Winter Outlook 2026/27

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

October 2026

NESO
National Energy System Operator

Table of Contents

Welcome 3

Key Messages: Winter Outlook 2026/27 4

Preparations for Winter 2026/27 5

Understanding Adequacy 6

01 **De-rated Margin** 7
Reliability Standard 8
Sensitivity analysis 9

02 **Operational Surplus** 10
Base case and forecast range 11
Comparison to previous winters 12
Managing low surplus days 13

03 **Demand and Supply** 14
Peak demand and forecast range 15
Conventional generator availability 16

04 **Europe and Interconnected Markets** 17
Overview 18
Interconnector availability 19

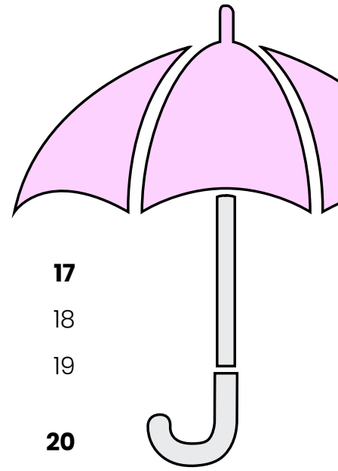
05 **Energy Markets** 20
Wholesale power prices 21
Power fundamentals 22
Gas fundamentals 23

Appendices 24
Appendix A: List of Figures and Tables 25
Appendix B: Relationship between Types of Demand 26
Appendix C: Understanding Capacity Market Notices (CMNs) and Electricity Margin Notices (EMNs) 27
Appendix D: Capacity Modelling Updates 28
Appendix E: Operational Surplus Analysis 29

Table of Corrections 30

Glossary 31

Get in Touch 35



Welcome

Welcome to the National Energy System Operator (NESO) Winter Outlook report, which provides our assessment of the electricity security of supply for November 2026 to March 2027.

This report presents our view of electricity security of supply for the coming winter. It builds on the assessment 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 2026/27* published by National Gas.

Growing global threats, geopolitical volatility and energy market disruption highlight the importance of energy security and whole system resilience, which remain at the forefront of NESO's priorities.

The ongoing conflict in the Middle East is causing constraints on liquefied natural gas (LNG) flows through the Strait of Hormuz. This disruption, combined with lower-than-normal European gas storage at the start of winter has resulted in elevated gas prices and, therefore, power prices. Fundamental differences in European power markets, together with structural changes in European gas markets, mean that prices, while above pre-conflict levels, remain below the highs seen in 2022 following the onset of conflict in Ukraine. However, uncertainties remain, including the duration of the effective closure of the Strait of Hormuz, how long production will take to return to pre-conflict levels and global weather patterns, including the ongoing impact of El Niño. We are working closely with government, Ofgem and National Gas to monitor market conditions, develop a shared understanding of potential challenges and enable coordinated action where necessary.

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. The de-rated margin is higher than that published in the Early View due to a refined modelling approach which is explained in Appendix D. We anticipate a sufficient operational surplus throughout the winter, although we may still experience some tight days when we need to use operational tools – including system notices – to balance the system.

Our winter preparations cover a wide range of activities, including system operation, market development, network planning and whole energy system resilience. This reflects the growing complexity of the energy system and the increasing dependencies between electricity and other forms of energy.

We continue to work closely with stakeholders across the energy industry to assess whole system interactions, monitor market conditions, track global events and identify emerging risks. This collaboration helps ensure Great Britain's electricity system is prepared for the coming winter and resilient to the challenges it may face.

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 X at @NESO_energy.

Kayte O'Neill
Chief Operating Officer
National Energy
System Operator

Key Messages: Winter Outlook 2026/27

1 Margins

Our analysis indicates that margins will be adequate, within the Reliability Standard and comparable to recent winters.

Our base case de-rated margin for winter 2026/27 is 5.9 GW (equivalent to 9.5% of average cold spell (ACS) peak demand), with an associated loss of load expectation (LOLE) of less than 0.1 hours per year. This remains in line with margins forecast in recent winters.

Year-on-year, an increase in forecast peak demand has been largely offset by new capacity across a range of technologies, including battery storage, gas-fired power generation and wind generation. On a like-for-like basis, our assessment remains comparable to the *Early View of Winter*.

Alongside our base case, we model a range of illustrative sensitivities to show how reliability varies under different conditions and assumptions. LOLE remains within the Reliability Standard across all sensitivities.

2 Operational surplus

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

We expect a sufficient operational surplus throughout winter, although there may still be tight days when we need to use our standard operational tools, including system notices. Current market submissions suggest that such days are most likely in December or January, excluding the Christmas period.

3 Markets

Indicators suggest adequate generation availability in key interconnected power markets. However, uncertainties remain.

While gas and power prices are higher and more volatile than in recent years, reflecting the impact of the ongoing conflict in the Middle East, European fundamentals are improved compared with 2022. We will continue to work closely with our strategic partners to monitor the factors influencing global energy markets and, where necessary, build resilience and mitigate risks.

Wholesale prices for Great Britain are currently at a premium to France and in line with other major European markets, indicating that Great Britain will typically be a net importer across electricity interconnectors this winter. We will continue working closely with neighbouring Transmission System Operators (TSOs) to coordinate and optimise interconnector flows.

Preparations for Winter 2026/27

We continue to prepare for a wide range of eventualities, ensuring that 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.

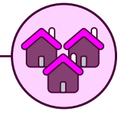
1

Neighbouring Transmission System Operators (TSOs)

We will continue to engage closely with our neighbouring Transmission System Operators to identify developments that could affect interconnector flows.

Following short-term measures to restrict our intraday trading volumes, we expect an increased use of Net Transfer Capacity (NTC) restrictions to limit potential interconnector exports at the day-ahead stage to help manage Great Britain's security of supply more effectively (see page 18).

By working closely with Transmission System Operators in neighbouring countries, we can optimise and coordinate interconnector flows to ensure reciprocal support between countries.

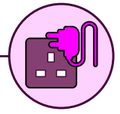


2

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

We work closely with Transmission Owners to minimise the impact of winter network outages and ensure that electricity can flow safely and reliably from where it is generated to where it is needed.

By optimising network outages, we maximise the amount of electricity available to consumers. We carefully manage constraints to ensure access to generation when it is needed.

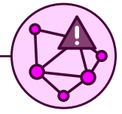


3

Resilience and readiness

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

Alongside resilience assessments, security of supply insights and emergency response coordination, we engage with industry to support 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. Prices are higher and more volatile than in recent years but remain below highs seen in 2022.

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

Understanding Adequacy

Interpreting the metrics in this report

De-rated margin

The de-rated margin is 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, the capacity based on its expected availability and technical characteristics. The de-rating factor reflects our assessment of each technology's expected contribution during a period of system stress. The de-rated margin provides a snapshot of adequacy for the season as a whole and therefore does not consider specific periods within the winter. It should not be interpreted as a forecast of the minimum operational surplus expected this winter.

Loss of load expectation (LOLE)

LOLE is 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 affecting consumers. The government's Reliability Standard for security of electricity supply is expressed as an 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. Perfectly reliable baseload capacity can be thought of as a generator that is 100% reliable and has no duration limits. 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 values. Our adequacy calculation accounts for this variability by modelling thousands of scenarios, including low-wind, high-demand conditions and supply-side losses.

De-rating factor

The de-rating factor is the ratio of a technology's EFC to its installed (nameplate) capacity of a given technology. For example, if the installed wind capacity is 33 GW and the EFC is 5.4 GW, the de-rating factor is approximately 16.5%. This reflects the statistical contribution of wind to system reliability, accounting for its variability and intermittency.

Average cold spell (ACS) peak demand

ACS peak demand is the estimated peak electricity demand – at transmission and distribution levels – 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 winter scenarios, each incorporating different weather conditions. The peak demand in each simulated winter is estimated and the median of these values gives the ACS. The ACS peak demand forecast used in our de-rated margin assessment differs from the peak demand observed on the transmission system, which is simulated in our operational surplus. Several factors contribute to this, including distribution-connected generation meeting demand close to the point of use and demand-side response.

Operational surplus

To complement the seasonal view of adequacy provided by the de-rated margin, we also produce a day-by-day view of the operational surplus. This is generated by simulating 30,000 scenarios that incorporate different weather conditions, National Demand (observed at transmission level), conventional generation availability, wind output and interconnector availability. For each scenario, we calculate a daily surplus time series across the winter. This provides a forecast range for the operational surplus and highlights when tight periods may occur.

Our supporting *Technical Workbook and Methodology* provides additional information about the key adequacy metrics contained in this report.

01

De-rated Margin

Reliability Standard

Margins are expected to be adequate, within the Reliability Standard and comparable to recent winters. Our base case de-rated margin is 5.9 GW (9.5%) 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 5.9 GW (9.5% of average cold spell (ACS) peak demand) for this winter (see Figure 1 for a breakdown of this capacity). The associated LOLE is below 0.1 hours/year, which is within the Reliability Standard of 3 hours/year.

The de-rated margin is broadly similar to the 6.1 GW (10.0% of ACS peak demand) published in last year's *Winter Outlook*. However, our modelling shows that a year-on-year increase in forecast peak demand is almost entirely offset by:

- new capacity across a range of technologies, including battery storage, gas-fired power generation and wind generation
- an increase in the Equivalent Firm Capacity (EFC) assumed for wind generation in our new de-rated margin modelling approach

As referenced above and in our *Early View of Winter*, we have updated our assessment methodology to better reflect observed correlation between renewable generation availability and demand. This has led to a moderate increase in the assumed EFC of the wind fleet and contributed to a higher de-rated margin than that published in the *Early View of Winter*. Our approach to de-rating generation is now consistent with the approach used in our Capacity Market assessment. Our updated methodology is explored in more detail in our accompanying *Technical Workbook and Methodology*, which we have published alongside this report.

On a like-for-like basis, our assessment remains comparable to the *Early View of Winter*. A like-for-like comparison is included in Appendix D.

While our assessment accounts for intermittency and weather variability, we also include several sensitivities (see page 9) to show how the de-rated margin and LOLE vary under different assumptions. As always, we continue to monitor risks and uncertainties and, if necessary, will act to strengthen resilience.

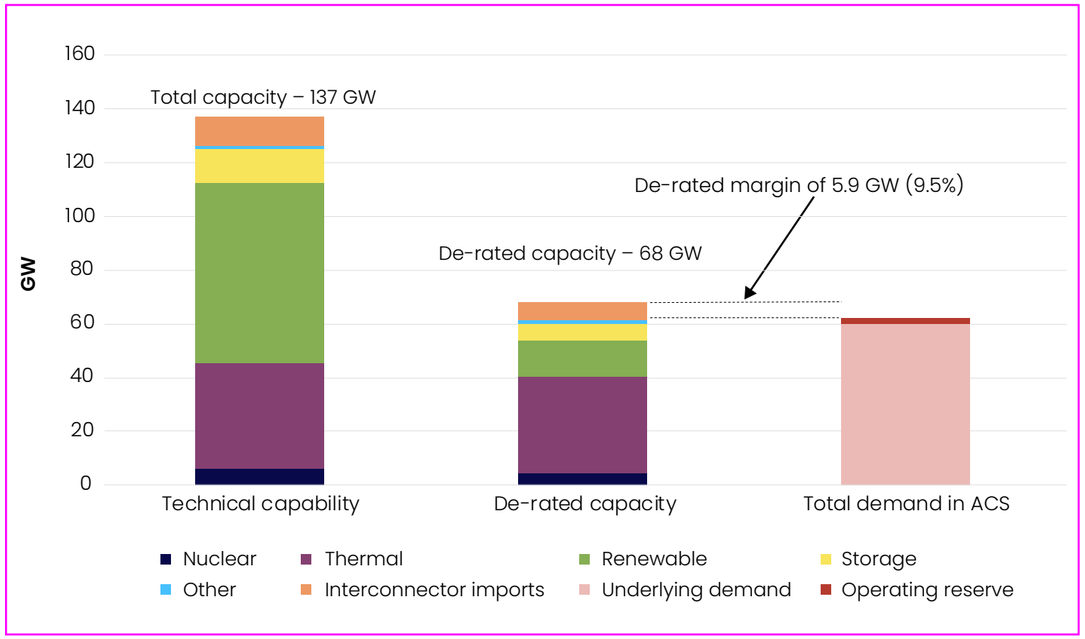


Figure 1: Total technical capacity of transmission- and distribution-connected supply and the resulting de-rated contribution during a period of system stress, shown against ACS peak demand

Did you know?

To balance the national electricity network, we procure reserve services. We hold several 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 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 they are needed. The technical features of our reserve services are designed to ensure reliable delivery of power over different timescales.

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 for all these sensitivities.

Our base case de-rated margin of 5.9 GW (9.5%) 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. This de-rating accounts for the availability of conventional generation, the duration limits of batteries and the intermittency of renewables. More information on this is available in the accompanying *Technical Workbook and Methodology* published alongside this report.

Our modelling approach accounts for weather effects, 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.

There is approximately a 50% chance that peak demand in any given winter will exceed the ACS value. We have assessed the de-rated margin at a higher demand level, where our modelling uses forecast demand at the 90th percentile, and the LOLE remains within the Reliability Standard of 3 hours/year.

Table 1 shows how the de-rated margin and LOLE for winter 2026/27 vary under illustrative sensitivities. We have included generation downside sensitivities, in which 2 GW, 3 GW and 4 GW of de-rated conventional generation or interconnector imports are assumed to be unavailable. All supply scenarios are based on ACS peak demand. The LOLE remains within the Reliability Standard in each case.

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

Scenario	De-rated Margin	Associated LOLE (Hours/Year)
Base case	5.9 GW (9.5%)	<0.1
High demand (peak demand is at the 90th percentile of our forecast)	4.7 GW (7.3%)	<0.1
2 GW less de-rated generation or interconnector imports	4.4 GW (7.1%)	<0.2
3 GW less de-rated generation or interconnector imports	3.7 GW (6.0%)	<0.4
4 GW less de-rated generation or interconnector imports	3.1 GW (5.0%)	<1

02

Operational Surplus

Base case and forecast range

We expect sufficient operational surplus throughout the winter, considering natural variations in demand, wind generation and generator outages. There may be some tight days, most likely in December or January, excluding the Christmas period.

Our analysis shows that demand – and our reserve requirement – can be met under the wide forecast range of modelled operational conditions expected this winter. However, there may be times when we need to use our standard operational tools, such as system notices. The reduced use of intraday trading as an operational tool is expected to lead to an increase in other standard operational tools including Net Transfer Capacity (NTC) restrictions to limit potential interconnector exports at the day-ahead stage. This may also lead to an increase in the use of system notices although this will be dependent on the system conditions. Page 13 provides more information on the likelihood of these conditions and the operational tools available in such circumstances.

Figure 2 shows the central forecast (pink line) and forecast range (shaded pink plume) for the daily operational surplus this winter. To derive the forecast range, 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.

We are working closely with the Met Office to understand the potential impacts of the strong El Niño event. Our operational surplus forecast considers the full range of weather conditions that could occur in winter, based on weather data dating back to 1987, including simulations of winters following strong El Niño events. Our operational surplus forecast has not been weighted to reflect the Met Office forecast for this winter, as El Niño is just one of several climate drivers influencing weather patterns in Europe and Great Britain. We are taking a prudent approach to consider all possible weather, as Great Britain's most extreme historic weather years are not associated with a strong El Niño.

El Niño can increase the likelihood of unsettled conditions, including a higher chance of milder and windier weather during autumn and early winter. It can also increase the likelihood of colder, calmer-than-average conditions in late winter. However, there is no clear signal of its potential effects on Great Britain. We will continue to work with the Met Office to incorporate the latest forecasts into our operational surplus analysis.

Our operational surplus does not include potential market responses to higher demand or tighter conditions, such as power stations temporarily increasing their output. Appendix E provides more information on our operational surplus calculation.

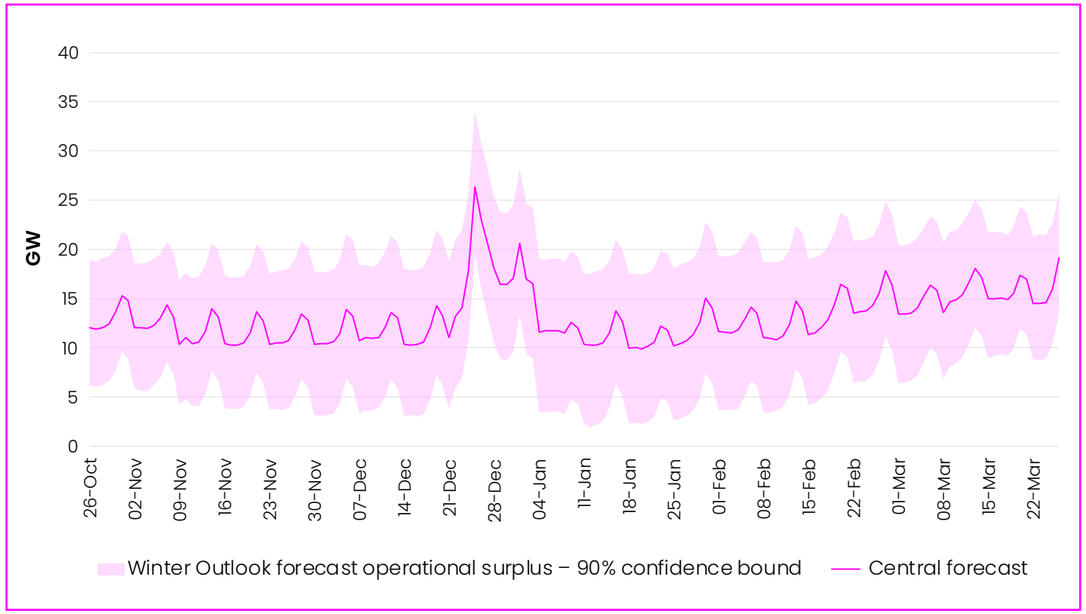


Figure 2: Range of outcomes for the daily operational surplus in our base case under different supply and demand conditions. This is the 90% confidence level and we therefore expect days when the operational surplus falls below the shaded range.

Comparison to previous winters

The base case de-rated margin for this winter remains comparable to recent winters and is broadly unchanged from winter 2025/26. The base case operational surplus is also expected to remain broadly in line with last winter.

Our base case de-rated margin for this winter is 5.9 GW (9.5% of average cold spell (ACS) peak demand), compared with last year's margin of 6.1 GW (10.0% of ACS peak demand). The year-on-year stability in the de-rated margin is due to new capacity across a range of technologies, including battery storage, gas-fired power generation and wind generation. It also reflects an increase in the assumed EFC of wind generation in our de-rated margin modelling. These increases are more than offset by a forecast increase in peak demand.

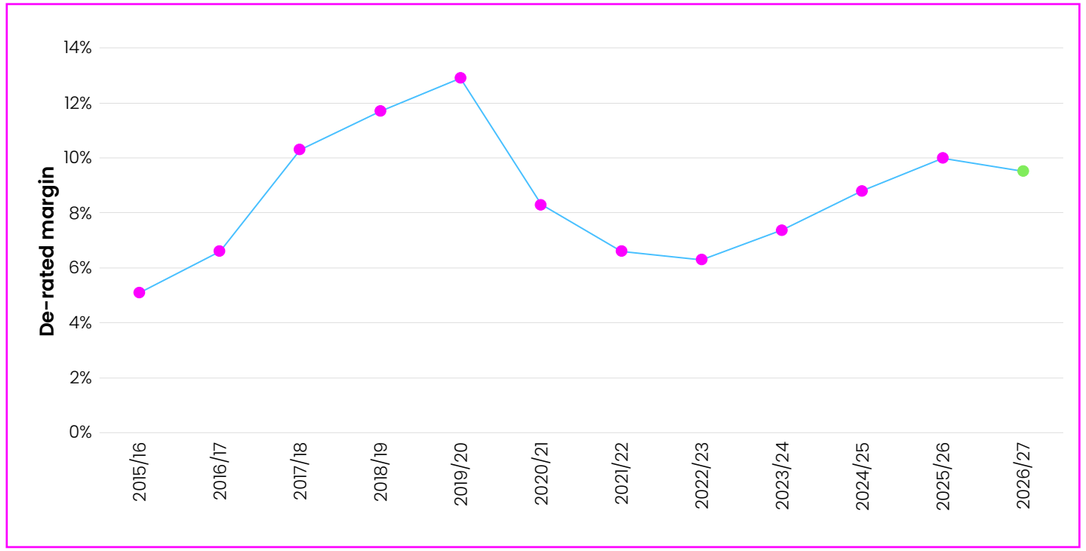


Figure 3: Historic de-rated margin forecasts made ahead of each winter in the Winter Outlook reports. The figure for 2026/27 is derived from our updated modelling approach and is therefore not directly comparable with figures from previous years.

Figure 3 shows the de-rated margins from previous *Winter Outlook* reports. Our forecast for winter 2026/27 is comparable to those for recent winters.

Figure 4 shows that we expect the daily operational surplus to be comparable to last winter. The pink shaded region shows the forecast range for this winter, while the grey shaded region shows the corresponding range for last year.

As detailed in our *Winter Review and Consultation 2025/26*, we continually review the performance of our analysis. This includes recalibrating models and improving methodologies to forecast supply and demand variables more effectively. These variables, in turn, affect the operational surplus.

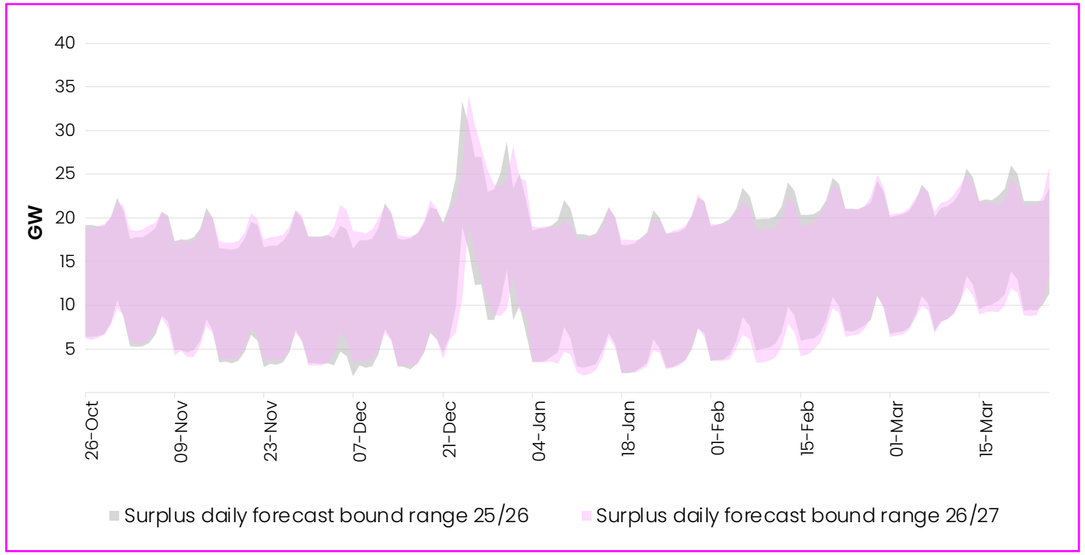


Figure 4: Daily forecast range of operational surplus for this winter (pink plume) compared with the forecast range in the *Winter Outlook 2025/26* report (grey plume)

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, supported by a diverse mix of technologies that contribute to security of supply. Our analysis shows that a period of low operational surplus may materialise if multiple conditions coincide – such as cold weather, low wind, low interconnector imports or exports and high levels of generator outages relative to the peak demand for that period. A combination of some of the above conditions could cause the initial supply provided by the market to approach or fall below our reserve requirement. We plan for these situations and have a range of operational tools available to balance the system should they occur.

Our modelling allows us to assess the likelihood of these conditions occurring on any given winter day. The probabilities are based on the 30,000 simulations of weather, demand, interconnector availability and conventional generator unavailability used in our base case operational surplus. Figure 5 shows that the maximum daily probability for any given day remains low at less than 2%.

Although the daily probability is low, a small number of low surplus days may still occur over the roughly 150-day winter period. On these days, we may need to use standard operational tools, including system notices, to manage the system. This remains part of our normal winter preparedness. Our analysis continues to show that there is sufficient available supply to meet consumer demand.

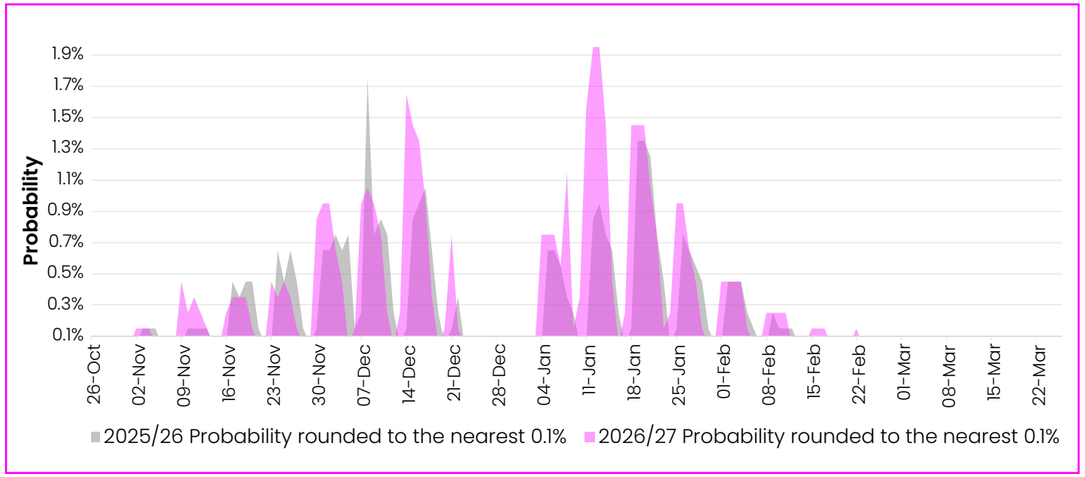


Figure 5: Daily probability that the initial excess supply provided by the market falls below the reserve requirement under the base case for winter 2025/26 and winter 2026/27 – these probabilities are based on the latest available data (as of 30 September) and will change as system conditions develop over the winter

What tools do we use to balance the system?

One of our main 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 Electricity National Control Centre (ENCC).

Our ENCC 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 are a normal feature of managing the system, particularly during winter. System notices include both Capacity Market Notices (CMNs) and Electricity Margin Notices (EMNs).

A system notice 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.

Demand and Supply

Peak demand and forecast range

The forecast range for daily peak demand in winter 2026/27 is marginally higher than last winter. The highest daily demand periods are most likely from mid-December to early February, excluding the Christmas period.

Daily peak demand can vary significantly depending on weather conditions. Figure 6 shows our daily peak National Demand forecast for the coming winter. 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.

Figure 7 shows the probability of National Demand exceeding a range of thresholds. Across the winter season, there is approximately a 20% chance that National Demand could exceed 48 GW on at least one day.

Did you know?

Transmission system demand can be higher than National Demand. This can happen when pumped storage is operating, battery energy storage systems are charging, or electricity is being exported through interconnectors.

Throughout this report, we forecast National Demand. This is influenced by weather, including temperature, wind speed and solar radiation; calendar effects, such as time of day, day of week, bank holidays and school holidays; and market factors, including time-of-use tariffs.

Observed transmission system demand also reflects additional market factors, such as price differences between interconnected markets. In our operational surplus base case, we assume 600 MW of demand from transmission-connected power stations and around 1 GW of exports to Ireland and Northern Ireland at peak demand. Appendix B provides a visualisation of the relationship between different types of demand.

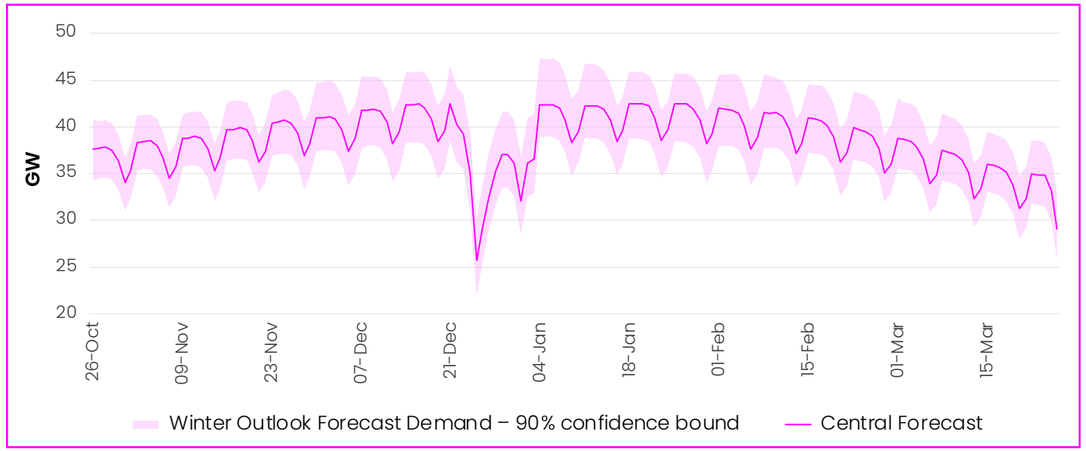


Figure 6: Forecast range of peak National Demand for winter 2026/27

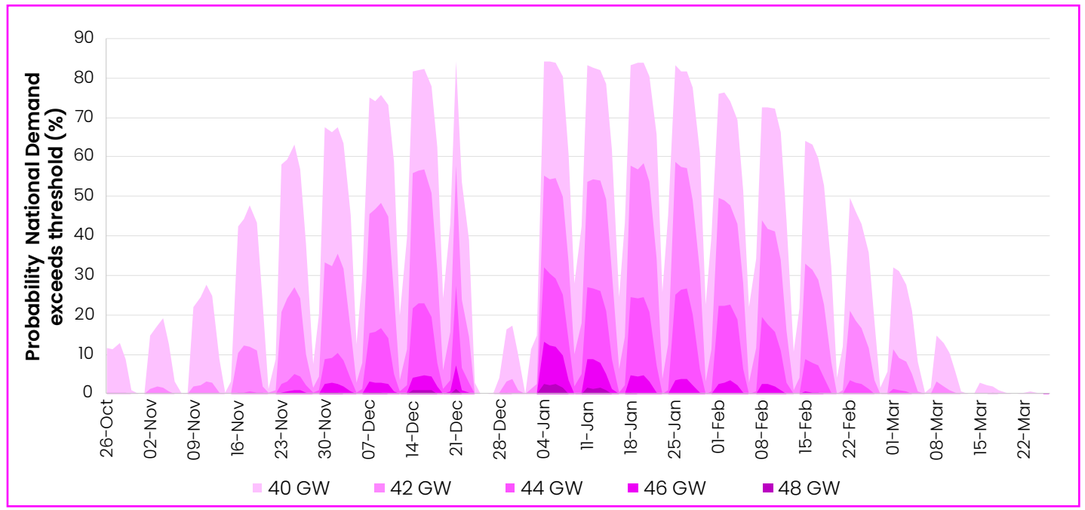


Figure 7: Daily probability of National Demand exceeding stated thresholds

Conventional generator availability

The wide range of forecast weather patterns creates considerable variation in non-wind generation requirements. Cold, calm conditions can result in prolonged periods of high demand, requiring more non-wind generation.

Based on planned generator outages, we expect the lowest levels of generation availability in November (see Figure 8). We include planned outages in our supply assessment using the latest market submissions from generators. We expect generator availability to be higher than last winter throughout the season due to growth in generation capacity and a slight decrease in planned outages for the coming winter.

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 historical variation from expected availability to inform our forecast of how available supply is likely to change throughout winter. From this historical data, we produce an unavailability factor for each technology. This reflects the extent to which generator unavailability is likely to increase throughout the season. The unavailability factor for each technology type is included in our accompanying data workbook.

Figure 9 shows our forecast of demand net wind for winter 2026/27. This is the demand we expect will need to be met by other forms of generation and capacity, such as conventional generation, interconnectors and storage.

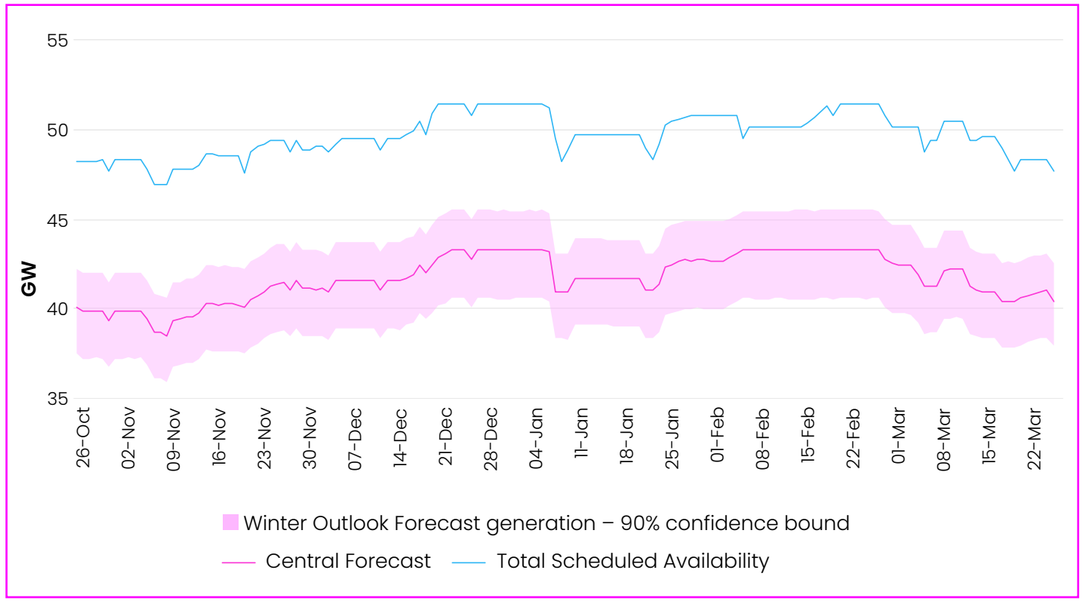


Figure 8: Planned generator availability for winter 2026/27, with the forecast range of de-rated generation availability and the central forecast of expected demand

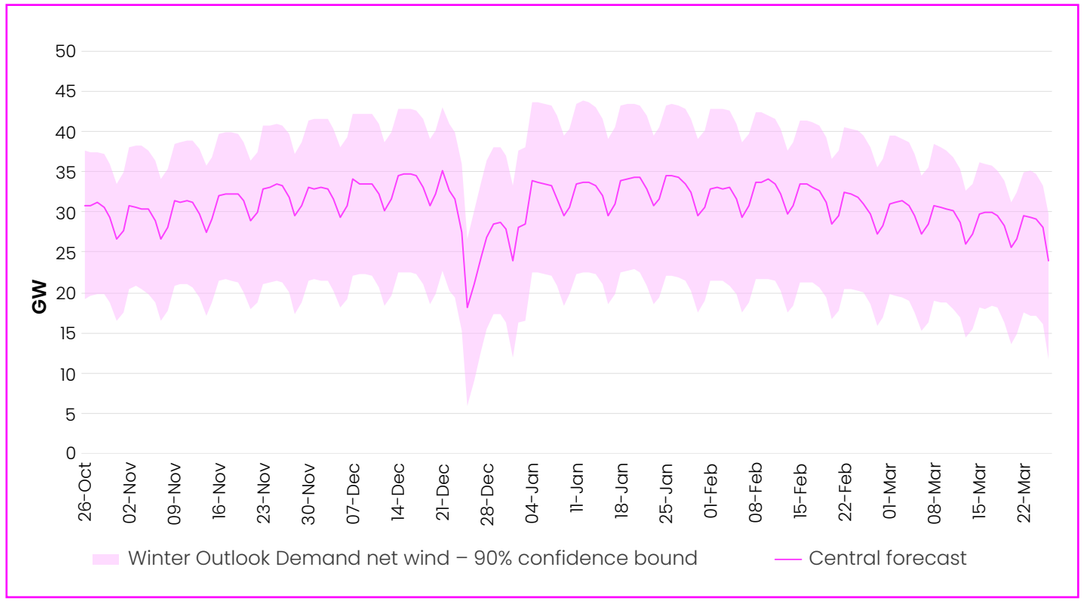


Figure 9: Forecast demand net wind for winter 2026/27

Europe and Interconnected Markets

Overview

Our analysis suggests that imports will be available when required, supported by improved electricity supply fundamentals in Europe compared with 2022, although uncertainties remain. We will continue working closely with our European neighbours, adopting a coordinated approach to optimise interconnector flows and ensure reciprocal support between countries.

Electricity flows across interconnectors are primarily driven by price differentials between markets. While forward electricity price differences between connected markets can indicate expected net electricity flows for the season, actual flows on any given day will 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 (see page 22).

On occasions when specific conditions on the system require a different level of imports or exports, we have a range of operational tools available to alter flows. These vary according to the timescale and nature of the system need. They include intraday trading, System Operator (SO)-SO trading, Net Transfer Capacity (NTC) restrictions, Intraday Trading Limits (ITLs), Enhanced Actions and Emergency Instructions.

We previously announced short-term measures to restrict our intraday trading volumes. These were introduced following extensive engagement with EU TSOs and are expected to remain in place in the near term, while more enduring solutions are agreed. Restrictions on the volume of NESO intraday trading may require greater use of alternative standard operational tools, including NTC restrictions, which limit potential interconnector exports at the day-ahead stage, and system notices.

We have been working closely with DESNZ, Ofgem, the European Commission and neighbouring TSOs to ensure that processes maintain security in Great Britain and interconnected regions. Established channels are in place to ensure open communication between neighbouring TSOs and that support is available when required, for example through Emergency Assistance.

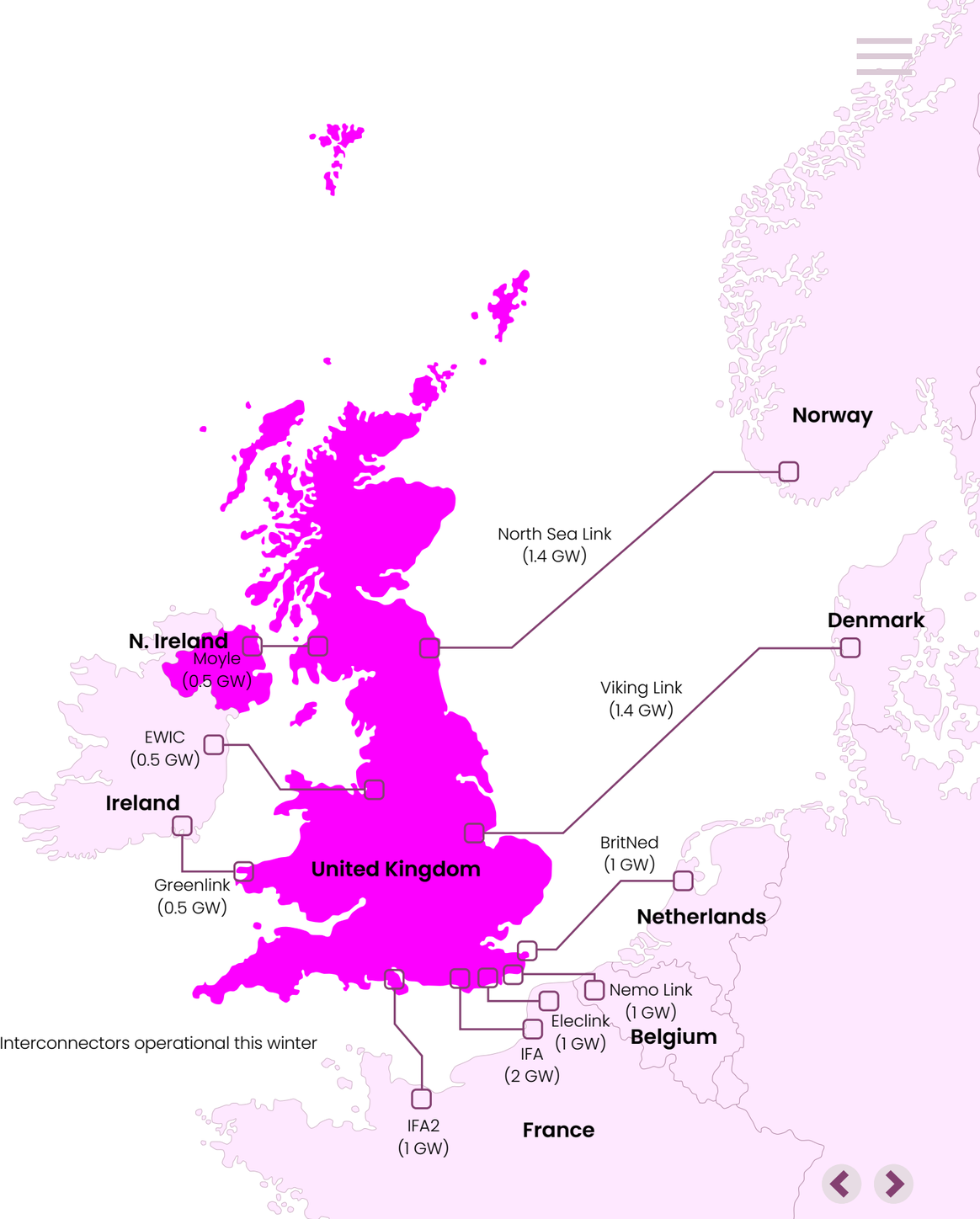


Figure 10: Interconnectors operational this winter

Interconnector availability

Few interconnector outages are planned for this winter. When assessing the contribution of interconnectors during a period of system stress, we apply the de-rating factor from the T-4 Capacity Market auction for 2026/27 to the technical capacity of the interconnector.

Planned outages

Interconnectors and other assets typically undergo routine maintenance outside the peak winter months, when the risk of system stress is lower. Therefore, planned maintenance is minimal during winter 2026/27. For most of the season, we expect the interconnectors to be fully available, 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 and reflected in our operational surplus analysis.

Capacity Market obligations

In a period of system stress, we assume imports into Great Britain in line with the relevant Capacity Market de-rating factor under our base case.

Information on how the Capacity Market de-rating factor for interconnectors is determined is set out in the *Capacity Market Rules*, and further detail on the modelling and assumptions can be found in the *Methodology and Assumptions Book: Electricity Capacity Report 2026*.

Table 2: Interconnector planned outages for winter 2026/27

Interconnector (Capacity)	Connects With	Planned Winter Outages (Resulting Capacity)
IFA (2 GW)	France	08:00 24 October – 18:00 26 November 2026 (1 GW) 18:00 26 November – 08:00 11 December 2026 (1.5 GW) 08:00 11 December – 20:00 12 December 2026 (1 GW)
Moyle (0.5 GW)	Northern Ireland	None
BritNed (1 GW)	Netherlands	None
EWIC (0.5 GW)	Ireland	None
Nemo Link (1 GW)	Belgium	None
IFA2 (1 GW)	France	None
North Sea Link (1.4 GW)	Norway	None
Eleclink (1 GW)	France	None
Viking Link (1.4 GW)	Denmark	None[1]
Greenlink (0.5 GW)	Ireland	None

1 Table 2 has been corrected to show that there are no planned winter outages for Viking Link. Please see our Table of Corrections on page 30 for more details.

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, together with interconnector capacity auction results, suggests an overall import bias this winter.

Power flows through interconnectors are primarily driven by price differences between markets. Figures 12 and 13 show peak electricity price evolution in Great Britain and key European markets for the coming winter. Higher prices in Great Britain than in France indicate that Great Britain will typically be a net importer of electricity from France over this winter. Prices are more closely aligned across Great Britain, Belgium and the Netherlands, suggesting that flows may be more variable. We expect Great Britain to export to Ireland and Northern Ireland under typical conditions. Wholesale power prices have increased over recent months due to higher gas prices but remain below highs seen in 2022.

Our expectation that Great Britain will be a net importer is supported by the results of long-term interconnector capacity auctions, which reflect how market participants assess the cost of import and export capacity (see Figure 11). Import capacity for Q4-26 was valued higher than export capacity on every interconnector with long-term auctions, indicating that market participants expect power prices in Great Britain to be higher than in Europe on average over Q4-26, reflecting an expectation of net imports into Great Britain. Actual flows will be driven by prices and prevailing conditions closer to real time. However, wholesale power prices do not reflect system constraints. Any actions taken to address these constraints will therefore be reflected in the balancing services rather than in wholesale prices.

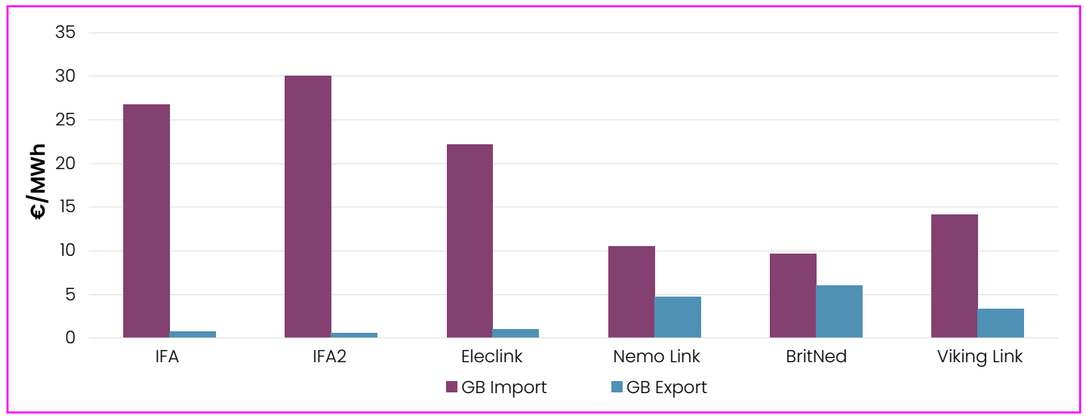


Figure 11: Most recent results from long-term interconnector capacity auctions for Q4-26 baseload power

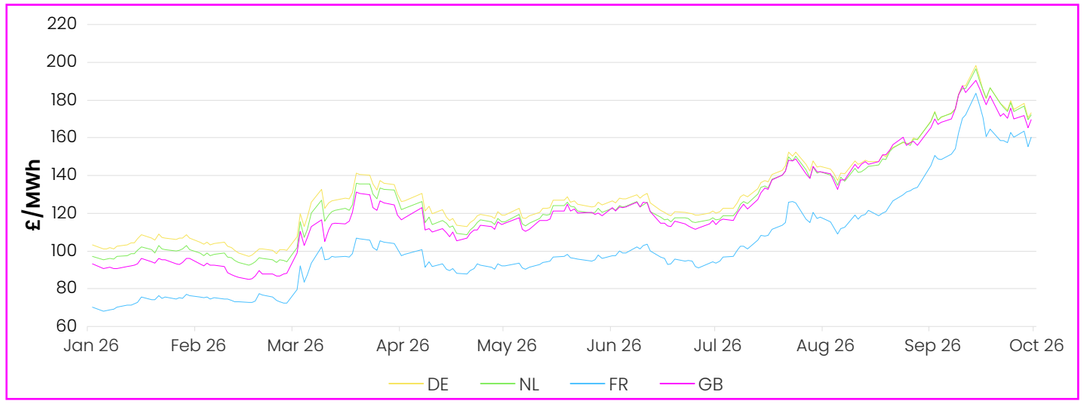


Figure 12: Q4-26 peak load price evolution

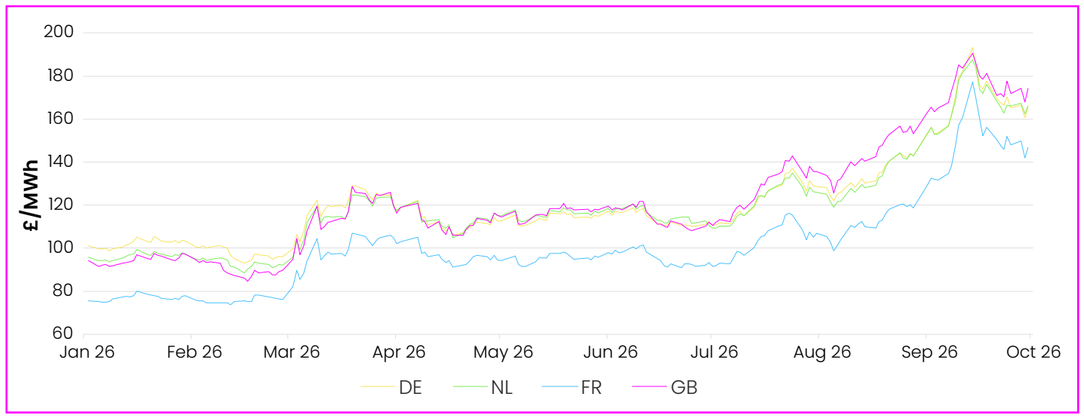


Figure 13: Q1-27 peak load price evolution

Power fundamentals

Power prices have climbed in recent months but remain below highs seen in 2022. Similarly, European supply fundamentals are stronger than in 2022. However, some indicators suggest lower generation availability in major interconnected markets compared with last winter.

Hydroelectric reserves in Europe

As shown in Figure 14, hydroelectric reservoir levels in the Southern Norway (NO2) market area – where North Sea Link connects – are particularly low for this time of year and have remained below the 10-year minimum since late July. Overall, reservoir levels across Norway are slightly stronger, at 68% on 24 September, compared with 51% in the NO2 market area. We continue to expect imports into Great Britain from Norway when required, although we may see greater variability in flow direction than last winter.

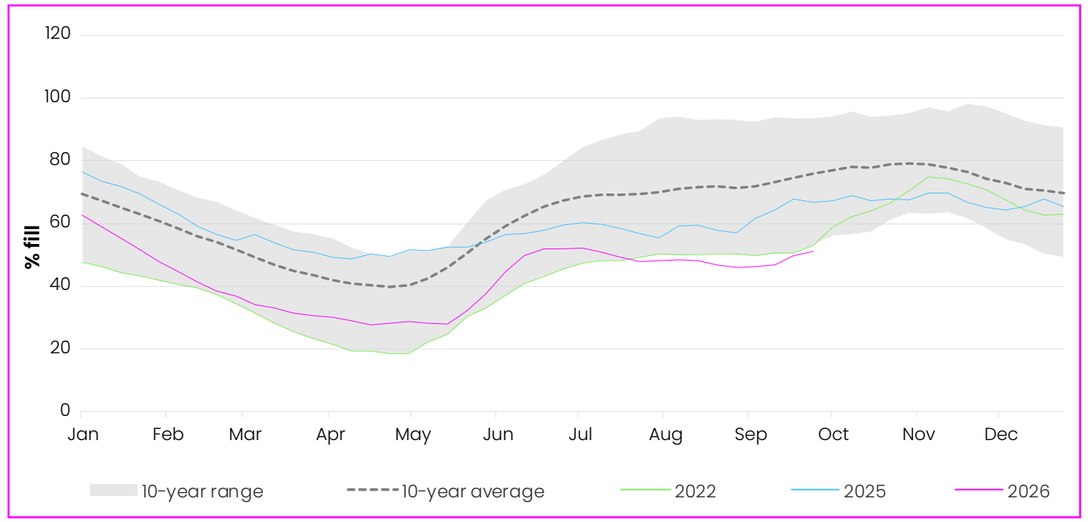


Figure 14: Hydroelectric reserves in the Southern Norway (NO2) market area

Nuclear availability in France

Figure 15 shows scheduled French nuclear outages for the coming winter compared with historical availability over the last five years. Allowing for upward revisions, we anticipate unavailability to remain towards the lower end of the five-year historical range from December to February and well below 2022 levels. We will continue to monitor generator availability across all interconnected markets and work closely with our neighbouring Transmission System Operators to identify developments that could affect interconnector flows.

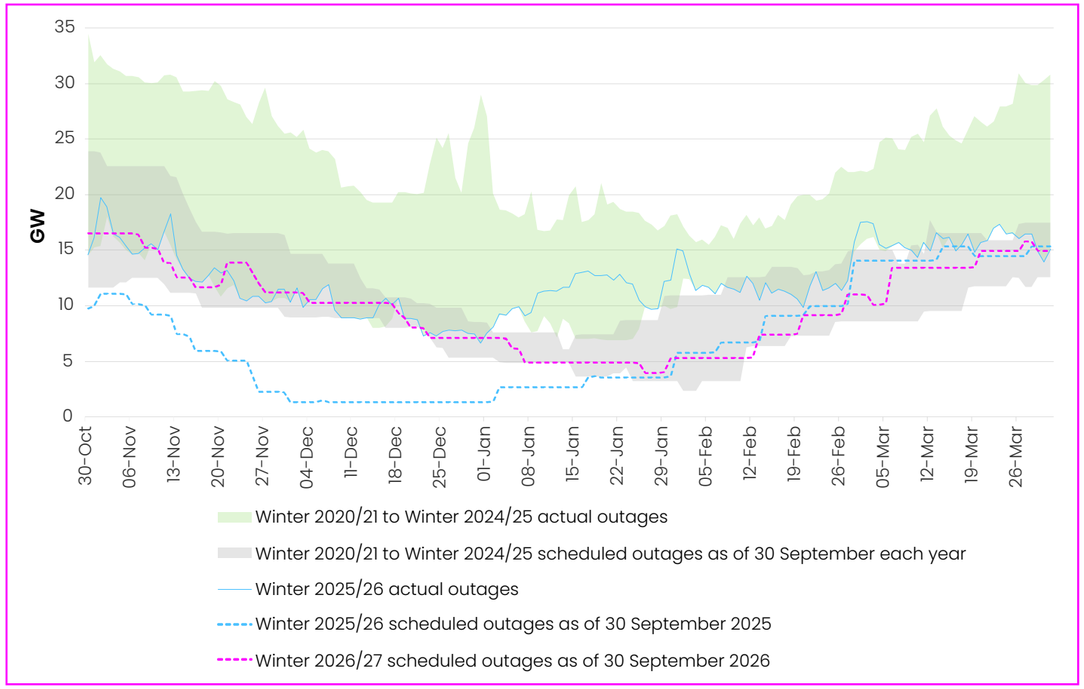


Figure 15: Scheduled French nuclear outages for winter 2026/27 compared with historical ranges

Gas fundamentals

Wholesale gas prices are higher and more volatile than in recent years. We will continue to work closely with our strategic partners to monitor the key factors influencing global energy markets and, where necessary, build resilience and mitigate risks.

Figure 16 shows that winter gas prices are higher and more volatile than in recent years, following the conflict in the Middle East and the effective closure of the Strait of Hormuz. However, prices remain below highs seen in 2022 following the loss of Russian gas volumes.

European gas storage filled slowly over the summer as market disruption pushed summer prices above winter prices. EU gas storage was 72% full on 30 September, just below the 10-year minimum. This is 11 percentage points lower than the 2025 level and 17 percentage points below the 10-year average. EU-mandated filling targets were not met by 1 October and the trajectory indicates that the 80% target is unlikely to be met by 1 December.

As Europe has entered winter with lower-than-normal gas storage levels, the volume of liquefied natural gas (LNG) required over the winter in Great Britain and Europe could vary widely. A cold winter or further supply disruption would be likely to increase volatility in gas and power prices. National Gas assesses EU gas storage under varying LNG import levels in its separate *Gas Winter Outlook 2026/27*.

We continue to work closely with government, Ofgem and National Gas to identify, assess and mitigate potential risks. We undertake a range of activities – collaborating widely with partners and industry – to ensure the whole energy system is ready for the coming season and resilient to the various conditions it may face.

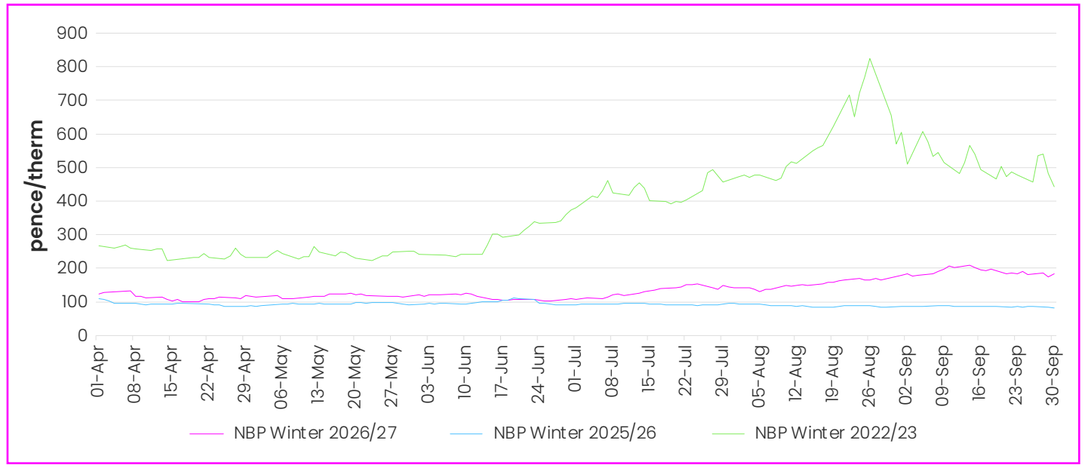


Figure 16: Evolution of prices for the National Balancing Point (NBP – Great Britain's gas trading hub) winter 2022/23, 2025/26 and 2026/27 contracts (source: ICIS)

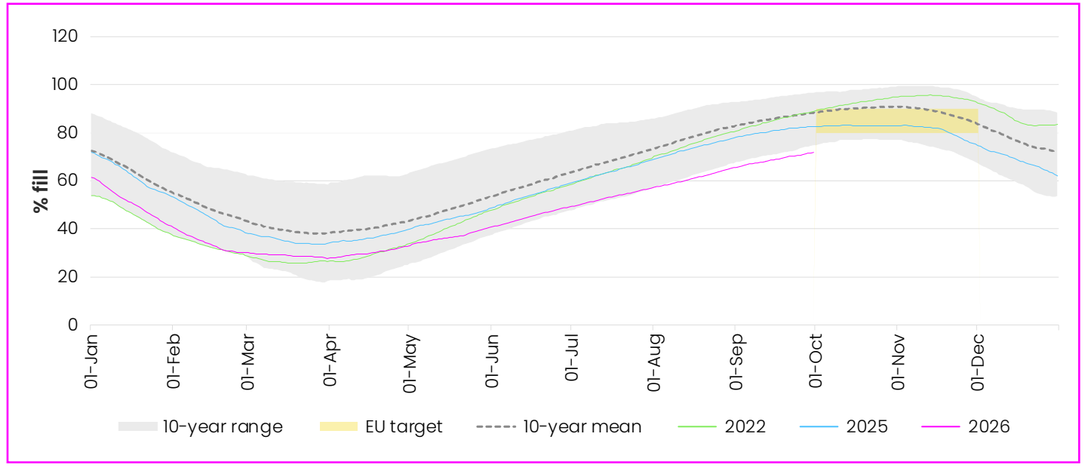
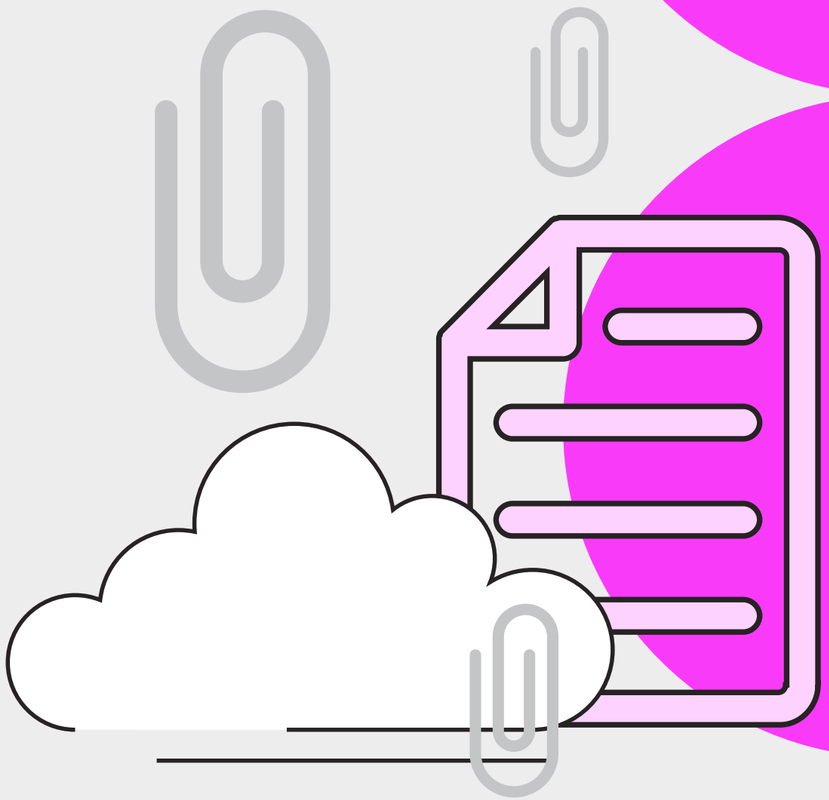


Figure 17: Aggregated EU gas storage

Appendices



Appendix A: List of Figures and Tables

Figures

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 8

Figure 2: Range of outcomes for the daily operational surplus in our base case under different supply and demand conditions. This is the 90% confidence level and we therefore expect days when the operational surplus falls below the shaded range. 11

Figure 3: Historic de-rated margin forecasts made ahead of each winter in the Winter Outlook reports. The figure for 2026/27 is derived from our updated modelling approach and is therefore not directly comparable with figures from previous years. 12

Figure 4: Daily forecast range of operational surplus for this winter (pink plume) compared with the forecast range in the *Winter Outlook 2025/26* report (grey plume) 12

Figure 5: Daily probability that the initial excess supply provided by the market falls below the reserve requirement under the base case for winter 2025/26 and winter 2026/27 – these probabilities are based on the latest available data (as of 30 September) and will change as system conditions develop over the winter 13

Figure 6: Forecast range of peak National Demand for winter 2026/27 15

Figure 7: Daily probability of National Demand exceeding stated thresholds 15

Figure 8: Planned generator availability for winter 2026/27, with the forecast range of de-rated generation availability and the central forecast of expected demand 16

Figure 9: Forecast demand net wind for winter 2026/27 16

Figure 10: Interconnectors operational this winter 18

Figure 11: Most recent results from long-term interconnector capacity auctions for Q4-26 baseload power 21

Figure 12: Q4-26 peak load price evolution 21

Figure 13: Q1-27 peak load price evolution 21

Figure 14: Hydroelectric reserves in the Southern Norway (NO2) market area 22

Figure 15: Scheduled French nuclear outages for winter 2026/27 compared with historical ranges 22

Figure 16: Evolution of prices for the National Balancing Point (NBP – Great Britain's gas trading hub) winter 2022/23, 2025/26 and 2026/27 contracts (source: ICIS) 23

Figure 17: Aggregated EU gas storage 23

Figure 18: Relationship between some of the different types of demand (not to scale) 26

Figure 19: Historic de-rated margin forecasts made ahead of each winter in the Winter Outlook reports derived from the previous CA model 28

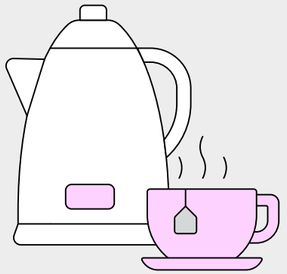
Tables

Table 1: Impact of illustrative sensitivities on de-rated margin and associated LOLE 9

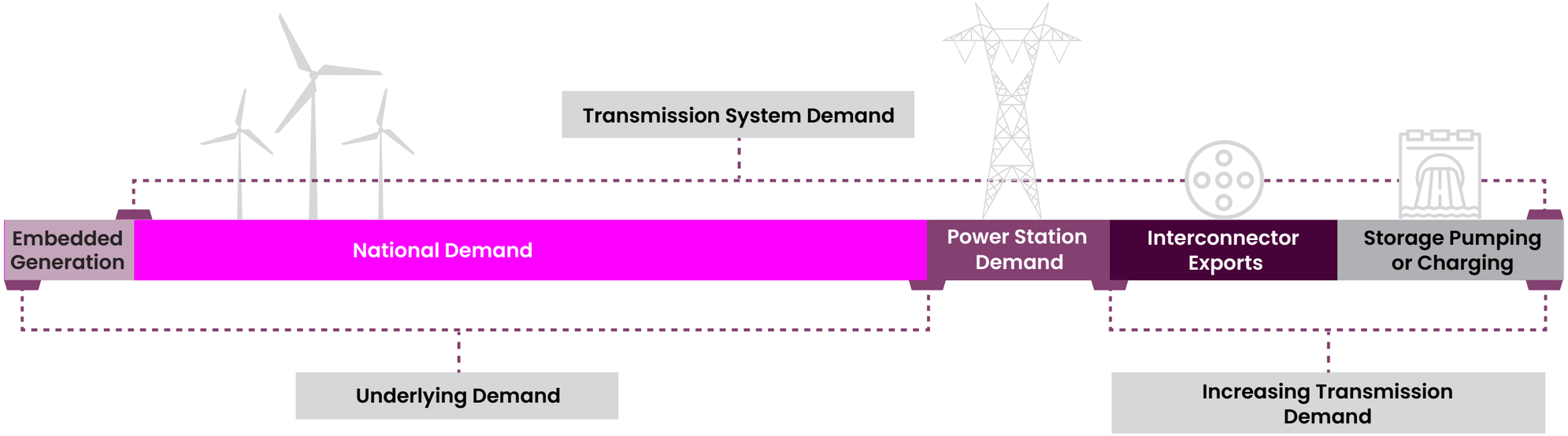
Table 2: Interconnector planned outages for winter 2026/27 19

Table 3: Number of EMNs and CMNs issued in recent winters 27

Table 4: Differences between CMNs and EMNs 27



Appendix B: Relationship between Types of Demand



The market or NESO may take actions to increase exports across the interconnectors or to increase pumping at pumped storage stations or on battery energy storage systems to increase the amount of demand on the transmission system. While charging battery storage can increase the amount of demand on the transmission system, this is not currently reflected in the published Transmission System Demand value.

Figure 18: Relationship between some of the different types of demand (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. More information can be found on our What are system notices? webpage.

Table 3: Number of EMNs and CMNs issued in recent winters

Year	EMNs issued	CMNs issued
2025/26	0	0
2024/25	1	3
2023/24	0	0
2022/23	1	2
2021/22	0	2
2020/21	6	2
2019/20	0	0

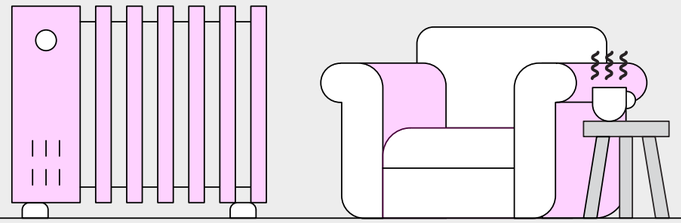


Table 4: Differences between CMNs and EMNs

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. This winter, we have published the de-rated margin from our refined modelling approach for the first time.

Our new modelling approach, based on the PLEXOS simulation tool, better reflects observed correlation between renewable generation availability and demand. It brings our Winter Outlook modelling of demand and renewable correlation 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*. Our accompanying *Technical Workbook and Methodology* provides more information on our modelling updates.

The previous Capacity Assessment (CA) model was used to derive the de-rated margin and LOLE published in the *Early View of Winter* and previous Winter Outlooks. We have included the de-rated margin for winter 2026/27 derived from the previous CA model in this Appendix to enable a like-for-like comparison. The de-rated margin for winter 2026/27 from the CA model is 5.2 GW (equivalent to 8.4% of average cold spell (ACS) peak demand), with an associated loss of load expectation (LOLE) of less than 0.1 hours per year, which is well within the Reliability Standard of 3 hours per year. This is comparable to the de-rated margin of 5.5 GW (8.8%) published in the *Early View of Winter* and in line with recent winters, as shown in Figure 19.

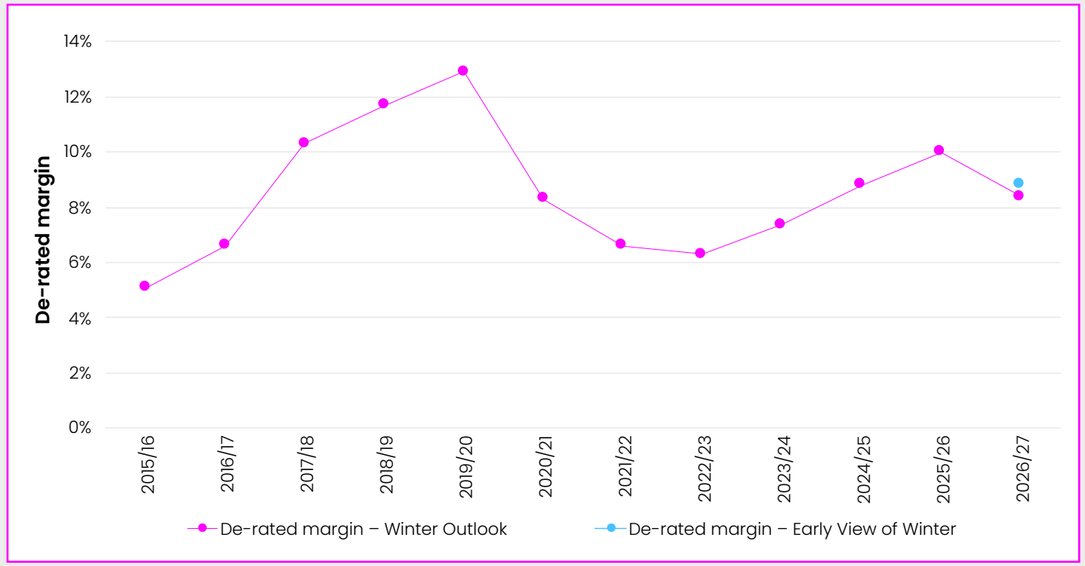
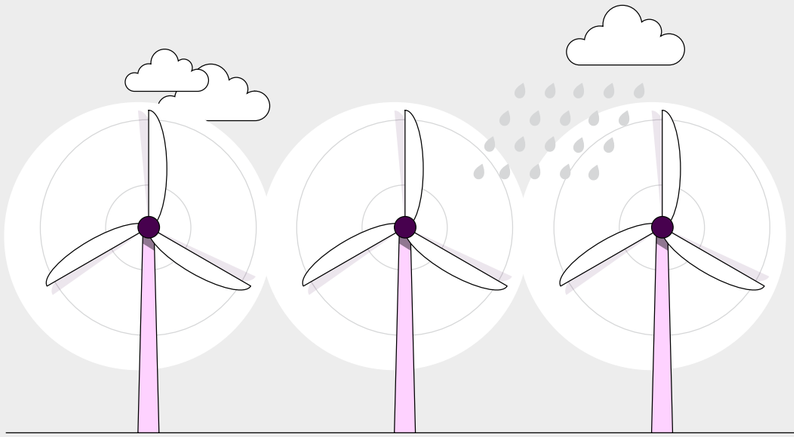


Figure 19: Historic de-rated margin forecasts made ahead of each winter in the Winter Outlook reports derived from the previous CA model



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 30 September 2026. 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 to use 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.

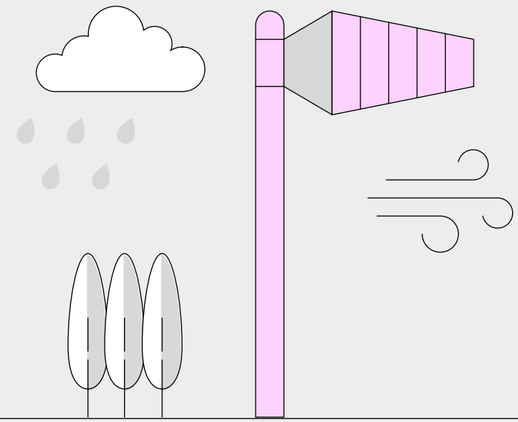
We use historic variation from expected availability to inform our forecast of how available supply is likely to change across winter. Unavailability factors are derived by fuel type, based on historic data. To calculate unavailability rates, we first estimate the maximum capacity of each unit as a benchmark 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.

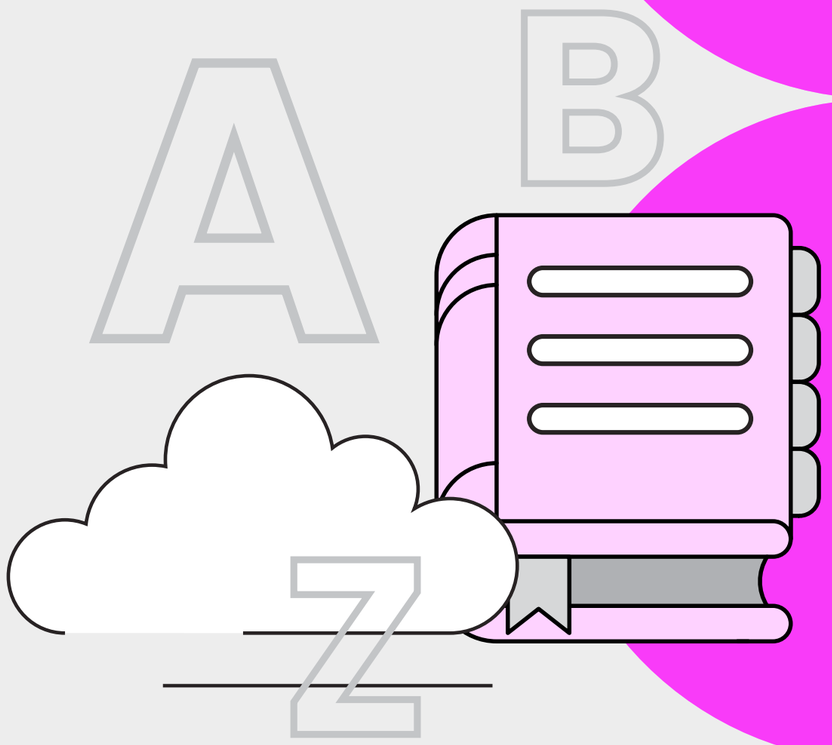
From this, we calculate the availability rate of each generator as the average availability across all peak demand periods, divided by the maximum capacity of the unit. This can then be converted into an unavailability rate.

Table of Corrections

Date	Page	Correction details
27 October 2026	19	Table 2 has been corrected to show that there are no planned winter outages for Viking Link. A notice by Energinet, related to Great Britain to Denmark capacity, was incorrectly shown as reduced Viking Link availability.



Glossary



Average cold spell (ACS)
The ACS methodology is an approach to calculating peak demand that takes into consideration behavioural effects 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 (BM)
The BM is NESO's primary tool to balance electricity supply and demand on Great Britain's network. It allows participants to set prices at which they will increase or decrease their output. The Electricity National Control Centre (ENCC) uses 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. Visit britned.com to find out more.

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)
CMN is based on CM margins, which are calculated using 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. (DFS) has undergone significant updates, with the service transitioning from an enhanced action service to an in-merit margin tool.

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 the 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 between Ireland and Great Britain commissioned in 2012. Visit Interconnection on the EirGrid website to find out more.

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

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

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.

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.

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

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

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 is the policy objective set by government for security of supply.

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

Moyle
A 500 MW interconnector between Northern Ireland and Scotland commissioned in 2001. Visit mutual-energy.com to find out more.

Nemo Link
A 1 GW interconnector between Belgium and Great Britain commissioned in 2019. Visit What is Nemo Link? on its website to find out more.

Net Transfer Capacity (NTC)
NTC is the maximum electricity flow that an interconnector can import into or export out of the Great Britain power grid for a given time period. It represents the upper limit of electricity flow that can be reliably accommodated without violating system security or operational constraints. NTC allows market participants to plan cross-border electricity transactions and system operators to manage interconnector flows safely.

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.

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.

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 day-by-day basis. It includes both notified planned outages and an assumed unavailability factor for each technology type.

Outage
The planned or unplanned maintenance that requires a complete shutdown of a unit (and reduction in the MEL to 0).

Outturn demand
Actual historical operational demand from real-time metering.

Peak load 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 Great Britain's 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 observed once the effect of weather has been 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 2026/27 at marketoutlook@neso.energy and we will get in touch.

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Winter Outlook 2026/27 is part of a suite of documents prepared by NESO. Visit neso.energy for more information.

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