October 2021

Winter Outlook Report

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

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Foreword

Fintan Slye

Director, Electricity System Operator

I am pleased to welcome you to our 2021/22 Winter Outlook Report. We publish a Winter Outlook Report every year, setting out our view of electricity supply and demand for the winter ahead.

Our analysis shows that we expect sufficient margins over the winter and the system is within the Reliability Standard.

Overall, our analysis shows a margin between supply and peak demand of 3.9 GW for this winter – equivalent to 6.6% – this is calculated on a 'de-rated' basis and is after provision for typical outages and breakdowns.

In tighter periods we may issue Electricity Margin Notices and Capacity Market Notices. These notices are part of the normal operating toolkit, they serve to notify the market that we would like a greater buffer of spare capacity. We expect that the number of EMNs issued will be broadly similar to last year.

All analysis in this document represents our view at this point in time. Throughout the coming months the situation may change, as it does every winter, and we will provide updates to our analysis through our ESO Operational Transparency Forum.

This document only covers the electricity outlook for the winter ahead; the Gas Winter Outlook can be found here.

For more information, you can:

- email us at marketoutlook@nationalgrideso.com
- join the conversation at the weekly ESO Operational Transparency Forum
- use social media via LinkedIn and Twitter.

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Executive summary / Key messages

Security of supply

System margins remain within the Reliability Standard.

Electricity Margin Notices (EMNs)

It is likely that we will issue margin notices during the winter for market participants to respond to.

These are normal operational tools used to highlight when margins are looking tight ahead of real time and don't indicate that demand will not be met.

Operability

Operability requirements (e.g. voltage and frequency management) remain complex as we move into the winter period.

We have existing tools and services to manage anticipated operability challenges across the winter period.

Market Prices

Any tight margin days could see significant price spikes in the Balancing Mechanism. In addition, forward prices are high due to external pressures such as high gas prices.

This will increase balancing costs even if the volume of system actions remains consistent with previous winters.

Executive summary / Winter margin

There is sufficient generation availability and interconnector imports to meet demand throughout winter 2021/22.

The **Loss of Load Expectation (LOLE)** is 0.3 hours/year under the base case scenario, with a range between 1.2 hours/year (low case) and <0.1 hours/year (high case).

However, under all scenarios, margins remain within the Reliability Standard of three hours LOLE set by the Government.

The **de-rated margin** at underlying ACS demand[1] level is 3.9 GW in our base case scenario. All **demand suppression** assumptions related to COVID-19 have been lifted, leading to higher peak demands than last winter.

How to interpret this view of margin

This view of margin sets out how much supply capacity we expect to have to meet demand. This reflects actions taken through the **Capacity Market (CM)** to secure capacity. In the **Operational Surplus** section we provide insight into how we access these sources.

For example, we may need to use our tools (e.g. issue **Electricity Margin Notices (EMNs)** / **Capacity Market Notices (CMNs)**) to access some of these sources. This assessment gives us assurance that there is sufficient capacity available to respond to market signals to meet demand.

For more detailed information, including scenarios around the base case, see page 8.

Key statistics

	2020/21	2021/22 (early view base case)	2021/22 (updated base case)
De-rated margin at underlying demand level	4.8 GW 8.3%	4.3 GW 7.3%	**3.9 GW 6.6%**
Loss of load expectation	<0.1 hours / year	0.1 hours / year	**0.3 hours / year**
ACS peak underlying demand (including 1.5 GW reserve requirement)	58 GW	59.5 GW	**59.5 GW**
Total maximum technical capability from generation	100.7 GW	103.6 GW	**103.2 GW**
Net interconnector import flows (at peak demand)	3 GW	4.5 GW	**4.2 GW**

Glossary: Definitions for the terms in bold purple text can be found in the glossary on page 24.

[1] In this report, "**underlying demand**" includes demand met by distributed generation whereas "transmission demand" is the level the ESO sees at grid supply points. There is also a distinction between "normalised" demand (which is based on seasonal normal weather) and **Average Cold Spell (ACS)** demand which represents colder weather.

Executive summary / Operational Surplus

Our operational surplus represents a day-by-day view of the market's current intentions (i.e. based on market submissions before we take actions). This analysis is based on market submissions as of 20th September. It is a dynamic view that changes throughout winter and, as such, we will be providing regular updates at the ESO Operational Transparency Forum. This operational surplus provides insight on the periods when we may need to send market signals / use tools to ensure there is enough generation on the system to meet demand and contingency requirements. For more information, see page 12.

Based on this analysis, we expect sufficient operational surplus for each week of winter 2021/22.

Normalised weather corrected transmission system demand is forecast to be higher than **weather corrected** outturns last year as Covid-19 restrictions are lifted. The **normalised peak transmission demand** is expected in mid-December based on our latest forecasts. The minimum operational surplus is projected to be throughout December to mid-January (excluding the Christmas period), when these forecasts are combined with current generator submissions. Tightest margins do not necessarily occur at times of peak demand.

We also explored sensitivities around our central view of operational surplus (which is based on market submissions) by simulating many possible outcomes of daily surplus under varying weather conditions, demand, and generator and **interconnector** availability. This sensitivity analysis indicates that the tightest margins could occur in the first two weeks of December. More detail is available on page 13.

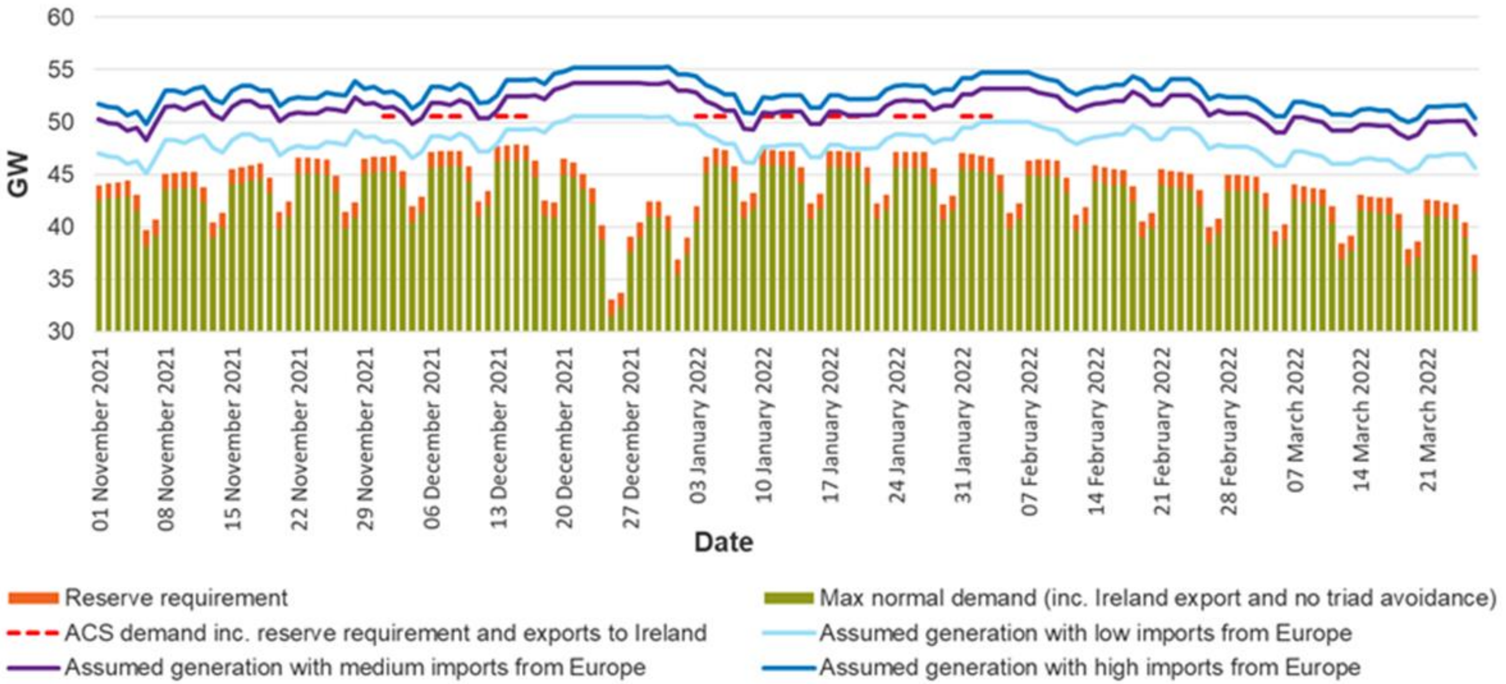

Figure 1: Day-by-day view of operational surplus for winter 2021/22 (based on market data submissions from 20th September)

Based around the central operational view outlined above, we expect to issue a broadly similar number of EMNs this winter as we did last winter (EMNs in winter 2020/21 = 6). More detail is available on page 14.

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Spotlight / Electricity Margin Notices last winter (2020/21)

Margin notices are used as a normal operational tool to highlight when margins are looking tight ahead of real-time – they don't indicate that demand will not be met. The first EMNs since 2016 were issued last winter, with six EMNs being issued in total between November 2020 and February 2021. Each one was cancelled ahead of real-time.

While these EMNs reflected normal ESO operational process, there was a significant rise in the number issued last year which was primarily due to two main factors:

1. The forecast supply margin last year, while well within the security of supply standard of 3 hours loss of load expectation (LOLE), was tighter than the previous three years; and
2. Elements of the generation portfolio under-performed, with the overall supply availability at times below that indicated by generators, and below historic performance levels (see Figure 2)

There were some specific generation and interconnector **outages** at the times of the EMNs, and while wind was generally low, it was within the range of what could be expected.

In all cases when an EMN was issued, there was an appropriate market response – prices rose, generation made itself available, interconnection flowed into GB – such that security of supply was always maintained through the peak periods (i.e. we had enough to cover demand and frequency response with reserves) and EMNs could be cancelled before real-time.

In the event of any EMNs issued this winter we would expect a similar market response.

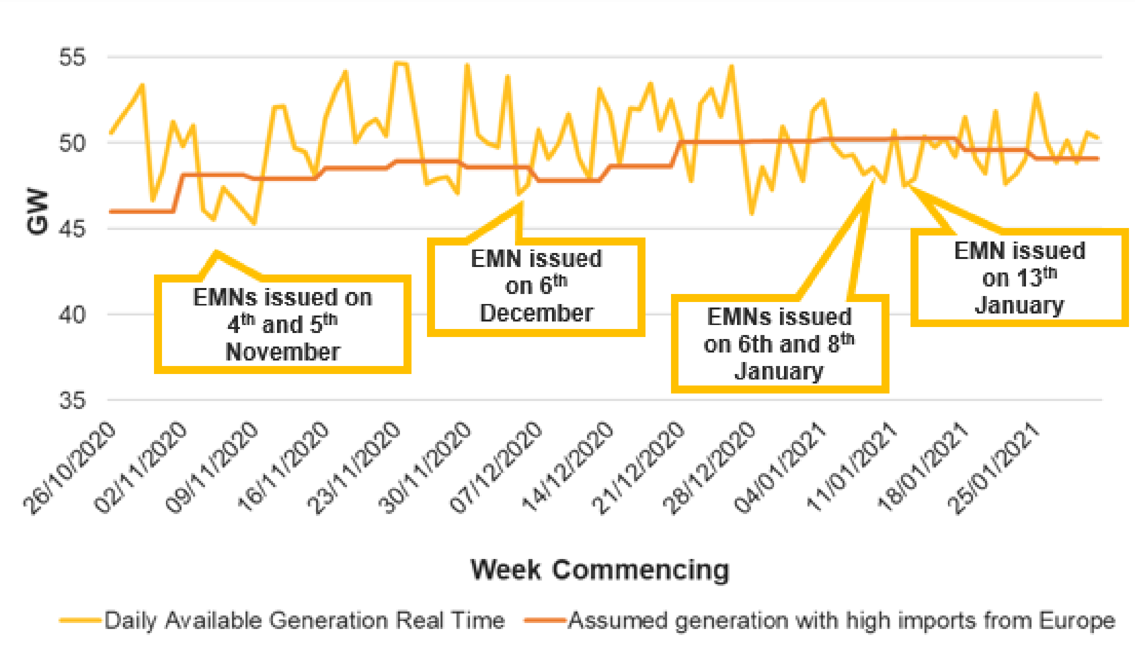

Figure 2. Generation portfolio availability

Six EMNs were issued for the darkness peaks on Wednesday 4 November, Thursday 5 November, Sunday 6 December, Wednesday 6 January, Friday 8 January and Wednesday 13 January.

The fact that an EMN was issued on a Sunday in particular highlights the varying impact of demand levels on margins (i.e. margins can be tight at times of lower demand if corresponding supply drops sufficiently).

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System margins / Winter view

Our winter view analysis is based on the EMR Base Case supply and demand assumptions and reflects recent changes to the generation mix. It is an updated version of our 'Early view of margins' report published in July.

The **de-rated margin** of 3.9 GW (6.6%) is lower than last year but higher than in some recent years, with a higher peak demand forecast as all COVID-19-related demand suppression assumptions are lifted.

- The de-rated margin has also reduced by 0.4 GW since the "early view" was published.
- The corresponding LOLE has increased but remains within the Reliability Standard level of three hours per year, even in our low case sensitivity (e.g. that accounts for a combination of potential risks such as early plant closure or late return of the **IFA** interconnector) where the de-rated margin is reduced by a further 1.4 GW from the base case (Figure 4).
- The Base case LOLE is ~ 0.3 hours/year.

- **Electricity Margin Notices (EMNs)** and **Capacity Market Notices (CMNs)** are likely to be issued this winter (see page 14).
  - These are normal operational tools used to highlight when margins are looking tight ahead of real-time and do not indicate that demand will not be met.

Did you know?

We have modelled a wide range of sensitivities that explore how the de-rated margin and LOLE could change if our demand and supply assumptions were different. These range from a low case, where de-rated margin is reduced by a further 1.4 GW from the base case, to a high case where the de-rated margin is 0.9 GW higher (Figure 4).

While it may be possible to stack multiple downside risks, such that the Reliability Standard would not be met, we do not consider this in our credible range. Great Britain has a well-functioning electricity market and so we would expect a market response driven through higher prices to mean such an outcome would be less likely.

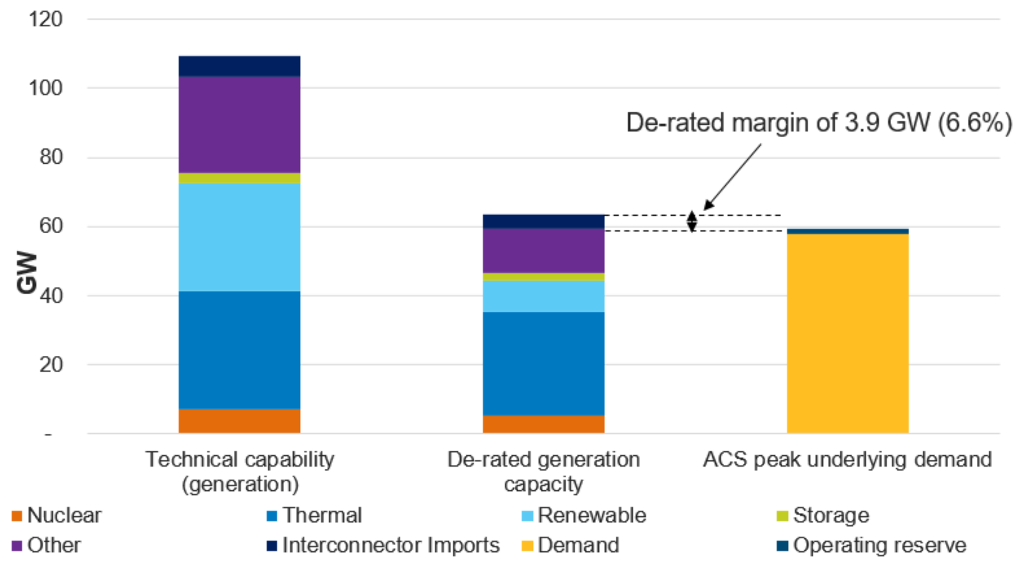

Figure 3. Supply margin in relation to generation capacity and demand

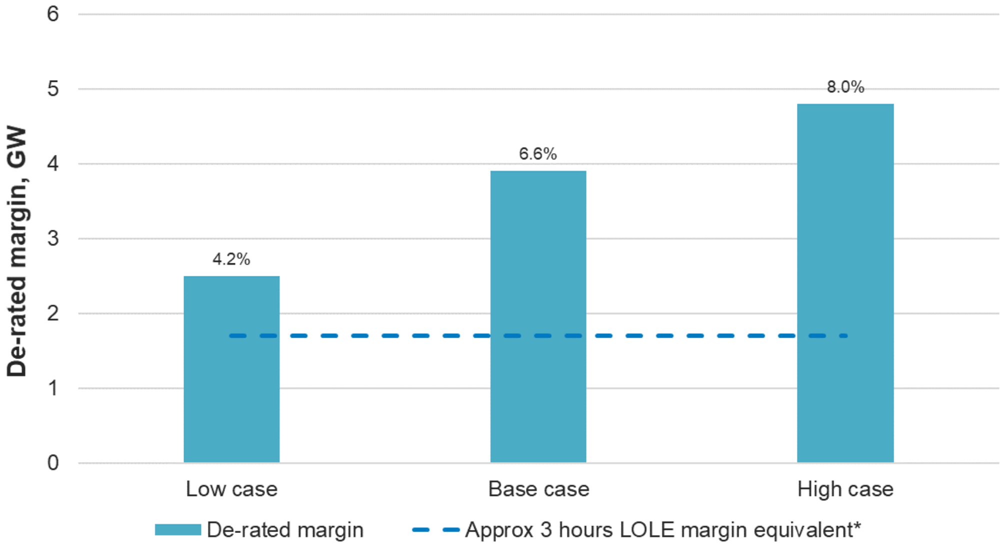

Figure 4. Range of outcomes for de-rated margin winter 2021/22 under different supply and demand scenarios

System margins / Winter view

In the Winter Outlook Report we set out how much capacity we expect to have to meet demand (i.e. the capability of supply to meet demand). This reflects actions taken through the Capacity Market to secure capacity.

System margins remain within the Reliability Standard.

<u>How this view of margin is calculated and used</u>

The planning time horizon is the period before winter, running from around 4 years down to around 6 months ahead of winter. Our security of supply assessment assesses the winter as a whole (i.e. we don't explicitly consider specific time periods within winters). It produces metrics that are used to characterise the whole winter (e.g. Loss of Load Expectation (LOLE) or a single snapshot view of de-rated margin).

Because we cannot predict reliably what the weather will be or what outages will actually happen in these time horizons, we use historic data such as weather patterns or probability distributions on plant availability and de-rating factors.

These assessments help us prepare for winter through securing capacity via the Capacity Market and provide an indication of the security of supply risk for the winter. It is not designed to inform our view on the frequency of tight periods that we could see during a winter or their timing.

As we get closer to winter, we add further to this approach. We consider more real-time information including actual plant outages, current weather patterns, price differentials that drive interconnector flows and a more granular weekly / daily view of operational surplus.

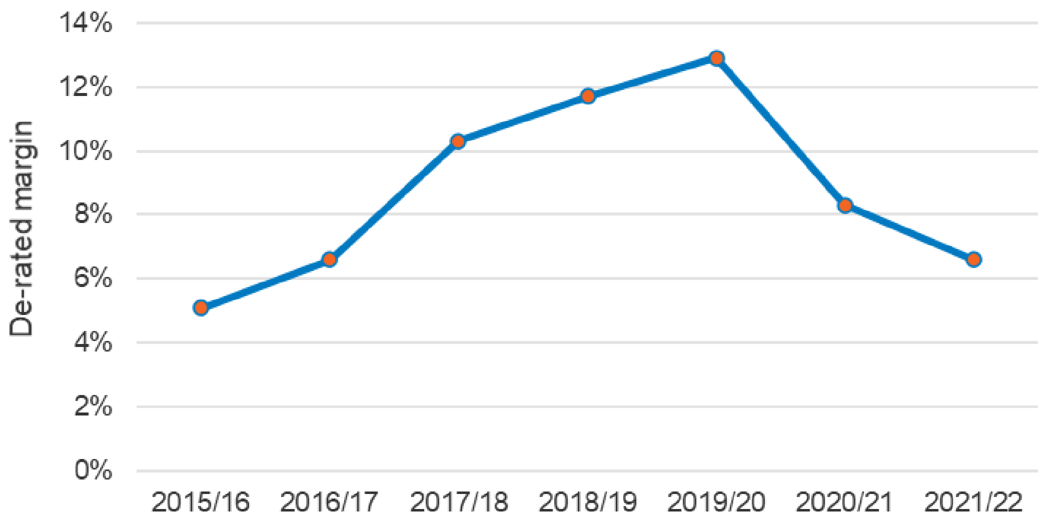

Figure 5. Historic de-rated margin forecasts made ahead of each winter in the WOR (i.e. not out-turns)[1]

Did you know?

The chart in Figure 5 shows the de-rated margins included in previous Winter Outlook Reports and highlights how, while this year is slightly lower than last year, it is still higher than the corresponding margin seen in 2015/16 and is the same as in 2016/17.

When we calculate the de-rated margin for the winter, we use the total underlying demand across both the transmission and distribution systems. This accounts for the growth in **embedded generation** and the impact of the Capacity Market when we assess security of supply.

However, throughout the rest of this report electricity demand is purely **Transmission System Demand (TSD)**. As the System Operator of the high voltage electricity transmission network, we balance supply and demand at transmission level across Great Britain.

The de-rated margin for winter takes into account the ESO's view on plant availability, public announcements on whether plant will be operational throughout winter and their capacity market arrangements.

The view of operational surplus in this document is informed by submission of availability by generators and historic breakdown rates.

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

System margins / Margin notices

Margin notices are used as a normal operational tool to highlight to market participants when margins are looking tight ahead of real-time and are intended to stimulate a market response through, for example, additional generation making itself available. They don't indicate that demand will not be met.

The two views of margins which National Grid ESO works with result in two different types of margin notices.

- **Capacity Market Notices (CMNs)** are based on Capacity Market margins which are calculated from whole system demand and whole system capacity (including **Distributed Energy Resources (DER)**).
- **Electricity Margin Notices (EMNs)** are based on operational margins which are calculated from transmission system demand and transmission system capacity.

National Grid ESO is working with Ofgem to improve the communication of warning notices. This is an ongoing process and more detail will be published in due course.

There are a number of significant differences between the operational System Warning messages (such as EMNs) 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 buffer between available generation and the total of forecast demand and Operating Margin falls below a threshold. The threshold is taken from the Capacity Market Rules. System Warnings are triggered by varying volumes, for example an EMN may be issued where National Grid ESO expects to utilise a certain amount of its Operating Margin.
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. System Warnings can be issued at any time but we would generally expect to issue a first EMN at the day ahead stage.

For more information about margins and margin notices…

https://www.nationalgrideso.com/news/everything-you-need-know-about-electricity-system-margins

Operational Surplus / Day-by-day view

Our operational surplus analysis represents the market's current intentions (i.e. based on market submissions before we take actions). This analysis is based on market submissions as of 20th September.

It is a dynamic view that changes throughout winter and, as such, we will be providing regular updates at the ESO Operational Transparency Forum. It provides insight on the periods when we may need to send market signals / use tools to ensure there is enough generation on the system to meet demand and contingency requirements.

How the operational surplus is calculated and used

- For the operational surplus analysis, we plan based on the operational data submitted to us. We are not just looking at the capacity provided via the Capacity Market (a market tool that helps to set us up for winter), but also at the supply that is forecast to be available on a day-by-day basis. To do this we need to consider a more granular view of the winter.
- We consider a daily view as we get closer to real-time and start assessing the daily views in August ahead of the Winter Outlook Report publication in October. The Winter Outlook Report includes a daily view of margins for the winter, as well as information on the effects of variability and the likelihood of tight operational margins.
- The operational data includes information relating to planned plant outages, the impact of weather (e.g. on wind and demand) and flows on interconnectors. As generators can also have unplanned outages, we also apply **breakdown rates** based on averages of the last 3 winters. In addition, we study the effects of variability of all relevant factors, particularly weather, **renewable** resource and unplanned outages. The operational data may be different from the assumptions based on historic data / long-term averages used for the winter view of margin.
- The operational surplus also considers grid constraints and largest loss requirements. In the central daily view we use a low wind scenario, so the grid constraints play only a small part in the calculation. When we consider the credible range of values, grid constraints become more significant.
- The operational surplus helps us to identify when we might have tight periods. However, the operational data provided to us changes throughout the winter. There may be some tight periods that are apparent a week in advance; others may not become apparent until much closer to real-time (e.g. day ahead or on the day itself).
- These assessments of security of supply are used to support decisions taken in operational timescales (e.g. whether to issue an EMN).
- The periods of tightest margins do not necessarily occur at times of peak demand but rather when supply is lowest relative to demand.

Operational Surplus / Day-by-day view

Our central operational view shows sufficient operational surplus for each week of winter 2021/22.

This winter we expect…

- **Average Cold Spell (ACS)** transmission demand to be met on all days under the high and medium import interconnector scenarios.
- Normalised weather corrected transmission system demand to be higher than weather corrected outturns last year as Covid-19 restrictions are lifted.

Did you know?

Normalised peak transmission demand is expected in mid-December, based on our latest forecasts. The minimum operational surplus is currently projected to be lowest throughout December to mid-January (excluding the Christmas period), when these forecasts are combined with current generator submissions. Tightest margins do not necessarily occur at times of peak demand.

This year we have changed our analysis from weekly to daily operational surplus to focus more on periods of lower margins. However, this means a direct comparison with last year's weekly margins cannot be made. Page 14 considers how many EMNs we might expect this winter, allowing us to make a comparison to last winter.

We analyse three levels of electricity supply, which include a view of generation accounting for breakdown rates and a range of interconnector flows. This ranges from a low scenario where there is no import from Europe, to a high scenario where all interconnectors are importing to GB at full capacity excluding any planned outages where applicable (maximum 4,700 MW). The medium scenario assumes an additional 1,500 MW of interconnector capacity is not available on the above (maximum 3,200 MW available).

We don't include potential market responses to higher demand or tighter conditions, such as power stations increasing their output levels for short periods. During periods of low operational surplus, generators may be incentivised to reschedule planned outages by Capacity Market obligations or through revenue opportunity from higher market prices. ACS demand has historically always occurred between the first week in December and the first week in February, but never during the Christmas fortnight.

Normalised peak transmission system demand	46.9 GW
Minimum demand	20.7 GW
Maximum Triad avoidance	1.2 GW

Figure 6 appears to show occasions over weekends under the medium import interconnector scenario where generation drops below ACS demand. However, ACS demand does not occur over a weekend as demand is lower than weekdays; the red ACS line has breaks in it over weekends to reflect this.

Whilst the market may provide low or medium import flows for some periods over winter, we don't expect to see this occur at peak times (e.g. ACS).

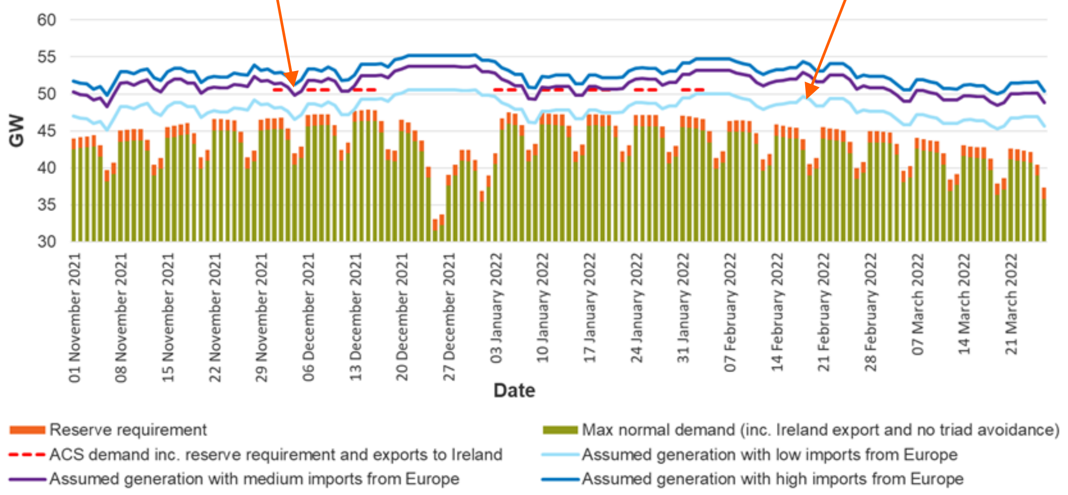

Figure 6. Day-by-day view of operational surplus for winter 2021/22 (based on market data submissions from 20th September)

Operational Surplus / Credible range

The daily view of surplus is calculated assuming typical conditions before we take actions. Here we explore the sensitivity of margins to a range of conditions. Based on this range, we expect to have sufficient operational surplus throughout winter.

This winter we expect…

- to have sufficient operational surplus throughout winter when routine tools such as margin notices are used
- tight margins are likely throughout December to mid-January (excluding the Christmas period).

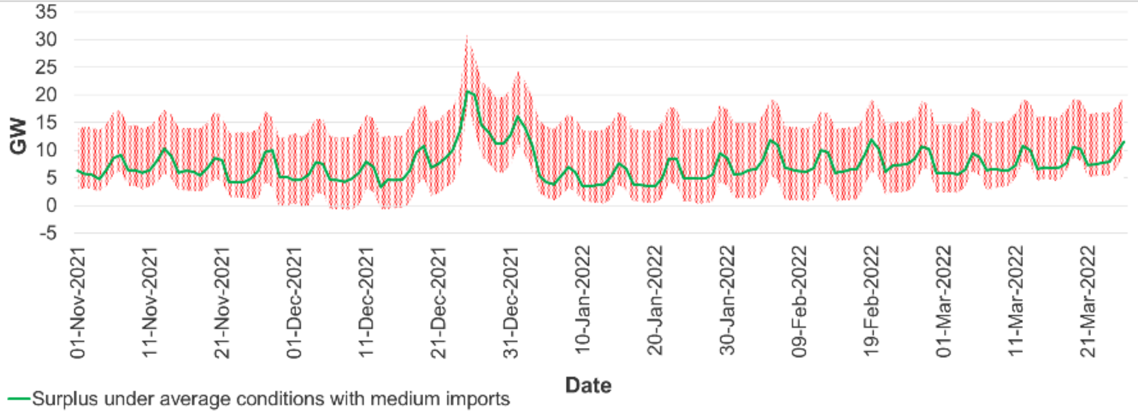

Figure 7. Range of outcomes for de-rated margin for winter 2021/22 under different supply and demand scenarios

Did you know?

Figure 7 shows the forecast of surplus under the medium interconnector scenario[1], with the shaded region representing the credible region within which the surplus can fluctuate. It is important to note that, although on any given day the fluctuation can reach the lower bound (or dip below it), it is not credible that surplus will remain at the lower bound level for the entirety of the winter.

The analysis behind Figure 7 considers a situation under typical conditions, using average weather conditions for demand, average availability for conventional generation and average wind conditions when margin is tight.

To explore the sensitivities around this central view, we simulate many possible scenarios for weather, demand, conventional generation availability, wind generation output and interconnector availability and, for each of these scenarios, we calculate the daily surplus time series across the entire winter for that scenario. We do not include any actions that could be taken by the ESO.

We look at a day-by-day analysis, finding the daily credible range of values for the surplus. By "credible" we mean a 90% confidence bound for the day-by-day fluctuations in surplus.

There are two caveats to this approach: first, it assumes that the stated planned outage patterns as declared through REMIT (at the time of publication) will not alter; and secondly it assumes that, for continental interconnectors, market forces will allow flow into GB of whatever interconnector capacity is available after unplanned outages.

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 [1]Note that the medium imports scenario is conservative and typically we would expect to be closer to the high imports scenario – especially at times of tight margins.

Operational Surplus / Likelihood of EMNs over winter 2021/22

After simulating 50,000 winter scenarios based around the submissions provided by the market, we expect to issue a broadly similar number of EMNs to the 6 that were issued last year.

Margin notices are used as a normal operational tool to highlight to market participants when margins are looking tight ahead of real-time and are intended to stimulate a market response through, for example, additional generation making itself available. They don't indicate that demand will not be met. Margins on the electricity system, and the risk of Electricity Margin Notices (EMNs) being issued, can vary throughout the winter. It will depend on actual weather patterns and outages taken by generators.

To assess the likelihood of an EMN this winter we need to consider simulations of every day throughout an entire winter, and for that entire winter observe how often the surplus reaches the EMN trigger level. From this we can calculate the probability on any single day of an EMN being issued (Figure 8), subject to the current notification of planned outages, consistent with our central operational view.

Given the notified pattern of outages, this accounts for natural fluctuations in weather, demand levels, breakdown of conventional plant and interconnectors, and fluctuations in wind generation output and, as a result of simulating 50, 000 winters, we expect to issue a broadly similar number of EMNs as last year (EMNs in winter 2020/21 = 6).

We have also looked at how the risk of EMNs may change if plants which are "near end of life" have a fault which leads to permanent closure because cost of repair is more than the expected return from the rest of life once repaired. If a total of 2 GW of capacity (i.e. roughly equivalent to one coal and one nuclear plant) is assumed to close in this way, then the expected number of EMNs could double.

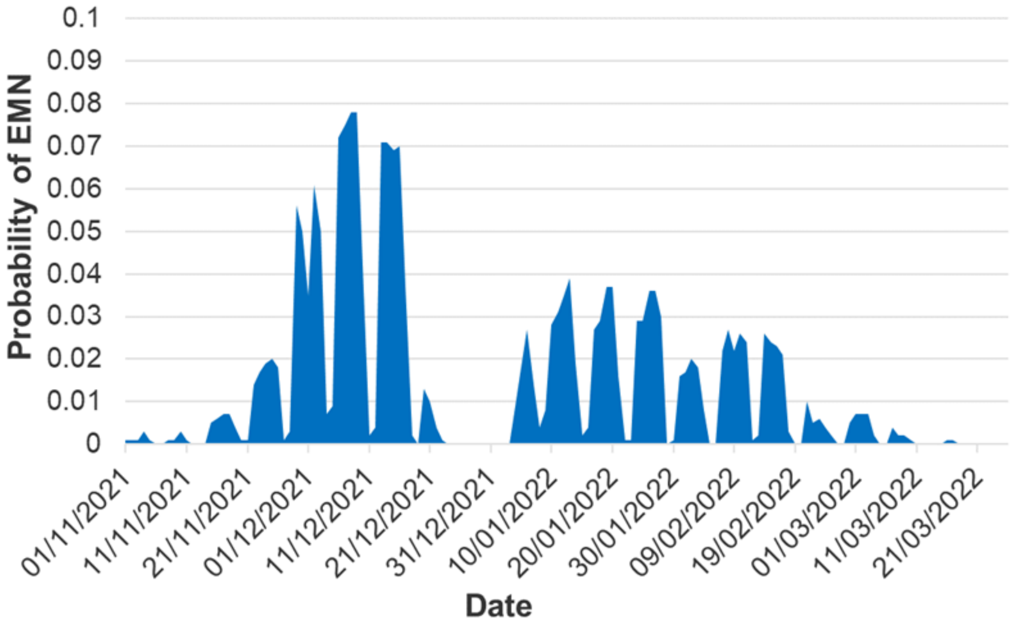


Figure 8. Probability of Electricity Margin Notices

Demand / Normal peak demand

Weather corrected peak demand for winter 2021/22 is expected to be higher than the previous winter, largely due to COVID-19 restrictions being lifted, and broadly in line with winter 2019/20[1]. Weather corrected minimum demand is expected to be greater than last winter.

This winter we expect…

- weather corrected peak **transmission system demand (TSD)** to be 46.9 GW, based on assumptions in the table below.
- weather corrected **minimum demand** to be 20.7 GW (assuming no interconnector exports overnight), see Table 1.

Did you know?

When we forecast demand in this section, it is transmission system demand (TSD) which includes the demand from power stations and interconnector exports. We base our peak demand forecasts on **seasonal normal weather**, modelling the average of various weather variables for the past 30 years. We then adjust our forecast to account for a standardised daily amount of embedded wind and solar generation (based on the seasonal normal weather and historical **load factors**).

At peak times, interconnectors typically export across the **Moyle** and **EWIC** interconnectors which connect GB to Ireland, so our peak TSD forecast accounts for this demand.

Minimum demand typically occurs during the night, and so our interconnector assumptions are based on historical overnight flows. These indicate that the interconnectors are more typically importing overnight, so no adjustment is made to minimum demand.

Interconnectors	Import	Floating	Export	Total
EWIC	46.3%	27.1%	26.6%	100.0%
Moyle	58.1%	0.1%	41.8%	100.0%

Table 1. Historical interconnector flows to Ireland overnight

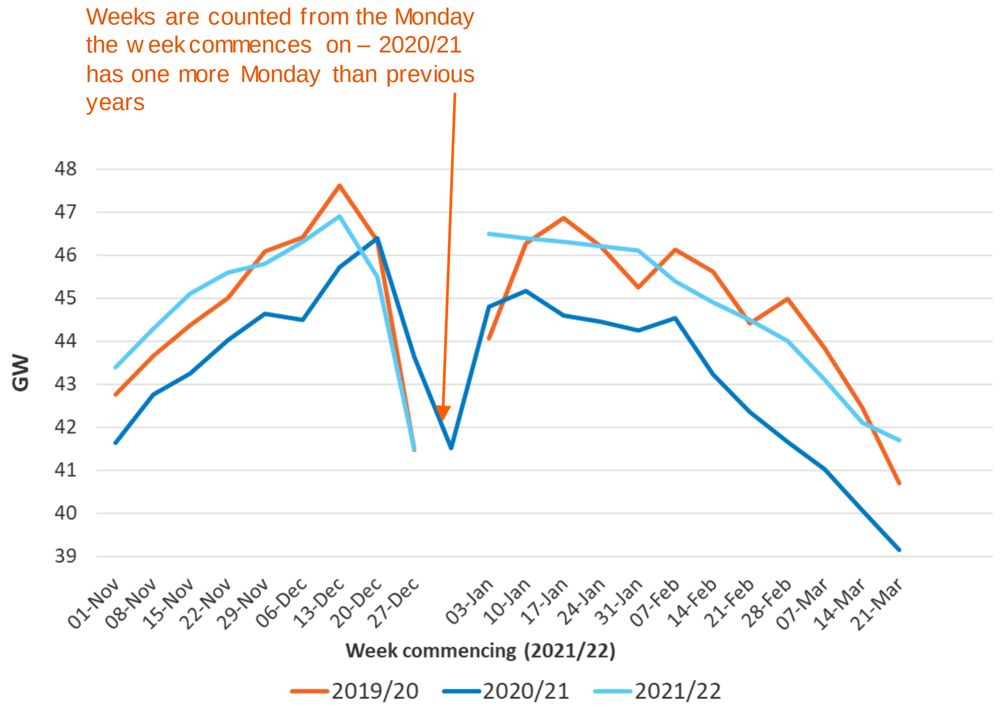


Figure 9. Historical and forecast normalised weekly peak winter demand[2]

Transmission connected power station demand	600 MW
Base case interconnector exports to Ireland (at time of peak)	750 MW
Embedded wind capacity	6.5 GW
Embedded solar capacity	13.1 GW
Pumped storage (at time of peak)	0 GW

Table 2. Assumptions for weather corrected peak TSD demand

[1]There was a one-week period between Thursday 10 and Wednesday 16 December 2020 when demand spiked and was part of a lead up towards Christmas with reduced COVID-19 restrictions in place.

[2]Data is adjusted for interconnector export, historical data is weather corrected, forecast uses normal weather.

Supply / Daily view

We currently expect sufficient levels of generation and interconnector imports to meet demand throughout the winter.

This winter we expect…

- slightly more available generator capacity than last year, largely due to more **Combined Cycle Gas Turbine (CCGT)** and biomass plant being available.
- generator reliability to be broadly in line with recent winters although coal, CCGT and biomass plant have seen a slight increase in assumed breakdown rate (Table 3).
- 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).

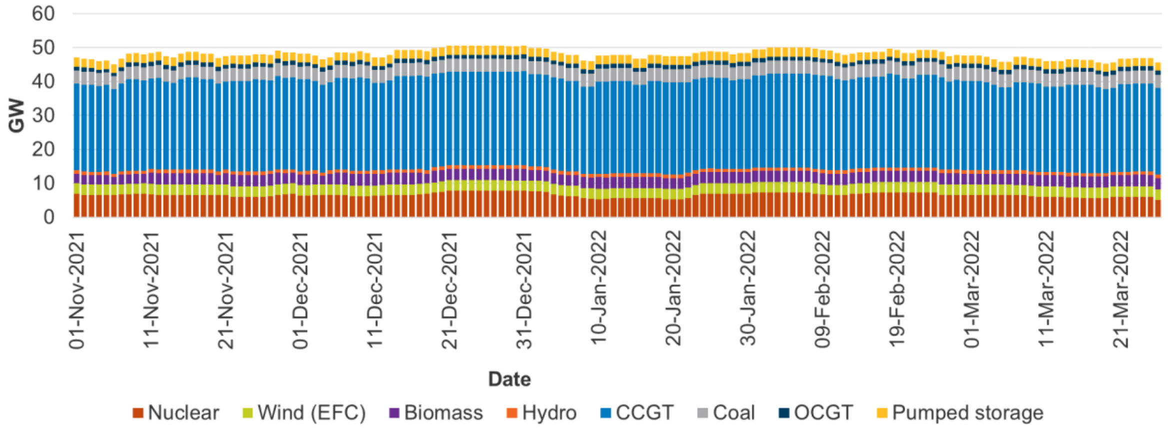


Figure 10. Daily generation availability by fuel type (based on market submissions and including breakdown rates)

Did you know?

Like Figure 1, Figure 10 has also changed this year from a weekly to daily view. It is based on generator submissions of availability which is different to our calculation of de-rated margin for the winter on page 4.

Our generation forecasts are based on published availability data broken down to a half-hourly profile, to which we apply a breakdown rate for each fuel type, to account for unexpected generator breakdowns, restrictions or losses close to real-time.

Our forecast explores the running order expected over the **winter period** based on the cost of producing energy. In Figure 10, the order of the column stack reflects the expected running order. Power stations with lower production costs will tend to run more often, so our forecast is heavily dependent on fuel prices.

The assumed breakdown rates are based on historic data to reflect how generators performed against their planned availability during peak demand periods over the last three winters (see Table 3).

For coal, CCGT and biomass, the three-year rolling average has increased when last winter was accounted for. For wind generation, we assume an **Equivalent Firm Capacity (EFC)** of 17 per cent.

	Assumed Breakdown Rate	
Power Station Fuel Type	**20/21**	**21/22**
Coal	9%	11%
CCGT	5%	6%
Nuclear	9%	9%
OCGT	5%	5%
Biomass	3%	5%
Hydro	8%	9%
Wind EFC	16%	17%
Pumped storage	2%	3%

Table 3. Breakdown rates by fuel type (based on a 3-year rolling average)

Europe and interconnected markets / Overview

We expect net imports of electricity through interconnectors from continental Europe to GB for most of the winter. We expect to typically export from GB to Northern Ireland and Ireland during peak times.

This winter we expect…

- **forward prices**, including peak prices, in GB to be ahead of those in continental Europe for the majority of the winter period
- based on last year's flows, 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.
- 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.

Did you know?

Figure 11[1] shows last year's average interconnector flows at peak times, and during periods when EMNs were issued. These, alongside the expected prices (see page 20) are used to help inform our expectations for interconnector flows this year.

The new **NSL** interconnector is assumed to be operational from October after commissioning and is expected to import to GB – especially at times of tight margins.

The new [ElecLink] interconnector is assumed not to be operational until after the winter period.

The recent fire at IFA means 1000 MW of interconnector capacity will be unavailable until 27 March 2022. Additionally, there is a planned outage of the remaining 1000 MW until 23 October 2021.

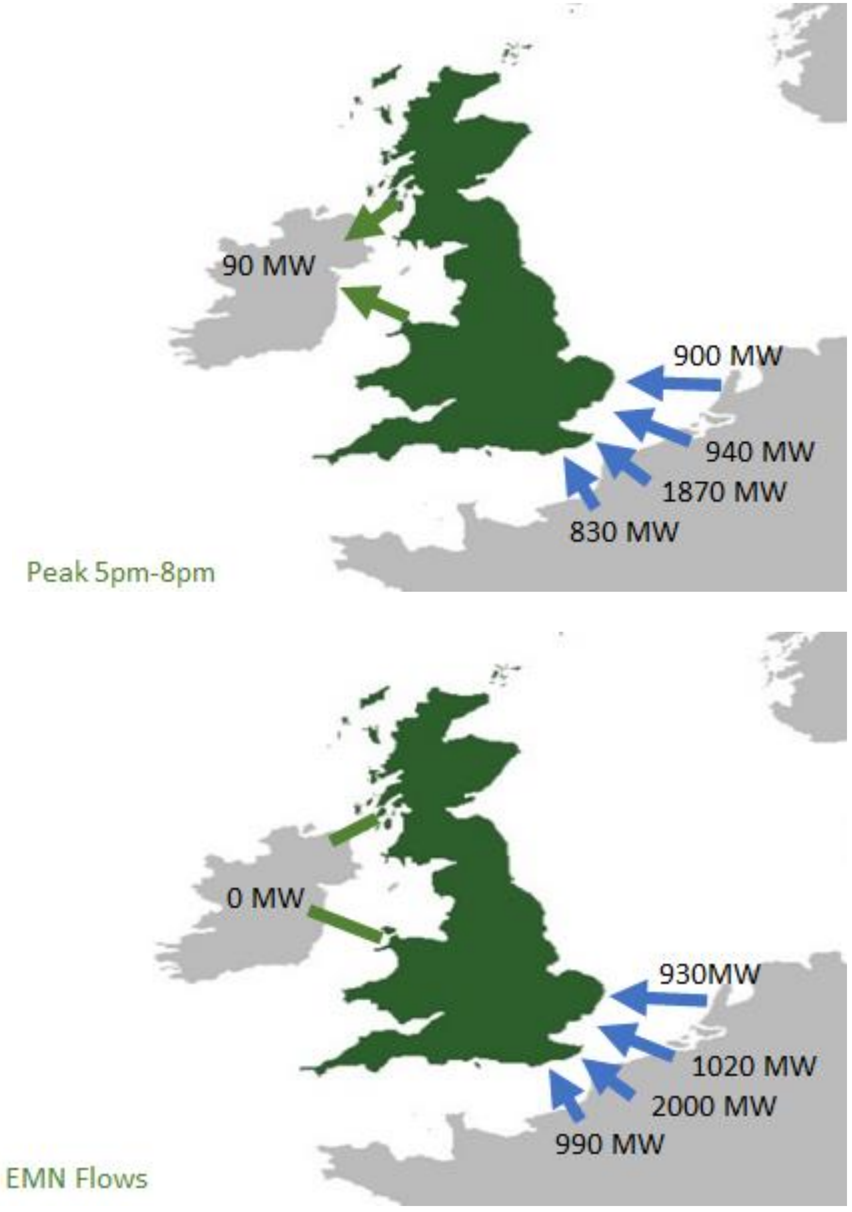


Figure 11[1]. Historical flows on the interconnectors for winter 2020/21

nationalgridESO

[1]Looking forward to this winter, known outages (e.g. reduced IFA capacity) need to be considered. See next slide for more information on interconnector outages.

Europe and interconnected markets / Peak flows analysis

Our assumptions around peak flow of electricity on the interconnectors depend on a number of factors.

1. Physical capabilities

Interconnector capability will be affected by the following outages.

Interconnector	Planned outages (resulting capacity)
IFA (2 GW)	4 Oct – 23 Oct (0 MW), 24 Oct – 27 Mar (1000 MW)
IFA 2 (1GW)	None
BritNed (1 GW)	None
Nemo Link (1 GW)	None
EWIC (500 MW)	None
Moyle (500 MW)	None
NSL (1400MW)	1 Oct - 31 Oct (700MW)

Table 4. Planned interconnector outages at time of analysis

The new interconnector **IFA2** was completed last winter and provides an additional 1000 MW capability between France and GB.

2. Capacity Market

Interconnectors (including the new IFA2 but excluding NSL) have secured contracts in the Capacity Market (CM) in the T-4 and T-1 auctions for 2021/22. We expect price signals from the wholesale market to incentivise flows to GB at peak times. We have also carried out modelling of flows using our updated approach for calculating interconnected country de-rating factors which has shown that interconnectors can meet their CM obligations for 2020/21 during system stress events. This supports our assumptions on interconnector flows at ACS peak demand over the coming winter.

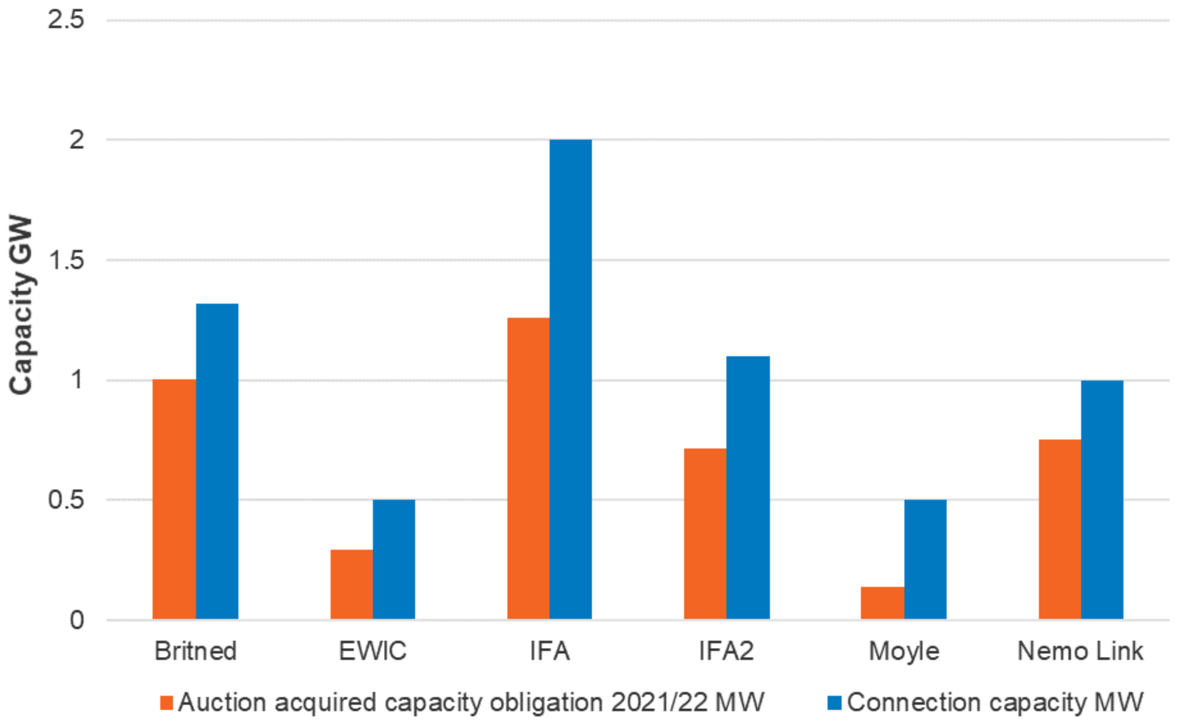
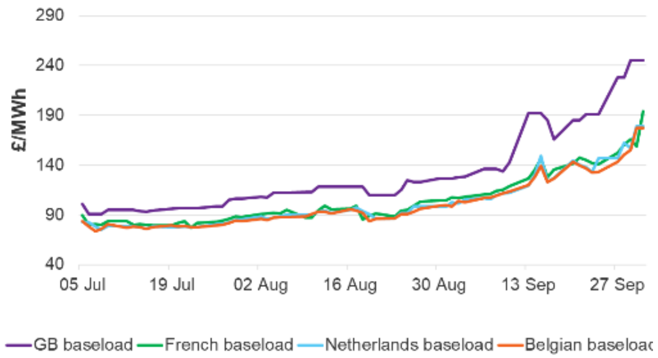


Figure 12. Conditional Capacity Market agreements 2020/21

Europe and interconnected markets / Peak flows analysis

3. European forward prices

- Electricity flows through the interconnectors are primarily driven by the price differentials between the markets.
- Forward prices for **baseload electricity** during winter 2021/22 in GB are higher than those in the French, Dutch and Belgian markets (see Figure 13a) and therefore we expect to see similar import/export patterns over these interconnectors as last winter.
- There may be some occasions when we see exports to continental Europe, however this is unlikely to be during peak times and should GB experience some tight/stress periods, we would expect GB prices to escalate and interconnectors to import. This is confirmed by Figure 13b, which shows forward prices for **peakload electricity** during winter 2021/22 are also generally higher in GB than France or the Netherlands.



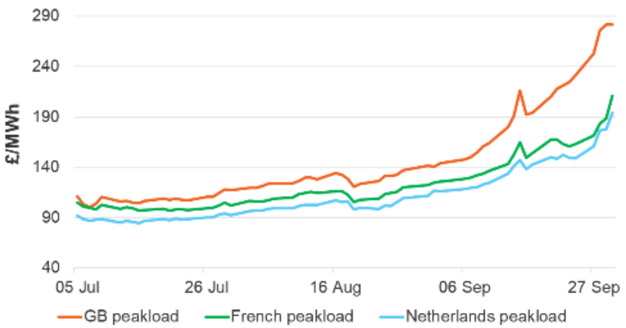


Figure 13 a) Winter 2021/22 electricity baseload and b) peak forward prices[1]

4. Network access constraints

- Transmission outages in the regions with interconnectors could cause power flow constraints resulting in disruption to interconnector flows.
- In previous years, there were some periods when IFA exported from GB to France during the winter, driven by lower available French generation as a result of nuclear plant outages. Figure 14 shows that the planned French nuclear outages for this year are, for the majority of winter, lower than the previous year. Even when they are higher, with GB forward prices ahead of those in France, we expect imports to continue, particularly during peak times.

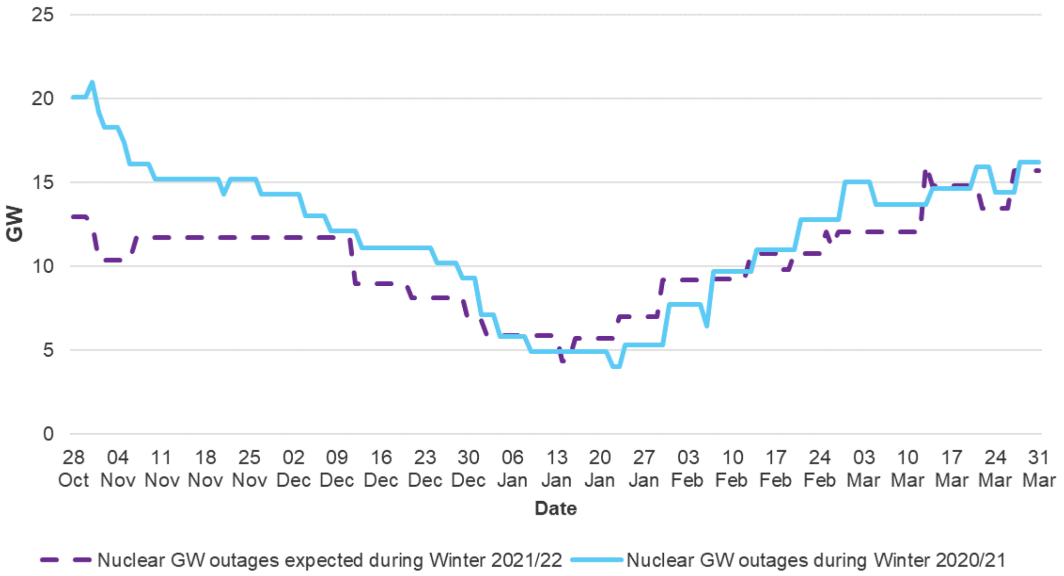


Figure 14. The impact on French nuclear capacity from planned outages in 2021/22 and last winter's actuals

nationalgridESO

[1]Figure 13a uses data from Bloomberg. Peak forward prices were only given for GB and France in Bloomberg, therefore Figure 13b uses data taken from Argus, which includes prices for the Netherlands.

Europe and interconnected markets / Historic flows

Overview of continental European interconnectors

Based on forward prices for the 2021/22 winter products, we expect imports into GB at peak times from France, the Netherlands and Belgium under normal network operating conditions. Occasionally, these may not be at full import due to weather variations, which could push demands higher during cold spells or affect renewable generation. See examples of this from last winter in Figure 15.

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.

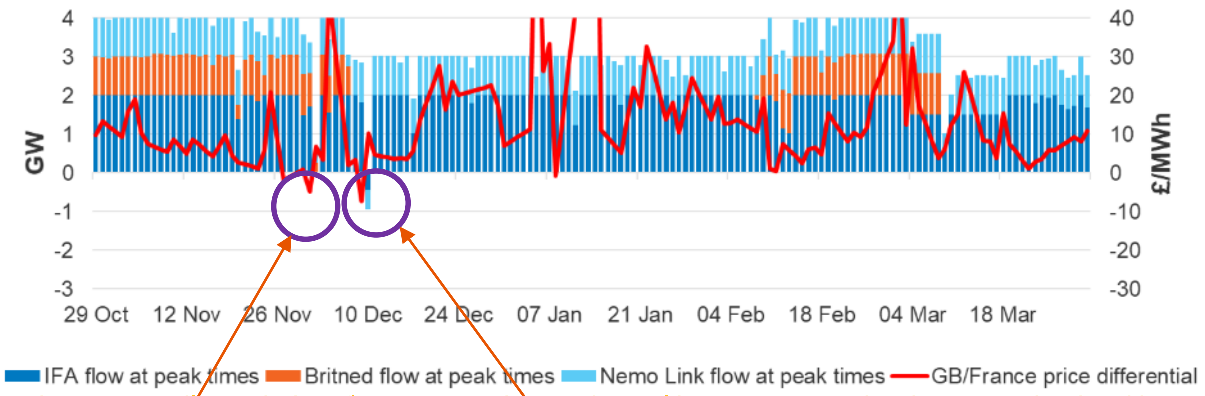


Figure 15. Daily peak time flows across the continental interconnectors in winter 2020/21 (positive MW values mean imports into GB)

Last winter we saw imports at peak times throughout the winter, despite day ahead baseload prices in France sometimes exceeding those in GB

Last winter when we saw exports it was not related to prices which were lower in France

Overview of Irish interconnectors

During peak times through winter 2021/22, we expect a higher proportion of exports than imports across the Moyle and EWIC interconnectors to Ireland. This may, however, be reversed during periods of high wind and system stress. Figure 16 shows examples of where market conditions and weather variance affected flows last winter.

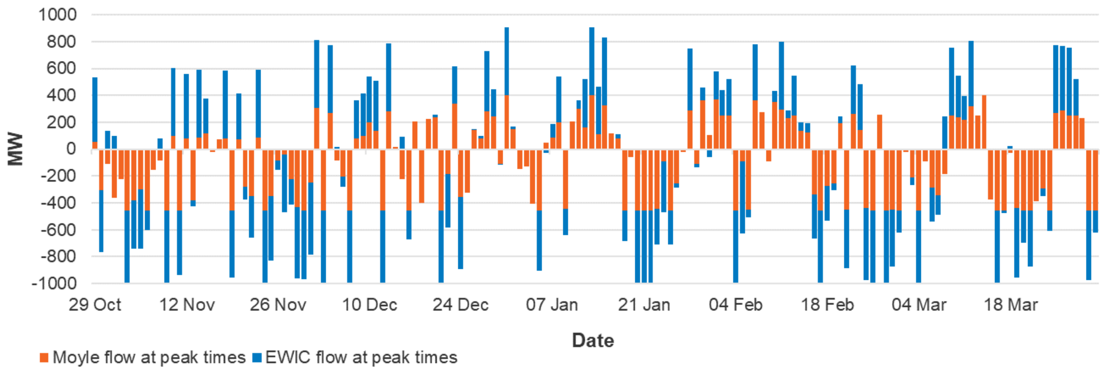


Figure 16. Daily peak time flows across the Irish interconnectors in winter 2020/21 (positive MW values mean imports into GB)

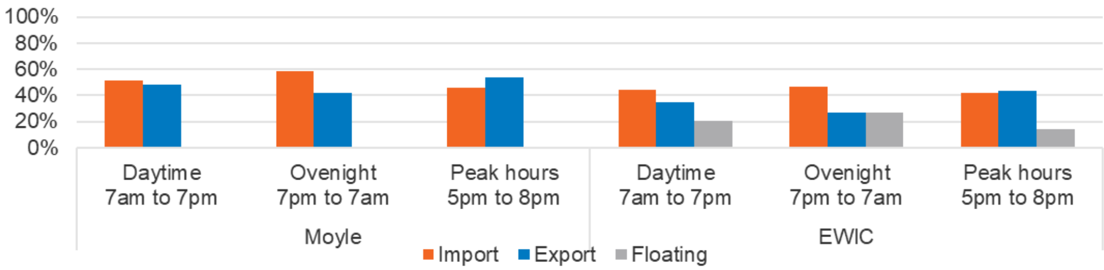


Figure 17. Proportion of import and export for Irish interconnectors during winter 2020/21

[1]Figure 15 peak forward prices were not provided for weekend days so interpolation was used to predict these values.

Market prices / Winter view

Forward wholesale electricity prices are higher than last year. In addition, tight margin days are likely to see significant price spikes in the Balancing Mechanism.

This winter we expect…

- forward prices in GB to be higher than last year across the winter period (Figure 18). This is due to external pressures such as high gas prices.
- days with tight margins to see spikes in the balancing mechanism. During periods of tight system margins, energy prices increase to reflect the scarcity of the resource, particularly when margin notices are issued.

Did you know?

Traditionally power plants have bid into the **Balancing Mechanism** at prices which largely reflected the marginal cost of running the plant over that period. Capital and operational costs were recouped over a longer period through forward markets and/or long-term contracts.

The need to decarbonise and consequent deployment of wind and solar energy has meant that many fossil-fuel plants are operating less of the time, with a greater proportion of their generation occurring through the balancing mechanism. As such they are bidding at higher prices to recoup some of their costs, particularly during tight margin days.

Due to how system prices are based on actions taken by the Electricity National Control Centre (ENCC), this means that high prices feed through into the imbalance settlement calculations which in turn impacts the wholesale price.

Last winter saw imbalance prices reach £4,000/MWh on several occasions, with the day ahead wholesale price also exceeding £1,000/MWh. This tended to take place over periods when EMNs were in force.

However, we have already seen examples of this effect in September 2021 (i.e. ahead of the Winter Outlook period) and in periods for which there is no EMN in force. For example,16 September saw wholesale prices exceed £900/MWh (Figure 19).

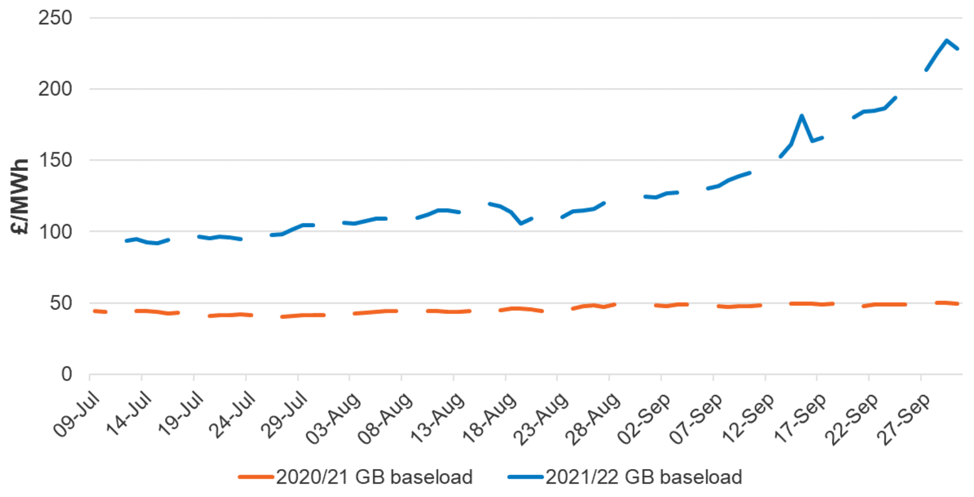


Figure 18 Historically traded GB winter ahead forward electricity baseload prices for Winter 2020/21 and Winter 2021/22 taken from Argus[1]

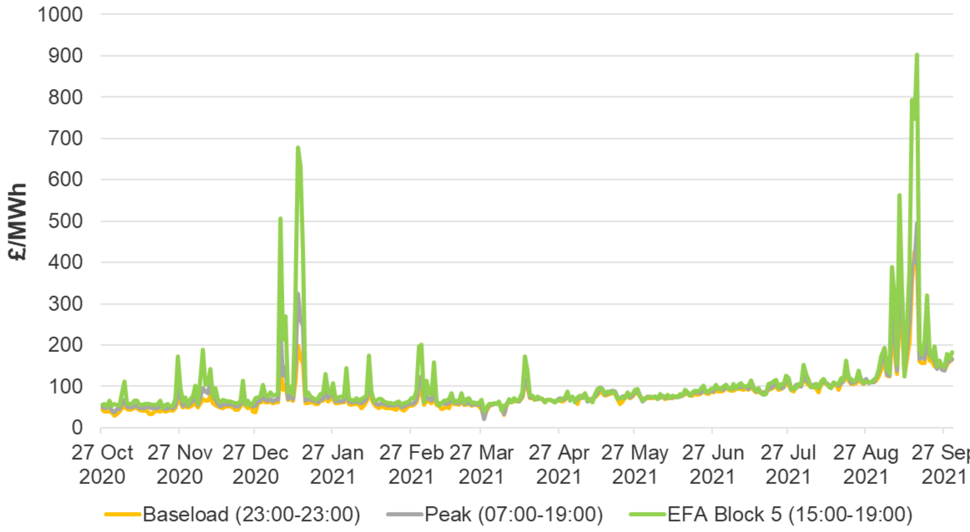


Figure 19. GB wholesale market prices 2020/21

[1] The numbers shown in Figure 18 are historical traded prices not forecasts. Gaps in Figure 18 reflect that trading does not take place on weekends.

Operability / Winter view (1/2)

As National Grid ESO we may need to take actions across our five core areas to maintain operability of the network. We have taken a number of measures to reduce costs to consumers, but high wholesale prices will offset this leading to overall higher costs.

1. Thermal

The Transmission Owners (TOs) have experienced some delays to their works because of COVID-19 but this has not resulted in significant overruns of outages into winter at this point. We will continue to work with the TOs to manage access alongside the operability of the network during winter.

Import and export from the south east of England and from Scotland have presented significant operability challenges in the past. Currently we expect there will be some restriction on the Scotland boundary at the beginning of November, but then unrestricted for the rest of winter. Boundaries between the north and south of Scotland will be restricted until the end of February. Transmission capacity at other boundaries are expected to be unrestricted, unless work planned in the autumn extends or there is a network fault.

The **Western High Voltage (HVDC) link (WLHVDC)** will further help relieve congestion between Scotland and England. Although Hunterston power station starts decommissioning at the end of 2021, the full capability of the WLHVDC (2.25GW) can be obtained with an intact network. We do not expect to take any further action to manage the operability issues relating to the import of energy into Scotland.

North Sea Link (NSL) interconnector has finished commissioning tests and is now offering commercial capacity to the market. NSL connects above the **B7 boundary** and when importing to the UK in combination with high wind conditions will add to the constraint volume.

In addition to higher market prices, new connections may increase constrained volumes contributing to increased costs over winter. We are providing forecasts of constraints on our data portal and will be providing further improvements to our constraint forecasts in the future.

2. Voltage

Managing **reactive power** and hence **voltage** levels continues to be challenging during low demand periods, which typically occur overnight at weekends. During winter, the main period of concern for management of high voltages is over Christmas and New Year when minimum demands can drop to levels seen during the summer.

Voltage control over the summer has been challenging in the north of England due to low levels of thermal generation availability across the region, though this situation is expected to improve as we move into the winter.

With the currently anticipated levels of availability of both TO reactive equipment and generation, management of voltage levels is expected to remain challenging though manageable. However, the availability of thermal/synchronous generation and TO equipment will be monitored as Christmas approaches and actions will be taken as necessary to assist the situation. The actions needed could include:

- Contracting generators in advance to be available to provide reactive power
- Taking within-day trading actions, or bid/offer acceptances, via the Balancing Mechanism, so that generators provide reactive power capability
- Work with TOs to ensure an appropriate outage plan for reactive equipment maintenance so critical reactive equipment can be in service to manage voltage when needed
- Taking within-day action to manage MW flows across the network and voltage levels

Forecasting volumes required for voltage actions, and therefore cost, is difficult due to the impact of system behaviour on the voltage requirement. However, in general terms, reactive power demands are still falling so there will be an increase in the volume of MVAr.h procured to maintain a voltage profile similar to last year's. Increased demands due to the lifting of COVID-19 restrictions may offset some of this volume. There is also a small number of additional **Balancing Mechanism Units (BMUs)** since last year which can provide MVAr at zero MW, as well as the reactive range provided by **Stability Pathfinder (Phase 1)** contracts which will further offset additional volume to be procured.

Therefore, the volumes required this year should be broadly similar to last year, however high market prices may result in a slight increase in cost.

Operability / Winter view (2/2)

3&4. Frequency and Stability

As the ESO, our role is to ensure that we know of and manage risks on the system in order to manage the security of supply of the national electricity transmission system across GB. User and network licensees' obligations ensure compliance with the **Grid Code** and **System Transmission Operator Code (STC)** is maintained at all times. We're continuing to work with the industry around fault ride-through and Grid Code and STC requirements.

The frequency risks on the system for 2021 have been reviewed as part of the first Frequency Risk and Control Report (FRCR). An overall recommendation of the cost versus risk balance of the system was made in the Report and consulted on with industry in March 2021. This has been approved by Ofgem and has resulted in an updated Frequency Control Policy.

The recommendations made in the report simplify frequency control and will result in balancing cost savings as National Grid ESO operate a policy where frequency risks are secured in line with the standards agreed by industry via the FRCR consultation process.

The new fast acting frequency response service, **Dynamic Containment** Low[1], launched last autumn and volumes have continued to grow to over 900MW. Dynamic Containment High will be launched in October 2021, which will allow larger demand losses to be secured. As set out in our 2020/21 winter review, the ESO has implemented a more granular procurement of Dynamic Containment Low to improve the ESO's ability to signal the value of Dynamic Containment throughout the day.

Increasing volumes of Dynamic Containment and the reduction in DER capacity with over-sensitive protection settings through the **Accelerated Loss of Mains Change Programme (ALoMCP)** will reduce the scale of intervention the ESO must take in market dispatch through trades and Balancing Mechanism actions to reduce individual loss risks, moving those to the system-wide response and inertia controls and competitive balancing markets. The introduction of Dynamic Containment has increased the overall volume of response the ESO is seeking to procure. This enables market participants to better optimise across markets as they can now offer volumes into Dynamic Containment across the day in 6-hour blocks rather than choosing to lock in for the entire 24-hour period.

This April we moved the procurement of **Short Term Operating Reserve (STOR)** to a day ahead auction mechanism. The STOR market has remained competitive since this change was introduced and will be a key tool in our frequency control toolkit for securing the largest loss during the winter.

Costs for frequency response will increase as a result of the increased volume of response being procured, but this increase will be partially offset by a decrease in the cost of individual loss risk controls due to fewer targeted actions being taken on large infeed and outfeed loss risks, including generators and interconnectors. Due to the increased holding of frequency response, specifically, the addition of Dynamic Containment, the volume of targeted actions will be lower than last year. However, the cost of some of these balancing actions may be pushed up as a result of higher wholesale market prices.

The impact of ALoMCP changes is a reduction in the requirement for the ESO to intervene in the market dispatch of power stations in order to raise the inertia of the system, and as such we expect to see a reduction in balancing costs currently attributed to **Rate of Change of Frequency (RoCoF)** constraint management (i.e. maintaining the **RoCoF limit**).

The cost of reserve is expected to increase as this is closely linked to wholesale prices which are high. Costs for reserve and frequency response will outweigh savings from RoCoF constraint management.

5. Restoration

Availability of Restoration services is generally good over winter, with few stations having planned outages and more stations running economically in the market without needing additional warming to maintain capability. Availability is continuously monitored and actions will be taken if required.

Costs are likely to increase in 2021/22 compared to the current year as we will incur an increase in capital contributions via our Restoration contracts.

[1]Dynamic Containment 'low', refers to the part of the dynamic containment service which provides low frequency response, Dynamic Containment 'high' will provide high frequency response.

Glossary

Accelerated Loss of Mains Change Programme (ALoMCP)

A joint initiative between National Grid ESO, Energy Networks Association, Distribution Network Operators and independent Distribution Network Operators. It provides funding to non-domestic distributed generators to upgrade their loss of mains protection to be compliant with the Distribution Code by September 2022.

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 combine have a significant effect on peak electricity demand.

B7 boundary

The electricity transmission network is divided into a number of different areas, with boundaries separating them. The B7 boundary bisects England south of Teesside.

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.

Balancing Mechanism Unit (BMU)

A unit which participates in the Balancing Mechanism.

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 close to real time. Forecast breakdown rates are applied to the operational data provided to the ESO by generators. 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 link between Great Britain and the Netherlands. It 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. 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:

https://www.nationalgrideso.com/news/everything-you-need-know-about-electricity-system-margins

Combined Cycle Gas Turbine (CCGT)

A power station that uses the combustion of natural gas or liquid fuel to drive a gas turbine generator to produce electricity. The exhaust gas from this process is used to produce steam in a heat recovery boiler. This steam then drives a turbine generator to produce more electricity.

Demand suppression

The difference between our pre-Covid forecast demand levels and the actual demand seen on the system. We have not included any Covid-related demand suppression this winter.

Glossary

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 (https://www.nationalgrideso.com/research-publications/winter-outlook).

Distributed Energy Resources (DER)

Resources connected to the distribution network which can generate or offtake electricity.

Dynamic containment

This is a new fast-acting post-fault service to contain frequency within the statutory range of +/- 0.5Hz in the event of a sudden demand or generation loss. The service delivers very quickly and proportionally to frequency but is only active when frequency moves outside of operational limits (+/- 0.2Hz). Dynamic Containment 'low', refers to the part of the dynamic containment service which provides low frequency response. Dynamic Containment 'high' will provide high frequency response.

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/.

Embedded generation

Power generating stations/units that are not directly connected to the National Grid electricity transmission network and for which we do not have metering data/information. They have the effect of reducing the electricity demand on the transmission system.

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:

https://www.nationalgrideso.com/news/everything-you-need-know-about-electricity-system-margins.

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.

Floating

When an interconnector is neither importing nor exporting electricity.

Forward prices

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

Grid Code

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

GW Gigawatt (GW)

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

Interconnector

Electricity interconnectors are transmission assets that connect the GB market to Continental Europe and Ireland. They allow suppliers to trade electricity between these markets.

Interconnexion France–Angleterre (IFA)

A 2,000 MW link between the French and British transmission systems. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE). See more at https://www.ifa1interconnector.com/.

Glossary

Interconnexion France–Angleterre 2 (IFA2)

A 1,000 MW link between the French and British transmission systems commissioned in 2020. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE). See more at https://www.ifa1interconnector.com/.

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.

Loss of Load Expectation (LOLE)

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

Minimum demand

The lowest demand on the transmission system. This typically occurs overnight.

Moyle

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

MW Megawatt (MW)

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

Nemo link

A 1 GW HVDC sub-sea link between GB and Belgium. See more at https://www.nemolink.co.uk/.

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/.

Normalised transmission demand

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

Normalised peak transmission demand

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

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.

Peakload electricity

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

Pumped storage

A system in which electricity is generated during periods of high demand by the use of water that has been pumped into a reservoir at a higher altitude during periods of low demand.

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.

Glossary

Reactive power

The movement of energy across a network which is measured in MVAr. Different types of network assets and generators can generate or absorb reactive power. The flows of reactive power on a system affect voltage levels.

REMIT

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

Renewables

Electricity generation from renewable resources, which are naturally replenished, such as sunlight or wind.

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.

RoCoF limit

The maximum loss we can allow on the system. A loss of generation larger than this limit has a high risk of resulting in a RoCoF of 0.125Hz/s.

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.

System Operator Transmission Code (STC)

The System Operator Transmission Owner Code defines the relationship between the Transmission Owners (TOs) and the ESO.

Technical capability

The capacity of connected plant expected to be generating in the market, based on the Capacity Market auctions and another sources of market intelligence, but not taking any account of potential breakdown or outage.

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.

Glossary

Underlying demand

Demand varies from day to day, depending on the weather and the day of week. Underlying demand is a measure of how much demand there is once the effects of the weather, the day of the week and distributed generation have been removed.

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 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.

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.

Electricity System Operator legal notice

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

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

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

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