Winter Outlook 2025/26

Helping to inform the electricity industry and prepare for the winter ahead

October 2025

NESO
National Energy System Operator

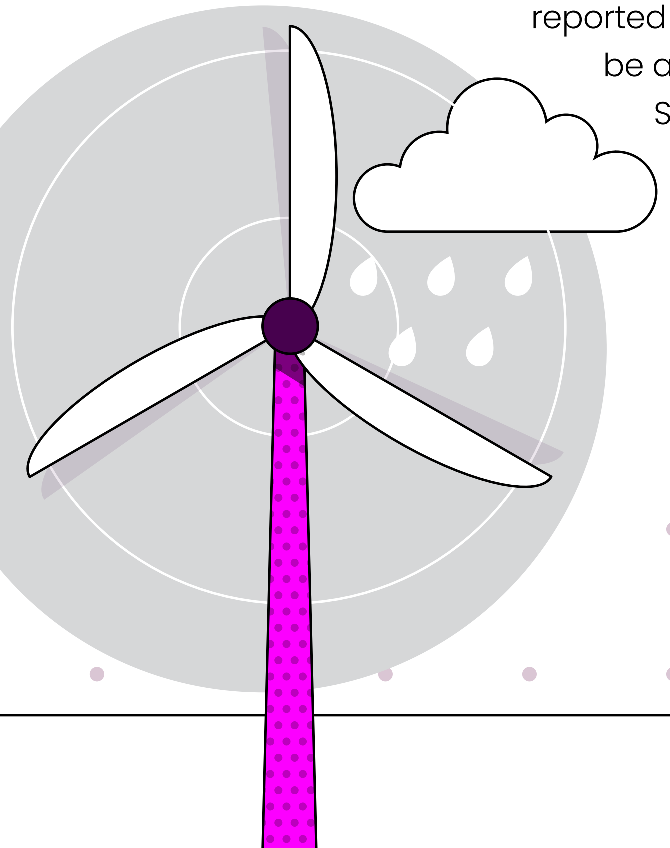
Contents

Welcome

Welcome to the *Winter Outlook 2025/26* report, which provides our assessment of the electricity security of supply for November to March.

The *Winter Outlook 2025/26* presents our view of electricity security of supply for the coming winter. It builds on the analysis in our *Early View of Winter*, providing more detailed analysis and greater visibility of our underlying assumptions to help industry prepare for the season ahead. It should be read alongside the separate *Gas Winter Outlook 2025/26*, published by National Gas.

Our overall assessment remains broadly similar to that reported in June, with margins expected to be adequate and within the Reliability Standard under our base case scenario. We also anticipate a sufficient operational surplus throughout the winter, although we may still observe some tight days that may require the use of routine system notices.



As a prudent system operator, our planning and preparation never stops. This spans a wide range of activities, including system operation, market development, network planning, and resilience and emergency management. We continue to develop the operational tools and balancing services at our disposal to manage a rapidly changing electricity system reliably.

Working closely with strategic partners, we consider the interactions between electricity and other energy forms, monitoring market conditions, global events and emerging risks. We collaborate widely to ensure Great Britain's electricity system is ready for the coming winter and resilient to the various conditions it may face.

This year, alongside our base case de-rated margin, we have included additional sensitivities to show how margin and other adequacy metrics could vary under different conditions. Alongside our operational surplus, we also provide detail on the likelihood of tighter days. We hope these additional insights support industry stakeholders to plan and prepare more effectively.

We want to ensure the Winter Outlook contains the right information and welcome feedback on how it could be improved as a tool for industry planning. You can email us at marketoutlook@neso.energy, join us at the NESO Operational Transparency Forum or connect with us on social media via X @NESO_energy.

Kayte O'Neill
Chief Operating Officer
National Electricity
System Operator

Key messages:
Winter Outlook 2025/26 at a Glance

1

Margins

Our analysis indicates that margins will be adequate and within the Reliability Standard.

Our base case margin for winter 2025/26 is 6.1 GW (representing 10.0% of average cold spell peak demand), with an associated loss of load expectation (LOLE) below 0.1 hours. This is an increase from the 5.2 GW forecast in last year's *Winter Outlook* and the highest de-rated margin since 2019/20.

This higher de-rated margin is due to increased battery storage capacity, a net increase in gas-fired power generation, an additional interconnector and ongoing growth in renewable generation.

Alongside our base case, we produce a range of sensitivities to show how adequacy metrics vary under different conditions and assumptions. LOLE remains within the Reliability Standard under each of our sensitivities.

2

Operations

Our planning, preparations and balancing tools will enable the reliable operation of the system under varied supply and demand conditions.

We expect a sufficient operational surplus throughout winter, although there may still be tight days that require us to use our standard operating tools, including system notices. Current market submissions suggest such days are most likely in early December or mid-January.

3

Markets

Our analysis suggests that imports will be available when required, supported by adequate electricity supply across Europe.

Indicators suggest adequate generation availability in key interconnected power markets, but uncertainties remain. We continue to monitor the wide range of factors influencing power prices in neighbouring markets and work closely with our strategic partners to assess potential risks in global energy markets.

Prices suggest Great Britain will typically be a net importer across electricity interconnectors this winter, although interconnector flows may be more sensitive to prevailing conditions.

Preparations for Winter 2025/26

As a prudent system operator, we continue to prepare for a wide range of eventualities, ensuring we have the tools needed to operate the system reliably. We work closely with the government, Ofgem, National Gas and other stakeholders to assess emerging risks and strengthen resilience ahead of this winter.

1

Neighbouring Transmission System Operators (TSOs)

We will continue to engage closely with our neighbouring transmission system operators, identifying developments that could affect interconnector flows.

By working closely with neighbouring countries' transmission system operators, we can optimise and coordinate interconnector flows to ensure reciprocal support between countries.

2

Transmission Owners (TOs) and Distribution Network Operators (DNOs)

We work closely with transmission owners to minimise the impact of network outages across the winter, ensuring electricity flows safely and reliably from where it is generated to where it is needed.

By optimising the network outages, we maximise the amount of energy available to consumers. Constraints will be carefully managed to ensure access to generation when required. We also collaborate with DNOs through transparent data sharing and coordinating NESO and DNO services, such as the Demand Flexibility Service (DFS).

3

Resilience and readiness

Our energy system is complex, with growing interconnections and dependencies. Disruption in one part of the system can have consequences elsewhere. We work to identify, understand and mitigate risks in order to create a more resilient and adaptable energy system.

Alongside resilience assessments, security of supply insights and coordination of emergency response, we engage with industry to ensure preparedness ahead of winter.

4

Strategic partners

We continue to work closely with strategic partners to monitor the range of factors affecting power and gas prices in Great Britain, Europe and globally. While prices are showing signs of stability, disruptions in global energy markets remain possible.

We work closely with DESNZ, Ofgem and National Gas to develop a shared understanding of potential challenges for the season ahead and to enable coordinated action where necessary.

Understanding Adequacy

Interpreting the metrics in this report

De-rated margin

Our assessment of the expected excess supply after Average Cold Spell (ACS) peak demand (defined below) and reserve requirements have been met. We calculate this figure by taking the total technical capacity of generation connected to the transmission and distribution networks and adjusting (or de-rating) this capacity based on expected availability and technical characteristics.

The de-rated capacity reflects our assessment of each technology's expected contribution during a period of system stress. The de-rated margin provides a seasonal-level view of adequacy, meaning it does not consider specific time periods within winter. It should not be interpreted as a forecast of the minimum operational surplus expected this winter.

Loss of Load Expectation (LOLE)

A long-term probabilistic assessment of the expected number of hours per year when demand exceeds supply under normal operations – that is, after standard operational tools (including system notices) have been used, but before enhanced or emergency actions are taken. In most cases, such periods would be managed without impacts on consumers.

The government's reliability standard for security of electricity supply (which defines the standard of reliability that the electricity system must meet) is expressed as a LOLE of three hours per year.

Equivalent Firm Capacity (EFC)

EFC is the amount of perfectly reliable baseload capacity that could be replaced by another technology, such as wind or battery storage, while maintaining the same level of system reliability measured by LOLE. For perfectly reliable baseload capacity, imagine a generator that always has 100% reliability and no energy duration limits.

The EFC is a statistical value, calculated over a wide range of possible demand, weather and operational conditions. As these metrics are long-run statistical assessments, actual interconnector flows, peak demand, wind output and generation availability may vary from the modelled value. Our adequacy calculation accounts for this variability by modelling thousands of scenarios, including low-wind, high-demand conditions and supply-side shocks.

De-rating factor

The de-rating factor refers to the ratio of the EFC to the installed (nameplate) capacity of a given technology. For example, if the installed wind capacity is 28 GW and the EFC is 3.9 GW, the de-rating factor is approximately 14%. This reflects the statistical contribution of wind to system reliability, accounting for its variability and intermittency.

ACS peak demand

The estimated peak electricity demand – at transmission and distribution level – during typical cold winter weather conditions. As this is an average figure, there is approximately a 50% chance that demand in any given winter will exceed the ACS peak value. This is calculated by simulating 30,000 scenarios of winter, each incorporating a different contribution of weather. The peak demand in each simulated winter is estimated, and the median of these values gives the ACS.

01

De-rated Margin

Reliability Standard

Margins are expected to be adequate and within the Reliability Standard. Our base case is 6.1 GW (10.0%) with an associated loss of load expectation (LOLE) below 0.1 hours/year.

Our current assessment shows sufficient available capacity to meet demand, with a de-rated margin of 6.1 GW (10.0% of average cold spell peak demand) for this winter (see Figure 1 for a breakdown of this capacity). This is an increase from the 5.2 GW (8.8% of peak demand) published in last year's *Winter Outlook* and is comparable to the 6.6 GW (10.9 %) detailed in the *Early View of Winter*. The associated LOLE is below 0.1 hours/year, which is within the Reliability Standard of 3 hours/year.

As detailed in the *Early View of Winter*, the year-on-year increase in the de-rated margin is driven by several factors, including greater battery storage capacity at both transmission and distribution levels, an increase in available gas-fired power generation, and the commissioning of the Greenlink interconnector to Ireland. We assume that 6.9 GW (de-rated) of net imports will be available via interconnectors at times of tighter margin, and that all providers with Capacity Market (CM) agreements deliver in line with their obligations unless specific market intelligence suggests otherwise.

This year, we have included several sensitivities (see page 9) to show how the de-rated margin and LOLE vary under different assumptions.

While our margin assessment has improved from last winter, we continue to monitor risks and uncertainties and, if necessary, will take steps to strengthen resilience.

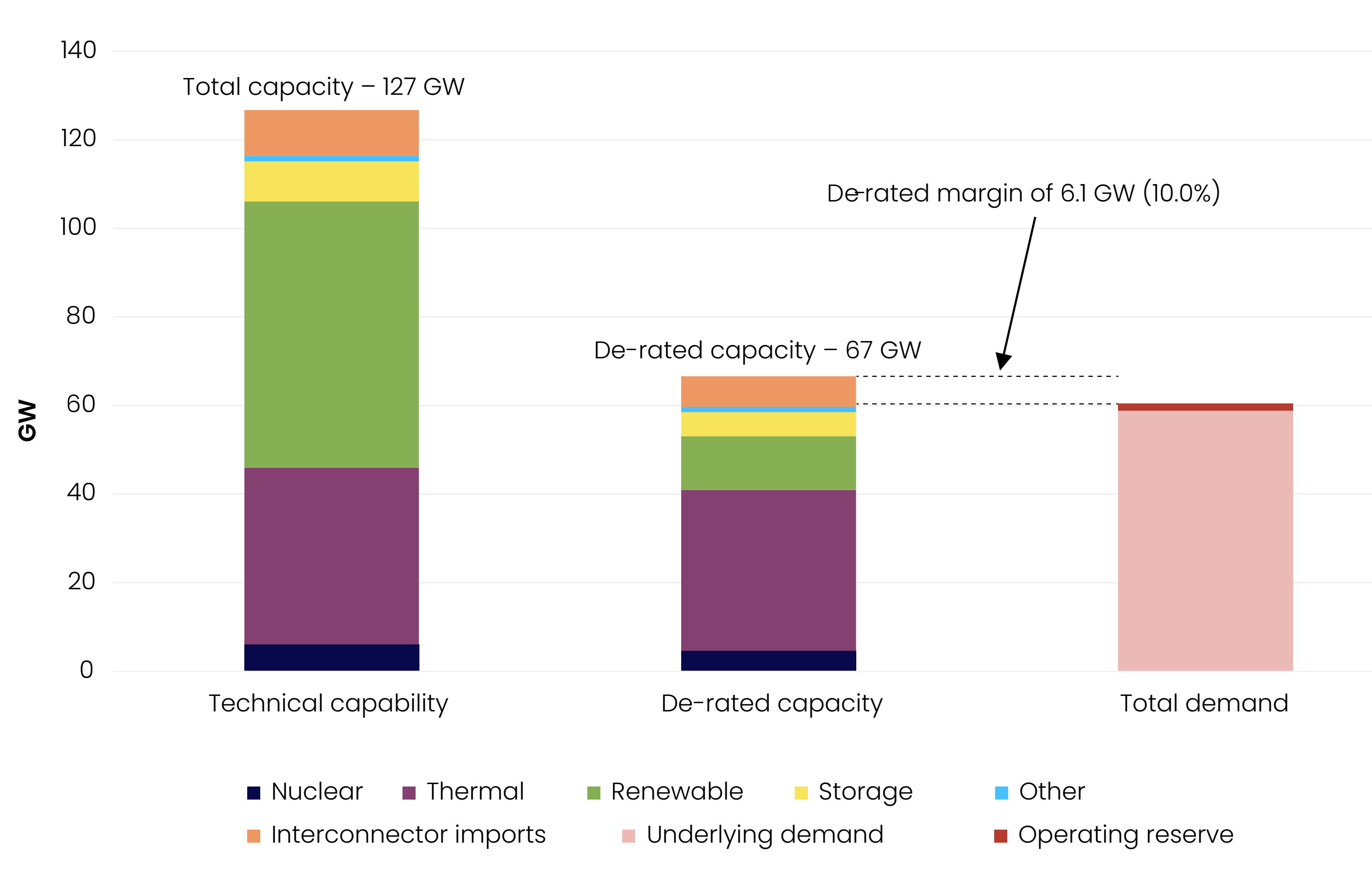


Figure 1: Total technical capacity of transmission and distribution connected supply and the resulting de-rated contribution during a period of system stress, shown against ACS peak demand

Did you know?

To balance the national electricity network, we procure reserve services. We hold several different categories of reserve to meet different requirements. Operating reserve is held to cover the largest infeed loss (that is, the loss of the largest source of supply) and additional reserve to account for uncertainty in forecast demand and supply. Beyond this we hold additional contingency reserve – to account for the risk of further losses of capacity or changes in forecasts. This final category of reserve decreases over time as the risk reduces.

Our balancing services markets provide us with efficient access to sources of extra power when it's needed. The technical features of our reserve services are designed to ensure reliable delivery of power over different timescales, depending on the system need they address.

Sensitivity analysis

We model a range of sensitivities around our base case to understand the impact of changes to key variables, market uncertainties or material supply disruptions. LOLE remains within the Reliability Standard in each of these illustrative sensitivities.

Our base case de-rated margin of 6.1 GW (10.0%) is an assessment of the expected excess supply after ACS peak demand and reserve requirements have been met. The technical capacity of generation is de-rated to reflect each technology's expected contribution during a period of system stress.

Our modelling approach accounts for weather effects (including interactions between demand and wind), plant unavailability and supply risks in interconnected markets. Given the dynamic nature of energy markets, and uncertainties in these variables, we assess adequacy under a range of scenarios.

Table 1 shows how the de-rated margin and LOLE for winter 2025/26 vary under illustrative sensitivities. As there is approximately a 50% chance that peak demand in any given winter will exceed the ACS value, we also assess the de-rated margin at higher demand levels.

Table 1 also includes generation downside sensitivities, in which 2 GW and 4 GW of de-rated conventional generation or interconnector imports are assumed to be unavailable. Both supply scenarios are based on ACS peak demand. The LOLE remains within the Reliability Standard of 3 hours/year in each case. More information on updates to our Capacity Adequacy (CA) modelling is provided in Appendix D.

Table 1: Impact of illustrative sensitivities on de-rated margin and associated LOLE

Scenario	De-rated Margin	Associated LOLE (Hrs/Year)
High demand (peak cold spell demand at the 90th percentile)	4.3 GW (6.8%)	0.1
Supply Scenarios		
2 GW less de-rated generation or interconnector imports	4.7 GW (7.7%)	<0.1
4 GW less de-rated generation or interconnector imports	3.4 GW (5.5%)	<0.5

02

Operational Surplus

Base case and credible range

We expect to have a sufficient operational surplus throughout the winter when taking into account natural variations in demand, wind and generator outages. There may be some tight days, most likely in early December or mid-January, excluding the Christmas period.

Our analysis shows that demand – and our reserve requirement – can be met under the full forecast range of operational conditions expected this winter, although there may be times when we need to use our standard operational tools, such as system notices.

Figure 2 shows a central forecast (the pink line) and a forecast range (the shaded pink plume) for the daily operational surplus this winter. To derive this, we simulate 30,000 variations around the central view, using multiple scenarios for weather, demand, conventional generation availability, wind generation and interconnector availability. For each scenario, we calculate a daily surplus time series across the winter. Weather simulations are based on historic data from 1987 to the present, capturing a wide range of possible conditions.

There could still be days when the operational surplus falls below the shaded range in Figure 2 (around 5% of days). More information on the likelihood of these conditions – and the operational tools available in such circumstances – is provided on page 13.

Our operational surplus does not include potential market responses to higher demand or tighter conditions, such as power stations temporarily increasing output levels.

The day-by-day view of forecast operational surplus (showing maximum normalised demand and assumed generation), which appeared in last year's *Winter Outlook*, is included in the accompanying *Winter Outlook* data workbook.

Appendix E provides more details on our operational surplus calculation.

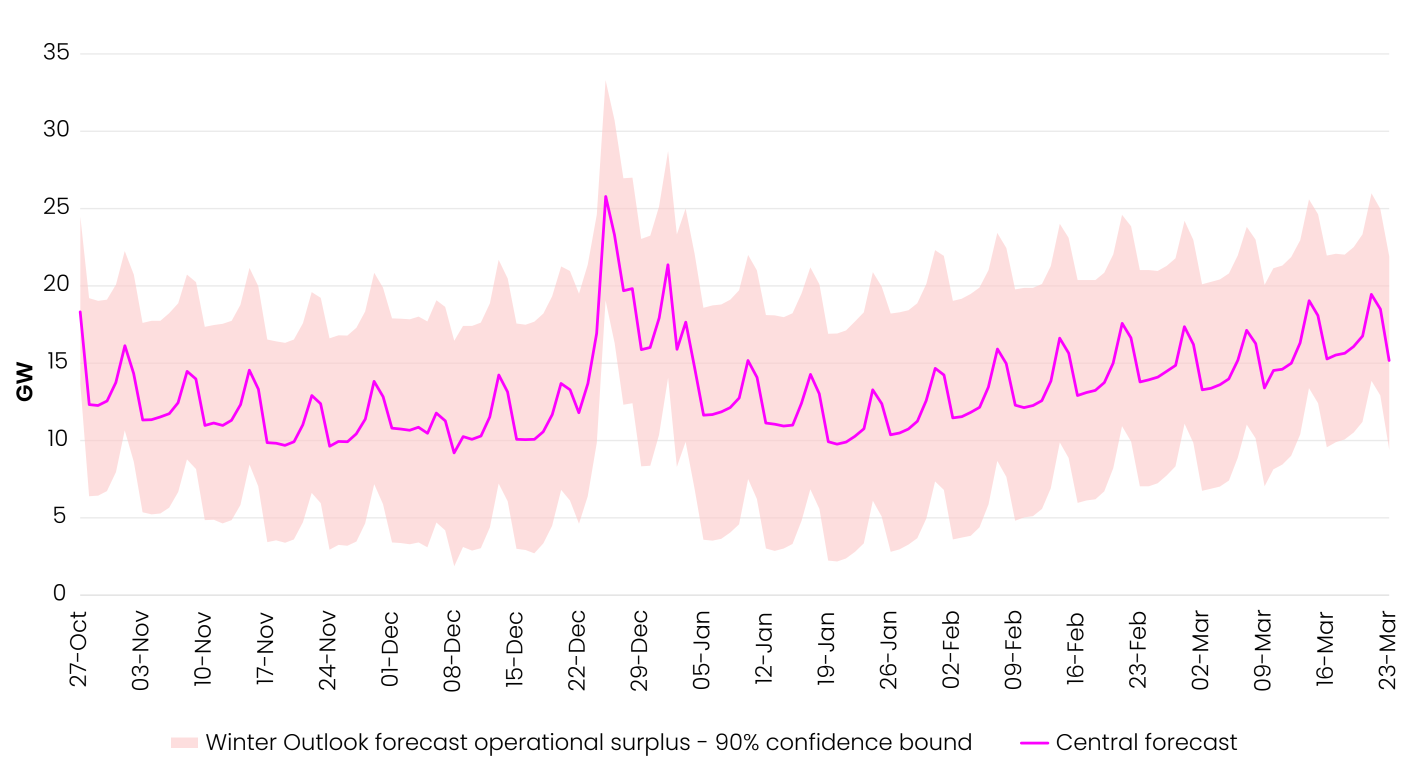


Figure 2: Range of outcomes for the daily operational surplus in our base case under different supply and demand conditions

Comparison to previous winters

The de-rated margin for this winter is the highest forecast since 2019/20 and represents a slight increase on recent winters. The operational surplus remains comparable to winter 2024/25.

Our base case de-rated margin for this winter is 6.1 GW (10.0% of average cold spell peak demand), compared with last year's margin of 5.2 GW (8.8% of average cold spell peak demand). The year-on-year increase is driven by several factors, including more battery storage capacity at both transmission and distribution levels, greater availability of gas-fired power generation, and the commissioning of the Greenlink interconnector to Ireland.

Figure 3 shows the de-rated margins from previous *Winter Outlook* reports. Our forecast for winter 2025/26 is the highest since 2019/20 and above recent winters.

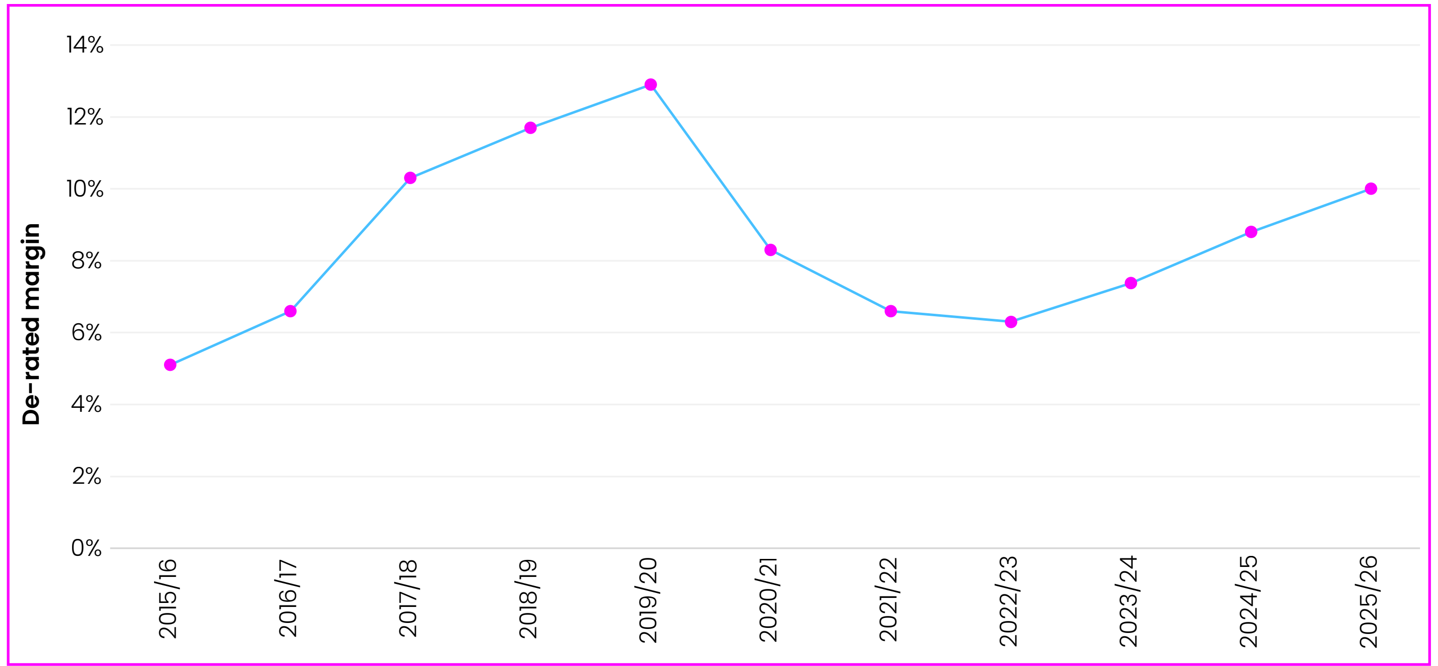


Figure 3: Historic de-rated margin forecasts made ahead of each winter in the Winter Outlook reports

Figure 4 shows our expectation that the daily operational surplus will be comparable to last winter. The red shaded region shows the credible range for this year, while the grey shaded region shows the corresponding range for last year.

As detailed in our Winter Review and Consultation, we continually review the performance of our analysis, re-calibrating models and improving methodologies to forecast supply and demand variables more effectively, which in turn affect the operational surplus. As a result of that review, we have widened the range of conventional generator unavailability within our operational surplus modelling for this winter.

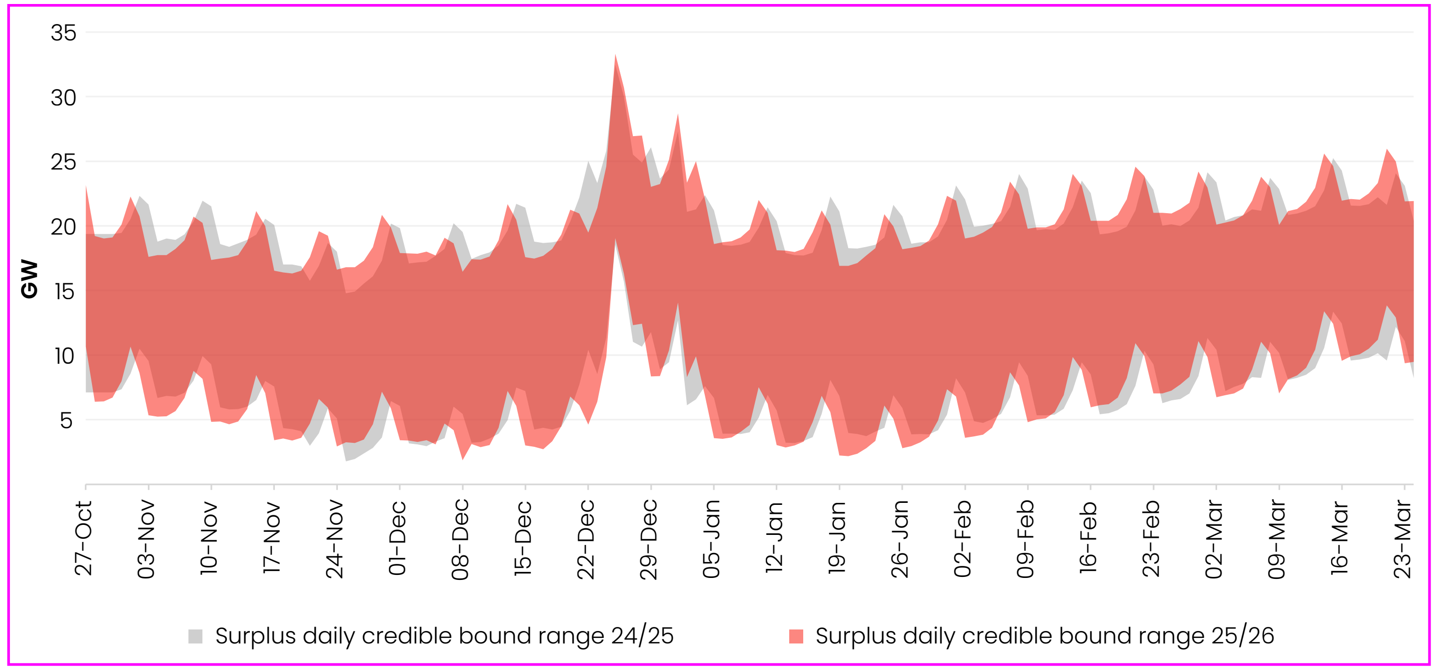


Figure 4: Daily credible range of operational surplus for this winter (red plume) compared with the credible range in last year's Winter Outlook report (grey plume)

Managing low surplus days

While we expect to have a sufficient operational surplus throughout winter, there may still be some tight days when we need to use our full range of operational tools, including system notices.

Great Britain has a secure and resilient electricity system, with a diverse range of technologies contributing to security of supply. Our analysis shows that a combination of factors – including periods of cold weather with low wind, low interconnector imports and high levels of generator outages – would be required for a period of low operational surplus to materialise; that is, for the initial supply provided by the market to approach our reserve requirement. We plan for such occasions and have a range of operational tools to balance the system should they occur.

We use advanced modelling to assess the likelihood of such combinations of conditions on any given day during winter. The resulting probabilities are derived from our 30,000 simulations of weather, demand, interconnector availability and conventional generator unavailability. Figure 5 shows that the likelihood on any given day is low, reaffirming that Great Britain has a secure and resilient system.

Although this daily probability is low, it would not be unusual for a small number of such instances to occur, given that there are around 150 days in the winter period. On these days, we may need to use our standard operational tools, including system notices, to manage the system. This remains within our normal operational preparation for winter, and our analysis continues to show sufficient available supply to meet consumer demand.

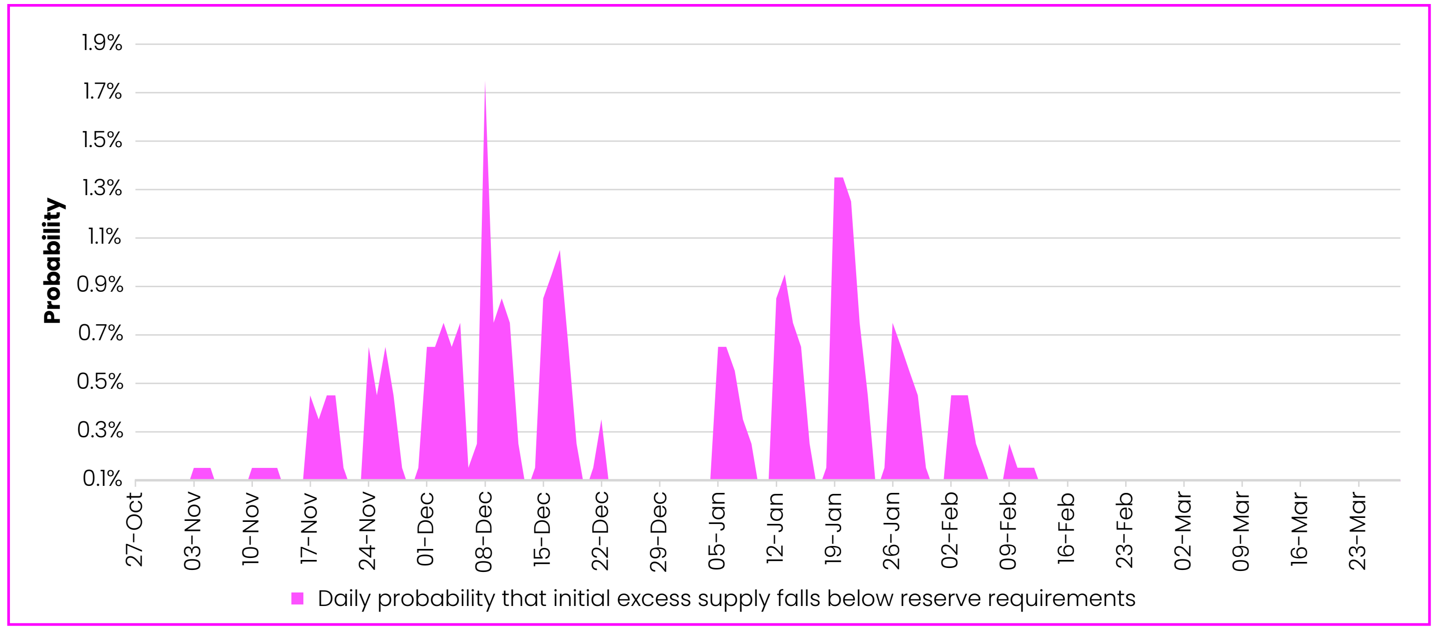


Figure 5: Daily probability that the initial excess supply provided by the market falls below the reserve requirement under the base case – these probabilities are based on the latest available data (as of 19 September) and will change as system conditions develop over the winter

What tools do we use to balance the system?

One of our key roles is to operate the electricity transmission system reliably, ensuring electricity flows from where it is generated to where it is needed. To do this, we make sure that the supply of electricity from the market always matches demand. This process is known as 'balancing the system' and is managed by our National Control Room.

Our control room experts use a range of operational tools to maintain this balance – the primary one being the Balancing Mechanism (BM). Balancing the system effectively requires continuous communication with the electricity market. When supply and demand cannot be balanced through everyday mechanisms, we issue formal communications to the market.

These messages are known as system notices and, although rare, are a normal feature of managing the system, particularly during winter. System notices include both Capacity Market Notices (CMNs) and Electricity Margin Notices (EMNs).

This does not mean there is insufficient electricity to meet demand; rather, it signals that we want a larger cushion of spare capacity and are asking the market to provide it. More information on the differences between system notices is provided in Appendix C.

03

Demand and Supply

Peak demand and credible range

The forecast range for daily peak demand in winter 2025/26 is broadly in line with last winter. The highest daily demand periods are most likely in December and January.

Daily peak demand can vary significantly depending on weather conditions (see Figure 6). Historically, peak winter demand has occurred between the first week of December and the first week of February, but never during the Christmas fortnight or on a weekend. During this period, cold and calm weather could lead to weekday demand exceeding 45 GW.

Figure 7 shows the probability that National Demand could exceed a range of thresholds. Across the whole season, there is approximately a 5% chance that National Demand could exceed 48 GW on at least one day.

Did you know?

The demand on the transmission system can be higher than National Demand. Pumped storage, charging of battery energy storage systems (BESS) or exports via interconnectors can result in transmission system demand (TSD) exceeding National Demand.

Throughout this report, we forecast National Demand, which depends on weather (temperature, wind speed, radiation), calendar effects (time of day, day of week, bank holidays, school holidays) and market factors (such as time-of-use tariffs).

Observed transmission system demand will also depend on additional market factors, such as price differences between interconnected markets. In our operational surplus base case, we assume transmission-connected power station demand of 600 MW and interconnector exports to Ireland and Northern Ireland of about 1 GW at peak demand. A visualisation showing the relationship between types of demand can be found in Appendix B.

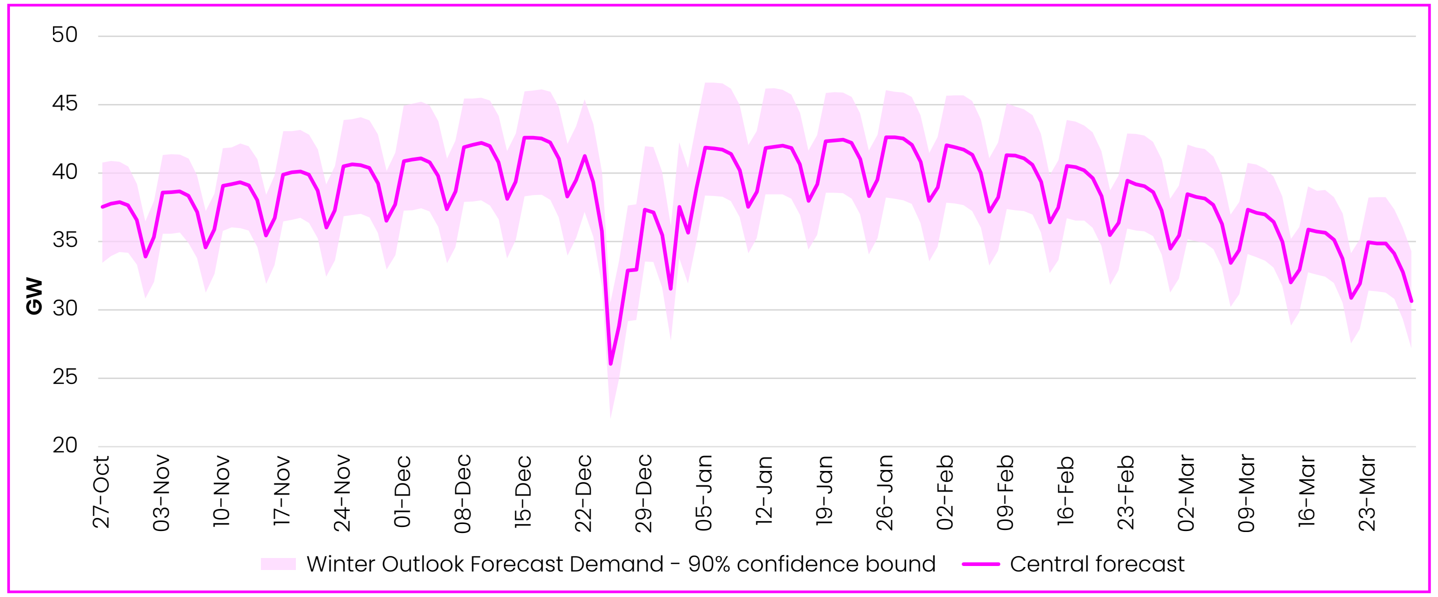


Figure 6: Credible range of peak National Demand for winter 2025/26

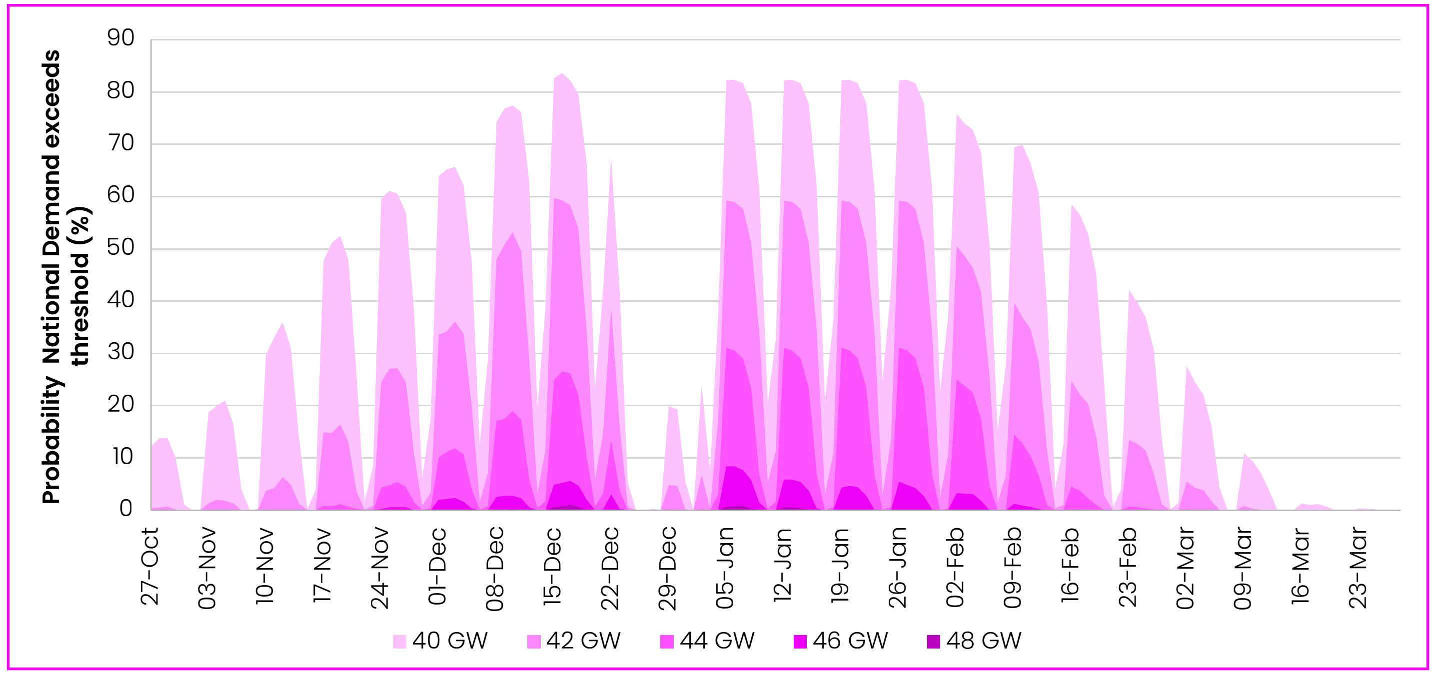


Figure 7: Daily probability of National Demand exceeding stated thresholds

Conventional generator availability

The wide range of credible weather patterns leads to large variability in the requirement for non-wind generation. Cold, calm conditions can result in prolonged periods of high demand, with higher levels of non-wind generation required to meet that demand.

Based on planned generator outages, we expect the lowest levels of generation availability in early December (see Figure 8). Planned outages are included in our supply assessment using the latest market submissions provided by generators.

Actual availability may deviate from this schedule due to the rescheduling or extension of existing outages, or due to new planned or unplanned outages occurring during the season. We use historic variation from expected availability to inform our forecast of how available supply is likely to change across winter.

From this historic data, we produce an unavailability factor for each technology, reflecting the extent to which generator unavailability is likely to increase across the season. Figure 8 shows total conventional generator availability based on current market submissions (grey columns) and the forecast range based on historic unavailability (pink plume).

The unavailability factor by technology type is included in our accompanying data workbook.

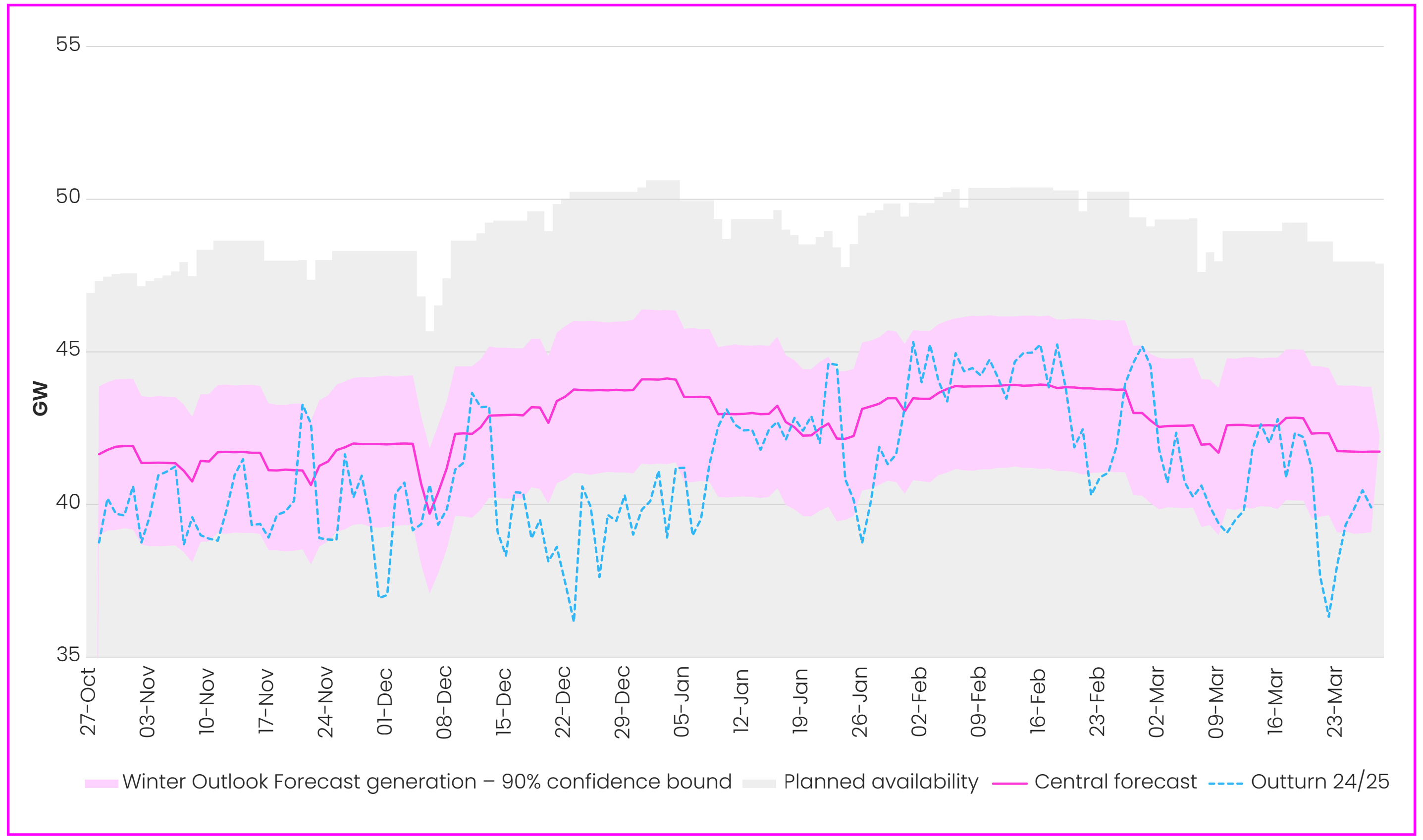


Figure 8: Planned generator availability for winter 2025/26 with forecast credible range of de-rated generation availability and central forecast of expected demand

04

Europe and Interconnected Markets

Overview

Our analysis suggests that imports will be available when required, supported by adequate electricity supply across Europe. We expect to continue working closely with our European neighbours, adopting a coordinated approach to optimise interconnector flows and ensure reciprocal support between countries.

Flows between markets are determined by price differentials. While prices in forward markets can indicate expected net power flows for the season, actual flows on any given day depend on short-term prices and conditions. Global energy markets are dynamic and complex, with prices influenced by a range of factors such as Norwegian hydro reservoir levels, French nuclear availability and German wind output.

Based on current indicators for this winter, we expect:

- imports into Great Britain to be available when required, provided by the market or, if necessary, NESO actions
- Great Britain to be a net importer from continental Europe over the winter, as baseload forward power prices in key markets show a premium in Great Britain for the winter period
- actual flows to vary with weather conditions and on-the-day events, with some periods of exports from Great Britain to Europe – including during peak periods when operational surplus is sufficient

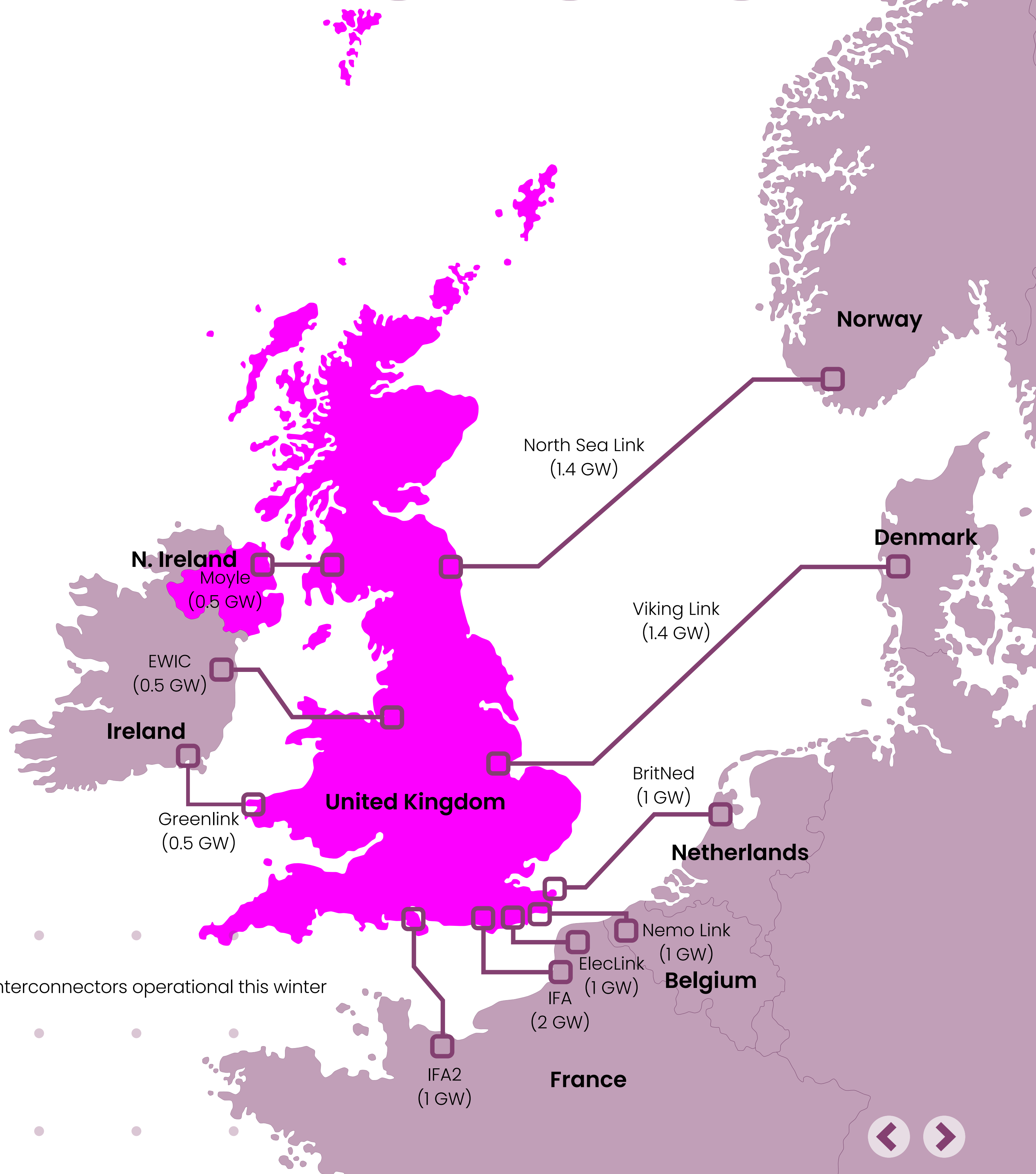


Figure 9: Interconnectors operational this winter

Interconnector availability

There are minimal planned outages on the interconnectors scheduled for this winter. The T-4 and T-1 2025/26 Capacity Market auctions secured 6.9 GW of interconnector capacity.

Planned outages

Interconnectors and other assets typically undertake routine maintenance outside peak winter months, when the risk of system stress is lower. There is therefore minimal planned maintenance during winter 2025/26. For most of the season, we expect full availability of the interconnectors, providing flexibility and security of supply for Great Britain and Europe.

Unplanned outages can occur, and these are accounted for in the unavailability factor methodology.

Table 2: Interconnector planned outages for winter 2025/26

Interconnector (Capacity)	Connects With	Planned Winter Outages (Resulting Capacity)
IFA (2 GW)	France	08/09/25 – 17/10/25 (1 GW)
Moyle (0.5 GW)	Northern Ireland	N/A
BritNed (1 GW)	Netherlands	N/A
EWIC (0.5 GW)	Ireland	N/A
Nemo Link (1 GW)	Belgium	N/A
IFA2 (1 GW)	France	27/10/25 – 01/12/25 (0 GW)
North Sea Link (1.4 GW)	Norway	N/A
ElecLink (1 GW)	France	12/10/25 – 15/10/25 (0 GW)
Viking Link (1.4 GW)	Denmark	N/A
Greenlink (0.5 GW)	Ireland	N/A

Capacity Market obligations

Interconnectors secured agreements in the 2022 T-4 and 2025 T-1 Capacity Market auctions for delivery in 2025/26, as shown in Figure 10. In a period of system stress, we would expect at least 6.9 GW of net imports into Great Britain. This is an increase of 0.3 GW from the previous winter, reflecting the addition of the Greenlink interconnector – a new 0.5 GW link to Ireland, commissioned in Q1 2025 – which secured a Capacity Market agreement in that year's T-1 auction.

Information on how the capacity market derating factor for interconnectors is determined can be found in the *Electricity Capacity Report (ECR)*.

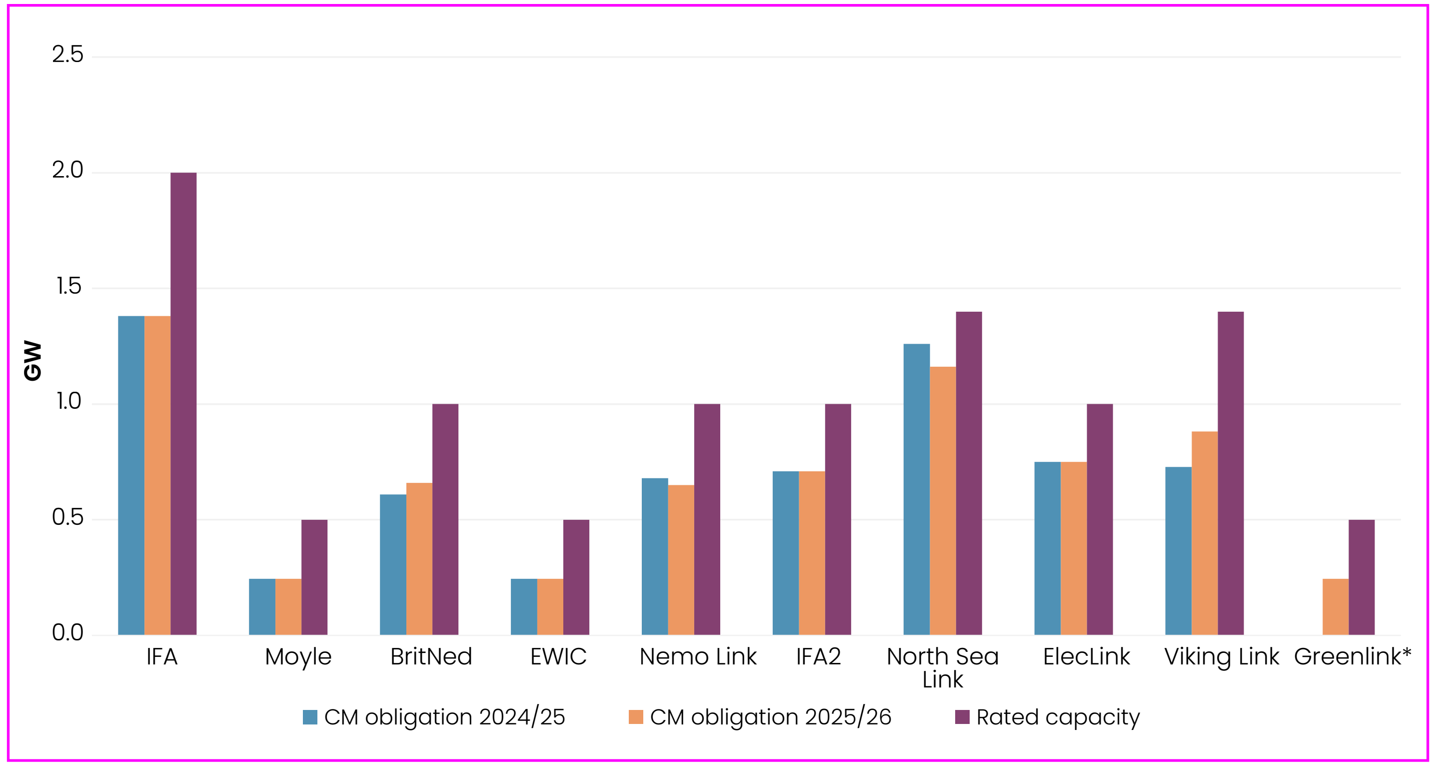


Figure 10: Interconnector Capacity Market obligations for 2025/26

05

Energy Markets

Wholesale power prices

Wholesale prices for Great Britain are in line with other major European markets and trading at a premium to France. This price signal, along with interconnector capacity auction results, suggests an overall import bias this winter.

Power flows through interconnectors are primarily driven by price differences between markets. Current prices suggest that Great Britain will be a net importer of electricity this winter, most notably from France. However, flows from Belgium, the Netherlands and Denmark may be more variable as prices are more closely aligned. We expect Great Britain to export to Ireland and Northern Ireland under typical conditions.

Our expectation that Great Britain will be a net importer is supported by the results of long-term interconnector capacity auctions, which reflect market participants' views on the value of baseload import and export capacity (see Figure 11). Import capacity for Q4-25 was valued higher than export capacity on every interconnector with long-term auctions. Actual flows will be driven by prices and prevailing conditions closer to real time.

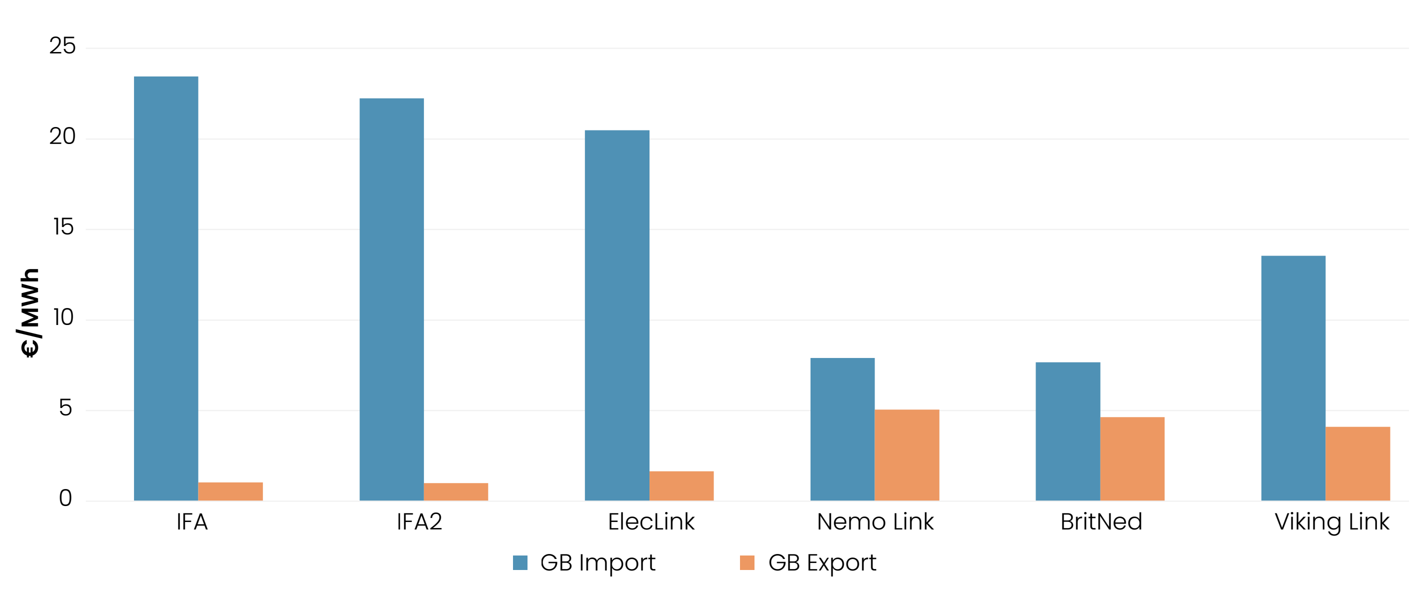


Figure 11: Most recent results from long-term interconnector capacity auctions for Q4-25 baseload power

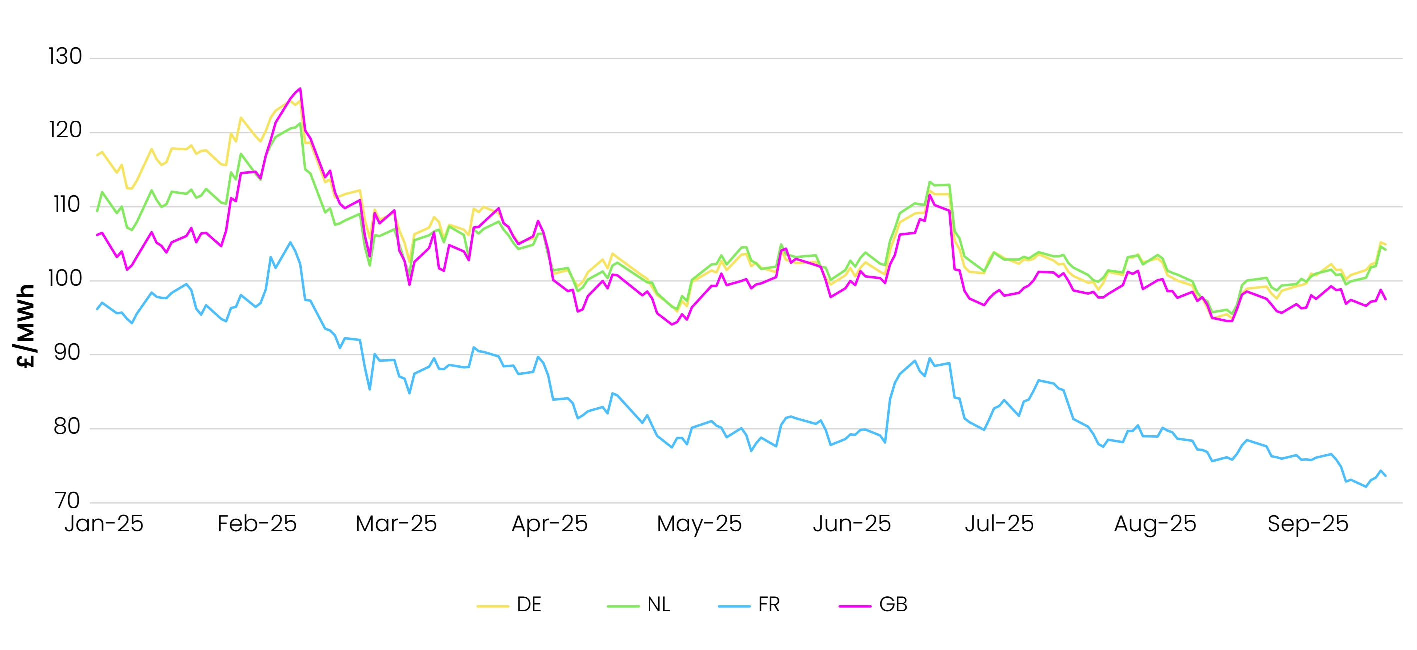


Figure 12: Q4-25 peak load price evolution

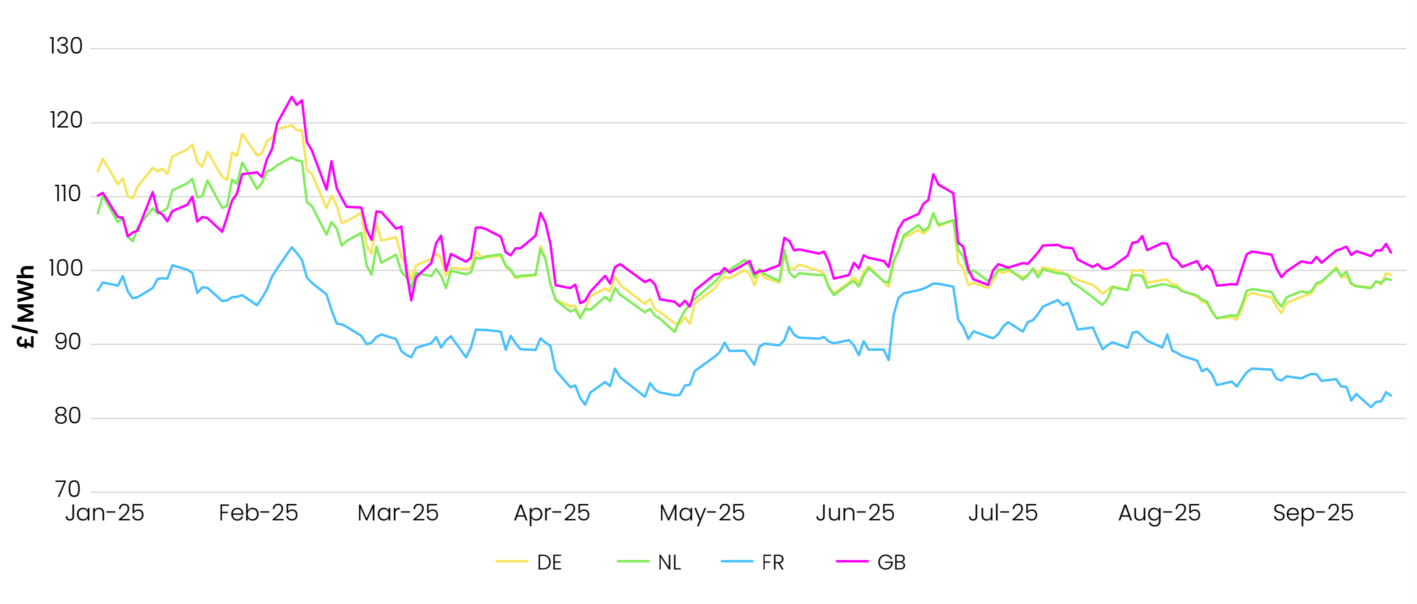


Figure 13: Q1-26 peak load price evolution

Power fundamentals

While current indicators suggest adequate supply in European electricity markets, uncertainties remain.

Nuclear availability in France

Figure 14 shows that French nuclear outages scheduled for winter 2025/26 are broadly within the historical range and mostly below the levels planned for last winter (as of 19 September 2025).

We expect outages this winter could still be revised upwards, as seen historically, with the green shaded range (actual outages) largely above the grey shaded range (scheduled outages in the preceding September). Even allowing for revisions, we anticipate outages to remain towards the lower end of the five-year history.

Initial reports of stress corrosion at the 1.5 GW Civaux 2 reactor in June 2025 prompted a price response, as nuclear availability in France was heavily constrained over winter 2022/23 when corrosion issues forced several reactors offline. No similar issues have been reported across the wider nuclear fleet. Production levels have remained high, and scheduled availability suggests healthy output across this winter.

We will continue to monitor generator availability across all interconnected markets and maintain close coordination with neighbouring TSOs.

Hydroelectric reserves in Europe

Hydroelectric reservoir levels are just below the historical mean for Norway overall, but reserves in the NO2 market area – where North Sea Link connects – are significantly lower. This reflects limited precipitation and strong production over summer.

Reservoir stocks are at 79% of capacity in Norway and 65% in the NO2 region (as of 19 September 2025). We continue to expect imports into Great Britain from Norway when required, although we may see greater variability in the direction of flows compared with last winter.

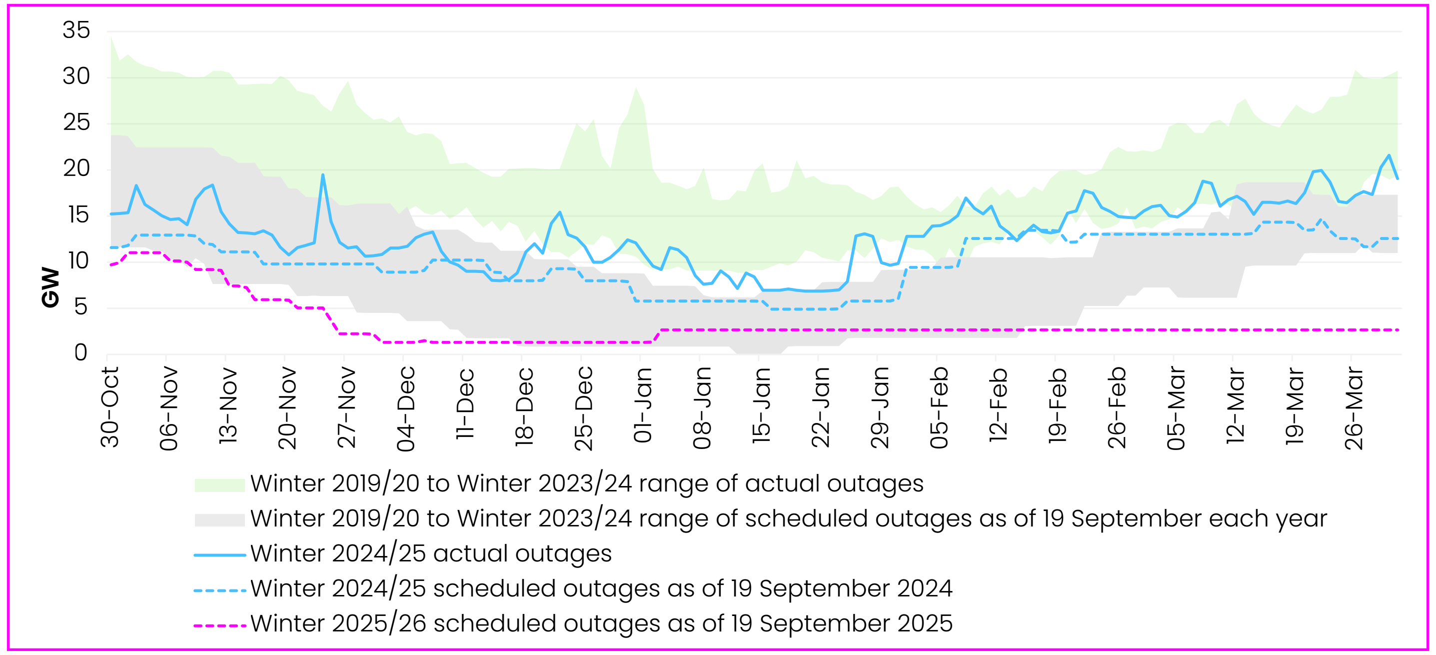


Figure 14: Scheduled French nuclear outages for winter 2025/26 compared with historic ranges

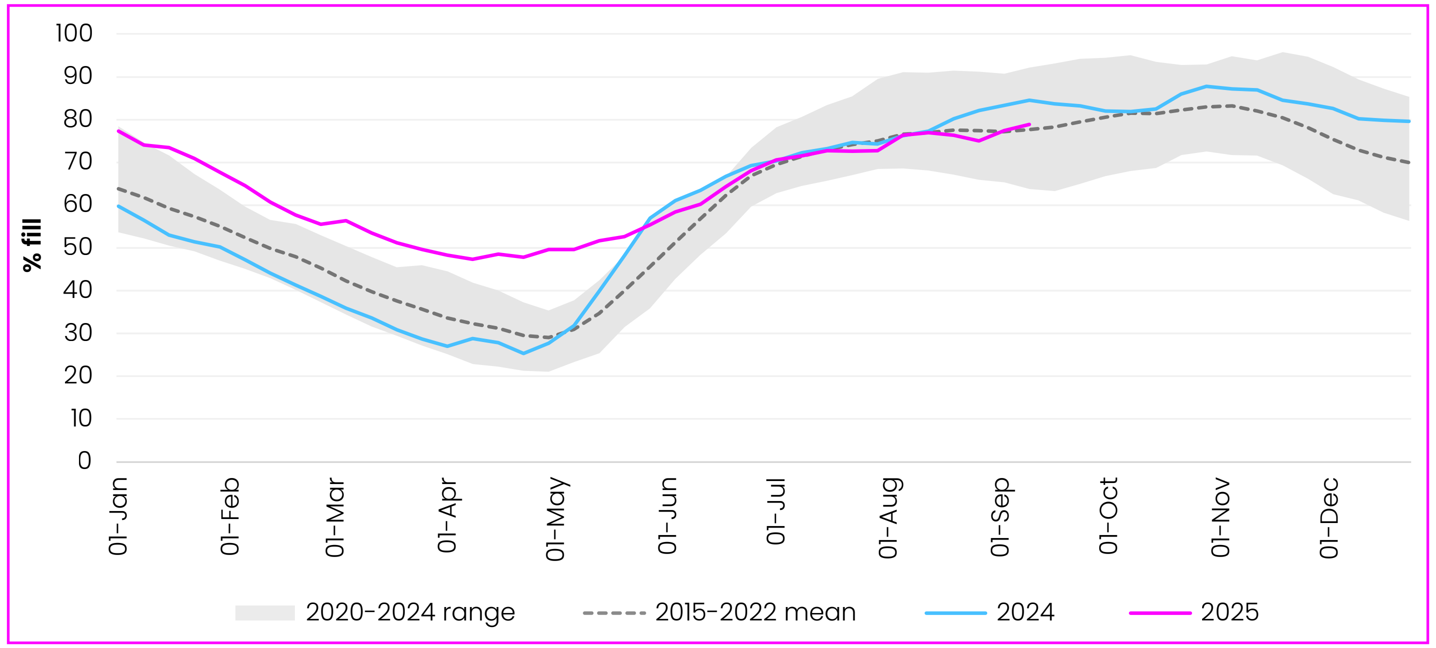


Figure 15: Norwegian hydroelectric reserves

Gas fundamentals

Wholesale gas prices in Great Britain for this winter showed some volatility in forward markets earlier this summer but have stabilised as winter approaches. Prices are below last year's and significantly lower than the highs seen in winter 2022/23.

Great Britain and European gas prices

The winter 2025/26 National Balancing Point (NBP) contract has traded slightly lower in the run-up to winter compared with the evolution of the winter contract last year, as shown in Figure 16. Prices for this winter were more volatile earlier in the summer due to geopolitical uncertainties. However, they have remained within a €11/MWh range over 1 June–19 September 2025, showing much lower volatility than in the same period in 2022, when winter 2022/23 prices ranged from €92/MWh to €329/MWh.

European gas storage

European Gas storage was 82% full on 19 September 2025, just below the ten-year average. This is 13 percentage points lower than levels in 2024 and 2023, but the trajectory indicates that EU-mandated filling targets will be met.

There is now more flexibility in these targets, as member states can meet the 90% target any time between 1 October and 1 December, rather than the previous fixed deadline of 1 November. Additionally, countries can deviate by 10 percentage points from the target in "difficult conditions", and the European Commission can lower the targets by a further 5 percentage points in "particularly difficult circumstances".

Slightly lower European stocks heading into winter may lead to a greater requirement for liquefied natural gas (LNG) imports during a cold winter, which could affect gas and, in turn, power prices. As a prudent system operator, we continue to monitor risks in global energy markets working closely with National Gas to coordinate analysis and understand the interaction between the power and gas systems.

We also work closely with DESNZ, Ofgem and other strategic partners to develop a shared understanding of potential challenges for the season ahead and to enable coordinated action where necessary.

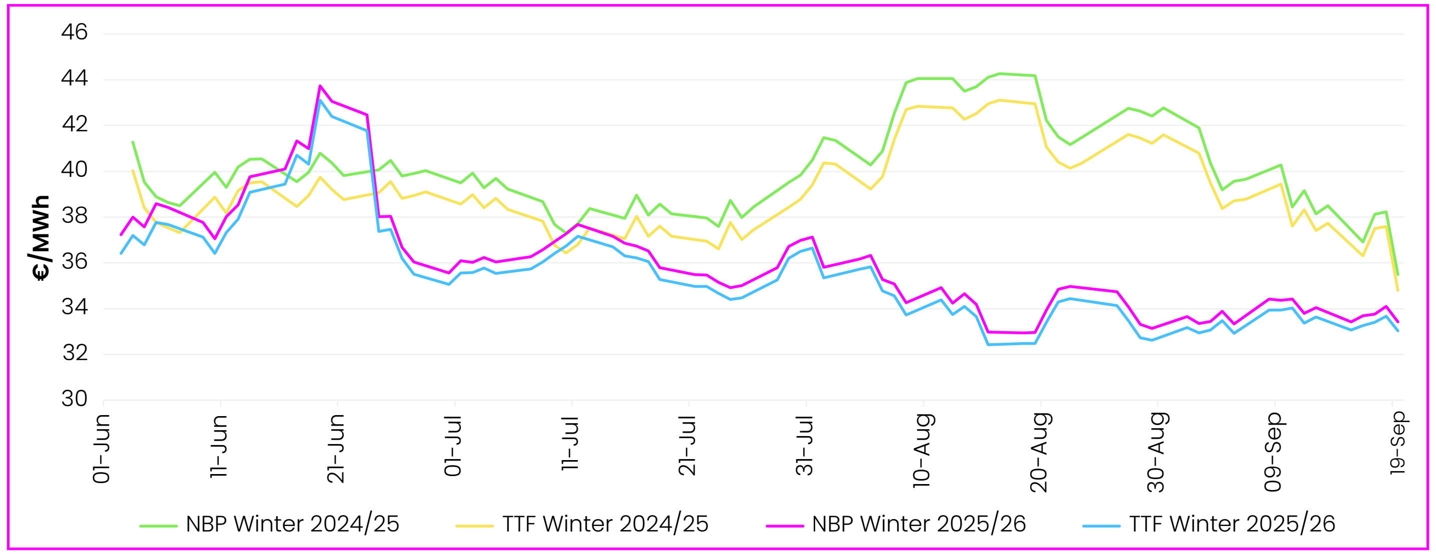


Figure 16: Evolution of NBP (National Balancing Point – Great Britain's gas trading hub) and TTF (Title Transfer Facility – the European gas benchmark) winter 2024/25 and winter 2025/26 contracts from Argus

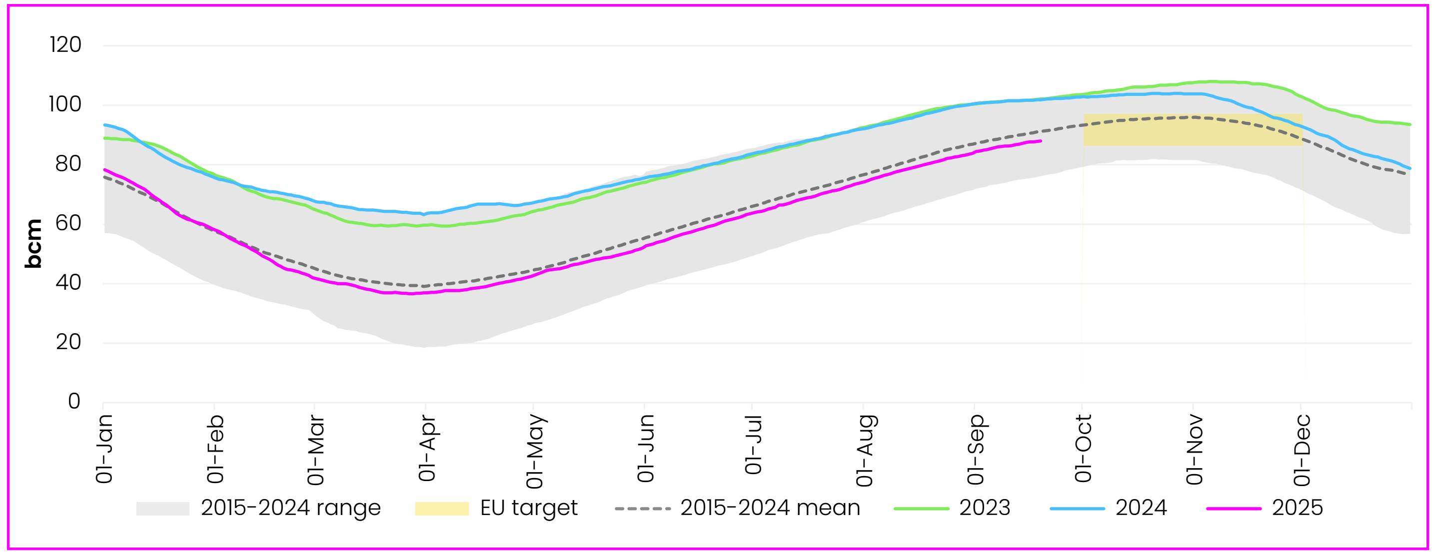
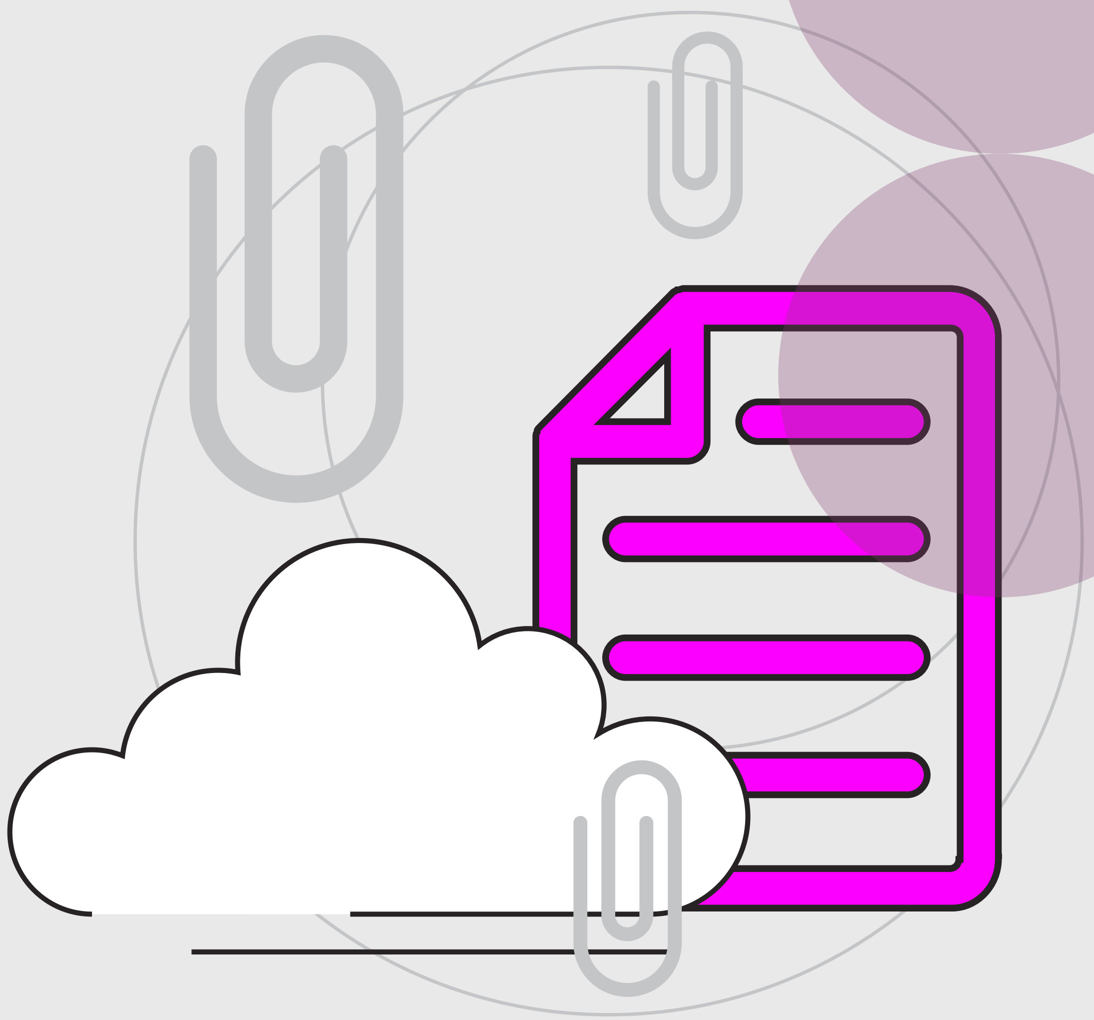


Figure 17: Aggregated EU gas storage

Appendices



Appendix A: List of Figures and Tables

Figures

Tables

Appendix B: Relationship between Types of Demand

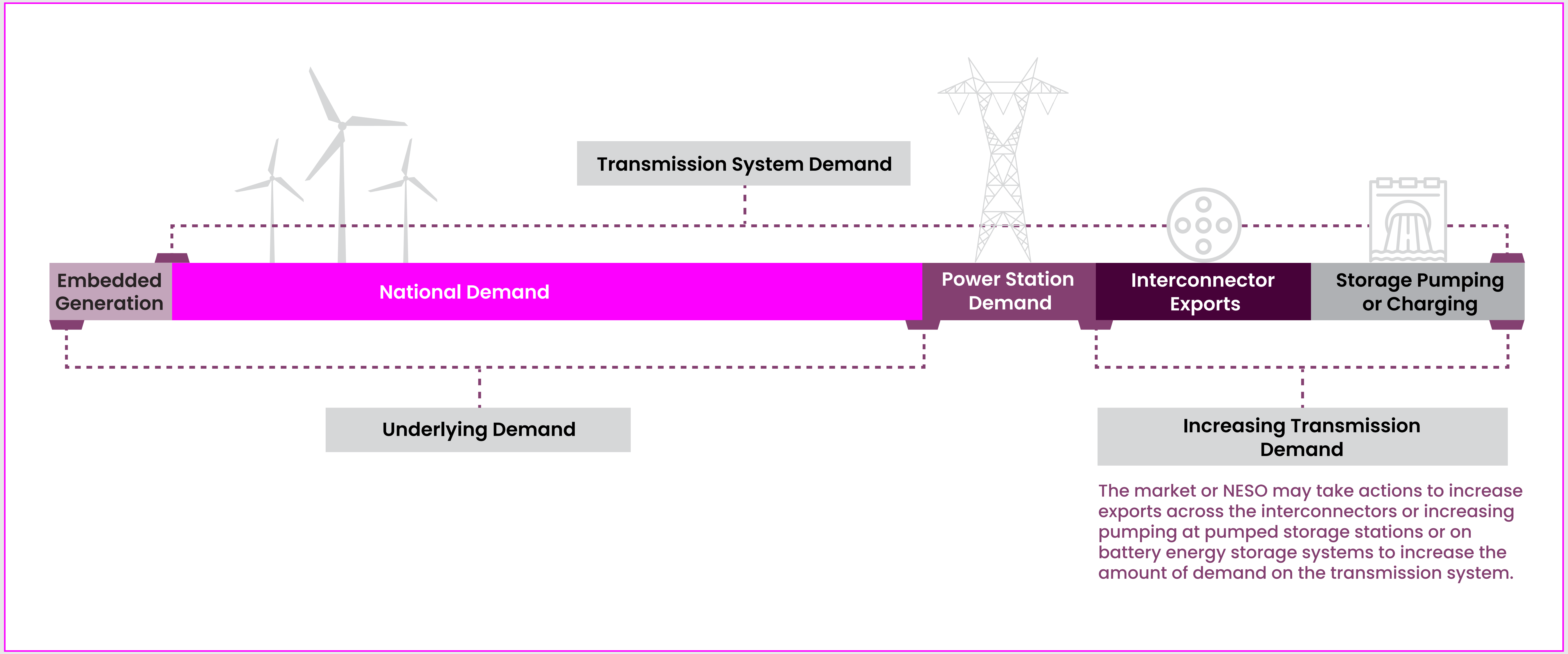


Figure 18: Shows the relationship between types of demand (this is not to scale)

Appendix C: Understanding Capacity Market Notices (CMNs) and Electricity Margin Notices (EMNs)

While CMNs and EMNs are based on the same fundamental data (such as generator availability and demand forecasts), they differ in how they are triggered, the thresholds at which they are issued, the treatment of constraints and their lead times.

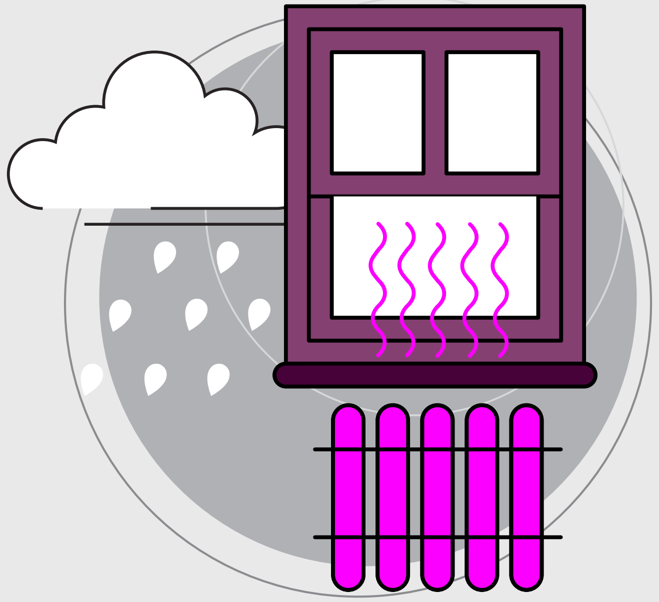


Table 3: Differences between CMNs and EMNs

Aspect	Capacity Market Notices (CMNs)	Electricity Margin Notices (EMNs)
Trigger	Automatically issued four hours ahead of real time, based on specific market data relating to the system's operating margin	Issued manually by the control room, based on operational and engineering judgement
Threshold	Triggered when the volume of available generation above the sum of forecast demand and the operating margin is less than 500 MW. This threshold is set in the Capacity Market Rules	No fixed threshold; issued based on expert assessment, which can result in some variance compared with CMNs
Constraints	Does not account for transmission system constraints that may prevent capacity from being delivered	Accounts for transmission system constraints and operational conditions
Lead time	Issued four hours ahead of the anticipated shortfall	Can be issued at any time, typically from the day-ahead stage onwards

Appendix D: Capacity Modelling Updates

We regularly update our modelling to reflect changes in the electricity system, ensuring our approach and methodology accurately capture the contribution of diverse forms of capacity to security of supply. For this winter, we have developed our Capacity Assessment (CA) Model process and related tools.

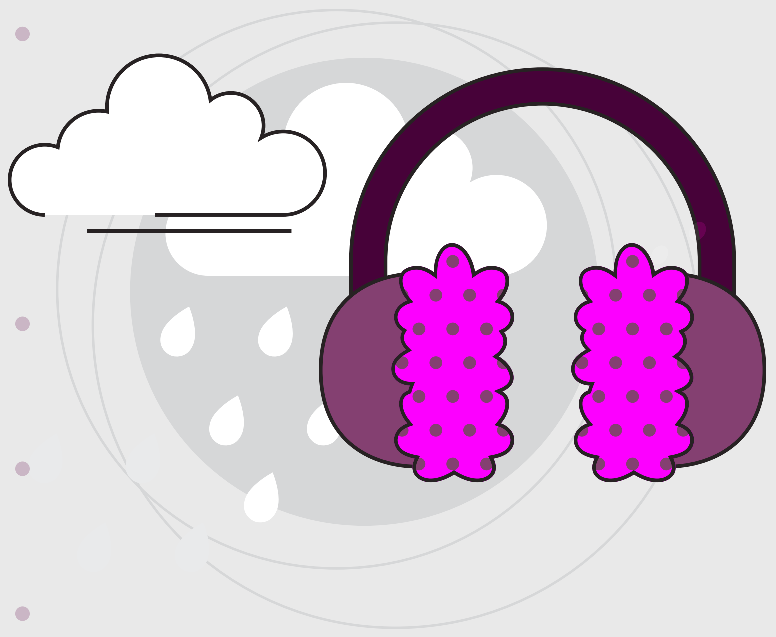
The CA Model, which has been used to derive the de-rated margin and LOLE, applies an inherently 'time-collapsed' approach. This generates a discrete probability distribution of available capacity, which is then compared with weather-driven demand and variations in renewable generation.

What are the benefits of the new approach being developed?

This year, we have further developed the CA process to better reflect observed dependencies between renewable generation availability and demand. This has been embedded in a standalone alternative process, based on the PLEXOS simulation tool developed by Energy Exemplar.

This new approach, which uses direct pairwise time series sampling of historical demand and renewable observations, remains a time-collapsed calculation. However, it brings our *Winter Outlook* modelling of demand and renewable dependency for margin assessment more in line with other processes, such as the operational view in this document, as well as wider NESO resource adequacy modelling used in the Great Britain Capacity Market and *Resource Adequacy in the 2030s*.

This approach will still produce the headline metrics of de-rated margin and LOLE. For winter 2025/26, these are 7.1 GW and <0.1 hrs/year respectively – approximately 11.7% of ACS peak demand under the new modelling process, compared with 10.0% in the CA Model used to date. This development not only provides new insights into adequacy in Great Britain, but also embeds a flexible modelling foundation that can evolve as the energy system changes.



Appendix E: Operational Surplus Analysis

Our operational surplus analysis represents the market's current intentions, based on market submissions before any NESO actions are taken. This analysis uses market submissions as of 19 September 2025. It includes notified plant outages, weather conditions, and applies historic unavailability factors to de-rate generation and reflect the potential for unplanned outages.

It is a dynamic view that changes throughout winter. We provide regular updates at the NESO Operational Transparency Forum. Our operational modelling helps to identify when tight periods are most likely to occur and indicates when we may need to use our operational tools to manage margins.

How the operational surplus is calculated and used

For the operational surplus analysis, we plan using operational data submitted to us. We consider not only the capacity provided via the Capacity Market – a mechanism designed to support security of supply for winter – but also the supply forecast to be available on a day-by-day basis. To do this, we use a more granular view of the season.

The operational data includes information on planned plant outages, the impact of weather (for example, on wind and demand) and flows on interconnectors. As generators can also experience unplanned outages, we apply unavailability factors based on averages from the last three winters. In addition, we study the effects of variability in weather, renewable resource availability and unplanned outages.

Unavailability factor methodology

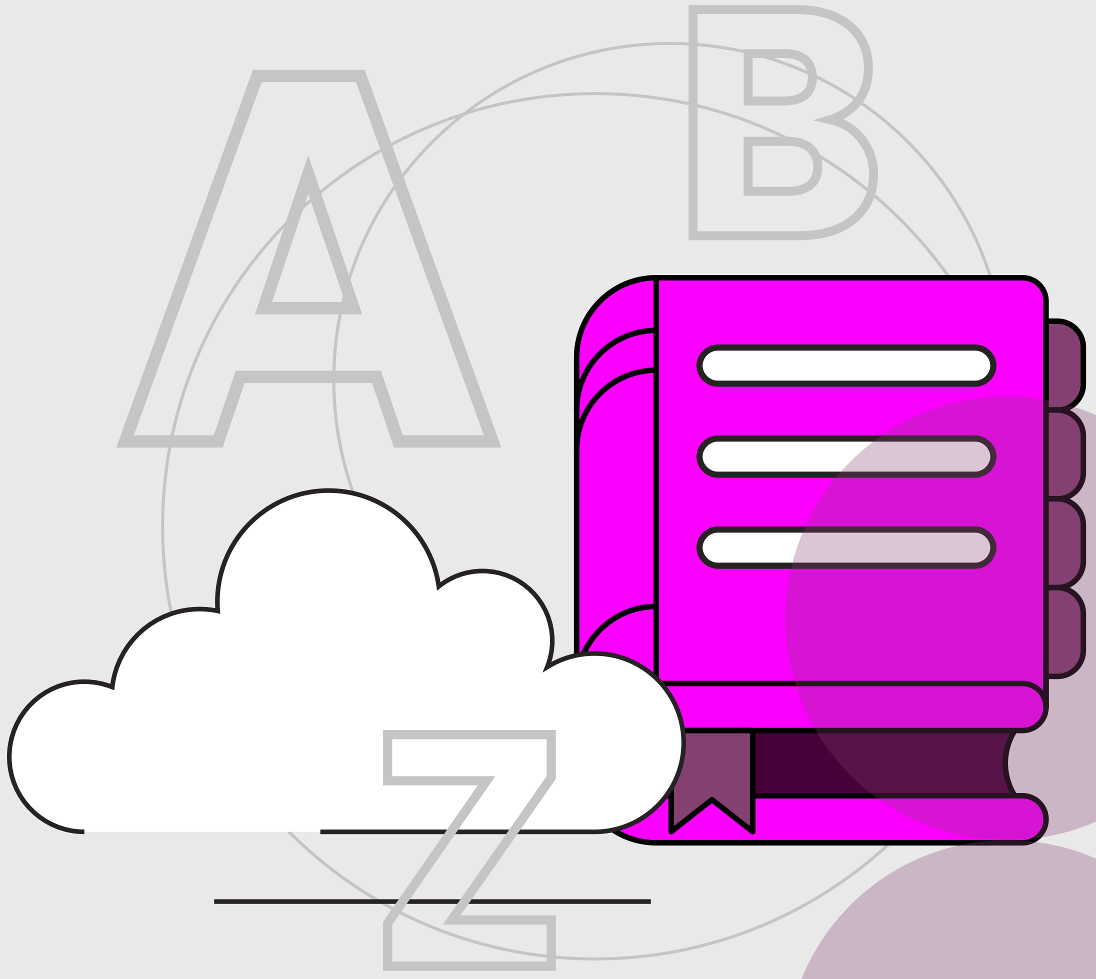
To assess the availability of supply throughout the winter, we need to consider both planned and unplanned generator outages. Planned outages are included in our supply assessment using the latest market submissions from generators. Actual availability may deviate from this schedule due to the rescheduling of existing outages, or due to new planned or unplanned outages arising during the season.

We use historic variation from expected availability to inform our forecast of how available supply is likely to change across winter. Unavailability factors are derived by fuel type, based on historic data. To calculate unavailability rates, we first estimate the maximum capacity of each unit as a benchmark for actual availability. The maximum capacity of each generator is defined as the highest output achieved for two consecutive half-hour periods over the past year.

We then identify the periods of high demand over the last three winters. Periods when half-hourly demand exceeded the 80th percentile for the season are considered peak demand periods. We assess the availability of generators for each of these peak demand periods and compare this with the Maximum Export Limit, excluding any periods when a planned outage (submitted before the start of the season) was in place.

From this, we calculate the availability rate of each generator as the average availability across all peak demand periods, divided by the maximum capacity of the unit. This can then be converted into an unavailability rate.

Glossary



Average cold spell (ACS)

The ACS methodology is an approach to calculating peak demand that takes into consideration people's changing behaviour due to the variability in weather, for example, increased heating demand when it is colder, and the variability in weather-dependent distributed generation, such as wind generation. These two elements combined have a significant effect on peak electricity demand. In addition to these two elements, the methodology uses the NESO Daily Demand Forecasting models, with Monte Carlo simulations undertaken to capture the variability of demand and weather. As this is an average figure, there is approximately a 50% chance that demand in any given winter will exceed the ACS peak value.

Balancing Mechanism

The Balancing Mechanism is NESO's primary tool to balance electricity supply and demand on Great Britain's network. It allows participants to set prices for which they will increase or decrease their output. The Electricity National Control Centre (ENCC) use the BM to procure the right amount of electricity on a minute-by-minute and second-by-second basis.

Baseload electricity

A market product for a volume of power across the whole day (the full 24-hour trading day) or a running pattern of being on continuously for power sources that are inflexible and operate all the time.

BritNed

A 1 GW interconnector between the Netherlands and Great Britain commissioned in 2011. You can find out more at britned.com.

Capacity Market (CM)

The CM is designed to ensure security of electricity supply. It provides a payment for reliable sources of capacity, alongside their electricity revenues, ensuring they deliver energy when needed.

Capacity Market Notice (CMN)

Based on CM margins which are calculated from whole system demand and whole system capacity. For more information about margins and margin notices, visit What are system notices? on our website.

Combined Cycle Gas Turbine (CCGT)

A power station that uses the combustion of natural gas or liquid fuel to drive a gas turbine generator to produce electricity. The exhaust gas from this process is used to produce steam in a heat recovery boiler. This steam then drives a turbine generator to produce more electricity.

Demand Flexibility Service (DFS)

DFS was developed to allow access to additional flexibility when national demand is at its highest – during peak winter days – by incentivising consumers and businesses to voluntarily reduce or reschedule their electricity use away from peak times.

De-rated margin

The sum of de-rated supply sources considered available during the time of peak demand plus support from interconnection, minus the expected demand at that time and basic reserve requirement. This can be presented as either an absolute GW value or a percentage of demand (demand plus reserve).

Distribution connected

Any generation or storage that is connected directly to the local distribution network, as opposed to the transmission network. It includes combined heat and power schemes of any scale, wind generation, solar and battery units. This form of generation is not usually directly visible to NESO and reduces demand on the transmission system.

East West Interconnector (EWIC)

A 500 MW interconnector that links the electricity transmission systems of Ireland and Great Britain. You can find out more by visiting Interconnection on the EirGrid website.

Eleclink

A 1 GW interconnector between France and Great Britain. Visit eleclink.co.uk to find out more.

Embedded generation
Power generating stations/units that are not directly connected to the National Grid electricity transmission network for which we do not have metering data/information. They have the effect of reducing the electricity demand on the transmission system.

Enhanced Actions
Enhanced actions are part of NESO's order of actions for managing security of supply and are used if everyday actions are insufficient.

Electricity Margin Notice (EMN)
Based on operational margins which are calculated from transmission system demand and transmission system capacity. For more information about margins and margin notices, visit What are system notices? on our website.

Equivalent Firm Capacity (EFC)
EFC is the amount of perfectly reliable baseload capacity that could be replaced by another technology, such as wind or battery storage, while maintaining the same level of system reliability, measured by LOLE.

Forward prices
The predetermined delivery price for a commodity, such as electricity or gas, as decided by the buyer and the seller of the forward contract, to be paid at a predetermined date in the future.

Greenlink
A 0.5 GW interconnector between Ireland and Great Britain commissioned in early 2025.
Visit greenlink.ie to find out more.

GW Gigawatt (GW)
A measure of power. 1 GW = 1,000,000,000 watts.

Interconnector
Electricity interconnectors are transmission assets that connect the market in Great Britain to other markets including continental Europe, Ireland and Northern Ireland. They allow suppliers to trade electricity between these markets.

Interconnexion France–Angleterre (IFA)
A 2 GW interconnector between France and Great Britain commissioned in 1986.
Visit IFA to find out more.

Interconnexion France–Angleterre 2 (IFA2)
A 1 GW interconnector between France and Great Britain commissioned in 2021.
Visit IFA2 to find out more.

Loss of Load Expectation (LOLE)
LOLE is the expected number of hours when demand is higher than available generation during the year, before any mitigating or emergency actions are taken, but after all system notices and system operator (SO) balancing contracts have been exhausted. The 3-hour reliability standard for LOLE refers to the policy, and objective, set by government regarding security of supply.

Load factors
The amount of electricity generated by a plant or technology type across the year, expressed as a percentage of maximum possible generation. These are calculated by dividing the total electricity output across the year by the maximum possible generation for each plant or technology type.

Moyle
A 500 MW interconnector between Northern Ireland and Scotland.
You can find out more at mutual-energy.com.

MW Megawatt (MW)
A measure of power. 1 MW = 1,000,000 watts.

Nemo Link
A 1 GW interconnector between Belgium and Great Britain commissioned in 2019.
Visit nemolink.co.uk to find out more.

Normalised transmission demand
The demand seen on the transmission system, forecast using long-term trends and calculated with the effects of weather and the day of the week removed as appropriate. This takes into account the power used by generating stations when producing electricity (the 'station load') and interconnector exports.

Normalised peak transmission demand
The peak demand seen on the transmission system, forecast using long-term trends and calculated with the effects of the weather and the day of the week removed as appropriate. This takes into account the power used by generating stations when producing electricity (the 'station load') and interconnector exports.

North Sea Link (NSL)
A 1.4 GW interconnector between Norway and Great Britain commissioned in October 2021. Visit northsealink.com to find out more.

Operational surplus
The difference between the level of demand (plus the reserve requirement) and the generation expected to be available, modelled on a week-by-week or day-by-day basis. It includes both notified planned outages and assumed breakdown rates for each power station type.

Outage
The annual planned maintenance period, which requires a complete shutdown, during which essential maintenance is carried out.

Outturn
Actual historic operational demand from real-time metering.

Peak electricity
A market product for a volume of energy for delivery between 7am and 7pm on weekdays.

Pumped storage
A system in which electricity is generated during periods of high demand by using water that has been pumped into a reservoir at a higher altitude during periods of low demand.

Reliability Standard
The reliability standard for the British electricity system, is a Loss of Load Expectation (LOLE) of three hours per year. This represents the maximum average number of hours per year when supply is expected to be lower than demand under normal conditions.

Reserve requirement
To manage system frequency and respond to sudden changes in demand and supply, NESO maintains positive and negative reserves to increase or decrease supply and demand. This provides headroom (positive reserve) and footroom (negative reserve) across all generators synchronised to the system.

Seasonal normal conditions
The average set of conditions we could reasonably expect to occur. We use industry-agreed seasonal normal weather conditions, which reflect recent changes in climate conditions rather than being a simple average of historic weather.

Unavailability factors
A calculated value that accounts for generator outages not planned at the start of the season when the *Winter Outlook* analysis is carried out. These may result from the rescheduling or extension of existing outages, or from new planned or unplanned outages during the season. Forecast unavailability factors are applied to the operational data provided to NESO by generators.

Viking Link
A 1.4 GW interconnector between Denmark and Great Britain commissioned in 2023. Visit Viking Link to find out more.

Weather corrected demand
The level of demand expected or outturned with the effect of weather removed. A 30-year average of each relevant weather variable is calculated for each week of the year and applied to linear regression models to calculate what demand would have been under these standardised weather conditions.

Get in Touch

Email us with your views on *Winter Outlook 2025/26* at marketoutlook@nationalenergyso.com and we will get in touch.

You can write to us at:

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Winter Outlook 2025/26 is part of a suite of documents prepared by NESO.
Visit neso.energy for more information.

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