network development which is woefully behind where the industry needs to be for a viable Net Zero outcome.

	- Did not share details on the network development in meetings. - Should be more proactive in helping customers resolve Distribution Network Operator (DNO) issues with Third Party Works.

C.4 Metric Performance

There are no metrics for Role 3.

C.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 3 are:

- Network Options Assessment (NOA) enhancements (A7-A11)
- Taking a whole electricity system approach to connections (A14)
- Taking a whole electricity system approach to promote zero carbon operability (A15)
- Delivering consumer benefits from improved network access planning (A16)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit. Deliverable activity statuses reflect the delivery of RIIO-2 milestones and do not recognise either work completed prior to April 2021 nor progress made towards yet to be completed milestones.

The Panel will also consider NESO's Regularly Reported Evidence (RRE) as part of the Quality of Outputs criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the NESO Performance Arrangements Governance Document guidance. For Role 3, the items of RRE reported in our mid-year 2023-24 report are:

- 3A. Future Savings from Operability Solutions
- 3X. Timeliness of Connection Offers
- 3Y. Percentage of 'right first time' connection offers

CBA: Network Options Assessment (NOA) enhancements (A7-A11)

BP2 End-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £929 million over RIIO-2. Due to the significant changes to the NOA process during the BP2 period, building towards the enduring CSNP, NESO produced the second transitional CSNP (tCSNP2) published under 'Beyond 2030' in March 2024. The report recommends a coordinated onshore and offshore network against our four design criteria, to connect up to 86GW of offshore wind. We do not believe this CBA appropriately reflects our performance, so we have provided a qualitative evaluation for this End-Scheme update.

<table>
<tr><th></th><th colspan="2">Estimated gross benefits during the 2021-26 RIIO-2 period (£m)</th></tr>
<tr><th>Area</th><th>BP2 Plan view</th><th>Latest view</th></tr>
<tr><td>1. Facilitate competition by embedding Network Services Procurement (Pathfinder) projects into the NOA</td><td>564</td><td rowspan="6">We have provided a written update for End-Scheme.</td></tr>
<tr><td>2. Extend NOA approach to all connection's wider works</td><td>148</td></tr>
<tr><td>3. Extending NOA to end of life asset replacement decisions</td><td>118</td></tr>
<tr><td>4. Network Options Assessment</td><td>69</td></tr>
<tr><td>5. Support decision making for investment at the distribution level</td><td>30</td></tr>
<tr><td>Total</td><td>929</td></tr>
</table>

Summary of progress during BP2

Since the consumer benefit was presented for the Network Options Assessment (NOA) program, there have been significant changes in how we assess and develop the future transmission network. These changes have largely replaced the benefits previously delivered by the NOA with other benefits, although we have not quantified them in the same way.

There are three key areas to consider:

1. The NOA approach has rapidly evolved into the transitional Centralized Strategic Network Plan, which was published in March 2024.

2. The conversation between Ofgem and NESO recognised that the benefit metrics in A7-A11 did not appropriately capture the benefits.

3. The ongoing evolution towards the CSNP, which is now being defined for delivery in BP3 and beyond.

During the BP2 period, we produced a major report on the future of the transmission network, which significantly deviated from the NOA approach. In March 2024, we published the Beyond 2030 report, which recommended a coordinated onshore and offshore network to connect 86GW of offshore wind in the second transitional centralized strategic network plan (TCSNP2). This plan superseded the planned NOA report and some specific enhancements proposed in our business plan. However, this report outlined a plan for £112bn investment in the transmission network over the next decade, combining our output from the Holistic Network Design Follow-up exercise with our assessment of the wider network options provided by the Transmission owners. Importantly, we made significant changes to the methodology for the TCSNP2 compared to the NOA, incorporating environmental, societal, and deliverability criteria alongside our economic assessment. We believe that the benefits that would have been delivered through the NOA have been more than delivered through the publication of the Beyond 2030 report.

In 2023, further discussions between NESO and Ofgem led to an agreement that the benefit metrics being tracked in A7-A11 did not appropriately capture the benefits due to the following reasons:

The reported benefit is complex to quantify and depends on external factors and parties.

- Determining a counterfactual for network build and establishing a baseline for benefit calculation is complex. For example, assuming "no build" overstates the benefit, as some network would be built without our planning role. Additionally, using a baseline of 'doing the opposite of our recommendation' feels contrived, assuming that we always build the wrong thing. Our assessments aim to find an optimal set of projects from the options we are given, using various criteria.

- The options assessed by NESO in our processes are produced and submitted by the Transmission Owners, meaning we do not have control over the input data for our assessments. We have a process for 'interested persons' (i.e., other third parties) to contribute solutions, but this mechanism currently does not work and is being reviewed for CSNP.

- Our economic assessments are based on the future pathways specified in the Future Energy Scenarios. As these pathways are updated, the stated benefit of a project could change.

In BP3, we plan to collaborate with the regulator to better define these incentives, their benefits, and appropriately report on them. We are currently developing the methodology for the Centralized Strategic Network Plan and the other elements of NESO's Role as Strategic Energy Planner. In our methodology, we will consider the metrics for identifying the value that the planning activity brings.

Combined status by milestone for relevant deliverables
(Activities A7, A8 and A11)

Status	Count	%
Complete	22	76%
Delayed – Consumer Benefit	-	-
Delayed – External Reasons	4	14%
Delayed – Internal Reasons	2	7%
Milestone no longer valid	1	3%
Total	**28**	**100%**

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

CBA: Take a whole electricity system approach to connections (A14)

BP2 End-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £23.6 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 quantitative and qualitative evidence of the benefits that A14 has delivered.

	Estimated gross benefits during the 2021-26 RIIO-2 period (£m)	
Area	**BP2 plan view**	**Latest view**
1. Efficiency Savings	22.6	We have provided a written update for End-Scheme, with revised measures of success to reflect the current position.
2. Customer Service Improvement	1.0	
Total	**23.6**	

Since October 2022, the Transmission connections queue has grown by more than 330GW and has been growing at an average of over 20GW per month for the last c18 months. The Distribution connections queue has also continued to grow, and at the current rate of growth, the total queue (across transmission and distribution) is likely to exceed 800GW by the middle of 2025. This is well over double the installed capacity we anticipate needing by 2050.

The policy landscape has also evolved with the Powering Up Britain Energy Security Plan, the Energy Commissioners Report on Accelerating Electricity Transmission Network Deployment, Government's Transmission Acceleration Action Plan and Ofgem and Government's Connections Action Plan. These were followed by Government's Clean Power 2030 Action Plan in December 2024, which also included a connections reform annex, that set out the permitted capacities of in scope technologies to 2035, for the purposes of issuing connection offers.

We brought forward plans to launch a Connections Reform programme in BP2 and completed Phase 1 within BP1.

Given all of the above, the original BP2 CBA for connections no longer reflects the most appropriate success measures, nor the scale and pace of connections change being delivered.

Therefore, as agreed with Ofgem before the Mid-Scheme Report, we have replaced our existing CBA and instead provide different measures of success to enable a clearer and more accurate data-driven performance narrative.

Summary of progress in 2024-25

Deliverable	Detail	Update
Five Point Plan	To improve connections timescales through a number of tactical initiatives, ahead of the wider reform project.	To ensure improved project progression, in line with CMP376 implementation requirements, before the end of 2024, we successfully implemented milestones in all customer agreements with a post-Nov 2025 connection date. Those with pre-Nov 2025 dates have remained actively monitored by policy and compliance teams to ensure continued project progression or, where necessary, implementation of queue management milestones All second step offers from the two-step process were issued in May 2024 representing improved CPAs from the Transmission Works Review (TWR).
Connections Action Plan (CAP)	Develop additional options for improvements to connections, identified within Reform Phase 2 (above). To engage stakeholders and present recommendation s to the Connections Delivery Board (CDB).	NESO change delivery was mobilised to reflect new CAP actions, which we are delivering efficiently Within this we continued to deliver the introduction of queue management milestones, the new Letter of Authority (LoA) entry requirement and publication of the bay sharing policy We also took forward a range of CAP actions relating to introduction of our proposed TMO4+ proposal to go further and faster to improve connections (see "Connections Reform Phase 3")
Connections Reform Phase 3	Final detailed design and regulatory approval phase (code mods, methodologies	We raised urgent code mods to underpin TMO4+ in April 2024. Following a very intensive period of numerous working groups and two formal consultations, the final code modification reports were

		and licence changes)	submitted to Ofgem for decision on 20 December 2024. After NESO was commissioned by Government in summer 2024 to produce advice on how to meet Clean Power by 2030, NESO proposed at the Connections Delivery Board to align the TMO4+ process with the Clean Power by 2030 Plan (CP30 Plan) and in due course, future strategic energy plans. We developed three connections methodologies in late summer 2024 that align TMO4+ with the CP30 Plan and strategic energy plans more generally. These were formally consulted on in November 2024 and final proposed methodologies were submitted to Ofgem for decision on 20 December 2024. In parallel we worked with Ofgem on proposed changes to NESO and TO and DNO licences to support implementation of TMO4+. Ofgem published its minded-to decision to approve the code mods, methodologies and licence changes associated with TMO4+ in mid-February 2025. We have also been working closely with network companies since October 2024 (via a new 'Implementation Hub') to design the detailed processes and systems that will be needed to deliver the new TMO4+ process, including the 'Gate 2 to whole queue exercise' from Spring 2025.
	Establish dedicated Distributed Energy Resource (DER) account	Continuously deliver on the use of DER, learn lessons and implement improvements.	We have worked with DNOs directly, and collectively through the Strategic Connections Group, to develop technical limits and reallocation of capacity at Grid Supply Points where Distributed Energy Resources will benefit. We issued revised over 150 Bilateral Connection Agreements to DNOs that enable accelerated

management function		connection offers for (DER) where network capabilities allow for technical limits. And updated the same number again for reallocation of capacity, to allow DNO's to further enhance and manage their connection pipeline.
Whole electricity system connection seminars on an ongoing basis	Ongoing seminars	We have continued to provide a regular series of both online and in person customer connections Forums and Seminars.

Combined status by milestone for relevant deliverables (Activity A14)

Status	Count	%
Complete	**57**	97%
Delayed – Consumer Benefit	-	-
Delayed – External Reasons	**2**	3%
Delayed - Internal Reasons	-	-
Total	**59**	100%

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

Supporting evidence

Type	Evidence
Performance Against Business Plan 2 (BP2) Deliverables	We have estimated that Transmission and Distribution projects in the transmission queue and waiting to connect could reach 800GW by the middle of 2025 without further intervention As a result, customers continued to get later and later connection dates despite the interventions through our 5 Point Plan. Therefore, aligned to the ambition within the Connections Action Plan, our goal is to reduce the average transmission connection dates for viable, net zero aligned projects to no more than six months beyond the date requested by the customer. Currently, this stands at c60 months. We can only do this through the radical actions set out within our

	proposed TMO4+ process, which, subject to Ofgem approval, is expected to be introduced in mid-2025.
5 Point Plan	*CAP target: The CAP target identified 150 GW estimated impact of the 5 Point Plan, however in April 2024 Ofgem noted that the CAP was likely to deliver 100 GW of benefit.* **Performance**: TEC Amnesty: The TEC Amnesty is now closed, and 7.9 GW of projects expressed interest in participating, of which 4.1 GW were implemented as anticipated. QM: Following CUSC modification CMP376 implementation, the six-month notice period for projects in the queue to either request a delayed connection date, or have QM milestones applied to their current date was successfully issued to all relevant projects. This puts us in a good position to robustly monitor project delivery against contracted milestones. Currently, at the end of 2024, 573 projects (221.9 GW) received an Agreement to Vary putting milestones in their agreements, with other projects categorised as in-flight mod apps or second step offers awaiting signature. In addition, for projects that were due to connect before Nov 2025, 30.9 GW of projects have or are seeking to delay their connection and therefore will receive QM milestones. Accelerated BESS: 9.3 GW of accelerated non-firm offers have been issued in the first phase to 20 projects in England and Wales with over 5GW projects being signed. We have also rolled out this policy in SSEN-T's region with 1.9 GW offers being sent so far.
RRE 3X - Timeliness of Connection Offers	In 2024-25, of the 1879 offers issued, 1745 offers were made within 3 months (93%) and 134 were issued after more than 3 months.
RRE 3Y - Percentage of 'right first time' connection offers	94% of connection offers were right first time in 2024-25.

CBA: Taking a whole energy system approach to promote zero carbon operability (A15)

BP2 End-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £1,430.5 million over RIIO-2. For this End-Scheme update, we provide quantitative updates for NOA and DER, and a written update for DER.

	Estimated gross benefits during the 2021-26 RIIO-2 period (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
1. Whole system operability NOA-type assessment (TOTAL)	1,303	1,351	+48
• Stability Phase 1	n/a	401	+401
• Stability Phase 2	1,303	568	-735
• Mid-term (Y-1) Stability Market: Year 1 2025/26	n/a	24	+24
• Voltage Mersey	n/a	192	+192
• Voltage Pennines	n/a	22	+22
• Constraints B6	n/a	112	+112
• Constraints EC5	n/a	32	+32
2. RDP Carbon Saving	67	Estimated accelerated/enabled DER volume detailed in Table 2 item (b).	
3. RDP Asset Savings	39		
4. DER Visibility Savings	23	Written update provided for End-Scheme (see below)	
Total	**1,431**	N/A	N/A

Summary of progress in 2024-25

1. NOA

More detail on what has been delivered and achieved in BP2 is provided above in the section on Network Services Procurement (Pathfinders).

Stability Phase 1

- The 12 awarded contracts continued in service in 24-25 with most contracts remaining in place until March 2027. Some units whose contract ends in March 2026, were eligible to participate in the first Mid-Term (Y-1) Stability tender (more information on this below).

Stability Phase 2

- The first two units contracted under Stability Phase 2 entered into service and are providing crucial stability capability at locations in Scotland. Among these is the first Grid Forming unit in GB that is able to provide stability services alongside clean power.

Mid-Term (Y-1) Stability

- The first Mid-term (Y-1) Stability Market tender for Year 1 2025/26 concluded in November 2024 with five synchronous condenser solutions contracted to provide 5GVA.s of inertia capability to the GB network. These will deliver savings from October 2025 when compared to alternative sources of inertia that will be accessible in the Balancing Mechanism.

Voltage Mersey

- The two contracts continued in service in 24-25 and provided reactive power capability that reduced the need to run thermal plant in the Mersey area through Balancing Mechanism. These contracts are in place until March 2031.

Voltage Pennines

- Three reactors were delivered by NGET and entered into operation throughout the year. These new assets have reduced the need to run thermal plant in the Pennines/Yorkshire regions and will be in service until at least 2035. The remaining unit from the tender is due to enter service in late 2025.

Constraints

- Contracts with generators in the B6 (Southern Scotland) and EC5 (East Anglia) regions continued in 24-25 and provided an alternative to curtailing generators in the balancing mechanism. Further work has been undertaken for future services and these are detailed in the Role 3 report.

2. RDPs

- MW dispatch and N-3 intertripping projects were delivered. These were delayed due to external reasons. However, there was no significant impact on benefit due to delayed connection background.
- The GEMS delivery did progress in 2023-24. It was decided to close the project with agreement from Ofgem and SPT. The functionalities delivered by the Open Balancing Programme (OBP) will cover the short-term needs case. Given the slower rate of new generation connections, the needs case for securing this network now aligns with the roadmap and timescales of the OBP’s additional capabilities. No impact on benefit is expected as a result of this change.

- RDP 3 & 4 – Throughout the period April 2024 to March 2025 we have continued to enhance our MW Dispatch service as planned to ensure we add value for consumers from our RDP deliveries. Through these enhancement activities we have made step change improvements in the underlying processes and technology in three key areas building on the MVP implementations under RDP 1 and 2. Specifically we have, wherever possible, aligned the business processes and technology supporting the NGED and UKPN MW Dispatch solutions, we have also automated a number of manual processes that were present in the MVP solutions including the exchange of, and our handling of, incoming DNO MW Dispatch unavailability data as well as the process for DERs to register their assets for the service. Importantly, the RDP team focus with the enhancements made has been to build in scalability to the solutions so that we can be confident they will support the planned increase in DER volumes and MW capacity in the SW Peninsula and South East coast of England where the solutions have been delivered. Implementation of the MWD solution and the associated DER Visibility & Control obligation has already facilitated otherwise blocked DER connections as follows, as well as providing the potential for DERs currently with a far reaching expected connection date to be brought forward in the Connections queue should their project be ready to deliver sooner:

- NGED region
    - 49MW connected and signed up for MWD with a further;
    - 922MW of capacity currently scheduled to connect by the end of 2026.
- UKPN region
    - 22MW already connected and signed up for MWD with;
    - 269MW of capacity also scheduled to connect by the end of 2026.
- Alongside the technical and process changes made, the RDP team has also engaged the wider NESO business and external stakeholders to open up discussions on the evolution of the MW Dispatch service and to understand how this fits with the wider future plans for Balancing Services more generally, ensuring that we can drive maximum consumer benefit from the work already undertaken by considering opportunities for similar types of solutions in other areas as well as understanding how MW Dispatch will support our future Balancing Services strategy.
- And finally on MW Dispatch, we are also progressing changes with both NGED and UKPN to expand the MW Dispatch unavailability data received ahead of time to include all DERs and all GSPs in their regions that are not registered or signed up for the MW Dispatch service. This is primarily to provide visibility of this data to our Network Access Planning teams with a view to allowing them to make more informed and more effective system

access / outage decisions based on a more holistic view of asset availability to support system security.

- RDP 5 – The minimum viable product (MVP) GSP Technical Limit (TL) infrastructure was successfully delivered for NGED enabling/accelerating DER connections without the need for reinforcement. We have also documented the end-to-end process for the required IT infrastructure to enable GSP Technical Limits that will provide clarity to internal and external parties when deploying GSP TLs at other DNO sites in the future.
- RDP 6 –The complexity of the Scottish transmission network, presence of Load Management Schemes, and other control schemes that were deployed historically have presented significant challenges and conflicts associated with the deployment of a MW Dispatch solution under RDP 6. We worked with SPD to validate the estimated benefit that can be realised from deploying this solution and concluded that approximately 50MW of DER capacity will be available under the MWD scheme, presenting little value for consumers. This is compounded by the recent approval of a parallel 132kV network reinforcement that will increase capacity and reduce constraint costs.
- The anticipated approval of GC0117 also greatly reduces the reach of the MWD parties, as all Generators (inclusive of DERs) with a capacity ≥10MW will be classified as Large Power Stations and therefore will be part of the Balancing Mechanism and available for NESO to instruct directly.
- We will continue to work with SPD to determine if another area of the network could provide a more sustainable consumer benefit.

3. Distributed Energy Resource (DER) Visibility

- In April 2023, we launched the TIDE programme with a commitment towards improving DER and Consumer Energy Resources (CER) visibility and access. By March 2025, we successfully delivered six out of seven key milestones across three programme phases: Phase 1, Phase 2, and Phase 3 Alpha. The outstanding milestone pertaining to commencement of building the storage and transfer capability is no longer within scope of the TIDE programme for BP2 and therefore will not be completed.
- We have established a core delivery team and collaborated with industry to draft a vision, design principles, and roadmap by capturing and prioritising industry use cases and data points to support this vision. We have assessed how advancements in DER and CER visibility and access meet real-time operations requirements and conducted NESO business, technology, and policy impact assessments to outline the necessary activities within NESO to achieve the vision and use cases.
- In terms of collaboration, we have advanced three innovation projects—DERIVE, Cascade, and Fractal Flow—to identify solutions for future-facing

use cases. We have also progressed demonstrator projects to mitigate delivery risks, such as accessing smart meter data via Smart DCC, establishing data governance processes for CER/DER data, and agreeing on harmonisation and prioritisation of NESO-DNO Operational Data. We have collaborated with DNOs to agree approaches to impact assessment, and progressed the quantitative benefits assessment for the detailed scope of the TIDE Programme. The programme has worked with DD&T and NESO business teams to facilitate solutioning delivery of use cases from BP3 period onwards.

- Achieving DER and CER visibility and access requires collaboration beyond just the TIDE programme. During BP2, we worked with multiple NESO initiatives to support other key outcomes, during which we have informed the definition of key programmes related to DERs and CERs, including Primacy, the Enabling Demand-side Flexibility Programme, and the Operational Metering Standards Review, delivering additional value to the business. We have also supported the definition of bilateral connections agreements through assuring NESO-DNO data sharing agreements and assisted NESO's regional development programmes in creating regional NESO-DNO solutions such as MW Dispatch and GSP Technical Limits.
- In BP3, the TIDE Programme will continue to collaborate with industry to develop and agree on an industry transformation roadmap. Simultaneously, we will explore opportunities to deliver benefits early by achieving priority NESO use cases, focusing on modelling & forecasting, real-time operations, outage planning, and procurement. To support our work with industry partners in agreeing on an industry transformation roadmap, we require Ofgem to provide us with a formal mandate to lead the delivery of TIDE as an industry transformation programme. This will involve establishing an industry delivery structure, collaboration agreement, and governance for the cohesive roadmap and plan.

Combined status by milestone for relevant activities (A15 activities, plus deliverable D8.1)

Status	Count	%
Complete	**82**	89%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**2**	2%
Delayed – Internal Reasons	**2**	2%
Milestone no longer valid	**6**	7%
Total	**92**	100%

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

Detail: Calculation of monetary benefit

1. Whole system operability NOA-type assessment

Stability Phase 1	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The £401m savings reported in the summary table at the start of this CBA is calculated by comparing actual payments made to the 12 contracted units against the outturn BM counterfactual costs that would have been incurred to access the same level of inertia capability across had the contracts not been put in place. This is initially done from the start of RIIO-2 to date and then extrapolated for the remaining period of RIIO-2. This is an improvement on the methodology used in previous BP2 reports which pro-rated the forecasted savings calculated at the point of contract award over the contract duration to the period that the reports covered and therefore did not consider outturn of counterfactual costs.
Stability Phase 2	£1,303m between April 2024 and March 2026 based on the Balancing Mechanism (BM) cost of satisfying the Short Circuit Level.	In the summary table the forecasted benefit of Phase 2 has been revised down from the initial BP2 Plan view as some of these projects have been delayed from their initially contracted start date, thereby reducing the duration they will be in service during the RIIO-2 period.
Stability Y-1 Year 1	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The forecasted benefits for Y-1 (£47.3m) are calculated on the difference between the forecast spend for the five awarded contracts (£25.4m) to the costs of accessing the same level of inertia in the balancing mechanism (£72.7m). However, as these contract will deliver between October 2025 to September 2026, only 50% of the benefits have been included in the table above.

Voltage Mersey	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The £192m savings reported in the summary table is calculated by comparing actual payments made to the two contracted units against the outturn BM counterfactual costs that would have been incurred to access voltage capability in the region had the contracts not been put in place. This is initially done from the start of RIIO-2 to date and then extrapolated for the remaining period of RIIO-2. This is an improvement on the methodology used in previous BP2 reports which pro-rated the forecasted savings calculated at the point of contract award over the contract duration to the period that the reports covered and therefore did not consider outturn of counterfactual costs.
Voltage Pennines	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The £22m savings reflects the forecast avoided spend on BM units in the region between September 2024 to March 2026. Based on studies carried out by our system planning team, we have identified the generation units that no longer are required to be accessed in the BM due to the three NGET reactors being in service. This is an improvement on the methodology used in previous BP2 reports which compared the cost of the reactors in Pennines to the reactor in the Mersey region. This approach did not consider the locational drivers and alternatives to determine previous forecast benefits.
Constraints B6	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The £120m figure reflect the savings expected to be delivered by arming contracted units to the intertrip scheme compared to the costs of managing constraints in the area by taking action in the balancing mechanism. The counterfactual in the BM considers both the cost of turning a generator down in the area of constraint as well as the cost of replacing that energy elsewhere on the network.

Constraints EC5	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	Similar to above, the £31m figures reflects the savings of the EC5 intertrip contracts to alternatives in the BM. Savings are based on the cost to arm units to the intertrip versus the cost that would have been incurred in the Balancing Mechanism to curtail these units.

2. RDP Carbon Saving

<table>
<tr><th>Assumptions</th><th>BP2 Plan view</th><th>Latest forecast view</th></tr>
<tr><td>(a) Carbon intensity in grams of CO_2 per kilowatt hour (gCO2/kWh)</td><td>FES 2021 Steady Progression. Figures vary between 86 and 112 gCO2/kWh over the five years of RIIO-2.</td><td rowspan="4">Reflecting on our original Benefits Assumptions, we believe a more appropriate measure of the value added from RDPs is the total accelerated/enabled volume of DER Connections without the need for reinforcement works:

RDP 3&4:

NGED area:
Up to end of 2023: 1373MW
2024 and beyond: 2813MW (inc. the 2023 figure)
UKPN area (as at Jan 2024):
Up to end of 2023: 257MW
2024 and beyond: 1343MW (inc. the 2023 figure)
<u>RDP 5&6:</u>

RIIO 2 period (FY 21/22-25/26)

NGED: 445MW
UKPN: 0MW
SSEN: 530MW*

Post RIIO 2 period (FY 26/27 onwards)</td></tr>
<tr><td>(b) Carbon generation reduction (GWh)</td><td>RDP 2 provided 278 MW of network access for renewable generation. Assuming this continues with an estimated load factor of 40% gives 974 GWh per year (278/1000*0.4*365*24 = 974)</td></tr>
<tr><td>(c) Carbon price pounds per tonne of CO_2 equivalent (£/tCO2e)</td><td>Figures vary between 248 and 264 £/tCO2e over the five years of RIIO-2. Source: <u>UK Government Policy Paper: Valuation of greenhouse gas emission 2 September 2021</u></td></tr>
<tr><td>RDPs completed</td><td>Zero for 2021-22 and 2022-23

One for 2023-24, 2024-25, and 2025-26</td></tr>
</table>

Calculation	CO_2 saved (Tonnes) (a)* x 974 (b) = average of 90,205 per year *(a) varies by year Benefits = CO_2 saved x carbon price (c) x RDPs completed	NGED: 1643MW UKPN: 1706MW SSEN: 0MW ENW: 799MW NPG: 1084MW SPM: 541MW It should be noted that all figures have been provided by the DNOs and could be subject to change following Connection Reform.
Gross benefits	Total £66.5m 2021-22: - 2022-23: - 2023-24: 22.2m 2024-25: 22.3m 2025-26: 22.0m	

3. RDP Asset Saving

Assumptions	BP2 Plan view	Latest forecast view
(a) RDP's completed	We have committed to a minimum of three inflight RDPs annually during the RIIO-2 period, depending on system needs. Based on experience, these will take approximately two years to complete. Assumption phasing as follows: 2021-22: - 2022-23: 1 2023-24: - 2024-25: 1 2025-26: 1 Total: 3 RDPs	2021-22: - (Actual) 2022-23: 2 (Actual) 2023-24: 1 (Actual) 2024-25: 1 (Actual) 2025-26: 0 (Actual) (detailed in '*Summary of progress in 2024-2025*', item 2 above) Total: 4 RDPs (including N-3)
(b) Value of RDP avoided asset build	Based on RIIO-1 avoided asset build of £12.9m per RDP. This is a net value with costs accounted for	Refer to Table 2.
Calculation	3 (a) x £12.9 (b)	Refer to Table 2.
Gross benefits	£38.7m	Refer to Table 2.

4. DER Visibility Savings

<table>
<tr><th>Assumptions</th><th>BP2 Plan view</th><th>Latest forecast view</th></tr>
<tr><td>(a) Forecast operability costs per year</td><td>2021-22: £0
2022-23: £746m
2023-24: £660m
2024-25: £848m
2025-26: £1,458m

Based the DER Visibility Benefits Assessment Master</td><td rowspan="5">During BP2, we have completed a detailed qualitative benefits study for the captured TIDE use cases to identify which should be prioritised to deliver maximum consumer benefit. This identified the following benefits:
Reduced volume of balancing and system services required (e.g. by improving network constraint forecasting)
Reduced unit cost of balancing and system services that are procured (e.g. by procuring services from low-cost DER & CER)
Reduced network expenditure (e.g. enabled by improving conservative assumptions about DER & CER operation when planning network investment)
Reduced cost of achieving system resilience standards (e.g. via reduced spend on network resilience investments because the ability to control DER&CER enables resilience levels to be maintained at lower levels of network spend).
We are currently delivering a quantitative study to finalise the expected financial benefits of the programme, which will complete during BP3. We will use this to forecast the expected benefit to be delivered through</td></tr>
<tr><td>(b) Reduction in constraint costs from DER Visibility</td><td>Greater visibility improves market access for smaller distributed participants and therefore liquidity. We are proposing a conservative reduction of 1% in unit costs for constraints.</td></tr>
<tr><td>(c) Improved forecasting</td><td>Calculation: Annual constraint cost (£m) * (percentage improvement of forecasting, assumed to be 10% for this calculation based the most conservative view from ‘Steady Progression’ scenarios in the DER Visibility Benefits Assessment Master) * (% non-visible distribution connected generation). This gives £8.11m.</td></tr>
<tr><td>(d) Number of years of benefit</td><td>One, as we do not expect the visibility savings to be realised until 2025-26.</td></tr>
<tr><td>Other</td><td>There are other consumer benefits of DER Visibility which are difficult to quantify at this stage, therefore we expect this</td></tr>
</table>

	CBA to present a conservative view of its benefits.	delivery of the programme's scope in Phases 3-5, replacing the original benefits assessment completed for the BP2 plan.
Calculation	(£1,458m (a) x 1% (b)) + £8.11m (c)	
Gross benefits	£22.7m	

CBA: Delivering consumer benefits from improved network access planning (A16)

BP2 End-Scheme view of gross benefits compared to BP2

We now estimate gross benefits of £202m over the RIIO-2 period, which is a decrease of £82m compared to the BP2 figure of £284m.

	Estimated gross benefits during the 2021-26 RIIO-2 period (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
Expanding NAP to England and Wales	284	202	-29%
Total	**284**	**202**	**-29%**

The main driver of the decrease is the lower outturn of the actual England & Wales constraint costs against the forecast. However, a lower outturn constraint cost is beneficial for the end consumer and we introduced the Constraint 5-Point Plan in 2021 to help reduce overall constraint costs.

Summary of progress in 2024-25

As part of our Planning and Outage Data Exchange programme we have continued to deliver a series of eNAMS functionality and code change releases to provide improved business processes and user experience, taking input and requirements from both internal and external stakeholders.

We have also scoped and designed an expansion of the existing MW Dispatch unavailability reporting to non-MW Dispatch relevant DERs and GSPs to improve our whole system view of the network and allow us to make more informed and effective outage planning decisions. The data is already being shared manually with development of an API automated data sharing solution planned for later this year. We are also providing our existing OC2 reports in csv format to UKPN to allow them to feed into their own systems thus improving their own processes also. We have also worked with SSEN and UKPN to scope out a series of potential future strategic changes in readiness for post BP2 development and delivery.

The programme also continues to run a third workstream, that is working to deliver the technical upgrades necessary to be compliant with the upcoming GC0139 changes as well as understanding the impacts of these on our operational teams and ensuring we have the relevant business processes and user training in place to implement these changes.

Combined status by milestone for relevant deliverables (Activity A16)

Status	Count	%
Complete	**35**	92%
Delayed – Consumer Benefit	**1**	3%
Delayed – External Reasons	**2**	5%
Delayed - Internal Reasons	**-**	-
Total	**38**	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 NAP policy process is firmly embedded within NESO and all three onshore TOs. There are four elements to this being a success and we have shown that having an auditable process of tracking outage change and cost savings have been successful. We have seen a steady rate of all of the above activities since expanding the NAP process across England and Wales. 1) STCP 11-4 which is a facility which allows us to procure an enhanced service from a TO, to reduce constraint costs. We have accepted more than 40 enhanced services this year to increase constraint limits and lower constraints costs. 2) STCP 11-3 which is a process that allows us to postpone outages where a planning step has been missed or where there is consumer benefit. The 11-3 process has been used 32 times in this plan year 3) The NAP TO Justification process that allows us to assess the TO versus NESO cost of major outages in current year. Over 40 sanction papers have been produced this year detailing the need for the outage and the forecast constraint costs

		4) The CVO (customer and consumer value opportunities) process whereby we track the positive changes made to an outage plan or optimisations made. In 2024-25 across England and Wales, we have processed outage optimisations saving the end consumer a total of 14.53 TWh and approximately £648m.
Regularly Reported Evidence	RRE 1H Constraints Cost Savings from Collaboration with TOs	2024-25: Q1: £210m Q2: £809m Q3: £381m Q4: £146m These figures show that the expansion of the NAP policy and the CVO process has driven successful collaboration between NESO and TO with regards to reducing constraint costs.

For background on CVOs, please refer to CBA A16 in BP2 Mid Scheme Report 2023-24 Evidence Chapters, page 206.

CVO savings for England and Wales:

- 2021-22: £1,135m
- 2022-23: £921m
- 2023-24: £956m
- 2024-25: £834m

The table below show three of the outages from 2024-25 that were some of the highest CVOs.

S/N	Outage	Description	Saving
1	Two 400kV circuits in the South West of England & Wales were needed on outage at the same time.	NGET had a system access request which would overlap with a planned outage. Overlapping the two outages would drop South Coast constraint by 2700MW for 54 days. NESO liaised with NGET to take these outages in turn to avoid the constraint costs.	£125.9m
2	A planned outage in North Yorkshire was deferred due to a fault on a 400kV	A 400kV circuit connecting Eggborough and Stocksbridge was on a planned outage, when a fault on the system occurred. Overlapping these two outages would drop the constraint by 2000MW.	£30m

	substation in this area.	NGET agreed to delay the 400kV circuit outage until the fault had been resolved. This action mitigated the issue of dropping the boundary constraint capacity.	
3	Network reconfiguration at the substation	NGET had requested for an outage on a 400kV circuit connecting two 400kV substations in Flintshire. Outage planners reconfigured a 400kV substation to improve constraint capacity by 800MW to facilitate the placement of the outage.	£27.0m

Detail: Calculation of monetary benefit

Expanding NAP to England and Wales

Assumptions	BP2 Plan view	Latest forecast view
(a) Estimated England and Wales constraint costs	Total £2,466m based on NOA modelling 2021-22: £351m 2022-23: £464m 2023-24: £322m 2024-25: £453m 2025-26: £876m	England and Wales constraint costs. 2021-22: £190m (Actual) 2022-23: £436m (Actual) 2023-24: £275m (Actual) 2024-25: £232m (Actual) 2025-26: £624m (NOA forecast reduced by 28.7% based on the sum of the first 4 years' actuals being 28.7% lower than the first 4 years' NOA forecast)
(b) Forecast reduction in constraint costs	11.5% based on benefits from NAP in Scotland. This assumption is based on observed results from Scotland and power system knowledge that system complexity is approximately the same between Scotland and England and Wales, allowing benefits to be extrapolated across from Scotland. 2018/19 benefits in Scotland were forecast to be between £16 million and	11.5%. Original assumption is still valid.

	£36.7 million, equivalent to between a 7% and 16% reduction in costs. We have used the mid-range estimate of an 11.5% reduction in costs.	
Calculation	£2,466m (a) x 11.5% (b)	£1,757m (a) x 11.5% (b)
Gross benefits	£284m Phasing: 2021-22: £40m 2022-23: £53m 2023-24: £37m 2024-25: £52m 2025-26: £101m	£202m Phasing: 2021-22: £22m 2022-23: £50m 2023-24: £32m 2024-25: £27m 2025-26: £72m

Regularly Reported Evidence

Table: Summary of RREs for Role 3

Role 3 RREs don't have performance benchmarks.

RRE	Measure	BP2 outturn			
3A Future savings from Operability Solutions	i) Saved balancing costs:	£592m (Breakdown in 3A section below)			
	ii) Saved infrastructure costs:	£1,894m (Breakdown in 3A section below)			
	iii) Indicative impact on the SZCP limit:	See 3A section below			
3X Timeliness of Connection Offers *Number of offers made (from clock-start date):*	Within 3 Months / 9 months*	Q1: 626	Q2: 386	Q3: 382	Q4: 351
	Longer than above timeframes	Q1: 117	Q2: 2	Q3: 13	Q4: 2
3Y Percentage of 'right first time' connection offers		Q1: 92%	Q2: 96%	Q3: 93%	Q4: 94%

RRE 3A Future Savings from Operability Solutions

April 2023 to March 2025 Performance

This Regularly Reported Evidence (RRE) outlines the forecast medium to long term benefits from new operability measures including:

- Saved balancing costs
- Monetised carbon reductions
- Any indicative impact on the SZCP limit

In each report we show projects concluded in the BP2 period so far, with estimated benefits up to the end of contracts. In the narrative we also call out what upcoming projects are likely to be included in subsequent reports during BP2.

Q4 2024-25 performance

i. Saved balancing costs

Table: Forecast balancing costs savings for operability measures concluding in BP2 so far

Operability Solution projects	LATEST VIEW End-Scheme 24-25 View: Forecast Savings £m	PREVIOUS VIEW Mid-Year 24-25 View: Forecast Savings £m
Constraints Management Pathfinder (CMP) B6 extension (October 2025 to September 2026)	**5**	**68**
Constraints Management Pathfinder (CMP) B6 extension (October 2026 to September 2027)	**8**	**-**
Constraints Management Intertrip Service (CMIS) EC5 Interim (February 2024 to March 2025)	**7**	**11**
Constraints Management Intertrip Service (CMIS) EC5 Interim (April 2025 to June 2026)	**36**	**-**
Constraints Management Intertrip Service (CMIS) EC5 Enduring (July 26 – Sept 29)	**171**	**-**
Mid-term (Y-1) Stability Market: Year 1	**47**	**-**

Voltage 2026	**318**	**-**
TOTAL*	**592**	**79**

The method to calculate the costs savings for CMIS is to compare the forecast constraint costs had the contracts not been entered into against those with the contracts being in place. The model we use forecasts constraints across the whole of GB, rather than on a specific boundary.

The savings for Mid-Term Stability and Voltage 2026 are the difference between the forecast spend over the contract lengths to the alternative cost to access the equivalent amount of inertia and reactive power capability respectively in the Balancing Mechanism.

Supporting information

Constraints Management Pathfinder (CMP) B6 – Extension of contracts to September 2027

In the Mid-Year 24-25 report, we provided information on the extension of the B6 CMIS contracts to September 2026. As the report also mentioned, we have been engaging the Scottish TOs on possible future needs for intertrip scheme on other boundaries in Scotland to manage the increased that are forecasted until 2030 and beyond, primarily due to network upgrades and outages taking place in this region.

It is estimated that this would not be delivered until mid-2027 due to the work that the Transmission Owners would need to carry out as part of any intertrip solution. Given that a solution for these boundary areas could also incorporate the existing B6 scheme (Southern Scotland) as part of a wider solution with an upgraded tripping scheme, the decision was taken by NESO to extend the current B6 2024-2026 contracts for a further 12 months, taking them to September 2027. This allows the time to finalise future Constraint Management solutions across the B2, B4, and B6 regions in the next 12 months.

The extension of the contracts is forecasted to deliver a further £8m of savings in October 2026 to September 2027, though for the period October 2025 to September 2026, this has reduced from £68m to £5m to reflect the constraints expected on other boundaries in Scotland that the current B6 intertrip scheme cannot be used for.

Constraints Management Intertrip Service (CMIS) EC5 Interim – (April 2025 to June 2026)

The Mid-Year 24-25 report outlined the driver for NESO awarding interim contracts for the EC5 region. Since then, we have agreed with the relevant generators on an extension of the interim contracts to July 2026, while NGET complete the necessary works to upgrade the existing intertrip scheme.

The savings forecast for the period February 2024 to March 2025 has been revised down slightly, while the forecast benefit for the period of extension, April 2025 to June 2026 has been added in this report.

Constraints Management Intertrip Service (CMIS) EC5 Enduring – (July 26 – Sept 29)

The tender for the enduring service has concluded and the estimated savings from these contracts is [£m]. The service will make use of the upgraded intertrip scheme which will have an enhanced trip speed of 200 milliseconds, allowing the scheme to be used for increased operational conditions, thereby delivering increased savings.

Mid-term (Y-1) Stability Market: Year 1

The first Mid-term (Y-1) Stability Market tender for Year 1 2025/26 concluded in November 2024 with five synchronous condenser solutions contracted to provide 5GVA.s of inertia capability to the GB network. This is a significant milestone in the implementation of a new market, following NESO's efforts with industry since 2021 to consider options for the design of a stability market.

These first set of contracts are forecast to deliver consumer savings in excess of £47m throughout the delivery year (October 2025 to September 2026) compared to accessing the same level of inertia capability in the balancing mechanism.

Voltage 2026

The tender for Voltage 2026 concluded in December 2024, awarding contracts to four solutions to provide reactive power absorption services across two regions in England (London and North England). These contracts are forecast to deliver £318M of benefit over the 10 year contract period from 2026 out to 2036, when compared to the cost of accessing the same level of reactive power capability form units in the balancing mechanism.

ii. Monetised carbon reductions

The carbon prices used in the tables below are taken from the BEIS publication 'valuing greenhouse gas emission in policy appraisal'[7]. These prices are also those used in our RIIO-2 Business Plan 2 Cost-Benefit Analysis – Annex 2[8]. The prices are weighted for the calendar year in which the services are contracted to deliver.

Table: Constraints Management Intertrip Service (CMIS) B6 (October 2024 – September 2027)

Constraint Management Pathfinder B6	Unit	Oct 25 – Sept 26
CCGT generation output avoided in GWh	GWh	379
Carbon intensity for Gas (Combined Cycle) from NESO Carbon Intensity Forecast Methodology	gCO2/kWh	394
CO_2 in tonnes	tCO2	149,365

[7] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal
[8] https://www.neso.energy/document/266121/download

Carbon price (BP2)	£/tCO_2e	263
Savings	**£m**	**39**

Table: Constraints Management Intertrip Service (CMIS) EC5 Interim – (February 2024 to March 2025)

Constraint Management Intertrip Service EC5 Interim	Unit	Feb 24 – June 26
CCGT generation output avoided in GWh	GWh	442
Carbon intensity for Gas (Combined Cycle) from NESO Carbon Intensity Forecast Methodology	gCO2/kWh	394
CO_2 in tonnes	tCO_2	174,232
Carbon price (BP2)	£/tCO_2e	259
Savings	**£m**	**45**

Table: Constraints Management Intertrip Service (CMIS) EC5 Enduring – (July 2026 to September 2029)

Constraint Management Intertrip Service EC5 Enduring	Unit	Feb 24 – Mar 25
CCGT generation output avoided in GWh	GWh	3,392
Carbon intensity for Gas (Combined Cycle) from NESO Carbon Intensity Forecast Methodology	gCO2/kWh	394
CO_2 in tonnes	tCO_2	1,336,448
Carbon price (BP2)	£/tCO_2e	270
Savings	**£m**	**361**

Supporting information

To calculate the monetised value of carbon savings, we have used the prices from BEIS' 'Valuation of greenhouse gas emissions: for policy appraisal and evaluation' policy paper. The prices have been weighted for the calendar year in which the services are contracted to deliver.

Constraints Management Pathfinder (CMP) B6 – Extension of contracts to September 2027

The Constraint Management Pathfinder B6 contracts are a contractual arrangement where generators in Scotland are contracted to provide an intertrip service to alleviate system constraints. This allows more renewable generation to be exported which would otherwise have been curtailed. The service has been in use since April 2022 with the table above showing forecasted savings for the contract delivery period of October 2024 to September 2027.

Constraints Management Intertrip Service (CMIS) EC5 Interim – (February 2024 to June 2026)

The CMIS EC5 contracts make use of generators that are already connected to the East Anglia Tripping Scheme AOTS to be able to be armed to alleviate system constraints. This allows more renewable generation to be exported which would otherwise have been curtailed. The service has been in place since February 2024 with the table above showing forecast savings for the contract delivery period March 2025.

Constraints Management Intertrip Service (CMIS) EC5 Enduring – (July 26 – Sept 29)

The Enduring service will contract with new generators to connect the East Anglia tripping scheme with an enhanced trip speed of 200 milliseconds, allowing the scheme to be used for increased operational conditions.

Mid-term (Y-1) Stability Market: Year 1 – (October 2025 – September 2026)

The five solutions contracted under the first Y-1 tender are all synchronous condensers and will reduce the need to take action in the balancing mechanism to buy on thermal units to access the same level of inertia capability.

Voltage 2026

The four successful solutions from the tender are all zero-carbon technologies and will reduce the need to run the equivalent of three CCGT units, split between two in the North region and one in London.

iii. Any indicative impact on the SZCP limit

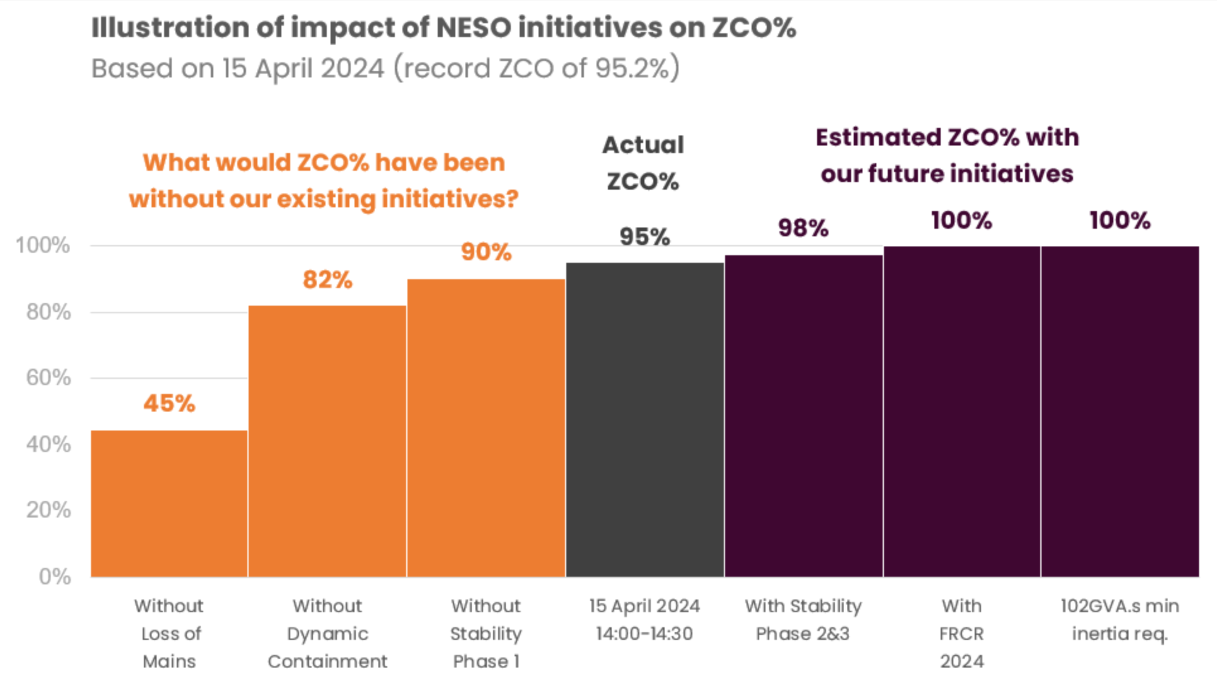
RRE 1F uses the original methodology for calculating the zero carbon operation metric. Under this methodology, a new record was achieved on 30 March 2025 of 93.5%.

As outlined in our Operability Strategy Report 2025, we are updating this methodology to reflect the clean power technologies as set out in the Clean Power Action Plan. This means including biomass as a clean power source in our zero carbon generation definition. Under this methodology, the record for zero carbon operation is 95.2% on 15 April 2024. The below graph shows how much lower the ZCO% would have been on 15 April without the delivery of Stability Phase 1, Dynamic Containment and the Loss of Mains change programme. Each programme is assessed independently rather than cumulatively.

- **Stability Phase 1** delivered 12.5GVA.s of inertia, reducing the need for four units at 1000MW. Without Phase 1 the ZCO% would have been 90%.
- **Dynamic Containment (DC)** has significantly reduced the need to hold legacy frequency response products. Without DC, an additional 2,500MW of headroom would have been required on synchronous carbon emitting generation. This equates to 11 units at 250MW each, reducing the ZCO% to 82%.
- **The Loss of Mains change programme** has reduced the potential volume of embedded generation susceptible to trip following a frequency change faster than 0.125Hz/s. Had we not completed the programme, we would have required 285GVA.s of inertia to prevent the largest single generation loss causing frequency to change faster than 0.125Hz/s, leading to further generation loss. The system was expected to have 140GVA.s, so an additional 48 units would have been needed to deliver 130GVA.s at 250MW each. This would have reduced the ZCO% to 45%.

The graph then shows how our future projects will help close the ZCO gap to 100% by 2025.

- **FRCR 2024** was approved on 27 September 2024, which was to maintain the minimum inertia requirement at 120GVA.s. Therefore FRCR 2024 would reduce the minimum inertia requirement from the 140GVA.s on 15 April to 120GVA.s. This has the effect of needing approximately six less carbon emitting generators. This would increase the Zero Carbon MW by 1500MW and the ZCO% to 100%.
- **102GVA.s min inertia req.** As outlined in our Operability Strategy Report, we are aiming to reduce the minimum inertia requirement to 102GVA.s by 2025. This means more periods with a zero carbon generation mix will be operable. Compared to 15 April 2024, this could reduce the number of carbon emitting units by ten. This would effectively increase the Zero Carbon MW by another 3000MW and the ZCO% to 109%. As this isn't possible, the calculation is capped to 100%.



NB - The calculations make assumptions about the contribution to system needs on 15 April 2024, taken from FRCR. Each synchronous generator provides 3GVA.s of inertia, operating at a minimum output (Stable Export Limit – SEL) of 250MW with a maximum available output of 500MW.

Whilst this exercise shows that future projects will enable a day like 15 April to be zero carbon, there are further projects which will enable zero carbon on other days too.

There are four reactors being delivered throughout 2025 which are for economic reasons, effectively removing the need for a further four generators (1000MW).

Stability Phase 3 bought 17.1GVA.s which, once delivered, removes the need for five units (1250MW).

Looking beyond 2025, our voltage tender for 2026 will procure enough reactive power to remove another two units (500MW).

RRE 3X Timeliness of Connection Offers

This Regularly Reported Evidence (RRE) reports on the number of connection offers made within 3 months of clock start date, and the number of connection offers made that took longer than 3 months. The table is populated based on the offers sent during the quarter.

We provide this information separately for the England and Wales area, the Scotland area and by Transmission Owner (TO) area:

1. England and Wales: National Grid Electricity Transmission (NGET)
2. Central and Southern Scotland: SP Transmission (SPT)
3. North of Scotland: Scottish & Southern Electricity Networks (SHET)

In year 1 (2023-24), in England and Wales, while the two-step offer process has been running, we have been reporting:

- The number of standard offers issued within 3 months.
- For two-step offers,
    - the number of (one-step) offers issued within 3 months;
    - the number of two-step offers issued within 9 months, after counter signature of the step one offer; and
    - the number of any connection offers that took longer than the above timeframes.

The two-step offer process concluded on 31 May, 2024. As a result, reporting on this process ceased in Q1 of Year 2 (2024-25).

As of 2 September 2024, Transitional Arrangements have been implemented for all new directly connected transmission applications. We will report on the timeliness of offers sent under these arrangements, with the first offers expected to be issued in Q4 2024-25.

We also report on the scale of the connection queue in terms of GW and time from offer acceptance to connection date. We include a breakdown of assets in the connection queue by size, technology type, and TO area.

Please note these figures are consistent with the Connections monthly data submission provided to Ofgem.

Q4 2024-25 performance

Table: Quarterly connection offers by time taken

Area	Connection offers issued:	Q1	Q2	Q3	Q4	Total
NGET (England and Wales)	(Standard offer) Within 3 months	146	225	228	169	768
	(One-step) Within 3 months	-	-	-	-	-
	(Two-step) Within 9 months*	332	-	-	-	332
	New transitional offers	-	-	-	21	21
	Longer than the above timeframes	115	-	10	1	126
	Total	**593**	**225**	**238**	**191**	**1247**
SPT (Scotland)	(Standard offer) Within 3 months	53	61	63	49	226
	New transitional offers	-	-	-	18	18
	Longer than 3 months	0	2	-	-	2
	Total	**53**	**63**	**63**	**67**	**246**
SHET (Scotland)	(Standard offer) Within 3 months	95	100	91	81	367
	New transitional offers	-	-	-	13	13
	Longer than 3 months	2	0	3	1	6
	Total	**97**	**100**	**94**	**95**	**386**
TOTAL	Within 3 months / 9 months*	**626**	**386**	**382**	**351**	**1745**
	Longer than the above timeframes	**117**	**2**	**13**	**2**	**134**
	% Within 3 months / 9 months*	**84%**	**99%**	**97%**	**99%**	**93%**
	% Longer than 3 months	**16%**	**1%**	**3%**	**1%**	**7%**
	Total	**743**	**388**	**395**	**353**	**1879**

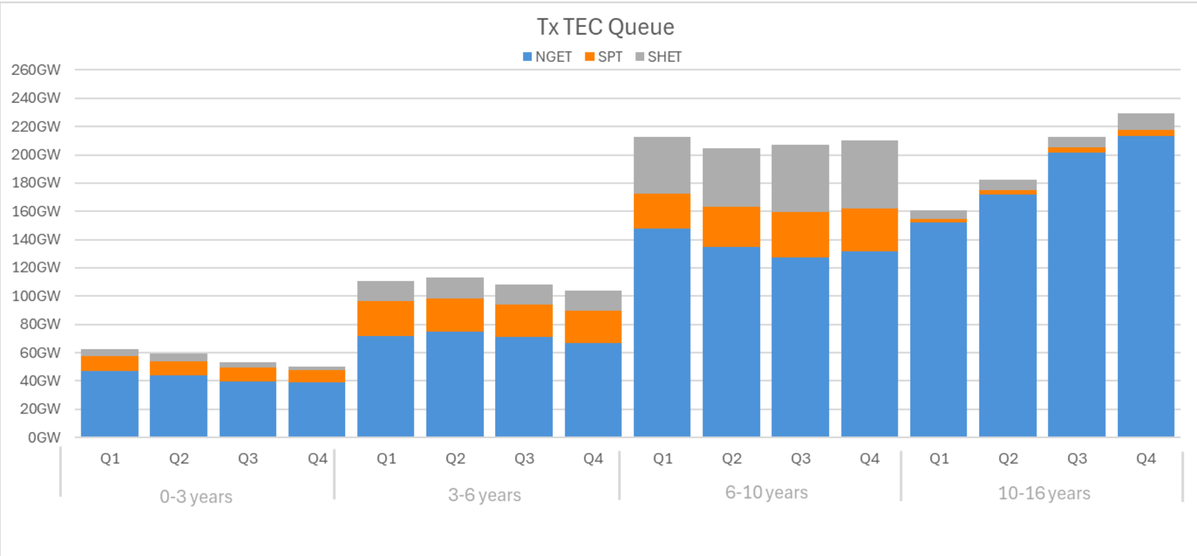
* After countersignature of the step one offer

500 1st Step Applications – 7 did not receive an offer (withdrawn) - remaining 493 Offers Made before 1 March 2024

477 2nd Step Offers made – 29 Issued before 1 March 2024 – 448 issued before 31st May 2024

The two-step process was originally agreed with Ofgem to conclude on the 1 March 2024, however it was agreed that for connection applications received between 27 November 2023 and 29 February 2024, they could be extended to 1 June 2024.

Graph: Connections queue in MW split by time from offer acceptance to connection: Q1 (30 June 2024) vs Q2 (30 Sep 2024) vs Q3 (31 December 2024) vs Q4 (31 March 2025) **



** Graph updated to show Queue in relation the base year 2024

The above graph records the connection queue based on the MWs that are scheduled to connect at various future time horizons. Previously (for Q1 and Q2 reports) it was measuring the time to connect from 2023-24, but this has been revised so that it now measures the time to connect from 2024-25.

Table: Connections queue in MW split by time from offer acceptance to connection

Host TO	Unit	0-3 Years	3-6 Years	6-10 Years	10-16 Years	Total*
NGET	MW	38,793	66,544	131,404	213,139	**449,879**
SPT	MW	8,815	23,376	30,764	4,578	**67,532**
SHET	MW	2,779	14,212	48,329	11,747	**77,066**
Total*	MW	50,386	104,131	210,497	229,463	**594,478**

*Timescale MW values are rounded up in this table but Totals are reflective of the unrounded base figures and therefore might appear slightly lower than the sum of the columns or rows.

Graph: Connections queue in MW by technology type (31 March 2025)

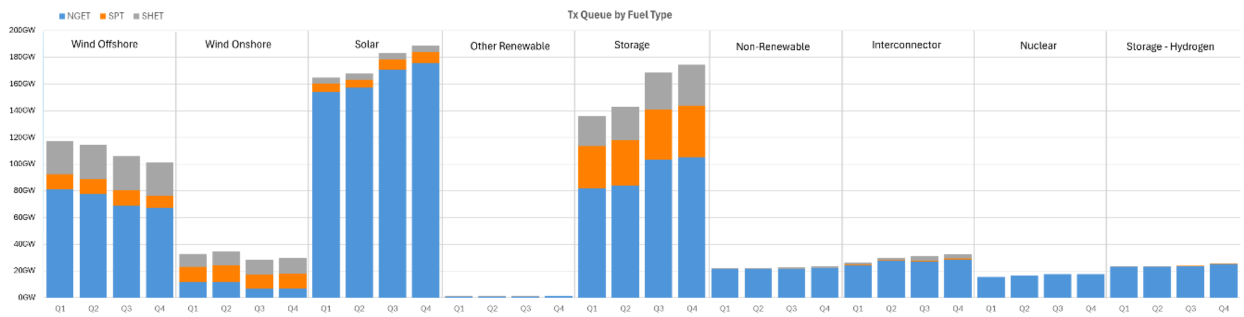


Table: Connections queue in MW by technology type (31 March 2025)
*Technology Type MW values are rounded up in this table but Totals are reflective of the unrounded base figures and therefore might appear slightly lower than the sum of the columns or rows.

Host TO	NGET	SPT	SHET	Total*
Wind Offshore	67,401	8,836	25,143	**101,380**
Wind Onshore	6,853	10,944	11,815	**29,612**
Solar	175,837	8,082	5,028	**188,947**
Other Renewables	1,097	0	352	**1,449**
Storage	104,985	38,966	30,619	**174,569**
Non-Renewable	22,376	0	910	**23,286**
Interconnector	28,609	700	3,200	**32,509**
Nuclear	17,620	0	0	**17,620**
Storage - Hydrogen	25,100	5	0	**25,105**
TOTAL*	**449,879**	**67,532**	**77,066**	**594,477**

Supporting information

Timeliness of connection offers

The number of offers sent within licensed timescales has improved across all three TO areas, with 99% of offers being sent out on time.

This quarter, 52 transitional offers have been made, with 89 more scheduled for the first quarter of 2025/26.

Two offers were sent this quarter outside of their licensed timeframes - all key stakeholders engaged.

Connections queue

The Queue has continued to grow, evidenced by a 2% increase over the past three months. This growth is driven by ongoing increases by battery storage and solar project developers.

CUSC modification CMP376 (Inclusion of Queue Management process within the CUSC) was approved and implemented in November 2023. This introduces queue management milestones into connection contracts and allows us to terminate contracted projects which are not progressing against agreed milestones. This is a significant step towards being able to reduce the size of the overall queue and remove stalled projects. Our connections reform proposals (proposed to go live in Q2 2025) will go further and faster towards reducing the overall queue by removing stalled projects.

BP2 Performance Summary 2024-25

Timeliness of Connection Offers

This year we have issued over 1800 licensed offers, a 12% increase on the previous year. Our performance over the last year has dropped to 93% offers being sent on time. This is in part attributable to the high volume of offers being managed as part of the two-step process and the subsequent blanket extension on connection applications received between 27 November 2023 and 29 February 2024, having offer dates being extended out to 1 June 2024.

Of the 66 subsequent requested extensions, 8 were withdrawn by the Customer, 42 were completed on time or earlier and 16 exceeded licensed timescales.

Connections Queue

Queue growth is less than the previous quarter, but there has been an overall increase across the year of just over 11% from Q4 23/24 and just over 50% across the 2-year period.

Queue at Q1 23/24 - 394GW
Queue at Q4 23/24 - 533GW
Queue at Q4 24/25 - 594GW

The increase is primarily driven by new connection applications from battery storage and solar developers. There continues to be an observed rise in connection dates within the 10-16 year period, aligning with average connection timescales.

RRE 3Y Percentage of 'right first time' connection offers

This RRE measures the % of connection offers made which did not need reissuing. For those that needed reissuing, we break these down by reason.

We include details of the number of connection offers made for the England and Wales area, and the Scotland area, in addition to each TO area. During the period where the 2-step offer process is in place, we will report this separately for step 1 and step 2 offers.

The two-step process concluded on 31 May 2024, however as Right First-Time reporting is measured on when the offer was signed, we are likely to see 2nd Step offers reflected in this table until the end of Q3.

Q4 2024-25 performance

Table: Quarterly % of 'right first time' connection offers

Area	Connection offers	Q1	Q2	Q3	Q4	TOTAL
NGET	Total Step 1 offers signed	1	1	-	-	2
	Number right first time	-	1	-	-	1
	Percentage right first time	**0%**	**100%**	**100%**	**100%**	**50%**
	Total Full / Step 2 offers signed	86	264	208	252	810
	Number right first time	76	238	174	215	703
	Percentage right first time	**96%**	**97%**	**96%**	**96%**	**97%**
SPT	Total connection offers signed	54	38	52	60	204
	Number right first time	44	21	38	45	148
	Percentage right first time	**93%**	**92%**	**87%**	**88%**	**89%**
SHET	Total connection offers signed	68	33	50	144	295
	Number right first time	52	22	29	109	212
	Percentage right first time	**90%**	**95%**	**86%**	**91%**	**90%**
TOTAL	Total connection offers signed	209	336	310	456	1311
	Number right first time	172	282	241	369	1064
	Percentage right first time	**92%**	**96%**	**93%**	**94%**	**94%**

Table: Connection offer that needed reissuing by reason

Area	One-step connection offers	Q1	Q2	Q3	Q4	Total
NGET	Customer driven	5	16	26	25	72
	NESO driven	5	6	8	9	28
	TO driven	2	12	12	16	42
	Total	**11***	**26***	**34***	**37***	**108***
SPT	Customer driven	6	5	6	10	27
	NESO driven	4	4	7	7	22
	TO driven	4	10	2	5	21
	Total	**10***	**17***	**14***	**15***	**56***
SHET	Customer driven	7	6	10	16	40
	NESO driven	8	2	7	13	29
	TO driven	2	4	8	18	32
	Total	**16***	**11***	**21***	**35***	**83***
TOTAL	Customer driven	19	27	42	51	139
	NESO driven	16	12	22	29	79
	TO driven	8	26	22	39	95
	Total	**37***	**54***	**69***	**87***	**247***

* Please note that re-offers can be driven by more than one factor. Therefore, the totals can be lower than the sum of the figures for each reason.

Supporting information

We have seen an increase in signed offers over the last quarter as customers look to secure a place in Gate 2 to Whole Queue (G2TWQ) ahead of Connections Reform.

The percentage of offers right first time (not due to a NESO Driven re-offer) has increased to 94% - with performance showing a recovery after a dip in Q3 across the Scottish TO areas.

NESO driven Re-Offers this quarter may primarily be categorised into the following causes:

- Adjusting contracts following post-offer discussions to correct issues identified by the Customer

- Re-issue of contracts with regards to missing/incorrect information

- Amendments due to typographical errors

The monthly reporting of re-offers is currently under review to identify measures for performance enhancement.

BP2 Performance Summary 2024-25

We have received over 1,300 signed licensed offers in 2024/25 with an average performance of 94% Right First Time across the whole year.

The performance reflects a generally high level of accuracy and efficiency in the offer processes, especially within the NGET area. Despite a minor decline in performance during Q3 from the Scottish TO areas, we have consistently maintained relatively low numbers of NESO re-offers, even with an increased volume of offers being processed.

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