June 2022

Winter Review and Consultation

Helping to inform the electricity industry, reflect on last winter and prepare for the winter ahead.

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Welcome

Welcome to our *2022 Winter Review and Consultation Report*. This annual document provides a review of how what we said in the *2021/22 Winter Outlook Report* compared to what actually happened.

This document includes a review of all the standard analysis from the *2021/22 Winter Outlook Report* in relation to elements such as demand levels, performance of generators and any operability challenges faced.

This year we will be publishing an early view of Winter 2022/23 in July 2022 to give earlier information to the industry in light of the recent very high energy prices. This means that the consultation questions in this document are less specific to the coming winter and more about this document and the Electricity Outlooks process in general. However, feedback on our potential plans and on preparations for the upcoming winter remains extremely important and so we will make sure any comments and information received via this document are passed to the relevant teams within the ESO. If you would like to share your views, or if you have any general queries or comments, please don't hesitate to email us at marketoutlook@nationalgrideso.com, join us for a discussion at our Operational Transparency Forum (OTF) or get in touch via social media.

This document covers Winter 2021/22 from the electricity perspective. National Grid Gas Transmission (NGGT) publish a similar document from the gas perspective, the Gas *2022 Winter Review and Consultation Report,* which can be found here. We continue to engage with NGGT on approach and consistency.

Contents

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Key Messages / Winter Review 2021-22

1 System conditions

Conditions over Winter 2021/22 were close to average with no prolonged cold spells coincident with low wind output.

Interconnectors imported when needed, and availability of thermal generation was in line with forecasts.

2 Margins

As margins over winter 2021/22 were less tight than the previous winter, no Electricity Margin Notices (EMNs) were issued.

The *Winter Outlook Report* highlighted a potential need for EMNs but none were issued.

3 Prices

High wholesale electricity prices meant that the cost of individual ESO actions was higher than in previous years although overall volumes of actions were lower.

This was largely due to the unexpected and significant rise in gas prices which translated into higher balancing costs overall and therefore increased costs for consumers.

Review / Margins

Operational surplus: a look back at our *Winter Outlook Report* forecasts

The *2021/22 Winter Outlook Report* contained a day-by-day view of operational margin (also referred to as surplus) and this is shown in Figure 1.

The green bars represent the transmission system demand forecast (under average weather conditions, with average embedded wind generation).

Demand is then combined with the expected reserve requirement (in orange). The red dotted line represents where demand and reserve could be, should average cold temperature conditions be experienced thereby raising demand levels. This is referred to as ACS (Average Cold Spell) conditions.

Finally, the light and dark blue and purple lines represent the forecast of generation supply when combined with low, medium and high imports from interconnectors.

Note that generation supply is made up of Balancing Mechanism generation availability submissions (de-rated using historic data to take account of breakdowns) plus an assumption of expected wind generation. Other forms of distribution connected generation are excluded as quoted demands are at transmission level.

This day-by-day chart showed that normalised peak transmission demand was expected in mid-December. The minimum operational surplus under average weather conditions was projected to be lowest throughout December to mid-January (excluding the Christmas period).

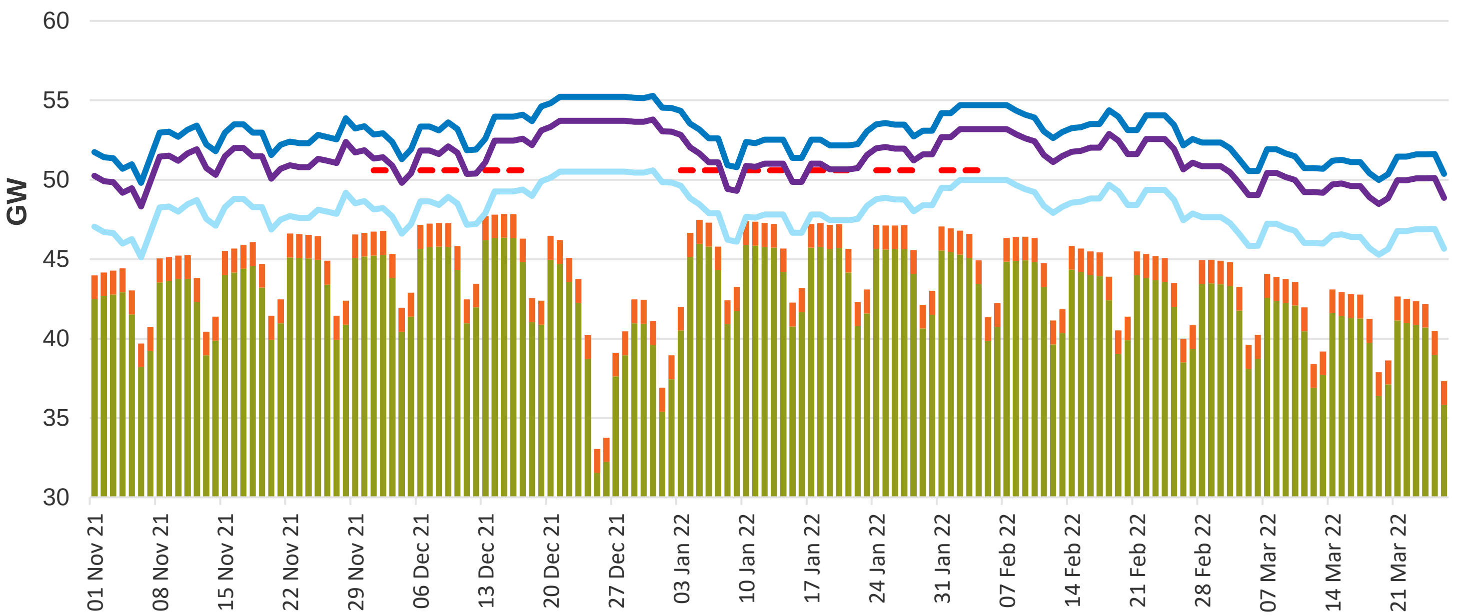

Figure 1. Day-by-day forecast view of operational surplus for winter 2021/22 (Figure 1 from *Winter Outlook Report 2021/22*)

Review / Margins

How did the winter compare to the forecast in the *Winter Outlook Report*?

Figure 2 overlays the forecast from the *Winter Outlook Report* with the actual outturns from the winter for both demand and plant availability and is designed to be comparable with Figure 1 on the previous page.

Demand

- green and orange bars respectively show the forecast daily normal demand and reserve requirements as in the *Winter Outlook Report* (exact same values)
- solid black line indicates daily outturn total of "demand plus reserve".
- dotted red line represents the forecast Average Cold Spell (ACS) peak demand at transmission level as in the *Winter Outlook Report* (exact same values).

The actual winter peak demand was close to the forecast peak, and well below the ACS peak.

Supply

- dotted purple line shows the daily expected plant availability under the base case interconnector scenario from the *Winter Outlook Report* (exact same values).
- solid yellow line shows the actual daily plant availability, including wind output and interconnector flows.

Tight margin days, occur when the solid black outturn demand is close to the solid yellow outturn supply.

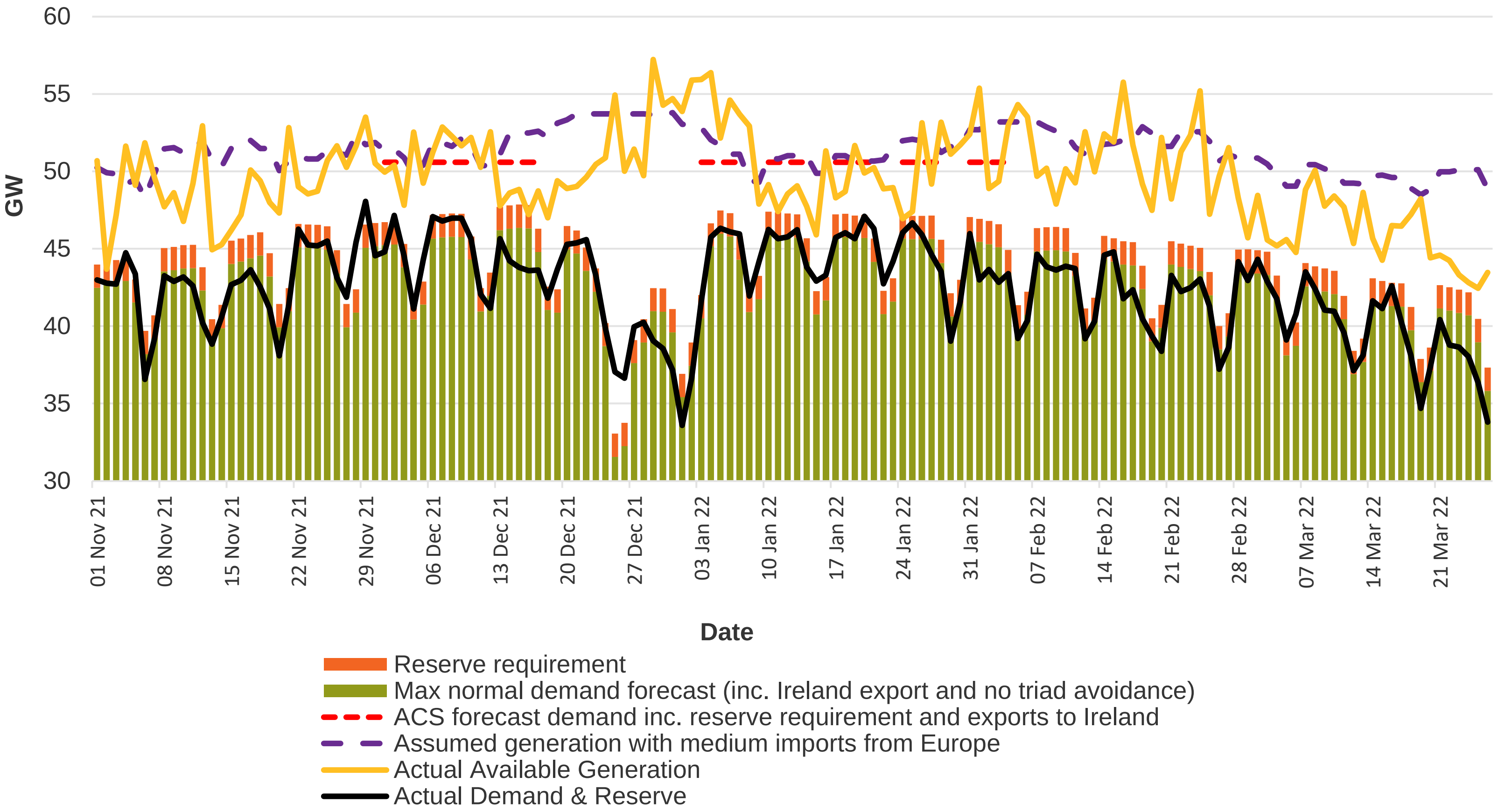

Figure 2. Day-by-day view of actual operational surplus for winter 2021/22

The graph in Figure 2 clearly demonstrates the variability in both demand and generation but also shows healthy margins for the majority of the winter.

Review / Margins

How did the winter compare to the forecast in the *Winter Outlook Report*?

Figure 3 overlays the forecast range for operational surplus from the *Winter Outlook Report* with the actual outturns from the winter for operational surplus.

In the *Winter Outlook Report* we published a central view for operational surplus (dashed green line) which assumed typical conditions and medium imports. To explore the sensitivities around this central view, we simulated many possible scenarios for weather, demand, conventional generation availability, wind generation output and interconnector availability and, for each of these scenarios, we calculated the daily surplus time series across the entire winter for that scenario. This did not include any ESO actions. Our credible range was defined as the 90% confidence bound for the day-by-day fluctuations in surplus (red dashed area on chart).

Figure 3 overlays this forecast range with the outturn of operational surplus for winter 21/22 (solid purple line).

From this you can see that the actual surplus varies across the winter, but stays within this range for the vast majority of the time. There were just 15 days when the surplus was outside this range, these were the days with the tightest margins.

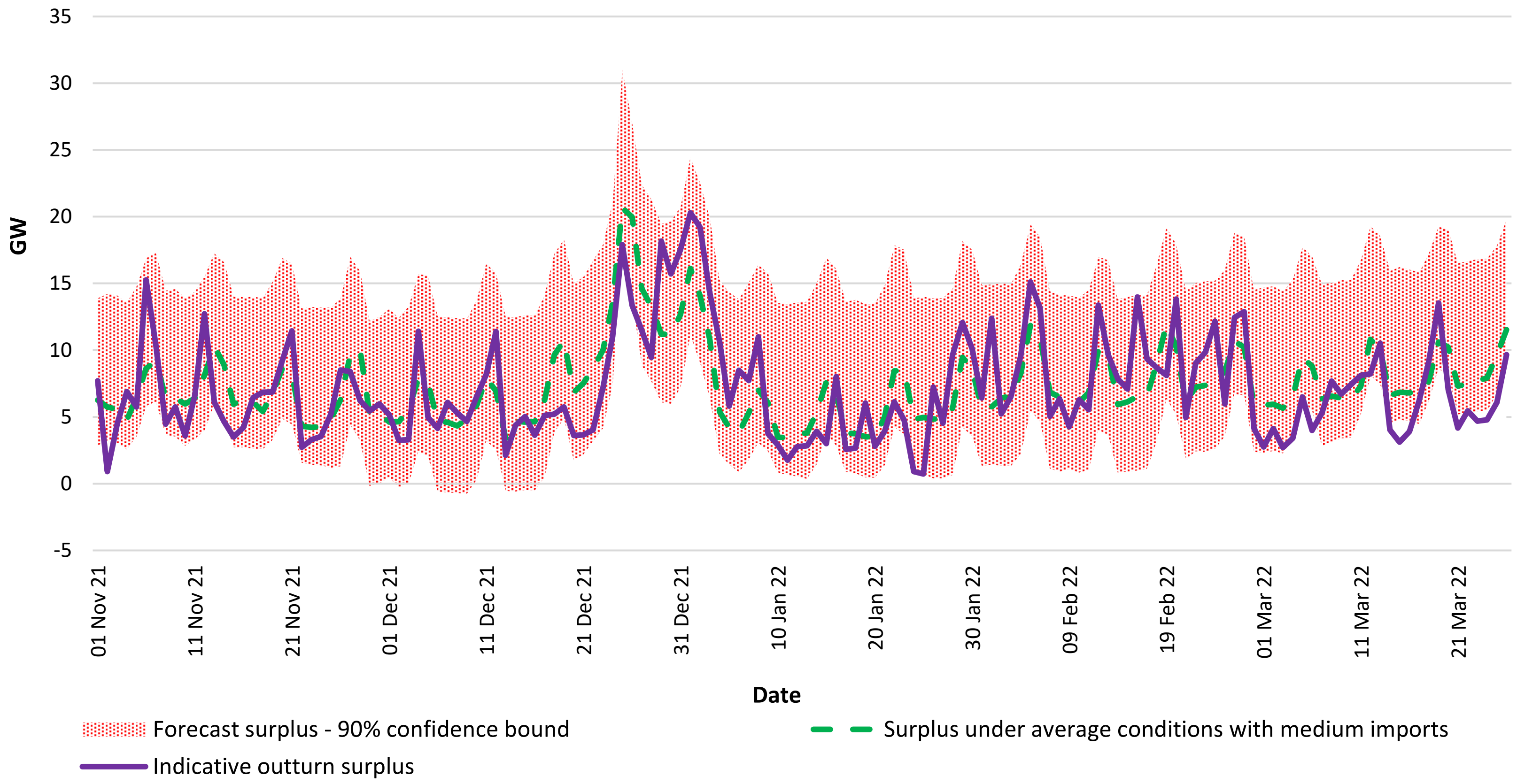

Figure 3. Day-by-day view of actual operational surplus for winter 2021/22 against the forecast surplus and credible range sensitivity from the *Winter Outlook Report*

Review / Margins

How did the winter compare to the forecast in the *Winter Outlook Report*?

Overall, winter 21/22 was windier than the previous winter, and temperatures were close to the seasonal average, meaning margins were not unduly tight.

What we said in the *Winter Outlook Report*	**What actually happened**	**Why was there a difference?**
Average Cold Spell (ACS) transmission demand to be met on all days under the high and medium import interconnector scenarios.	ACS demand (calculated proxy rather than metered figure) would not have been met in all weeks but there was sufficient generation and interconnector imports to meet demand throughout the winter period.	The *Winter Outlook Report* considers what would happen under different average conditions whilst the outturn fluctuates around the average level. Had cold spells fallen on different days the ESO would have called upon the market to deliver a response through its range of routine tools (i.e. comparison has to be hypothetical).
To have sufficient operational surplus throughout winter when routine tools such as margin notices are used. We expect to issue a broadly similar number of EMNs as last year (EMNs in winter 2020/21 = 6).	Operational surplus was sufficient throughout the winter and we issued just two CMNs and no EMNs. Surplus was within our credible range of outcomes throughout the majority of the winter.	The *Winter Outlook Report* considered the possibility of system conditions being outside of the typical range. Temperatures outturned close to the seasonal normal average, interconnector availability and flow patterns over tight periods were as expected and wind output levels were generally high.

Table 1 below shows the days when Electricity Margin Notices (EMNs) and Capacity Market Notices (CMNs) were issued over the winter period.

There were no EMNs issued in winter 2021/22 (compared to 6 issued in winter 2020/21), and there were only 2 CMNs (winter 2020/21: 2 CMNs).

Date	**EMN**	**CMN**
3 December	No	Yes
24 January	No	Yes

Table 1. Days of EMNs and CMNs over Winter 2021/22

Across the last two winters, three CMNs have been issued when margins were relatively healthy, including both CMNs last winter. Under a specific set of circumstances, CMN margin is calculated to be too pessimistic. The ESO are implementing a fix to this ahead of next winter and we will continue to monitor margins and aim to investigate and engage promptly with industry in the event that any further spurious CMNs are issued.

Review / Margins

Wind generation output

For wind generation, we consider a shortfall to be the gap between actual wind generation on a given day and the level assumed in the *Winter Outlook Report* which is based on a statistical consideration of the contribution of wind to capacity adequacy (i.e. not its average annual load factor).

Figure 4 shows this Equivalent Firm Capacity (EFC) for wind assumed and what was actually available throughout the winter at peak.

Wind generation output was high throughout most of the winter. On many of the days with tighter margins, wind generation output compensated for any shortfall in other forms of generation.

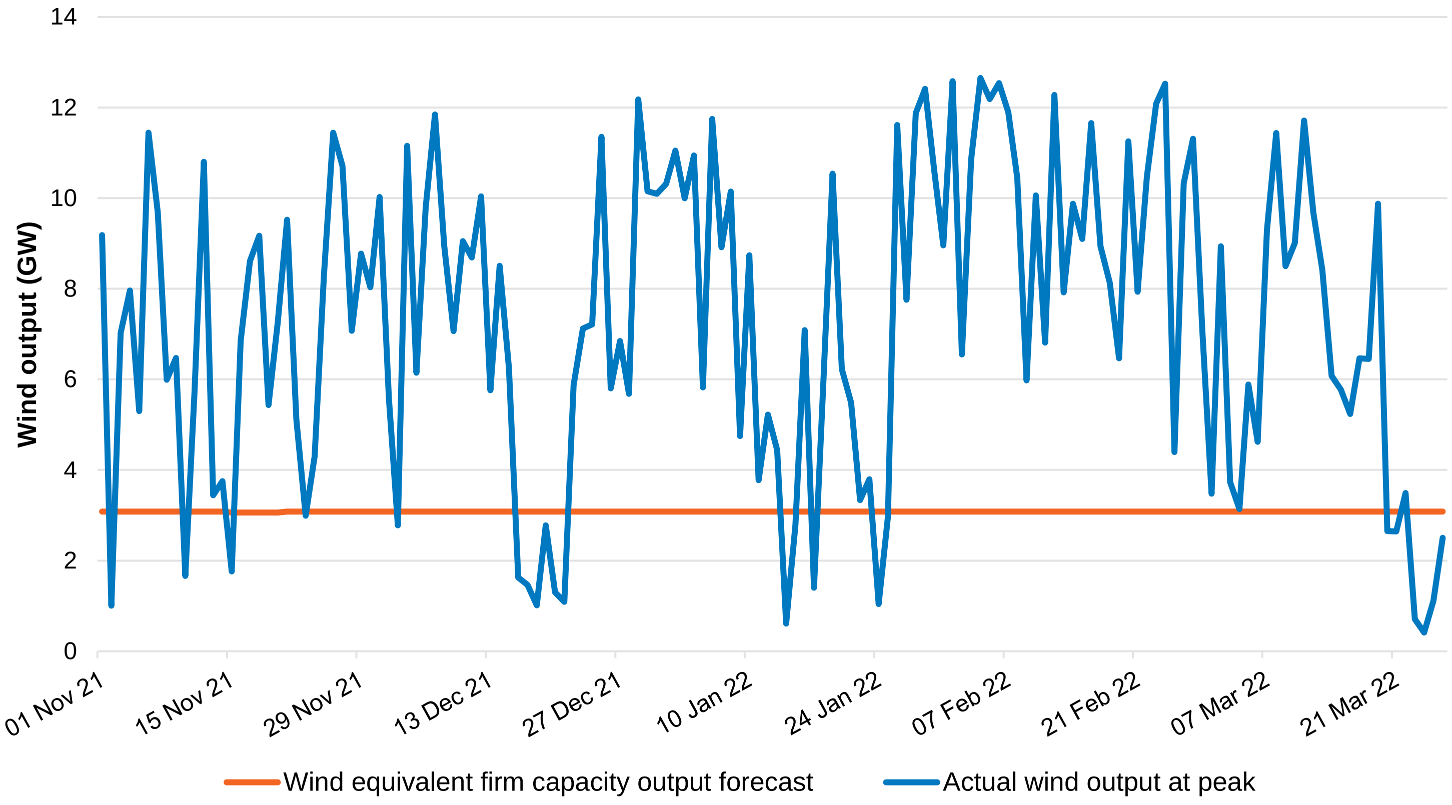

Figure 4. Wind output against equivalent firm capacity

Other generation shortfall

For Continental interconnectors, we treat shortfall as the gap between actual availability and our high import scenario in the *Winter Outlook Report*. For all other generators, it is the difference from the de-rated daily expectations of the *Winter Outlook Report* and the actual available generation on the day.

The main drivers for lower margins came from nuclear and CCGT plant being less available than had been notified at the time of the *Winter Outlook Report*. Nuclear generation availability was lower than forecast through most of the winter.

There was also reduced interconnector availability at times across the whole winter due to unplanned outages but, despite this, imports were still typically available when needed at peak.

More detail on other generator shortfall is available in the data workbook which can be downloaded here.

Review / Margins
Generation and interconnector background to margins

Figure 5 shows the difference or shortfall between generation availability notified when the *Winter Outlook Report* was published, and the prevailing view of availability at real time. There are a number of different reasons for the lower than anticipated availability of generators and no common theme. This chart excludes wind and solar generation assets. There is no impact of a large shortfall between expectations and outturns when demands are lower, typically at weekends and over Christmas.

When forecasting interconnector flows in the *Winter Outlook Report* over the peak period of the day, we expect imports from the continent to GB and exports from GB to Ireland. We model both a high import case based on outage plans and price spreads and a more conservative base case which includes some unavailability as well as lower levels of import.

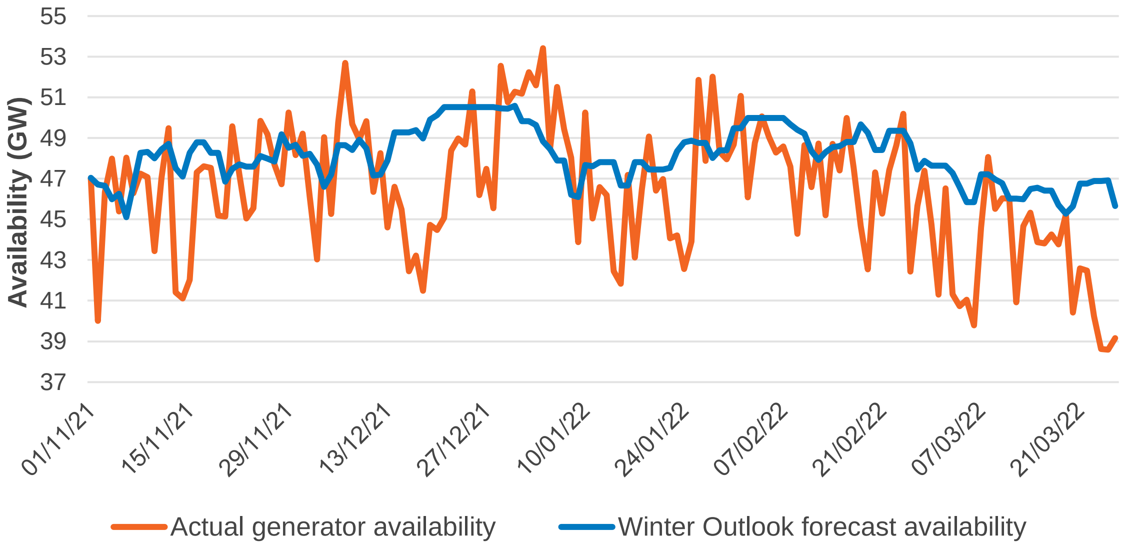

Figure 5. Shortfall between generation availability notified in the *Winter Outlook Report* and actual generator availability (excluding wind and solar)

There were planned outages affecting IFA and NSL interconnectors ahead of the winter and, beyond this, there were a high number of unplanned interconnector outages over the winter, details of which are explored later in the report. Despite this, winter interconnector availability was consistently higher than the base case and typically in line with the high case (see Figure 6).

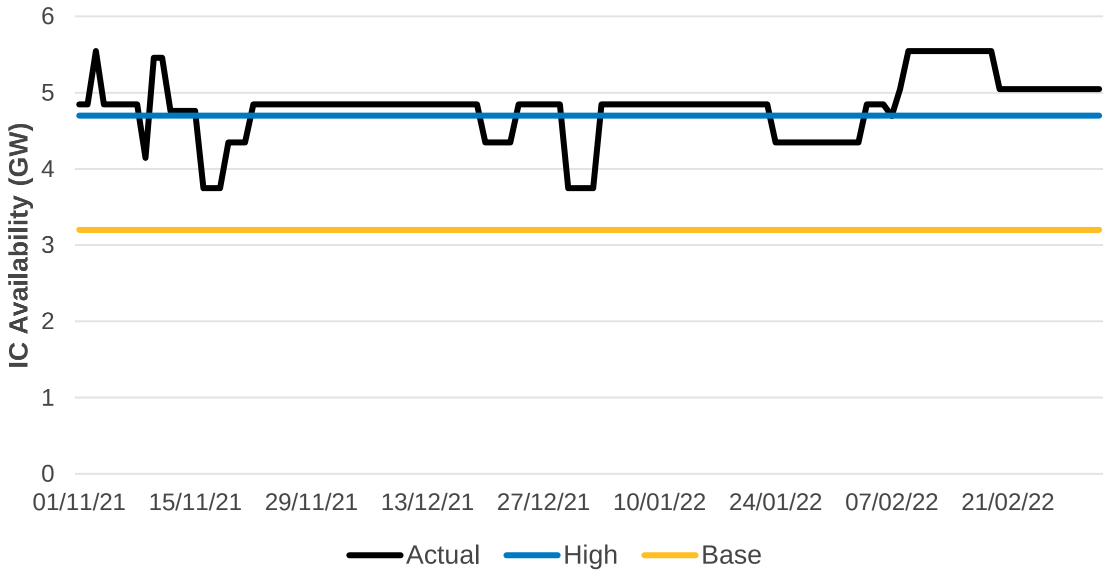

Figure 6. Interconnector scenarios in the *Winter Outlook Report* and actual availability during peak times

* Outage continues beyond the winter period

Review / Margins
Transmission demand

Peak actual weather-corrected Transmission System Demand (TSD) was in line with the forecast from the *Winter Outlook Report*.

The highest normalised demand was expected (from the *Winter Outlook Report*) in the week commencing 13th December, the actual peak demand occurred in the week commencing 6th December (see Figure 6). Otherwise demand tracked broadly in line with our forecast.

2021/22 Winter Outlook Report forecast peak (normal weather used) (GW)	Actual 2021/22 peak (weather-corrected) (GW)	Actual 2021/22 peak (not weather-corrected) (GW)
46.8	46.7	47.1

Table 2. Peak transmission system demands for winter 2021/22

CMN date	Day of week	Actual Peak TSD on days with a CMN (GW)
3 Dec 2021	Friday	44.2 GW
24 Jan 2022	Monday	45.0 GW

Table 3. Actual peak Transmission System Demand on days with CMNs (not weather-corrected)

On both occasions when CMNs were issued, actual TSD (as opposed to weather-corrected as in the forecast) was lower than the actual winter peak TSD (47.1 GW) in Table 5.

In general, times when margins are tight do not necessarily occur on the days with the highest demand but on the days with the biggest shortfall of generation.

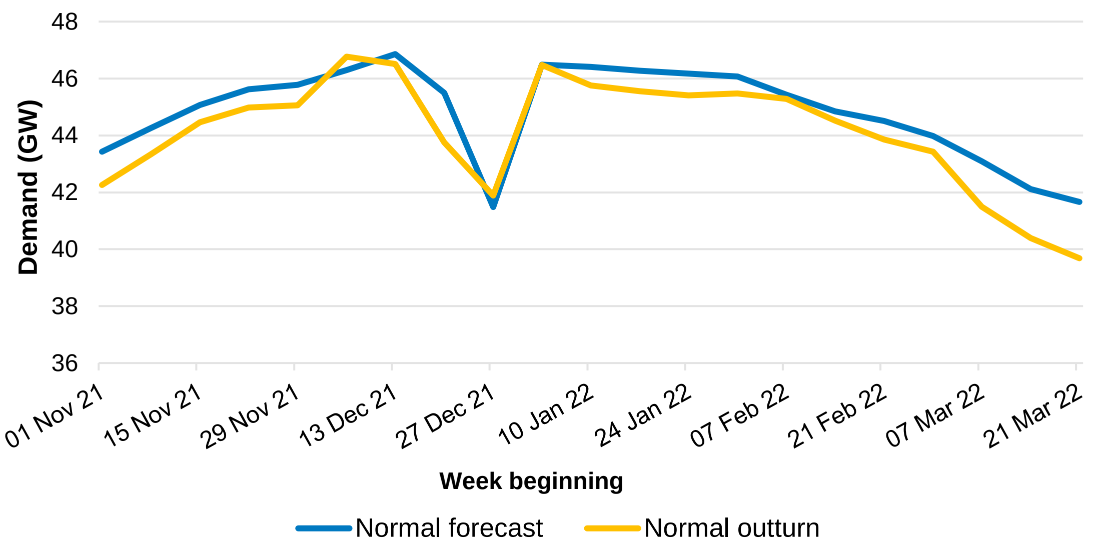

Figure 7. Peak Transmission System Demand (TSD) forecast and outturn for winter 2020/21 (weather-corrected)

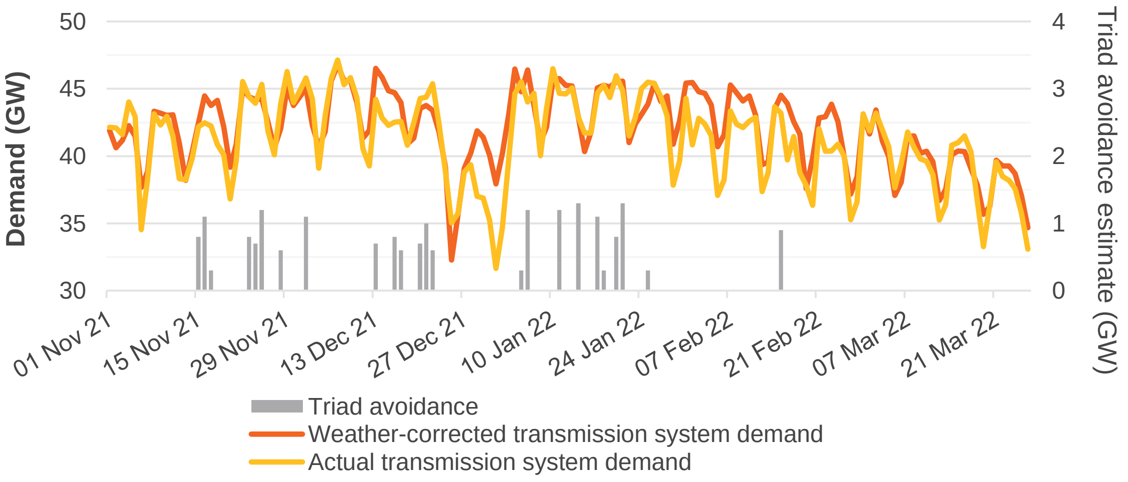

Figure 8. Daily actual and weather-corrected peak demands including triad avoidance

* For the purpose of the Outlook and Review Reports, TSD includes national demand, 600MW of station load and 750MW export on interconnectors (over the peak only).

Review / Triad avoidance

Triad avoidance occurs when industrial and commercial users alter their pattern of energy use during peak periods to avoid transmission charges. The three half-hourly periods with the highest demand over the winter, separated by 10 calendar days, are known as Triads.

Triad avoidance levels were lower again than the previous year (maximum estimated avoidance level stands at 1.3 GW), down from 1.7 GW the year before. As shown in Figure 9, one Triad corresponds to much lower temperature than the seasonal normal temperature for that date, while the others occurred under seasonal normal conditions in January.

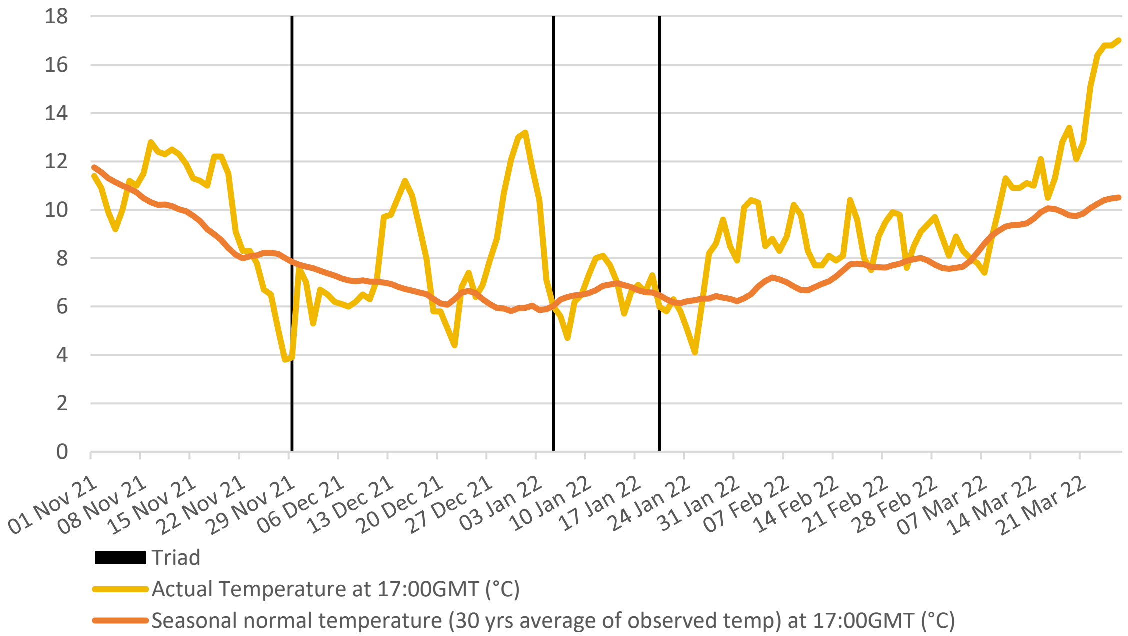

Figure 9. Daily actual temperature for winter 2021/2022 and seasonal normal temperature alongside the date of the three triads (three vertical black lines)

What we said in the *Winter Outlook Report*	What triad avoidance occurred (estimation)	Why was there a difference?
Maximum forecast Triad avoidance: 1.2 GW	The values corresponding to the three triad dates (operational view) were 0 GW, 0 GW and 0.4 GW (see Table 9).	Maximum estimated triad avoidance was broadly in line with our forecast ahead of the winter at 1.3 GW compared to a forecast of 1.2 GW. This maximum response was not seen on any of the actual triad days however. Response rates close to the forecast did occur through late November, and through much of January, around the times of the triads, but not during the triad days themselves.

Date	Time Half hour ending	National Demand (MW)	Estimated* triad avoidance (HH corresponding with the peak) (MW)
29/11/21	1730	45679	0
05/01/22	1800	44245	0
20/01/22	1730	44977	400

Table 4. Details of Triads for winter 2021/22

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* The triad avoidance estimate is not based on demand reduction data provided to us by suppliers, customers or aggregators.

Review / Electricity supply

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Clean spark spreads vs. clean dark spreads*	Remaining coal-fired generation to potentially run more frequently due to price effects (but for overall levels of coal generation to remain low due to continued reductions in capacity levels).	Coal provided the same proportion of generation as the previous winter, and overall levels remained low, while gas generation output was lower than in winter 2020/21.	Wind generation was higher than expected displacing some gas generation, and gas prices were also high.
Breakdown rates (this term covers all aspects of plant reliability, including restrictions and unplanned generator breakdowns).	Generator reliability to be broadly in line with recent winters although coal, CCGT and biomass plant had a slight increase in expected breakdown rate compared to the previous winter.	Breakdown rates (where by breakdown we mean outages that were not notified in advance of the outage, and do not include planned unavailability) on average across the winter as a whole were largely in line with expectations (see Table 5) – with most generators within a small range of between 1 and 3%. However, the breakdown rate for nuclear was much higher than forecast, at 20%. OCGT breakdown rate was also significantly higher at 11% compared to a forecast of 5%.	Unexpected outages were higher for OCGTs and nuclear generation, nevertheless the percentage energy provided by nuclear generation across the winter was the same year on year.

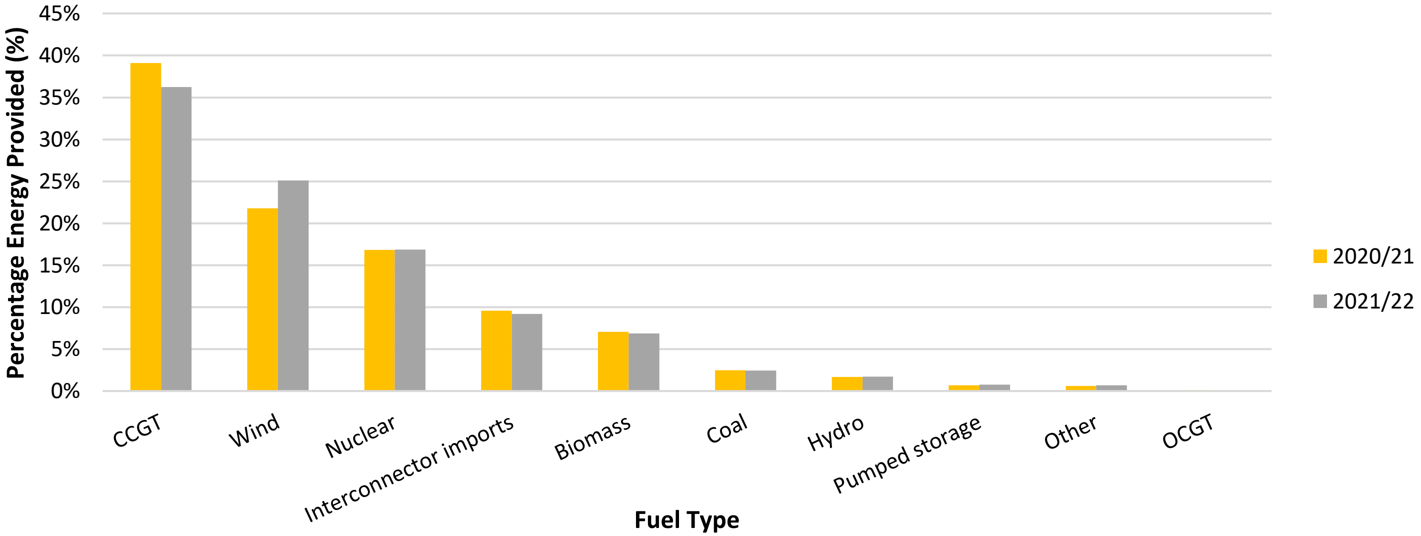

Figure 10. Percentage of energy provided by each fuel type over Winter 2020/21 and Winter 2021/22 (transmission connected)

Fuel Type	Forecast	Actual
Coal	11%	8%
CCGT	6%	5%
Nuclear	9%	20%
OCGT	5%	11%
Pumped Storage	3%	2%
Biomass	5%	8%
Hydro	9%	6%

Table 5. Breakdown rates by fuel type for winter forecast and actual winter.

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*Clean spark spread : The revenue that a gas-fired generation plant receives from selling electricity once fuel and carbon costs have been accounted for.
Clean dark spread : The revenue that a coal-fired generation plant receives from selling electricity once fuel and carbon costs have been accounted for.

Review / Europe and interconnected markets
Continental Europe

There was greater variation in interconnector imports at peak than in previous winters, but flows still followed price spreads across the winter, with imports into GB at peak seen throughout the vast majority of the winter.

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Overview of continental European interconnectors (BritNed, IFA, IFA2, NEMO Link, NSL)	Imports into GB at peak times via the IFA, IFA2, BritNed and Nemo Link interconnectors, although occasionally not at full import and subject to weather variations. During times of tight margins, such as a typical period when an EMN could be issued, imports continue into GB but at closer to full import.	There were more periods of export to continental Europe at peak times than usual, along with a much higher level variation in import at peak. Most exports that were seen at peak were over interconnectors to France.	This was driven by unplanned outages and relatively higher prices in European markets.
	We don't have historic flows for NSL as it only recently began commercial operation but we expect imports to GB, especially at times of tight margins, based on price spreads.	NSL began running on 01/10/21. As part of its trial phase it spent a lot of time running at partial capacity, with a capacity of 700 MW through most of the winter. As seen in Figure 12, NSL flowed into GB as expected.	N/A

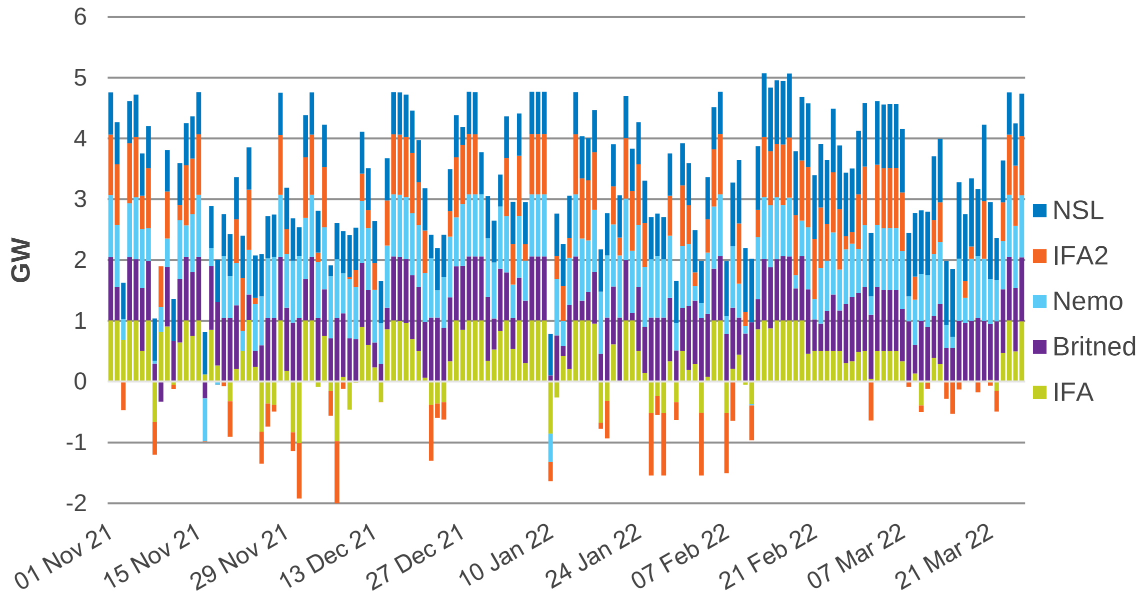

Figure 11. IFA, IFA2, BritNed, Nemo Link and NSL flow at peak times

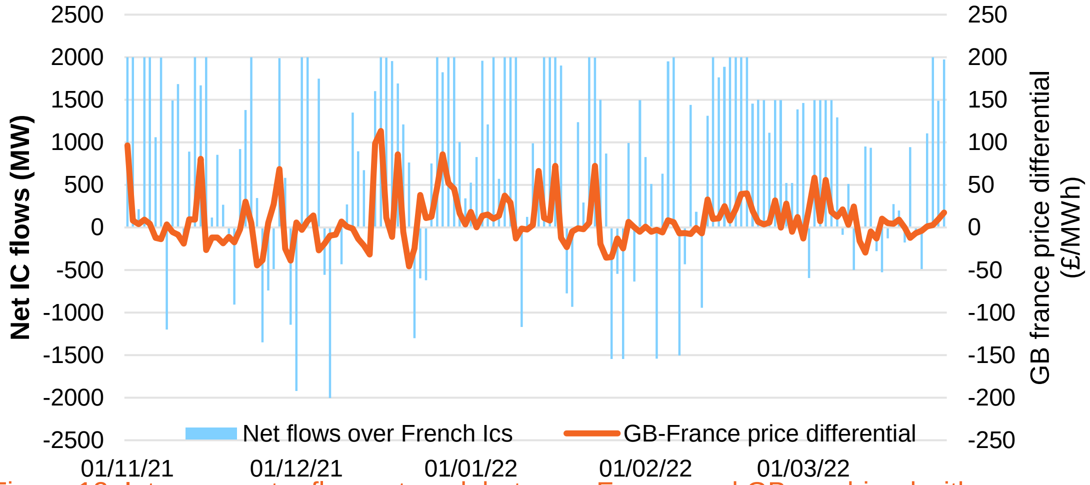

Figure 12. Interconnector flows at peak between France and GB combined with the GB France price differential (positive values signify imports into GB and GB prices ahead of French prices)

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Review / Europe and interconnected markets

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Physical capabilities	Interconnector capability will be affected by the following outages: IFA: 4 Oct - 23 Oct (0 MW), 24 Oct - 27 Mar (1000 MW) NSL: 1 Oct - 31 Oct (700MW)	There were a high number of changes in interconnector availability status through the winter across a range of interconnectors.	Unplanned outages impacted interconnector availability.
European forward prices	Forward prices, including peak prices, in GB to be ahead of those in continental Europe for the majority of the winter period	Prices in continental European markets were closer to GB prices than usual, and exceeded them more often (see Figure 11). While we still saw a net flow of electricity from the continent to GB as expected the majority of the time, there were more occasions than usual when this wasn't the case as prices in France were higher than in GB on a number of occasions.	Prices were higher than usual in both GB and European markets reducing the differential that is usually seen.

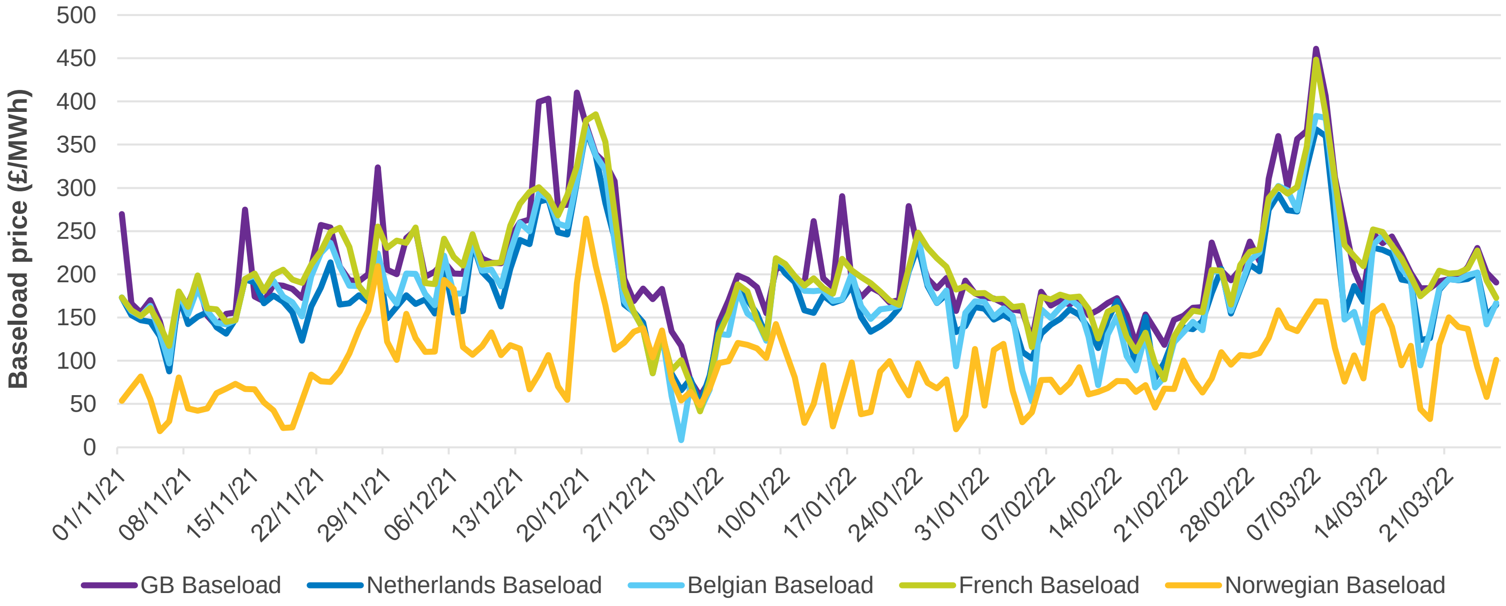


Figure 13. GB and European day-ahead baseload prices across winter 2021/22

The Data Workbook contains further detail on:

- Interconnector outages;
- specific interconnector behaviour; and
- Breakdown rates

Review / Europe and interconnected markets

Irish interconnectors

Flows across the EWIC and Moyle interconnectors to Ireland and Northern Ireland were broadly as expected.

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Overview of Irish interconnectors (Moyle and EWIC)	Moyle and EWIC to typically export from GB to Northern Ireland and Ireland during peak times, although at substantially less than maximum capacity due to high demand on the GB system. During a typical EMN period, exports to Northern Ireland and Ireland are expected to reduce to zero.	Both Moyle and EWIC exported electricity to Northern Ireland at peak times for the majority of the winter (see Figure 14).	N/A

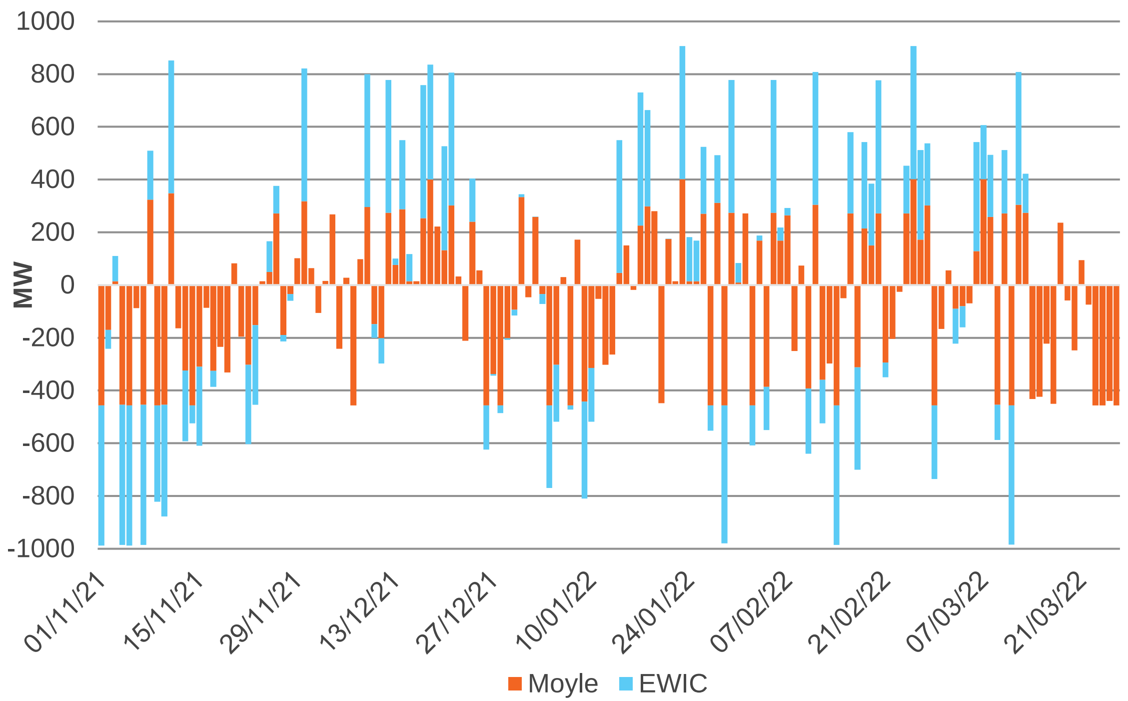


Figure 14. Moyle and EWIC flows at peak times (positive MW values mean flows into GB)

Review / Operational view – transmission system

We took action across the five core areas to ensure operational security over the winter period.

Thermal

The TO experienced delays to the scheme to connect a major windfarm at Tealing substation. This resulted in greater levels of constraints across the B4 boundary. Additional outages and delays were experienced/required for bird nest removal which exacerbated the situation and the restrictions ran beyond autumn and into the winter months.

A proposed scheme to allow maximum use of the Western Link HVDC could not be accelerated in to 2022 as planned, impacting the B6 boundary between Scotland and England following the decommissioning of Hunterston in January 2021. NSL interconnector completed commissioning and, as noted in the *Winter Outlook Report*, it did contribute to volumes required to be bid off above the B7 boundary. It can also restrict the B6 boundary when NSL is at full export. However, as expected we did not have to take additional actions to manage operability issues relating to the import into Scotland

The significant rise in gas prices had the consequence of increasing the net exposure cost of all thermally driven outage combinations, as replacement energy prices rose to extraordinary levels.

Stability

As part of Stability Pathfinder Phase 1, three further units went live over the winter providing additional inertia and fault infeed to the network, thereby reducing the reliance on buying on thermal plants during periods of high renewable generation. The remaining units are expected to go-live by this year providing additional support for winter 2022/23.

Frequency

From November 2021 to March 2022 there were no frequency events causing a deviation greater than ± 0.5 Hz.

Our Dynamic Containment High service was in operation last winter for the first time and this was the first winter whereby Short Term Operating Reserve was procured through a day ahead auction mechanism. More details can be found on the following page.

Restoration

Our Restoration capability was maintained over the Winter period as per our requirement.

Voltage

Control of high voltages proved challenging though manageable through the Christmas and New Year period. High availability of synchronous generation meant that lack of available generation was not the main challenge.

Variable system conditions were seen through the period, with swings from high wind and high flows to low wind with low flows requiring frequent reassessment within day to optimise the requirement for voltage control.

Actions to synchronise generation to manage the system reactive power balance and voltages were required, depending on the forecast system demand and other conditions. Some operational actions were also required.

Review / Operational view – transmission system

Services

Dynamic Containment (DC) is designed to operate post-fault, i.e. for deployment after a significant frequency deviation in order to meet our most immediate need for faster-acting frequency response. Dynamic Containment Low (DCL) was launched in October 2020 with Dynamic Containment High launched in October 2021.

We launched Dynamic Containment High as a new tool in our tool-kit to help manage largest loss risks. exporting interconnectors or demand loss risks. We also improved our procurement of DC, making our procurement more granular which enabled consumer savings.

The move to EFA block procurement meant that, instead of procuring volume to cover the maximum DC requirement over a 24-hour window, the ESO was able to signal the value of DC across a day, as system conditions such as demand, inertia and largest loss risks change.

Last winter we saw providers exiting DC during tight periods impacting volume across the day. More granular procurement enables providers to choose which market they participate in and which EFA block they were available for which helped to minimise the impact of such market behaviour

The record-high wholesale prices since the start of September 2021 led to increased volatility in the participation of Dynamic Containment, with some providers choosing to participate in the wholesale market during lucrative periods.

However, despite the impact of the wholesale energy price on participation, the implementation of EFA block procurement still resulted in a saving of around £18.7m during the period compared to the counterfactual scenario if the procurement granularity and costs had remained unchanged.

The Winter 2021/22 season, was also the first in which Short Term Operating Reserve (STOR) was procured at the day-ahead level. We experienced some similar challenges with market providers leaving the market on tight days but reviewed our buy order methodology in response to this and were able to mitigate this.

These changes brought with it significant challenges – in no small part due to the unprecedented wholesale market dynamics which permeated all Ancillary Services markets. Notwithstanding this, the ESO were able to deliver significant savings through the implementation of the procurement strategy for STOR versus the costs that would have been incurred in the absence of the service.

The primary challenge arising during the Winter 2021/22 season was reserve volume shortfalls: where less volume was secured via the day-ahead auction process than was required. Occurrences of reserve shortfalls were most prevalent on days characterised by significant electricity system tightness, i.e. low margin. More specifically, the associated effect of system tightness on prices in the Balancing Mechanism and wholesale market saw a marked fall in the number of providers tendering for day-ahead STOR contracts. This, in turn, resulted in fewer MWs of firm reserve capacity than required being procured ahead of delivery.

To address this, the ESO implemented changes in the pricing methodology for Short Term Operating Reserve during the Winter 2021/22 season to ensure that the service was providing sufficient commercial incentive for providers, even on days where the electricity system was forecast to be tight.

As a result of the amendments, and the inherent benefit of Day-Ahead procurement versus real-time, the ESO were able to delivery cost savings of over £90mn between 1st October 2021 and 31st March 2022, against the alternative cost of the STOR service, (i.e. the cost of securing the full daily requirements via the Balancing Mechanism in real time).

Consultation / Introduction

The purpose of this annual consultation is to gather feedback on our Outlook documents and gather stakeholder insight each year to inform our analysis for the upcoming *Winter Outlook Report*, to be published in October 2022.

Your views on the market and related issues are always important to provide a comprehensive picture of the challenges and opportunities of the forthcoming winter.

It also allows us to test how useful the suite of Outlook documents are and to identify areas for improvement with our engagement.

The ESO has committed to providing an early view of winter 2022/23 in July 2022 to give earlier information to the industry in light of the recent very high energy prices.

As this early view of winter 2022/23 will include a consultation aspect, the consultation questions in this document are less specific to winter 2022/23 and more about this document and the Electricity Outlooks process in general.

However, feedback on our potential plans and on preparations for the upcoming winter remains extremely important and so we will make sure any comments and information received via this document are passed to the relevant teams within the ESO.

This year's consultation closes on 30 July 2022.

Please refer to the next slide for questions. You can send us your views via email: marketoutlook@nationalgrideso.com

The ENCC Operational Transparency Forum will also provides an opportunity for you to share your views on the winter ahead and ask us questions. Please register here.

Consultation / Questions

Winter Review and Consultation

1. What do you use the *Winter Review and Consultation Report* for? What information in the report is most useful to you for this?

2. Is there anything else that could be included in the *Winter Review and Consultation Report*?

3. How do you think the *Winter Review and Consultation Report* could be improved more generally to increase benefit for consumers?

4. Do you have any other feedback on this report or the other Outlook documents?

Winter Outlook

5. Is there anything you are particularly interested in seeing as part of our early winter view in July?

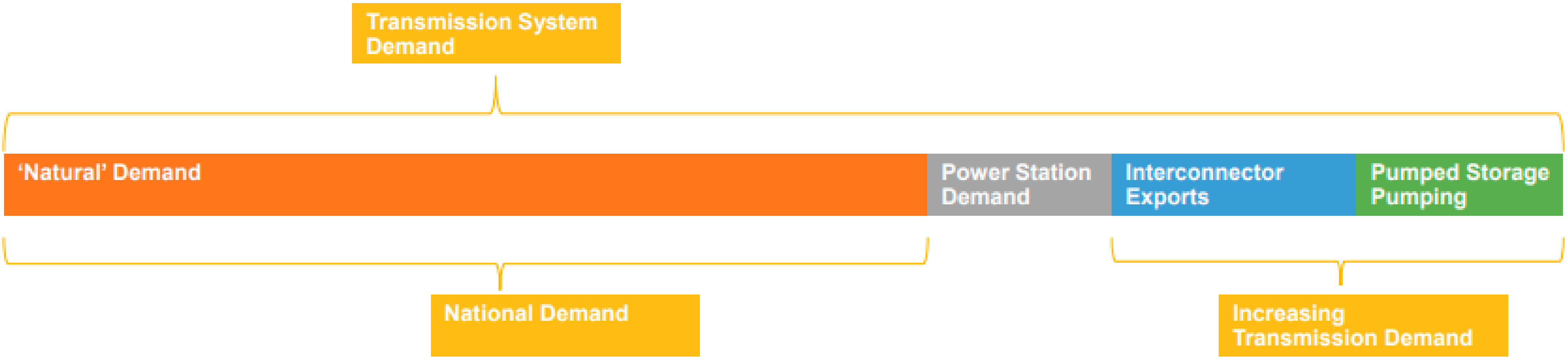
6. Is there anything different you would like to see in the *Winter Outlook Report,* to be published in October 2022?

7. Do you have any general queries or concerns in relation to winter 2022/23?

Appendix

Contains extra information on demand definitions and margin notifications

Demand Definitions



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 if required.

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Find out more on the differences between Electricity Margin Notices (EMNs) and Capacity Market Notices (CMNs) here.

Did you know? / Capacity Market Notices and Electricity Margin Notices

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 week-by-week 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 500MW. The 500MW 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 1,000MW+ 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.

Glossary

Active Notification System (ANS)
A system for sharing short notifications with the industry via text message or email.

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 3 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. BritNed is a bi-directional interconnector with a capacity of 1,000MW. You can find out more at www.britned.com.

Capacity Market (CM)
The Capacity Market is designed to ensure security of electricity supply. This is achieved by providing a payment for reliable sources of capacity, alongside their electricity revenues, ensuring they deliver energy when needed.

Carbon intensity
A way of examining how much carbon dioxide is emitted in different processes. It is usually expressed as the amount of carbon dioxide emitted per kilometre travelled, per unit of heat created or per kilowatt hour of electricity produced.

Clean dark spread
The revenue that a coal fired generation plant receives from selling electricity once fuel and carbon costs have been accounted for.

Clean spark spread
The revenue that a gas fired generation plant receives from selling electricity once fuel and carbon costs have been accounted for.

CMP264/265
Changes to the Charging and Use of System Code (CUSC). These changes were phased in from 1 April 2018 and reduce the value of avoided network charges over triad periods.

CO2 equivalent/kWh
The units ‘gCO2eq/kWh’ are grams of carbon dioxide equivalent per kilowatt-hour of electricity generated. Carbon dioxide is the most significant greenhouse gas (GHG). GHGs other than carbon dioxide, such as methane, are quantified as equivalent amounts of carbon dioxide. This is done by calculating their global warming potential relative to carbon dioxide over a specified timescale, usually 100 years.

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.

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 and battery units. Generation that is connected to the distribution system is not usually directly visible to National Grid ESO as the system operator and acts to reduce demand on the transmission system.

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

Electricity Forward Agreement (EFA)
EFA blocks are a product used to trade electricity on the wholesale market. There are 6 EFA blocks in a baseload day. EFA5 (15:00 – 19:00) contains the Darkness Peak in winter.

European Union Emissions Trading System (EU ETS)
An EU-wide system for trading greenhouse gas emission allowances. The scheme covers more than 11,000 power stations and industrial plants in 31 countries.

Floating
When an interconnector is neither importing nor exporting electricity.

Glossary

Footroom
When a generator can reduce its output without going below minimum output levels.

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

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

Interconnexion France–Angleterre (IFA)
A 2,000 MW link 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 (IFA 2)
A 1000 MW link between the French and British transmission systems (commissioned early 2021). Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).

Inertia
System inertia is how resilient a system is to frequency change. System inertia will depend on what types of generation are connected to the system. Typically, generators with large moving parts have high inertia – because their moving parts continue to move even after they are switched off or turned down. In contrast, some types of generation that have no moving parts, such as solar panels, are classed as low inertia generation

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 due to commercial arrangements or technical reasons. Examples of inflexible generation include nuclear, combined heat and power (CHP) stations, and some hydro generators and wind farms.

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.

Load Factors
An indication of how much a generation plant or technology type has output 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.

Margins Notice Issued
When forecast demand for the day ahead exceeds a pre-defined forecast of supply.

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

National electricity transmission system (NETS)
High voltage electricity is transported on the transmission system from where it is produced to where it is needed throughout the country. The system is made up of high voltage electricity wires that extend across Britain and nearby offshore waters. It is owned and maintained by regional transmission companies, while the system as a whole is operated by a single Electricity System Operator (ESO).

Nemo Link
A 1000MW interconnector between GB and Belgium. Ownership is shared between National Grid and Elia.

Positive and negative reserve
To manage system frequency and to respond to sudden changes in demand and supply, the ESO maintains positive and negative reserve which is the capability to increase or decrease supply and demand.

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.

Glossary

Rate of Change of Frequency (RoCoF)

How quickly system frequency changes on the electricity network. Usually measured in Hertz per second. Some generators have a protection system that will disconnect them from the network if the Rate of Change of Frequency goes above a certain threshold.

Reserve requirement

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

Seasonal normal weather

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

Short Term Operating Reserve (STOR)

At certain times of the day, we may need access to sources of extra power to help manage actual demand on the system being greater than forecast or unforeseen generation unavailability. STOR provides this reserve.

Stability Pathfinder (Phase 1)

A process to identify the most cost-effective way to address stability issues in the electricity system. Phase 1 was looking to increase inertia and resulted in 12 contracts being awarded to 5 providers.

Transmission System Demand (TSD)

Demand that the ESO sees at grid supply points, which are 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.

Voltage

Unlike system frequency, voltage varies across different locations on the network, depending on supply and demand for electricity, and the amount of reactive power in that area. Broadly, when electricity demand falls, reactive power increases and this increases the likelihood of a high voltage occurrence.

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.

Western High Voltage (HVDC) Link (WLHVDC)

The Western Link uses DC technology to reinforce the UK transmission system and move electricity across the country in very large volumes between Hunterston in Scotland and Deeside in North Wales.

Winter period

The winter period is defined as 1 October to 31 March.

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 Review Report* at: marketoutlook@nationalgrideso.com and we will get in touch.

You can write to us at:
Energy Insights and Analysis, Electricity System Operator
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

The *Winter Review & Consultation 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.