October 2020

Winter Outlook

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

nationalgridESO

Foreword

Welcome to our 2020/21 Winter Outlook Report. This report draws together analysis and feedback from across the industry to present a view of supply and demand for the winter ahead. It examines margins on the electricity system and their implications for security of supply for the winter.

The impact of the COVID-19 pandemic has been widespread. Over the spring and early summer, with the country in lockdown, we saw record low demands on the electricity system. We implemented measures to ensure UK consumers continued to receive secure and reliable electricity supplies during these uncertain times.

While electricity demand has recently started to recover to near normal levels, we anticipate continued uncertainty over the impact of the pandemic on our daily lives through the winter. For this reason, we have continued the scenario-based approach to demand forecasting taken in the Summer Outlook Report.

Margins on the electricity system will vary through the winter – driven by many factors including generator outages, demand levels and renewable output levels. Overall, we expect that margins will remain within the reliability standard for safely and securely operating the system.

In previous years, the report has covered both gas and electricity. This will be the first year where two separate documents are published, and this document covers only the electricity outlook. This is the same approach that has been taken with the Summer Outlook and Winter Review and Consultation earlier in the year. We will continue to engage with National Grid Gas Transmission to ensure consistency in approach, the Gas Winter Outlook can be found here.

You can join the conversation at our weekly ESO Operational Transparency Forum, by email at marketoutlook@nationalgrideso.com or by following us on Twitter (@ngeso).

Fintan Slye

Director, Electricity System Operator

Executive summary / Key messages

COVID-19

Due to the uncertainty caused by COVID-19, we're examining a range of scenarios for margins rather than a single forecast. We expect to see downward pressure on demand compared to last winter.

Operability

Operability remains complex. We have existing tools & services and are developing others, including dynamic containment, to manage anticipated operability challenges across the winter period. We expect to use these similarly to last winter as increased demands generally cause relatively fewer operability challenges than we have seen this summer.

Security of supply

System margins aren't quite as high as last winter but remain well within the Reliability Standard set by the Government under all COVID-19 scenarios.

End of the EU Transition Period

We foresee no additional operability or adequacy challenges this winter as a result of the EU Exit transition period ending.

Executive summary / Overview

We expect there to be sufficient generation and interconnector imports to meet demand throughout winter 2020/21.

The **de-rated margin** at underlying ACS demand* level is lower than last year, but the associated **loss of load expectation (LOLE)** remains less than 0.1 hours/year. So it is therefore well within the Reliability Standard of three hours set by the Government and we remain confident there is sufficient supply to meet peak demand.

We expect normalised **transmission system demand** to peak at 44.7 GW, which is lower than last winter. Transmission system demands include an average 5% reduction due to the pandemic, which is informed by what has been experienced over the past months.

Based on the data provided by the market, we can meet normalised demand and reserve requirement every week during winter under the medium and high import scenarios†.

GB baseload **forward prices** are higher than those in France, Belgium and the Netherlands and so we expect to see imports from those markets over interconnectors. 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.

We expect interconnector flows to be unaffected by the end of the EU Transition Period and to continue to reflect price spreads between GB and Europe. Furthermore, even in the highly unlikely event of no interconnector flows between GB and continental Europe we have the tools and capabilities to ensure security of supply.

Key statistics

	2019/20 forecast	2019/20 weather corrected	2019/20 actual	2020/21 base case
De-rated margin at underlying demand level (GW)	7.8 GW			4.8 GW
De-rated margin at underlying demand level (%)	12.9%			8.3%
Loss of load expectation (LOLE)	<0.1 hours/ year			<0.1 hours/ year
ACS peak underlying demand (including reserve requirement)	60.4 GW			58.0 GW
Peak transmission system demand (normalised)	46.4 GW	47.6 GW	46.8 GW	44.7 GW
Minimum demand (normalised)	19.7 GW	20.3 GW	20.9 GW	19.6 GW
Total maximum supply technical capability	106.7 GW			100.7 GW
Interconnectors net imports	2.7 GW			3 GW
Maximum Triad avoidance	2.6 GW		2.0 GW	2.2 GW

Glossary: Definitions for the terms in bold purple text can be found in the glossary on page 19

* 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.

† There are three weeks in the low import scenario where demand and reserve are not met based on current submissions

Executive summary / COVID-19 impact

We have modelled scenarios to consider the impact of COVID-19 on the electricity system this winter.

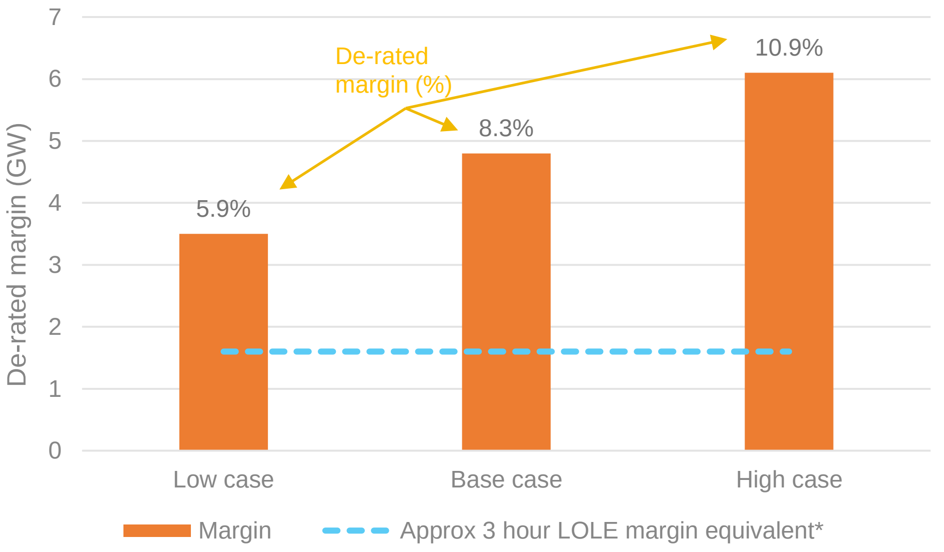
The effect of the pandemic this winter leaves a higher degree of uncertainty compared to previous years. At the height of the pandemic, average demand on the electricity system dropped by as much as 18%. To help manage this we have carried out scenario-based modelling of likely outcomes.

Our base case forecast for peak underlying demand over the winter is for a 3% reduction in **ACS peak** against normal expectations, reflecting the level of demand in recent months. This forecast assumes government action and mitigation of the effects of the pandemic leading to the current level of demand being maintained. We expect lower reductions in ACS peak demand than overall demand. More detail on the effects of COVID-19 on normalised demand can be seen on page 9.

The results of this modelling are shown in Figure 1, with the **de-rated margin** for winter 2020/21 likely to be between 5.9% and 10.9% or 3.5 GW to 6.1 GW. An approximate figure for the de-rated margin associated with an LOLE of 3 hours – the Reliability Standard – is shown for comparison*. All modelled scenarios are well above this level.

We have not seen any evidence to suggest that the **demand side response (DSR)** information and assumptions used in the electricity capacity report analysis has changed due to the impact of COVID-19.

Figure 1. Range of outcomes for de-rated margin winter 2020/21 under different COVID-19 related demand suppression outcomes



Our low case for the de-rated margin is a case with no demand suppression, while the high case is a scenario with higher levels of demand suppression, up to 6%.

We have also modelled a large number of other scenarios (e.g. further demand suppression, generator unavailability or reduced interconnector imports) to test the level of resilience but consider this range to be most reflective of the uncertainty caused by COVID-19.

* The margin that exactly meets 3 hours LOLE may vary depending on demand and generation assumptions.

Contents

System margins / Winter view

The margins on the electricity system are lower than last winter but forecasts are well within the national Reliability Standard. Our winter view analysis is based on the EMR Base Case supply and demand assumptions[1] adjusted for expected demand suppression due to COVID-19 and recent changes to the generation mix.

This winter we expect…

- the **de-rated margin** to be lower than last year due to generation outages and plant closures, but higher than those forecast for other recent years including 2015/16 and 2016/17
- the corresponding **loss of load expectation (LOLE)** to be well within the national Reliability Standard level of three hours per year

Did you know?

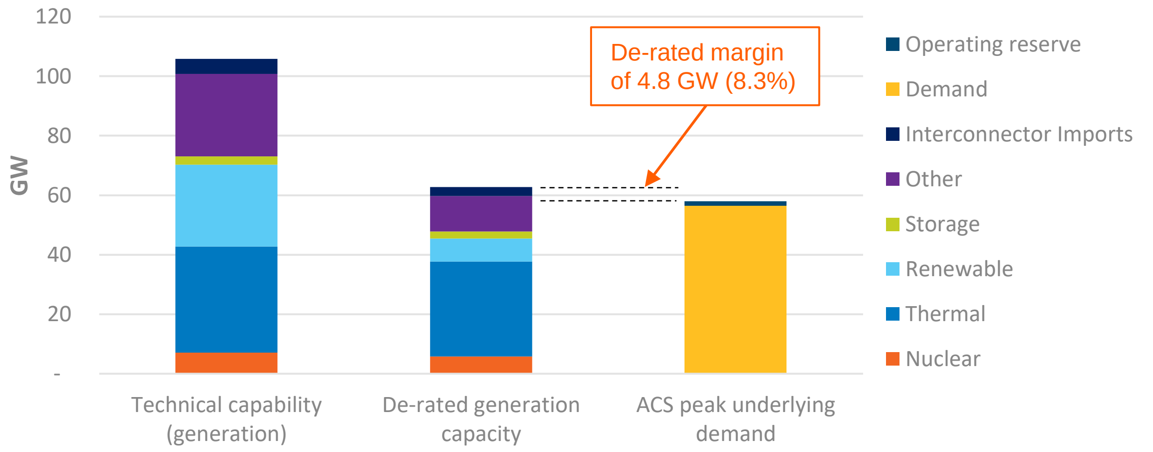
When we calculate the de-rated margin for the winter, we use the total underlying demand across both the transmission and distribution systems. This accounts for the growth in **embedded generation** and the impact of the **Capacity Market** (CM) when we assess security of supply.

However, throughout the rest of the *Winter Outlook* publication, 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. So this *Winter Outlook* is our forecast of transmission supply and demand and the associated operational outlook.

Our central forecast for the de-rated margin is 8.3% including 3% demand suppression at peak times. Due to uncertainty in demand levels this winter, we have also analysed scenarios either side of this. Variations from 0% - the high demand case - to 6% - the low demand case – of underlying demand suppression lead to de-rated margin figures of between 5.9% and 10.9%.

	High demand	Base case	Low demand
De-rated margin at underlying demand level	3.5 GW	**4.8 GW**	6.1 GW
Margin as a percentage of underlying demand	5.9%	**8.3%**	10.9%
LOLE at underlying demand	0.3 hours / year	**<0.1 hours / year**	<0.1 hours / year
Total average cold spell (ACS) peak underlying demand (including operating reserve)	59.7 GW	**58.0 GW**	56.2 GW
Total maximum supply technical capability	**100.7 GW**		
Operating reserve	**1.5 GW**		
Net interconnector import flows (at peak demand)	**3 GW**		

Figure 2. Supply margin in relation to generation capacity and demand



1. https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202020.pdf

Operational surplus / Week-by-week view

We expect sufficient operational surplus for each week of winter 2020/21.

This winter we expect…

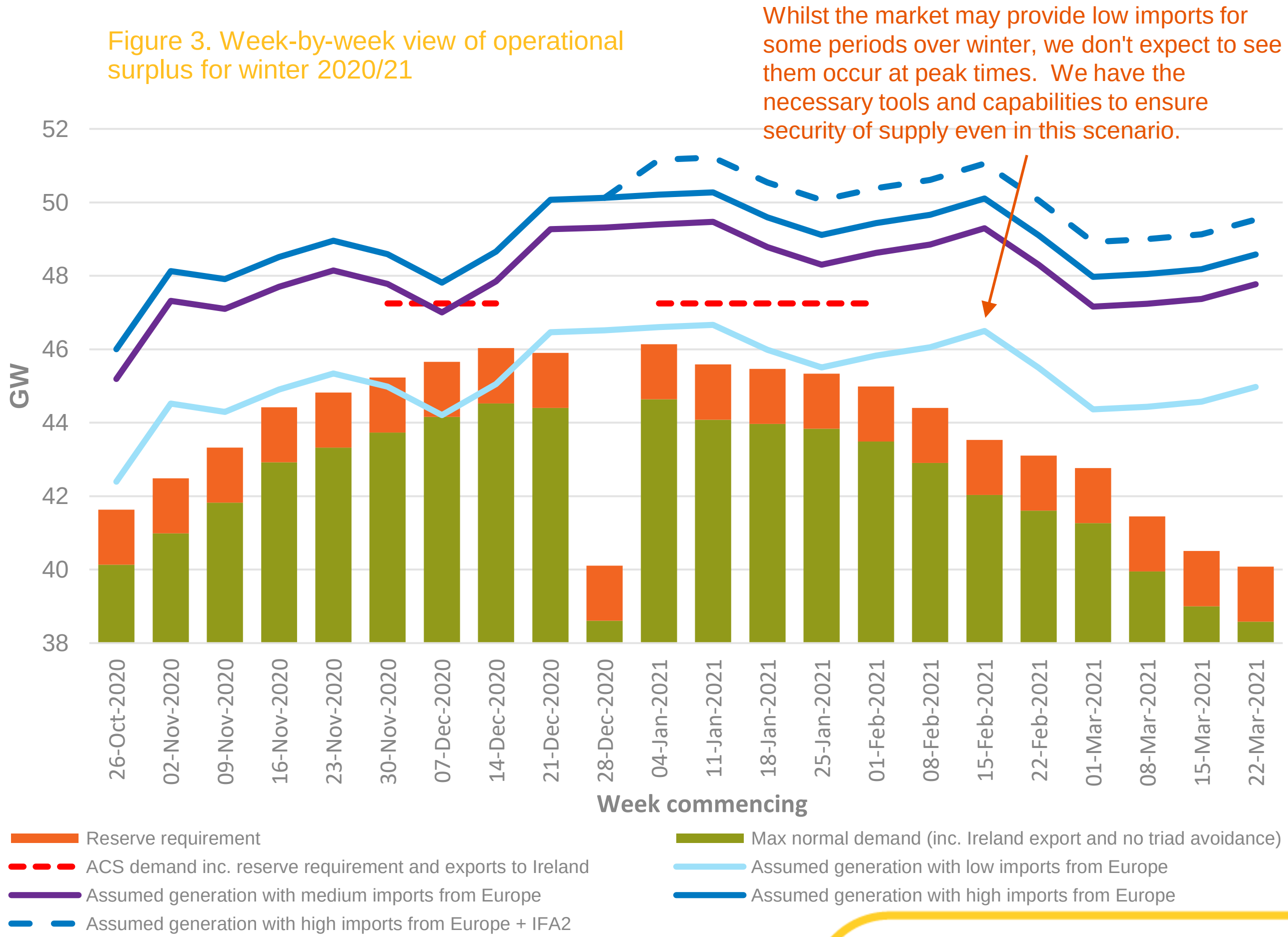
- the **operational surplus** to be lower than last year due to generation **outages** and plant closures of up to 2.25 GW bringing a reduction in maximum technical generation capacity
- **Average Cold Spell (ACS)** transmission demand to be met in all weeks under the high import interconnector scenario and all but one week in the medium import scenario
- weather corrected **transmission system demand** to be lower than weather corrected outturns in previous years, due to the effects of COVID-19 putting downward pressure on demand
- market signals to incentivise flows, through the **Capacity Market** and price signals, to ensure that **weather corrected demand** (normalised) is met under all interconnector scenarios. We have also done modelling based on stress events to ensure that we can manage these scenarios.

Based on current generator submissions, normalised peak transmission demand is expected in the first week of January, while the minimum operational surplus is projected to be lowest at start of December.

We analyse three levels of electricity supply, which includes a view of generation accounting for **breakdown rates** and a range of interconnector flows. 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	44.7 GW
Minimum demand	19.6 GW
Maximum Triad avoidance	2.2 GW

Figure 3. Week-by-week view of operational surplus for winter 2020/21



Demand / COVID-19 impact

We have modelled scenarios to consider the impact of COVID-19 on the electricity system this winter.

As our central operational scenario we are taking an overall level of **demand suppression** of 5% from anticipated pre-COVID demands. The pandemic situation remains uncertain, which is why we have taken a scenario-based approach.

Observation from the summer shows that demands during the day are suppressed more than overnight and evening demands, as shown in Figure 4. We are assuming that the peak of the day, occurring once it is dark, will behave more like an evening demand than a daylight demand in terms of its suppression. Peak demands shown here are from the transmission system under normal weather conditions, and different to the **ACS peak demands** discussed on slide 7.

Our base scenario assumes that the normalised peak transmission demand will be suppressed by 4% (i.e. compared to the 5% average suppression in this case).

We have also modelled additional scenarios for normalised transmission demand, including:

- A 10% overall suppression in demand: this models the effect of many local partial lockdowns (this corresponds to a peak suppression of 7%)
- A 15% overall suppression in demand: this models a return to a full lockdown (this corresponds to a peak suppression of 11%)

We believe it is very unlikely that either of these two more severe cases could persist for more than a month. So it is likely that the peak demand of the winter will occur in the base scenario of 5% overall suppression. The end of the furlough period is likely to bring some economic shock, but we do not believe it will have a great impact on demands. We estimate the effect as an extra suppression of between 0% to 2%, which could bring us between our central operational scenario and the local lockdowns scenario.

Figure 4. ESO % change in demand relative to pre-COVID expectation

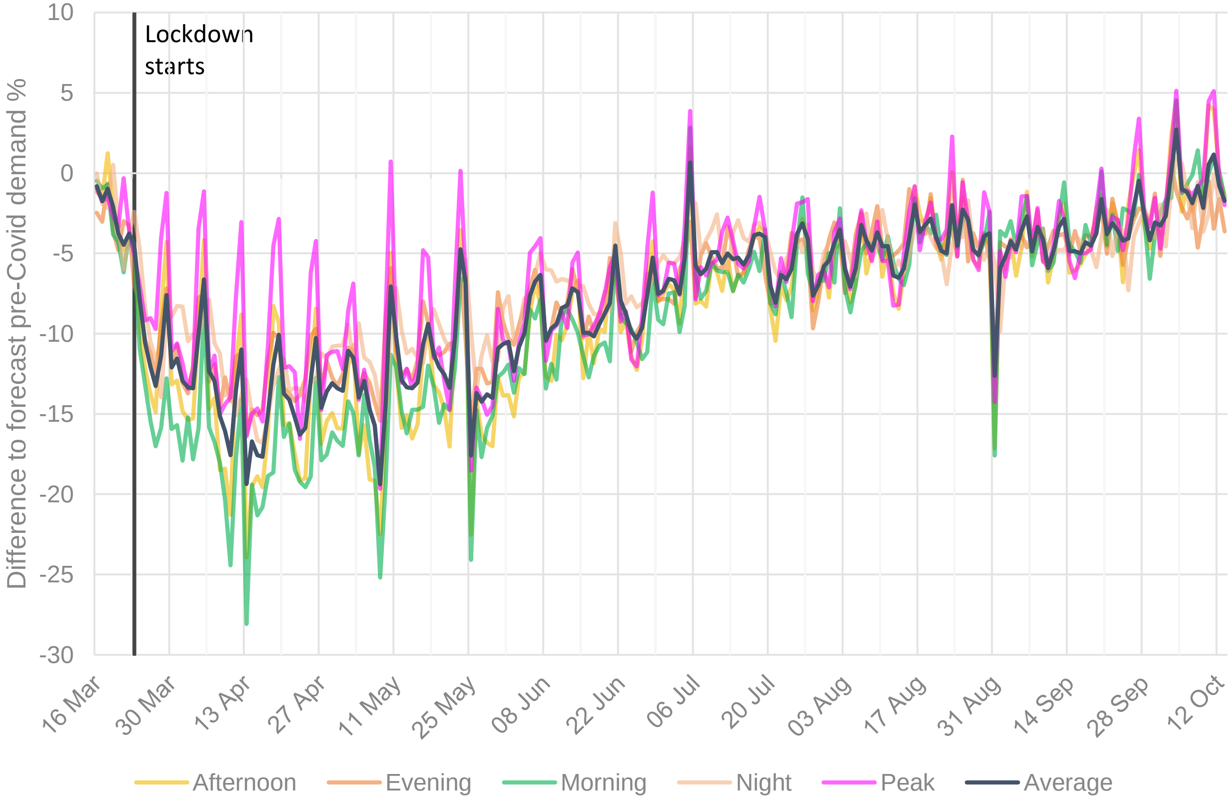


Figure 4 above presents the latest view of demand relative to pre-Covid expectations. We will continue to monitor this situation and discuss changes in our forecasts at our weekly ESO Operational Transparency Forum.

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Demand / Normalised peak demand

Weather corrected peak demand for winter 2020/21 is expected to be lower than the previous two winters, largely as a result of COVID-19 impacts. Weather corrected minimum demand is also expected to be lower than last winter.

This winter we expect…

- weather corrected peak **transmission system demand (TSD)** to be 44.7 GW, based on assumptions in the table below
- weather corrected **minimum demand** to be 19.6 GW (assuming no interconnector exports overnight), see Table 1

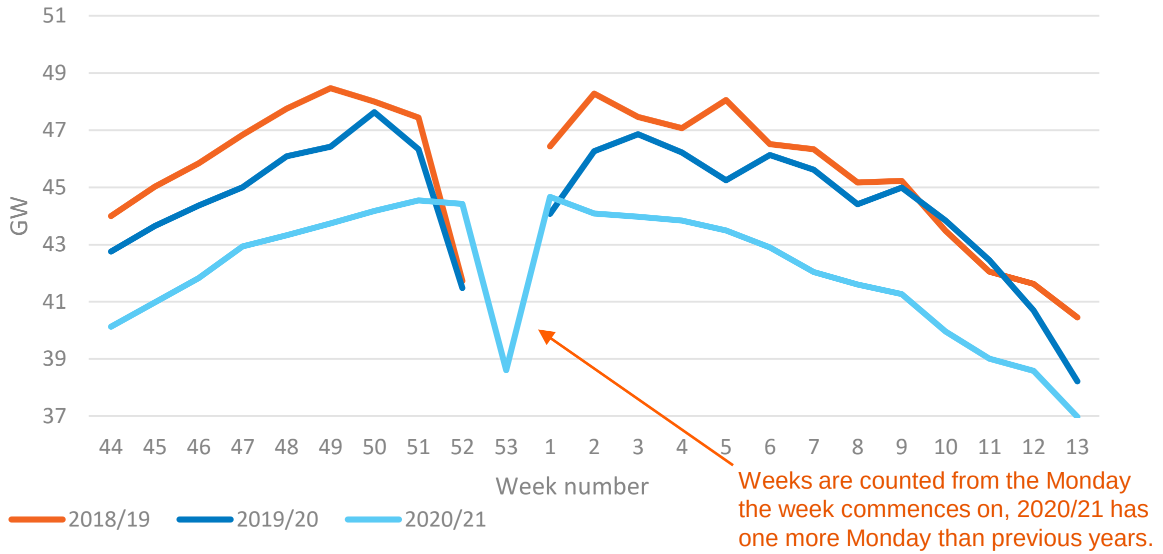
Did you know?

When we forecast demand in this section, it is transmission system demand (TSD) which includes the demand from power stations and interconnector exports. This forecast is based on historical data and current market conditions.

We base our peak demand forecasts on **seasonal normal weather**, applying regression models to 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).

Transmission connected power station demand	600 MW
Base case interconnector exports	750 MW
Embedded wind capacity	6.5 GW
Embedded solar capacity	13.1 GW
Pumped storage	0 GW

Figure 5. Historical and forecast normalised weekly peak winter demand[1]



At peak times, interconnectors are typically exporting across the Moyle and EWIC interconnectors which connect GB to Ireland and 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.

Table 1. Historical interconnector flows to Ireland overnight

Interconnectors	Import	Floating	Export	Total
EWIC	45.6%	22.4%	32.0%	100.0%
Moyle	52.3%	0.1%	47.6%	100.0%

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

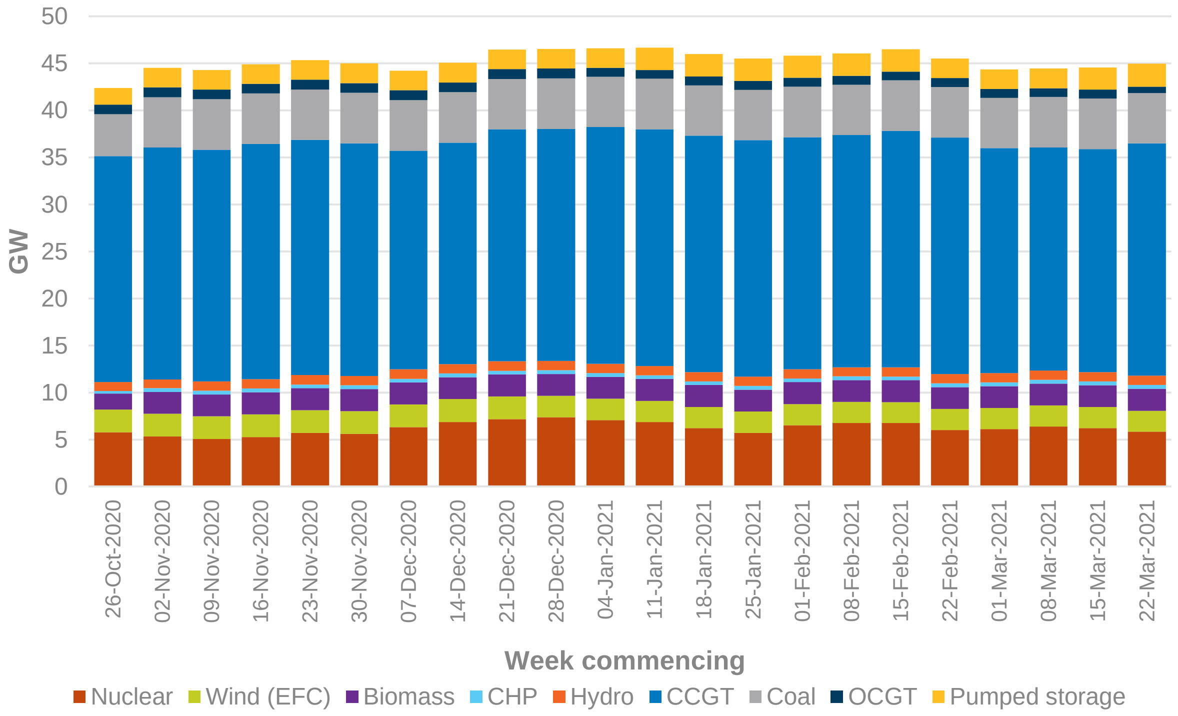
Supply / Week-by-week view

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

This winter we expect…

- gas to be ahead of coal in the generation running order, based on current forward fuel prices
- generator reliability to be in line with recent winters and we have not been made aware of any significant impact on maintenance schedules as a result of COVID-19

Figure 6. Generation by fuel type (including breakdown rates)



Did you know?

This week-by-week generator view is driven by generator submissions of availability. This is different to our calculation of de-rated margin for the winter on page 7.

Our generation forecasts are based on published OC2 data, 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 6, 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 2). For wind generation, we assume an **equivalent firm capacity (EFC)** of 16 per cent.

Table 2. Breakdown rates by fuel type (based on a 3-year rolling average)

Power station fuel type	Assumed breakdown rate 19/20	20/21
Coal	7%	9%
CCGT	6%	5%
Nuclear	9%	9%
OCGT	4%	5%
Biomass	3%	3%
Hydro	8%	8%
Wind EFC	18%	16%
Pumped storage	3%	2%

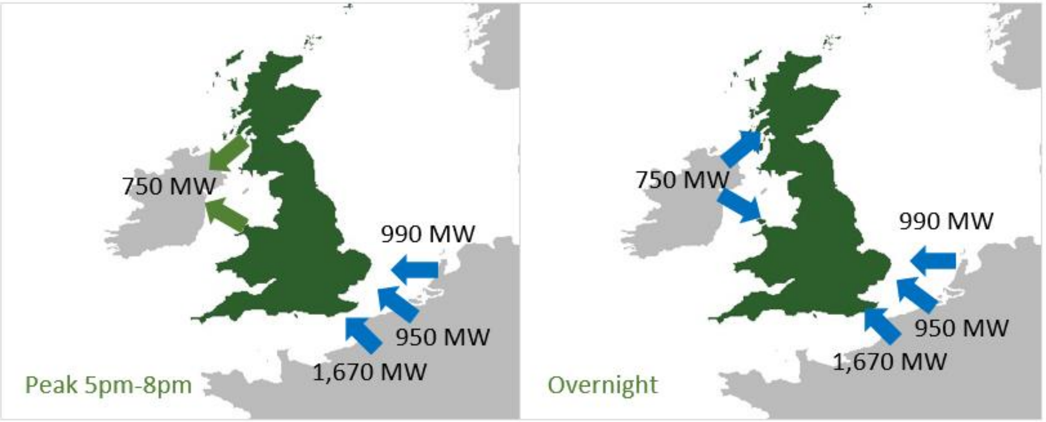
Europe and interconnected markets / Overview

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** in GB to be ahead of those in continental Europe for the majority of the winter period
- imports into GB at peak times via the **IFA**, **BritNed** and **Nemo Link** interconnectors, although occasionally not at full import and subject to weather variations
- **Moyle** and **EWIC** interconnectors typically to be exporting from GB to Northern Ireland and Ireland during peak times
- some import through Moyle and EWIC at times of high wind output in Ireland or during periods of system stress in GB

Figure 7. Forecast flows (high import scenario) on the interconnectors for winter 2020/21



Interconnector Import Scenario	Resulting in…
Low (0 MW)	net export (750 MW) from GB
Medium (2,800 MW)	net import (2,050 MW) to GB
High (3,610 MW)	net import (2,860 MW) to GB

Did you know?

We explore the potential range of interconnector flows each winter using a set of three scenarios. Each scenario includes a varying level of imports via IFA, BritNed and Nemo Link interconnectors.

Scenarios assume a 750 MW export to Ireland via the EWIC and Moyle interconnectors during peak times.

These scenarios do not include a potential extra 1,000 MW of import via **IFA2** (subject to commissioning work).

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)	None
BritNed (1 GW)	None
Nemo (1 GW)	None
EWIC (500 MW)	None
Moyle (500 MW)	None

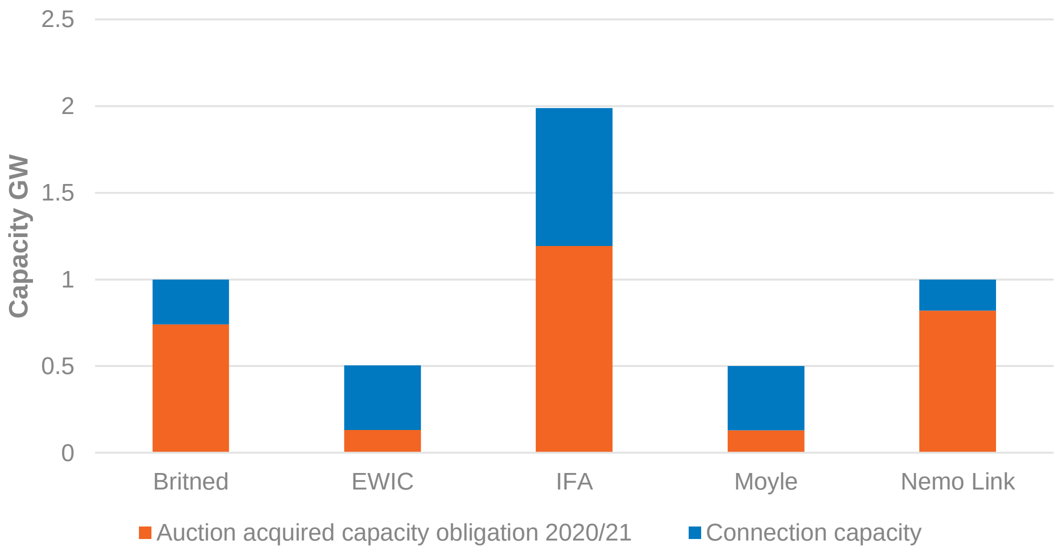
The new interconnector '**IFA2**' is under construction and may come into operational service over the winter period. Once commissioned, it will provide an additional 1 GW capability between France and GB. There are plans to carry out commissioning tests for IFA2 in late 2020.

We don't currently expect any **outages** that would impact our ability to import over interconnectors at peak times.

2. Capacity Market

Interconnectors other than IFA2 have secure agreements in the **Capacity Market (CM)** in the T-4 and T-1 auctions for 2020/21. 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 8. Conditional Capacity Market agreements 2020/21



Europe and interconnected markets / Peak flows analysis

3. European forward prices

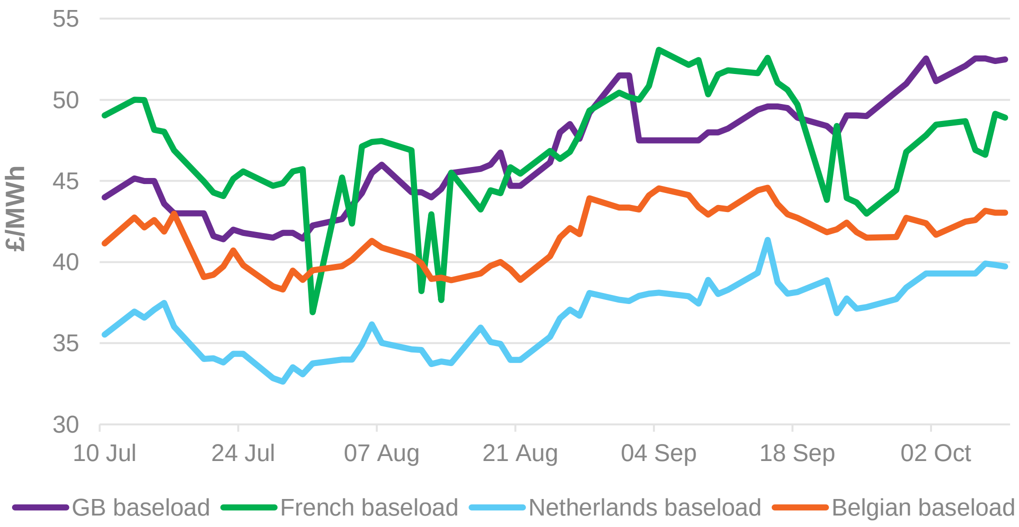
Electricity flows through the interconnectors are primarily driven by the price differentials between the markets.

Forward prices for **baseload electricity** during winter 2020/21 in GB are higher than those in the French, Dutch and Belgian markets (see Figure 9) 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.

IFA2 connects the GB and French markets and is expected to behave similarly to the current **IFA** interconnector.

Figure 9. Winter 2020/21 electricity baseload forward prices

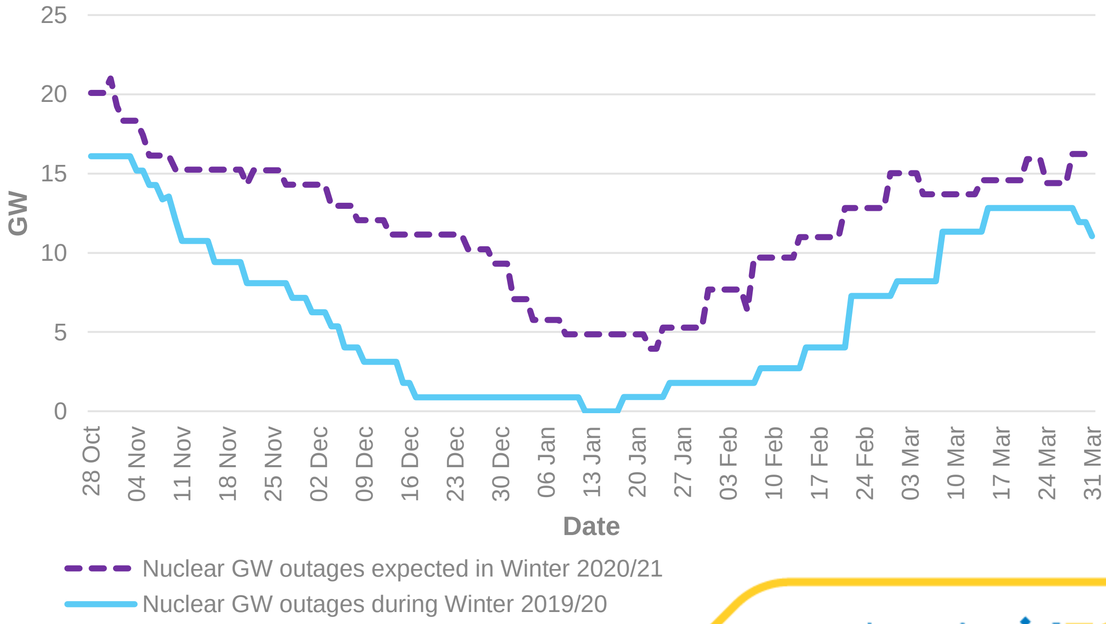


4. Network access constraints

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 10 shows that the planned French nuclear outages for this year are higher than the previous winter, however with GB forward prices ahead of those in France we expect imports to continue, particularly during peak times.

Figure 10. The impact on French nuclear capacity from planned outages in 2020/21 and last winter's actuals



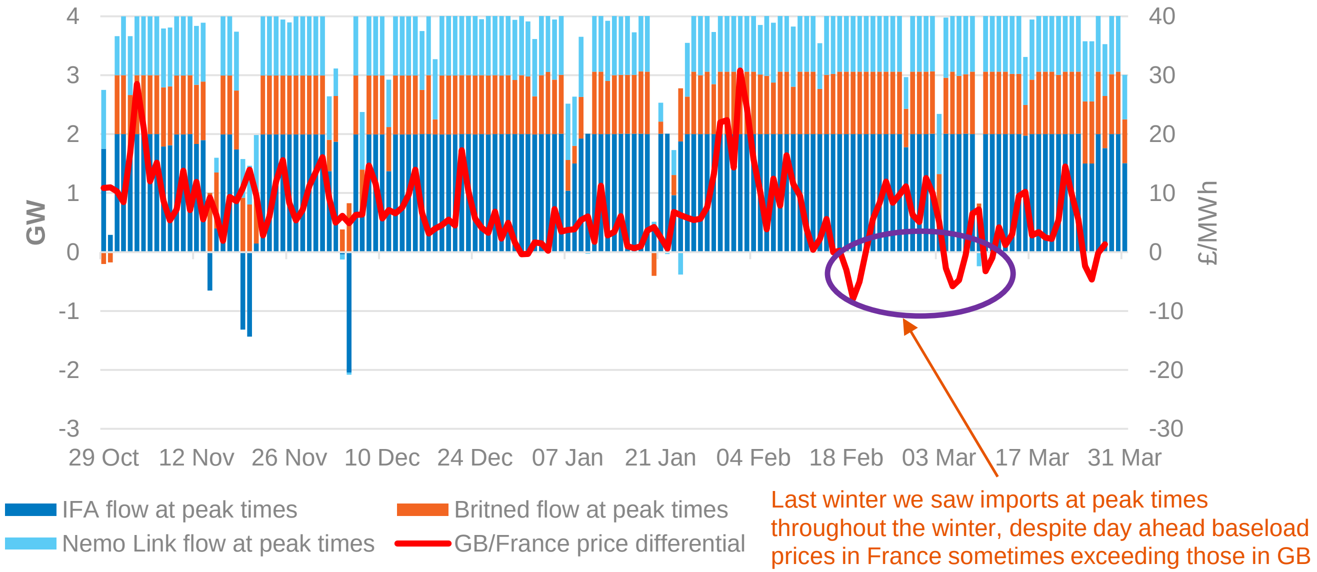
Europe and interconnected markets / Historic flows

Overview of continental European interconnectors

Based on **forward prices** for the 2020/21 winter products, and no planned outages on continental interconnectors, 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 11.

The flow over the new **IFA2** is expected to be similar to the **IFA** interconnector, depending on the outcome of the planned commissioning work. Once in service, IFA2 is expected to provide an additional 1 GW of capacity between the GB and French markets.

Figure 11. Daily peak time flows across the continental interconnectors in winter 2019/20 (positive MW values mean imports into GB)



Overview of Irish interconnectors

During winter 2020/21, we expect GB to export to Northern Ireland and Ireland during peak times on the **Moyle** and **EWIC** interconnectors. This may, however, be reversed during periods of high wind and system stress. Figure 12 shows examples of where market conditions and weather variance affected the flows last winter.

Figure 12. Daily peak time flows across the Irish interconnectors in winter 2019/20 (positive MW values mean imports into GB)

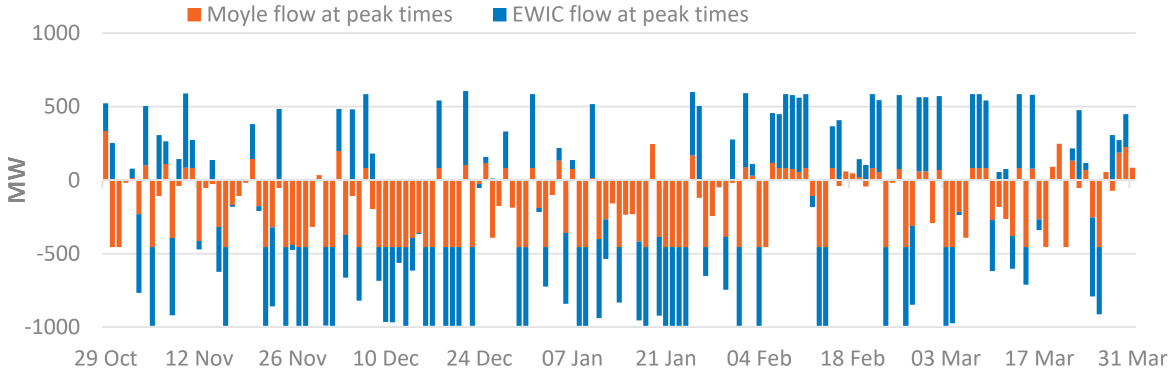
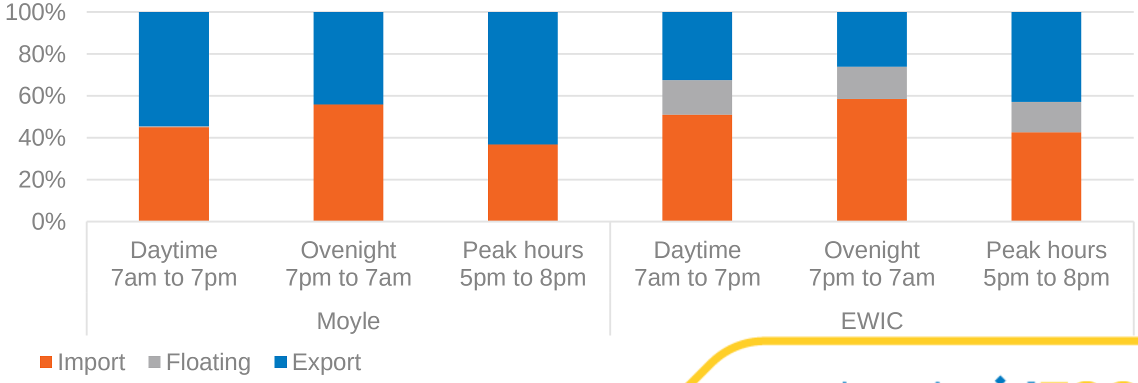


Figure 13. Proportion of import and export for Irish interconnectors during winter 2019/20



Hot topics / EU transition period end

Impact of the UK's exit from the European Union

As part of our contingency planning, we have carried out analysis on a range of scenarios to test the risks associated with the end of the transition period after the UK's exit from the European Union.

- We expect interconnectors to continue to flow and that we will be able to manage the system as at present. There will be changes to the trading arrangements for the interconnectors but this is not envisaged to have any material implications. In the highly unlikely event of no interconnector flows between GB and continental Europe we have the tools and capabilities to ensure security of supply.
- Currently when electricity is traded over interconnectors with connected markets in the EU a day ahead of real time, this is done using implicit arrangements. This makes trading faster and more efficient. In the event that there is not a negotiated trade agreement with the EU at the end of the transition period, these arrangements would no longer apply and interconnectors would have to move to fall-back arrangements.

For more information…

Trading electricity in a no-deal scenario:

gov.uk/government/publications/trading-electricity-if-theres-no-brexit-deal/trading-electricity-if-theres-no-brexit-deal

Replacement Reserve: **nationalgrideso.com/industry-information/balancing-services/reserve-services/replacement-reserve-rr?overview**

RR update 04 September: nationalgrideso.com/document/176006/download

Send further comments and questions on TERRE to:
box.BalancingProgramme@nationalgrideso.com

Project TERRE

The **Trans-European Replacement Reserve Exchange (TERRE)** project, set up by **ENTSO-E**, is implementing a new **Replacement Reserve** (RR) balancing product for use by national **transmission system operators** (TSOs) to support their Balancing Mechanisms (BMs).

This product will be traded in 15-minute blocks with an activation time of 30 minutes (the time during which a provider must reach full delivery following an instruction from the System Operator).

Project update

On 9 July 2020, the European Commission released a statement highlighting that 'third countries' outside the single market of the European Union (EU), and which do not have a free trade agreement on energy, will not be able to participate directly on dedicated EU platforms. This includes the new Libra platform for the RR market, being established by the TERRE industry project, of which NGESO is a leading member. After Transitional Arrangements with the EU end on 31 December 2020, the UK will be a third country. The EC has therefore clarified that this could affect TSOs including SwissGrid and National Grid ESO, until free trade agreements are ratified by the EU and the respective national parliaments.

- It is now not possible to facilitate GB participation in RR before the end of 2020.
- We remain committed to the TERRE project as a leading member, and to the RR market and the Libra platform on which it will be traded.
- We are continuing to consult with Ofgem and BEIS, concerning the manner in which NGESO will be able to facilitate participation in RR by GB energy providers, and the appropriate timescale for executing GB Go-Live for TERRE.

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Operability / Winter view

As National Grid ESO we may need to take actions across our five core areas to maintain operability of the network.

Thermal

The Transmission Owners have needed to delay a high volume of works during the COVID-19 lockdown and are now requesting access to allow these works to be completed. We will continue to manage this 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. This winter we expect the transmission capacity at these boundaries to be unrestricted, unless work planned in the autumn extends or there is a network fault.

The **Western High Voltage (HVDC) link** will further help relieve congestion between Scotland and England. The return of Hunterston power station also means that we can use the full capability of the link (2.25GW) and we do not expect to take any further action to manage the operability issues relating to the import of energy into Scotland.

IFA2 is expected to finish commissioning tests towards the end of November at which point trial operations will begin and IFA2 will start offering commercial capacity to the market.

Stability

We expect that in periods of low demand, high volumes of low **inertia** generation can cause an increase in operational issues such as high rates of change of frequency (RoCoF). Alongside the introduction of **dynamic containment** (see *Frequency* section), critical work is being accelerated by the Distribution Network Owners (https://www.ena-eng.org/ALoMCP/) to move smaller generation to new protection settings. This will reduce the need and cost to manage system stability using operational tools. We anticipate taking actions such as bids and offers during low demand periods likely including the Christmas period and overnights.

More details on the actions we can take can be found in our Balancing Principles Statement.

Frequency

This winter will see the go-live of our new frequency response service, **dynamic containment**. This is a critical service to contain frequency within statutory limits in a range of system conditions and for a range of loss-sizes. This will lead to less severe and fewer frequency excursions due to dynamic containment being a much faster acting service compared to existing services.

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.

Voltage

Managing **reactive power** and voltage levels will continue to be challenging during low demand periods which are likely to include some overnight periods and the Christmas week. The actions needed could include:

- Contracting in advance with generators 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 help manage voltage when needed
- Taking within day action to manage MW flows across the network and voltage levels

Glossary

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

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.

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 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.

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

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

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

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

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

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

Demand side response (DSR)
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. We observe this behaviour as a reduction in transmission demand.

Demand suppression
The difference between out pre-COVID forecast demand levels and the actual demand seen on the system. We have considered a range of potential outcomes for demand suppression this winter.

Glossary

De-rated margin for electricity
The sum of de-rated supply sources declared 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 17/18 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).

Distribution connected
Any generation or storage that is connected directly to the local distribution network, as opposed to the transmission network. It includes combined heat and power schemes of any scale, wind generation and battery units. This form of generation is not usually directly visible to National Grid as the system operator and reduces demand on the transmission system.

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).

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

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.

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.

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

Floating
When an interconnector is neither importing nor exporting electricity.

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

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.

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).

Interconnexion France–Angleterre 2 (IFA2)
A 1,000 MW link being between the French and British transmission systems being commissioned in 2020. 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.

Interconnector (elec)
Electricity interconnectors are transmission assets that connect the GB market to Continental Europe. They allow suppliers to trade electricity between these markets.

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.

Glossary

Loss of load expectation (LOLE)
Used to describe electricity security of supply. It is an approach based on probability and is measured in hours/year. It measures the risk, across the whole winter, of demand exceeding supply under normal operation. This does not mean there will be loss of supply for three hours per year. It gives an indication of the amount of time, across the whole winter, which the System Operator (SO) will need to call on balancing tools such as voltage reduction, maximum generation or emergency assistance from interconnectors. In most cases, loss of load would be managed without significant impact on end consumers.

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

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

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

Nemo Link
An HVDC sub-sea link between GB and Belgium.

Normalised transmission demand:
is 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:
is 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 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.

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.

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.

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.

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

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.

Glossary

Restoration
Services used to restore power in the event of a total or partial shutdown of the national electricity transmission system, previously referred to as Black Start services.

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 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.

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

TNUoS demand charges
Transmission Network Use of System charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. Generators are charged according to TEC (Transmission Entry Capacity). Suppliers are charged based on actual demand.

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.

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.

Vector shift
The sudden change in voltage phase angle in a part of the network. When this happens a generator’s protection settings may disconnect it from the network to protect the equipment.

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

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

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

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

Email us with your views on the Winter Outlook Report at:
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