Winter Review and Consultation

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

June 2023

ESO

Welcome

Welcome to our 2023 Winter Review and Consultation Report. This annual document provides a review of how what we said in the *2022/23 Winter Outlook Report* compared to what actually happened.

This document includes a review of all the standard analysis from the *2022/23 Winter Outlook Report* in relation to elements such as demand levels, performance of generators and any operability challenges faced.

This year we have published an early view of Winter 2023/24 alongside this report, to give earlier information to the industry to help them prepare for the coming winter.

As with previous years the consultation section of this report focus primarily on the 2022/23 Winter Outlook and the general Electricity Outlooks process.

However, we welcome feedback on our potential plans and preparations for the upcoming winter, 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 2022/23 from the electricity perspective. National Gas Transmission (NGT) publish a similar document from the gas perspective, the Gas 2023 Winter Review and Consultation Report, which can be found here. We continue to engage with NGT on approach and consistency.

Contents

Key Messages / Winter Review 2022-23

1. Margins

Winter margins were broadly in line with those of our Base Case from the *Winter Outlook Report* and there was no interruption to customer demand due to unavailable supply.

Winter 2022/23 was generally milder than average with three notable cold spells in December, January and March.

We issued one Electricity Margin Notice for 7th March, which was cancelled ahead of real-time. This was also the only day we dispatched coal contingency units.

Reciprocal support between European system operators helped maintain an efficient position across all markets, delivering benefits for us and our European neighbours. This led to periods of the winter when Great Britain exported power on interconnectors to Europe and periods when imports flowed from Europe when we needed them.

2. Demand

Electricity demand was lower than expected for most of the winter, except during the coldest spells.

Daily peak demand (weather-corrected) was generally lower than our central forecast and lower than comparable demand from the previous winter, as customers responded to high prices.

Peak demand during cold spells in December, January and early March was relatively high with little apparent reduction.

The highest observed peak demand of the winter was close to our average cold spell (ACS) peak forecast, indicating electricity customers prioritised their use of energy for the coldest days in winter.

3. Demand Flexibility Service

Our world-leading Demand Flexibility Service (DFS) delivered 3.3 GWh through consumer & business demand flexibility over the winter.

DFS demonstrated that demand flexibility can be provided at national-scale, allowing customers to benefit from shifting electricity usage away from specific periods.

Participation grew throughout winter with over 31 suppliers signing up, highlighting the potential for further growth of such services.

We used the service on two days in January and there were a further 20 tests of the service.

At its peak, DFS reduced electricity demand by around 300 MW when the service was used live.

4. Balancing costs

While balancing costs have reduced by 20% from the peak of winter 2021/22, this is still higher than previous years, driven principally by gas wholesale prices.

An independent Balancing Market Cost Report commissioned by the ESO reviewed balancing costs for winter 2022/23, considering the impact of different factors on balancing costs, including the drivers behind high cost days. The report is available on our website here.

The report found that tight margins were one of the factors that led to days with higher balancing costs. It also found that, in general, use of our enhanced actions did not lead to increased costs.

Review / Surplus

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

Margins were adequate throughout winter with daily operational surpluses in line with expectations of the Base Case in the *Winter Outlook Report*. Tighter periods in late November to mid-December, late January and early March were driven by a combination of colder weather, low wind, generator outage delays and lower imports from Europe.

Demand

- The daily peak demand was generally lower than the Winter Outlook central forecast, as shown in Figure 1. However, periods of cold, calm weather in December, January and March led to relatively high demand.
- The actual winter peak demand was close to the ACS peak.

Further analysis on the demand can be found on page 9.

Supply

- Generator and interconnector availability was generally in-line with Winter Outlook expectations. Higher outages at the start and end of winter led to lower generator availability in November and March. Imports from Europe were generally lower in November due to the availability of the French nuclear fleet.

Further analysis on the generator availability can be found on page 11. Further analysis on interconnector flows can be found on page 13.

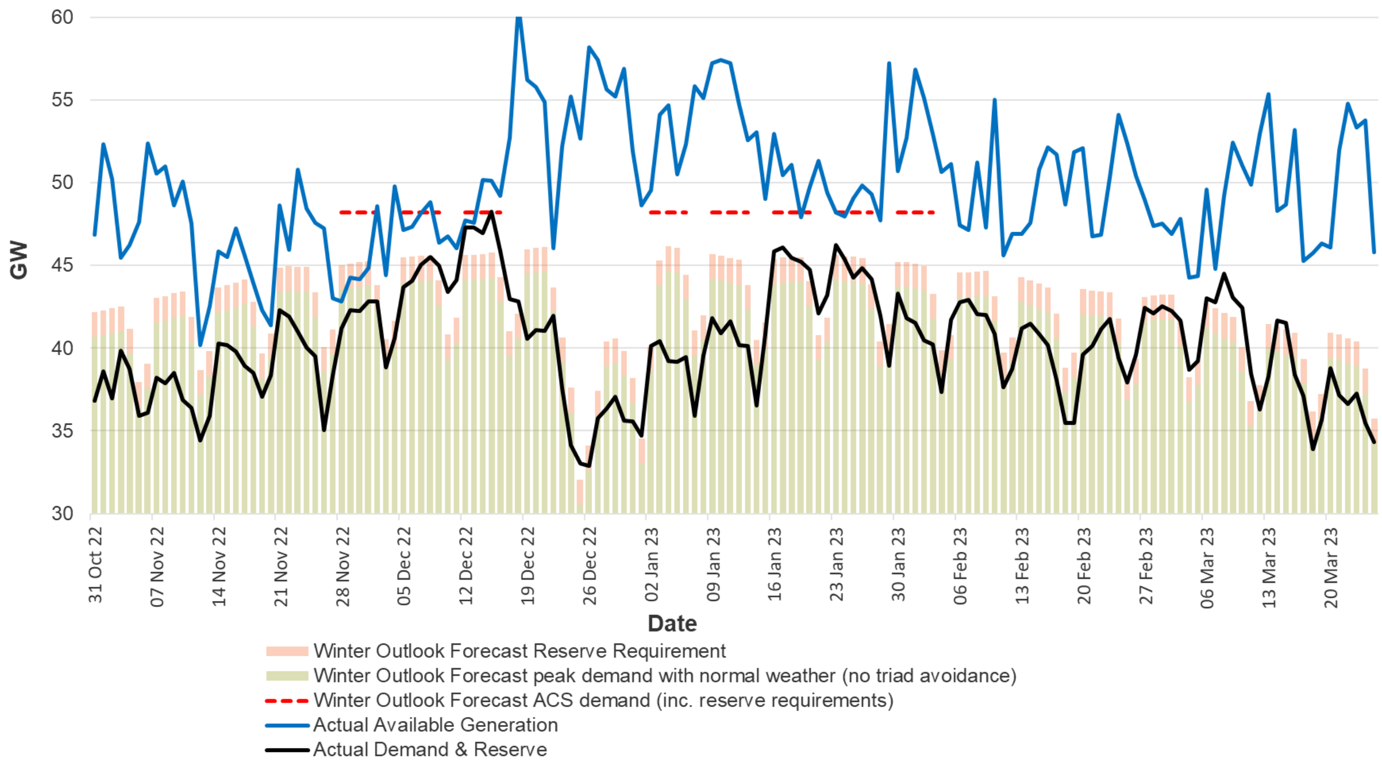

Figure 1: Winter 2022/23 day-by-day view of operational surplus. Forecasts from the Winter Outlook of demand are compared to the actual available generation, demand (and reserves).

Interpreting this chart: Figure 1 shows our forecasted day-by-day peak demand under normal weather conditions (green bars) and our reserve requirement (orange bars) from the *2022/23 Winter Outlook Report*. It also shows the forecasted peak demand under average cold spell conditions (dashed red line) also from the *2022/23 Winter Outlook Report*. The solid black line shows the actual peak demand for each day during winter. The solid blue line shows the actual available supply at peak for each day during winter. Margins were tighter on days when the solid blue and black lines were closer together.

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Review / Surplus
How did the winter compare to the *Winter Outlook Report*?

The daily operational surplus varied throughout winter in line with the credible range set out in our Base Case.

Figure 2 shows how the indicative outturn surplus (solid purple line) was broadly in line with the expected credible range (shaded red region) set out in the *Winter Outlook Report*.

The out-turn surplus was generally below the central forecast throughout November. This was due to net exports on the continental interconnectors, driven mainly by the availability of the French nuclear fleet returning from outages. Reciprocal support between European system operators maintained an efficient position across all markets. The out-turn surplus was more balanced for the rest of winter, with periods above and below our central forecast.

There were a small number of days where the indicative outturn surplus was outside the red-shaded region. This was around 10% of the days and consistent with the modelled 90% confidence bound.

The tightest days outside the lower bound were in late November, mid-December, and early March. These periods saw below average temperatures and low wind generation.

The days outside the upper bound were in late December, early January, and late March. These were periods of low demand, above average temperatures, and high wind generation.

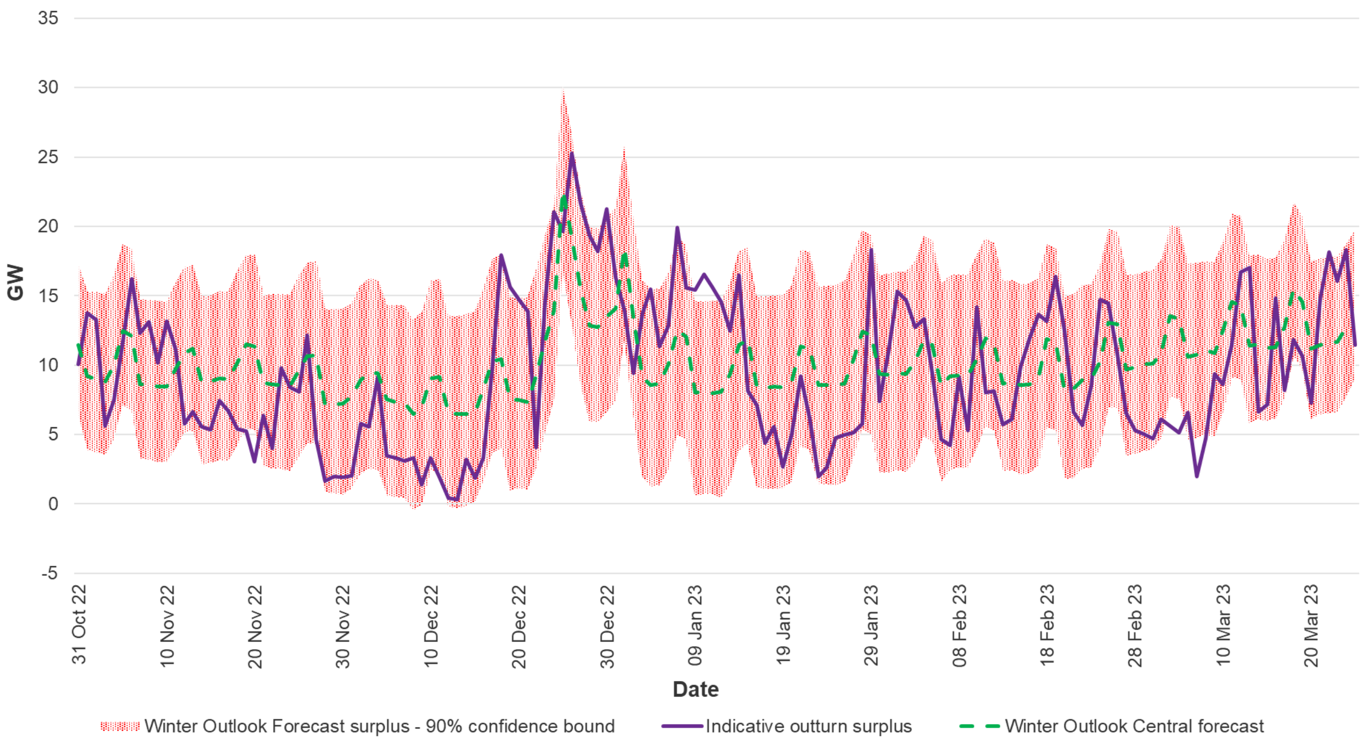


Figure 2. Day-by-day view of actual operational surplus for winter 2022/23 against the forecast surplus and credible range sensitivity from the Winter Outlook.

Interpreting this chart: Figure 2 shows the credible range of operational surplus that we expected on each day's demand peak throughout winter as published in the 2022/23 *Winter Outlook Report*. The credible range (red-shaded region) represents the 90% confidence bound reflecting day-to-day variations in weather and available generation. A central view (dashed green line) was also published in the *Winter Outlook Report*. The solid purple line shows an indicative view of the outturn operational surplus on each day.

Review / Surplus

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

Margins were sufficient throughout the winter in-line with those expected in the Base Case from the *Winter Outlook Report*. On some tighter days margin notices and enhanced services were used to manage uncertainty.

There was one Electricity Margin Notice (EMN) issued in winter 2022/23 compared to none issued in winter 2021/22. There were two Capacity Market Notices (CMNs) issued, which is the same as the previous winter. The EMN and both CMNs were cancelled ahead of real-time. On each occasion when market notifications were issued, actual transmission system demand was lower than the actual winter peak transmission system demand (47.1 GW) shown in Table 2. This highlights how times when margins are tight do not necessarily occur on the days with the highest demand because shortfall of generation also needs to be accounted for. See Appendix B for more information on EMNs and CMNs.

Over the winter, the Operational Transparency Forum (OTF) featured deep dives on each of the days in Table 1. For more information, please see the OTF slides (or watch the recorded webinars here):

- CMNs: OTF on 30th November
- EMN: OTF on 15th March

Date	Day of week	EMN	CMN	Actual Peak Transmission System Demand (GW)
22nd Nov 2022	Tuesday	No	Yes	40.8
28th Nov 2022	Monday	No	Yes	40.1
7th Mar 2023 (issued 6th Mar)	Tuesday	Yes	No	42.6

Table 1: Days of EMNs and CMNs over Winter 2022/23 with actual peak Transmission System Demand (not weather corrected)

What we said in the *Winter Outlook Report*	What actually happened	Explanation
In the Base Case, we expect to have sufficient operational surplus throughout winter when routine tools such as margin notices are used. Tight margins to be likely throughout December to mid-January (excluding the Christmas period).	Operational surplus was sufficient throughout the winter and there was available supply from Europe when we needed it. Enhanced services were activated on a few days to manage uncertainty around interconnector flows and margins. The potential risk of reduced electricity imports from Europe and gas supply shortages (outlined in the illustrative scenarios in the *Winter Outlook Report*) did not materialise.	Throughout the winter the ESO took a collaborative approach to managing margins, working closely with neighbouring TSOs to provide reciprocal support. While the contingency coal units were warmed for 7 days across winter as a precaution, they were only run on 7th March. This is the same day an EMN was issued for. For more information on this event see the slides from the OTF on 15th March. Live Demand Flexibility Service (DFS) events were run on 23rd and 24th January to help manage uncertainty around interconnector flows. See more about DFS on page 8 and on the slides from the OTF on 25th January.

Spotlight / Demand Flexibility Service

Our Demand Flexibility Service (DFS) demonstrated that demand flexibility can be provided at national-scale, allowing customers to benefit from shifting electricity usage away from specific periods. Participation grew throughout winter highlighting potential for further growth of such services.

This new innovative service allowed consumers, as well as some industrial and commercial users (through suppliers/aggregators), to be incentivised for voluntarily flexing the time when they used their electricity. As part of a range of tools designed to help manage the electricity system this winter, we wanted to collaborate with energy suppliers/aggregators to allow participating consumers and businesses to reduce their bills this winter.

To assess the readiness and generate interest and enthusiasm for consumer flexibility on an unprecedented scale, the ESO ran a maximum of 12 regular (non-onboarding) tests with each electricity supplier and aggregator between November 2022 and March 2023.

Over **1.6** million reach

c.**350** MW submitted capacity

31 DFS approved providers

20 onboarding & regular Tests

2.5 GWh delivered

2 Live events

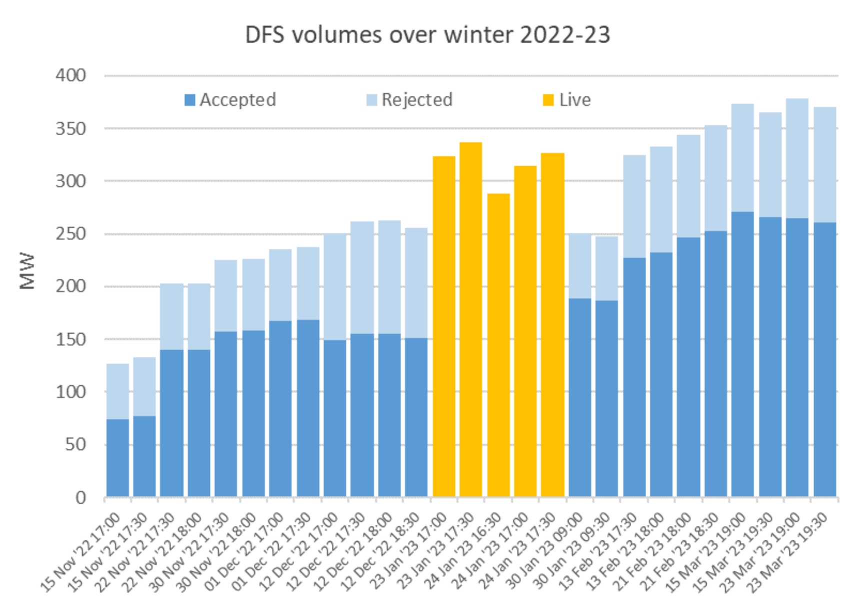
0.8 GWh delivered

For more information on the live DFS events, please visit our Operational Transparency Forum page where you can find a recording of the webinar and slides from 25th January 2023: https://www.nationalgrideso.com/what-we-do/electricity-national-control-centre/operational-transparency-forum

The tests have seen a steady increase in participation through the winter achieving a remarkable level of demand flexibility to a capacity of c.350 MW by March 2023.

The success of the tests and live events have demonstrated that demand flexibility can effectively provide scalability in flexibility, allowing consumers and businesses nationwide to benefit from shifting their electricity usage away from specific peak periods. These regular tests had a guaranteed minimum price of £3/kWh.

The Figure below shows the volume of participation in the tests and live events. The accepted volume is the bids that were successful and contracted with and the rejected volume is the bids that were unsuccessful. In the live events all submitted bids were accepted (note that tests of small volumes have been omitted from this chart).



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Review / Demand

The day-to-day peak demand was generally lower than the previous winter and the Winter Outlook central forecast. However, periods of cold, calm weather in December, January and March led to relatively high demand.

Due to the potential impact of high wholesale electricity prices, there was large uncertainty in the level of demand ahead of the winter. Figure 3 shows the outturn demand (weather corrected) was significantly lower than the previous winter (approximately 6% across winter). This is a result of increased embedded generation and a change in customer behaviour, likely due to price sensitivity.

Figure 4 shows that, in general, the outturn demand (solid purple line) was lower than our central forecast (dashed green line). However, periods of cold, calm weather in December, January and March led to relatively high demands (close to the top of the credible range (red shaded region) from the *Winter Outlook Report*). Milder, windier weather over the Christmas and New Year period led to relatively low demand.

The actual peak transmission system demand was 47.1 GW on 12th December as a result of much lower than seasonal normal temperatures and wind speeds.

Table 2 shows the actual weather corrected peak demand was lower at 44.2 GW which occurred in the week commencing 9th January.

See Appendix A for more information on the different demand definitions.

2022/23 Winter Outlook Report forecast peak (normal weather) (GW)	Actual 2022/23 peak (weather corrected) (GW)	Actual 2022/23 peak (GW)
45.3	44.2	47.1

Table 2: Peak transmission system demands (TSD)* for winter 2022/23

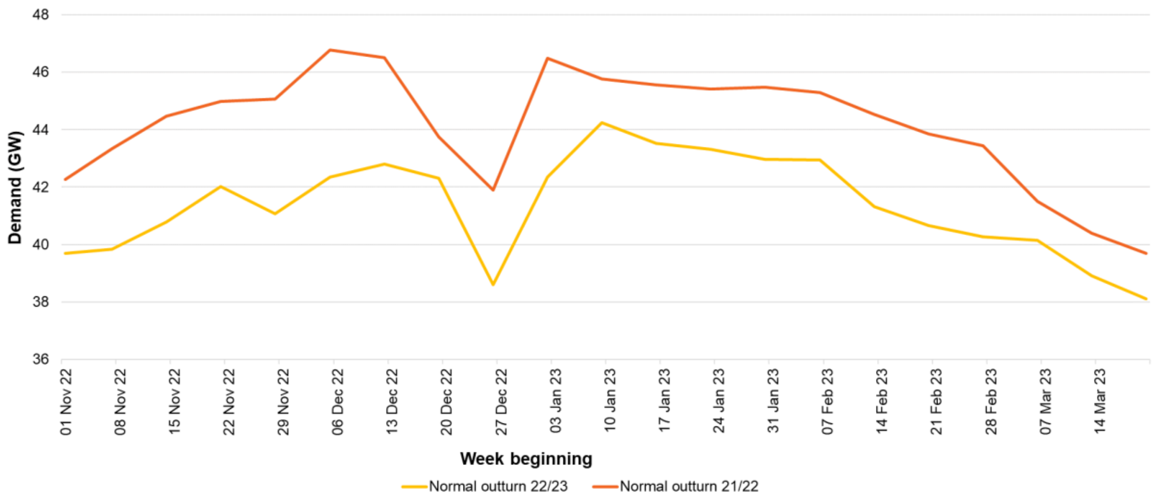

Figure 3: Peak Transmission System Demand (TSD) outturn (weather corrected) for winter 2022/23 compared to winter 2021/22.

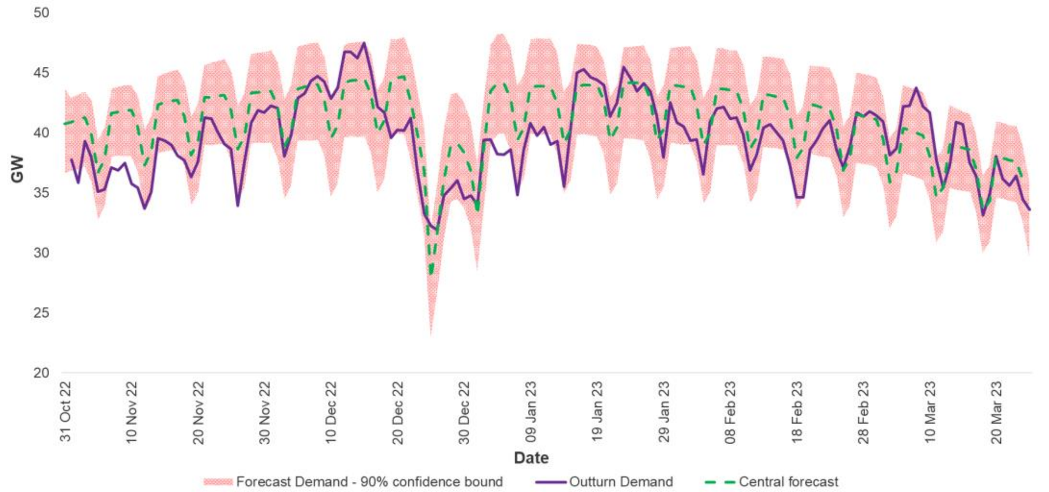

Figure 4: Comparison between the daily outturn peak demand and our forecasts from the *Winter Outlook Report*. The dashed green line shows our central forecast, while the red-shaded region represented a credible range for our forecast reflecting natural variation in weather.

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

Review / Demand
Triad Avoidance

Triad avoidance was observed throughout the winter. Levels of avoidance were generally in-line with the Winter Outlook forecast except on a single day when the avoidance was estimated to be 1.9 GW.

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.

The maximum triad avoidance level was higher than the previous year, with the maximum estimated level of 1.9 GW, compared to 1.3 GW the year before. As shown in Figure 5, the Triad in mid-December corresponds with temperatures much lower than seasonal normal, while the other two occurred when conditions were closer but slightly colder than seasonal normal.

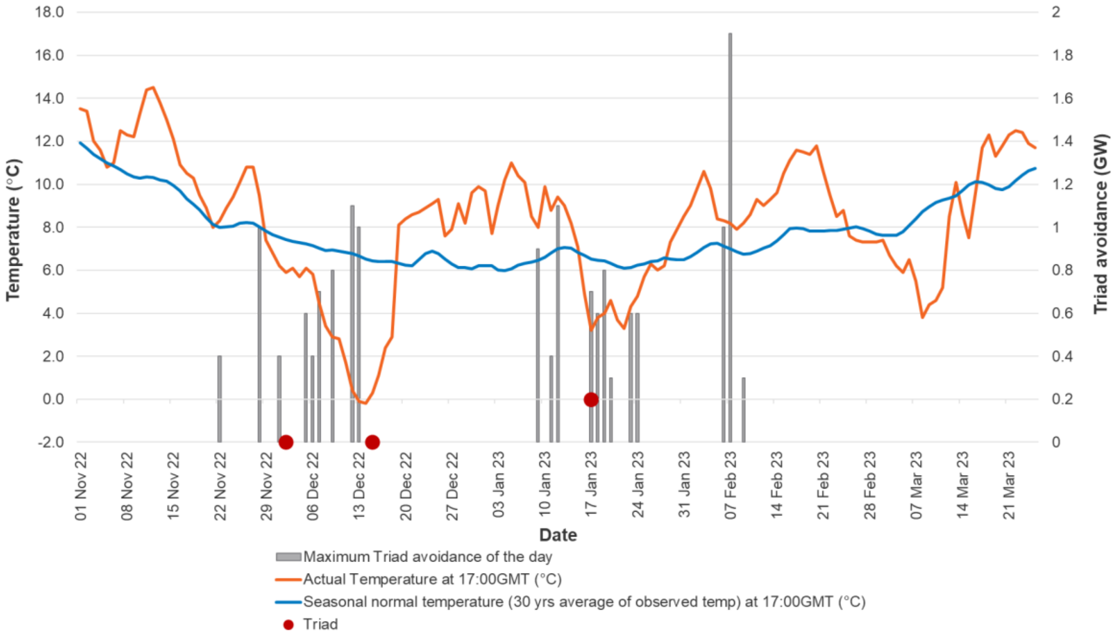

Figure 5: Daily actual temperature for winter 2022/2023 and seasonal normal temperature alongside the date of the three triads (three red dots). Note that the triad avoidance is the maximum on each day.

What we said in the *Winter Outlook Report*	What triad avoidance occurred (estimation)	Why was there a difference?
Maximum forecast triad avoidance: 0.8 GW	The values corresponding to the three Triad dates and times (operational view) were 0 GW, 0 GW and 0.2 GW (see Table 3).	Maximum estimated Triad avoidance was 1.9 GW, which was higher than our forecast of 0.8 GW. However, this high level was only seen on one day, and the next highest avoidance values were 1.1 GW. Due to the unpredictable nature of Triads, this maximum response was also not seen on any of the actual Triad days. The demand on each of the triad days were very close to the days around them, meaning triad avoidance itself could have impacted the final Triad days and times.

Date	Time Half hour (HH) ending	National Demand (MW)	Estimated* triad avoidance (HH corresponding with the peak) (MW)
15/12/22	17:30	44561	0
17/01/23	17:30	42022	200
02/12/22	18:00	39573	0

Table 3: Details of Triads for winter 2022/23, including the triad avoidance for the half hour of the triad (different to the maximum triad avoidance for the day shown in Figure 5)

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

Review / Supply

The proportions of electricity provided by each fuel type were very similar to winter 2021/22. Breakdown rates were higher than forecast for nuclear generation, but lower for CCGTs, giving a comparable level of breakdowns on average to that forecast in the *Winter Outlook Report*.

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Percentage of electricity provided by each fuel type	Remaining coal-fired generation to potentially run more frequently due to high gas prices (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 as shown in Figure 6.	While very high compared to the longer term history, gas prices were similar to the previous winter so there was no additional driver for coal generation to run more frequently than in winter 2021/22.
Breakdown rates (this term covers all aspects of plant reliability, including restrictions and unplanned generator breakdowns but not planned unavailability known ahead of winter)	Generator reliability to be broadly in line with recent winters.	Breakdown rates were on average slightly lower than expectations, but with larger variation for individual fuel types (see Table 4). Nuclear generators and OCGTs saw higher breakdown rates than anticipated, at 14% and 11% respectively. However, other fuel types including coal, CCGTs and biomass saw lower rates than anticipated.	Nuclear generators saw lower availability than anticipated because some individual generators delayed their return from summer outages beyond the dates notified at the time of the *Winter Outlook Report*.

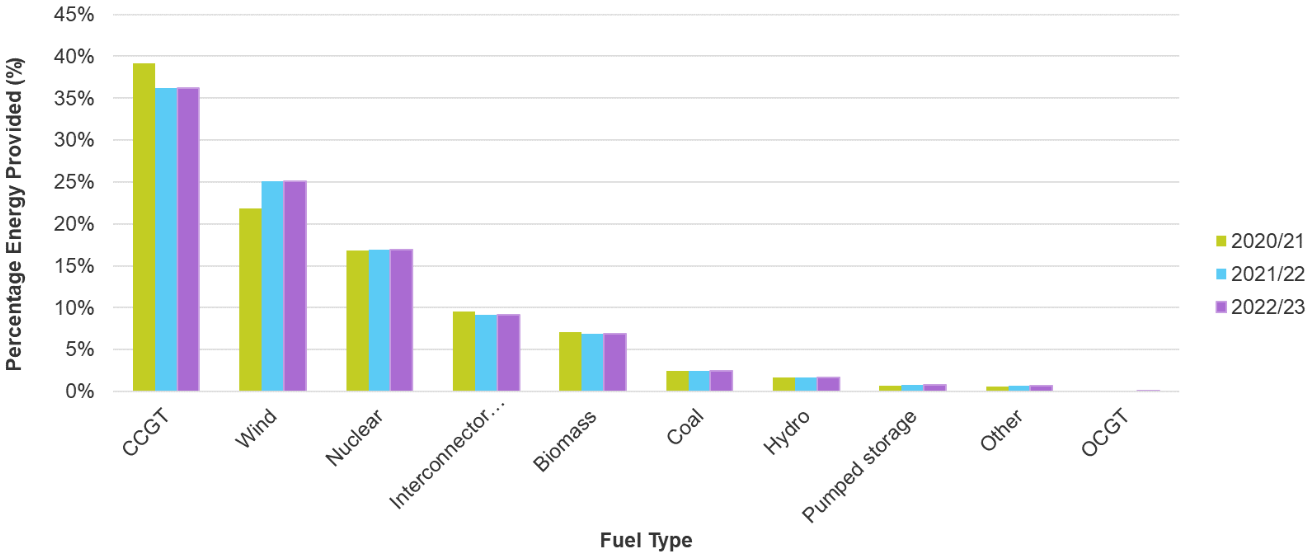

Figure 6: Percentage of electricity provided by each fuel type over Winters 2020/21, 2021/22 and 2022/23 (transmission connected generation only)

Fuel Type	Forecast	Actual
Coal	10%	6%
CCGT	6%	4%
Nuclear	10%	14%
OCGT	7%	11%
Pumped Storage	3%	3%
Biomass	6%	4%
Hydro	8%	7%
Weighted Average	6%	5%

Table 4: Breakdown rates by fuel type for winter forecast and actual winter. Weighted average is calculated based on derated capacity.

Review / Supply

Generator availability

Generation availability was broadly in line with, or above, expectations in our Winter Outlook for most of the winter.

Figure 7 shows the how the actual available generation at real time (including actual wind output) compared with the expected available generation (including availability notified at the time of publication and wind at its Equivalent Firm Capacity (EFC)) forecast in the *Winter Outlook Report*.

For most of winter generator availability was above that estimated in the Winter Outlook, but there were some short periods with a supply shortfall, mostly due to low wind generation. The time period with the biggest shortfall was in the second half of November. This was primarily driven by nuclear generators extending their summer outages beyond the dates notified when the *Winter Outlook Report* was produced, along with low wind. As there were some tight days in late November, generator availability would have contributed to low surplus on those days.

Wind generation output

Wind generation during peak demand was highly variable throughout winter but generally higher than the Equivalent Firm Capacity level.

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 8 shows this Equivalent Firm Capacity (EFC) for wind and the actual availability throughout the winter at peak.

At time of peak, wind generation output was generally higher than the EFC level, however there were 10 points where the output was below. Of these only three were significantly below, which all fell in late November to Mid-December. These three were some of the tightest days this winter (according to the indicative outturn surplus), and so this wind generation output shortfall would have contributed to the low surplus on those days.

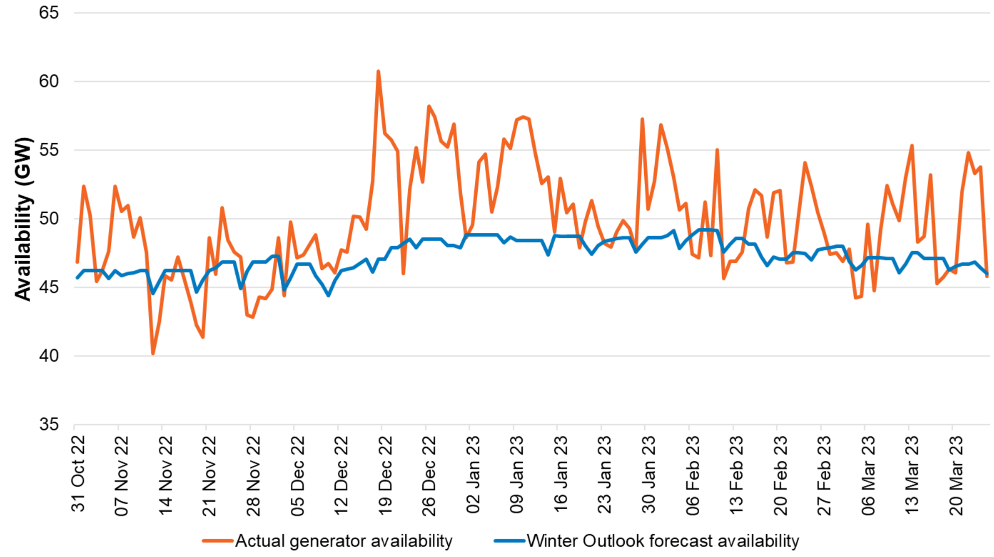

Figure 7: Shortfall between generation availability notified in the *Winter Outlook Report* and actual generator availability (including wind generation)

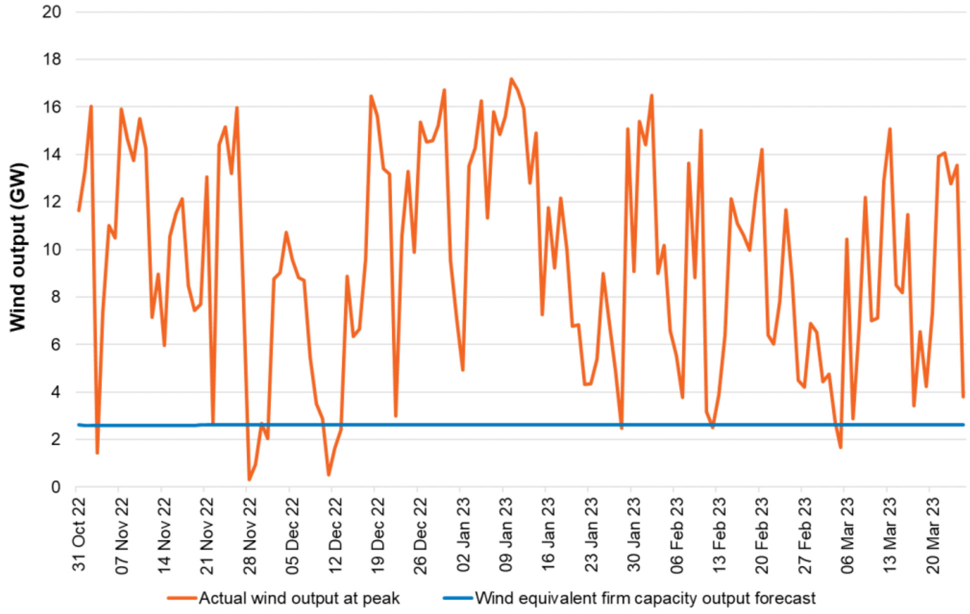

Figure 8: Wind output at peak against equivalent firm capacity

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Review / Europe and interconnected markets

Continental Interconnector Flows

Across the winter, interconnectors with Continental Europe were generally importing to Great Britain at peak, following the direction of the price spreads. However, there were some days, particularly in November, when we saw export to France at peak.

	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)	Based on forward prices for the 2022/23 winter products, we expect imports into GB at peak times from the Netherlands and Belgium under normal network operating conditions. We may see greater levels of export to France at peak times than in previous years.	Over winter, we generally saw imports into GB at peak times from Continental Europe as expected (see Figure 9). Most exports that were seen at peak were in November and over interconnectors to France. There were a similar number of days with export to France in this winter compared to the previous winter.	Figure 10 shows that France generally had higher prices at peak than GB in November which contained most of the days with net export to France.
	We expect net imports from Norway across the NSL interconnector over the winter period, particularly at peak.	For the vast majority of days, we saw imports of electricity across NSL at peak. However, this couldn't always be at full capacity as there were capacity restrictions on flow to GB for most of winter to support the management system security.	On 97% of days this winter NSL was importing to GB, which matches our expectations of net imports across winter.

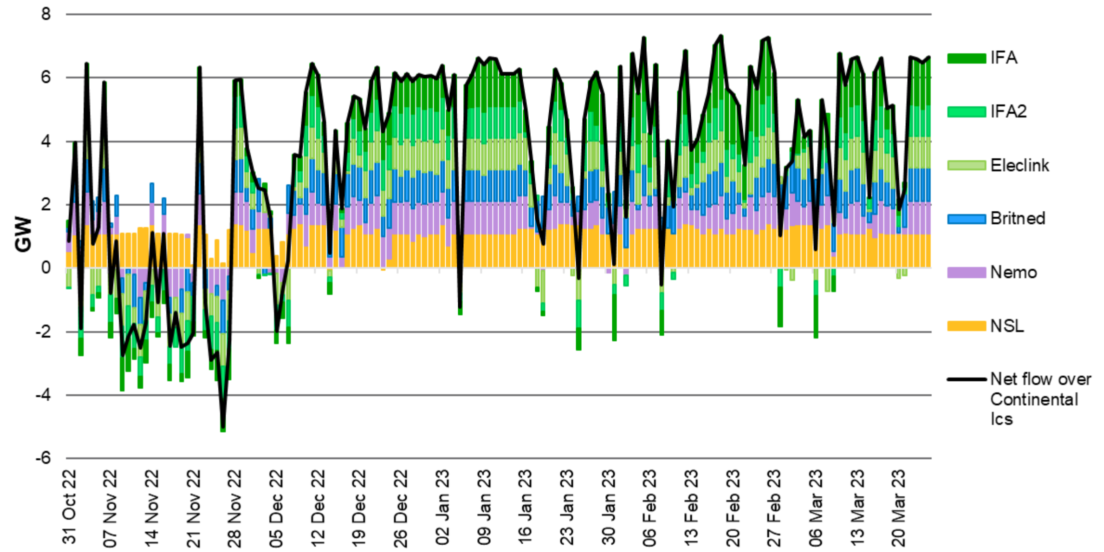

Figure 9: IFA, IFA2, BritNed, Nemo Link and NSL flow at peak times

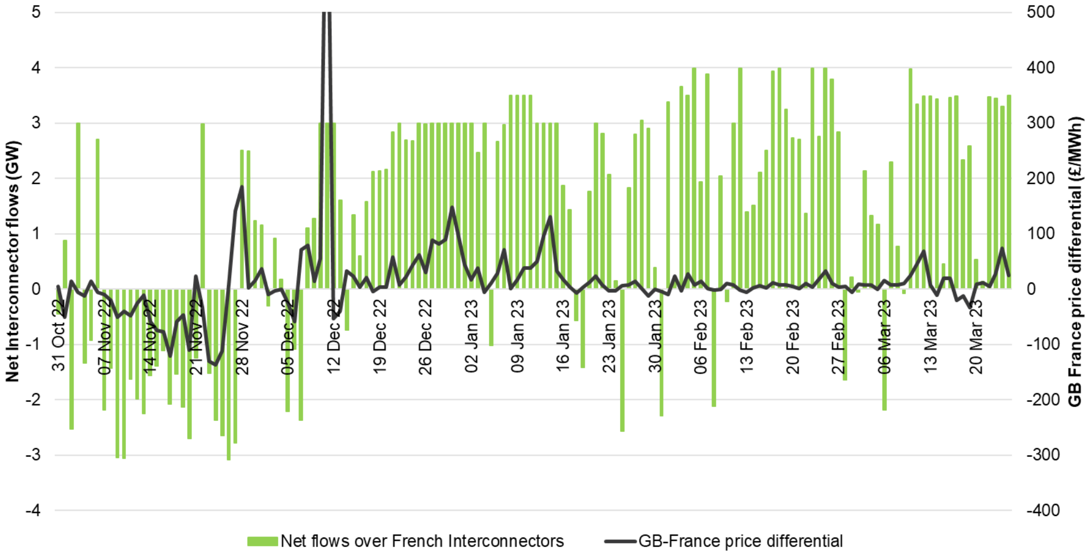

Figure 10: Interconnector flows between France and GB at the GB demand peak for each day combined with the GB France price differential based on the within-day prices at that same time (positive values signify imports into GB and GB prices higher than French prices)

Review / Europe and interconnected markets
Continental Interconnector Availability

Available interconnector capacity was generally lower than expected throughout winter compared with the available capacity expected at the time of the *Winter Outlook Report*. The available capacity was sufficient to support flows assumed in our Base Case.

	What we said in the *Winter Outlook Report*	**What actually happened**	**Why was there a difference?**
Physical capabilities	Interconnector availability will be affected by the following outages: IFA: 21 Oct – 30 Oct (1000 MW) 31 Oct – 15 Dec (1500 MW)	Available interconnector capacity was below that in the *Winter Outlook Report* for the majority of winter, as shown in Figure 11.	The IFA interconnector returned to 1500 MW on 8th January, compared to the expectation in the *Winter Outlook Report* of 31st October. IFA's return to 2000 MW was then on 28th January, compared to the expectation of 16th December based on information known at the start of winter. There were very few outages on the other interconnectors.

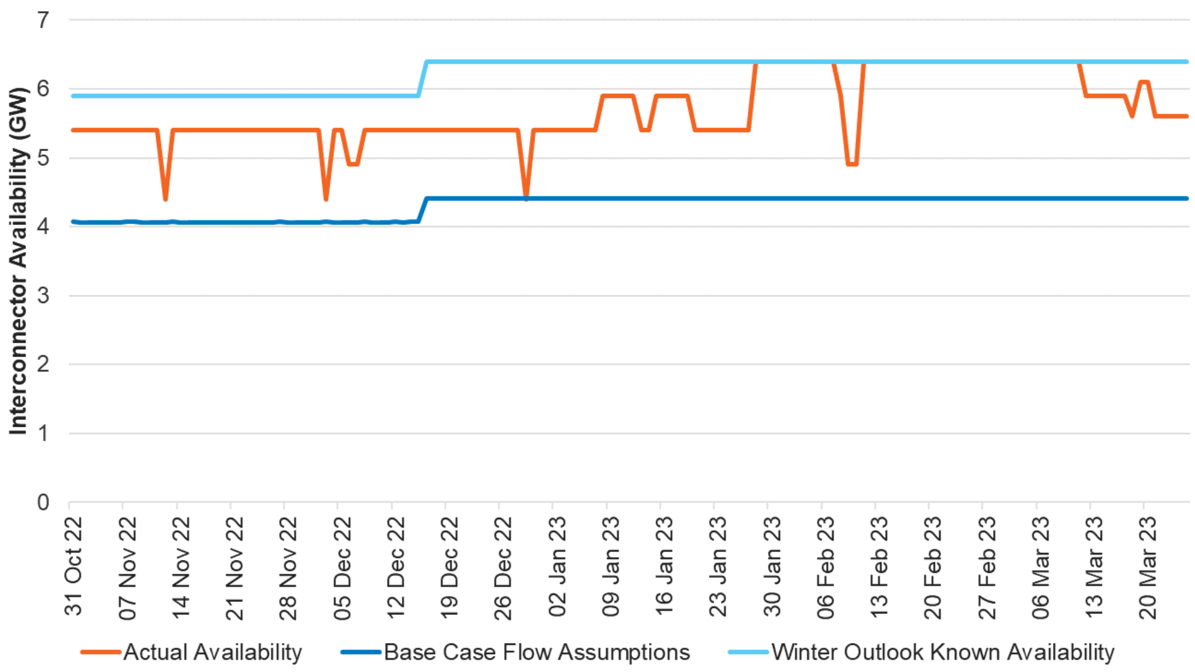

Figure 11: Actual interconnector availability compared to the availability known in the *Winter Outlook Report* (in each case Continental availability is netted off with Irish interconnector availability). Winter Outlook Base Case flow assumptions are also shown for context (Capacity Market levels for continental interconnectors and 750MW export to Ireland)

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Review / Europe and interconnected markets

Continental Europe Prices

On average across the whole of winter, GB day-ahead peak prices were higher than those in the Netherlands, Belgium and Norway but lower than those in France. Early winter saw the lowest GB prices relative to the continental European markets.

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
European forward prices	GB forward prices for peak are higher than those in the Dutch market but significantly below prices in France. GB forward prices for baseload are above those in the Belgian markets, where peak prices are not available. This indicates we may see exports to France at peak times over the winter. However, should GB experience some tight/stress periods, we would expect GB prices to escalate and interconnectors to import in line with Capacity Market obligations.	Day-ahead peak prices in continental European markets were generally closer to GB prices over winter than shown in the forward markets when the *Winter Outlook Report* was published. GB peak prices were then higher on average than those in the Netherlands, Belgium, and Norway as shown in Table 5. French peak prices were generally higher than GB at the start of the winter, although there were some tighter days in early December when GB prices were higher (see Figure 12). French prices were similar to, or slightly higher than, those in GB for the latter half of the winter coinciding with higher French nuclear output.	At the time the *Winter Outlook Report* was published there was huge uncertainty for Winter across European markets, driven by risks around a gas shortage, which didn't materialise. Prices in France were highest, particularly in November, due in part to extended nuclear outages, and industrial action.

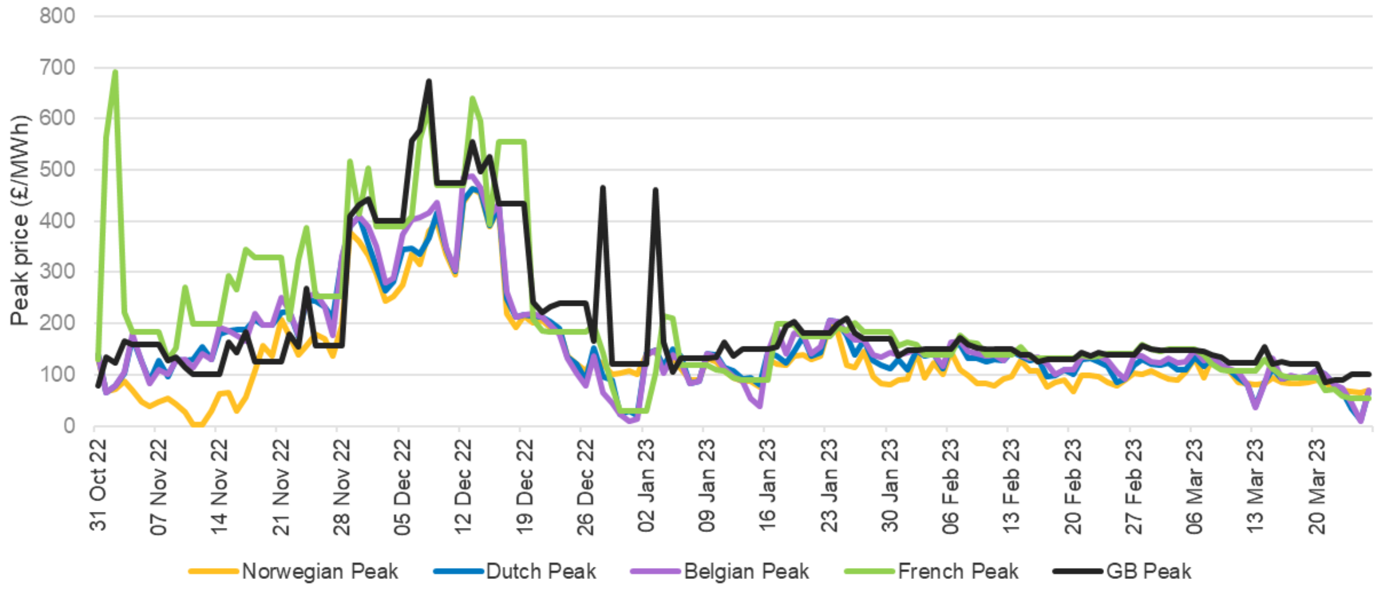


Figure 12: GB and European day-ahead peak prices across winter 2022/23

Market	*Winter Outlook Report* Peak Prices (£/MWh)	Average Day Ahead Peak Prices (£/MWh)
GB	630	198
France	1518	211
Netherlands	473	161
Belgium	N/A	166
Norway	N/A	137

Table 5: Market wholesale electricity prices, comparing the forward market data published in the *Winter Outlook Report* (sourced from Bloomberg and Argus) to the average Day Ahead prices across the winter. Note: forward prices were not available for all European markets.

Review / Europe and interconnected markets
Irish Interconnector Flows

Exports across the EWIC and Moyle interconnectors to the Republic of Ireland and Northern Ireland were in line with expectations in the *Winter Outlook report*.

	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 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. When operational surplus is particularly tight, exports to Northern Ireland and Ireland are expected to reduce to zero, and could even provide imports to GB.	Moyle and EWIC exported electricity to Ireland and Northern Ireland at peak times for the majority of the winter (see Figure 13). GB was exporting to Ireland and Northern Ireland at peak on about 60% of days. However, GB was exporting to Ireland on only 5 our of the 10 tightest margin days.	Interconnector flows were generally as expected, with some tight days showing imports to GB.

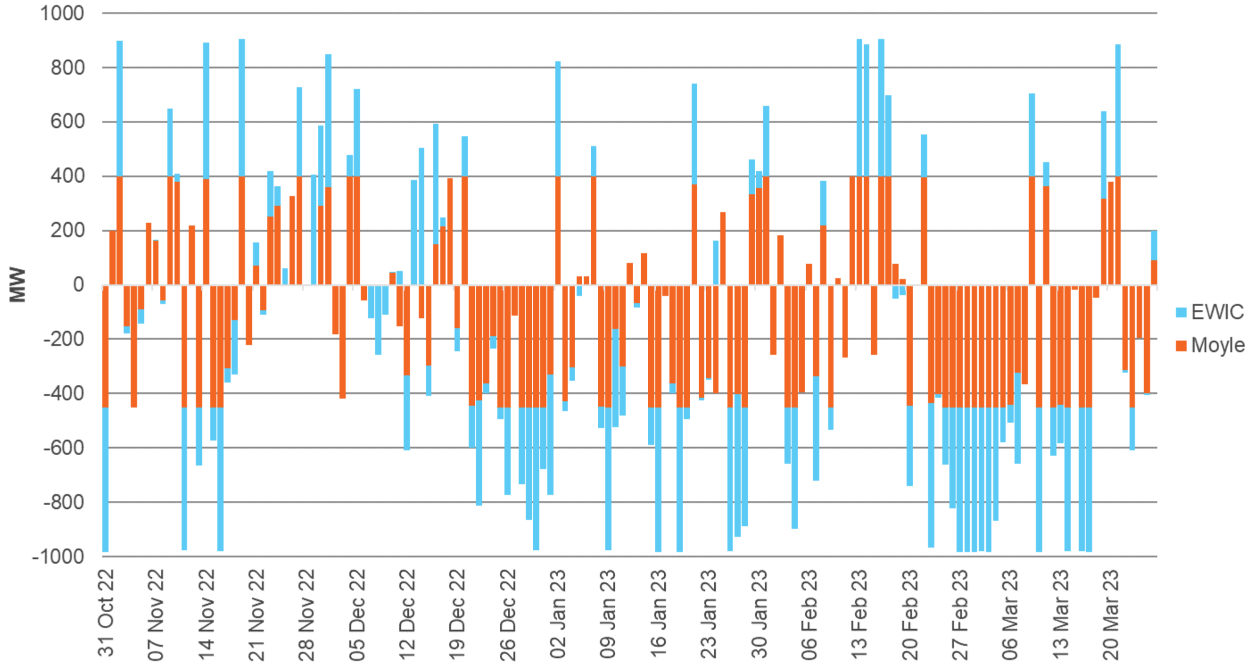


Figure 13: Stacked bar chart showing Moyle and EWIC flows at peak times (positive MW values mean flows into GB)

Spotlight / Interconnector Trading

Over this winter, the ability to trade on interconnectors was vital to maintain security of supply both in GB.

The ESO can step in and seek to trade to deliver the operational flows required to secure the system. The period with the largest amount of trading was in November (see Figure 14). Market prices supported exports to the continent, but surplus in GB was not high enough every day to support this at peak and so trading was used to reduce the magnitude of the exports. Without this action, some of these days would have been among the tightest of the winter.

When temperatures dropped below seasonal normal in late November and early December, there were less trades because the market positions already provided imports into GB. After January there was some trading on tight margin days, but generally trading contributed much less to the margin position.

On some of the tighter days (Table 6), there was minimal trading because the net positions were importing to GB, and in some cases additional uncertainty due to industrial action in France. Interconnectors were not necessarily importing at their maximum levels because reciprocal support between European system operators maintained an efficient position across all markets.

For more information on interconnector trading, see the Operational Transparency Slides from 8th March here.

Key Dates	Net IC Flow pre-trading (GW)	Net IC Flow post-trading (GW)
22/11/2022 (CMN)	5.2	6.0
28/11/2022 (CMN)	5.7	5.7
23/01/2023 (DFS Live)	4.2	4.2
24/01/2023 (DFS Live)	2.7	2.7
07/03/2023 (EMN)	2.2	2.2

Table 6: Interconnector flows at the demand peak on key dates in winter

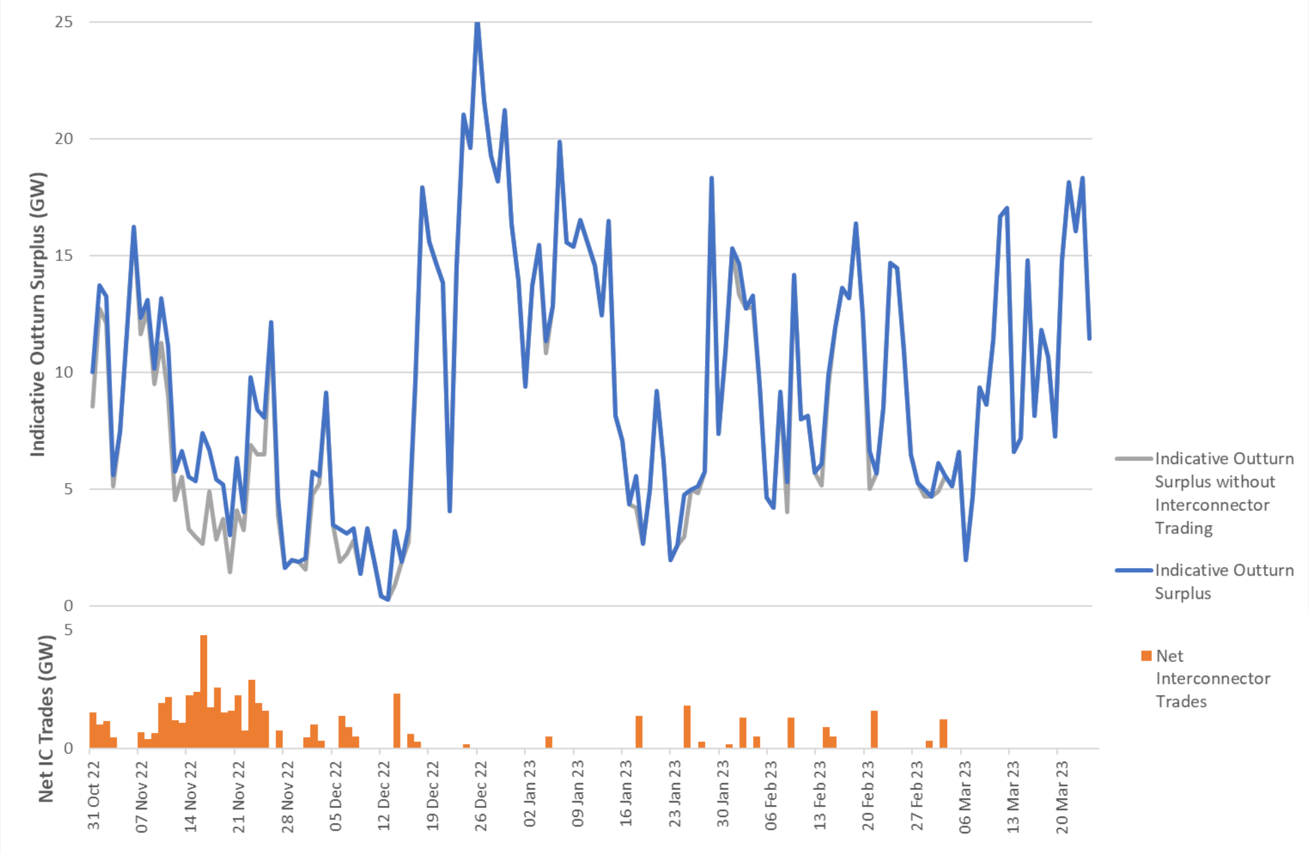


Figure 14: Indicative outturn surplus at the time of the demand peak each day, both the final position after any trading and the positions using the interconnector flows that were provided by the markets (prior to trading). Trades are also shown in the orange bars.

ESO

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 Autumn 2023.

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.

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 20th July 2023.

Please refer to the next page 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. What would you like to see in the 2023/24 *Winter Outlook Report*, in terms of content or modelling?

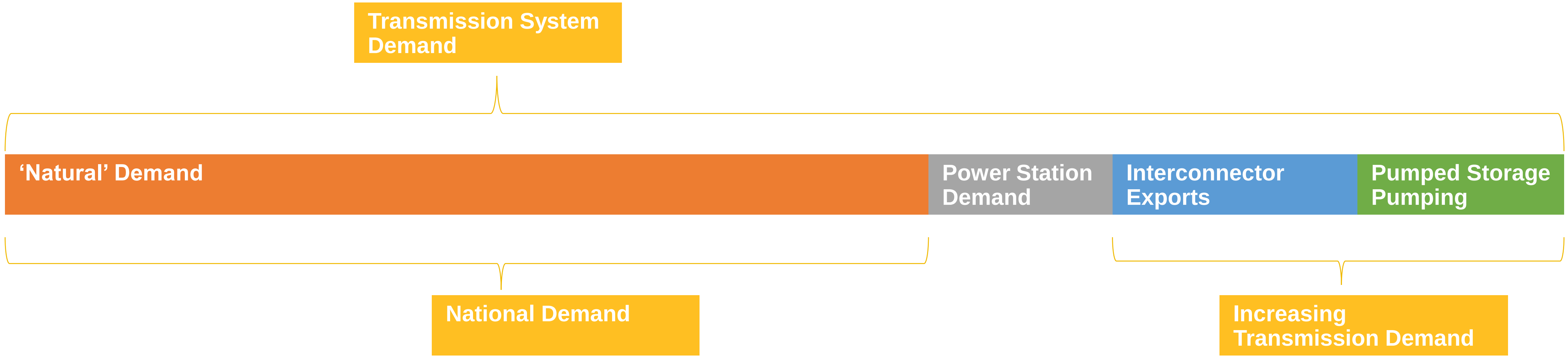
6. Do you have any general queries or concerns in relation to winter 2023/24?

Appendix

Contains extra information on demand definitions and margin notifications

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

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

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.

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-notices

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. 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. For winter 22/23, two additional enhanced services were developed: the Demand Flexibility Service and contingency coal contracts. For more information on the order of action for winter 2022/23 see: www.nationalgrideso.com/document/268116/download

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-notices

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

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

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

Interconnector
Electricity interconnectors are transmission assets that connect the 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).

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.

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

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

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

Nemo Link
A 1 GW interconnector between GB and Belgium.

Normalised transmission demand
The demand seen on the transmission system, forecast using long-term trends and calculated with the effects of 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.

Glossary

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 this October. 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.

Outturn
Actual historic demand operational demand from real time metering

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

Positive and negative reserve
The ESO maintains positive and negative reserve to increase or decrease supply and demand in response to manage system frequency as required.

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.

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.

Seasonal normal conditions
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.

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.

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

You can write to us at:

Energy Insights

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.