

Winter Outlook Report

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

September 2023

Welcome



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Director, Electricity System Operator

Welcome to our 2023/2024 Winter Outlook. Despite the ongoing conflict in Ukraine, the broad European energy situation has improved since last year. The market has responded bolstering European gas storage and supplies and the French nuclear fleet capacity is back to pre-pandemic levels.

We have built on our experience of winter 2022/23, and continued to build resilience and minimise the potential impact of credible risks and uncertainties in the energy markets should they arise.

To support the energy industry's preparations for this winter, this year's Winter Outlook sets out our view for winter and the steps we have taken to ensure we are well prepared.

Our central view, as set out in the Base Case scenario in this document, is that there will be adequate margins (4.4GW / 7.4%) through the winter to ensure Great Britain remains within the reliability standard¹.

This represents a slight increase on the margins forecast across last winter and is

broadly in line with recent winters. We do however expect that there will be some days where we will need to utilise many of the tools in our operational toolkit, including the use of system notices².

However, we have seen that the energy markets performed as expected over the last year and there is currently no reason to doubt this won't be the case for this winter.

As a prudent system operator, we cannot completely discount risks of credible events occurring. It is therefore important that we prepare and plan for a wide range of eventualities.

Alongside our Base Case we have stress tested the impact of credible GB and EU energy market events on the system against the backdrop of operational tools available to us.

We have also announced our intention to reintroduce the innovative Demand Flexibility Service for this winter, to incentivise customers to reduce consumption at periods when margins

are tightest.

As the ESO is responsible for the balancing of national electricity supply and demand, this document only covers the electricity outlook for the winter ahead.

This report covers the period from 30 October 2023 to 30 March 2024. The data freeze date for this outlook was 14th September 2023.

The Gas Winter Outlook published by National Gas Transmission can be found on their website [here](#).

For more information, you can email us at marketoutlook@nationalgrideso.com

¹ The reliability standard is 3 hours Loss of Load Expectation (LOLE). Modelling shows the Base Case LOLE to be 0.1 hrs, well within the standard.

² These would include Electricity Margin Notices (EMNs), Capacity Market Notices (CMNs) etc.

Key Messages / Winter Outlook 2023/24

1. Margins

Margins are slightly higher than last winter under our Base Case. Under normal market conditions margins are expected to be adequate and within the Reliability Standard.

Our Base Case margin is 4.4 GW / 7.4%, which is slightly higher than last year and broadly in line with recent winters. The associated loss of load expectation (LOLE) is 0.1 hours.

We expect there to be sufficient operational surplus in our Base Case throughout winter.

There may be some days when margins are tighter and we may need to use the tools in our standard operational toolkit, including use of system notices.

2. Reciprocal support with neighbouring countries

We will continue to work closely with our neighbours in Europe, adopting a coordinated approach providing reciprocal support.

Close co-operation between European system operators through reciprocal support has played an important role in helping maintain secure supplies for customers in Great Britain and Europe.

This will continue this winter, leading to periods when imports flow from Europe when we need them, provided by the market and / or ESO trading, which is an important operational tool for us.

Where there is sufficient market surplus, we expect there to be periods when exports flow from Great Britain to Europe, including over some peak periods.

3. Winter preparations

We have taken steps to build resilience and minimise the potential impact of further risks and uncertainties in the energy markets.

We continue to actively engage with Government, Ofgem, National Gas Transmission and industry stakeholders to ensure we understand and mitigate any emerging risks for winter and that we are well prepared.

We have also announced our intention for the return of the Demand Flexibility Service that incentivises customers to voluntarily flex the time they use energy to help us manage the system this winter.

Winter Preparedness

We have worked closely with Government, Ofgem, National Gas Transmission and other stakeholders to take steps to build our resilience and minimise the potential impact of any further risks and uncertainties arising in GB and European energy markets.

While our Base Case margin is slightly higher than last year, risks and uncertainties remain in global energy markets. Markets have responded, lessening the risks since last winter, and we are continuing to actively monitor potential developments. For example, two notable differences compared with last winter are that European gas storage stocks are much higher than this time last year (see National Gas Transmission's [Winter Outlook Report](#)), and the availability of the French nuclear fleet is also expected to be higher (page 17).

As a prudent system operator we continue to prepare and plan for a wide range of eventualities. This ensures we have the tools we need to operate the system safely and helps to minimise the impact on electricity customers in Great Britain. We have continued to work actively with Government, Ofgem, National Gas Transmission, and other stakeholders to build resilience ahead of this winter. To prepare for winter we have:

- Announced our intention for the return of the Demand Flexibility Service
- Continued to work closely with neighbouring transmission system operators in Europe as we take a coordinated approach to provide reciprocal support to each other that benefits all electricity customers
- Continued to work closely with Transmission Owners in GB to minimise the impact of network outages over winter
- Taken steps to improve our ESO emergency actions and tools through changes to the Grid Code

Demand Flexibility Service (DFS)

We recently announced our intention for the return of DFS used last year and have submitted our proposal for this year's service to Ofgem for approval.

DFS incentivises consumers, as well as industrial and commercial users, to voluntarily flex the time they use their electricity to help manage the system this winter.

Last winter, DFS successfully saved over 3,300MWh across 22 events, enough to power nearly 10 million homes. This year, we're committed to developing DFS even further and are keen for more consumers and businesses, large and small, to take advantage of this opportunity to reduce their energy bills and carbon footprint.

Alongside potential live uses of the service to balance the network this winter, we're running 12 incentivised test events that consumers and businesses can participate in. Electricity suppliers, aggregators and businesses who directly contract with us will receive a guaranteed acceptance price of £3/kWh for at least six of the test events, subject to registered volumes from January 2024.

Want to learn how DFS can benefit your business? [Find out more](#)

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Base Case / System margins

Margins are expected to be adequate and within the Reliability Standard under normal market conditions. Our Base Case margin is 4.4 GW / 7.4%, which is slightly higher than last year.

The de-rated margin of 4.4 GW (7.4%) is similar to the levels in recent years, but slightly higher than last year (see page 9 for the drivers of the difference).

- The Base Case loss of load expectation (LOLE) is 0.1 hours/year, which is within Reliability Standard of three hours per year set by Government.
- Margins are slightly lower than in the Base Case in our [Early View of Winter](#), which had a de-rated margin of 4.8 GW (8%). Since the Early View we have revised our demand-side response (DSR) assumptions. Upon review, we now believe that a portion of the DSR included in the Early View (around 350 MW) would be more likely to come through the Demand Flexibility Service (DFS) and so we have now excluded this from our Base Case margin here.
- Our Base Case assumes all providers with Capacity Market (CM) agreements deliver in line with their obligations unless we have specific market intelligence otherwise (e.g. notified outage on REMIT). This includes generators, storage, interconnectors and DSR providers. We assume interconnectors can provide 5.1 GW net imports at times when we need them to meet demand, in line with their CM agreements.
- Our Base Case assumes that there is no disruption to gas supplies.
- Our Base Case does not include any contribution from enhanced actions or out-of-market services such as the Demand Flexibility Service.

We still expect that there could be some tight periods this winter where we need to use our standard operational tools - such as issuing Electricity Margin Notices (EMNs). Capacity Market Notices (CMNs) may also be triggered. See [Appendix B](#) for more information on EMNs and CMNs. We expect there to be sufficient available supply to respond to these signals to meet demand.

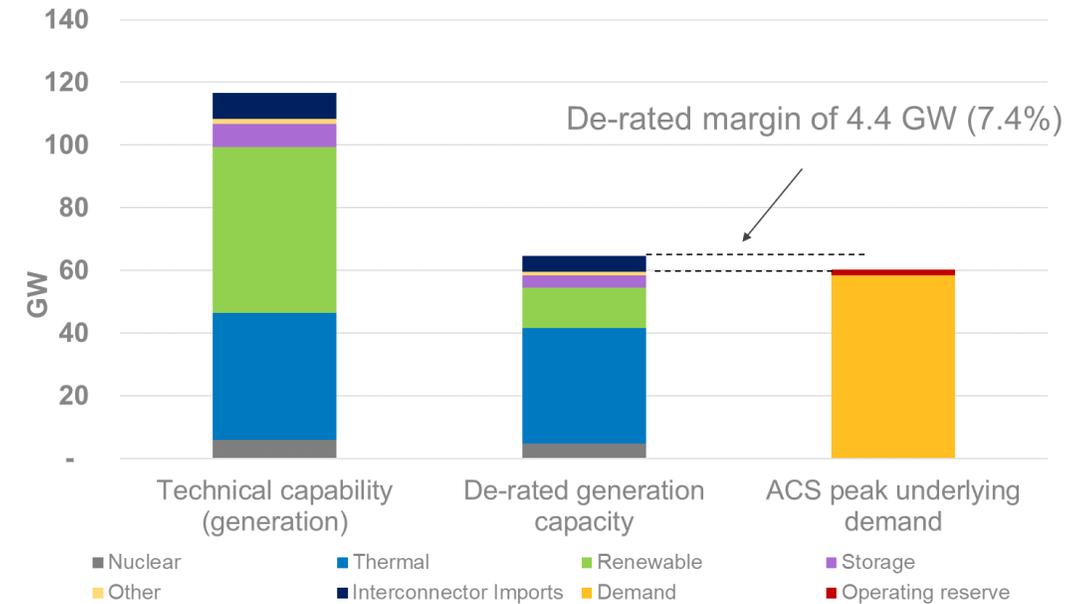


Figure 1. Supply margin in relation to generation capacity and demand

Base Case / Operational Surplus

Our base case operational view shows sufficient operational surplus for each week of winter.

This winter we expect

- normalised weather corrected national demand¹ to be met in the Base Case before using any operational tools.
- Average Cold Spell (ACS) demand to be met under our base case but we may still need to use our operational tools (e.g. system notices).
- normalised peak demand to occur in the first two weeks of January, based on our latest forecasts.
- the minimum operational surplus to be lowest in early January when the demand forecasts are combined with current generator submissions.

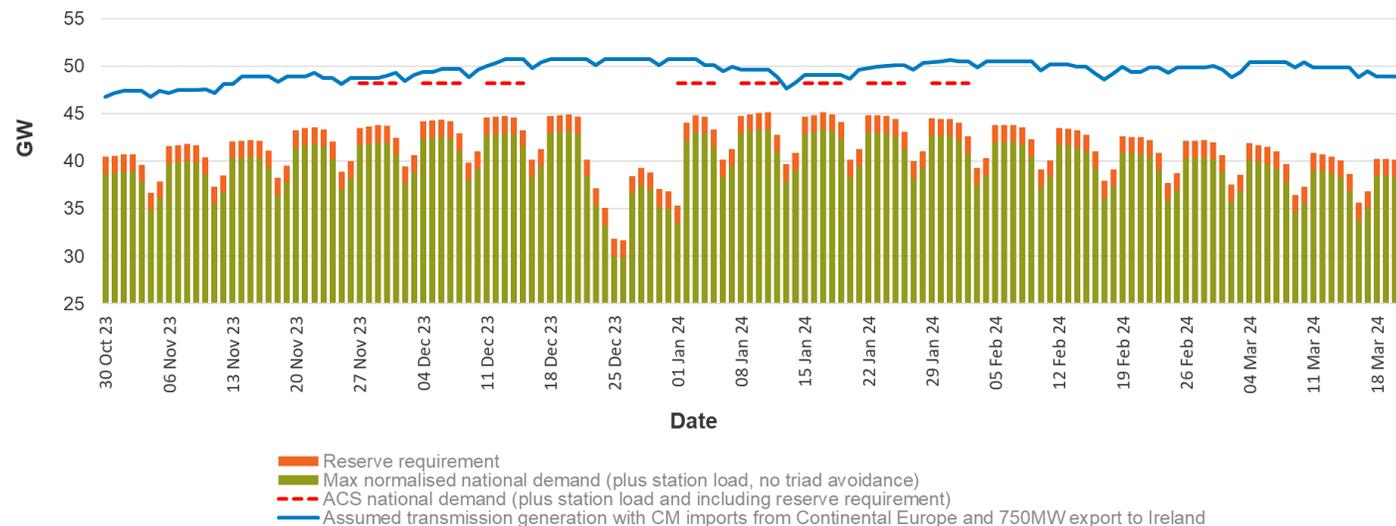


Figure 2. Day-by-day view of operational surplus for winter 2023/24 (based on market data submissions from 14th September 2023)

How our assessments are developed

As we get closer to winter, we move from an assessment that considers the winter as a whole, to one where we consider margin on a day-by-day basis, as in Figure 2. This is our operational modelling, and is closer to the perspective used in our control room. It includes actual plant outages, and is based on normalised national demand and transmission generation, therefore representing what the market is currently intending to provide. Transmission constraints are not included. 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. These periods do not necessarily occur at times of peak demand. This view will change throughout winter, based on weather, changes to plant outages, and price differentials that drive interconnector flows. The operational surplus is a conservative scenario, especially with regard to wind generation where the Effective Firm Capacity (EFC) level is used. Our [2022-23 Winter Review](#) report shows that last winter there were only a few days when the EFC was not exceeded at peak.

Our Base Case operational view assumes imports from Continental Europe in line with Capacity Market agreements. It also assumes 750 MW exports to Ireland, which is based on long-term historic flows. However, we have observed that the flows on interconnectors to Ireland have become much more variable in recent years and could reverse direction in the event of tight periods in Great Britain, responding to market signals. Our Base Case operational view does not include potential market responses to higher demand or tighter conditions, such as power stations increasing their output levels for short periods. Nor does it include our mitigation measures for winter (i.e. the Demand Flexibility Service). During periods of low operational surplus, generators may be incentivised to reschedule planned outages by Capacity Market obligations or through revenue opportunities from higher market prices. ACS 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. See [Appendix C](#) for more details on our analysis.

Base Case / Credible Range

We expect to have sufficient operational surplus throughout winter in our Base Case, even when we consider the expected natural variation of demand, wind and outages.

This winter we expect

- to have sufficient operational surplus throughout winter but there may be times when we need to use our standard operational tools.
- the tightest margins to occur over the period between late November to mid-January (excluding the Christmas period).

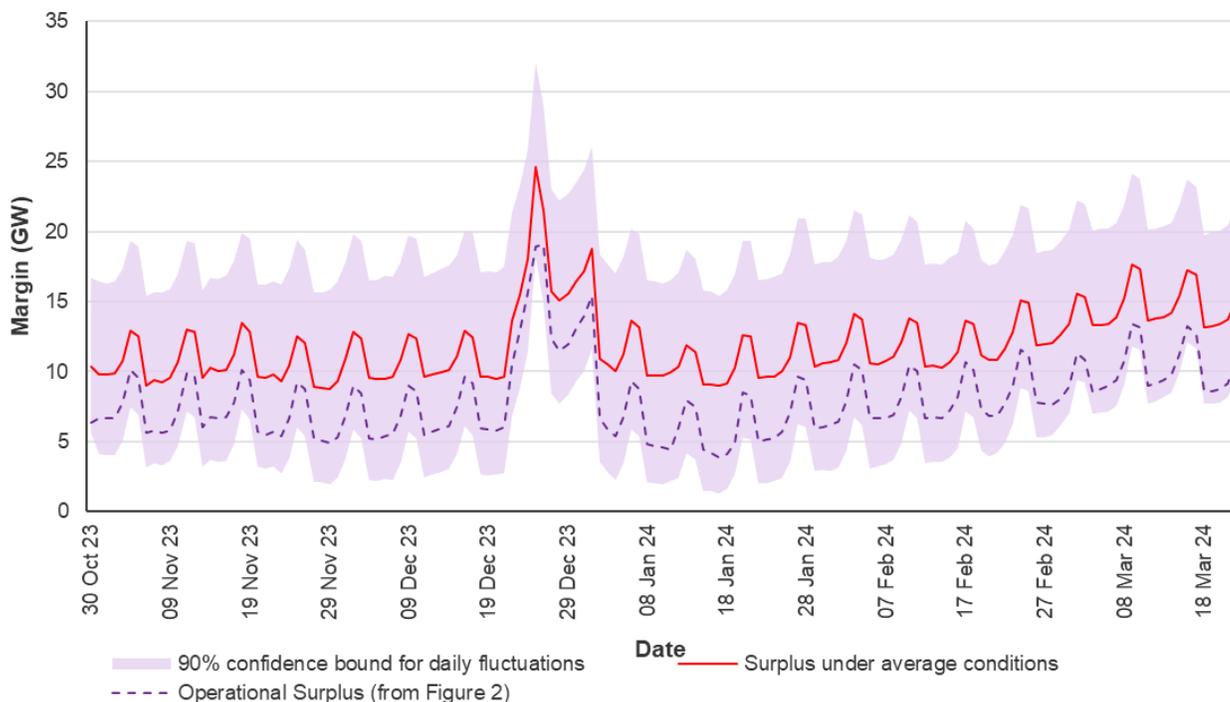


Figure 3. Range of outcomes for the daily operational surplus in our Base Case under different supply and demand conditions

How our assessments are developed

Figure 3 shows the forecast of daily surplus under our Base Case, with the shaded area representing the credible region within which the surplus can fluctuate. As with other Base Case assessments, we do not include any actions that could be taken by the ESO.

The analysis considers a situation under typical conditions, using average weather conditions for demand, average availability for conventional generation and average wind conditions. This is shown by the solid red line.

To explore the variation around this central view, we simulate tens of thousands of scenarios to consider variations in weather, demand, conventional generation availability, wind generation output and interconnector availability. This means our assessment considers cold days with low wind. For each of these scenarios, we calculate the daily surplus across the entire winter for that scenario.

From this range of simulations we calculate the ‘credible range’, which has been defined as the 90% confidence bound for the day-by-day fluctuations in surplus (covering between the 5th and 95th percentile). It is important to note that, although on any given day the fluctuation can reach the lower bound (or dip below it), it is not credible that surplus will remain at the lower bound level for the entirety of the winter.

The modelling here considers the natural variation of forced outages. Planned outages are assumed to be in line with those declared through REMIT at the time of the data freeze for this report (14th September 2023). This modelling also assumes that, for continental interconnectors, market forces will allow flow into GB of whatever interconnector capacity is available after unplanned outages.

For comparison, we have included the operational surplus from Figure 2 as a dashed purple line within the shaded region. It is towards the lower end of the shaded region because the view in Figure 2 is a relatively conservative scenario with wind represented by its Equivalent Firm Capacity (EFC). The EFC is a relatively low level of wind, and our [2022-23 Winter Review and Consultation](#) showed wind output at peak only fell below this value on a handful of times last winter. See the Supply section on page 13 for more information on the wind EFC.

Base Case / Comparison to last winter

The de-rated margin in our Base Case for this winter is slightly higher than last year and broadly in line with margins of recent winters.

The de-rated margin in our Base Case for this winter is 4.4 GW (7.4%), which is slightly higher than last year's margin of 3.7 GW (6.3%).

The main drivers of the increase are:

- more generation being available, which includes additional capacity from units that were partially or fully unavailable last winter plus one of the coal contingency units returning to the market;
- more battery storage and demand-side response since last winter, reflecting delivery through the Capacity Market and improved quality of our data sources.

These are partially offset by:

- lower assumptions on electricity interconnectors reflecting their Capacity Market agreements for this winter;
- lower de-rating factors for storage that better align to the latest values in the Capacity Market;
- an increase in our assumptions for ACS peak demand including operating reserve.

Figure 4 shows the de-rated margins included in previous Winter Outlook Reports and highlights how this year's de-rated margin is broadly similar to those in recent winters (e.g. 2020/21, 2021/22 and 2022/23).

The range of daily operational surplus is also higher compared with last year. This is shown in Figure 5 where the red shaded region shows the credible range for this year and the blue/grey shaded region shows the corresponding range for last year. The biggest differences are in the second half of November and in December, while January is much closer. This reflects the higher surplus for winter a whole, but with the tightest period moving from December to January due to the particular generation outage patterns this year.

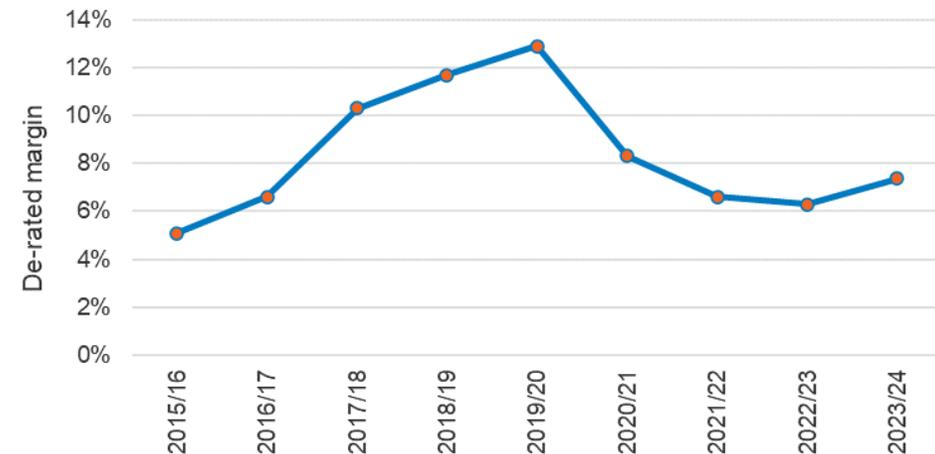


Figure 4. Historic de-rated margin forecasts made ahead of each winter in the Winter Outlook Report (i.e. not out-turns)¹

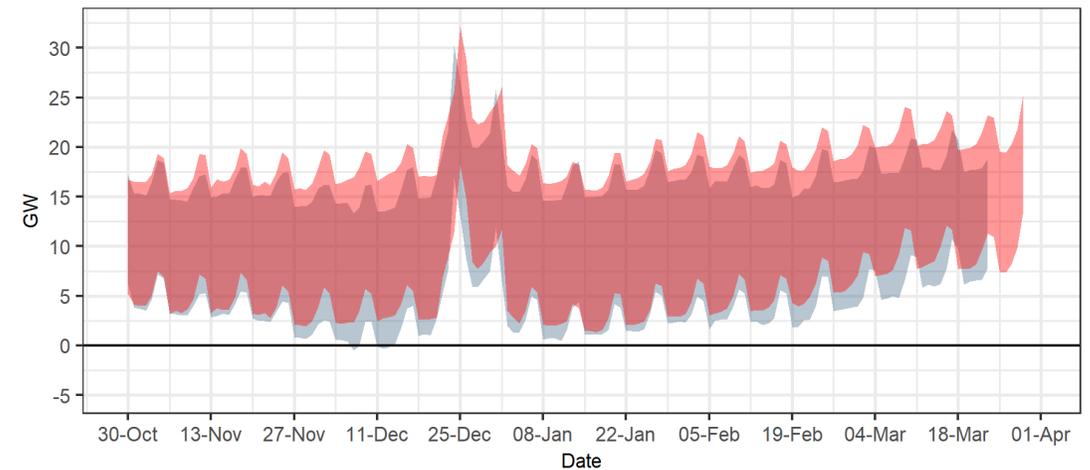


Figure 5. Daily credible range of operational surplus for this winter (red plume) compared with the credible range in last winter's outlook report (blue/grey plume)

¹ Includes additional reserves (Supplemental Balancing Reserve and Demand Side Balancing Reserve – SBR and DSBR) of 2.4 GW and 3.5 GW procured in 2015/16 and 2016/17 respectively.

Winter scenarios

As a prudent system operator we continue to prepare and plan for a wide range of eventualities, even those that may be considered less likely. This helps to minimise the potential ongoing impact on customers from Russia’s illegal invasion of Ukraine and ensures we have the tools we need to operate the system safely.

While our Base Case margin is higher than last year, risks and uncertainties remain in global energy markets due to the ongoing impact of Russia’s illegal invasion of Ukraine.

In last year’s Winter Outlook Report, we set out two illustrative scenarios showing the impact in the event of there being reduced electricity imports from Europe and reduced electricity imports from Europe combined with insufficient available gas supply in Great Britain.

There are some notable differences in the energy market outlook for this winter compared with last year. For example, European gas storage stocks are now much higher than 12 months ago and National Gas Transmission’s [Winter Outlook Report](#) suggests that it would take a combination of events (e.g. a very cold winter in the UK coinciding with a major interruption to one of our gas supply sources) for there to be a material risk to our gas system such that they consider this to be an unlikely scenario. Furthermore, the availability of the French nuclear fleet is also expected to be higher this winter.

Nevertheless, last winter was generally mild, particularly in Europe, and even though market prices have fallen since last year, they remain higher than in recent years and as such it is important that we plan for a wide range of eventualities should risks and uncertainties materialise.

In Figure 6 we illustrate a hypothetical scenario in which there are materially reduced electricity supplies totalling around 4 GW (which could arise from unexpected reduced output from GB generation and/or reduced imports available from Europe¹). Our assessment shows that adequate margins can be maintained by deploying our Demand Flexibility Service. Margins would be within the Reliability Standard with a fairly moderate take-up of DFS (up to around 1 GW). Higher take-up of DFS (around 2 GW) would provide even greater resilience.

We continue to plan for a wide range of eventualities and should there be insufficient supplies due to unexpected exceptional events, even after we deploy all mitigating measures including DFS, then there are available further emergency measures which could be enacted, including planned, controlled and temporary rota load shedding.

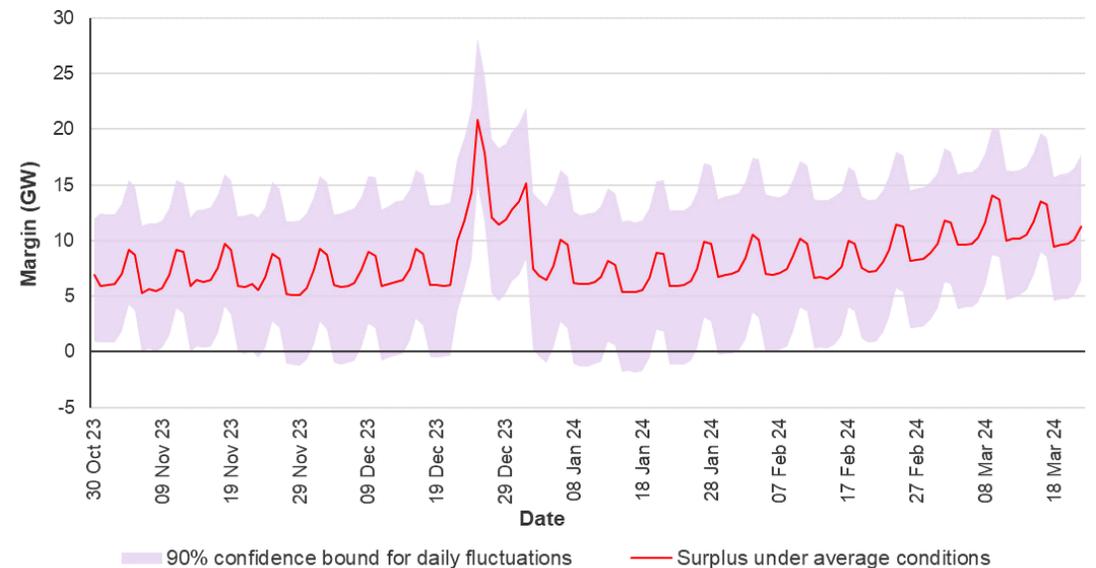


Figure 6. Credible range of daily operational surplus for an illustrative scenario of reduced electricity supplies (but including 2GW of DFS), similar to that set out in last year’s Winter Outlook.

Demand / Normal peak demand

Weather corrected peak demand for winter 2023/24 is expected to be similar to the previous winter, but still considerably lower than winter 2021/22.

This winter we expect

- Weather corrected peak transmission system demand (TSD) to be 44.1 GW and to occur in the first two working weeks in January (based on the assumptions in Table 1).
- Embedded wind generation at time of normal peak demand to be similar to last winter.
- The maximum triad avoidance to be 0.8 GW. This reflects the changes made to TNUoS charging. As part of Ofgem’s Targeted Charging Review from April 2023 the Transmission Demand Residual (the largest component of the TNUoS charges) will no longer be recovered via the traditional triad methodology. Further details are available on Ofgem’s website [here](#).
- DFS could reduce peak demand below levels shown in the forecast in Figure 7, but as this is an enhanced service it is not included in the demand forecast.

See [Appendix A](#) for more information on the different demand definitions.

Transmission connected power station demand	600 MW
Base Case interconnector exports to Ireland (at time of peak)	750 MW
Embedded wind capacity	6.5 GW
Embedded solar capacity	15.6 GW
Pumped storage (at time of peak)	0 GW

Table 1. Assumptions for weather corrected peak transmission system demand

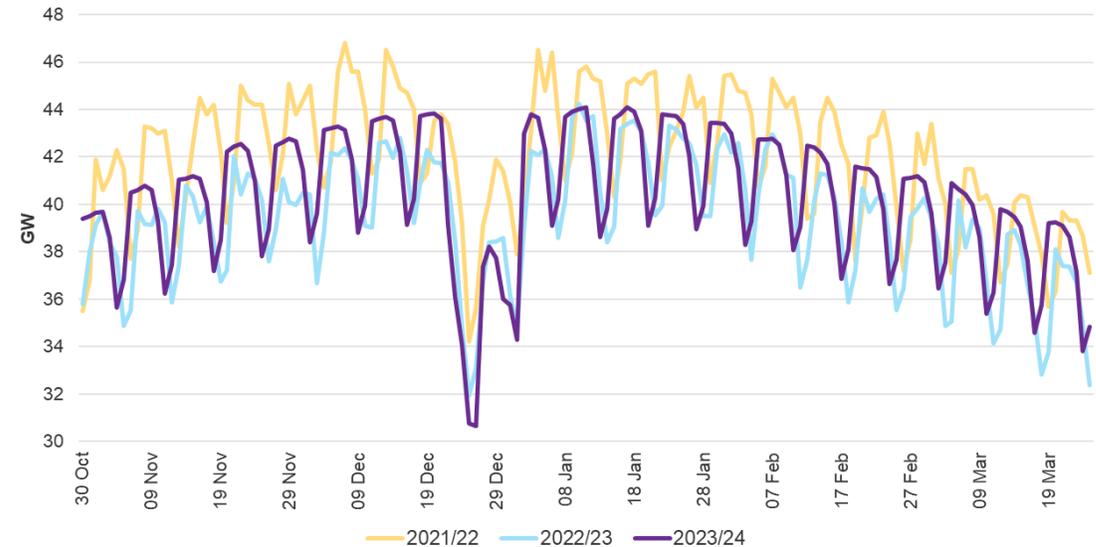


Figure 7. Historical and forecast weather corrected weekly peak transmission system demand

Supply / Overview

Based on market submissions we expect higher available generator capacity than in last year's Winter Outlook.

This winter we expect

- higher available generator capacity than last year, driven primarily by small increases to the contribution from Wind due to newly installed capacity, an additional Coal unit (see section below), and more capacity from CCGT units.
- early November and early January to have the lowest levels of generation availability (see Figure 8), primarily driven by Nuclear outages.
- generator reliability to be broadly in line with recent winters (see Table 2 on the next page).

Coal Contingency Units

For last winter, at the request of the Department of Business, Energy and Industrial Strategy, the ESO signed contracts for 5 additional coal generation units. These units would not have otherwise generated electricity last year. One of the units held in contingency last winter has returned to the market, and the other four units have now closed.

Therefore coal contingency units will not be available as an enhanced action this winter. We have included the unit that has returned to market in all our capacity assumptions in the same way as for any other market generator.

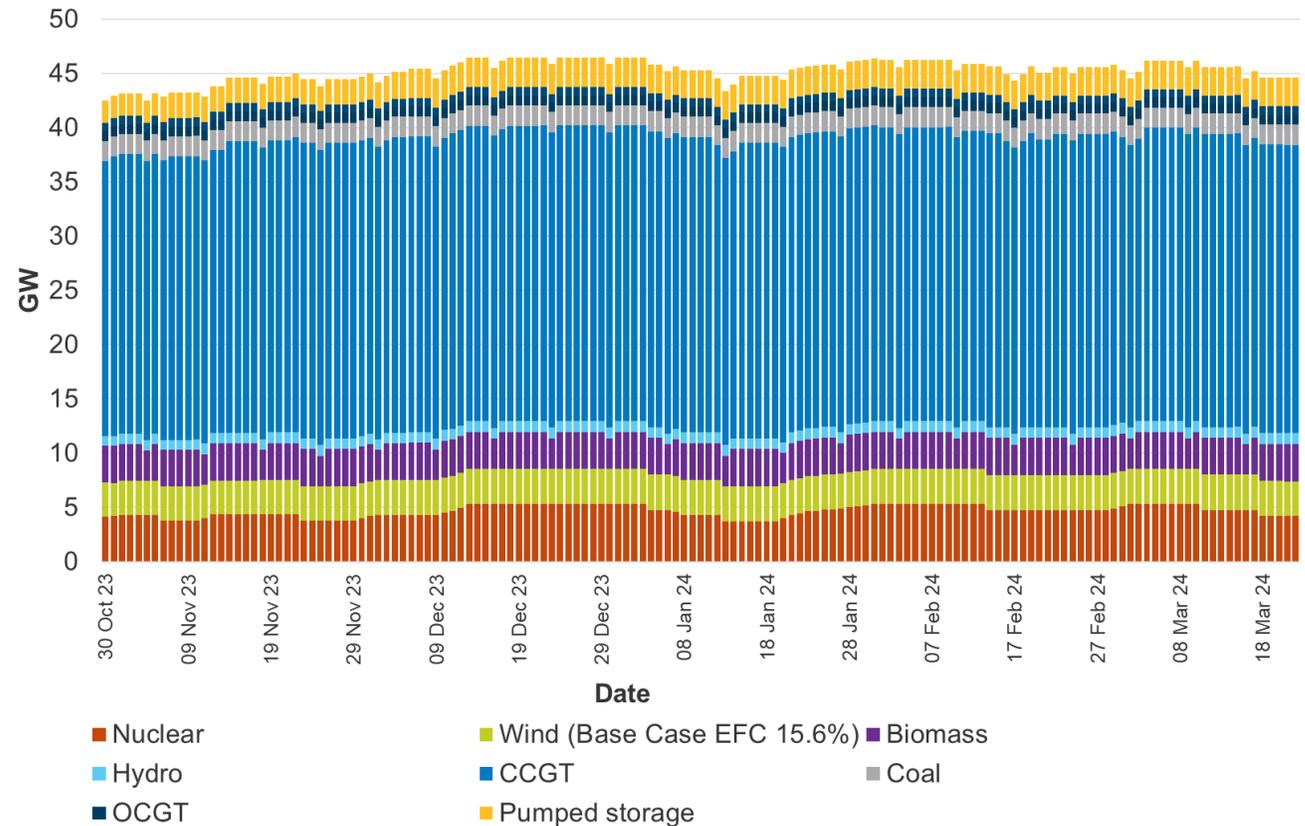


Figure 8. Daily generation availability by fuel type (based on market submissions and including breakdown rates)

Supply / Breakdown Rates and Constraints

Our assumed breakdown rates are at a similar overall level to those used in last year's Winter Outlook.

Breakdown rates

The assumed breakdown rates are based on historic data and reflect how generators performed against their planned availability during peak demand periods over the last three winters (see Table 2).

In net, the new assumed breakdown rates are similar to the rates used for last winter. The most significant change is for nuclear, with the three-year rolling average increasing when last winter was accounted for.

For wind generation, we have assumed an Equivalent Firm Capacity (EFC) of 16%, which is very close to the level used last winter, but slightly higher than in the early view. Wind EFC represents how much 100% available conventional plant would be needed to replace the entire wind fleet without affecting security of supply measures (e.g. LOLE). Therefore, with our view of de-rated margin reduced compared to the early view, wind has a larger impact on security of supply and the EFC is increased. Our [2022-23 Winter Review and Consultation](#) shows that there were only a few days last winter when the EFC was not exceeded at peak, making this a conservative estimate.

Network access constraints

Analysis of network access constraints over this winter show a similar background to previous years. There is likely to be some periods of congestion in Scotland, North Wales and the South East due to essential works. However, this will be carefully managed to minimise associated constraints and ensure access to generation is maximised when required.

Power Station Technology Type	Assumed Breakdown Rate	
	22/23	23/24
Coal	10%	9%
CCGT	6%	6%
Nuclear	10%	14%
OCGT	7%	7%
Biomass	6%	5%
Hydro	8%	9%
Wind (EFC)	16%	16%
Pumped storage	3%	3%
Weighted Average	7.1%	7.4%

Table 2. Breakdown rates by technology type (based on 3-year rolling average). Weighted average is calculated based on derated capacity. Rates shown in the table for 22/23 are the assumed levels used in last year's winter outlook, not the outturns as used in the calculation.

Europe and interconnected markets / Overview

We expect to continue working closely with our neighbours in Europe, adopting a coordinated approach providing reciprocal support.

Figure 9 shows last year's average interconnector flows at peak times, and during periods when operational surplus in Great Britain was below 2 GW. It shows that GB was generally importing from Continental Europe and exporting to Ireland and Northern Ireland at peak across last winter, but also that the magnitude of those imports increased when the operational surplus in GB was lower. These, alongside the factors on the following pages, have been used to help inform our expectations for interconnector flows this winter.

This winter we expect

- close cooperation between European System Operators to play an important role in helping maintain secure supplies for customers in Great Britain and Europe.
- imports into GB at times of tight margins or stress on the GB system, provided by the market and / or ESO trading, which is an important operational tool for us. We don't expect the interconnector market positions to provide exports to Europe if this would mean we were unable to meet GB demand.
- there will also be periods when exports flow from Great Britain to Europe, including over some peak periods, when we have sufficient operational surplus.
- net imports from Norway across the NSL interconnector across the winter period, particularly at peak.
- net exports from GB to Northern Ireland and Ireland during peak times across the winter. When operational surplus is particularly tight, exports to Northern Ireland and Ireland are expected to reduce, and may even provide some imports to GB.

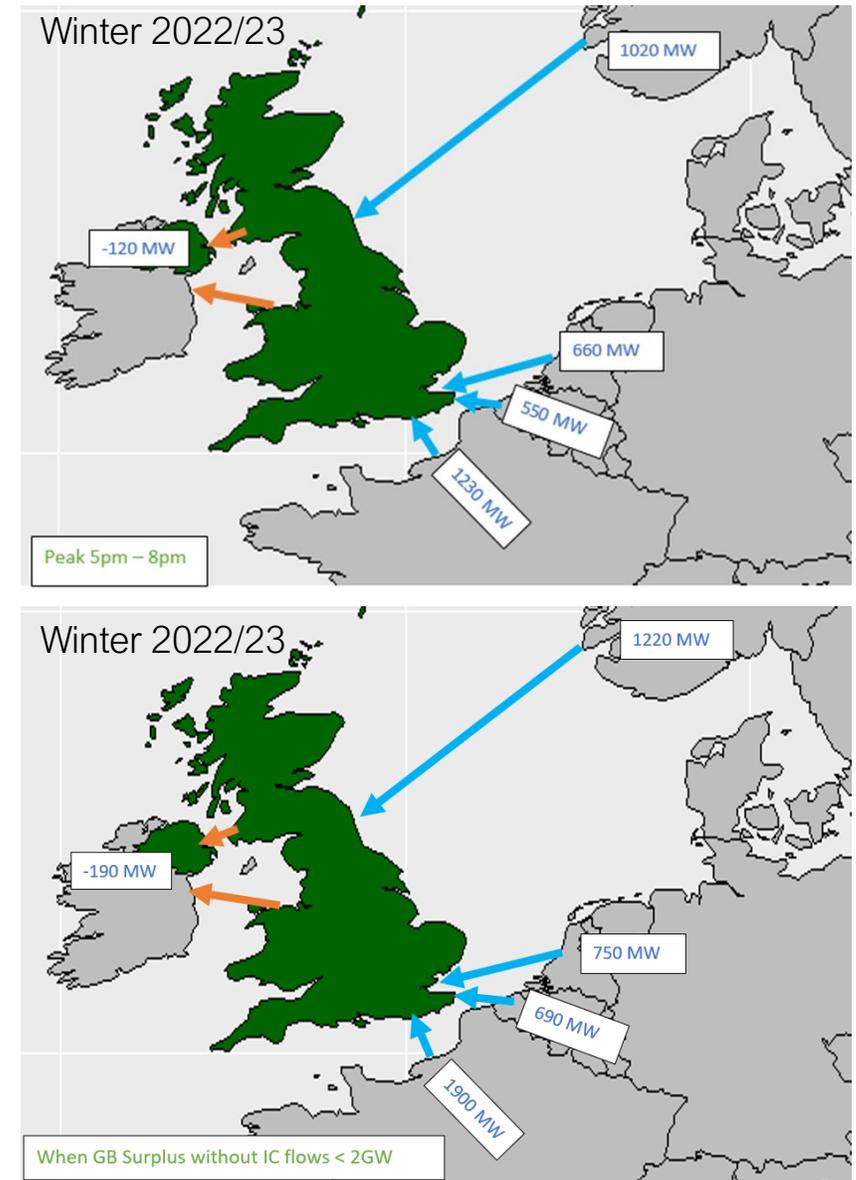


Figure 9. Average historical flows on the interconnectors for last winter

Europe and interconnected markets / Peak Flows Analysis

Our assumptions around peak flow of electricity on the interconnectors depend on a number of factors, outlined in the following slides.

1. Physical Capabilities

Interconnector capacities are set out in Table 3. There are currently no known outages affecting these capacities for the winter period.

No new interconnectors between GB and continental Europe have come into service since last winter. Viking Link is an interconnector connecting GB and Denmark with 1.4 GW capacity, and might provide some flows before the end of winter. As of late August, Viking Link passed its final cable test and the project is expected to complete by the end of this year¹. However, as it has no capacity market contract for this winter it has not been included in our analysis.

Interconnector	Connection with	Maximum capacity	Winter Planned outages
IFA	France	2 GW	None
IFA2	France	1 GW	
ElecLink	France	1 GW	
BritNed	Netherlands	1 GW	
Nemo Link	Belgium	1 GW	
NSL	Norway	1.4 GW	
EWIC	Ireland	0.5 GW	
Moyle	Northern Ireland	0.5 GW	

Table 3. Interconnector capacities and planned outages at time of analysis (14th September 2023)

2. Capacity Market

Interconnectors have secured agreements in the Capacity Market (CM) T-4 auction for 2023/24 as set out in Figure 10 below. At times of tight margins or stress in GB (e.g. when a Capacity Market Notice was issued) we would expect to see flows into GB.

Our Base Case assumes interconnectors deliver in line with their CM obligations.

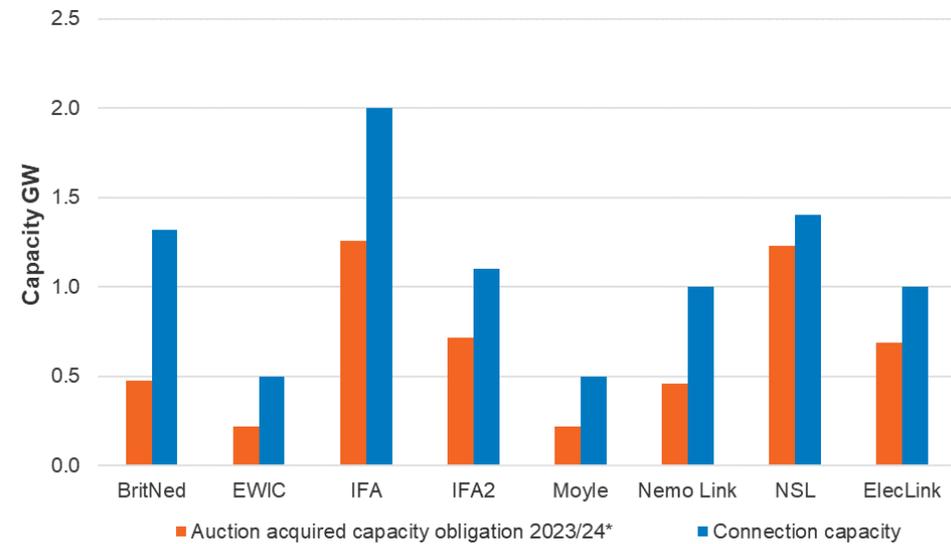


Figure 10. Capacity Market agreements for interconnectors in Delivery Year 2023/24

¹ <https://www.viking-link.com/news/final-cable-test-complete-for-national-grid-s-viking-link-interconnector/>

Europe and interconnected markets / Wholesale Prices

3. European forward prices

- Electricity flows through the interconnectors are primarily driven by price differentials between the markets. Figure 11 shows the electricity forward price spreads for winter peak and baseload¹. The price spreads for this winter are calculated using the latest prices at the time of analysis (14th September 2023), while the spreads for last winter are based on the prices published in last year's winter outlook (as of 22nd September 2022).
- For this winter, based on current prices, there is no clear signal for the flow on the continental interconnectors. The price spreads with France are very close this year, especially compared to in last year's outlook when spreads strongly supported exports to France. Price spreads with Netherlands and Belgium are also very close for this winter, but with the GB price slightly higher, giving a slight indication of imports to GB.

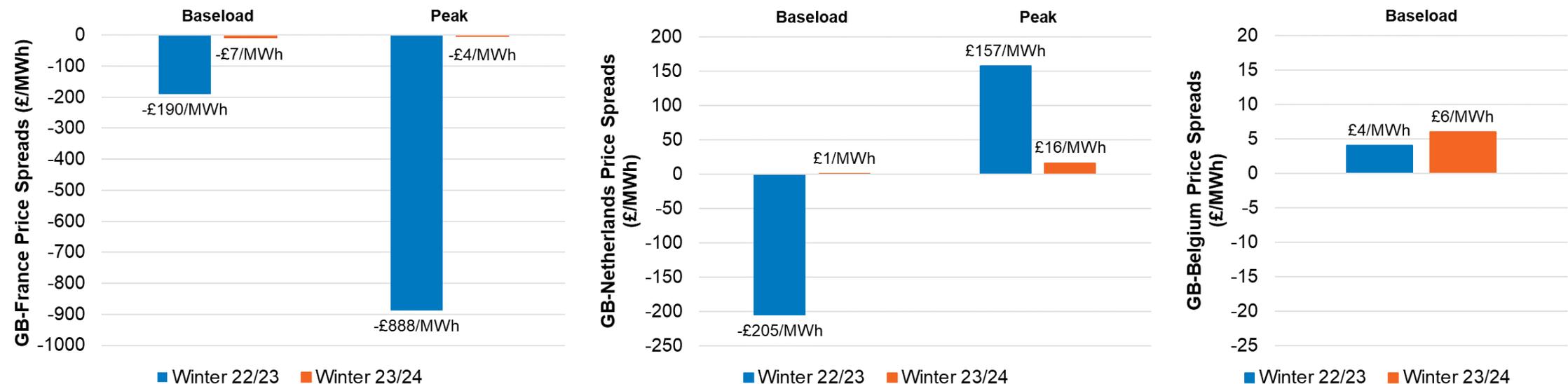


Figure 11. Forward price spreads¹ for peak and baseload this winter compared to the spreads in last year's winter outlook. From left to right: GB-France, GB-Netherlands, GB-Belgium. Positive price spreads indicate forward prices are higher in GB than in the comparator (suggesting imports).

¹ Figure 11 uses data from Bloomberg and Argus. Lower liquidity means no peak forward prices were available for Belgium.

Europe and interconnected markets / Nuclear Availability and Constraints

3. European forward prices - continued

- Figure 12 shows how electricity forward prices for winter peak 2023/24 have changed in recent months.
- French prices for this winter have dropped significantly over the past few months. As a result the price spread with GB has reduced and there is now a minimal price signal between the two markets.
- Prices for this winter in the Netherlands and GB peak markets have remained much more constant in the past few months, leading to little change in the price spread.

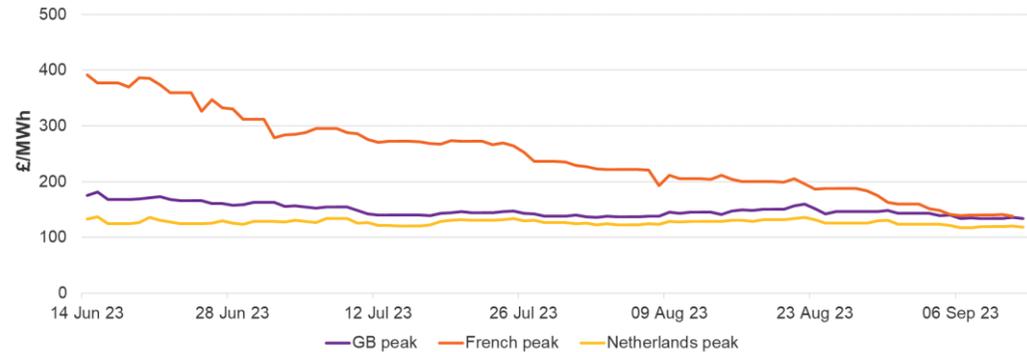


Figure 12. Winter 2023/24 electricity peak forward prices¹ for GB, France and the Netherlands. The equivalent chart for baseload forward prices can be found in our data workbook.

4. Nuclear availability in France

- Figure 13 shows French nuclear outages for the winter ahead against historical outages.
- Outage levels were very high last year, particularly in the middle and end of winter.
- Expected outages for this winter are much lower than last year and much more in line with typical historical years.

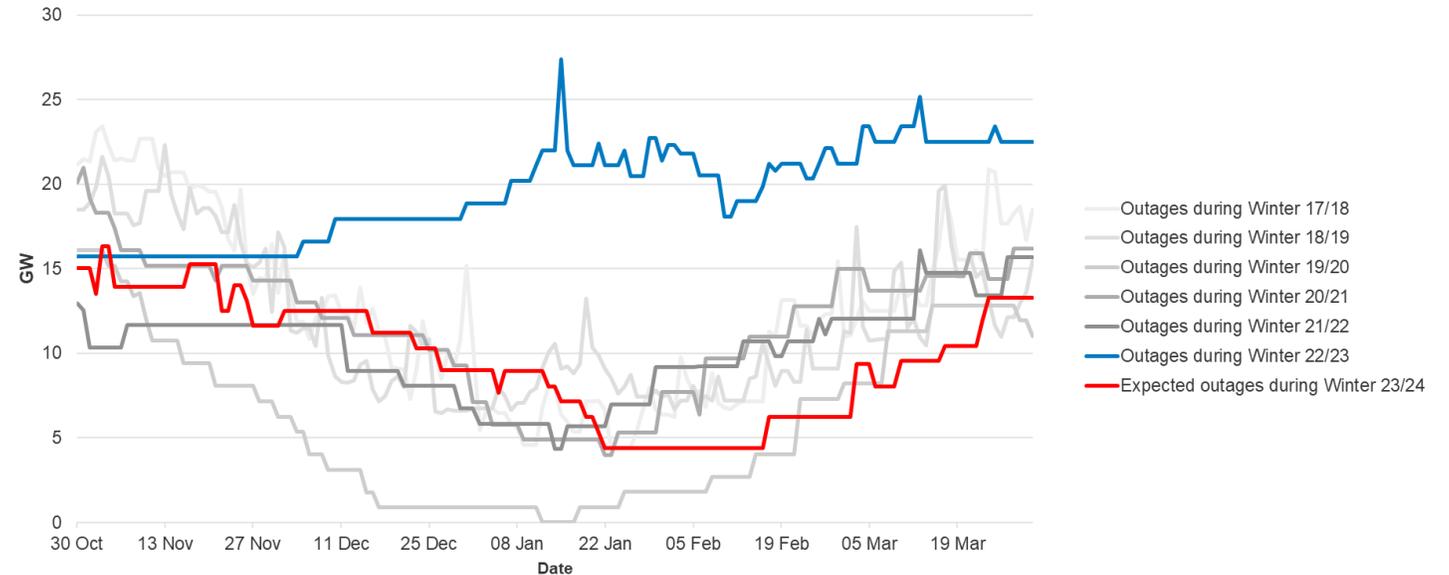


Figure 13. The impact on French nuclear capacity from planned outages in 2023/24 and actual outages in recent years²

¹ Figure 12 uses data from Bloomberg and Argus. Lower liquidity means no peak forward prices were available for Belgium

² <https://www.edf.fr/en/the-edf-group/who-we-are/activities/optimisation-and-trading/list-of-outages-and-messages/list-of-outages>

Market prices / Winter view

GB wholesale electricity prices for this winter in the forward markets are significantly lower than last year, and more in line with winter 2021/22. However, tight margin days are likely to see significant price spikes in the Balancing Mechanism.

Wholesale electricity prices

- Baseload forward prices in GB for this winter are much lower than last year. These prices have remained at that lower level consistently for the past few months, showing much lower volatility than we saw in the approach to last winter (Figure 14).
- However, even with lower baseload prices for winter as a whole, days with tight margins are likely to see spikes in the Balancing Mechanism. During periods of tight system margins, prices increase to reflect the scarcity of the resource, particularly when margin notices are issued.
- Forward prices were high for last winter due to external pressures, particularly very high gas prices. Gas prices have dropped for this winter but the price is dependent on a range of geopolitical factors, which could change as we approach this winter.

Balancing Mechanism Cost Review

Balancing Costs for 2023 are so far significantly lower compared to 2022. The monthly average Balancing Cost from January to September (YTD) compared to the same time period last year is £79 million lower, a 26% decrease. Whilst lower wholesale prices are a significant driver of lower Balancing Costs, the ESO have actioned, led, and advised on many new initiatives aimed to minimise Balancing Costs which have also contributed to this reduction.

These initiatives have been tracked and reported in our balancing costs strategy, which is available on the ESO's [Balancing Costs webpage](#). The strategy focuses on 4 key areas of development and initiatives; Network Planning and Optimisation, Commercial mechanisms, Innovation, and Control Room Actions.

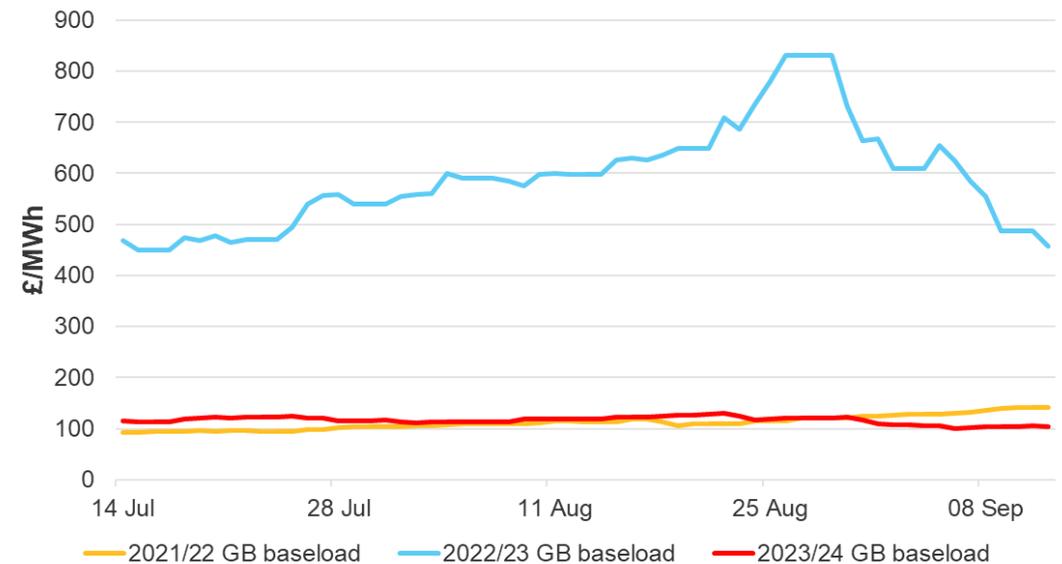


Figure 14. Historically traded forward electricity baseload prices for season-ahead in Winter 2021/22, Winter 2022/23 and Winter 2023/24 taken from Argus¹

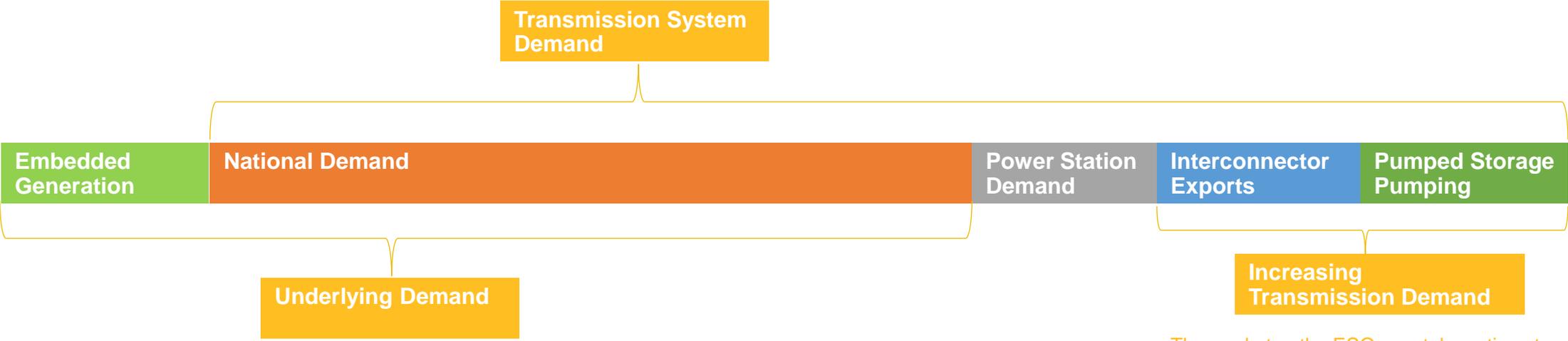
¹The numbers shown in Figure 14 are historical traded prices not forecasts. Trading does not take place on weekends or bank holidays so these values have been interpolated.

Appendix

Contains extra information on demand definitions, margin notifications, and operational surplus analysis.

Appendix A / Relationship between types of demand

This figure shows the relationship between some of the different types of demand



The market or the ESO may take actions to increase exports across the interconnectors or increasing pumping at pumped storage stations to increase the amount of demand on the transmission system.

Appendix B / 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 don't indicate that demand will not be met.

Margins on the electricity system can vary throughout the winter. This will depend on actual weather patterns and outages taken by generators. The Winter Outlook Report also considers how margins could change on a day-by-day basis throughout winter for the transmission system only.

There are two views of margins which the ESO works with. **Capacity Market Margins** are based on whole system demand and whole system capacity (including Distributed Energy Resources (DER)).

As the majority of the DER are not visible to the ESO, **Operational Margins** are based on transmission system demand and transmission system capacity. The EMN process is based around the Operational Margins and the CMN process is based around the Capacity Market Margins.

The EMN and CMN processes both rely on the visible generation as that is the data provided to the ESO. The Winter Outlook Report provides both margin views; the overall **Capacity Market Margin** for the winter as a whole and the weekly **Operational Margin**.

There are a number of significant differences between the operational System Warning messages (such as EMN) and Capacity Market Notices:

- 1. Trigger** - Capacity Market Notices are issued based on an automated system margin calculation using data provided by market participants, whereas System Warnings are manually issued by the National Grid ESO control room using engineering judgement based on experience and knowledge of managing the electricity transmission system.
- 2. Threshold** - Capacity Market Notices are triggered where the volume of available generation above the sum of forecast demand and Operating Margin, is less than 500 MW. The 500 MW threshold is taken from the Capacity Market Rules. System Warnings are triggered by varying volumes, for example a EMN may be issued where National Grid ESO expects to utilise 500MW of its Operating Margin. There is therefore a 1,000 MW+ variance between these two discrete alerts.
- 3. Constraints** - The Capacity Market Notice calculation does not take account of any transmission system constraints that may be preventing capacity from accessing the network. System Warnings however do take such constraints into account.
- 4. Lead time** - Capacity Market Notices are initially issued four hours ahead of when the challenge is foreseen, whereas System Warnings can be issued at any time but we would expect to issue a first EMN at the day ahead stage.

Appendix C / Operational surplus analysis

Our operational surplus analysis represents the market's current intentions (i.e. based on market submissions before we take actions). This analysis is based on market submissions as of 14th September 2023.

It is a dynamic view that changes throughout winter and, as such, we will be providing regular updates at the [ESO Operational Transparency Forum](#). It provides insight on the periods when we may need to send market signals / use tools to ensure there is enough generation on the system to meet demand and contingency requirements. 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 set us up 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 the daily views in July ahead of the Winter Outlook Report publication in September. 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 (e.g. on wind and demand) and flows on interconnectors. As generators can also have unplanned outages, we also apply breakdown rates based on averages of the last 3 winters. In addition, we study the effects of variability of all relevant factors, particularly weather, renewable resource and unplanned outages. The operational data may be different from the assumptions based on historic data / long-term averages used for the winter view of margin.

The operational surplus also considers grid constraints and largest loss requirements. In the central daily view we use a low wind scenario, so the grid constraints play only a small part in the calculation.

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

These assessments of security of supply are used to support decisions taken in operational timescales (e.g. whether to issue an EMN).

Glossary

Average cold spell (ACS)

ACS methodology takes into consideration people's changing behaviour due to the variability in weather, e.g. more heating demand when it is colder and the variability in weather dependent distributed generation e.g. wind generation. These two elements combined have a significant effect on peak electricity demand. Average cold spell is defined as a particular combination of weather elements which gives rise to a level of winter peak demand which has a 50% chance of being exceeded as a result of weather variation alone.

Balancing Mechanism

The Balancing Mechanism is a tool which we use to balance electricity supply and demand. It allows participants to set prices for which they will increase or decrease their output if requested by the ESO. All large generators must participate in the BM, whereas it is optional for smaller generators.

Baseload electricity

A market product for a volume of energy across the whole day (the full 24hrs) or a running pattern of being on all the time for power sources that are inflexible and operate continuously, like nuclear.

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 the ESO 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 Great Britain and the Netherlands. It is a bi-directional interconnector with a capacity of 1 GW. You can find out more at www.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 see: www.nationalgrideso.com/electricity-explained/how-do-we-balance-grid/what-are-system-notice

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.

Contingency coal contracts

At the request of the Government the ESO signed three contracts with EDF, DRAX and Uniper to provide additional coal generation for winter 22/23. Coal contingency units will not be available as an enhanced action this winter. More details can be found here: www.nationalgrideso.com/winter-operations.

Demand flexibility service (DFS)

The Demand Flexibility Service (DFS) has been developed to allow the ESO to access additional flexibility when national demand is at its highest – during peak winter days – which is not currently accessible to the ESO in real time. This service incentivised consumers and businesses to reduce or reschedule their electricity use away from peak times. More details can be found here: www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility-service-dfs.

De-rated margin for electricity

The sum of de-rated supply sources considered as being available during the time of peak demand plus support from interconnection, minus the expected demand at that time and basic reserve requirement. This can be presented as either an absolute GW value or a percentage of demand (demand plus reserve). The formula was revised in winter 2017/18 to include distribution system demand, and in winter 18/19 to better account for interconnection. See our previous publications for further details (www.nationalgrideso.com/research-publications/winter-outlook).

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 the ESO and reduces demand on the transmission system.

Glossary

East West Interconnector (EWIC)

A 500 MW interconnector that links the electricity transmission systems of Ireland and Great Britain. You can find out more at www.eirgridgroup.com/customer-and-industry/.

Eleclink

A power interconnector through the Channel Tunnel to provide a transmission link between the UK 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 the ESO's order of actions for managing security of supply, and are used if everyday actions are insufficient. The Demand Flexibility Service is an example of an enhanced action.

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 see: www.nationalgrideso.com/electricity-explained/how-do-we-balance-grid/what-are-system-notice.

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.

Grid Code

The Grid Code details the technical requirements for connecting to and using the National Electricity Transmission System (NETS).

GW Gigawatt (GW)

A measure of power. 1 GW = 1,000,000,000 watts.

Interconnector

Electricity interconnectors are transmission assets that connect the GB market to other markets including Continental Europe and 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 1 GW link between the French and British transmission systems commissioned in 2020. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE). See more at <https://www.ifa1interconnector.com/>.

Inflexible generation

Types of generation that require long notice periods to change their output, do not participate in the Balancing Mechanism or may find it expensive to change their output for commercial or operational reasons. Examples include nuclear, combined heat and power (CHP) stations, and some hydro generators and wind farms.

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 /emergency actions are taken but after all system warnings and System Operator (SO) balancing contracts have been exhausted. It is important to note when interpreting this metric that a certain level of loss of load is not equivalent to the same amount of blackouts; in most cases, loss of load would be managed by actions without significant impacts on consumers. The Reliability Standard set by the Government is an LOLE of 3 hours/year.

Moyle

A 500 MW interconnector between Northern Ireland and Scotland. You can find out more at: www.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.

Glossary

Normalised transmission demand

The 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 peak transmission demand

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

North Sea Link (NSL)

A 1.4 GW HVDC sub-sea link from Norway to GB commissioned in October 2021. See more at: <https://www.northsealink.com/>.

Operational surplus

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

Outage

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

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 the use of water that has been pumped into a reservoir at a higher altitude during periods of low demand.

REMIT

REMIT data is information provided by market participants to comply with Article 4 of Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) Regulation (EU) 1227/2011.

Reserve requirement

To manage system frequency and to respond to sudden changes in demand and supply, the ESO maintains positive and negative to increase or decrease supply and demand. provides head room (positive reserve) and foot room (negative reserve) provided across all generators synchronised to the system.

Rota load shedding

Scheduled disconnection and reconnection of electricity supplies in an electricity supply emergency, as set out in the government's Electricity Supply Emergency Code (ESEC).

TNUoS Charges

Recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and Offshore. For more information see: <https://www.nationalgrideso.com/industry-information/charging/transmission-network-use-system-tnuos-charges>.

Transmission system demand (TSD)

Demand that the ESO sees at grid supply points (the connections to the distribution networks).

Triad avoidance

When demand side customers reduce the amount of energy they draw from the transmission network, either by switching to distribution generation sources, using on-site generation or reducing their energy consumption. This is sometimes referred to as customer demand management but, in this section, we are considering customer behaviour that occurs close to anticipated Triad periods, usually to reduce exposure to peak time charges.

Triads

The three half-hourly settlement periods with the highest electricity transmission system demand. Triads can occur in any half hour on any day between November and February. They must be separated from each other by at least ten days. Typically, they take place on weekdays around 4.30 to 6pm.

Underlying demand

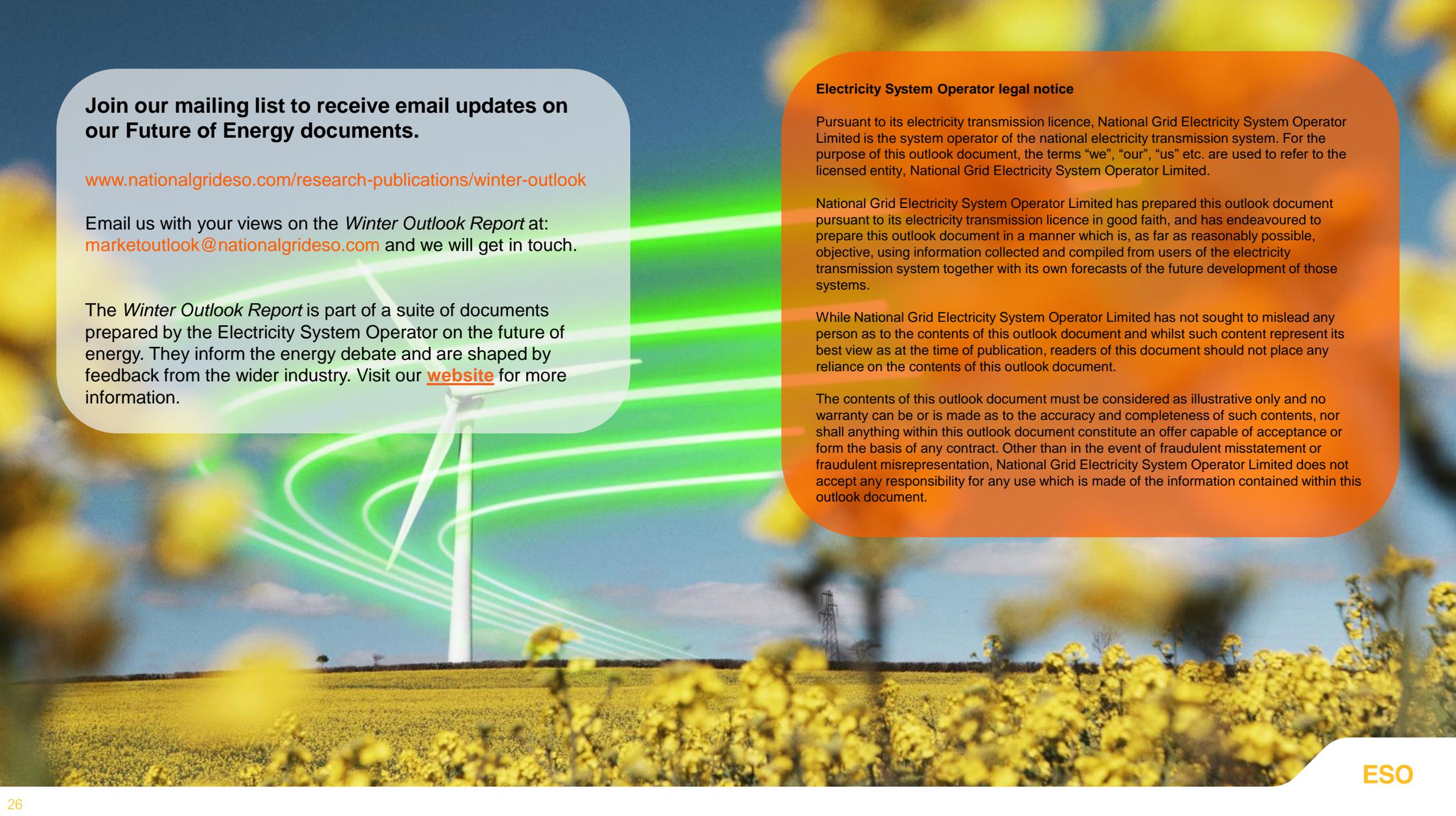
Underlying demand is a measure of how much demand there is once the effects of the weather and the day of the week have been removed. This is end user demand, which is measured by aggregating transmission demand, embedded generation and transmission system losses, but excludes station load, interconnectors, pumped storage consumption and demand-side response.

Viking Link

Viking Link is a 1400 MW high voltage direct current (DC) electricity link between the British and Danish transmission systems. See more at: <https://www.viking-link.com/>.

Weather corrected demand

The demand expected or out turned 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.



Join our mailing list to receive email updates on our Future of Energy documents.

www.nationalgrideso.com/research-publications/winter-outlook

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

The *Winter Outlook Report* is part of a suite of documents prepared by the Electricity System Operator on the future of energy. They inform the energy debate and are shaped by feedback from the wider industry. Visit our [website](#) for more information.

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