Winter Outlook Report

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

October 2024

NESO
National Energy System Operator

Welcome

Welcome to the National Energy System Operator (NESO) *Winter Outlook Report*. As a new, independent public corporation, we are responsible for planning Britain's electricity and gas networks and operating the electricity system. Central to our role as NESO is a whole system approach to strengthening energy security, helping deliver net zero and ensuring household bills are affordable in the long term.

Kayte O'Neill
Chief Operating Officer,
National Energy
System Operator

Our new roles and responsibilities reflect the unparalleled change required to deliver clean, affordable energy for everyone; a transformation that will only be possible through coordinating across the whole energy system.

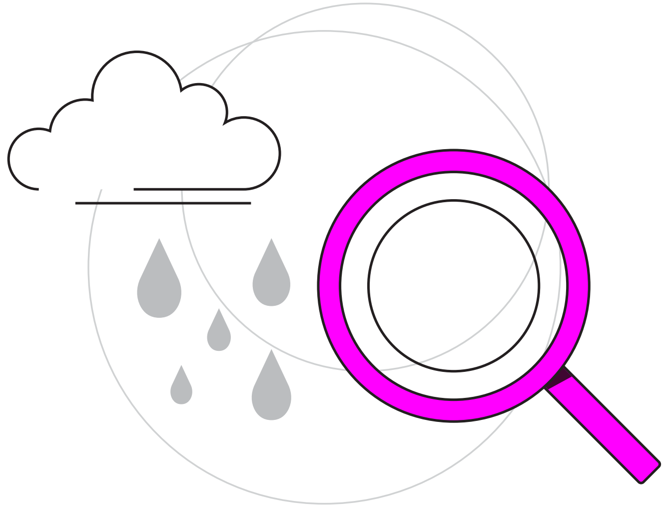
NESO has been founded on the current activities and capabilities of the Electricity System Operator (ESO). In turn, this report builds on the *Early View* of winter, published as ESO, and contains our latest assessment of Britain's electricity security of supply for winter 2024/25. Our market analysis looks at both gas and electricity fundamentals, which supports our responsibility as NESO to provide a whole-energy view. A separate *Gas Winter Outlook 2024/25* is published by National Gas.

Our analysis indicates that margins will be adequate and within the reliability standard under our base case. Our analysis also indicates that our operational surplus will be sufficient across winter, although there may be periods where we need our standard operational tools, including the use of system notices.

Structural changes in supply and demand have helped global energy markets find a new equilibrium following the significant volatility of recent years. While we see encouraging signs of stability, uncertainties remain. We continue to monitor market conditions, global events and emerging risks, working closely with the government, Ofgem and National Gas to develop any necessary mitigations.

We welcome input from stakeholders on the outlook for winter, including perspectives on our assessment of market conditions.

We want to make sure that our publications continue to improve and that they contain the right information to support industry planning. To provide feedback, you can email us at: marketoutlook@nationalenergyso.com; join us at the NESO Operational Transparency Forum; or use social media via X (previously Twitter) @NESO_energy.



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Key Messages: Winter Outlook 2024/25 at a Glance

Margins

1

Our analysis shows that margins are expected to be adequate and within the Reliability Standard.

The current Base Case de-rated margin is 5.2 GW (representing 8.8% of peak cold spell demand). The associated loss of load expectation (LOLE) is below 0.1 hours. This is higher than the 4.4 GW (7.4%) published in the *Winter Outlook Report* for 2023/24 and remains comparable to the *Early View* published in June.

The higher year-on-year margin is driven by new interconnection, growth in battery storage capacity and an increase in generation connected to the distribution networks. In combination, these changes more than offset generation retirements and other temporary capacity reductions.

Operations

2

We are confident that we can continue to meet the challenge of reliably operating a changing electricity system as new technologies and diverse forms of capacity contribute to security of supply.

We expect there to be sufficient operational surplus throughout winter, allowing for natural variations in demand, wind and outages.

We may still see some tight days where we need to use our standard operational tools, including the use of system notices.

Markets

3

Global energy markets show signs of finding a new equilibrium, but uncertainties remain. We will continue to monitor risks and take necessary steps to build resilience.

A rebalancing in European energy markets has further increased the resilience of interconnector imports to supply-side shocks. As a prudent system operator, we continue to systematically and comprehensively monitor risks in global energy markets, working closely with the government, Ofgem and National Gas to establish any actions necessary to build resilience.

Preparations for Winter 2024/25

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

1 Neighbouring Transmission System Operators

We will continue close and active engagement with our neighbouring transmission system operators, identifying developments that could impact interconnector flows.

We will coordinate reciprocal support to maintain secure supplies for customers in Great Britain (GB) and Europe.

2 Transmission Owners

We are working closely with transmission owners to minimise the impact of network outages this winter.

By optimising the outage plan, we maximise the amount of energy available to consumers.

Constraints will be carefully managed to ensure access to generation is maximised when required.

3 Demand Flexibility

We continue to develop tools, systems and services that provide clear and efficient routes for new technologies and all forms of capacity to contribute to the security of supply.

In June, we announced our intention to reintroduce the Demand Flexibility Service (DFS) for a third year. Due to the improved outlook for this winter, we proposed several changes to the service design that would see the DFS evolve from an enhanced action to a service that can be used under normal market conditions. You can read more about the proposed changes on our DFS webpage.

4 Balancing Costs

Wholesale power prices significantly influence balancing costs.

While the overall energy system is showing greater resilience, disruptions in global energy markets remain a possibility which could see wholesale prices, and therefore balancing costs, rise.

We continue to innovate and adapt to efficiently operate a rapidly changing electricity system. The systems, tools and services we develop help reduce costs and save carbon. You can read more about our balancing cost forecasts, and actions we're taking to minimise costs on our balancing costs webpage.

De-Rated Margin

Base Case and Reliability Standards

Margins are expected to be adequate and within the Reliability Standard. Our Base Case margin is 5.2 GW/8.8% with an associated Loss of Load Expectation (LOLE) below 0.1 hours.

Our current assessment shows sufficient available capacity to meet demand, with a de-rated margin of 5.2 GW (8.8% of the peak average cold spell demand) for this winter. See Figure 1 for a breakdown of this capacity. This is an increase from the 4.4 GW (7.4% of peak demand) published in last year's *Winter Outlook Report*. This represents a 0.4 GW decrease from the *Early View* published in June due to temporary reductions or restrictions to generator capacity.

The associated Loss of Load Expectation (LOLE) is below 0.1 hours/year, which is within the Reliability Standard of 3 hours. This assessment assumes a peak average cold spell demand of 59.8 GW (including operating reserve).

Available generation assumes an additional 1.2 GW (de-rated) of new or returning capacity connected to the transmission system and a 0.7 GW (de-rated) increase in the contribution from generation connected at distribution level. We assume that 6.6 GW (de-rated) 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 we have specific market intelligence otherwise.

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

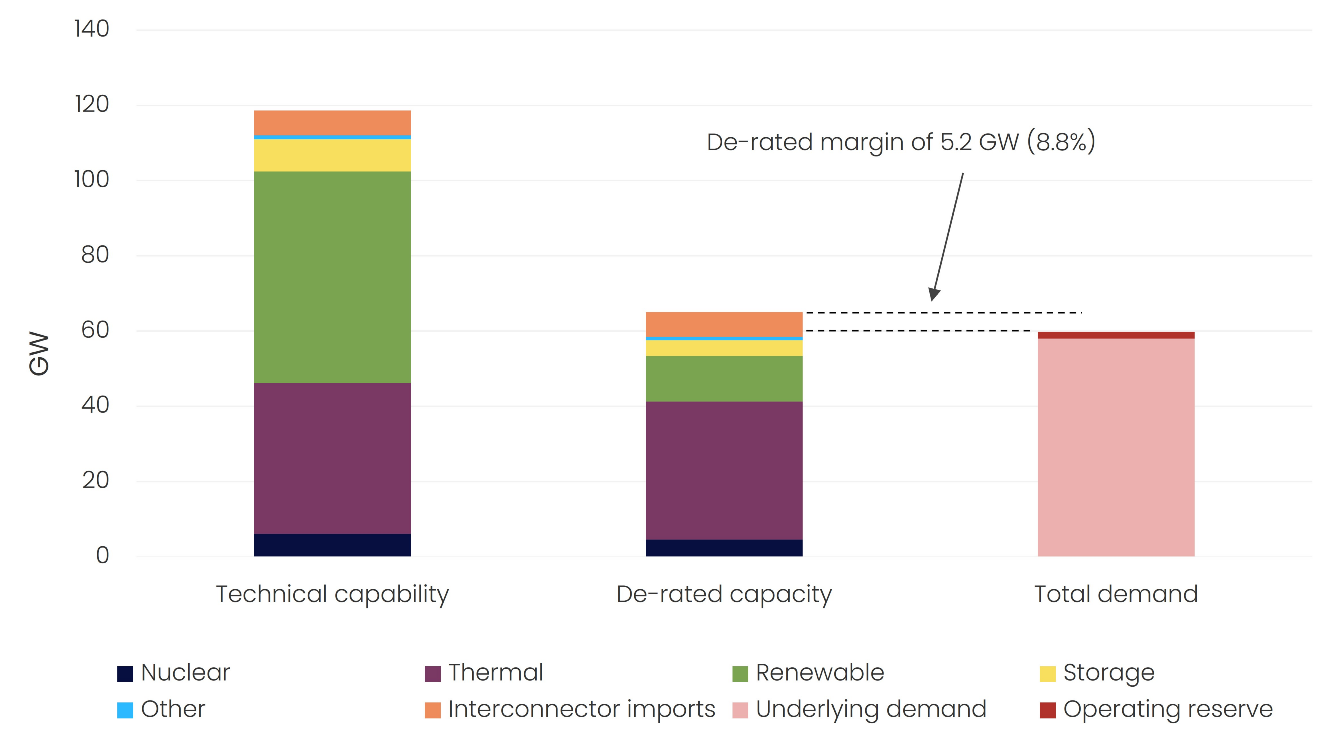


Figure 1: De-rated margin in relation to generation capacity and demand

What is De-Rated Margin?

Margin in this context refers to the excess supply remaining once demand, and reserve, has been met. De-rated means that total generation capacity has been adjusted to reflect availability by fuel type or technology. The derating factor for a given type of generation reflects the proportion of its total capacity that will deliver at times of peak demand.

What is Loss of Load Expectation?

LOLE is the expected number of hours when demand is higher than available generation, after all system notices and system operator (SO) balancing contracts have been exhausted but before any mitigating/emergency actions are taken. Information on how we'll be updating our de-rated margin and LOLE methodology for future seasonal outlook publications can be found in Appendix D.

Did You Know?

We need access to sources of extra power in the form of increased generation or demand reduction, which we call reserve. These services enable us to correct energy imbalances and respond to errors in forecasts for demand or unforeseen generation unavailability. The technical features of each service are designed to ensure the reliable delivery of active power at different timescales, depending on the underlying system need they address.

Operational Surplus

Base Case and Credible Range

We expect to have a sufficient operational surplus throughout the winter when considering the natural variations in demand, wind and generator outages. There may be some tight days, most likely between late November and the end of January, excluding the Christmas period.

Our analysis shows that demand can be met under our credible range scenarios, though there may be times when we need to use our standard operational tools such as system notices.

Figure 2 shows the central forecast and a range of credible outcomes for the daily margin for winter. To derive these credible outcomes, we assess the daily surplus under typical conditions, using average weather conditions for demand and wind generation, as well as average availability for conventional generation. We then simulate 30,000 variations around this central view using multiple scenarios for weather, demand, conventional generation availability, wind generation output and interconnector availability.

For each of these scenarios, we calculate the daily surplus time series across the entire winter, providing us with a credible range for the operational surplus. When the shaded region nears 0 GW, there is a risk that the system may become tight, and operational tools, including system notices, could be used to increase the margin.

There could still be days where the operational surplus falls below the shaded range in Figure 2 (up to 5% of days) and we may need to use our standard operational tools to manage these periods, including the use of system notices. More information on system notices can be found in Appendix C.

Our operational surplus does not include potential market responses to higher demand or tighter conditions, such as power stations increasing their output levels for short periods. During periods of low operational surplus, generators may be incentivised to reschedule planned outages due to Capacity Market obligations or revenue opportunities from higher market prices.

The day-by-day view of forecast operational surplus (showing maximum normalised demand and assumed generation), which was included in last year's *Winter Outlook Report*, can still be found in the accompanying *Winter Outlook Data Workbook*.

See Appendix E for more details on how our operational surplus is calculated.

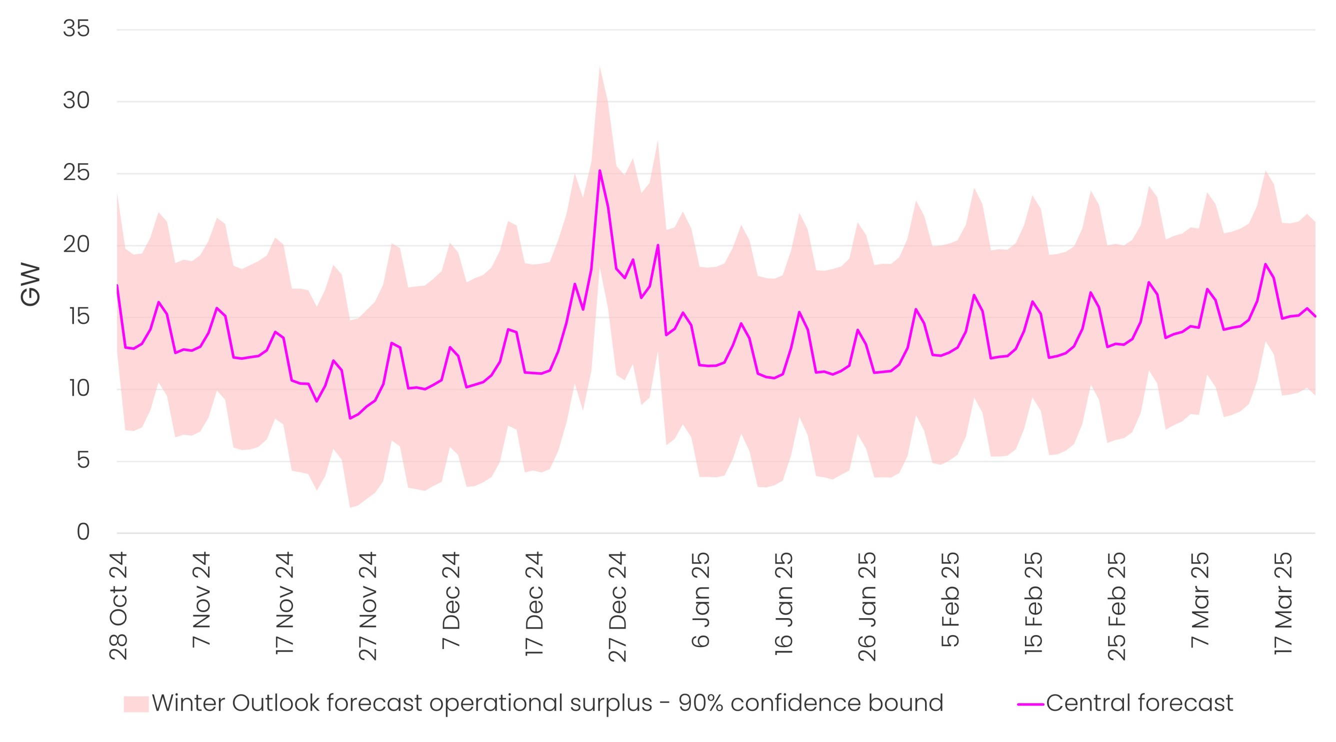


Figure 2: Range of outcomes for the daily operational surplus in our Base Case under different supply and demand conditions

Comparison to Previous Winters

The de-rated margin for this winter represents the highest forecast since 2019/20 and is broadly in line with recent winters.

The de-rated margin in our Base Case for this winter is 5.2 GW (8.8% of Average Cold Spell peak demand), which is higher than last year's margin of 4.4 GW (7.4% of the assessed Average Cold Spell peak demand for the corresponding period).

The year-on-year change is due to increased interconnector capacity, returning generation availability, growth in battery storage capacity and the effects of increased generation connected to the distribution networks. In combination, these changes more than offset generation retirements and other temporary capacity reductions.

Figure 3 shows the de-rated margins included in previous *Winter Outlook Reports*. Our de-rated margin forecast for winter 2024/25 is the highest since 2019/20 and is comparable to recent winters.

Figure 4 highlights our expectation that the daily operational surplus is forecast to be higher this year compared with last year's forecast. The red shaded region shows the credible range for this year and the grey shaded region shows the corresponding range for last year. More details on our operational surplus analysis are available in Appendix E. This analysis is underpinned by our expectations of available supply and likely demand, which can be found on pages 12–13.

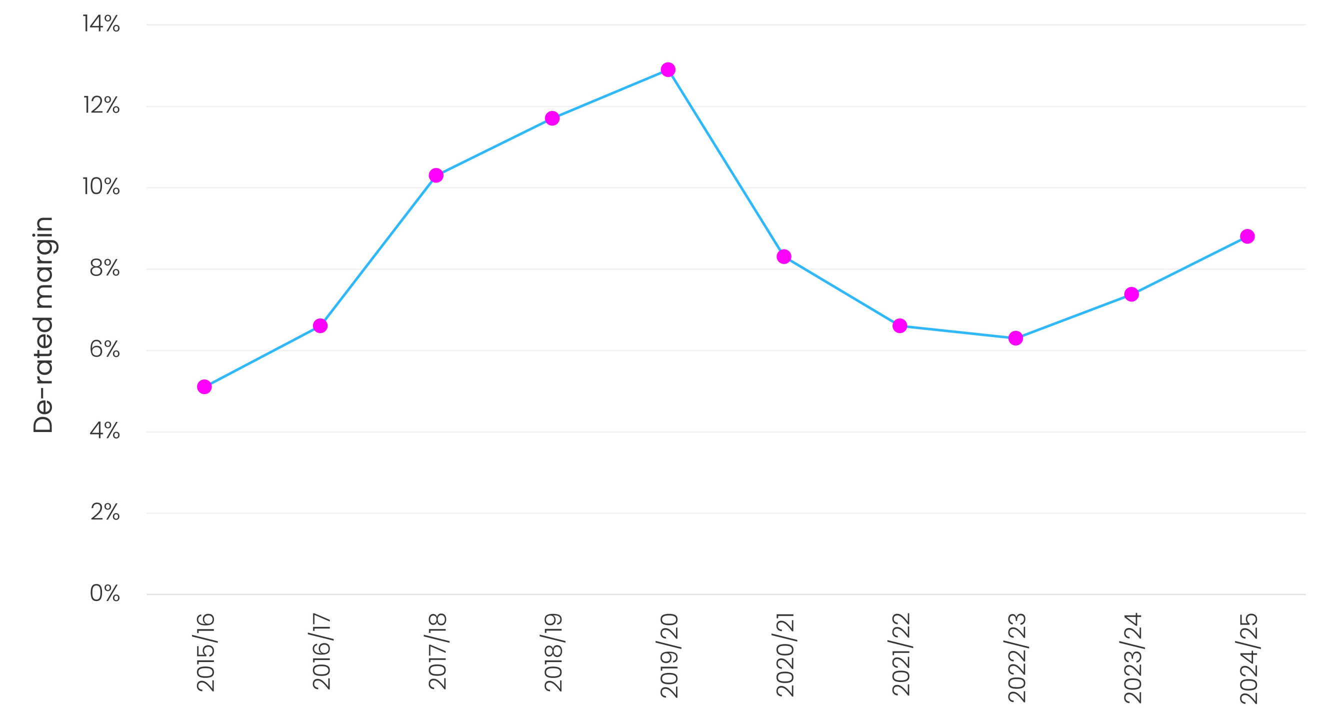


Figure 3: Historic de-rated margin forecasts made ahead of each winter in the *Winter Outlook Reports*

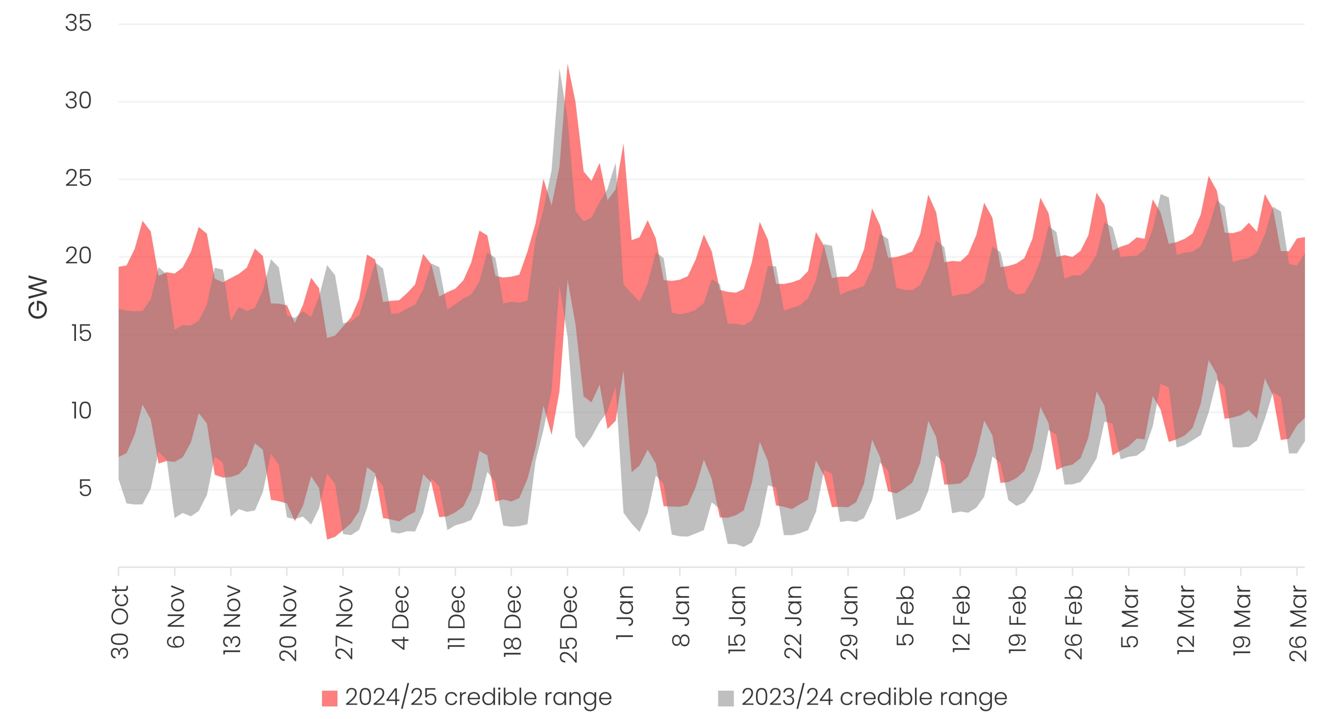


Figure 4: Daily credible range of operational surplus for this winter (red plume) compared with the credible range in last year's *Winter Outlook Report* (grey plume)

Demand and Supply

Peak Demand and Credible Range

Weather-corrected peak demand for winter 2024/25 is expected to be slightly lower than recent winters due to the continued growth in generation connected to the distribution networks.

This winter, we expect:

- weather-corrected peak Transmission System Demand (TSD) to be 44.4 GW and to occur in early to mid-January – this is down from 44.9 GW last winter
- embedded wind generation at the time of normal peak demand to be similar to last winter
- that weather-corrected peak TSD can be met before using our operational tools
- the maximum triad avoidance to be 0.8 GW – this is in line with the estimated observed levels in winter 23/24, the first since changes were made to TNUoS charging, whereby the Transmission Demand Residual (the largest component of the TNUoS charges) is no longer recovered via the traditional triad methodology

The peak winter demand has historically always occurred between the first week in December and the first week in February, but never during the Christmas fortnight or on a weekend.

Table 1: Assumptions for peak TSD

Assumption	Demand
Transmission connected power station demand	600 MW
Base Case interconnector exports to Ireland and Northern Ireland (at time of peak demand)	1000 MW
Embedded wind capacity	~6.5 GW
Embedded solar capacity	~17 GW
Pumped storage (at time of peak)	0 GW

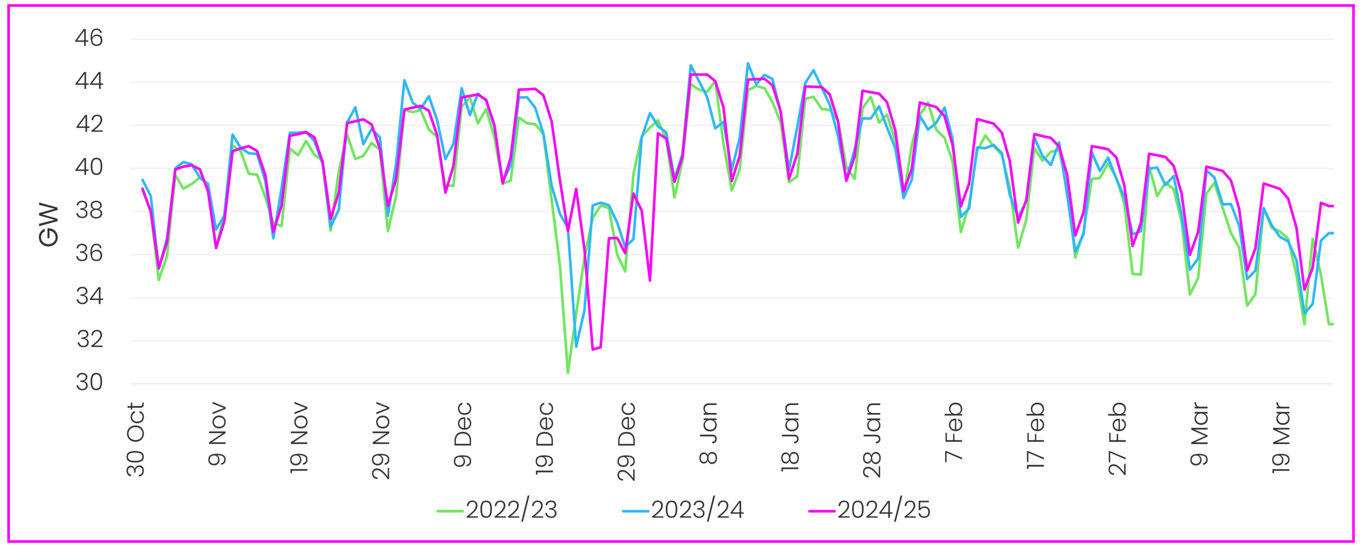


Figure 5: Historical and forecast weather-corrected daily peak TSD

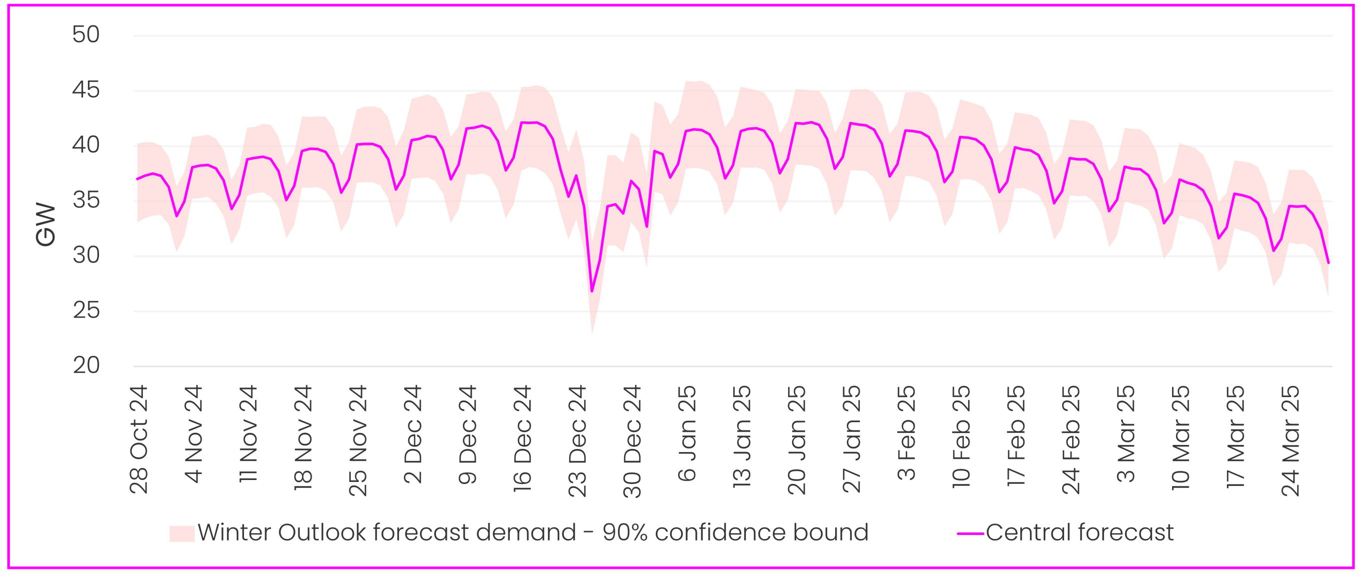


Figure 6: Credible range of peak national demand for winter 2024/25

Generator Availability

Late October to mid-December will see the lowest available generator capacity. Breakdown rates are assumed to be marginally higher, and the Equivalent Firm Capacity (EFC) of wind marginally lower, than those forecast last winter.

This winter, we expect:

- that late October to mid-December will see the lowest levels of generation availability (see Figure 7), primarily driven by nuclear outages during this period
- marginally higher breakdown rates, largely driven by an increase in the three-year rolling average breakdown rate for nuclear generation (see Table 2)

To account for unexpected generator unit breakdowns, restrictions or losses in our operational forecasts, we calculate a breakdown rate. Forecast breakdown rates are applied to the operational data provided to NESO by generators to reflect potential restrictions and unplanned generator breakdowns or losses close to real time. The rates are based on how generators performed against their planned availability on average, by fuel type, during peak demand periods (7am to 7pm) over the last three winters.

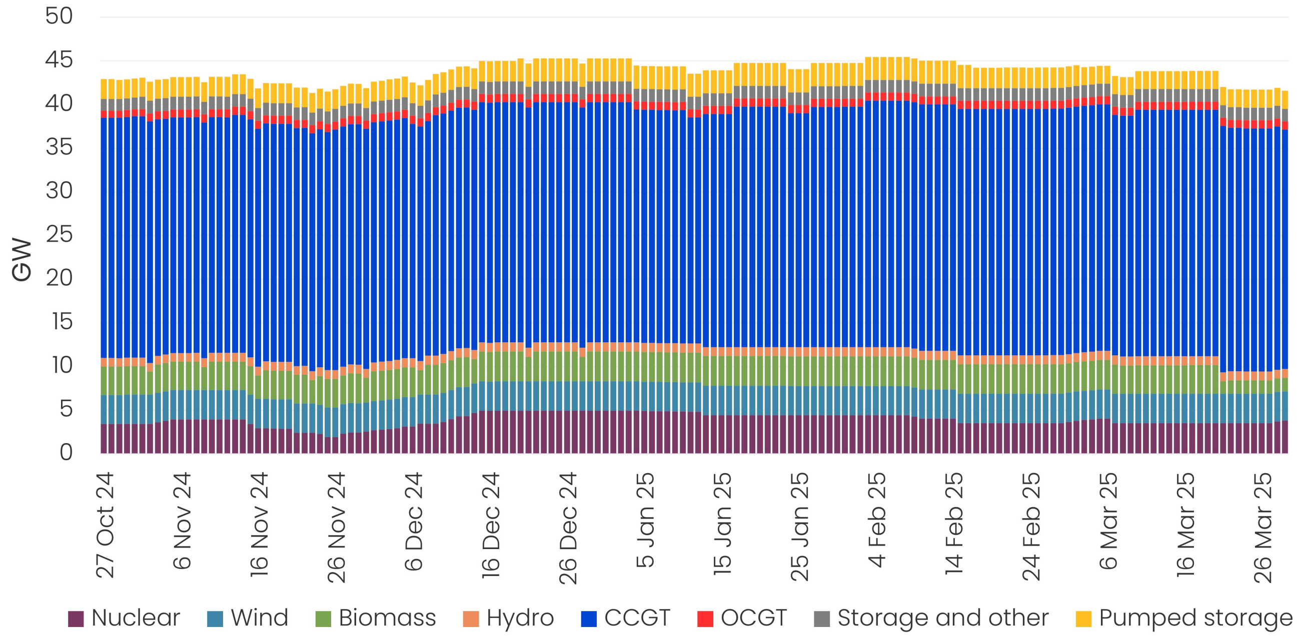


Figure 7: Daily generation availability by fuel type, based on market submissions and including breakdown rates. These figures do not include the contribution from interconnectors.

Extended, unplanned outages (in February and March) across the nuclear fleet have led to an increase in the forecast breakdown rate for winter 2024/25. Despite this, the weighted average for all fuel types is forecast to be lower than winter 2023/24 actuals. Wind generation is based on an EFC of approximately 14%, which is lower than the 16% EFC assumed last winter.

Table 2: Forecast breakdown rates for winter 2024/25 vs actual breakdown rates for recent winters

Technology Type	Breakdown Rate		
	Forecast 2024/25	Actual 2023/24	Actual 2022/23
CCGT	5%	7%	4%
Nuclear	24%	39%	14%
OCGT	11%	11%	11%
Pumped Storage	3%	3%	3%
Biomass	5%	3%	4%
Hydro	7%	9%	7%
Battery Storage	5%	7%	4%
Weighted Average	8%	12%	5%

Interconnectors

Overview

We expect to continue working closely with our neighbours in Europe, adopting a coordinated approach, providing reciprocal support, and ensuring that interconnectors remain mutually beneficial for flexibility and adequacy.

This winter, we expect:

- close cooperation between European system operators to play an important role in helping maintain secure supplies for customers in GB and Europe
- GB to be a net importer from continental Europe over the winter, as both base load and peak load forward power prices show a premium in GB for the winter period – however, weather conditions and on-the-day events will determine actual flows
- there will be imports into GB at times of tight margins or stress on the GB system, provided by the market and/or NESO actions
- there will be periods when exports flow from GB to Europe, including over some peak periods, when we have sufficient operational surplus

We don't expect the interconnector market positions to provide exports to Europe if this would mean we were unable to meet GB demand. As the system operator for the electricity transmission system, we have a range of operational tools to manage peak demands, which remain vital in supporting security of supply. Included in these standard tools is the ability to trade on the interconnectors to secure the flows required to meet peak demands.

Did You Know?

The 1.4 GW Viking Link interconnector was the most recent link to be commissioned, in December 2023. There are projects in construction that will further increase the interconnection capacity into GB. These include:

- **Greenlink:** a 500 MW link to Ireland due to be commissioned by the end of 2024
- **NeuConnect:** a 1.4 GW link to Germany due to be commissioned in 2028

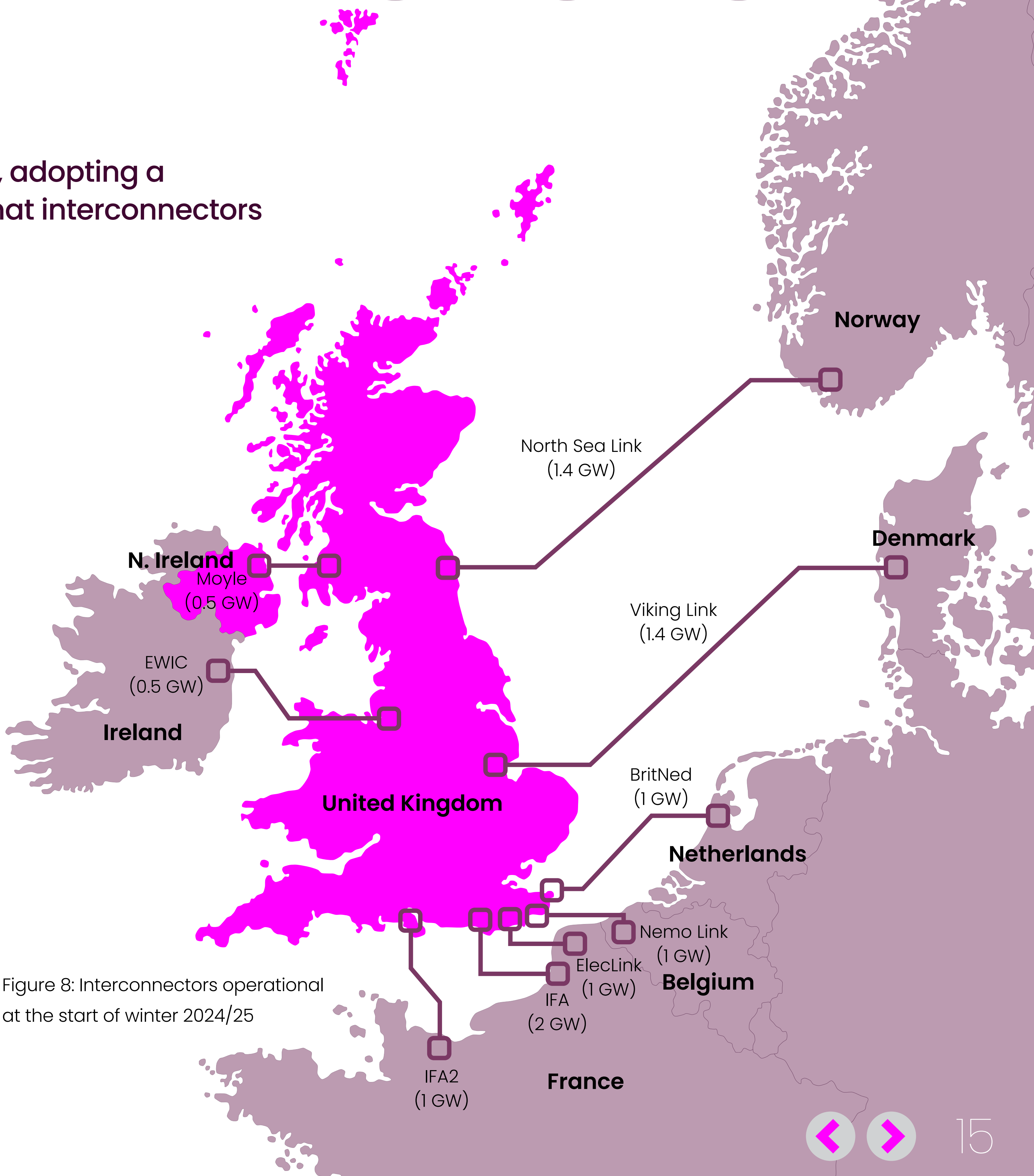


Figure 8: Interconnectors operational at the start of winter 2024/25

Interconnector Availability

There are minimal planned outages on the interconnectors scheduled for this winter, while the T-4 2024/25 Capacity Market has secured a net 6.6 GW of import capacity.

1 Planned Outages

Typically, assets including interconnectors undertake routine maintenance outside peak winter months when there is reduced risk of system stress. Therefore, there is minimal planned maintenance during winter 2024/25. The maintenance that is planned is short in duration and early in the season, when there is less risk of system tightness.

For the majority of the winter, we currently expect full availability of the interconnectors, providing key flexibility and security of supply for GB and Europe. Unplanned outages can also occur. We account for this by considering breakdown rates, which are factored into our modelling.

Table 3: Interconnector planned winter outages as of 20/09/2024

Interconnector (Capacity)	Connects With	Planned Winter Outages (Resulting Capacity)
IFA (2 GW)	France	09/09/24 – 24/10/24 (1 GW) 21/11/24 – 29/11/24 (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	N/A
North Sea Link (1.4 GW)	Norway	14/10/24 – 25/10/24 (0 GW)
ElecLink (1 GW)	France	06/10/24 – 09/10/24 (0 GW)
Viking Link (1.4 GW)	Denmark	N/A

2 Capacity Market Obligations

Interconnectors have secured agreements in the 2021 Capacity Market T-4 auction for delivery in 2024/25, as set out in Figure 9. In the event of extreme system stress leading to a Capacity Market event, we would expect to see at least 6.6 GW of net imports into GB. This is an increase of 1.5 GW from the previous winter due to new interconnection and increases in capacity, in line with Capacity Market methodology.

This is the first year in which Viking Link secured a Capacity Market contract, after commissioning in December 2023. Greenlink is commissioning in Q4 2024 and therefore does not hold a Capacity Market agreement for this winter.

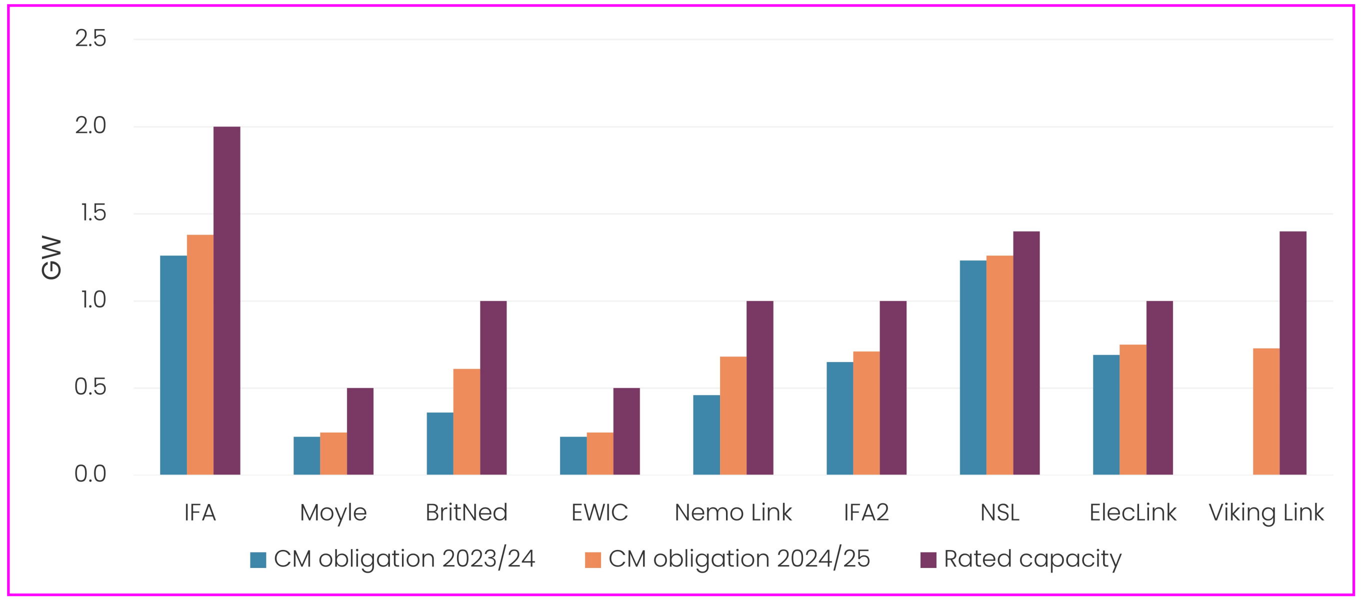


Figure 9: T-4 Capacity Market agreements for interconnectors in delivery year 2024/25

Energy Markets

Wholesale Power Prices and Spreads

Energy markets are showing signs of finding a new equilibrium. Wholesale prices for Great Britain are trading at a slight premium to other major European markets, which, along with interconnector auction results, indicate an import bias this winter.

Power flows through interconnectors are primarily driven by price arbitrage between the two markets. We expect GB to be a net importer this winter due to premium pricing compared to other interconnected markets. Analysing the results from long-term interconnector capacity auctions allows us to identify how market participants are valuing import and export capacity (see Figure 10). This further reinforces our view that GB will typically import this season, with import capacity in Q4 2024 valued significantly higher than export capacity on every interconnector with long-term auctions. Note that actual flows will be driven by prices, events and prevailing conditions closer to real time.

As a prudent system operator, we continue to monitor global energy markets and act as necessary to ensure continued security of supply. We use peak load prices (delivery weekdays 7am to 7pm) to assess how GB is pricing in relation to neighbouring markets at times of higher demand, when tight margins are mostly likely to occur, as seen in Figures 11 and 12.

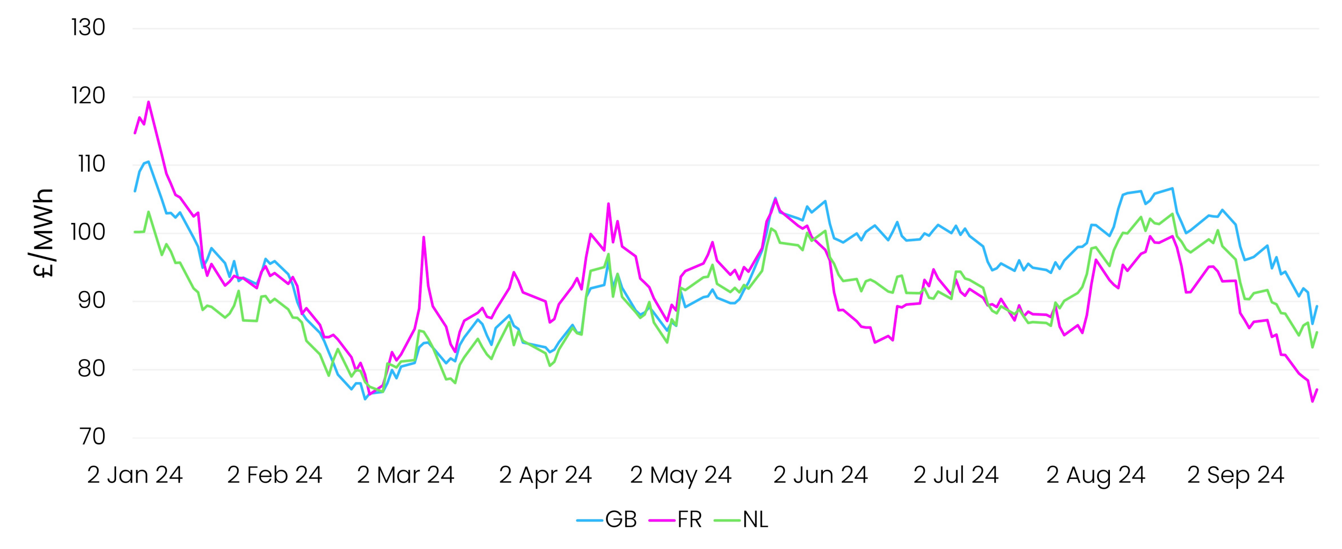


Figure 11: Price evolution of the Q4 2024 peak load power contract [2]

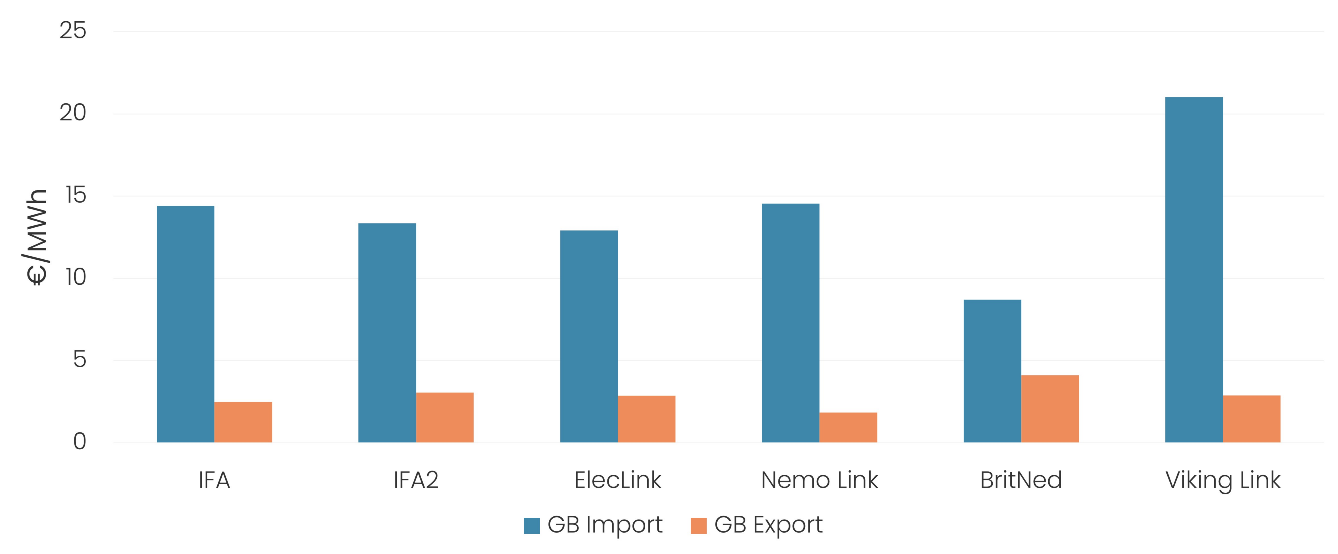


Figure 10: Most recent interconnector long term auction results Q4 2024 [1]

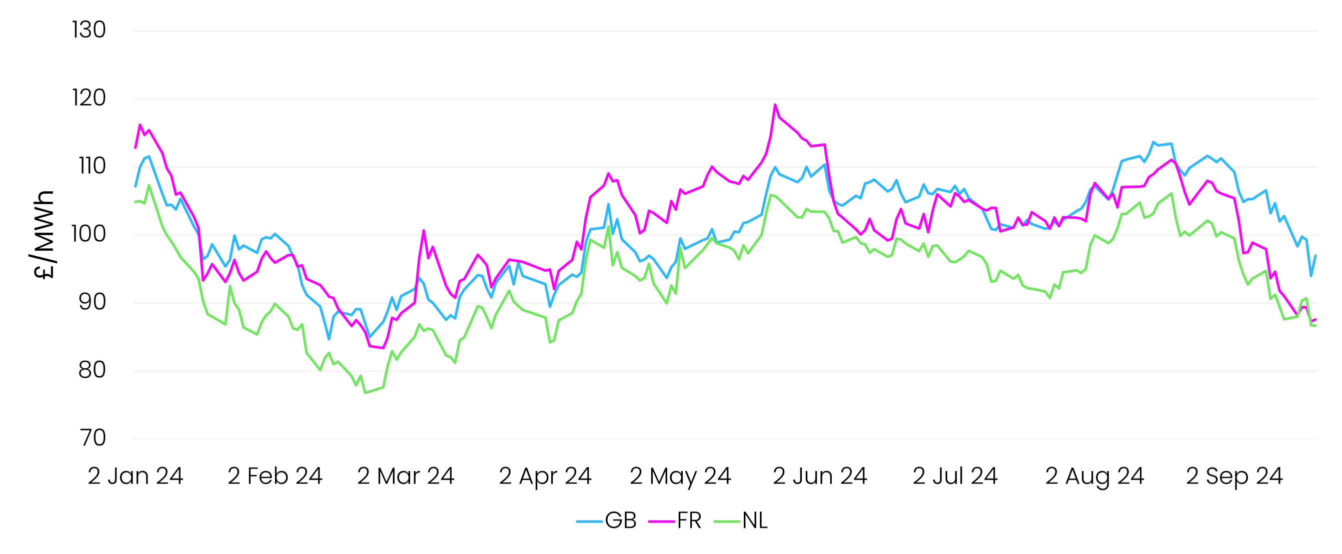


Figure 12: Price evolution of the Q1 2025 peak load power contract [2]

1 JAO Auctions.
2 Prices sourced from Argus. Lower liquidity means no peak load forward prices were available for Belgium, Denmark or Norway.

Power Fundamentals

Power prices in Europe are showing signs of stability, but uncertainties remain. Our analysis suggests healthy generation availability in key interconnected power markets when allowing for revisions and variations due to weather.

1 Nuclear Availability in France

French nuclear outages scheduled for winter 2024/25 are broadly within the historical range and mostly below the levels planned for last winter. Outages for this winter could be revised upwards, as shown historically by the green shaded range (actual outages) largely sitting above the grey shaded range (scheduled outages in the preceding September). When allowing for revisions, we still anticipate outages to be towards the lower end of the three-year history.

Nuclear availability in France was heavily constrained over winter 2022/23 due to corrosion issues, which forced several reactors offline. All high-risk reactors have now been repaired and returned to the grid, with the issues not expected to recur.

2 Hydroelectric Reserves in Norway

Norwegian hydro reservoir levels are above the historical mean, after slow filling at the start of the year. Reservoir stocks have recovered to 84% of capacity (as of 20 September 2024).

These reservoirs power hydroelectric generation, which is a prominent power source in the Nordics.

Steady hydro stocks limit the upside to Norwegian prices and increase the likelihood of consistent imports into GB via North Sea Link.

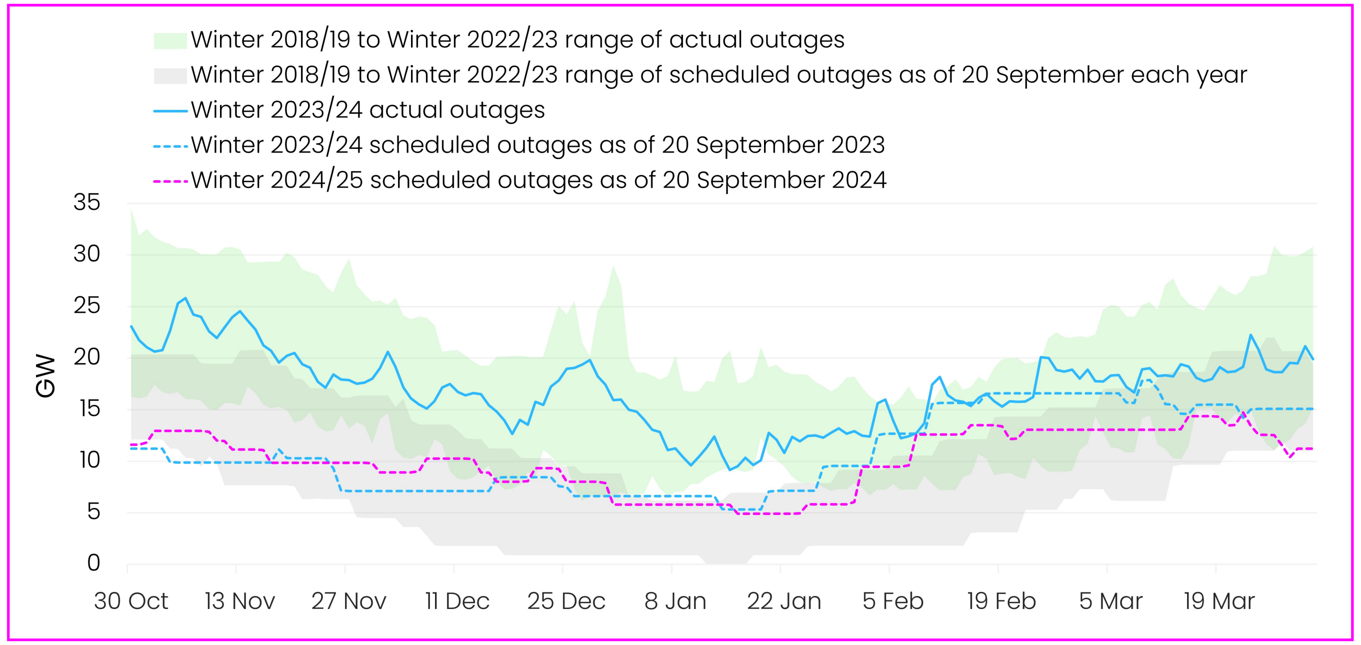


Figure 13: French nuclear outages over recent winters and scheduled for this winter[3]

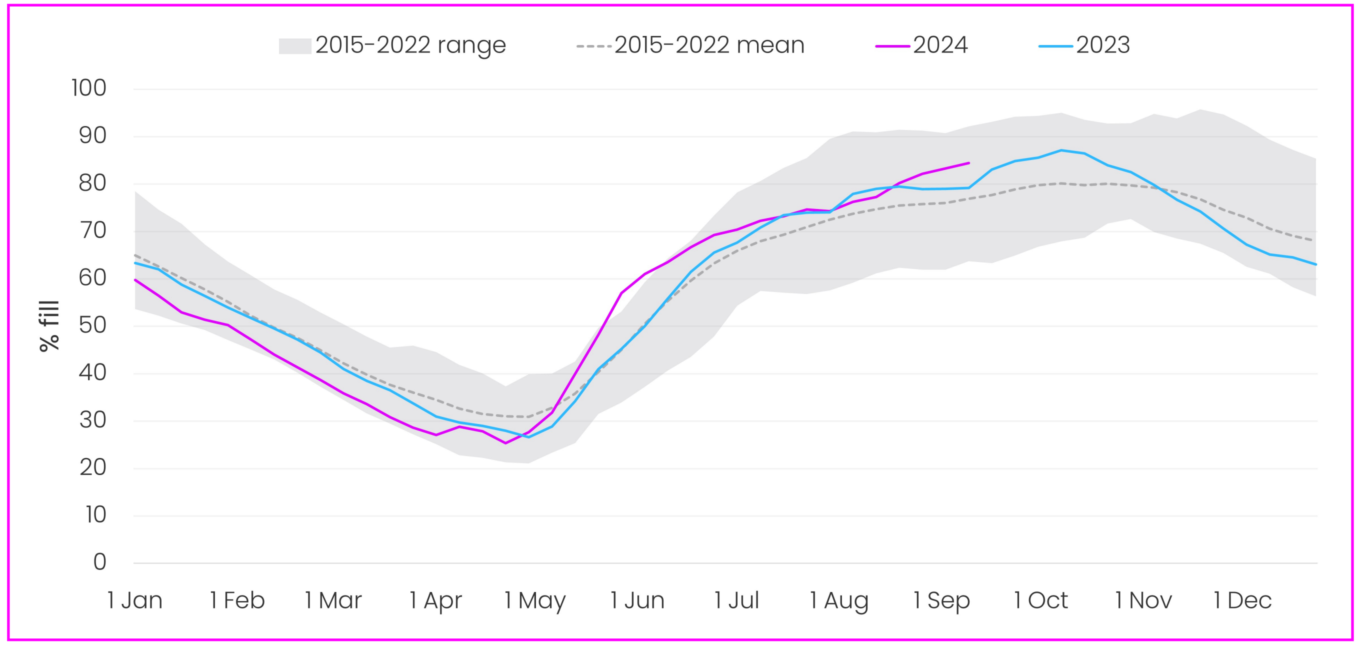


Figure 14: Norwegian hydroelectric reserves[4]

3 Indisponibilités des moyens de production
4 Water Reservoirs and Hydro Storage Plants

Gas Prices and Fundamentals

Structural changes in European gas markets have increased the resilience of the whole energy system. GB wholesale gas prices for this winter in the forward markets are below last year's and significantly lower than the highs seen over winter 2022/23.

1 GB and European Gas Prices

Figure 15 shows how the winter 2024/25 contract has traded lower in the approach to winter, compared to the evolution of the winter contract last year.

Prices for this winter have remained within a €9/MWh range, showing reduced volatility relative to the period from 1 June to 20 September 2023.

Increased European regasification capacity, from 263 bcm/y in October 2022 to 324 bcm/y by the end of 2024, has diversified the entry points for gas into Europe. This has improved the resilience of the whole energy system to supply-side shocks, but Europe remains exposed to potential price spikes resulting from a shortfall in global LNG.

2 European Gas Storage

Figure 16 shows that aggregate EU gas storage is in line with last year's levels and above EU-mandated targets (as of 20 September 2024).

The European Commission has set intermediate gas storage targets for EU member states to ensure that 90% of storage is filled by 1 November 2024.

EU gas storage levels serve as a good proxy for the state of the European gas market. High stocks heading into winter give the market a greater cushion to manage supply shocks or high-demand events like a cold winter.

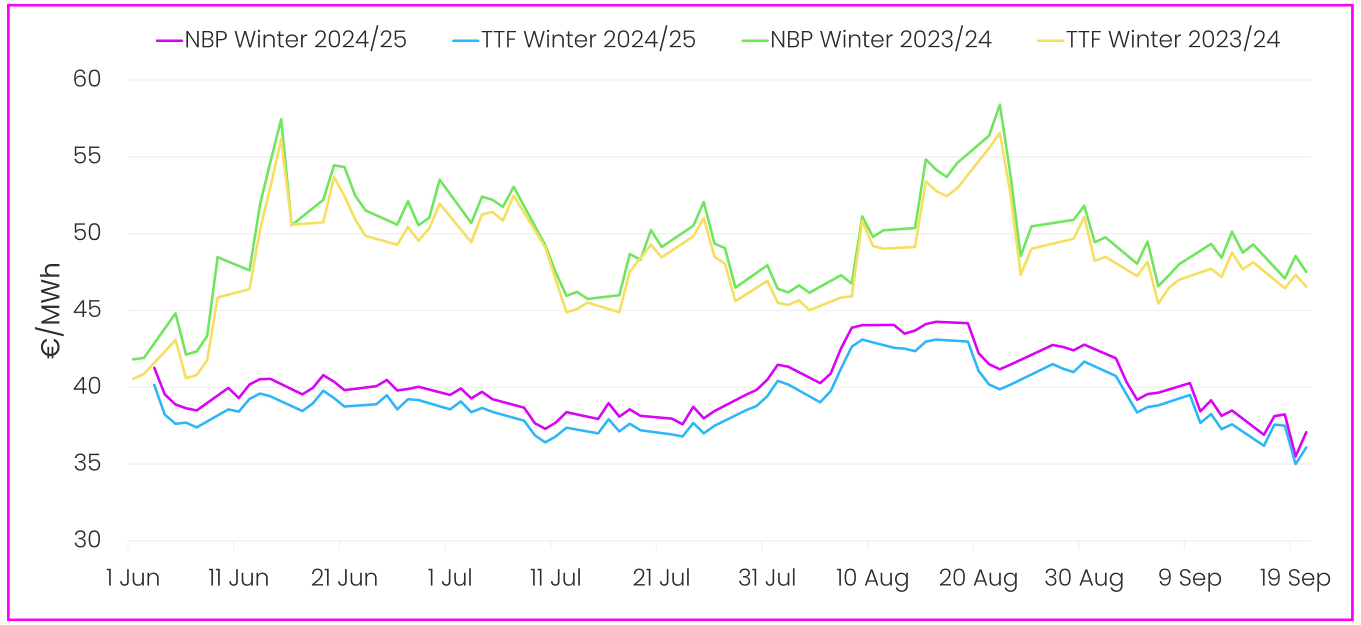


Figure 15: Evolution of NBP (GB gas hub) and TTF (European gas benchmark) winter 2023/24 and winter 2024/25 contracts from Argus

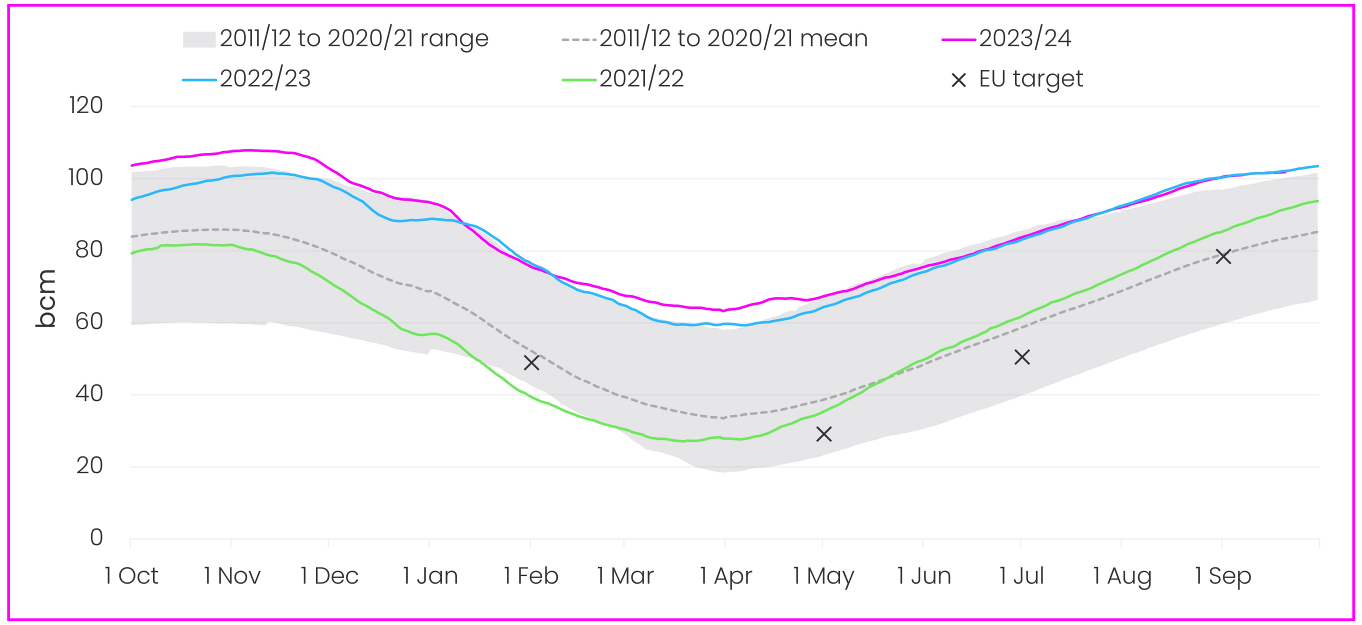
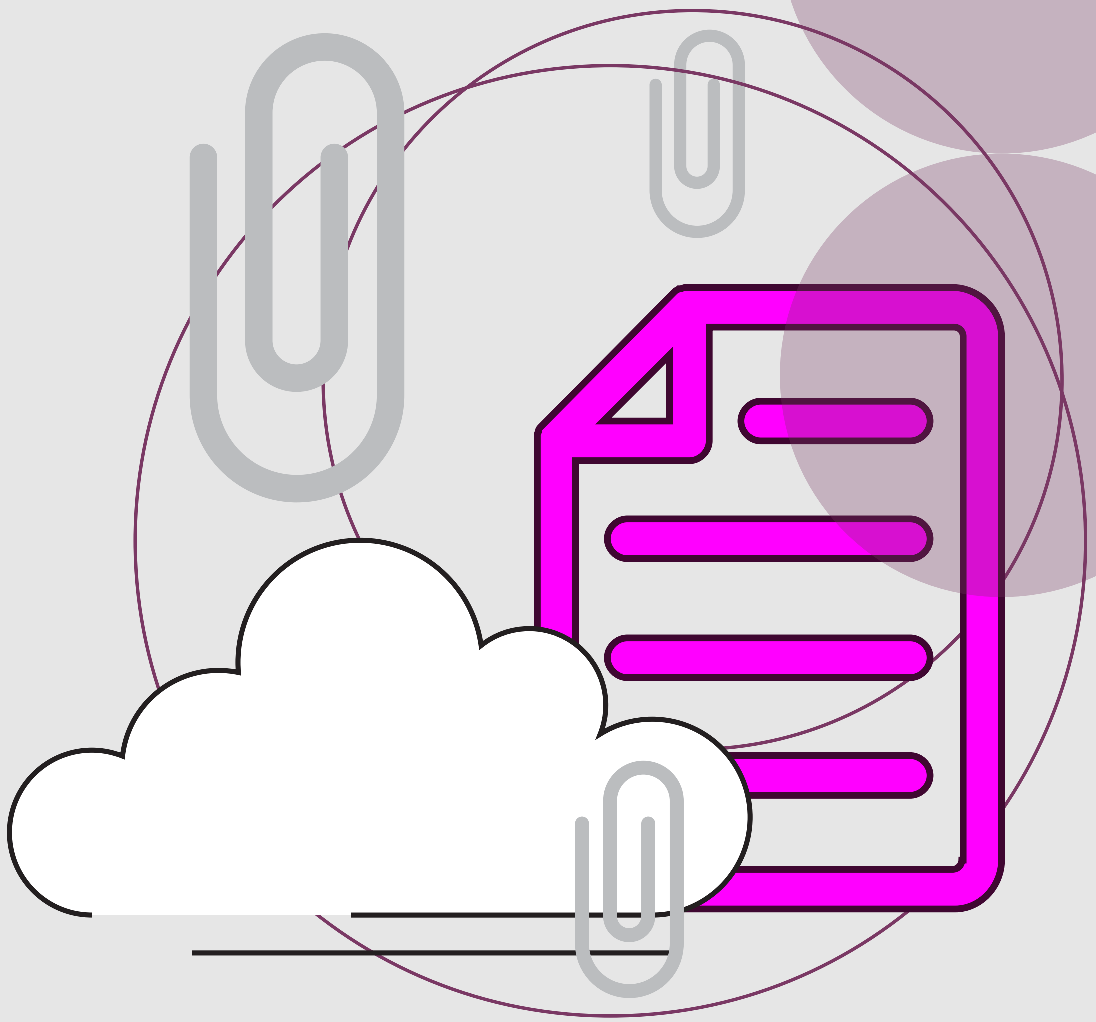


Figure 16: Aggregated EU gas storage[5]

5 EU Aggregated Gas Storage Inventory

Appendices

Contains additional information on demand definitions, margin notifications and how we construct our operational surplus assessment.



Appendix A: List of Figures and Tables

Figures

Tables

Appendix B: Relationship between Types of Demand

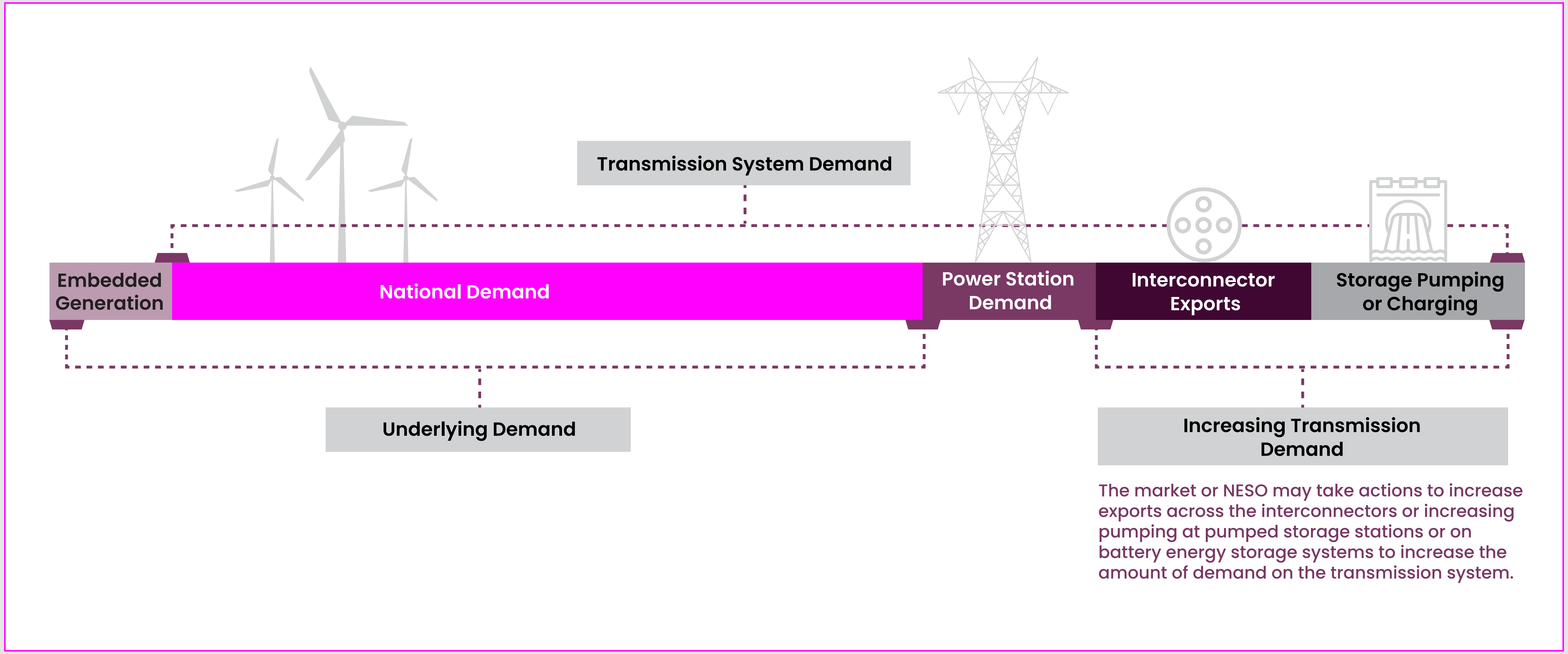


Figure 17: Shows the relationship between some of the different types of demand

Appendix C: Capacity Market Notices and Electricity Margin Notices

Electricity Margin Notices (EMNs) and Capacity Market Notices (CMNs) are used to highlight to market participants when margins are looking tight ahead of real-time. They are intended to stimulate a market response through, for example, additional generation being made available. They do not indicate that demand will not be met.

Margins on the electricity system can vary throughout the winter, depending on actual weather patterns and outages taken by generators.

This report includes two views of peak adequacy (often called margin). 'De-rated margins' are based on whole system demand and whole system capacity (including Distributed Energy Resources (DERs)).

As the majority of DERs are not visible to NESO, the 'operational surplus' is based on transmission system demand and transmission system capacity. The EMN process is based on the operational surplus (or operational margin) and the CMN process is based on the Capacity Market margins.

The EMN and CMN processes both rely on the visible generation, as that is the data provided to NESO.

While EMNs and CMNs are based on the same fundamental data – for example, generator availability and demand forecasts – there are several significant differences between them:

- **Trigger:** CMNs are issued based on an automated system margin calculation using data provided by market participants, whereas system notices (including EMNs) are manually issued by the Electricity National Control Centre (ENCC) using engineering judgement. Both EMNs and CMNs are based on actual margins, and not the de-rated margins used in the *Winter Outlook Report*. Generally, an EMN would be issued before a CMN.
- **Threshold:** CMNs are automatically triggered when the volume of available generation less forecast demand and reserve is less than 500 MW. This threshold is defined in the Capacity Market Rules. EMNs are issued by our control room using operational and engineering judgement and are based on our experts' experience, skill and knowledge of managing the electricity system. If, taking account of a range of factors they have a live view of in the control room, we can see that our normal safety margin for operating the system is not as large as we would like, then we would consider issuing an Electricity Margin Notice (EMN). This does not mean we do not have enough electricity to meet demand; it just means we would like a larger cushion of spare capacity and want the market to provide it.
- **Constraints:** The CMN calculation does not take account of any transmission system constraints that may be preventing capacity from accessing the network. Other system notices, however, do take such constraints into account.
- **Lead time:** CMNs are initially issued four hours ahead of when the challenge is foreseen, whereas other system notices can be issued at any time. However, we would expect to issue a first EMN at the day-ahead stage. This means that EMNs and CMNs can sometimes be issued and active at different times. That is normal – they are different signals being communicated to different parts of the electricity market.

Visit What are system notices? on our website for more information.

Appendix D: Capacity Modelling Updates

Next year, we are planning to evolve our Capacity Assessment (CA) Model process and the related set of tools. We regularly update our modelling to reflect changes to the electricity system.

The CA Model to date has used an inherently 'time-collapsed' approach, which generates a discrete probability distribution of the available capacity forms, comparing it to weather-driven demand and renewable energy variations.

To enhance our analysis capabilities, we will be evolving the CA process towards a time-sequential modelling simulation, which will improve the representation of the temporal nature of storage and more accurately capture demand and renewable energy dependencies, while still producing the same headline metrics of Margin and LOLE.

This transition will enable us to refine our technical analysis, providing more accurate insights into GB system adequacy and the contribution of diverse forms of capacity to security of supply, embedding an extensible modelling foundation as the nature of the wider GB energy system changes. We plan to publish more information in due course.

Appendix E: Operational Surplus Analysis

Our operational surplus analysis represents the market's current intentions, based on market submissions before we take actions. This analysis is based on market submissions as of 20 September 2024. It includes notified plant outages, as well as weather conditions, and de-rates generation using a historical breakdown rate to reflect the potential for unplanned outages.

It is a dynamic view that changes throughout winter and, as such, we will be providing regular updates at NESO Operational Transparency Forum. Our operational modelling helps to identify when tight periods are most likely to occur and to indicate when we may need to use our operational tools to manage margins. The periods of tightest margins do not necessarily occur at times of peak demand, but rather when supply is lowest relative to demand.

How the Operational Surplus is Calculated and Used

For the operational surplus analysis, we plan based on the operational data submitted to us. We are not just looking at the capacity provided via the Capacity Market (a market tool that helps to prepare us for winter), but also at the supply that is forecast to be available on a day-by-day basis. To do this, we need to consider a more granular view of the winter.

We consider a daily view as we get closer to real-time and start assessing these daily views in July, ahead of the *Winter Outlook Report* publication in October. The *Winter Outlook Report* includes a daily view of margins for the winter, as well as information on the effects of variability and the likelihood of tight operational margins.

The operational data includes information relating to planned plant outages, the impact of weather – for example, on wind and demand – and flows on interconnectors. As generators can also have unplanned outages, we apply breakdown rates based on averages from the last three winters. In addition, we study the effects of variability in all relevant factors, particularly weather, renewable resources and unplanned outages. The operational data may differ from the assumptions based on historic data or long-term averages used for the winter view of margin.

The operational surplus also considers grid constraints and largest loss requirements.

The operational surplus helps us to identify when we might have tight periods. However, the operational data provided to us changes throughout the winter. Some tight periods may be apparent a week in advance; others may not become apparent until much closer to real-time, for example, a day ahead or on the day itself.

These assessments of security of supply are used to support decisions taken in operational timescales, including whether to issue an EMN as described in Appendix C.

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.

Balancing Mechanism (BM)

The Balancing Mechanism is NESO's primary tool to balance electricity supply and demand on GB's network. It allows participants to set prices at 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.

Breakdown rates

A calculated value to account for unexpected generator unit breakdowns, restrictions or losses. Forecast breakdown rates are applied to the operational data provided to NESO by generators. They account for restrictions and unplanned generator breakdowns or losses close to real time. Rates are based on how generators performed on average by fuel type during peak demand periods (7am to 7pm) over the last three winters.

BritNed

BritNed Development Limited is a joint venture between Dutch TenneT and British National Grid that operates the electricity interconnector between GB and the Netherlands. It is a bi-directional interconnector with a capacity of 1 GW. You can find out more at britned.com.

Capacity Market (CM)

The Capacity Market 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 Capacity Market 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)

The Demand Flexibility Service (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 for electricity
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 that links the electricity transmission systems of Ireland and GB. You can find out more by visiting Interconnection on the EirGrid website.

Eleclink
A power interconnector through the Channel Tunnel to provide a transmission link between GB and France with a capacity of a 1 GW in either direction of flow.

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)
An assessment of the entire wind fleet's contribution to capacity adequacy. It represents how much of 100 per cent available conventional plant could theoretically replace the entire wind fleet and leave security of supply unchanged.

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.

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 GB 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 the French and British transmission systems. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).

Interconnexion France–Angleterre 2 (IFA2)
A 1GW interconnector between the French and British transmission systems. Commissioned in 2021, it is the second link to France that National Grid has developed with RTE. You can find out more at IFA2 | IFA1 Interconnector.

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. 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 GB and Belgium.

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 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 HVDC sub-sea link from Norway to GB commissioned in October 2021. Find out more at northsealink.com.

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 can require 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.

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.

Transmission System Demand (TSD)
TSD is equal to National Demand plus the additional generation required to meet station load, pumped storage demand and interconnector exports.

Viking Link
Viking Link is a 1.4 GW high voltage direct current (DC) electricity link between the British and Danish transmission systems, connecting at Bicker Fen substation in Lincolnshire and Revsing substation in southern Jutland, Denmark.

Weather-corrected demand
The demand expected or outturned with the impact of the weather removed. A 30-year average of each relevant weather variable is constructed for each week of the year. This is then applied to linear regression models to calculate what the demand would have been with this standardised weather.

Get in Touch

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

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The *Winter Outlook Report* is part of a suite of documents prepared by NESO. Visit neso.energy for more information.

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