Operability Strategy Report

March 2026

NESO
National Energy System Operator

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Executive Summary

Welcome to National Energy System Operator's (NESO) 2026 Operability Strategy Report (OSR). This annual publication outlines the future electricity system challenges associated with the whole energy system net zero transition and explains our strategy for defining system requirements and developing the future capabilities we need to meet them.

This year's report builds on the 2025 OSR and has been developed in close collaboration with the Electricity Markets Roadmap to provide an interdisciplinary view of what we define operability to be, what our operability requirements are and how we intend to meet them. The Electricity Markets Roadmap is published alongside this OSR. We have also developed a suite of supporting documents which are published on our website.

We have already made great progress towards clean power and 2025 saw record levels of both wind and solar output. We are transitioning from an electricity system underpinned by predictable demand met by synchronous fossil fuel generation to one dominated by asynchronous inverter-based renewable supply, and new forms of flexible demand. As fossil generation runs less, its historic operability contributions (such as inertia, voltage support, short circuit level, and restoration capability) are significantly reducing.

As the mix of technologies on the system changes, the operability requirements of the system change with them. This means that our tools, markets, operational procedures and procurement also need to evolve at pace to keep the system operating securely and efficiently.

Changing how we operate the system over the last decade has laid the groundwork for clean power operability in 2030 – continued delivery is now key.

2025 saw the GB power system reach 97.7% clean power for a short period and we are now on the cusp of achieving 100%. This would not have been possible without the voltage and stability Pathfinder projects first initiated prior to 2020. These projects are now connecting to the network and providing zero carbon services that previously relied on gas-fired generation. An example of this was the connection of Britain's first grid-forming battery last year. As more of these innovative projects are delivered, the duration of 100% clean power periods will increase as a higher proportion of renewable asynchronous generation can be accommodated.

At the same time, the delivery of new fast-acting and low-cost frequency services like Dynamic Containment have allowed the minimum system inertia to be progressively lowered while still increasing system security. This was evidenced by how the system managed a simultaneous fault of 3 power station units in 2025. This would likely have resulted in a major frequency excursion, or even demand disconnection, had it occurred prior to these new frequency services and the change to protection settings of 10,000s of distributed generators.

Building on this progress through timely delivery of the remaining pathfinder projects, and similarly for the Long Term 2029 tender, will be vital to supporting stability, voltage and restoration management on the CP30 system and beyond. Similarly, delivery of transmission reinforcements is needed to manage constraints and to facilitate connection of new solutions to manage operability challenges.

To support the Government's Clean Power 2030 (CP30) ambition we continue to address the associated changes to our operability requirements by integrating new technologies, optimising existing assets and facilitating network upgrades, innovation projects and market solutions.

Operability risks and opportunities must be managed holistically whilst harnessing the capabilities of new technologies and energy sector digitalisation.

Difficult electricity system conditions increasingly cause multiple operability challenges at the same time, which then interact. Actions addressing one challenge can often make another worse.

In the same way that synchronous coal or gas-fired generation has historically been utilised to provide multiple operability services at the same time, similar opportunities exist with new technology such as grid-forming inverters. We increasingly need to optimise how we procure these services in the future (e.g. in the bundled Long Term 2029 tender).

In the more dynamic decarbonised energy system of the future, operability challenges cannot be tackled in isolation and integration will be vital across market change, network delivery and technological developments, to ensure joined up and optimised solutions. NESO's agile and innovative systems are vital to facilitate efficiency, minimise risk and harness the benefits of technological advances and wider sector digitalization against a backdrop of increasing complexity and higher numbers of electricity industry participants.

Extended periods of very low transmission demand are leading to multiple operability issues today and will become increasingly pronounced in the future as more distribution-connected generation comes online.

Increasing levels of embedded generation and storage are a critical component of power system decarbonisation, and behind-the-meter assets provide recognised value for consumers. However, they also reduce minimum GB transmission demand which hit a record low of 12,912 MW in the summer of 2025 – this is lower than seen during the Covid-19 lockdowns and is expected to continue to fall year on year as more generation is connected to the distribution network.

Low transmission demand is a root cause of many operability challenges highlighted in this document:

- Difficulty reducing inflexible generation to ensure grid balance and adequate downward margin provision;
- High voltages at the interface between distribution and transmission; and
- Securing the largest losses as inertia reduces due to asynchronous embedded generation displacing synchronous transmission connected units.

These issues are exacerbated because embedded generation and storage that are capable of flexible operation do not always participate in the Balancing Mechanism (BM) and so may not respond to explicit price signals or to NESO instructions. Alongside greater levels of participation in the BM, improved data sharing and closer coordination with distribution companies is required to ensure NESO has visibility of and access to integrated whole system operability solutions.

Increased consumer led flexibility is necessary to manage periods of low transmission demand, and the introduction of market wide half-hourly settlement (MHHS) will help to facilitate this in the longer term. However it is only part of the solution, and more work is needed to bridge the current gap and create more opportunities for demand turn-up in the future.

Whilst the challenges that CP30 poses are significant, further operability challenges will emerge as part of the journey towards net zero in 2050 as more of the economy is electrified. In the same way that strategic energy planning will include electricity, gas and hydrogen, operability assessments and market reforms must consider interdependencies across the whole energy system. For example:

- Electrification of heating and transport as industry shifts national energy demand to electricity.
- Hydrogen production and storage for decarbonisation, managing constraints, energy balancing and long-duration energy storage.
- Growth of data centres to serve artificial intelligence and other needs increases electricity demand.
- Low carbon dispatchable generation, including hydrogen and potentially CCS-enabled plants, to support system operability.

Transformation of the wider energy system post 2030 will bring new operability challenges for the electricity system that require integrated whole energy solutions and market changes.

Electrification of transport, heat and industry will not only increase electricity demand but also change the shape and flexibility of demand leading to far faster swings and larger step changes in transmission demand. Flexibility to respond to market price signals is a key aspect of the electricity system of the future but the rapid, and harder to forecast, changes in demand that follow have the potential to challenge frequency and voltage management if not addressed.

Market and code changes, including from the Government's Reformed National Pricing (RNP) process, will need to be part of an integrated operability solution that:

- Provides siting and operational signals to large new transmission connections, including data centres and hydrogen electrolysers;
- Updates rules for smaller assets around ramping and BM participation to reflect how their combined impact, especially at settlement period boundaries, has to be managed in a similar way to that of larger units;
- Considers changes to settlement period length and aligning market trading deadlines with gate closure timings;
- Optimises interconnector behaviour to provide operability solutions as well as broader economic benefits to consumers on both side of the link; and
- Supports more locational procurement of system services by NESO and DSOs.

The pace and scale of the energy transition will continue to challenge how the system operates, but the progress already made demonstrates the capability and commitment across NESO and industry to respond. The OSR sets out how we will continue to build on this, ensuring the system remains operable as well as resilient, affordable and aligned with the UK's decarbonisation ambitions.

01

Introduction

What is the Operability Strategy Report

The Operability Strategy Report (OSR) sets out the National Energy System Operator's (NESO) independent view of the future operability needs of the electricity system, how those needs are changing as we move toward Clean Power 2030 (CP30), and the actions required to ensure the system can be operated securely, efficiently and at lowest overall cost. It provides an overview of real time (operational), short term (1-2 year) and long term (more than 2 years) considerations, risks and opportunities.

As in previous OSRs, we have structured how we analyse and communicate operability across seven areas: thermal, voltage, stability, restoration, frequency, within day flexibility (WDF) and adequacy. We have outlined our requirements and how we understand and meet these requirements against each of these operability areas. This sets out how needs are assessed today, how they are evolving, what this means for CP30, and how the solutions are progressing.

We have also taken a holistic view of how the evolution of the electricity and wider energy system impacts all of our operability areas. This holistic view shows the complex interactions that we need to consider as we continue to enable decarbonisation of the whole energy system with an operable electricity system.

The OSR is to be read in parallel with the Electricity Markets Roadmap that outlines the market mechanisms we expect to use to meet the operability requirements detailed in this report.

Changes in Operability in 2025

2025 was a record-breaking year in Great Britain's journey to decarbonise the electricity system. This has been driven by new low-carbon generation connecting to the grid, growing transmission network capacity, greater system flexibility, and increasing electrification.

With 1,648 hours of sunshine - the highest ever recorded across the UK according to the Met Office - this created ideal conditions for solar generation. This led to a record solar peak of 14,023 MW on 8 July 2025. More records were broken on 5 December at 5.30pm, when wind generation reached an all-time high of 23,825 MW, breaking a record set just weeks earlier. Records will continue to be broken as we transition to a decarbonised electricity system.

The energy system is dynamic and always changing. However, the change we expect to see in the coming years is ground-breaking and we need to ensure that, through all this change, the grid remains operable.

In 2019, we set an ambition to be able to operate Britain's electricity transmission system safely and securely with zero carbon sources of generation and free of conventional fossil fuels - for short periods when the generation is available to meet demand, and wider system conditions allow. Accelerating these periods of zero carbon operation is a key enabler for the longer term grid decarbonisation that is needed to deliver net zero by electrification of energy demand like heat and transport. Our initial definition of zero carbon operation on the transmission system is as follows.

$$\text{ZCO}(\%) = \frac{\text{sum (zero carbon transmission connected generation)}}{\text{sum (total transmission connected generation)}} \times 100$$

Domestic zero carbon transmission connected generation sources include power supplied from wind, solar, hydro, pumped storage, nuclear and batteries. We will include other zero carbon technologies as they become operational. Interconnectors, whether importing or exporting, are not included in the definition because they are non-domestic supply. In 2025 we refined the definition of our ambition to align with the Government's Clean Power Mission, including biomass as a clean power technology in the equation, and excluding Combined Heat and Power (i.e. sites that primarily provide heat for industry with electricity being cogenerated alongside) from the calculation altogether.

We have made substantial progress in meeting this ambition, operating Britain's transmission system safely and securely as more and more zero carbon sources connected. We reached 97.7% clean power for a short period in 2025, which is very close to what will be a historic milestone. Operating the system at these levels was helped by the connection of Britain's first grid-forming battery last year. As more of these innovative projects are delivered, the duration of clean power periods will increase as a higher proportion of renewable asynchronous generation can be accommodated.

As we work towards 2030, we continue to expect significant growth in low carbon generation from wind and solar, alongside new transmission infrastructure, new storage investments, a significant increase in the number of grid-forming inverters, and new nuclear as part of the delivery of CP30. Many of the projects and programmes across NESO and the wider industry are important to allow us to operate the electricity system effectively as it decarbonises. This includes measures outlined in the Electricity Markets Roadmap such as Stability Pathfinder delivery, the Constraints Collaboration Project (CCP) and intertrip programmes, reserve product markets, and changes to minimum inertia requirements.

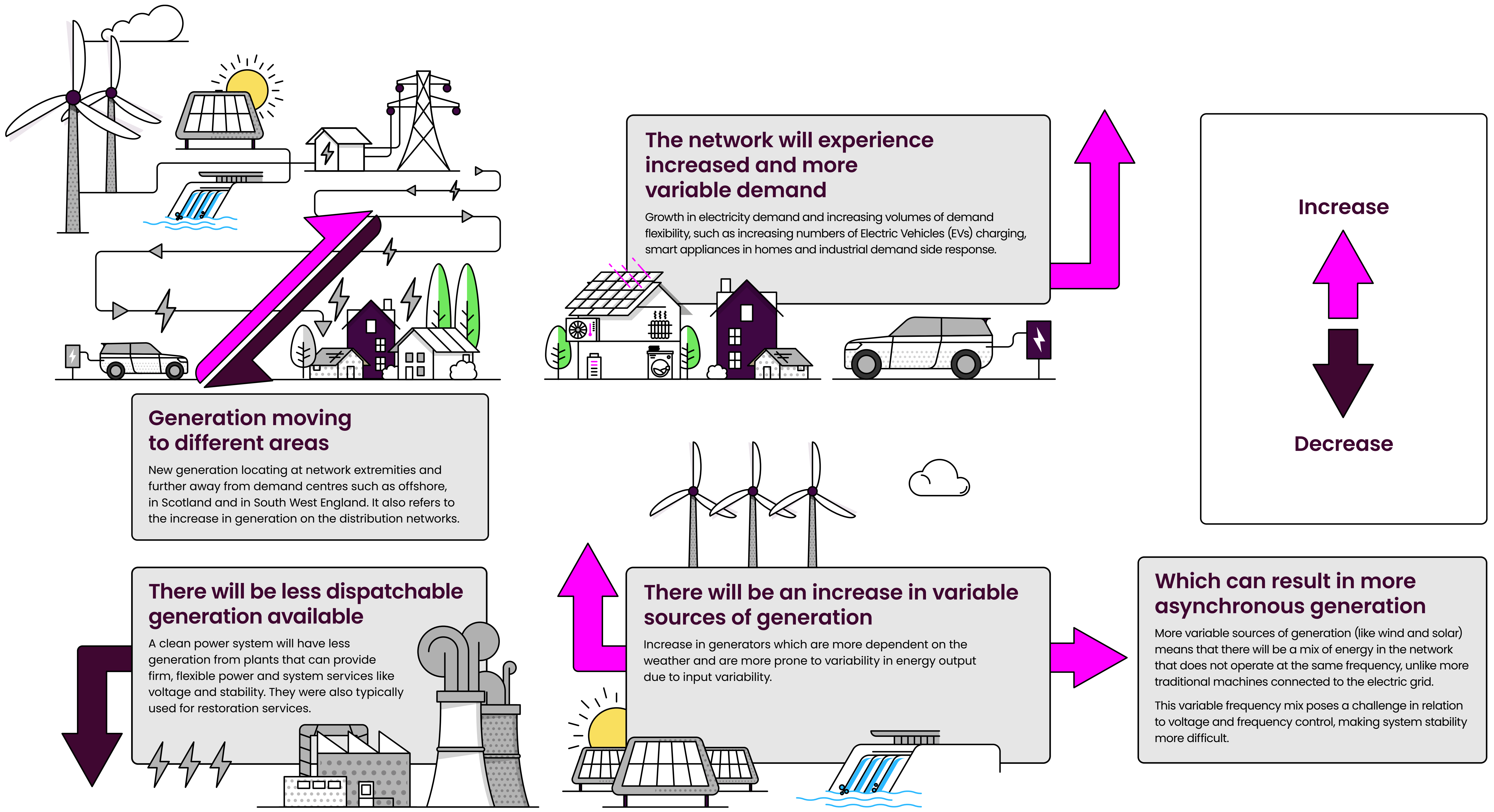
During 2025, we also managed emerging and continuing challenges to operability. These include step changes in demand from embedded assets, reactive power spill and complex thermal operability issues due to planned and short notice outages on the transmission system. These have helped inform our long-term risk strategy as outlined later in this report.

Reactive power spill occurs when high voltages on distribution networks propagate onto the transmission system. It is mainly driven by changes in embedded demand, as declining inductive load reduces local MVAr absorption. With demand becoming more power-electronic, the network absorbs less reactive power, increasing the likelihood of spill. High embedded generation output can intensify this, as power-electronic generation typically operates near unity power factor and provides little natural reactive absorption.

Operability for Clean Power by 2030

The Government's CP30 target is very clear - we need to meet electricity demand for prolonged periods of time without unabated gas (i.e. gas-fired plants which do not use carbon capture and storage). This implies that the unabated gas plants that currently provide operability services such as voltage and stability support will therefore not be dispatched for much of the year. At the same time, we expect wind and solar to be the biggest sources of generation for more of the time, which will change our operability needs (Figure 1).

Figure 1: System changes & operability considerations in a clean power network



In our 2025/26 Business Plan, we set out how this report was part of our Clean Power 2030 Implementation Performance Objective and would develop the strategy for ensuring that system operability enables, and is not a barrier to, clean power. To achieve this, we must identify the challenges to clean power operability and develop effective mitigating strategies.

CP30 is not just about having enough zero carbon generation and storage assets to meet electricity demand. It requires us to have right types of services and supporting assets, in the right locations, to manage the properties of the electricity system for extended periods of time without relying on unabated gas. To ensure efficiency, we will also enable assets to provide multiple services to the system.

The assumed level of unabated gas generation that can be dispatched to manage operability on a CP30 system is summarised in Table 1. This shows that, for five of our operability areas, we should not be planning to use unabated gas to deliver the associated system services. Using unabated gas generation in these operability areas could make it even harder to achieve the CP30 ambition overall.

The ways we will achieve this, and some of the associated challenges and opportunities (e.g. for consumer value) are outlined in this OSR. For example, to maintain stability, new assets such as grid forming inverters will be necessary to allow inverter-based resources like wind, solar and batteries to provide more of the services the system requires, such as inertia and short circuit level. Maintaining voltage control will require new reactive assets, reactive power markets and appropriate policy by 2030.

Table 1: Assumed use of unabated gas to meet operability needs over a typical weather year within the NESO Clean Power 2030 analysis.

Operability Area	Unabated gas use expressed as a percentage of Great Britain's total electricity generation in 2030
Adequacy	<3.5%
Thermal	<1.5%
Voltage, Stability, Frequency, Within Day Flexibility and Restoration	~0%

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Our Operability Needs

In this section of the OSR, we outline each of our operability need areas in detail, including how we calculate and meet our needs today and in the future. The Electricity Markets Roadmap report, which is published alongside this OSR, outlines how we intend to facilitate procurement of necessary services and assets to support each of these operability areas.

Thermal

The electricity transmission network has a limited capacity in some areas to transport power between generators, storage and demand. Thermal capacity is essentially a limit on the amount of current that can flow through a component of the transmission system before it overheats and creates a risk of dangerous electric arcs, equipment failures and other undesirable effects. To make the system easier to manage and study, we divide the network up using a set of boundaries and define the thermal capacity of each one. On a minute-by-minute basis, we need to effectively manage power flows across system boundaries, and we are frequently required to take balancing actions to ensure assets remain within their thermal capacity limits.

In the future, the volume of generation capacity constrained by these thermal limits[1] is expected to rise which will make the system more challenging to operate. This is exacerbated by misalignment between where generation, storage and demand are located. The thermal capacity of the transmission system therefore needs to grow to facilitate the connection of new generation and the electrification of the economy. To achieve this, we will require a combination of non-network solutions and new/upgraded power transmission infrastructure on the system. The thermal operability area covers this build-out, while exploring ways to minimise balancing costs, work around thermal constraints with innovative solutions, ensure regulatory compliance and meet decarbonisation goals.

As outlined in our Call for Input on Reformed National Pricing (RNP), we are concerned that the scale, complexity and cost of our balancing actions into the market to secure the system have grown, and will continue to grow, such that we are no longer the "residual balancer" as intended under the current market arrangements. At present, most of these actions are associated with managing thermal constraints.

How do we calculate our requirements?

On a minute-by-minute basis, our control room manages electricity supply and system operability around thermal constraints and the actions they take are often in the Balancing Mechanism (BM). To reduce the need for these actions, we use a holistic approach to addressing thermal constraints which balances new network, network optimisation, market frameworks, and commercial solutions.

Historically, the Electricity Ten Year Statement (ETYS) provided an overview of forecast thermal constraints on the existing network based on expected future power flows (for each of the Future Energy Scenarios). The Network Options Assessment (NOA) recommended network investment solutions proposed by Transmission Owners (TOs) based on the forecasted lifetime cost of the assets compared to the cumulative cost of curtailing generation behind a constraint boundary for the same period of time. Where new capability is recommended by the NOA, it is delivered by TOs.

Network capability requirements will now be published within the Centralised Strategic Network Plan (CSNP). The CSNP will deliver a whole-system view of electricity transmission, gas transmission and hydrogen transportation and storage systems. It will provide a 25-year blueprint of where the network infrastructure will be needed to transport energy around GB. It will use data and insights from the Strategic Spatial Energy Plan (SSEP), Future Energy Scenarios (FES), Regional Energy Strategic Plans (RESPs) and a wide range of stakeholders. These three plans will spatially optimise the GB energy system to better align the location of generation, storage and network delivery and so provide downward pressure on thermal constraints.

The SSEP will set out what energy sources GB needs, and broadly where in GB, from 2030 to 2050. The CSNP will focus on the transmission networks that carry energy long distances across GB. The RESPs will show where and when investment in energy distribution networks is required and inform future distribution network investment plans.

1 While many constraints are thermal in nature, the limiting factor can sometimes be voltage or stability instead.

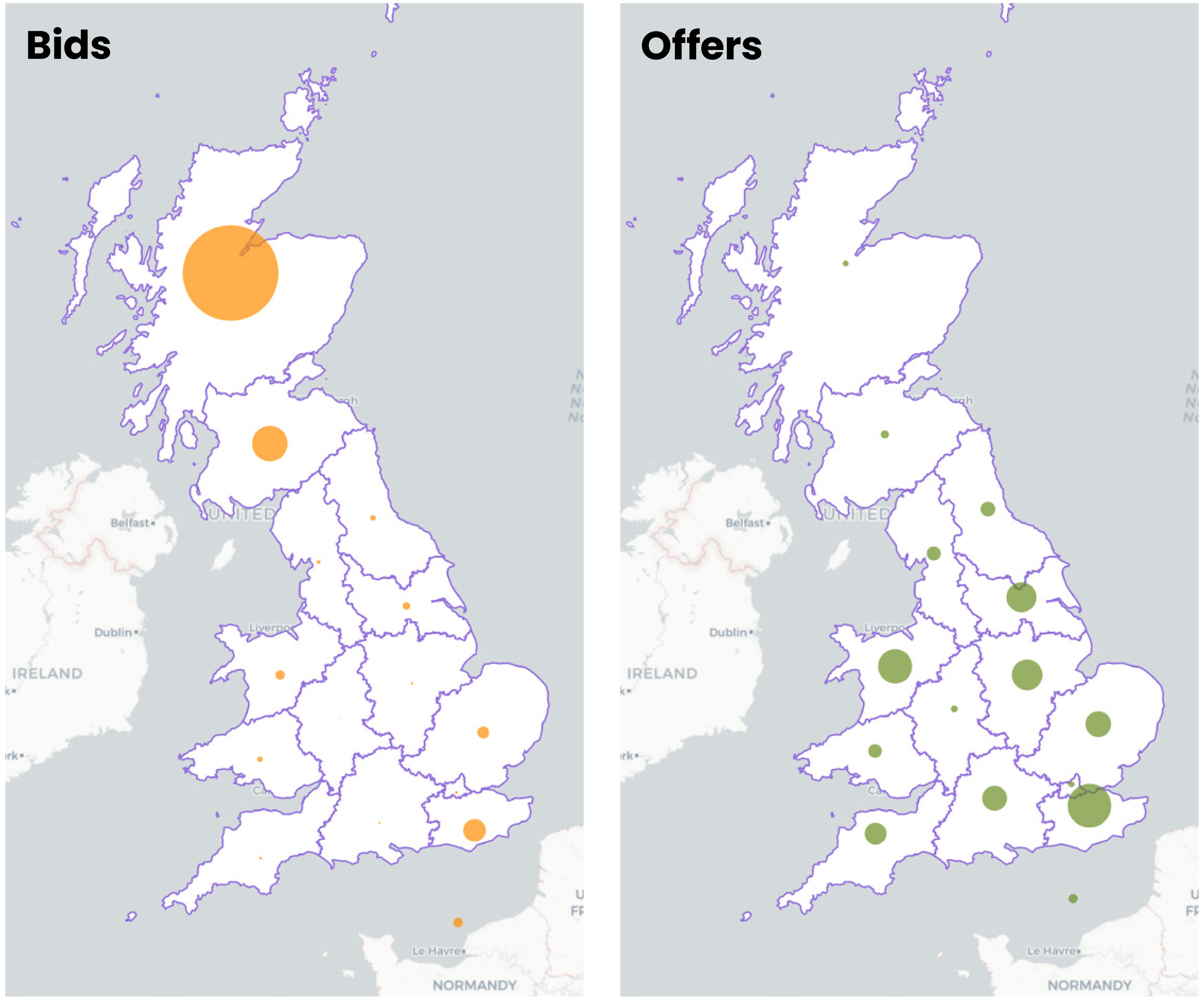
Over the last 12 months we have seen more renewable generation connect across the system, changes in boundary capacity (through new network equipment and new forecasting strategies) and the impact of planned outages on constraints.

Figure 2: Overview of our balancing actions for thermal constraints during financial year 2024/25.

(Left) shows that most our bids were due to thermal constraints in North Scotland. These bids were largely to constrain off wind generation.

(Right) shows that most of the offers were taken in regions further south. These offers were largely replacement energy actions on unabated gas generation linked to constraint management in Scotland. These actions can however serve multiple purposes, such as providing access to reserve, or supporting voltage/stability requirements.

Note: The size of the bubbles represents the relative volume of bid or offer actions. Further information on the costs associated with these actions can be found in the 2025 Annual Balancing Costs Report.



How do we currently meet these requirements?

We presently ensure we can meet our long-term thermal operability needs through network build-out (e.g. new AC and High Voltage Direct Current (HVDC) transmission lines) and other asset-based solutions, such as Static Synchronous Series Compensators (SSSCs), delivered by TOs. The primary operational market mechanism we use to unlock/manage capacity is the Balancing Mechanism supported by Local Constraint Markets (LCM) on the B4 and B6 boundaries. Other solutions we use include post fault intertrips on the B6 and EC5 boundaries. These allow a higher power flow across the relevant boundary without increasing risk by ensuring that generation can be tripped off in a fraction of a second in the event of a fault that reduced the boundary capacity. We are seeking to identify new measures through the Constraints Collaboration Project (CCP).

How are our requirements likely to change?

Over the next 25 years we expect to see significant volumes of new generation and demand connections, alongside significant expansion of the transmission network. For example, as outlined in FES 2025 we anticipate peak electricity demand could grow to around 120 GW by 2050 under the Holistic Transition scenario. As such, careful management of where new assets will connect will be important alongside added network and non-network solutions to facilitate better power transfers and to minimise constraints. Our focus on managing constraint costs centres upon reducing both the volume and the price of associated actions. The former relies on technical solutions, the latter on better use of flexibility, CCP and Reformed National Pricing (RNP).

What are the implications of CP30?

In our Clean Power 2030 advice, we stated that 80 transmission projects were critical to increase system capacity and reduce thermal redispatch. This included three projects that needed to be accelerated (which are listed in the CP30 Data Workbook). If they are not accelerated, we expect redispatch to exceed what can be tolerated to meet the Government's CP30 ambition in a typical weather year (as well as resulting in higher balancing costs).

How will we meet these requirements in the future?

We need to expand the generation on and capacity of the electricity system to meet growing electricity demand. Delivery of a number of new programmes will be critical in relation to future thermal operability needs including, but not limited to, Connections Reform, SSEP, CSNP and RESP.

We are also working to ensure better use of the existing network. Across NESO we are exploring and implementing a variety of mechanisms to alleviate thermal constraints and improve management of the network through technical, commercial and regulatory methods. These include, but are not limited to, code changes, non-network solutions (e.g. dynamic line ratings), network optimisation, energy storage, demand side measures, interconnectors, HVDC links and greater visibility of distribution-connected assets. The CCP is already exploring solutions to these issues.

> The Constraints Collaboration Project is intended to enable NESO and industry to work together to find solutions for thermal constraints, which can be implemented and deliver results in the short term. By results, we mean reducing costs to the consumer or reducing the curtailment of renewable generation (at no additional costs to consumers).

Irrespective of these technical changes, fundamental change will be required to ensure we can efficiently manage constraints. Our recommendations are outlined in the Call for Input on RNP.

Voltage

We are required to manage voltage on the transmission system within the limits defined in the Security and Quality of Supply Standard (SQSS). When maintaining these limits under conditions of low transmission system demand, we experience added challenges around high levels of reactive energy exported to the transmission system and reduced availability of reactive power compensation assets. Over the last 12 months we have continued to see significant changes across the system: increasing renewable and embedded generation, shifting demand patterns, new network assets, and planned/un-planned outages of existing generation and network assets. These all present both long-term and real time operational challenges to voltage operability, and therefore our methods for managing system voltage are evolving.

How do we calculate our requirements?

'Our pre- and post-fault voltage requirements are determined daily and locationally using detailed system studies which assess pre- and post-fault reactive needs across multiple scenarios, timescales and regions to ensure compliance with the SQSS. These studies evaluate how the system behaves under varying demand levels, generation patterns, network configurations, seasonal conditions and credible fault events, capturing both steady-state and dynamic voltage performance.

To calculate requirements in operational, medium- and long-term timescales, we apply a structured analytical process that includes:

- Developing scenario-specific network models, incorporating forecast demand, expected generation dispatch, outage patterns, and credible contingencies.
- Running power-flow and dynamic simulations to determine voltage behaviour before and after faults, including transient voltage dips, post-fault recovery and risks of voltage rise.
- Quantifying reactive power margins at key nodes, identifying where the system is likely to experience reactive shortfall or surplus.
- Assessing locational and temporal shifts in reactive needs, providing a granular view of how MVAr requirements evolve as system conditions change.

This technical process enables us to derive a consistent, evidence-based view of the reactive power capability needed to maintain secure voltage performance across the assessment period.

How do we currently meet these requirements?

To meet requirements in operational, medium and long-term timescales we review operational actions, reactive power markets, optimisation of existing assets, targeted network reinforcement options, and opportunities to better coordinate with Distribution Network Operators to manage reactive power transfer across boundaries, identifying locations where new MVAr capability will deliver greatest system value.

On a day-to-day basis, our primary mechanisms for managing voltage rely on the use of Transmission Owner assets such as transformer tap-changing, network reconfiguration, static reactive power devices and dynamic voltage support from assets including Static Synchronous Compensators (STATCOM) and Static VAr Compensators (SVCs) providing very fast dynamic reactive power support to inject or absorb reactive power independent of active power output. We also use a combination of commercial solutions, including procurement and dispatch of reactive power services through the balancing mechanism, and contracts for network services.

How are our requirements likely to change?

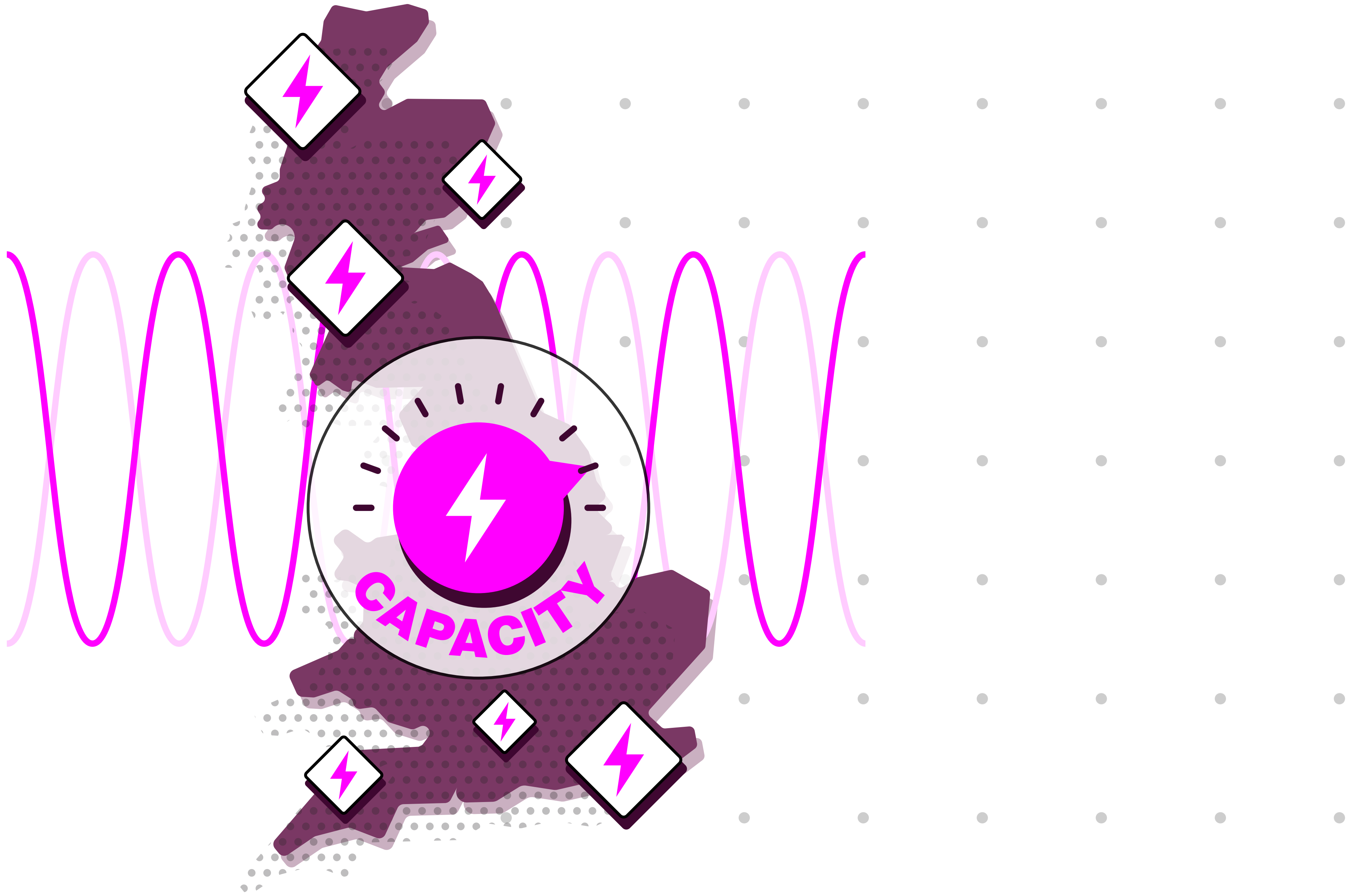
Levels of capacitive reactive power injection from the distribution system into the transmission network have been increasing steadily in recent years as greater volumes of embedded generation connect and we expect this trend to continue. When a large portion of real power demand is met by distribution connected generation, we are unable to dispatch some of the transmission connected generation we typically use for voltage control.

These system changes also increase the importance of coordinated voltage management at the transmission-distribution interface. As distribution connected generation grows, effective operation at this boundary – including visibility of reactive power flows and coordinated control actions with DNOs - will play a greater role in maintaining overall system voltage performance.

To assist in managing this, we expect a rapid scale up of assets that can provide voltage support independent of real power output. Our voltage pathfinders and reactive power markets specifically procure this capability – requiring providers to deliver reactive power at 0 MW or otherwise independent of active-power dispatch.

What are the implications of CP30?

The CP30 analysis assumes no additional dispatch of unabated gas plants for voltage support. Maintaining voltage levels within statutory limits will therefore rely on having a sufficient volume of appropriately located clean power alternatives, including both dedicated MVAr assets (such as SVCs, STATCOMs and synchronous condensers), low-carbon generation, and storage capable of delivering reactive power.



How will we meet these requirements in the future?

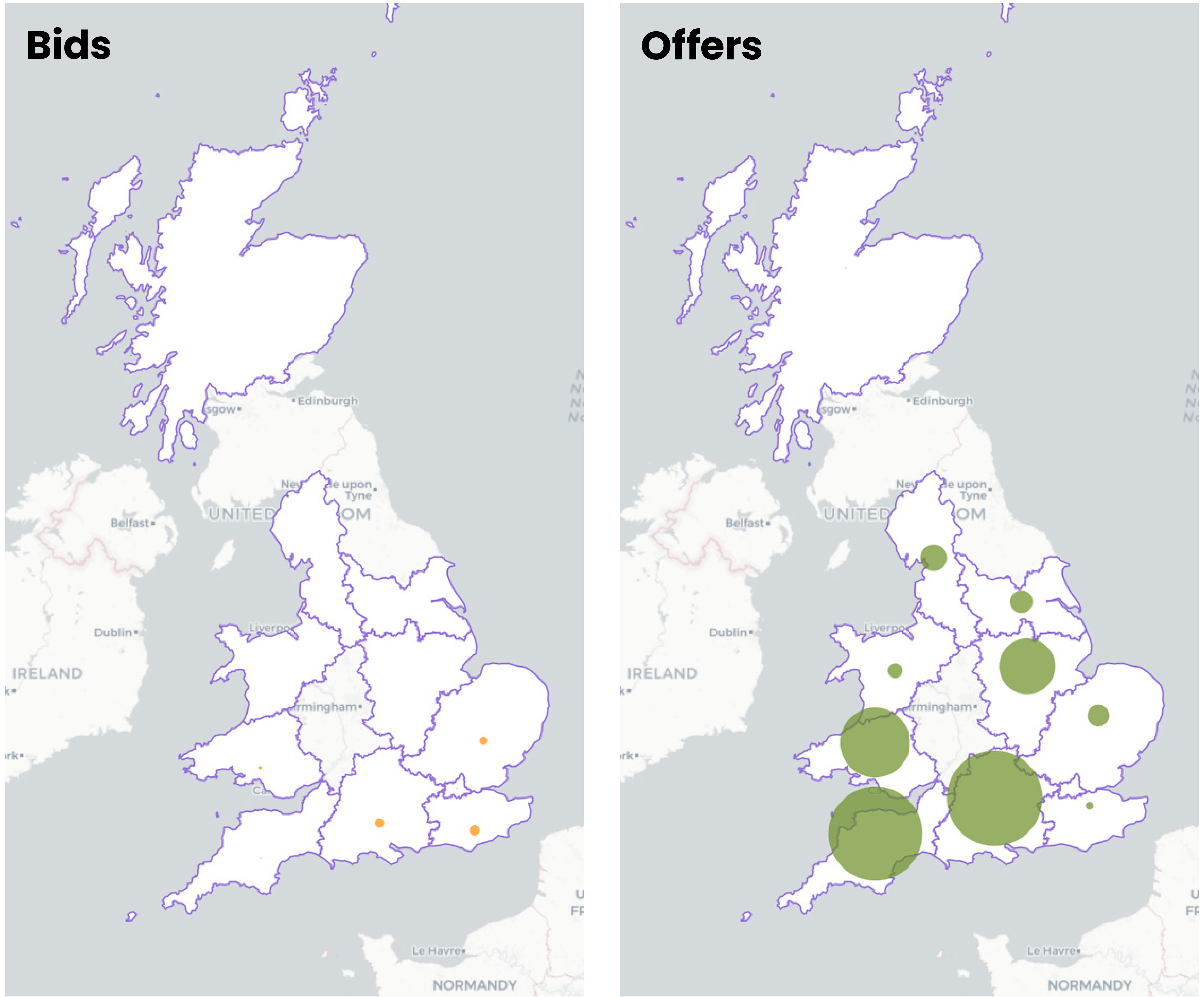
Future transmission-based voltage support solutions will increasingly be coordinated through the Centralised Strategic Network Plan (CSNP), ensuring that reactive power capability is optimised across GB through a whole-system planning approach.

Evolving reactive power markets, such as long-term tenders and the mid-term market, offer commercial ways to secure services when non-network solutions are more cost-effective. Ensuring that our requirements can be competitively procured and delivered by transmission owners and commercial providers, alongside mandatory provision as defined by Grid Code (including modifications currently being progressed for transmission connected generation) will be essential to meeting voltage operability needs.

Figure 3: **Overview of our balancing actions taken to manage voltage during financial year 2024/25.**

(Left) shows that most voltage-related actions are offers rather than bids.

(Right) shows that most of the offers to ensure voltage support were in the South West.



Note: The size of the bubbles represents the relative volume of bid or offer actions. Further information on the costs associated with these actions can be found in the 2025 Annual Balancing Costs Report.

Stability

Stability is the ability of the electricity system to withstand a network disturbance, remain secure, and recover promptly afterwards. A stable system is able to keep voltage and frequency within defined limits following an event. It is essential that connected equipment meets the requirements of the Stability Technical Criteria (STC), Grid Code and Distribution Code to support this outcome. The term stability covers a broad range of topics, including inertia, system strength and dynamic voltage performance.

Inertia is defined in the Frequency Risk and Control Report (FRCR) as "the total synchronous inertia that is online and electrically coupled to the GB system at a given point in time, expressed in GVA.s, and used as an input to assess frequency risk following credible loss events." Maintaining sufficient levels of inertia is important as it helps to dampen frequency fluctuations and provides time for control actions to respond.

System strength relates to how strongly the network can support stable operation of connected equipment. It reflects the ability of the system to maintain stable voltage and current waveforms following disturbances or changes in operating conditions. System strength is assessed using Short Circuit Level (SCL), which provides a measure of how robust the system is at a given location and helps determine whether additional measures are required to maintain stable operation.

How do we calculate our requirements?

To understand our inertia needs, we carry out studies that quantify how much inertia is necessary to maintain a secure system. The findings are summarised each year in the FRCR. We currently operate the electricity system to a minimum inertia requirement of 120 GVA.s, in line with the established operational policy set out in the FRCR. We assess the level of inertia expected to be provided by assets connected to the system against the minimum inertial level (which is reducing alongside the declining levels of synchronous generation on the GB system) to identify any deficits. The closure and commissioning of large synchronous generators can impact the magnitude of the deficit as seen in Figure 4.

System strength requirements are established by evaluating the short circuit levels available across the network. This involves detailed modelling across multiple time horizons, helping us understand how the system behaves.

What are our requirements?

Figure 4: **Peak Inertia deficit 2029-2040**

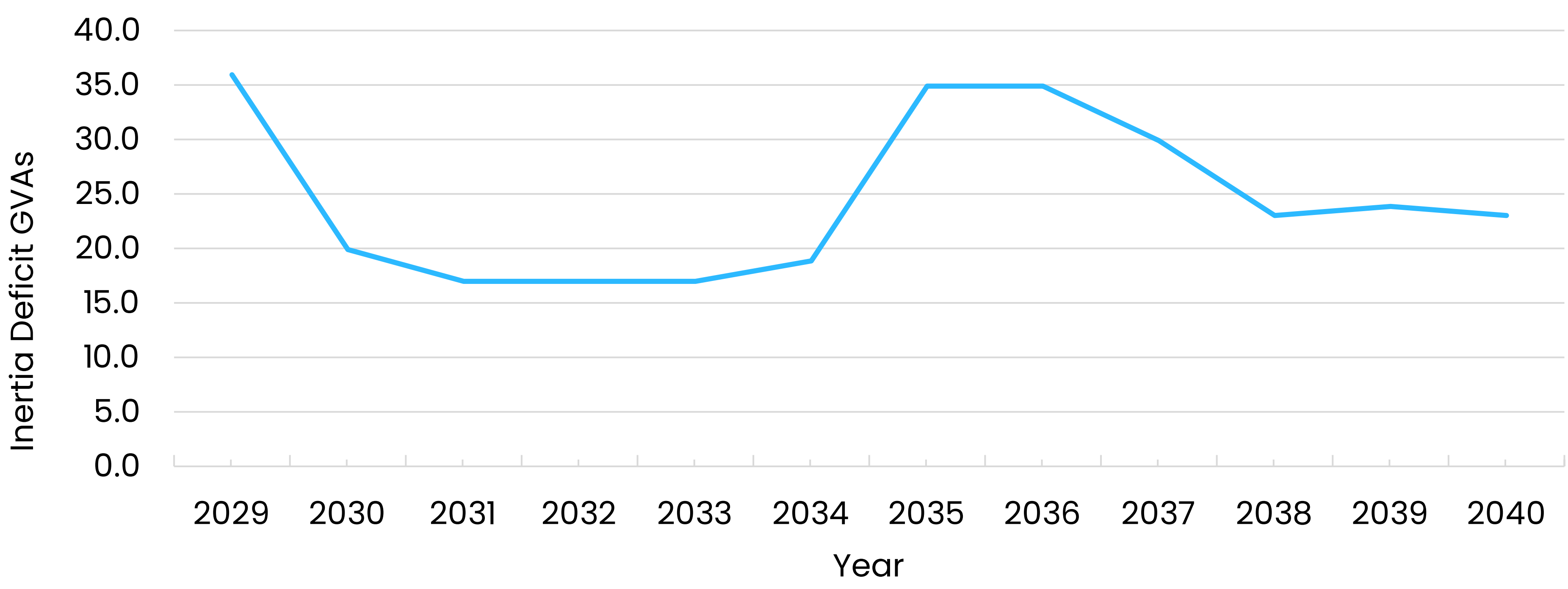
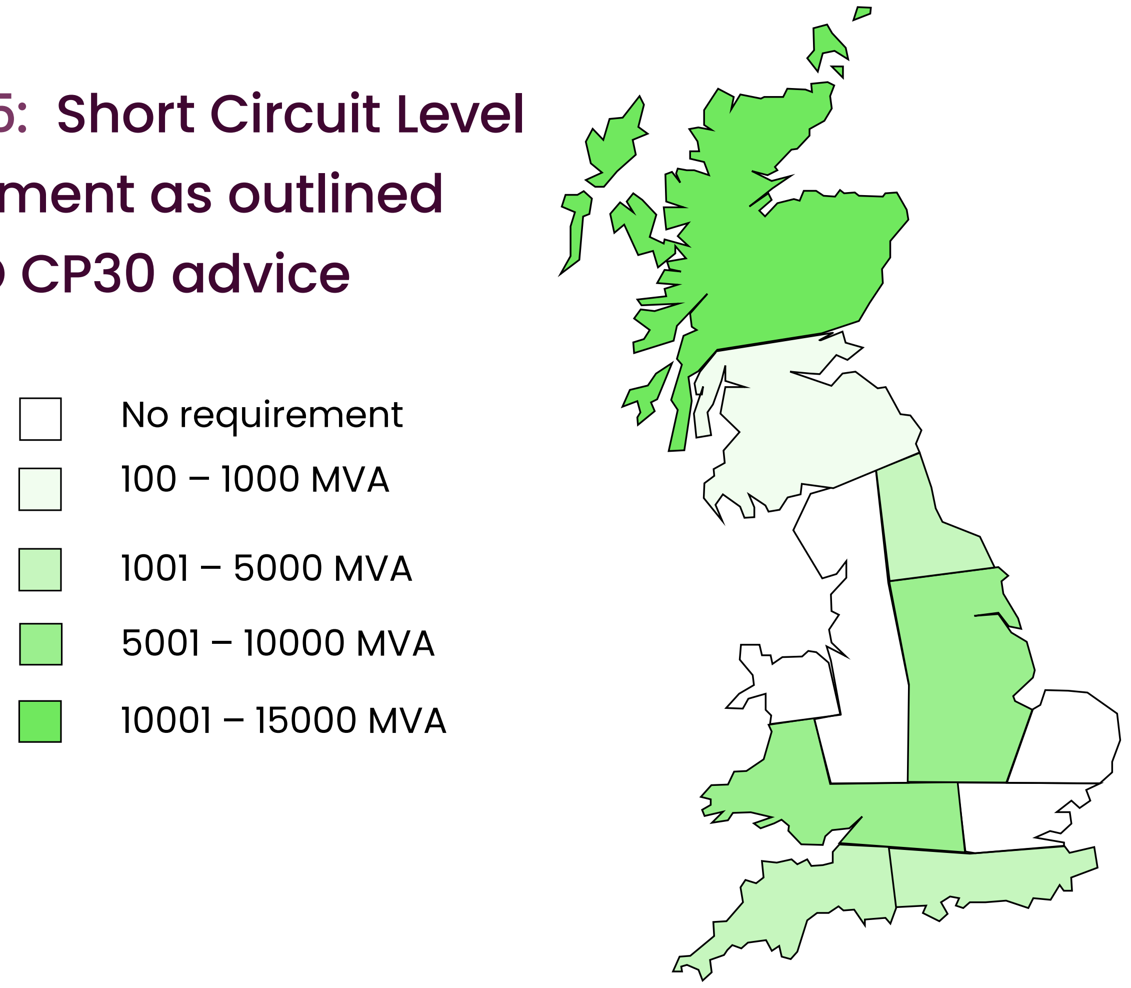


Figure 5: **Short Circuit Level requirement as outlined in NESO CP30 advice**



How do we currently meet these requirements?

We currently meet stability requirements through a combination of operational actions and market-based procurement. The Network Services programme, which includes contracts under the Stability Pathfinder regime and services procured through Stability Markets, allows us to secure services from assets such as synchronous condensers and grid forming batteries. Please see the Electricity Markets Roadmap for more information.

The Balancing Mechanism is used to dispatch synchronous generation when additional inertia is needed. These arrangements can provide both inertia and short circuit strength, ensuring the system remains stable under all credible system conditions.

How are our requirements likely to change?

Synchronous generation has traditionally been used to maintain system stability. In the future, we need to meet more of our stability requirements using low carbon technologies such as grid forming inverters and synchronous condensers. These can provide stability services without being required to provide active power. As well as buying more inertia we are also deploying advanced tools to monitor inertia on the system and implementing new Electromagnetic Transient (EMT) monitoring to strengthen visibility and management of issues such as sub-synchronous oscillation (SSO) risk.

Without procuring stability services from these technologies, the increasing proportion of non-synchronous generation would lead to periods of low inertia and reduced system strength. Our modelling indicates that by the late 2020s, inertia shortfalls could exceed 20 GVA.s and SCL requirements are expected to increase.

We currently apply a minimum system inertia requirement of 120 GVA.s, in line with the established operational policy set out in the FRCR. The 2025 FRCR has recommended revising the minimum inertia threshold downward to 102 GVA.s. Ofgem is now undertaking an independent review of the report's findings and has requested additional analysis before reaching a final determination in 2026. Until this regulatory process concludes, we will continue to plan and operate against the existing 120 GVA.s requirement, ensuring system resilience while preparing to integrate any future changes to the policy once confirmed. If there is a reduction in the minimum inertia threshold this could reduce our inertia requirements and the associated cost to consumers of meeting them.

Electromagnetic Transient (EMT)

Neural BB - a proof of concept, to use machine learning to create a surrogate model from a" black box" model of an AC/DC converter. The black box model and the surrogate are to be of the type used in PSCAD, a type of electromagnetic transient (EMT) simulation software. (Neural BB | ENA Innovation Portal)

Sub-synchronous oscillation (SSO)

Oscillation and regional RoCoF monitoring: provide monitoring capabilities, observing two dynamic phenomena in the GB power system – oscillatory behaviour and regional Rates of Change of Frequency (RoCoF) trends. (Oscillation and regional RoCoF monitoring | ENA Innovation Portal).

What are the implications of CP30?

Delivering stability without fossil fuel generation is essential to achieving CP30. Our Clean Power 2030 Advice confirms that by 2030, at least 95% of annual GB generation must be from clean sources, with unabated gas contributing less than 5% in a typical year. The clean power transition removes traditional sources of inertia and short circuit strength, requiring a rapid scale up of low carbon alternatives. Grid forming technologies, synchronous condensers and synchronous low carbon generation will be important for meeting our requirements.

Our Clean Power 2030 Advice also highlighted the need for market reform to incentivise these services, alongside accelerated investment in enabling infrastructure. If these enablers are not met then we would expect this to be reflected in higher redispatch, higher balancing costs and failure to meet the CP30 ambition. Please see the Electricity Market Roadmap for more details.

How will we meet these requirements in the future?

Future stability capability will be delivered through a combination of market evolution, technology deployment, and enhanced system planning. We will use mid-term and long-term procurement of stability services to provide certainty and reduce balancing costs to access inertia services (see the Electricity Markets Roadmap for more detail). Traditional synchronous generation inertia sources will be replaced by 0 MW assets, or otherwise independent of active-power dispatch, like synchronous condensers or grid-forming batteries with the Stability Market helping to meet inertia and system strength shortfalls.

We are progressing industry-wide updates to Grid Code requirements in respect of grid forming capability. NESO established a grid forming Expert Group in September 2024 which aims to develop recommendations for future updates to the Grid Code in respect of the grid forming technology. These recommendations would ultimately lead to a formal Grid Code change which would build on the grid forming requirements already in the Grid Code today. The aim of the Expert Group is to reflect on the experience gained through Stability Pathfinder projects and other grid forming projects which have progressed, or are progressing, through the compliance process. It will combine this with stakeholder input and international best practice to consider if a mandate should be applied in relation to grid forming capability in the future.

Restoration

Electricity System Restoration is the ability of the electricity system to recover following a partial or total shutdown. It involves safely re-energising the network, restarting generation, and progressively rebuilding supply and demand until the network is fully restored.

Restoration relies on being able to access self-starting units capable of initiating generation without external power. In addition to these electricity system restoration sources, further generators (secondary generators) are required in the restoration sequence to contribute to stable demand pick-up, system strength and voltage control as power islands are integrated. While these units do not energise completely dead sections of isolated network, they are vital to expanding the network once initial power islands have been successfully established as they are fundamental in maintaining the electrical load and stability conditions as the network expands. This allows for the progressive expansion and establishment of a fully synchronised GB power system.

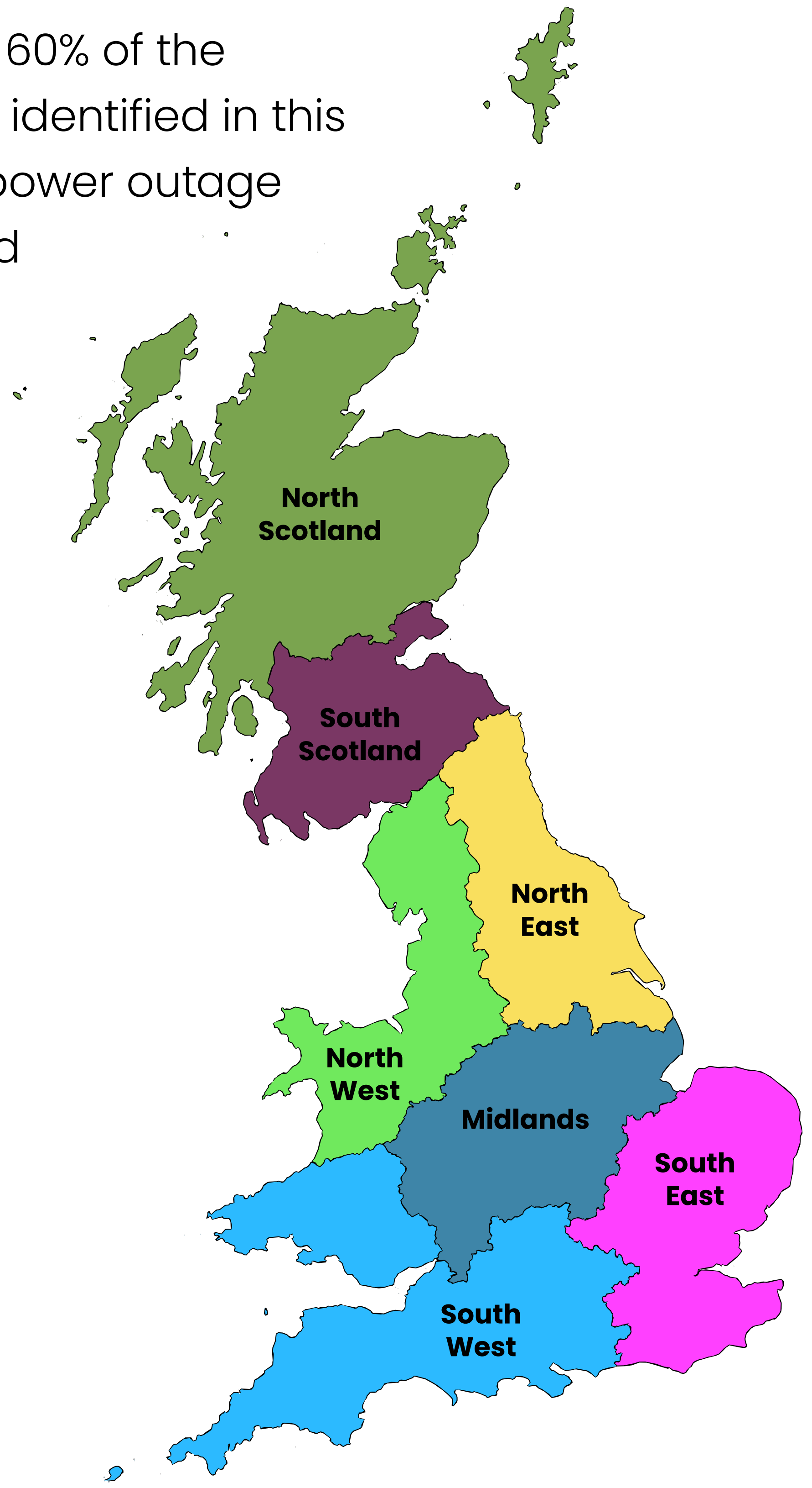
How do we calculate our requirements?

We calculate Electricity System Restoration requirements through annual modelling that assesses how much restoration capability is needed in each transmission region to meet the Electricity System Restoration Standard (ESRS). These outputs ensure we can restore 60% of demand (both regionally and nationally) within 24 hours and 100% within five days. To comply with the ESRS, it has been established in collaboration with industry that each of the seven restoration regions across Great Britain must possess the capability to initiate two Local Joint Restoration Plans (LJRPS) per region within an agreed time (typically around 120 minutes) following a national power outage. This requirement necessitates the deployment of diverse primary service providers distributed throughout the country. Ideally, a minimum of four providers per region is required to ensure operational flexibility and year-round availability. We must ensure that everything is in place to comply with the ESRS by no later than 31 December 2026.

What are our requirements?

Figure 6: NESO licence condition

Licence condition C4 mandates the restoration requirements to be able to recover 60% of the demand in each restoration region identified in this map within 24 hours of a national power outage and 100% national demand restored within 5 days. While the primary obligation is on us, successful restoration depends on all relevant industry stakeholders playing their part effectively. The Grid Code sections OC5 and OC9 underpin the requirements for the industry.



How do we currently meet these requirements?

We currently meet our Electricity System Restoration requirements by contracting a suitable geographically dispersed set of providers. These providers include a mix of generation types such as gas-fired units, interconnectors and pumped storage. We procure these services through competitive tenders and bilateral negotiations if the tender process does not yield the desired outcome.

How are our requirements likely to change?

Our electricity system restoration requirements are expected to evolve as the energy industry decarbonises, and the generation portfolio becomes increasingly inverter-based and distributed.

As traditional synchronous plant declines, there will be a growing dependence on non-traditional technologies to deliver the ESRS both in relation to initiating power islands and integrating secondary generators. Whilst some of these non-traditional technologies are connecting at transmission level, the proportion of generation capacity connecting at distribution level is increasing. This has the result of displacing potential transmission-connected restoration providers. To address this concern, when the industry codes (e.g. Grid Code, System Operator Transmission Owner Code (STC), Connection and Use of System Code (CUSC)) were updated to include provisions of the Electricity System Restoration Standard, updates were introduced for Distributed Restoration Zones, which is a mechanism by which NESO and Network Operators can use embedded generators to restart sections of the distribution system. This process will run in parallel to the restoration process applied to the transmission system. Meeting future obligations will therefore require a broader and more diverse set of providers capable of supporting restoration across a decarbonised system. This was investigated in the Distributed ReStart innovation project.

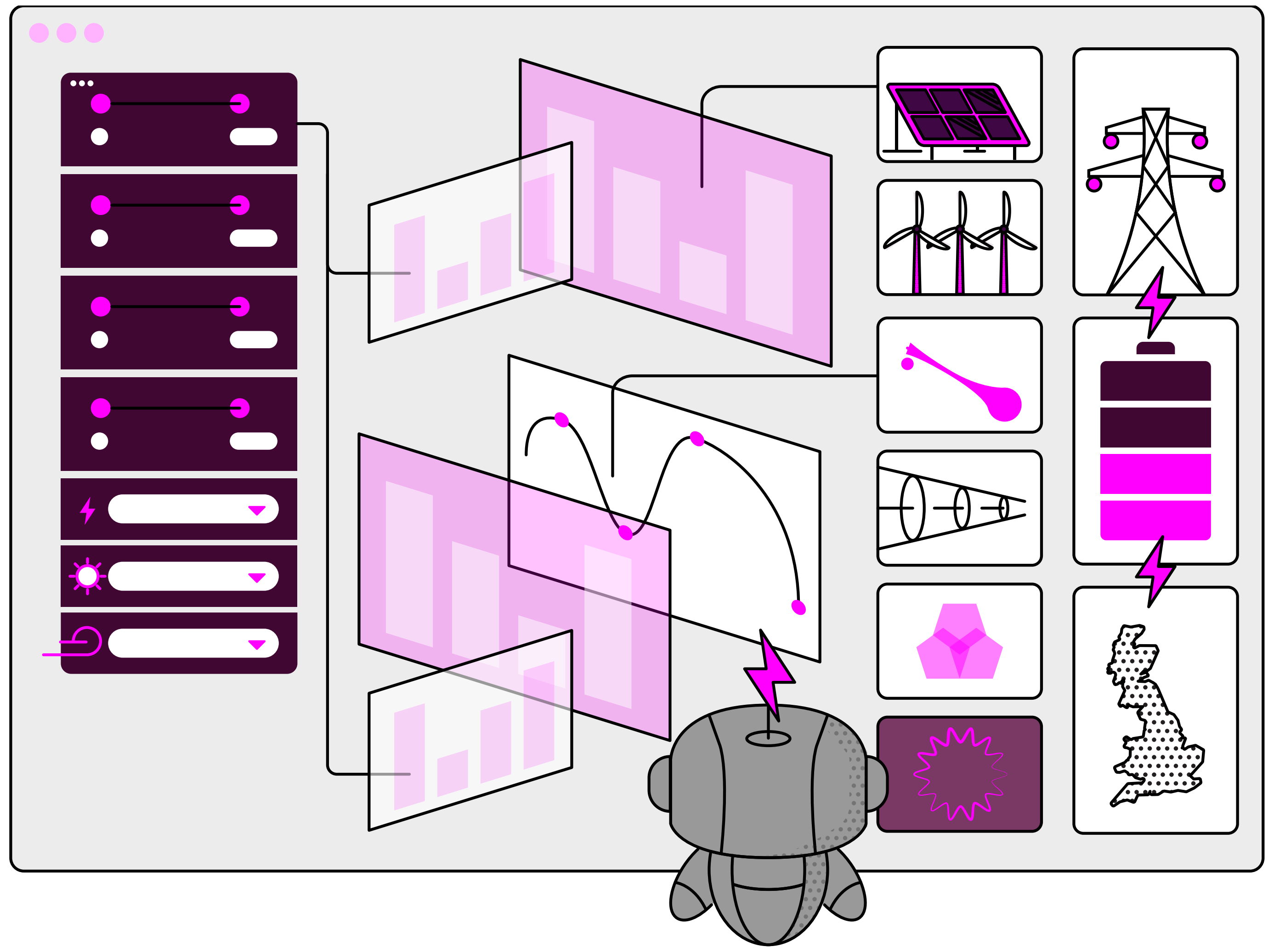
Distributed Restart innovation project

The Distributed ReStart project was a world-first initiative. The project explored how distributed energy resources (DER) such as solar, wind and hydro, can be used to restore power to the transmission network in the unlikely event of a blackout – a process known as electricity system restoration or black start.

What are the implications of CP30?

Gas-fired units, which have traditionally underpinned restoration capability, may no longer remain sufficiently warm and ready to operate as they run less frequently in a CP30 system. As plant components cool, start-up times increase and their ability to deliver contracted block loads within ESRS timeframes becomes progressively more difficult, increasing the risk of not meeting licence obligations. There is also an associated issue with ensuring maintenance and staffing levels can be sustained if both initiating and secondary units are running less frequently.

Maintaining readiness may require us to intervene operationally, such as warming units through the Balancing Mechanism. As well as increasing BM spend, doing so would increase the use of unabated gas and work against decarbonisation ambitions.



How will we meet these requirements in the future?

In future, relying on thermal plant for restoration could become more unsuitable. This reinforces the need to diversify restoration capability toward clean, fast-start technologies that can reliably reach operating conditions without extended heating cycles.

We are collaborating with industry partners to identify new technologies and improve existing renewable energy systems so they can better provide restoration services, including the Battery Reserve for Restoration innovation project. We also recognise the need to better reflect the significance of distributed energy resources in restoration. Our analysis suggests that effective direct restoration by distribution-connected assets can partially mitigate the impact of a changing transmission generation fleet. We are also investigating how offshore wind could support restoration through the Black Start Demonstration project.

Battery Reserve for Restoration innovation project

The Battery Reserve for Restoration project investigates how distributed Battery Energy Storage Systems (BESS) , including Vehicle-to-Grid technologies, can support top-bottom restoration following a National Power Outage (NPO). The objective is to identify the technical and commercial potential of BESS assets at distribution level.

Black Start Demonstration project

Black Start Demonstration from Offshore Wind. This is a collaboration with the Carbon Trust and a range of industry partners looking at how offshore wind could restore onshore electricity following a blackout.

Frequency

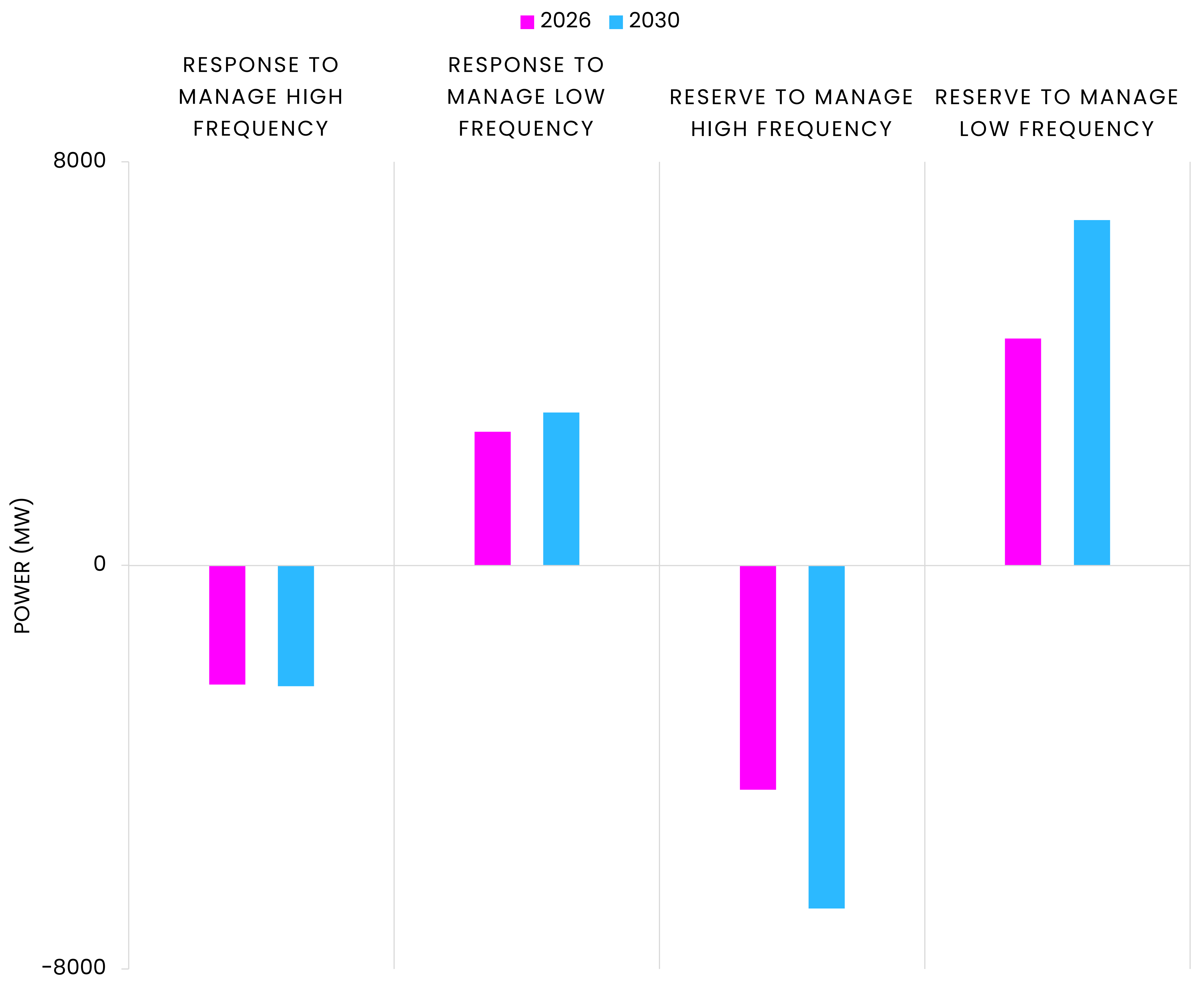
We operate the GB alternating current (AC) system at a frequency of 50 Hz. This means that the current oscillates between positive and negative voltage 50 times per second. Imbalances between supply and demand cause frequency deviations, and our innovative range of response and reserve services are used to counteract these deviations and ensure system frequency remains within one percent (0.5Hz) of 50Hz. Because of the important link between response and inertia, our approach to frequency management has to be consistent with the minimum inertia we hold. This relationship is set out and kept under review in the Frequency Risk and Control Report (FRCR).

How do we calculate our requirements?

Frequency standards are outlined within the SQSS and the EU System Operation Guideline which continues to influence the GB regulatory framework following the UK's withdrawal from the EU. Response and reserve volumes are procured to ensure we meet the specified frequency standards. We determine the requirement based on factors that impact frequency including volatility, uncertainty, replacement energy volumes (such as the size of the largest generation and demand losses on the system), and system inertia levels. The requirements for each of our services are published daily on our website.

What are our requirements?

Figure 7: Maximum daily frequency service volumes



Frequency Risk and Control Report (FRCR)

The Frequency Risk and Control Report (FRCR) includes an assessment of the magnitude, duration and likelihood of transient frequency deviations, forecast impact and the cost of securing the system and confirms which risks will or will not be secured operationally.

How do we currently meet these requirements?

Frequency response services are automatically activated when the frequency moves away from 50 Hz, while reserve is dispatched manually by a control room operator when there is a need to do so. Currently, our frequency response services include Dynamic Containment, Dynamic Moderation, Dynamic Regulation, Static Firm Frequency Response and Mandatory Frequency Response. Our reserve can be provided through the Balancing Mechanism, or through our services: Slow Reserve, Quick Reserve, Balancing Reserve and other legacy arrangements. Details of these markets are provided in the Electricity Markets Roadmap report as well as on our website pages covering frequency response and reserve.

How are our requirements likely to change?

Our requirements are heavily influenced by factors such as inertia levels and the largest potential loss of generation or demand on the system. The largest individual generation unit allowed to connect to the transmission system is set at 1,800 MW under the SQSS. The largest securable demand loss is currently set at 1,500 MW however, the SQSS is currently undergoing a review to accommodate a potential increase to 1,800 MW.

While these numbers relate to connections, the largest loss of generation or demand that must be secured for at any given time is dynamic and could be less than the SQSS limits depending on the operational parameters of the generation mix on the system. We expect this figure to increase from the present 1,400 MW to the allowed 1,800 MW with the connection of larger assets in the future.

As set out in the Stability section above, we may also see a reduction in the minimum inertia requirement. As system inertia continues to fall, driven by reduced synchronous operation, we anticipate a corresponding increase in both response and reserve requirements to ensure frequency can be contained and recovered following a disturbance.

What are the implications of CP30?

To achieve Clean Power by 2030, we cannot rely on any additional unabated gas generation to meet our frequency operability needs. This means that we need to plan to procure all of our response and reserve requirements from clean power sources, such as batteries, pumped storage and demand response. A significant amount of our response is already procured from batteries. There needs to be sufficient volumes of these assets available to ensure our frequency (and other operability) requirements can be met by clean power sources throughout 2030. If the growth of low carbon technology capable of providing frequency services slows, we might have to extend our reliance on traditional gas generators to meet some of our frequency requirements.

How will we meet these requirements in the future?

Future response and reserve requirements will likely be provided through the services we use today. We continually review our services to ensure they are fit for purpose and are currently assessing the potential benefits of intraday and locational procurement for certain products, as well as continuing to transition away from and reduce reliance on our legacy services.

Within-Day Flexibility

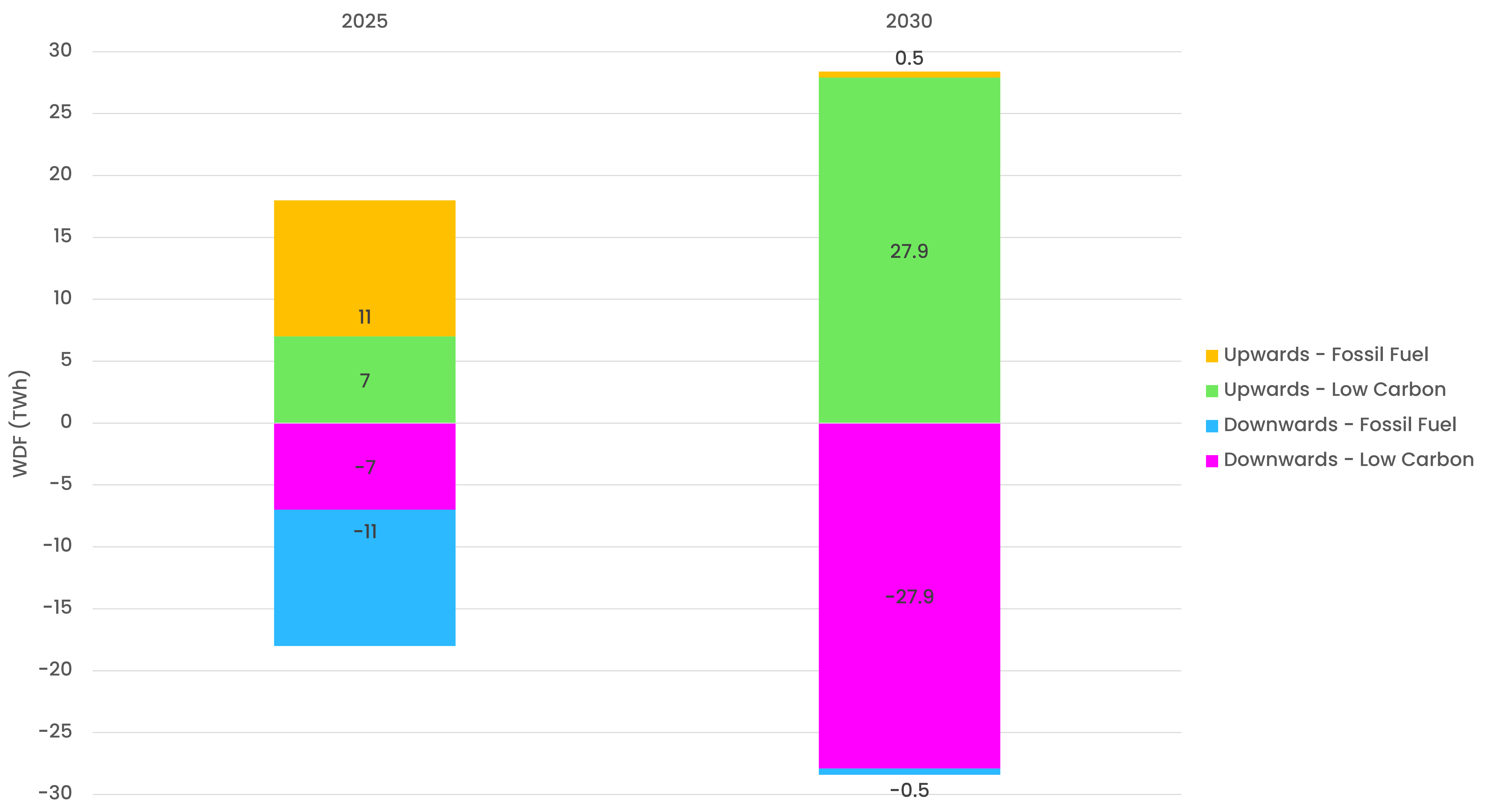
Within-day flexibility (WDF) is the ability to adjust flexible and dispatchable sources of generation, demand and storage in response to inflexible supply and demand within a 24-hour period. It can be used to balance supply and demand nationally and to manage network constraints locally.

How do we calculate our requirements?

We determine our future within-day flexibility needs by modelling the growth of key variables, such as wind and solar output, alongside changes in future demand volumes and shape. By understanding the behaviour of any inflexible variables, we can estimate the volume of low carbon WDF needed on the system in any given day.

What are our requirements?

Figure 8: Present day and 2030 system within-day flexibility need



How do we currently meet these requirements?

System WDF needs are currently met by market participants and consumers responding to price signals. GB market arrangements incentivise supply and demand to self-balance in the market, encouraging participation of flexible resources. We act as the residual balancer by making close to real-time adjustments, predominantly in the Balancing Mechanism, to maintain system frequency. These BM actions are taken on a combination of gas power stations, batteries, pumped storage, and interconnectors.

How are our requirements likely to change?

Additional WDF volumes will likely be required to operate the system effectively as renewable generation increases and reliance on fossil-fuelled gas plant declines. For example, as the capacity of distribution-connected wind and solar PV continues to grow, the depth and duration of low demand periods will become increasingly sensitive to weather patterns. This is likely to increase the variability in low transmission demand and the number of periods where generation exceeds demand, requiring additional WDF to maintain negative reserve requirements. WDF requirements in GB may be increasingly influenced by the prevailing conditions in neighbouring markets, particularly during solar-peak hours, as ongoing renewables growth in Europe leads to coincident periods of oversupply and WDF needs as a result of interconnector flows.

System advances such as greater deployment of smart meters, the launch of Market-Wide Half Hourly Settlement (MHHS), and the increasing availability of time of use tariffs are expected to increase the proportion of demand that can respond flexibly to price signals. This, alongside an increased volume of storage capacity responding to the same price signals, risks introducing additional operability challenges that require more WDF to manage. Examples include potential large ramps at the end of settlement periods or if assets respond to national price signals that don't reflect local constraints. However, if incentives are well designed and flexibility markets can reflect local requirements, demand-side assets, including electric vehicles and domestic heat pumps, can reduce the amount of additional WDF required.

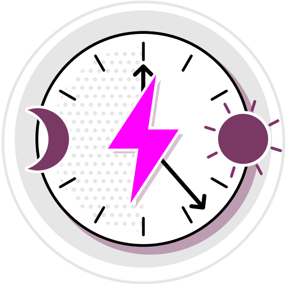
As the energy system becomes more complex, this could also make it harder to forecast our requirements. This complexity is due to variable renewable output, the non-visible actions of non-BM assets, and the increase in less predictable behaviour as fast-acting assets such as embedded storage participate in multiple markets and services, and respond to a range of different dispatch signals.

What are the implications of CP30?

CP30 requires a highly flexible system to manage the future variability in supply and demand such as in the Constrained Clean Power and Clean Power Shortfall System Conditions, outlined separately. To achieve a clean power electricity system, the procurement of WDF (along with other operability needs) must entirely shift away from gas power stations to clean energy sources. Managing this risk is a key component of the Clean Flexibility Roadmap which sets out the actions needed to increase flexibility across Great Britain.

Clean Flexibility Roadmap

The Department for Energy Security and Net Zero has published a joint NESO and Ofgem Clean Flexibility Roadmap. This outlines how Great Britain can develop a smarter, consumer-focused energy system.



How will we meet these requirements in the future?

With the procurement of WDF shifting away from gas power stations to clean energy sources, we see an increasing role for low carbon flexible assets such as batteries, Long Duration Energy Storage, and implicit and explicit demand flexibility (e.g. EV charging).

While these assets can provide implicit flexibility themselves, they are not always visible to our control room who may require more explicit WDF to balance the system if we become less confident in our forecasting of how distributed energy resources are likely to behave. As such, improved operational tools and services will become increasingly important. Consumer led flexibility can help to address these challenges, as demonstrated by the Crowdflex innovation project. Our Enabling Demand-Side Flexibility in NESO Markets report set out how flexibility participation in NESO markets could work in future.

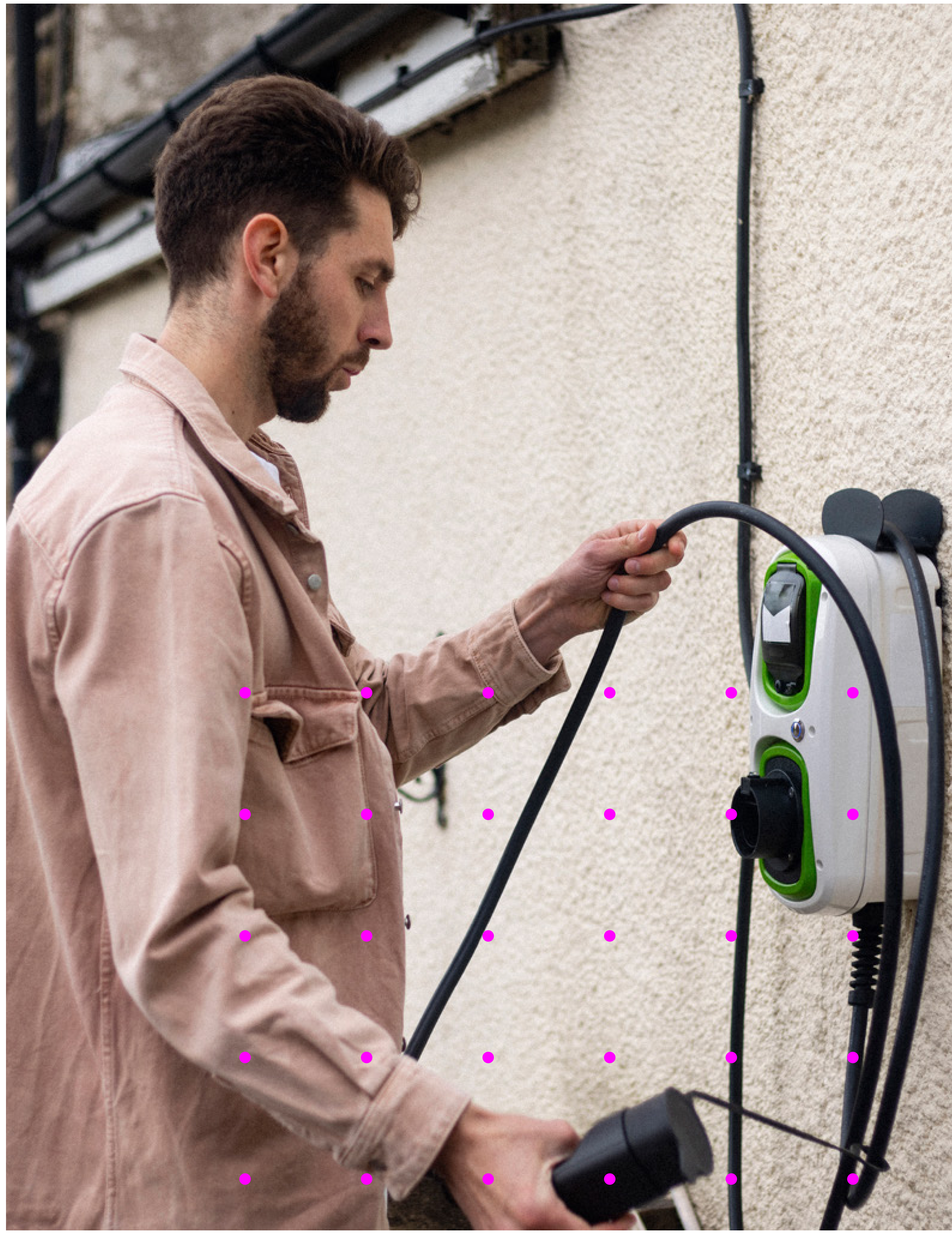
To ensure we continue to have the appropriate tools and capabilities to manage residual balancing needs, we will continue to monitor energy market changes that may impact WDF needs. This includes assessing the wider energy transition and any changes to market arrangements.

Crowdflex

Crowdflex is an Ofgem Strategic Innovation Fund (SIF) project that looks to understand how domestic flexibility can be used to help manage the electricity grid. Domestic flexibility refers to households shifting the times they use energy to help balance supply and demand. This helps consumers to reduce their energy costs.

Enabling Demand-Side Flexibility

In December 2024, we published a report entitled Enabling Demand-Side Flexibility in NESO Markets which set out our vision for demand-side flexibility participation in our balancing services markets. Since, lots has changed in this space with the publication of the Clean Power Action Plan and Clean Flexibility Roadmap; big strides are already being made in several areas across industry to enable demand-side flexibility participation in markets.



Adequacy

Adequacy is the ability to meet electricity demand, plus reserve requirements, throughout the year in a variety of weather conditions, and across planned and unplanned outages of network, interconnectors, storage and generators. It is assessed using a range of metrics including Loss of Load Expectation (LOLE) – the mean average number of hours in which load is not fully met, over a wide range of conditions, in one year. This assessment includes potential interconnector flows and so must reflect conditions in European countries as well as GB.

The GB Reliability Standard is for LOLE to not exceed three hours[2] (including non-delivery risk) and is set by the DESNZ Secretary of State. Typically, the assessed LOLE assuming expected new build generation is deployed on time would be in the range 0.1-0.3 hours (i.e. without consideration of non-delivery risk). It is not economic to aim for perfect adequacy in all scenarios which is why the Reliability Standard is used. This OSR focuses on electricity. Details on gas supply adequacy can be found in the Gas Supply Security Assessment published in November 2025, Future Market Plan for Gas. Security of supply of electricity is linked to that of gas due to the current reliance on gas-fired generation.

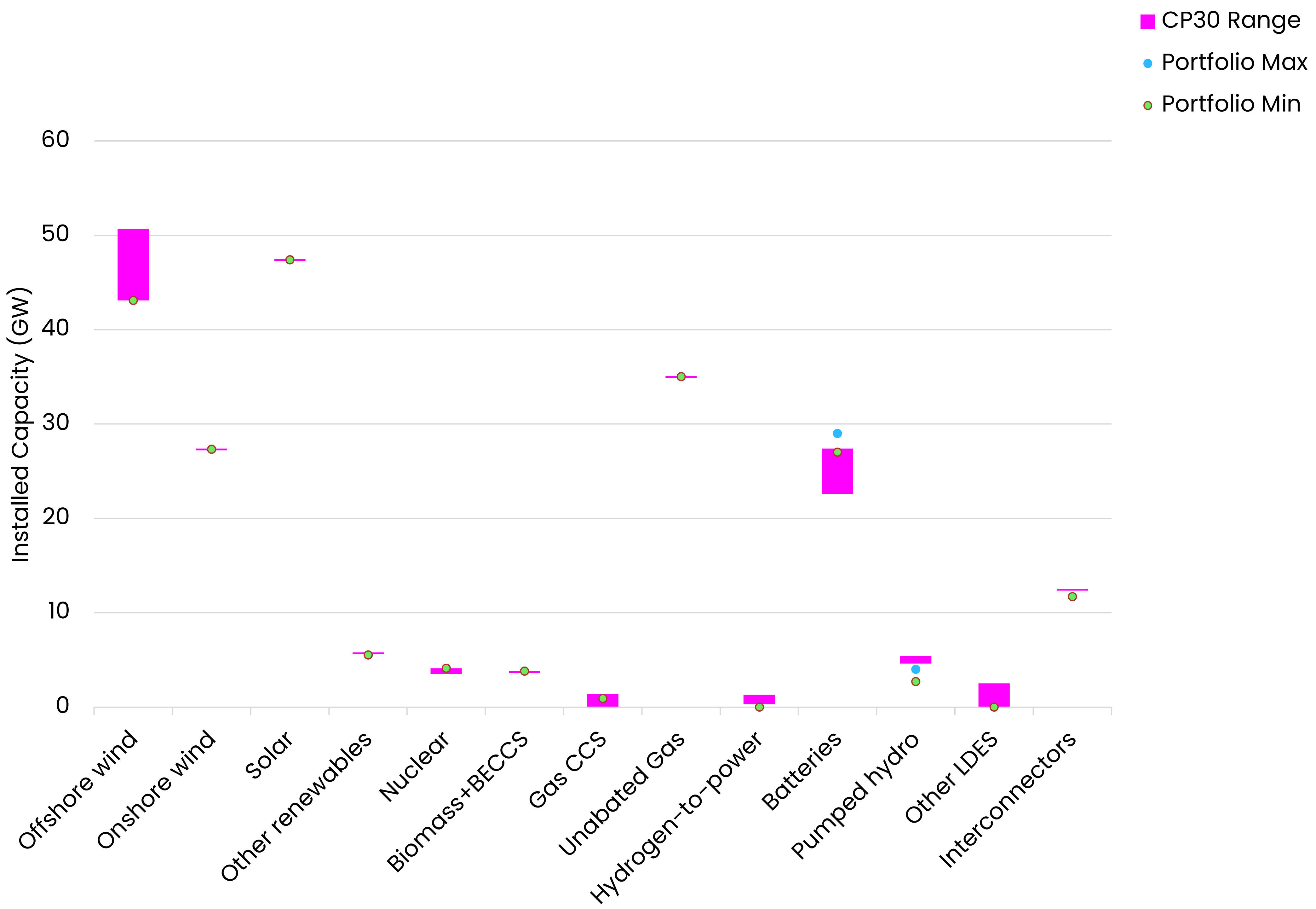
How do we calculate our requirements?

We carry out both long and short-term analysis to calculate our adequacy requirements. Every six months we consider near-term issues and account for recent changes in the electricity system, such as outage plans in our Winter Outlook and Summer Outlook reports.

Our long-term modelling seeks to identify possible future portfolios of generation, interconnection, energy storage and flexible demand to maintain a LOLE of 0.1-0.3 hours per year. Our most recent analysis was published in July 2025 as 'Resource Adequacy in the 2030s'. To identify combinations of weather and plant failures that could be particularly challenging, we assessed six selected portfolios against demand on an hour-by-hour basis under 34 years of weather data and 100 unplanned plant outage scenarios for 2030/31, 2035/36 and 2040/41. The demand profiles broadly corresponded with the annual energy demands in the FES 24 Holistic Transformation (HT) and Hydrogen Evolution (HE) scenarios. These portfolios are not recommended pathways but were chosen to test whether a future energy system can both follow a decarbonisation pathway and remain adequate.

What are our requirements?

Figure 9: Installed capacity of generation, storage and Interconnectors in 2030/31 for the 6 portfolios assessed in "Resource Adequacy in the 2030s" of July 25



2 This is a long-term average, and it does not mean that every year will have three hours of lost load, nor that the maximum number of hours of lost load in any year will not exceed three.

How do we currently meet these requirements?

The Capacity Market is our main mechanism to ensure electricity security of supply. We run a T-4 Auction 4 years before the Delivery Year and a T-1 Auction 1 year before the Delivery Year to fine-tune requirements. In the Electricity Capacity Report, we outline the recommended capacity for the T-1 and T-4 Capacity Market auctions needed to meet the three-hour LOLE GB Reliability Standard. Capacity Market contracts are awarded to eligible generators, DSR, storage and interconnectors.

How are our requirements likely to change?

Our future decarbonised power system will be dominated by weather-dependent generators, supported by higher levels of flexible resources such as storage, interconnection and demand-side flexibility. Weather can have a pronounced effect on security of supply; however, it is the combination of challenging weather and high levels of plant outages that create the greatest system stress.

We have introduced weather-conditional metrics in our adequacy analysis. We are also working with academics and the Met Office to better understand particularly stressful weather events, such as prolonged periods of low temperatures coinciding with prolonged periods of low wind. We publish an annual Winter Outlook which summarises our view of the available supply margins for the coming winter.

Electrification will see an increase in electricity demand as GB adopts more EVs and electrifies heat. This could see peak demand for electricity grow from <60 GW in 2024/25 to over 80 GW in 2039/40. However, as outlined in our view on changes to the whole energy system (Figure 6), electrification also offers improved efficiency compared to today's fossil fuel technologies. This leads to a reduction in total national energy demand and so electrification will have positive impacts on adequacy across the wider energy system.

What are the implications of CP30?

Our CP30 advice set out that, in order to meet the target, only up to 5% of our electricity can be generated using unabated gas in a typical weather year. This includes the use of unabated gas generation both to ensure adequacy when electricity demand exceeds supply from clean power sources (c3.5%) and to fulfil any need to re-dispatch gas to overcome thermal constraints (c1.5%). The modelling assumptions behind this are constantly being re-evaluated within NESO as the generation, network and demand of the system evolve.

How will we meet these requirements in the future?

Our Resource Adequacy in the 2030s Reports of December 2022 and July 2025 showed there does not need to be a trade-off between resource adequacy and decarbonising the power system to meet our energy needs. Continuing to provide a secure power system will require investment in new low carbon technologies including nuclear, hydrogen power and Long Duration Energy Storage (LDES).

We've signed a Memorandum of Understanding (MoU) with the Met Office, strengthening our relationship with experts in weather forecasting to ensure the resilience of Great Britain's energy networks as we transition towards a secure, affordable and clean energy system. Bolstering resilience to changing weather patterns through new agreement with the Met Office | National Energy System Operator.

We expect unabated gas capacity to remain on the power system by 2040, even with deployment of new low carbon technologies. While some plant could have very low or even zero utilisation in favourable weather, a year with challenging weather conditions (such as those of February 1986) could require high load factors from these plants over a period of 2-3 weeks. Work is ongoing to consider how such plant could be incentivised to remain on the system and in a reliable condition to ensure it is ready for such an eventuality.

03

Whole Energy Impacts on Electricity System Operability

Introduction

In October 2024, NESO was created with an expanded remit beyond our existing role as the Electricity System Operator (ESO) for GB. We are now responsible for strategic energy planning across multiple vectors including natural gas and hydrogen. As we integrate multiple energy vectors, our focus is on ensuring seamless and efficient planning that recognises this increasing interdependence.

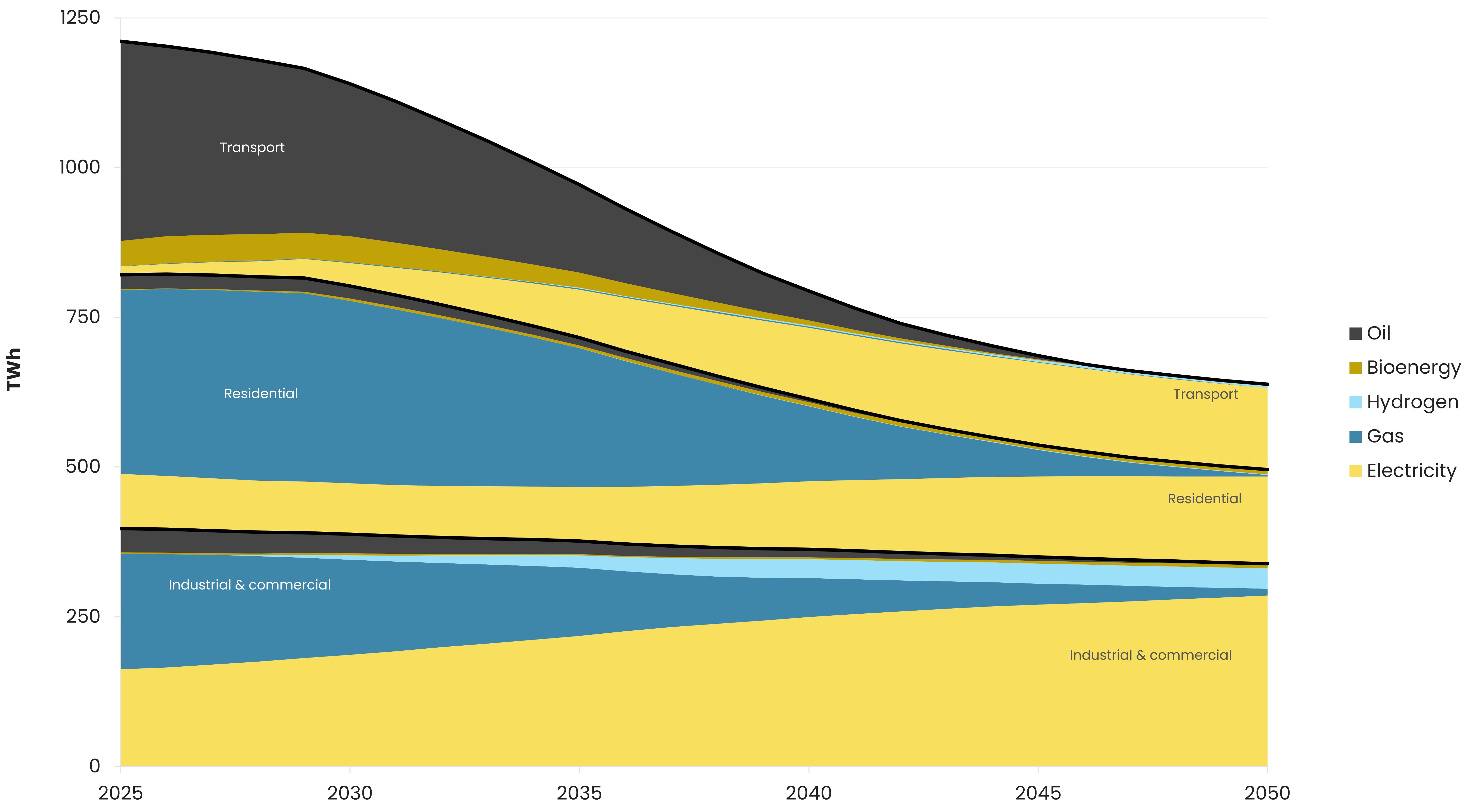
A 'whole energy system' approach means expanding beyond the electricity system to also consider other vectors such as the gas network serving domestic, industrial and generation customers and future hydrogen networks. It also means considering them all as one interlinked system whose components affect, and are affected by, each other. We will also need to consider the decarbonisation of other sectors such as domestic and commercial transport. This broader perspective enables us to better anticipate and address the complex operability challenges and opportunities associated with decarbonising the whole energy system.

Drivers for Whole System Operability

As GB decarbonises, the interactions between different energy vectors will become increasingly complex. A change in operation of one vector can have a significant impact on another. We need to consider these impacts to avoid unintended operational consequences and drive the best overall solution. A fully integrated energy system presents many opportunities to optimise energy usage and support system operation. Some of the drivers behind this shift to whole system thinking, as well as specific examples, are discussed below.

- **Transport and heating demands shift to the electricity system.** As we explained in the Clean Power 2030 advice to Government, "clean power is the foundation for wider electrification and achieving net zero". Increasing electrification of domestic heating, transport and industry will shift consumption (demand) that is currently met by gas and petroleum onto the electricity grid. This is shown from the whole system perspective of primary energy demand in Figure 10. It is one of the key drivers for expanding the grid to ensure we have sufficient renewable and low carbon generation to meet future demand. The FES25 Holistic Transition pathway also shows that a switch to more efficient electrified technologies could almost halve future annual energy demand, reducing it from 1,210 TWh to 638 TWh.

Figure 10: Electrification offers improved efficiency compared to today's fossil fuel technologies, facilitating demand reduction alongside decarbonisation (FES 2025)



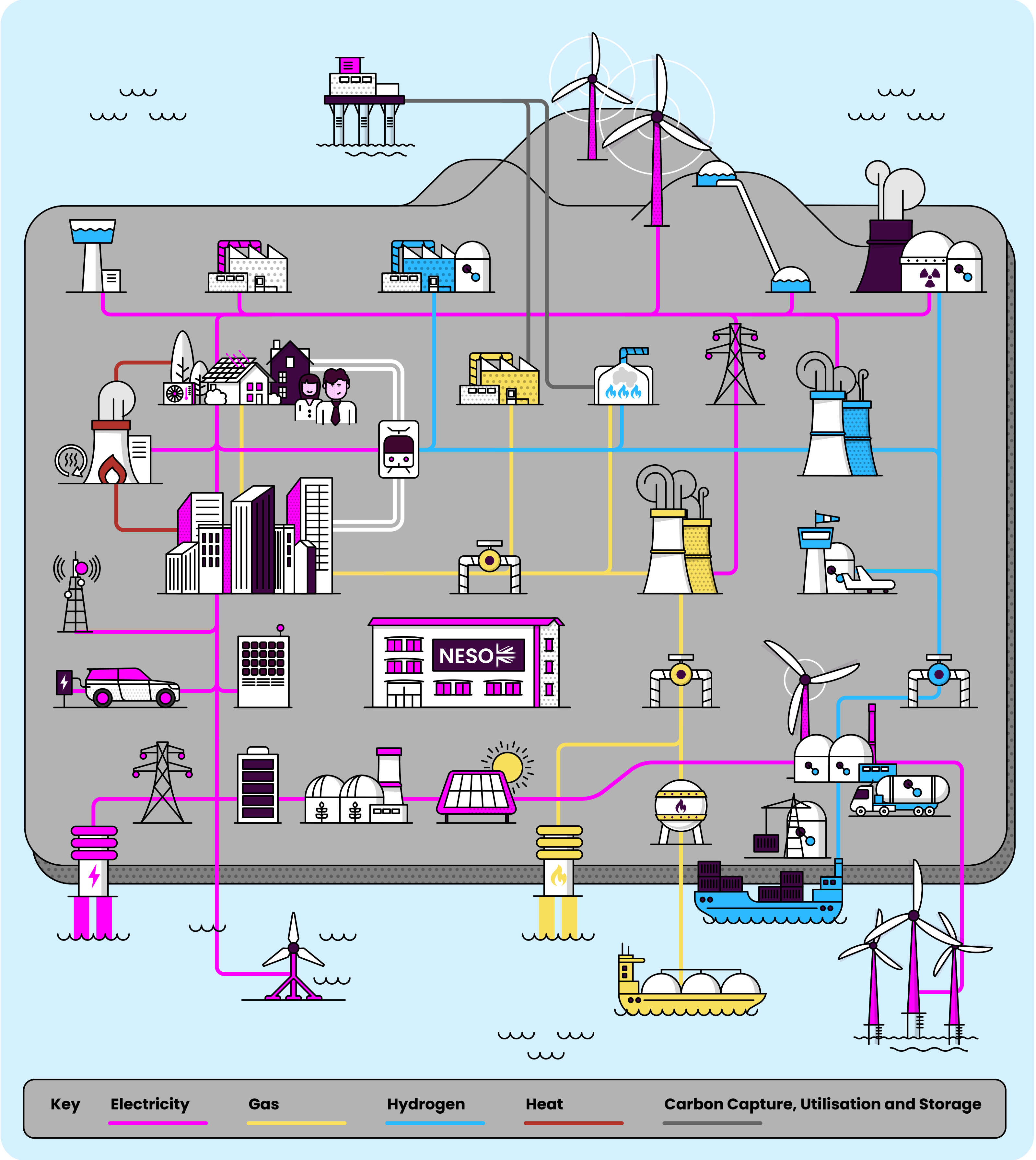
- **Heating, energy efficiency and flexibility.** The electrification of domestic heating will see homes gradually change their heating source from traditional gas boilers to low carbon technologies, such as air or ground source heat pumps (including air to air systems that may be able to provide cooling in summer). At the same time, modes of domestic transport will change from internal combustion engines to electric vehicles (EVs). This will shift the shapes and behaviours of those vectors onto the electricity grid, creating both challenges and opportunities. Issues, such as home insulation, energy efficiency, or access to on street EV charging, will become increasingly relevant to the electricity system. Opportunities, such as being able to use time of use (ToU) tariffs to bring new flexibility to the system will present new opportunities for the electricity system too.
- **Unabated gas reduction.** As discussed in the Adequacy section, gas generation capacity will be similar in 2030, but utilisation of that gas capacity will be much lower. Gas plants will shift further from frequent running to serving primarily as backup generation, such as during unfavourable weather for producing renewable power.
- **Hydrogen Production.** Alongside electrification, hydrogen is expected to play an important role in decarbonising key sectors, such as some parts of industry. One example is the HPP1 low carbon hydrogen production plant – part of the HyNet Northwest cluster - which will enable some local manufacturing and refining operations to switch away from fossil fuel-based processes. It will be important for us to understand the roadmap for hydrogen across industry because of the impact hydrogen pathways could have through interactions between electricity system operability, hydrogen networks and gas networks. Our Future Energy Scenarios 2025 (FES25) maps out potential pathways for hydrogen, with electrolysis included in all of the FES25 pathways and prioritised for sectors with few alternatives for decarbonisation. The Hydrogen Allocation Round 2 (HAR2) shortlisted 27 projects to progress to the next round in April 2025, and 448 MW of low carbon hydrogen supply is already under construction, with over half of all proposed green hydrogen production being located in Scotland.
- **Hydrogen Storage.** The properties of engineered solutions for hydrogen storage make them well suited for use in long duration and seasonal energy storage. Our Resource Adequacy in the 2030s update from July 2025 showed how hydrogen storage could contribute to electricity security of supply, when paired with electrolysis and hydrogen to power capability. This would reduce our reliance on unabated gas generation and help meet our operability requirements using clean power. It would also be helpful in addressing challenging system conditions such as constrained clean power, where electrolysers are located with wind generation behind the same thermal constraints. Our role as Hydrogen Planner will be important in ensuring strategic plans for the GB energy system take account of hydrogen's potential future uses for a clean power system. For example, a hydrogen pipeline bringing wind energy south could reduce pressure on the electricity system to make the same bulk transfer.
- **Hydrogen to Power.** A low carbon electricity system will require sources of flexible, dispatchable power generation to fulfill a variety of roles in terms of system operability. Our Resource Adequacy in the 2030s analysis identified power from hydrogen as one of a mix of technologies that has the potential to fulfill this role at scale. Research published by DESNZ into the costs and barriers to Hydrogen to power looked at different archetypes including turbines, reciprocal engines and fuel cells.

- **Data Centres and Artificial Intelligence.** The Government has set an ambition to ramp up the UK's public computing capacity 20-fold within five years. Our Future Energy Scenarios suggest that data centre demand for energy could triple by 2030, eventually representing 7% of domestic demand. This projected growth is supported by evidence from our Connection queue. The way we plan and operate the electricity system will be significantly affected by how much of this capacity is built in the UK, and where. NESO has not previously attempted to guide demand to particular parts of the system but the benefits to GB consumers from doing so could be significant. The SSEP Methodology includes plans to spatially optimise 1-2 GW of data centre demand.
- **Dispatchable Low Carbon Generation.** The development of low carbon dispatchable generation has the potential to offer flexible sources of power that are compatible with net zero goals. The electricity system will have specific needs for these power sources. Hydrogen for power generation, gas fired power stations fitted with CCS, and biomass provide the low carbon dispatchable generation needed under CP30. The Green Gas Support Scheme (GGSS), which provides tariff support for biomethane production, has seen an extension of the commissioning deadline by two years to 21 March 2030. These technologies can also provide other benefits in terms of system operability, such as providing inertia, reactive support, and system strength. A range of CCS projects have moved to the delivery stage, including the energy-from-waste facility at Protos, in Ellesmere Port which will form part of the HyNet carbon capture cluster in the North West. These projects and others will involve the development of carbon networks which are expected to support large scale power generation with CCS.

The figure to the right shows an example of what a future energy system could look like, focussing upon the interactions between different vectors.

Figure 11: A visual illustration of a possible future energy systems, showing interactions between different vectors and networks

The pink lines denote electricity flows from wind, solar and nuclear to homes, industry and storage such as hydrogen in blue. This in turn is used in aviation, industry and to generate electricity. A small amount of natural gas is used, denoted in yellow, for power generation or to produce hydrogen with the emissions being stored using CCUS. Carbon flows to storage are shown in grey. Finally, biomass is also used to generate electricity with the waste heat used in heat networks for both domestic and commercial heating.



This visual is intended to tell an illustrative story of a hypothetical future energy system. It is not intended to be comprehensive, nor does it define NESO's view of the future energy system.

What Are We Doing for Whole System Operability

Whole system operability will be a key consideration in our future workstreams. Whether in strategic or regional energy planning, network planning, or as we evaluate the impacts of new and emerging vectors upon the wider energy system, we will ensure that the operability of the future energy system remains assured. Below we discuss some of our work areas which will consider whole system operability.

Strategic Spatial Energy Planning. In October 2024 the government commissioned us to create a Strategic Spatial Energy Plan (SSEP) for the energy system across GB. In May 2025 we published our final SSEP Methodology, which has been accepted by Government. The SSEP will consider the whole energy system, and we will continue to identify risks and opportunities that may arise in relation to operability across networks. The SSEP is presently due for publication in Autumn 2027.

Regional Energy Strategic Planning. In November 2023 Ofgem published their decision to introduce Regional Energy Strategic Plans (RESPs) to co-ordinate sub-national, whole system energy planning. Following consultation, Ofgem published the RESP policy framework in April 2025, with the role of delivery assigned to NESO and mandating a whole system approach. A consultation on the proposed RESP Methodology ran from November 2025 to January 2026, with the final methodology due for publication in Summer 2026, following approval by Ofgem and DESNZ. Taking a whole system approach that aligns regional and national strategic planning of energy networks provides a strong foundation for ensuring that the system remains operable in future.

Centralised Strategic Network Planning. In December 2023 Ofgem published their decision on the framework for developing a Centralised Strategic Network Plan (CSNP). This will enable strategic and efficient investment to meet the requirements of net zero, including operability, by taking a holistic approach across all networks - both onshore and offshore electricity as well as gas and hydrogen. As an interim step towards the full CSNP, due for publication in 2028, we are developing a Transitional CSNP and submitted the refreshed methodology to Ofgem for review in 2025. The refreshed second tCSNP will be published by June 2026. It will be transparent, and evidence-led, providing the confidence required to identify the right options to take forward for regulatory and planning purposes.

04

Operability Considerations

The changing shape and magnitude of electricity demand

Impact	Increased complexity when forecasting demand which may require more reserve and within day flexibility to meet operability requirements.
Timeline	2027 onwards

Electricity demand is set to both grow and change shape, and this shift is now considered almost certain, with a high impact from 2027 onwards.

Looking ahead, we expect continued and noticeable changes in demand driven by several factors: growing uptake of EVs and heat pumps; greater use of demand-side flexibility; distribution and balancing mechanism (BM) assets responding dynamically to market conditions; and the connection of large new loads - potentially in areas of the network not previously designed for them.

As transport and heating become increasingly electrified, and new types of loads such as data centres connect, we expect overall demand to rise. Many of these new loads could also fundamentally reshape the daily and seasonal electricity demand profile. For example, winter demand should increase with electrified heating and overnight demand may increase due to EV charging. We also expect consumer-led flexibility to cause demand to shift in response to periods of high renewable generation. Together, these trends create new challenges and opportunities for our role as system balancer. Both national and transmission system demand are already showing early signs of batteries and electric vehicles responding to market signals and charging during low price periods.

One of the main impacts of these changes could be a rise in forecasting complexity across both operational and planning timescales, causing growing discrepancies between forecast and actual transmission system demand. Uncertainty makes balancing supply and demand more difficult and potentially more expensive.

A number of wider system conditions could make these risks more acute, such as limited visibility of assets outside the BM, actions taken by third-party aggregators that lie outside the direct control of the system operator, potential cyber-attacks and software issues. There is also a risk that NESO and DNO dispatch actions may conflict leading to primacy issues (i.e. whether a NESO dispatch instruction gets unwound by a DNO and thereby not achieve its objective). This is often manifested as interactions between NESO instructions and Active Network Management (ANM) schemes employed by DNOs to optimise flows across their networks and manage constraints.

Looking ahead, we are exploring a range of new solutions to help mitigate these risks, such as potential changes to codes and market arrangements (e.g. GC0117 and RNP) which will bring more assets into established processes for system operation (e.g. the BM) reducing the incidence of large steps from smaller assets.

We are also carrying out forward looking analysis to quantify how this risk is evolving, recognising that some elements stem from broader market behaviour. New predictive tools have already been developed and are in use within the ENCC to help improve our visibility and response capability and greater engagement with DNOs is also a key focus area to improve whole energy system efficiency and security.

Step changes in transmission system demand

Impact	Step changes can cause frequency deviations and possible tripping of embedded generation in extreme scenarios.
Timeline	Ongoing

We are currently seeing a rapid growth in smaller assets capable of being very flexible. This has the potential to be very beneficial to system operation but, if the incentives and rules that drive their behaviour are not aligned with system need, they can cause problems.

Fast ramping demand and generation are already creating new operational challenges for the electricity system. We always seek to minimise the gap between the generation dispatched through the market and the real-time power requirement. When demand and generation diverge quickly, system instability can arise. We are increasingly seeing situations where new technologies or market strategies create sudden, steplike changes in power flows. These swings are becoming more difficult to manage and the risk is intensified when large volumes of aggregated demand, such as fleets of battery units or EV chargers, disconnect or change state simultaneously, resulting in significant and abrupt demand variations.

This is an ongoing issue, and the underlying drivers suggest that its severity will continue to grow. Demand-side flexibility is projected to reach 10–12 GW by 2030, up from 2.5 GW in 2025 according to the Government's Clean Power Action Plan, but control room visibility of this flexibility is still limited. For example, suppliers may set low-price periods that trigger increased consumption, or aggregators may adjust set points of non-BM assets without real-time reporting. Assets participating in imbalance markets may move power output rapidly due to the absence of ramp-rate restrictions, creating noticeable swings.

The impacts of these rapid shifts are significant and include frequency and voltage excursions, and potential breaches of SQSS limits. Balancing costs increase as additional BM actions are required to stabilise the system.

We continue to manage frequency deviations using established services for reserve, response and inertia but changes to policy around these services may be required as the system becomes more dynamic and less predictable. The Balancing Mechanism (BM) remains our primary tool for correcting power imbalances, though this is becoming more challenging due to rising errors in power requirement forecasts and an increasing volume of plant falling outside the BM.

Another challenge is the risk of sudden changes in demand, which may necessitate the procurement of additional response and reserve services. Demand can ramp sharply up or down, and conflicting instructions between Distribution Network Operator (DNO) active network management and transmission level power needs may emerge. Increasing volumes of embedded generation will also add new weather-related variability to transmission system demand. This can also drive redispatch actions to resolve related issues, particularly around voltage management. Without mitigation, there is a risk of increasing costs on the system and inefficient outcomes for the consumer.

Despite the challenges, there are significant opportunities. We can no longer assume generation is the only controllable asset. With increasing flexibility on the demand side, there is now real potential to use this demand itself as a balancing tool, for instance shifting peak consumption to periods of high renewable output.

Our long-term planning frameworks, including SSEP, CSNP and RESP, are designed to ensure we have the appropriate tools and system design to meet future demand patterns. The wholesale market, balancing mechanisms, and ancillary service markets are also built to accommodate evolving demand behaviour. Looking forward, reforms such as Market-wide Half Hourly Settlement (MHHS) and wider uptake of time-of-use tariffs are expected to improve the controllability and coordination of demand, helping to guide flexible assets in ways that support system operability. We are continuing to support the Smart and Secure Electricity Systems (SSES) programme by working with DESNZ, Ofgem and Elexon to ensure that domestic flexibility can participate safely and coherently in markets, while maintaining system operability and ensuring cyber resilience.

Increasing requirements for and changing provision of voltage management

Impact	Increased balancing costs through use of gas generation to ensure system remains within voltage limits. Associated impact on CP30 target if not resolved.
Timeline	Ongoing

Voltage regulation challenges are already a feature of system operation and are highly likely to intensify as renewable and distributed energy resource (DER) penetration continues to rise. Declining synchronous reactive capability, and ongoing visibility and forecasting gaps across the TO–DNO interface are key factors affecting this.

A range of conditions contribute to the likelihood of changing voltage regulation requirements. High renewable and distributed generation output can cause reactive power to spill from distribution networks onto the transmission system, particularly as embedded generation volumes increase. The progressive retirement of synchronous units, together with outages of TO reactive assets, such as SVCs, STATCOMs and reactors/capacitors, reduces the availability of traditional reactive power sources. Limited visibility and forecasting uncertainty are making voltage behaviour harder to predict, further complicating operational planning. Certain regions, especially the South-West, are expected to face elevated voltage challenges under both low-demand and high embedded generation scenarios in the short to medium term. These challenges are compounded by the growing locational complexity of an inverter-heavy system (which leads to more volatile post-fault behaviour) and rapidly evolving system characteristics.

The impacts of these trends are important as we seek to ensure that statutory and operational voltage limits are maintained. Balancing and constraint-related costs are rising as more BM actions are required to manage reactive power.

Despite the challenges, the modern electricity system presents new opportunities for more dynamic and sophisticated voltage management. Voltage control can no longer be viewed solely through the lens of traditional, centralised reactive assets. More extensive distribution of assets, automation, and increased deployment of inverter driven solutions create new possibilities because, if appropriately designed, they can provide dynamic, localised voltage correction during sudden changes in renewable output.

A number of established solutions and management strategies are already in place. Existing TO reactive assets, including reactors, capacitors, SVCs, circuit switching schemes, and STATCOMs, remain core tools for voltage control under varying system conditions. Maintaining and improving the reliability of these assets is prioritised to ensure adequate reactive capability when needed. Commercial mechanisms are also important, including procurement of reactive services via the balancing mechanism, generator voltage target adjustments, and long-term contracts for network services (i.e. voltage pathfinders). Short-term coordination with DNOs continues to help manage the spill of reactive power up from distribution networks and facilitates more effective actions at GSPs.

Looking to the future, new approaches are being developed to enhance voltage management in an inverter-dominated system. Reactive power markets are expected to expand to unlock support from emerging technologies. Grid-forming capabilities offer dynamic reactive response such as stronger post-fault voltage recovery, improved damping and stability in periods of low short circuit levels, and more resilient behaviour during weak-grid interactions. These dynamic benefits don’t alter steady-state voltage control but do enhance overall voltage stability. When combined with their important role in inertia and SCL provision, this highlights how we expect holistic grid forming solutions to play an increasingly important role as the system transitions further away from synchronous plant.

More challenging network operation during a rapid transition

Impact	Increased balancing costs and operational complexity.
Timeline	Present - 2032

The transmission network is undergoing rapid transformation as the energy system electrifies. This expansion includes the development of new network infrastructure, emerging network services designed to increase capacity, and a rising number of outages needed for connections and upgrades. Alongside these changes, the growing use of HVDC assets alongside the AC system introduces both valuable opportunities and new operability challenges.

The pace of transmission system upgrades is accelerating, and with this comes an increase in the frequency of planned outages that affect more users of the system. Operating an increasingly complex system with more constraints, more outages, and more network services requires strong forward planning to retain operability. A key consideration arises when new generation or demand connects faster than the associated transmission assets needed to support them. Delays to network delivery, including offshore HVDC links and interconnectors, can result in generation connecting ahead of the reinforcements intended to accommodate it. This impact on costs and carbon emissions can be further exacerbated if planning assumptions diverge between ourselves and the TOs. New network services also introduce added operability complexity. For example, the use of intertrips on boundaries may require us to procure frequency management more locationally. Poorly coordinated or unplanned outages could also limit access to assets essential for secure operation.

As the system is driven harder and more assets operate closer to their limits, opportunities to manage network changes become fewer, unless decisive action is taken. Loop flows on interconnectors can also be difficult to control; without careful design, new grid infrastructure, particularly HVDC links, can create or shift constraints. Regional capacity constraints, such as those increasingly observed along the South and East coasts, may become more prominent.

These changes create several material impacts. Network upgrades add more outages to the system, which must be managed across both operational and planning timescales to maintain system operability. The System Access Reform programme will transform system access planning, setting a new standard for efficiency, coordination and transparency. In addition, if operational tools and models do not evolve alongside the changing network, redispatch decisions may become suboptimal.

Despite the challenges, there are significant long term opportunities. A holistic and forward looking approach to network transformation should reduce balancing costs and improve overall operability. The growing HVDC offshore network permits advanced optimisation opportunities, with HVDC technology offering new services and more direct control of power flows. The introduction of diverse control modes and expanded functional capabilities must align with GB's operational practices to fully realise their value. HVDC technology also provides a bidirectional and highly configurable platform to manage regional constraints, particularly in areas with high renewable penetration. New HVDC links are expected to help manage north–south constraints and offshore flows more efficiently, supporting the continued integration of renewables. Increasing the diversity of asset types and locations from which operability services are procured will further support system stability, and growing flexibility across the system will assist in managing network change.

Looking forward, several new solutions and management strategies are being developed. Some services currently procured nationally are expected to move toward regional procurement to maintain secure operation during periods of network change. Dynamic operational envelopes for HVDC links are being explored, enabling real time adaptation of HVDC behaviour to system conditions. The role of HVDC infrastructure in constraint management is likely to expand, reducing the need for redispatch and supporting the integration of offshore wind and other low carbon resources.

The changing nature of generation to and beyond 2030

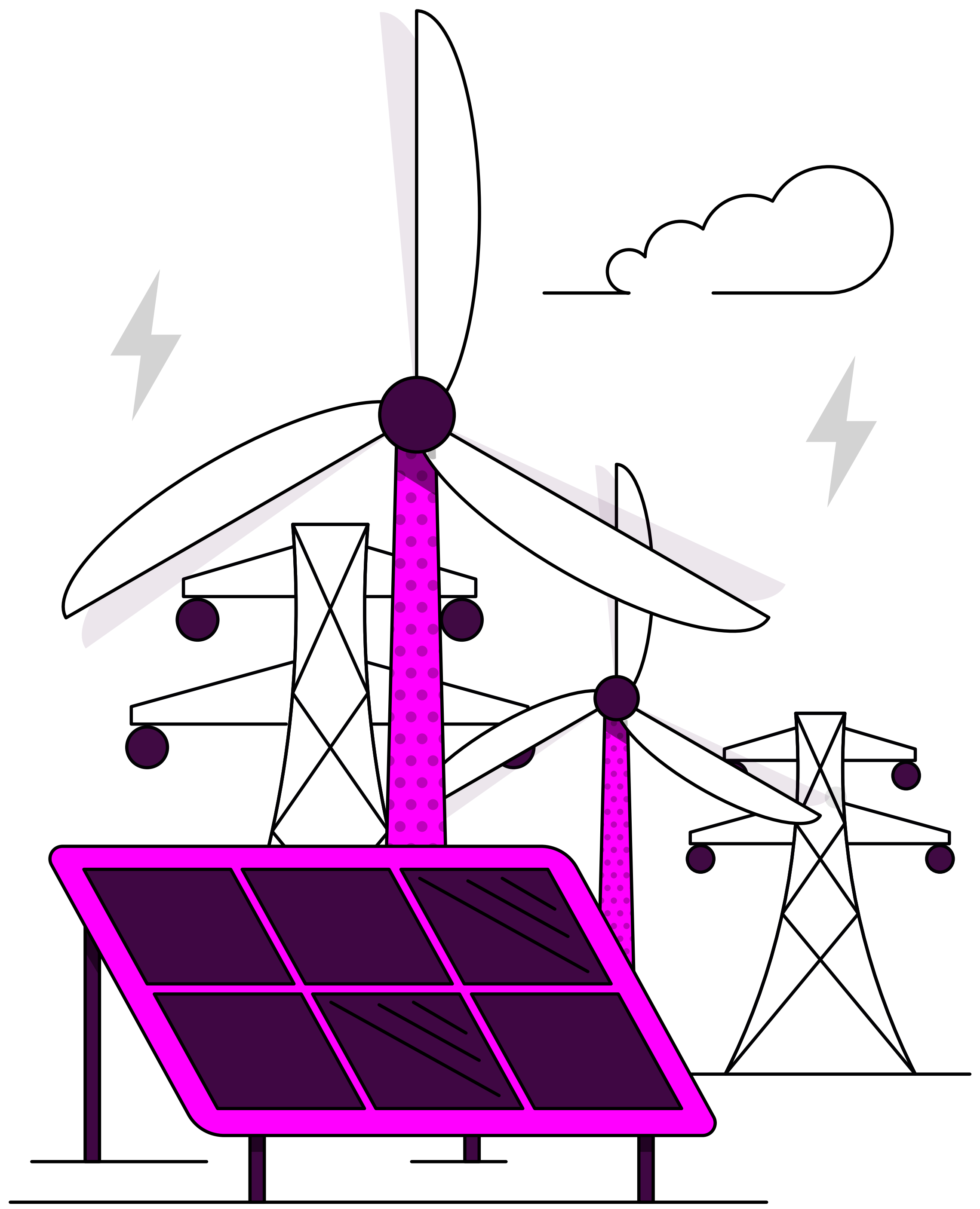
Impact	Meeting operability requirements with lower use of unabated gas and reduced availability of synchronous generation.
Timeline	Present - 2035

Inverter-based resources (IBRs) are already displacing traditional synchronous plant such as CCGTs and we expect this trend to continue. As synchronous plant runs less often, we must replace the stability, voltage, and frequency support that these units traditionally provided. Initially the system will rely on services from zero carbon sources only for brief periods when conditions are optimal. These periods will rapidly increase in length to cover hours and days. By 2030, the aim is that this will be the situation for almost the whole year. Weather-dependent generation introduces higher and more volatile ramping, which becomes problematic when forecasting is inaccurate across national or regional scales. Periods of excess renewable output may reduce downward margin, while declining synchronous generation lowers system short-circuit strength.

The rapid connection of wind, solar, storage, and hybrid assets, especially in regions with low natural system strength, can create operability challenges if growth outpaces our ability to operate securely. Visibility gaps, particularly for DERs and CERs, compound these issues. Similarly, connection and disconnection timescales of large assets such as nuclear need to be closely managed as periods of lower synchronous contribution could arise if older stations retire before new plant comes online.

Despite these challenges, there are significant opportunities. Grid forming assets can complement or replace synchronous plants. Developments outlined in the accompanying Electricity Markets Roadmap point toward new markets that support these needs. Advanced forecasting and real time monitoring of new generation types, including DERs and CERs, will improve situational awareness. Reducing barriers for DER and CER participation in our markets will also expand the pool of assets able to provide operability services.

A range of existing strategies is already in place to manage the transition. The Stability Pathfinders have procured inertia, system strength, and dynamic voltage services, while long term and midterm (Y-1) stability markets provide structured routes to securing operability capabilities. Established frequency response services help manage low inertia conditions, and operational tools and models support secure system planning. Synchronous condensers and grid-forming inverters are already being deployed in key regions, and grid-forming requirements may be expanded through changes to the Grid Code. The shift toward more dynamic operational planning and real-time optimisation is underway, supported by advances in digitalisation that improve observability of DERs and distributed storage and enhance the ability to dispatch these assets.



Increased levels and changing nature of interconnection

Impact	Reliance on interconnectors during low renewable periods and potential restrictions on redispatch could increase cost and emissions associated with thermal constraints.
Timeline	Present – 2032

The GB electricity system is becoming increasingly interconnected with neighbouring power systems. These interconnectors enhance resilience and reduce costs. However, they also introduce a range of operability challenges that must be actively managed.

Several trends are increasing the likelihood of interconnection-related risks unless appropriate mitigation is in place. Interconnector flow changes are a major component of power-requirement calculations, and their volatility necessitates improved flow forecasting. Short-notice schedule updates can significantly alter both pre-fault and post-fault conditions. There is also a risk of overreliance on interconnectors during periods of renewable undersupply, such as Dunkelflaute/anti-cyclonic gloom, when neighbouring countries may face similar weather conditions and be unable to support GB.

When scheduled interconnector flows would cause problems on the GB system, we send instructions to change the flow (redispatch). This can cause problems for the system on the other side of the link. Recently, system operators on the other side of our interconnectors have been requesting that we significantly reduce our redispatch instructions. However, our modelling of the system suggests that the need for redispatch actions will increase significantly in the coming years. This potential tightening of redispatch flexibility means new and innovative solutions may be required and this is an important consideration of RNP.

GB is increasingly exposed to changes in generation patterns across Europe; for example, the planned maintenance outages of Belgian nuclear units in summer 2026–27 will reshape continental supply patterns and may influence GB imports and exports. Upcoming changes in the European market, such as shorter imbalance settlement periods, will increase the frequency of schedule updates, placing greater pressure on operational decision-making within the ENCC.

The next generation of interconnectors introduces further considerations: grid-forming capability may be enabled on interconnectors such that, in the event of a disturbance in the interconnected country or wider continental system, power could change instantaneously from GB to Europe. While such cross-border grid-forming operation has the potential to introduce a substantial volume of rapid support, it may pose additional risk, particularly during periods of domestic system stress. This risk may also be asymmetrical where the relative size of the donor system is substantially smaller than the system receiving the support, as would be the case of GB supporting the continental European system.

Interconnection also brings significant opportunities to enhance operability. Strengthened operational cooperation with European TSOs improves cross-border resilience and enables access to shared low-carbon flexibility. Shorter imbalance settlement periods may unlock a more responsive market and enhance utilisation of interconnector capacity. As GB becomes more integrated with European energy markets, the potential for whole-system optimisation expands considerably.

Several existing tools and management strategies are already in place. FRCR processes consider the largest potential losses from interconnectors when determining frequency requirements. Real-time flow monitoring has improved situational awareness, supported by interconnector-specific operational limits. Coordination with neighbouring TSOs during contingency events is well established through European market-coupling and balancing frameworks - for example, joint work with European TSOs to understand the impacts of Belgian nuclear outages.

Looking forward, several new solutions are being developed or expanded. Opportunities exist to utilise advanced HVDC operating modes, including power damping, frequency support, and voltage control, to meet GB system needs. Incorporating grid-forming High Voltage Direct Current (HVDC) capability into long-term system planning could be increasingly important. Work is also underway to develop interconnector dispatch-optimisation systems to better align market outcomes with operational requirements. Enhanced forecasting models are being explored to reduce power-requirement inaccuracy and improve confidence in forecast interconnector behaviour.

More challenging control room operating conditions

Impact	Complexity of decision-making growing
Timeline	2027 onwards

Delivering a secure, reliable, clean and affordable electricity system requires not only sufficient generation and network capacity, but also the additional people capability to manage unprecedented variability, complexity, and interdependence across the whole energy system. As the system operator, we are already operating a system that differs fundamentally from the one for which many historic processes, tools, and roles were designed.

The GB electricity network is shifting from a centralised system to one increasingly shaped by weather dependence, decentralisation, and rising complexity. For example, two new Eastern Links will add 4 GW of capacity, alongside fast-growing DER and renewable connections that will increase modelling complexity. Rising wind and solar output increases variability and changes inertia requirements, while electrified heat and transport reshape demand. Interconnectors, flexibility services, and active DERs are now central to real-time system balancing.

These system changes are important because they significantly alter the operability risk profile faced by the Control Room. Real-time decisions must increasingly balance security, cost efficiency, and fairness under heightened uncertainty and time pressure. The volume of operational data that must be interpreted in real time has grown substantially, drawing on multiple sources that were not originally designed to be used together. Operators are required to synthesise this information rapidly to maintain situational awareness, often while coordinating with a wider range of operational customers than in the past. At the same time, expectations around transparency and explainability of operational actions have increased, reflecting the importance of consumer value and confidence in a high-cost, constraint-driven system.

We believe that these challenges will become increasingly material from 2027 onwards. This is when additional renewable capacity is expected to connect at scale, major network reinforcement programmes progress, and market and operational reforms take effect concurrently. Under CP30 conditions, system operation is often driven by the management of constraints rather than energy adequacy alone. A growing proportion of balancing actions are expected to be required to manage local and regional network limitations, increasing the frequency and complexity of interventions and amplifying the cost consequences of real-time decisions. In this environment, relatively small changes in weather, asset availability, or customer behaviour can produce disproportionately large impacts on operational outcomes and consumer costs.

To some extent, the Control Room is already operating in this new environment. The number and complexity of system constraints have increased, driving greater reliance on redispatch and non-standard operational actions. Coordination with generators, interconnectors, flexibility providers, and network companies has become more frequent and more operationally critical, often under compressed timescales. Operational teams are successfully managing growing volumes of information, reconciling differing data views, and applying expertise in new system conditions. However, as the complexity of the system increases, these challenges could start to impact both the speed and consistency of decision making.

To respond to these challenges, we are evolving the Control Room operating model to better align with the realities of a clean power system. This includes:

- Strengthening the use of high-quality, integrated data and associated computational tools to support faster and more confident operational decisions
- Embedding greater awareness of market and cost impacts within real-time operation
- Systematically improving operational processes to capture learning and reduce variability
- Enhancing coordination with operational customers to improve readiness, compliance, and shared situational awareness.

Together, these changes are designed to reduce operability risk, improve efficiency, and support consistent decision-making in an increasingly complex system.

05

Other Considerations for Operability

Reformed National Pricing

In 2022, the Government launched the Review of Electricity Market Arrangements (REMA) to assess options for reforming the GB electricity market to deliver a low-cost, secure, and decarbonised electricity system. The REMA programme considered a range of options before publishing its policy outcome in July 2025 to retain a single national wholesale price and to progress Reformed National Pricing (RNP) rather than moving to a zonal wholesale price. This introduces a series of reforms to market arrangements to help to deliver a more efficient, secure, and affordable clean power system. The package is built around three interlinked pillars:

1. **Reform siting and investment levers to deliver the Strategic Spatial Energy Plan**

   Aligning siting and investment levers across the power system behind the Strategic Spatial Energy Plan (SSEP), to incentivise the location of new assets in optimal areas, in a way that achieves the best balance between the roles of greater strategic planning and markets.

2. **Improve system operability and efficiency**

   Reducing the cost of running the power system in real-time, by reforming balancing and settlement arrangements, considering the potential for further dispatch reforms.

3. **Further bear down on network constraint costs**

   Additional action across our power system to further bear down on both the volume and cost of network constraints, including ahead of 2030.

NESO recently launched a Call for Input on the second pillar of the RNP package. This sets out the principles and challenges for balancing, settlement and dispatch reform to address, and introduces the proposed balancing reforms that aim to ensure the system can be operated in a secure and efficient manner and deliver cost savings for consumers. Initial implementation considerations for the reforms are outlined alongside high-level impacts on industry bodies and market participants. We also introduce the case for further dispatch reform, which builds on the balancing reform and constraint management packages.

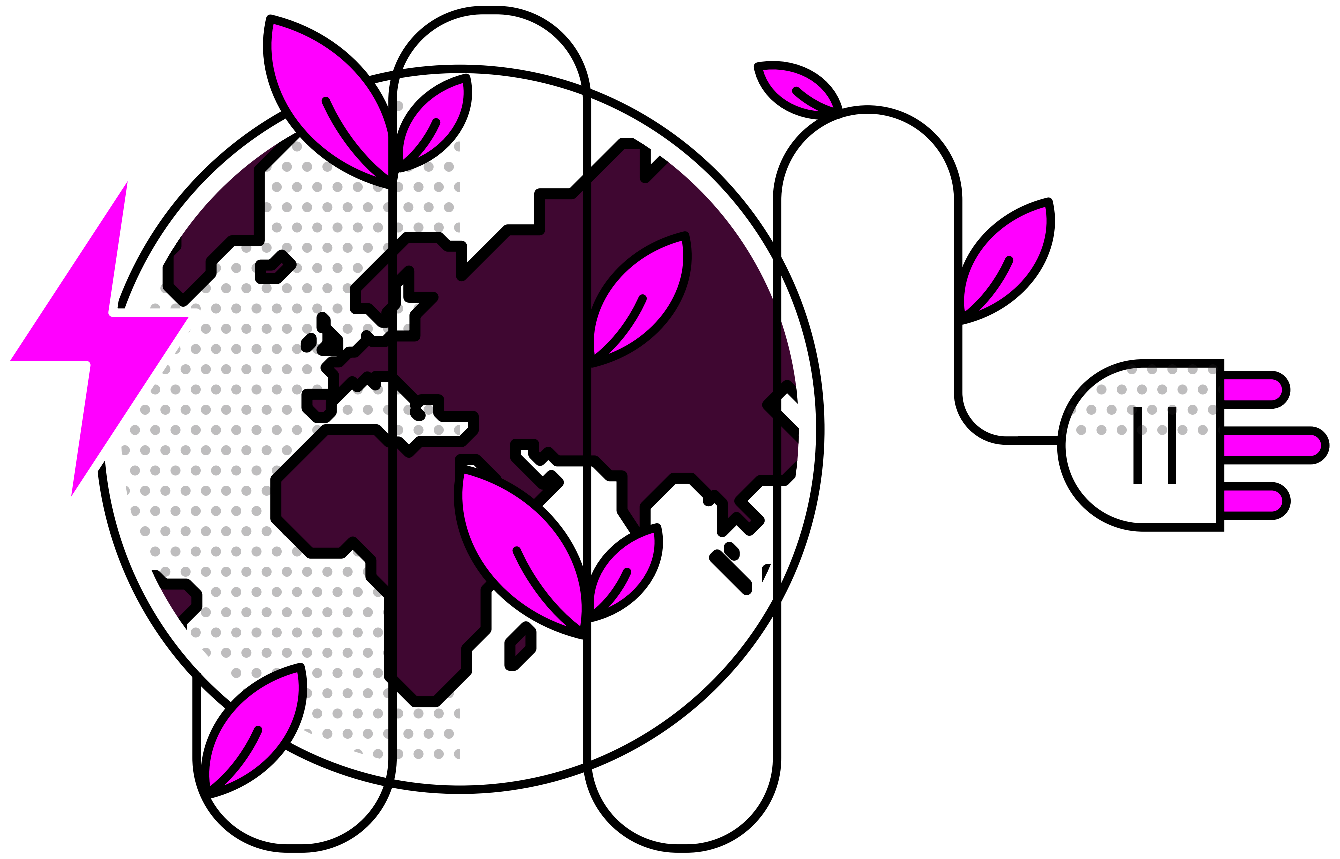
Distributed Energy Resources and Consumer Energy Resources - visibility and access

The percentage of underlying GB demand covered by DERs/CERs is rapidly increasing. There are already settlement periods where more than half of GB underlying demand is supplied by DERs/CERs. However, we lack visibility of and access to most of these assets either directly or through market mechanisms. This poses significant risks to the operability of the system.

A future energy system with high penetration of DERs/CERs has multiple implications for operability. Access to both CERs and DERs will bring benefits to operability such as by reducing peak energy demand through flexing demand in time which would help both in terms of thermal and adequacy requirements. Enhanced visibility and data sharing across the transmission and distribution interface will help achieve efficient long-term planning, deliver cost-effective real-time operation of the electricity system and aid in post-event analysis. Deeper visibility of DNO networks is also needed to accurately forecast and balance GB wide electricity demand. This is especially relevant because DERs/CERs are often weather dependent and Inverter-Based Resources (IBR). This weather dependency requires enhanced planning and forecasting capabilities.

We have published a roadmap setting out our view on the activities which will deliver the required levels of DER and CER visibility and access. These activities are intended to address the operational challenges outlined above and support the safe and cost-effective operation of a clean power system in 2030 with increased penetration of DERs and CERs. We will periodically review progress and changes to the roadmap to ensure that it remains an accurate view of the challenges to be addressed, and the activity required.

Developing the visibility and access required to maintain secure and efficient system operation, while matching pace with unprecedented DER and CER deployment, will be a significant challenge for the GB electricity system. The changes to codes and market arrangements that are in motion (e.g. GC0117[3] and RNP) will provide the foundations to fully integrate distributed capabilities into the electricity system and support clean power operability.



3 Grid Code Modification GC0117 -Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of Power Station requirements.

Glossary

Acronym	Description
ANM	Active Network Management
BESS	Battery Energy Storage System
CCGT	Closed Cycle Gas Turbine
CCP	Constraints Collaboration Project
CER	Consumer Energy Resources
CP30	Clean Power 2030
CSNP	Centralised Strategic Network Plan
DER	Distributed Energy Resources
DSR	Demand Side Response
ESRS	Electricity System Restoration Standard
FES	Future Energy Scenarios
GNCNR	Gas Network Capability Needs Report
HVDC	High Voltage Direct Current
IBR	Inverter Based Resource
LCM	Local Constraints Market
LDES	Long Duration Energy Storage
NOA	Network Options Assessment
OCGT	Open Cycle Gas Turbine
OSR	Operability Strategy Report
REMA	Review of Electricity Market Arrangements
RES	Renewable Energy Sources

Acronym	Description
RESP	Regional Energy Strategic Planning
RNP	Reformed National Pricing
SQSS	Security and Quality of Supply Standard
SSEP	Strategic Spatial Energy Planning
SSSC	Static Synchronous Series Compensator
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
TO	Transmission Operator
TOUT	Time of Use Tariff
WDF	Within Day Flexibility
ZCO	Zero Carbon Operation

NESO

National Energy
System Operator