Summer Outlook

Helping to inform the electricity industry and support preparations for the summer ahead

April 2022

nationalgridESO

Foreword

Welcome to our 2022 Summer Outlook Report. This report contains our view of the electricity system for the summer ahead and is designed to support the industry in its preparations for the period.

National Grid ESO is shocked and saddened by the events unfolding as the Russian invasion of Ukraine continues. We stand with Ukraine and we will do everything we can to support.

We all know the impacts of Russia's war are being felt beyond Ukraine and these events are challenging us all to look again at security of supply within the British energy system.

Our analysis concludes that we have sufficient capacity in place for this summer. Due to the situation in Ukraine, we have undertaken additional analysis to test the robustness of our conclusions. We also appreciate that there are already many questions about next winter and, for this reason, we will publish an early view of next winter in July.

Specifically, in relation to the coming summer, managing minimum demands is likely to continue to be more challenging than has historically been the case. We don't expect demands to be as suppressed as in 2020, but demand at transmission level continues to fall as more embedded generation connects at distribution level voltages and energy efficiency measures are taken forward.

The war in Ukraine is impacting wholesale energy prices, compounding the existing cost of living crisis as well as increasing costs of the balancing actions the ESO carries out to operate the network reliably and efficiently.

At the ESO, we continue to do everything we can to manage the system in a way that minimises costs. This includes a review of the balancing market and, in particular, some of the exceptionally high-cost days that took place over last winter. We are finalising this review and will publish our initial conclusions in the coming weeks – our focus in this review is on ensuring consumers are well served.

As ever, we will continue to monitor the situation and outlook for the electricity system and keep stakeholders up to date with any changes via the ESO Operational Transparency Forum.

National Grid Gas Transmission have published a separate Gas Summer Outlook which 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

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Executive summary / Key messages

The impact of the situation in Ukraine on global energy markets and systems is volatile and fast-changing.

We continue to monitor its impact on GB energy prices and system operability and will provide further updates through our Operational Transparency Forum as required.

1. Market prices

National Grid ESO has taken a number of measures to reduce costs to consumers. However, high wholesale prices will increase balancing costs even if the volume of system actions remains consistent with previous summers.

These measures include the development of pathfinder projects, new pre-fault frequency services and the delivery and implementation of this year's Frequency Risk & Control Report.

2. Security of supply

We will meet the world-leading reliability standards that we all expect throughout summer 2022.

Upward margins are traditionally less of a concern during summer due to lower peak demands than in winter. However, due to the events in Ukraine, we have carried out additional analysis assessing a range of possible interconnector scenarios.

3. Managing the system

Managing low demand is one of the most complex scenarios our control rooms have to face and requires the ESO to take a number of actions to protect the network. We expect electricity demands to be similar to summer 2021, but higher than the COVID-19 suppressed demands of summer 2020.

We continue to have the right tools and services available to manage system operability during the summer, such as our stability services and Dynamic Containment.

Executive summary / Overview

We are confident there will be sufficient supply to meet electricity demands over the summer and we will be able to meet operability challenges.

Demand

Weather corrected summer minimum demand is expected to be slightly lower than last year but higher than 2020. Increasing generation connected to the distribution networks continues to lower **transmission system demands** year on year. The forecasts for demand in the table and graph are for transmission demand, consistent with previous Outlook reports[1].

The key operability challenges over the summer period tend to be around periods of low rather than high demand. Whilst the peak weather corrected demand expected on the transmission system this summer will be higher than both 2020 and 2021 due to a reduced impact from COVID-19, it is significantly lower than during winter. We expect to be able to meet demand throughout the summer even in the shoulder periods and with no imports across the interconnectors.

Supply and Operability

We will be able to meet demand and our reserve requirement at all times throughout summer 2022 under all credible interconnector scenarios. We do not expect high interconnector exports when GB demand is high. We will have to take actions on the system when demand is low, but these will mainly be everyday actions such as trading on interconnectors and increasing demand by pumping.

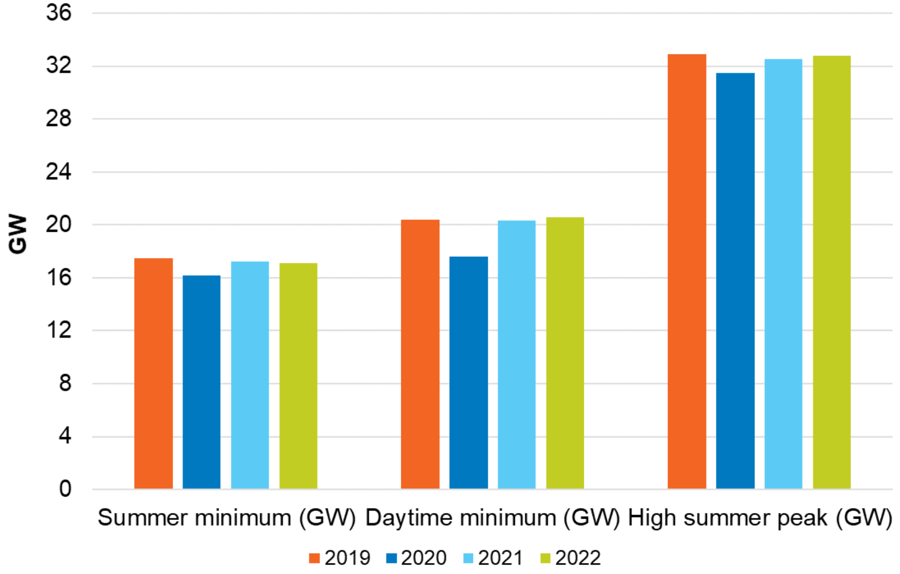
On a small number of occasions, if wind generation is high, we may need additional or enhanced actions such as issuing of a Negative Reserve Active Power Margin (NRAPM). However, these only occur if high wind generation occurs at periods of low demand, and we do not anticipate requiring emergency instructions. Our analysis indicates that, due to generation closure, the Optional Downward Flexibility Management (ODFM) service introduced during 2020 and retained last year will not be required this summer and so will not be offered.

National Grid ESO has taken a number of measures to reduce costs to consumers through the use of balancing tools and capabilities to manage the system effectively. However, high wholesale prices will offset this, leading to overall higher balancing costs. We recognise the importance of proactive, regular, quality engagement with industry and will continue to use our weekly Operational Transparency Forum as a key forum for engagement.

Key statistics

Summer 2022 forecasts (weather corrected)	GW
Electricity transmission **high summer** peak demand	32.8
Electricity transmission minimum demand	17.1
Electricity transmission daytime minimum demand	20.6
Minimum available generation	35.1

Figure 1. Weather corrected summer overnight and daytime minimum demand outturns for previous years and the summer 2022 forecast



Glossary: Definitions for the terms in bold purple text can be found in the glossary on page 26

1. See Appendix C for more information on different demand types

Contents

Demand / Overview

Weather corrected minimum transmission system demands for summer 2022 are expected to be just 0.1GW lower than last summer, with high summer peak demands slightly higher as COVID-19 restrictions are lifted.

This summer we expect…

- minimum demands to be very close to 2021 outturn
- weather corrected high summer peak **transmission system demand (TSD)** to be 32.8GW,
- weather corrected **minimum demand** to be 17.1 GW and to occur overnight rather than in the afternoon (when embedded solar output is highest)

Did you know?

Demands presented for previous years are the weather corrected outturn for demand on the electricity transmission system. These figures are for total demand after any actions taken by the ESO, so include actions to increase demand for pumping and electricity trading. Forecast demands do not include these, as they will depend on prevailing market conditions at the time.

These demands are all at Transmission level (i.e. unlike the demand definition used in the Capacity Market which is based on total consumer demand). What this effectively means is that it does not include demand that is met by generators connected below the transmission boundary and therefore, increased levels of this type of embedded generation effectively reduce transmission demand.

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. In the Appendix, we have included a table of different demand definitions on page 23.

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).

Table 1. Forecast and historic summer peak and minimum demands (weather corrected)

Year	Summer minimum (GW)	Daytime minimum (GW)	High summer peak (GW)
2019	17.5	20.4	32.9
2020	16.2	17.6	31.5
2021	17.2	20.3	32.5
2022 (central case)	17.1	20.6	32.8

High summer period
The period between 1 June and 31 August, or weeks 23 to 35.
It is when we expect the greatest number of planned generator outages.

Demand / Day-by-day view

Weather corrected minimum transmission system demands for summer 2022 are expected to be just 0.1GW lower than last summer, with high summer peak demands slightly higher as COVID-19 restrictions are lifted.

Periods of low demand can have an impact on how we operate the transmission system. As a result, it is important that we understand the minimum levels of demand along with the peak demand that we can expect to see during the summer months.

Figure 2 shows forecast minimum demands are only slightly less than last summer in our central forecast, at 17.1 GW compared to last summer's 17.2 GW. This is weather corrected and will vary according to real weather conditions as discussed on the following page. The minimum demand has moved forward some weeks from the 18th July to the 5th June, just before the high summer period where we usually expect the minimum demand. This is due to the four-day bank holiday weekend occurring to mark the Queen's Platinum Jubilee. We explore this in more detail on page 10.

Figure 3 shows the weekly peak demand for summer 2021 against our forecast for 2022. Our peak demand for the high summer period between June and the end of August is 32.8 GW, 0.3 GW higher than last summer. Generally our peak demand forecast is higher than last summer's **outturn** throughout the summer, although there is some variation, particularly towards the end of summer

Figure 2: Daily minimum transmission system demands for summer 2021 (outturn) against our summer 2022 minimum demand central forecasts (all weather corrected)

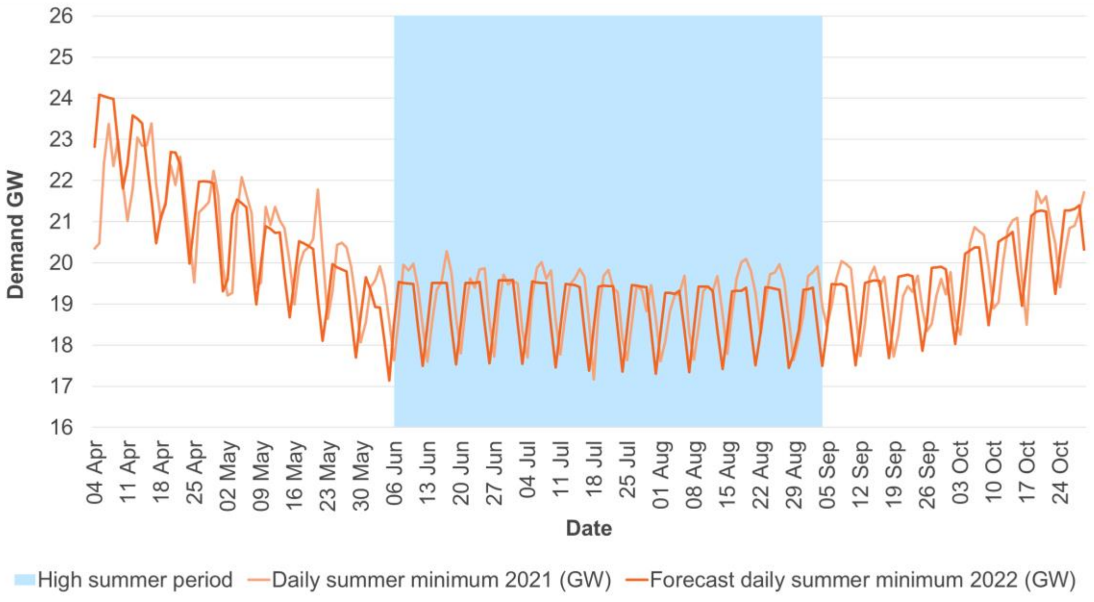
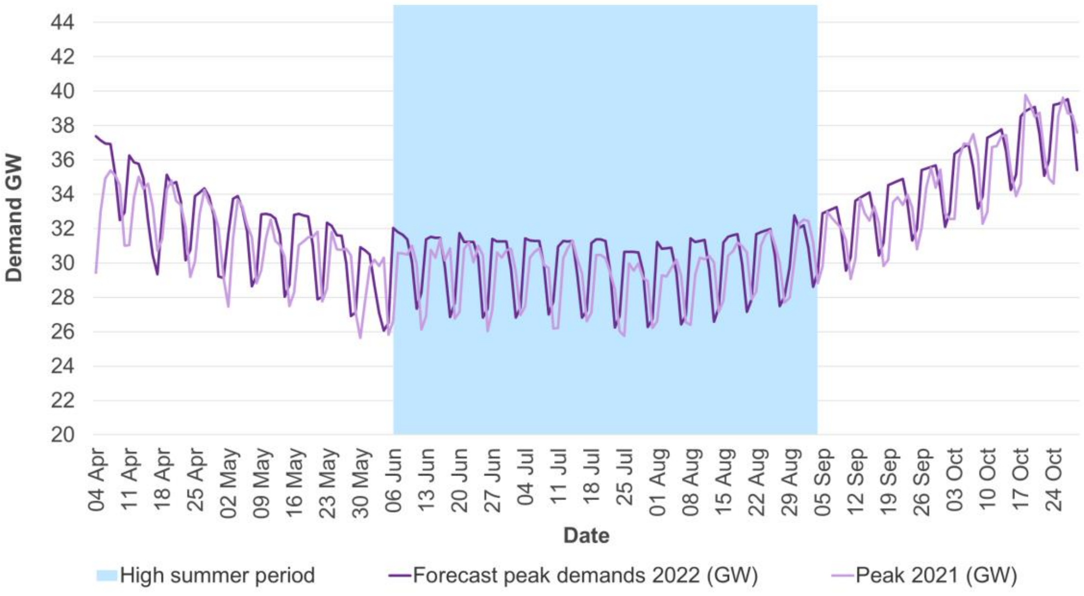


Figure 3: Daily peak transmission system demand for summer 2021 (outturn) against our summer 2022 peak demand central forecast (both weather corrected)



Demand / Demand variability

Weather variability will have an effect on demands over the summer. The demands presented on the previous page use seasonal normal weather conditions for the time of year, however weather variations can cause fluctuations around the central case.

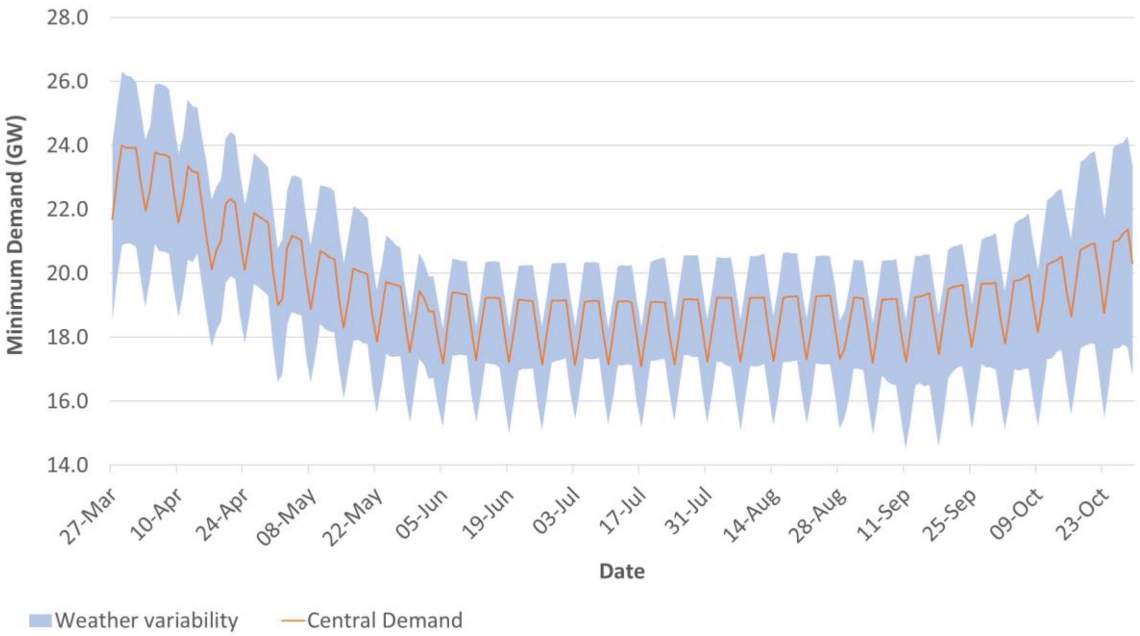
The demand values used in this report assume **seasonal normal weather conditions** and so are, in effect, average minimum demands. However, weather conditions are rarely at their average values. Figure 4 shows for each day the credible variation that can exist (to a 1 in 10-year risk level) because of weather variation alone. It would not be credible to expect the 1 in 10-year level for every day over summer, although it may occur on individual days over the summer period.

The graph shows it is possible that, under a 1 in 10-year weather risk level, **transmission system demand** could go as low as 14.5 GW around 11th September because of weather variation alone. The impact of weather is seen in the level of renewable generation output as well as through consumer behaviour (e.g. heating and cooling demand). For instance, the lowest overnight minimum demand will be when there is a lot of embedded wind and the lowest daytime minimum demand will be at times of high solar output.

This minimum demand is before any actions have been taken by the ESO and is 1 GW higher than the lowest equivalent minimum demand ever seen, which was 13.4 GW and occurred in 2020 (see Appendix B, p24).

We can use everyday actions, such instructing pumped storage, reducing flexible wind and trading on the interconnectors, to increase demand. See pages 12-13 for the range of actions available to us to manage low demand.

Figure 4: Daily minimum transmission system demands for our central COVID-19 scenario and the impact of weather variation



Demand / Summer 2021 retrospective

Figure 5 shows that last summer (2021) minimum (overnight) demand outturn was generally slightly higher than forecast throughout the summer, although the minimum demand of 17.2GW was correctly forecast.

Minimum daytime demand outturn (Figure 6) was often higher than forecast for most of the summer, including the high summer period, but was lower than forecast from the end of August onwards. This was due to economic activity recovering more slowly than expected from COVID-19 as infection rates began to increase and many workers self-isolated. The minimum forecast daytime demand of 20.1GW was slightly lower than the actual minimum daytime demand of 20.3GW.

The charts on this page present weather corrected forecasts and **transmission system demand outturns,** which is useful for comparison, but doesn't match exactly with actual demands on the system, which include real weather variations

Figure 5. Weekly minimum transmission system demand scenario forecasts for summer 2021 in purple against our summer 2021 minimum demand outturn in orange (weather corrected)

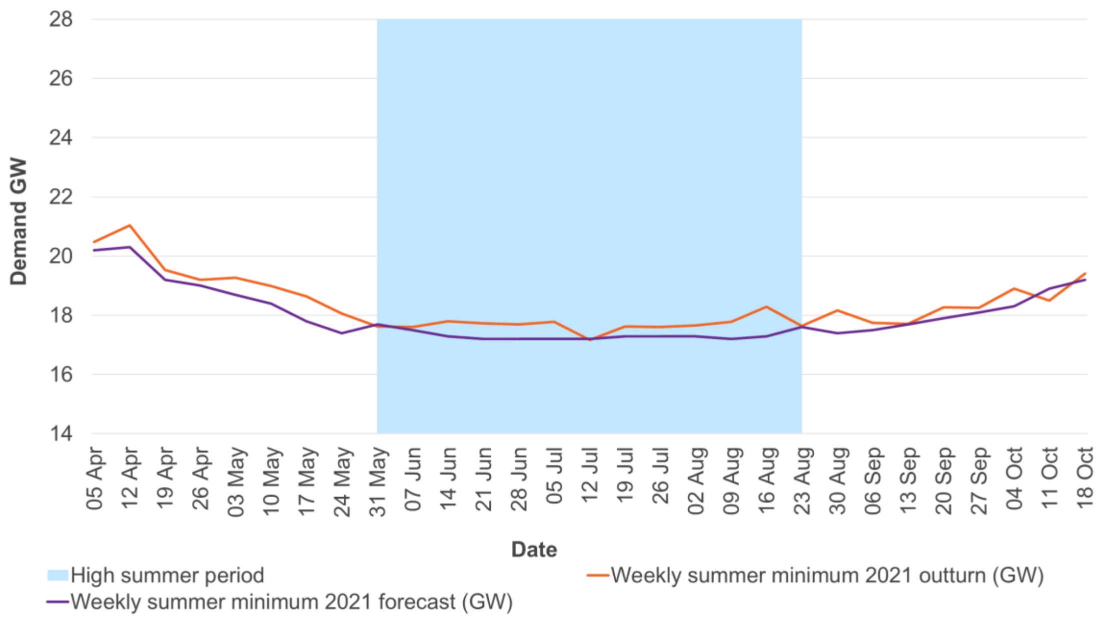
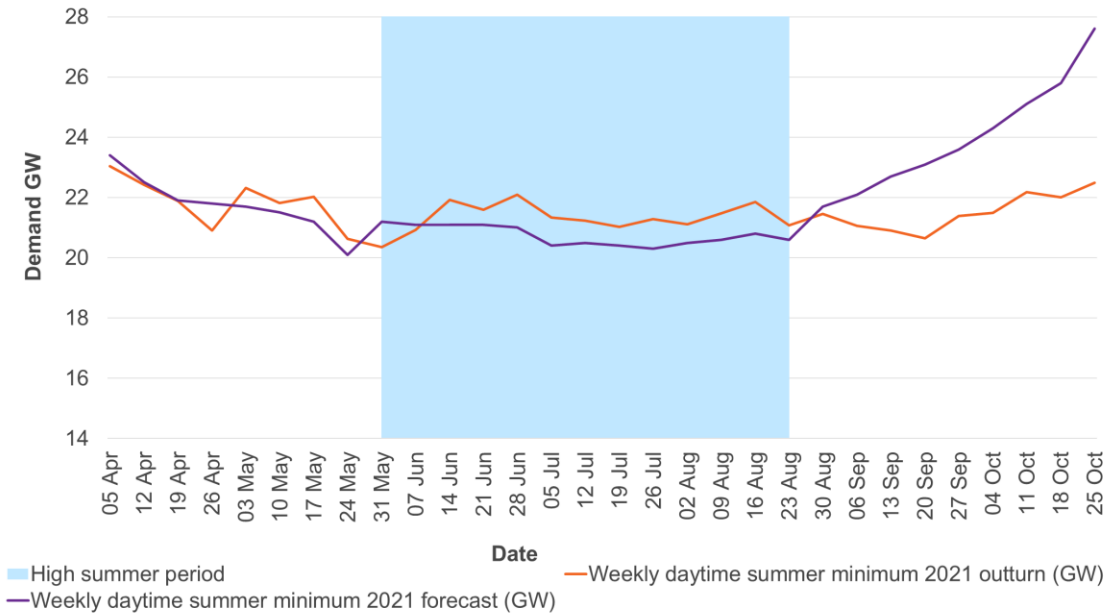


Figure 6. Weekly daytime minimum transmission system demand scenario forecasts for summer 2021 in purple against our summer 2021 minimum demand outturn in orange (weather corrected)



Spotlight / Bank holidays and minimum demand

Weather corrected minimum transmission system demand typically occurs during the high summer period. This year the forecast impact of the extended Platinum Jubilee bank holiday has moved this minimum demand forward.

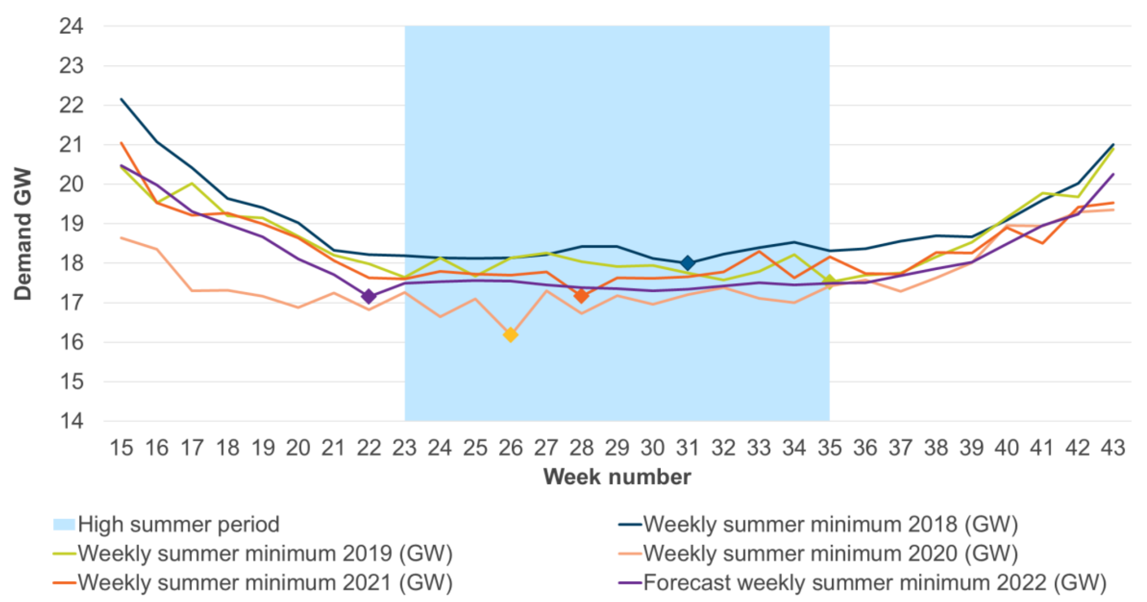
Weather corrected minimum transmission system demand typically occurs during the **high summer** period and over the last five years has occurred no earlier than week 26 (~27 June), see Figure 7. It is during this high summer period that we expect the greatest number of planned generator outages.

This year, to celebrate the Queen's Platinum Jubilee, a one-off additional bank holiday has been added, and the late May bank holiday moved to create a four day weekend from 2nd to 5th June. Bank holiday weekends typically see low demand as more people are on holiday and economic activity turns down, and so minimum transmission demand is expected to occur over this weekend (week 22).

Whilst the low demand expected to occur over this period has the potential to present an operability challenge, we do not expect this to occur. This is due to generator outages occurring over this period.

However, if unusual weather occurs over this weekend, we have the tools to manage any operability challenges that may occur - see page 12 for more detail on how we manage low demand.

Figure 7: Historic minimum ttransmission system demand and 2022 forecast minimum demand (weather corrected). Minimum demand per year highlighted by marker.



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Supply / Day-by-day view

We expect to be able to meet normalised transmission demand and our positive reserve requirement at all times throughout the summer, including throughout the shoulder months of April and September.

This summer we expect…

- Based on the data in Figure 8, minimum available generation to be 35.7 GW and to fall around the 7th August (no continental interconnector flow scenario) based on current operational data
- **Maximum demand** on this day to be up to 29.2 GW under our central demand forecast (assuming full export on Irish interconnectors).

Did you know?

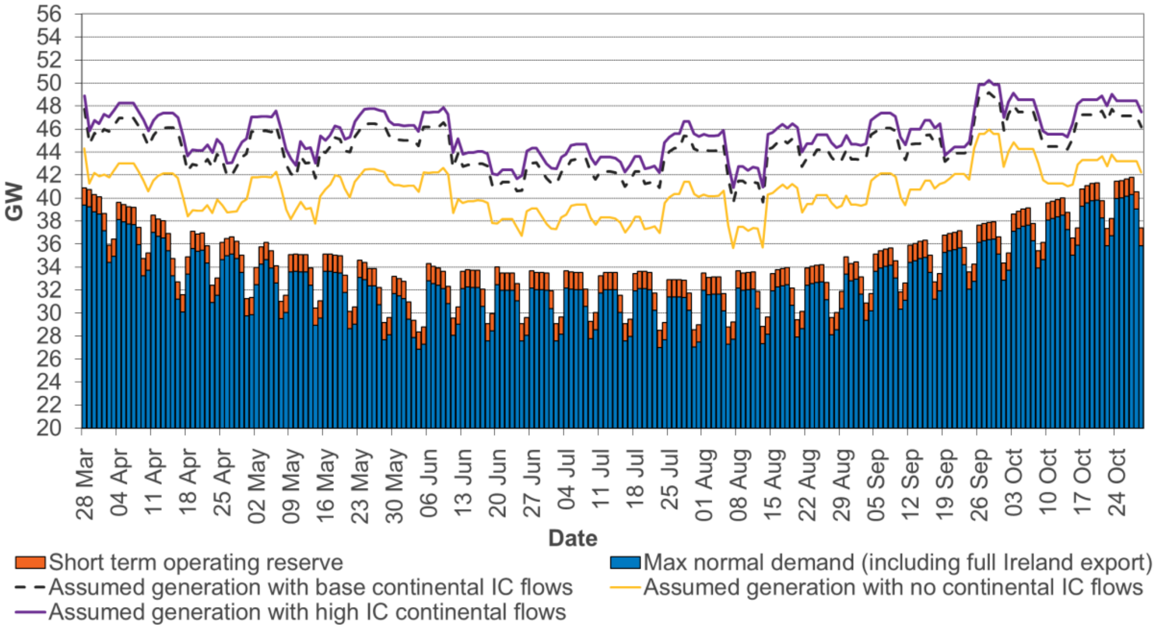
In the summer months, power stations often carry out planned maintenance as there is typically lower demand and lower electricity prices than in the winter.

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 and restrictions or losses close to real-time. For the latest OC2 data and operational view, see the BM reports website, updated each Friday. This data is dynamic and changes throughout the summer, with its analysis based on market submissions as of 28/03/2022.

For wind, the average wind level as a load factor for each week is used – this is based on the last 30 years of wind data.

Our continental interconnector flow assumptions for the summer include **IFA, BritNed, NEMO, IFA2** and **NSL** but not Eleclink, which is assumed to be still commissioning. For more detail see the "Assumptions" tab in the Data Workbook.

Figure 8. Day-by-day generation and demand forecast for summer 2022



Supply / Managing low demands

As National Grid ESO, we may need to take actions to maintain operability of the network. The graphic below shows the hierarchy of these actions. Our expectation is potentially to have to use enhanced actions, but only if wind generation is high during periods of low demand.

At times of low demand and high levels of renewable generation it is important to be able to reduce generation output or increase demand to ensure the system is balanced and frequency remains within operational limits. We do this using ‘everyday actions’ shown in the graphic on the right.

Our analysis indicates that, due to generation closures, the ODFM service introduced during 2020 and retained last year will not be required this summer and so will not be offered.

Enhanced tools include the use of local or national **NRAPM.** To date, a limited number of local NRAPMs have been issued, but none at a national level. You can read more about this tool on our website.

The graphic on the right also highlights the ‘emergency actions’ we can take over and above this to secure the system. However, our analysis does not suggest anything more than enhanced actions is likely to be required.

Everyday actions

- Bid actions on all other flexibility in the BM, including super-SEL
- Selling power to the continent to create exports on the interconnectors
- Creating demand through pumping demand at pumped storage sites

Enhanced Actions

- Issuing a local or national **NRAPM** and flag as alert status on the Balancing Mechanism Reporting Service.
- Taking additional actions obtained through NRAPM

Emergency actions

- Emergency Instruction to Transmission connected generation
- Emergency Instruction to DNO to disconnect DER

Supply / Day-by-day view

Based on current data we expect to be managing periods where inflexible generation output plus flexible wind output exceeds minimum demand and, therefore, will need to take actions to manage this. Under higher wind conditions, we could also see a small number of periods where inflexible generation output alone may exceed minimum demand.

This summer we expect…

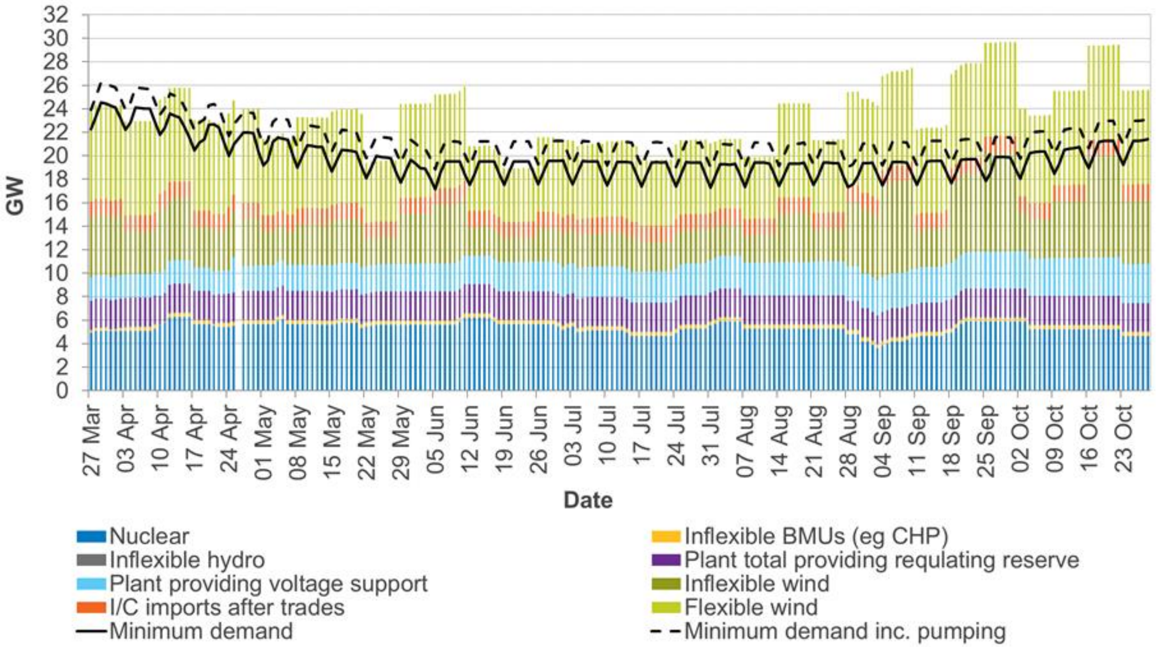
- Periods where pumping is required to manage low demand to occur less than last summer under similar weather conditions, partly due to nuclear plant closures over the last 12 months.
- A small number of periods through the shoulder period in September and October where inflexible generation output alone may exceed minimum demand with pumping.

Figure 9 shows how high wind generation can contribute to generation exceeding demand. In previous years we have assumed a central estimate of load factor, meaning that there was a 50% chance of wind being higher or lower than this. This year, to take a more risk averse view in our analysis, we used a credible high wind generation scenario, using the 70% percentile. We also assumed a cap on flexible wind capacity of 8GW due to the number of actions required by the control room, with anything above this added to the inflexible volume.

In Figure 9 we see periods where TSD, without pumping, is below the level that can be achieved by reducing the flexible wind. In most instances, when action is taken to increase demand by instructing pumping storage, the system can be managed by reduction in flexible wind and/or by trading on the interconnectors.

There are several days through September and October where, if wind generation is high, inflexible generation output alone may exceed minimum demand even with pumping. During these periods, a local or national **Negative Reserve Active Power Margin (NRAPM)** can be issued. A NRAPM warning is a request to encourage more flexible parameters from generators and inform participants of a risk of emergency instructions. It should be noted this only occurs under the very high wind scenario (70th rather than 50th percentile) used this year and therefore represents a more risk averse view rather than an increased risk of requiring an NRAPM.

Figure 9. Day-by-day forecast generation and minimum demand scenarios, summer 2022



Spotlight / Forward price comparison

Forward electricity prices for Summer 2022 are much higher than those for Summer 2021, driven by high gas prices

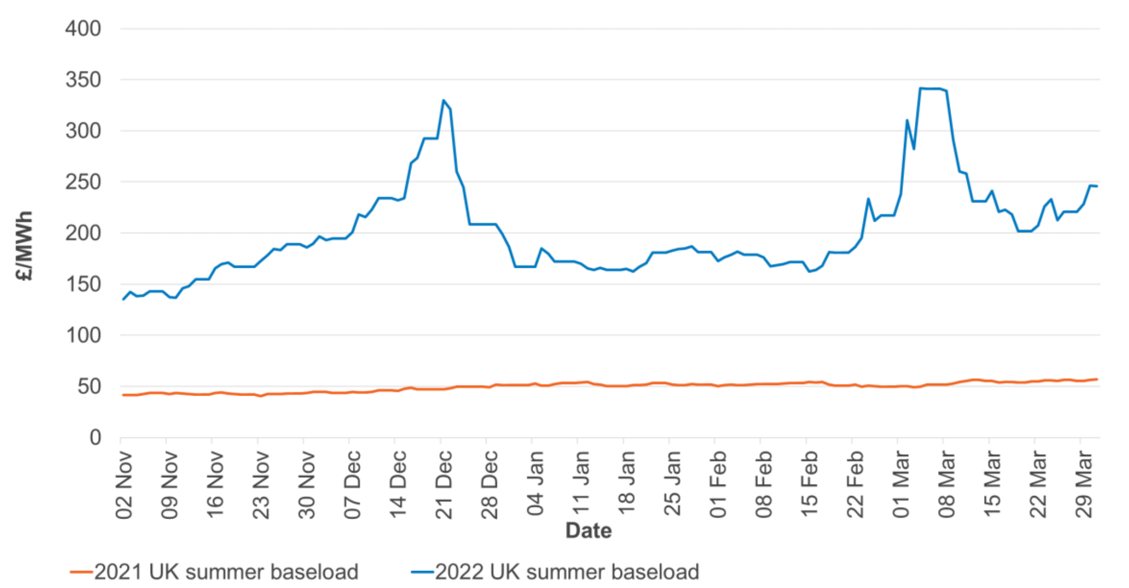
Figure 10 shows the UK forward electricity prices for summer 2022 compared to those of summer 2021. Those for summer 2022 are considerably higher, with the summer 2022 contract closing at around £250/MWh compared to around £55/MWh for last summer.

Electricity prices were expected to be high this summer due to high gas prices, which have persisted from last winter. Although still much higher than last year, these forward prices had fallen from their highest values to between £150-£200/MWh. However, the situation in Ukraine ,and the pressure it has put on global energy markets, has caused this price to rise significantly again.

Whilst this does not impact GB security of supply of electricity, it does increase the cost of the balancing actions the ESO carries out to operate the network reliably and efficiently. Although the ESO has taken measures to reduce the actions required and therefore the cost to consumers, the high energy prices will result in an increase in operability costs. More detail on this summer's expected trajectory for these operability costs are given on page 22.

We will continue to monitor market prices and their impact on the network and report back to industry through our Operational Transparency Forum as required.

Figure 10: UK forward prices summer 2021 and summer 2022



Europe and interconnected markets / Overview

There is potential for greater exports across interconnectors from GB to France than in previous years, however high prices and uncertainty related to the situation in Ukraine makes the import/export pattern across the interconnectors to continental Europe this summer very uncertain.

This summer we expect…

- Significant price volatility resulting in uncertainty around **forward baseload prices** in GB and those in Belgium, Netherlands and France.
- At current forward prices, imports into GB at peak times via the **BritNed**, **Nemo Link** and **NSL** interconnectors, although occasionally not at full import and subject to weather variations. Based on current forward prices, the interconnectors connected to France are likely to import less and export more than last year.
- **Moyle** and **EWIC** interconnectors typically to be exporting from GB to Northern Ireland and Ireland during peak times

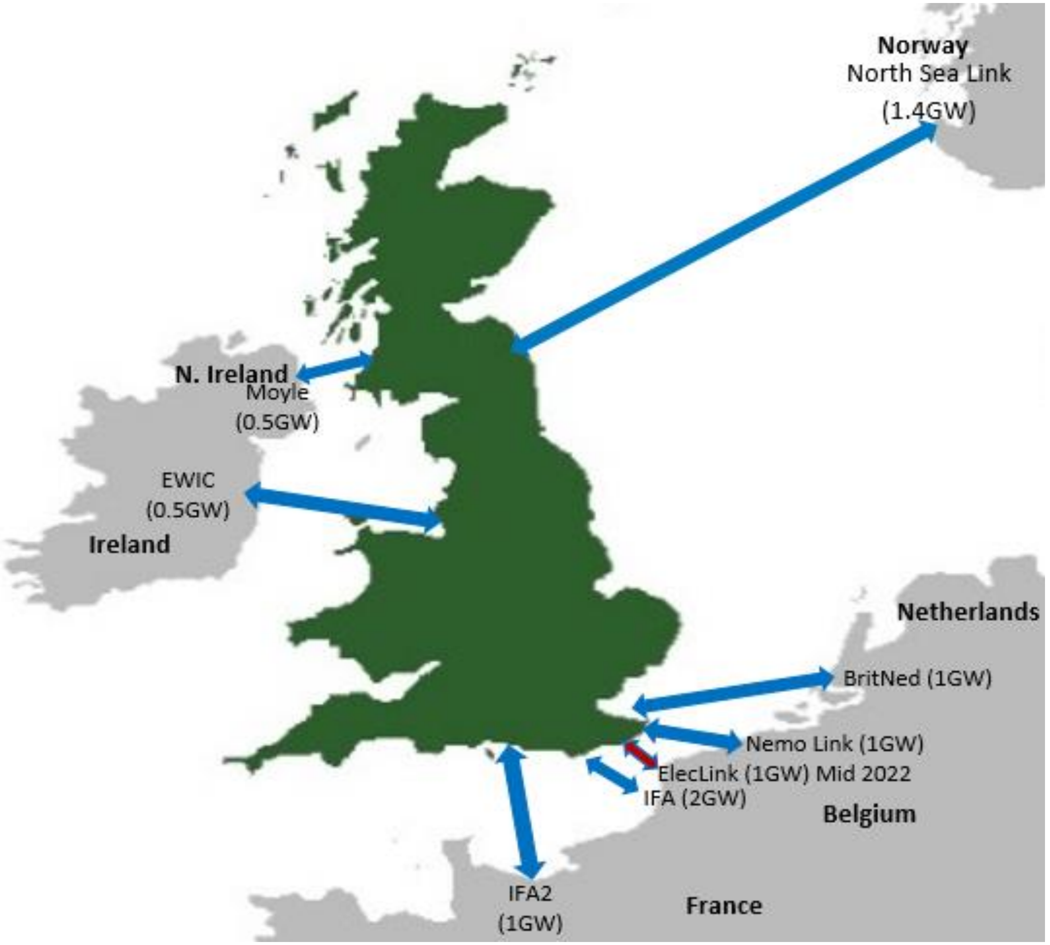
Did you know?

The insights on this page and page 16 are based on forward prices as of the 31st March (see Figures 12a and 12b on page 16). We haven't seen a significant change in forward prices since then and so the insights drawn remain current.

We will be working with our partners to commission the **ElecLink** interconnector during this summer. The 1000 MW cable laid in the channel tunnel will continue the growth in connection between GB and France to make a total of 4 GW following the successful commissioning of **IFA2** (1000 MW) at the start of 2021.

We will continue to monitor the development of new connections as they move through the commissioning process.

Figure 11. Current and planned iinterconnectors ahead of summer 2022



Europe and interconnected markets / Expected flows

European forward prices

Electricity flows through the interconnectors are primarily driven by the price differentials between the markets. Typically during the summer, GB prices are higher than those in European markets leading to interconnector imports. However, the situation in Ukraine is having a significant impact on prices across Europe and GB.

Whilst **forward prices for electricity** during summer 2022 have risen significantly across all markets, French baseload forward prices are now ahead of those in GB. The price spread between GB and the markets in Belgium and the Netherlands has also shrunk significantly[1]. The spread between peak forward prices has also shrunk.

We have undertaken additional scenarios to assess a range of possibilities relating to future interconnector flows and currently expect to be able to meet peak demand throughout the summer without relying on imports. We expect to also be able to support some exports to the continent although, in the event of tight GB margins, we would also expect GB prices to rise in response and that this would then incentivise imports. We also have a range of measures as part of our normal operating toolkit which we can use to manage interconnector flows.

Operability challenges over the summer are usually due to low demand, and so an increase in exports over the summer is unlikely to present an operability challenge. We will continue to monitor the situation and report back to industry as required through the Operational Transparency Forum.

Figure 12a: Summer 2022 electricity baseload forward prices,

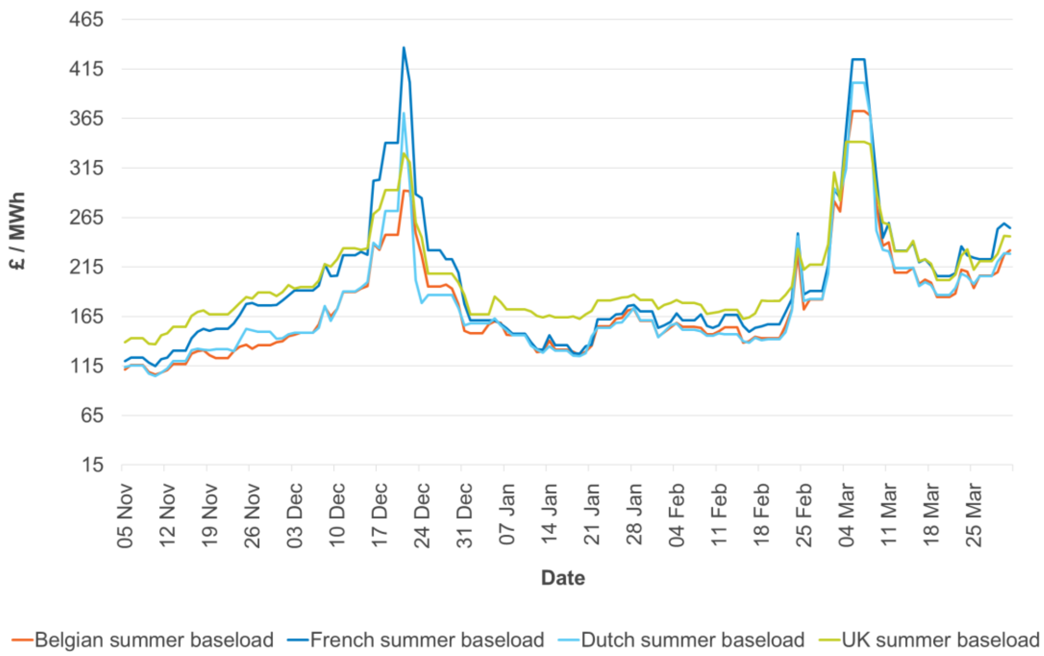
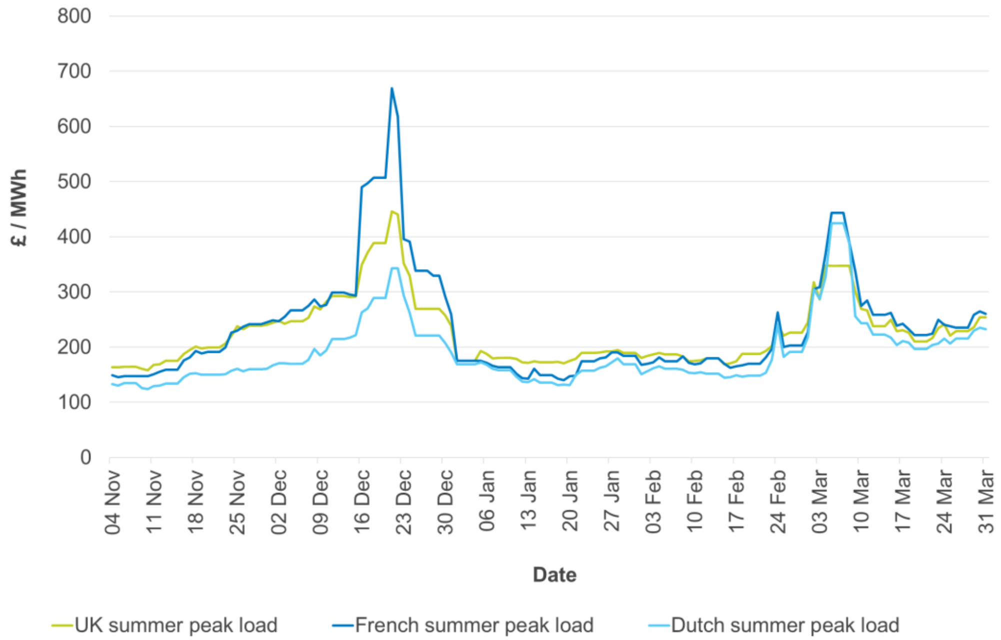


Figure 12b: Summer 2022 electricity peak forward prices



1. Forward prices for Norway are not included but Norwegian market prices are typically much lower than the UK.

Europe and interconnected markets / Expected outages

Physical capabilities

Since last summer, a new interconnector, **NSL,** has come into service between GB and Norway, providing an additional 1 GW capability. The **Eleclink** interconnector between GB and France is also expected to come online in summer 2022 providing 1 GW of capacity. Interconnectors may undertake planned outages over the summer, or experience fault outages. Table 2 shows current fault outages and planned outages for each interconnector.

In addition to the planned outages, National Grid ESO can, as part of its everyday processes, control the flow of interconnectors to manage operational constraints.

In previous years, there were some periods of export from GB to France across **IFA**, driven by lower available French generation due to nuclear outages. Planned French nuclear outages this summer are lower than some previous years and so are not expected to significantly impact interconnector flows.

Figure 13 French nuclear plants in outage :2017-2021 and planned for 2022

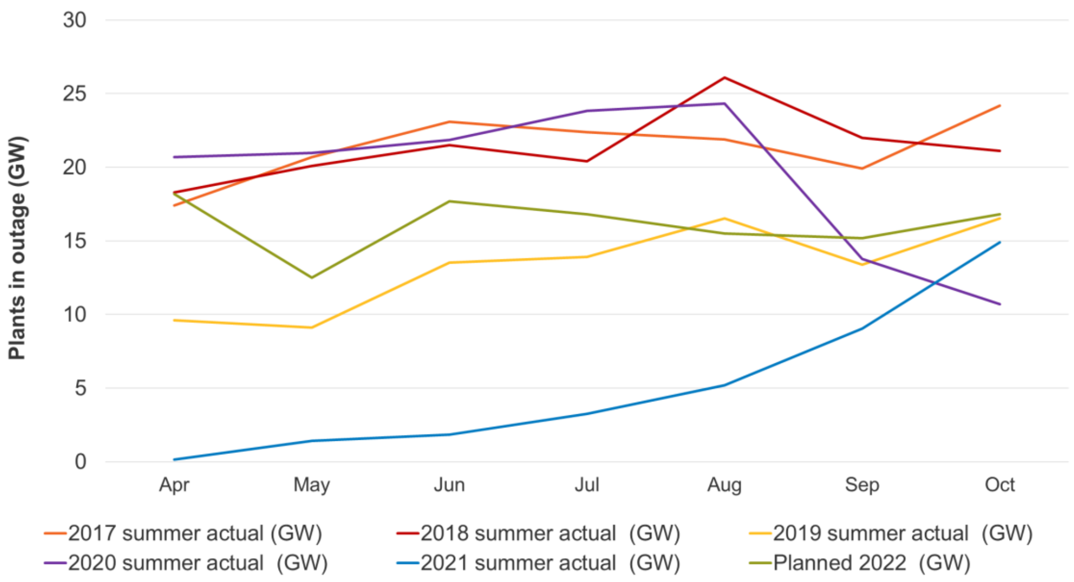


Table 2. Interconnector outage schedule

Interconnector	Planned outages (resulting capacity)	Current outages
IFA (2GW)	Present - 30 Oct (1GW fire) 26 Apr - 28 Apr (0 GW) 18 Sep -14 Oct (0 GW)	Present - 30 Oct (1GW fire)
BRIT (1GW)	16 May - 20 May (0 GW) 19 Sep - 23 Sep (0 GW)	None
IFA2 (2GW)	13 Jun - 24 Jun (0 GW)	None
NEMO (1GW)	19 Sep - 25 Sep (0 GW)	None
MOYLE (0.5GW)	Present- 15 Jul (0.25 GW) 13 May - 14 May (0 GW) 30 Jun - 22 Jul (0 GW)	None
EWIC (0.5GW)	14 Mar- 03 May (0 GW) 18 Aug - 19 Aug (0 GW)	Present - 03 May (0 GW)
NSL (1.4GW)	10/11/12/13 May 07:00-19:00 (0 GW)	Present - 14 Jun (0.7 GW)

Europe and interconnected markets / Summer 2021 interconnector flows

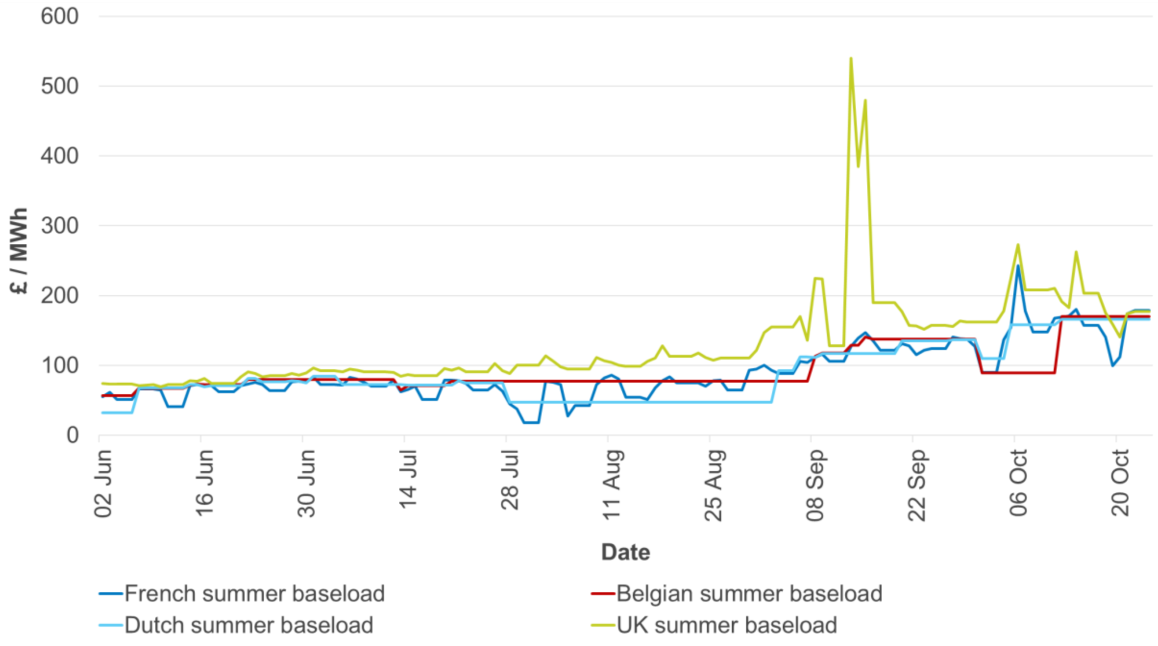
Baseload prices

Figure 14 shows GB and European day ahead electricity baseload prices for summer 2021. As shown, these were mostly higher in GB than in the Netherlands, France and Belgium, leading to net imports into GB (Figure 15).

The price differential between France and the UK was small at times, leading to some exports, mainly through **IFA 2**. However, imports still remained high at over 77%.

The price spike in September was due to the fire which impacted IFA 1.

Figure 14: Day ahead baseload prices during summer 2021



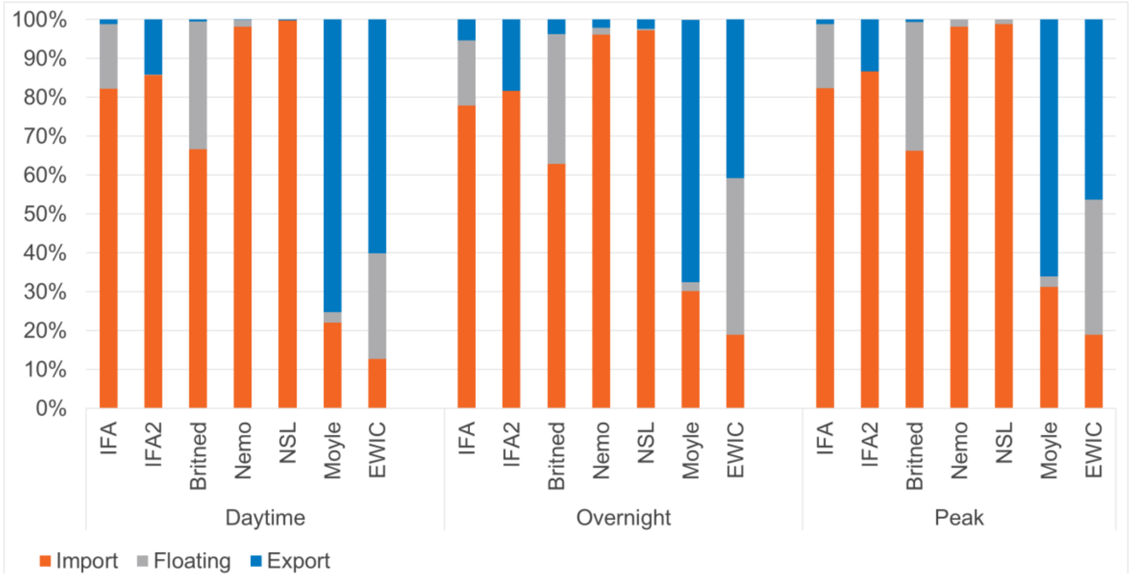
Interconnector flows

Figure 15 shows interconnector flows during the daytime, overnight and at peak times (5pm to 8pm) for summer 2021. Continental European interconnectors and **NSL** saw similarly high levels of imports at peak and daytimes, importing power for most of these times. However, this differed for the Irish interconnectors, which predominantly exported during these periods.

All European interconnectors and **NSL** were importing more than exporting during most of the overnight periods, although slightly less than during the other periods. The Irish interconnectors were again predominantly exporting overnight.

For Summer 2022, the high prices and uncertainty around the impact of the situation in Ukraine on the relative costs of the UK and European markets, means that import and export patterns are unlikely to be similar to 2021.

Figure 15: Proportion of import and export for continental and Irish interconnectors in summer 2021



Spotlight / New measures to manage the system

National Grid ESO is introducing a number of new services to help us manage the system this summer. These services include:

1. Dynamic Moderation

Currently, the electricity system is experiencing lower inertia and larger, more numerous losses than ever before. Faster acting frequency response products are needed because system frequency is moving away from 50Hz more rapidly as a consequence of imbalances.

Dynamic Moderation (DM) rapidly delivers with the aim of assisting the ESO to keep frequency within operational limits. Providers of DM will help manage sudden large imbalances between demand and generation (e.g. due to an erroneous wind forecast) by responding quickly when frequency moves towards the edge of the operational range.

2. Dynamic Regulation

A fast-acting frequency response product like DM, **Dynamic Regulation** (DR) is a pre-fault service designed to slowly correct continuous but small deviations in frequency. The aim is to continually regulate frequency around the target of 50Hz.

For more information on Dynamic Moderation and Dynamic Regulation see our website here.

3. Network Operation Assessment Pathfinders

We are always looking for innovative ways to operate the electricity system of today and tomorrow, and keep costs down for consumers. To achieve this, our pathfinder projects look for solutions to challenges in the electricity system.

There are currently three pathfinders projects in development:

High voltage pathfinder: looking for the most cost-effective way to address high voltage system issues created by the need to absorb more reactive power on the transmission network. The high voltage pathfinder providing voltage support in the Mersey region is currently due to have two units go-live from April 2022.

Stability pathfinder: looking for the most cost-effective way to address stability issues in the electricity system created by the decline in transmission connected synchronous generation. Stability Phase 1 has some units that have gone live and the remaining are expected to go-live by July 2022. These will help manage inertia and reduce frequency actions. Managing inertia through these stability contracts allows for greener system operation and more renewable energy.

Constraint management pathfinder: looking to reduce network congestion costs over the B6 (SCOTEX) boundary. The service is a post-fault inter-trip that rapidly (sub-150ms) disconnects selected generators in the event of a network fault. It aims to reduce the amount of curtailment on the B6 boundary and has the potential for significant consumer savings. The service is expected to formally go live in October 2023 but there are a number of generators able to commence the service early.

For more information on our pathfinders see our website here.

Operational view / Summer 2022

Summer 2022 is expected to present similar operational challenges to Summer 2021. We expect that the necessary tools will be in place to enable safe, reliable, efficient system operation.

As the generation mix continues to evolve, we are monitoring and forecasting system needs, defining requirements and ensuring the correct tools are in place for system operation as we move towards our 2025 zero carbon ambition. Summer 2022 is expected to present similar operational challenges as summer 2021 and we expect that the necessary tools will be in place to enable safe, reliable, efficient system operation.

The implementation of the recommendations from the **Frequency Risk and Control Report (FRCR)** 2021, combined with the continued delivery of the **Accelerated Loss of Mains Change Programme (ALoMCP)**, and growth of volumes participating in **Dynamic Containment (DC)** has resulted in a step change in our frequency control policy. This widens the operating envelope and significantly reduces the volume of actions needed to reduce largest loss risks through re-positioning units (via trades or the Balancing Mechanism) to avoid unacceptable frequency conditions.

Additionally, the Network Operation Assessment pathfinders are beginning to see units go-live throughout the summer which are contributing to our ability to manage and operate the network.

Our latest view on operability across our five core areas for summer 2022 is set out in the following section. Beyond this, we will continue to engage stakeholders and industry on the challenges and costs of operability through the weekly Operational Transparency Forum.

Thermal

There is a considerable volume of transmission outages planned for the summer to connect new generation and to improve system capacity. These outages can temporarily impact the capacity of the network resulting in constraints. ElecLink interconnector is due to be commissioned this summer in the south east of England and reconductoring work is ongoing to improve the SEIMP limits (South East Import constraint). Hinkley B Power Station is due to decommission in July and reinforcement work is ongoing in preparation for Hinkley C Power Station. Throughout the summer, we have several refurbishment outages on the B9 and B6 boundaries. Work is ongoing in northern Scotland for the longer-term upgrade to 400kV circuits. Whilst these outage related constraints may be set by thermal limits, they also have the potential to be set by locational voltage or stability constraint limits.

Costs are likely to be higher in summer 2022 than 2021, mainly driven by the significant increase in the gas price, increasing the cost of replacement plant (those generators instructed to run to replace generation that is constrained behind a constraint boundary). We are providing a 24 month ahead forecast of constraint limits and costs on our data portal.

Restoration

We have contracts in place to meet all restoration requirements. We are expecting an increase in assurance activities following the previous restoration tenders and new services coming online this summer. We will continue to work with providers, TOs and DNOs to carry out these activities safely and efficiently. Providers' summer availability monitoring will also continue to ensure we meet compliance with the Assurance Framework. See here for more information on restoration services.

Costs are likely to increase incrementally to account for assurance activities and new services that will include capital contributions.

Operational view / Summer 2022

Frequency and stability

The implementation of the **Frequency Risk and Control Report** (FRCR) 2021, combined with the progress of the **Accelerated Loss of Mains Change Programme** (ALoMCP), and growth of **Dynamic Containment** (DC) has allowed us to implement a step change in frequency policy. The FRCR phase 2 policy change allows infeed losses to cause frequency deviations within acceptable limits (down to 49.2Hz and recovered to 49.5Hz in 60s). This results in a significant reduction in the volume of actions needed to re-position units via trades or the balancing mechanism.

In 2020 we launched DC as a fast post-fault service to ensure frequency remains within the acceptable limits following a sudden loss of generation or demand. In the summer, the maximum DC requirement is generally higher as the frequency moves faster due to the combination of low demand and inertia. For instance, for July 2022, our Dynamic Containment Low (DC-L) requirement is anticipated to be over 600 MW for more than 90% of the time with a requirement of over 800 MW for more than 75% of the time between 19-23h. The maximum requirement for DC-L is expected to be approximately 1200MW.

In the case of Dynamic Containment High (DC-H), the maximum requirement for the service over the summer is expected to be around 800 MW. The latest response requirements can be found on the data portal here: https://data.nationalgrideso.com/ancillary-services/firm-frequency-response-market-information

In line with our Frequency Risk and Control Policy, the minimum inertia policy will continue to be 140 GVAs. The Stability Phase 1 contracts are a key tool in our toolkit to meet this requirement at least cost and will widen the operability envelope across the summer by reducing the volume of alternative actions needed to maintain minimum inertia (i.e. synchronising and re-positioning synchronous generation).

Two pre-fault frequency services will be introduced his summer. The first to be launched, in March 2022, was **Dynamic Regulation** (see page 19). DR is designed to correct random but small deviations in frequency around the target of 50 Hz. The second product to be launched, in April 2022, is **Dynamic Moderation** (see page 19). This service is aimed to correct sudden large imbalances between generation and demand due to e.g. erroneous wind forecasts. During summer 2022, the procured capacities of each product will be limited to 100 MW for each, as we review and validate service performance.

This year will see the end of several Enhanced Frequency Response (EFR) contracts. Given their similar operational profiles, the difference will be reflected as increased DC requirements.

This year's FRCR focused on the question of whether securing simultaneous events was cost-effective, considering their historic rate of occurrence and the cost to fully mitigate their risk. It was concluded that we will not take additional actions to secure those simultaneous events which are above the coverage of our current policy. The existing policy covers 74% of simultaneous events and to secure against the remaining 26% would entail an additional spend of around £360m per year (around 3 times the current response costs).

Operational view / Summer 2022

Voltage

When demands are lower, the ESO needs to ensure there is enough voltage support from reactive power providers in the local areas. This is typically more expensive in the summer when fewer generators self-dispatch to meet the lower demand. The forecast demand level for summer 2022 is very similar to the demand out-turn from the same period last year, so we would anticipate that the actions required for voltage management will be broadly similar to previous years.

Where there are outage patterns that result in periods where there are deficits in regional reactive power, the ESO may need to intervene through a tender to secure the requirement. This will be communicated via our website and account managers.

The expected closure of Hinkley Point B before July 2022 may result in higher voltage management costs in south Wales and south-west England; however, we are exploring operational options to minimise this.

As a result of the Mersey High Voltage Pathfinder, we are expecting a new reactive power provider to connect in April/May which should provide us with another voltage management option in the area and reduce local voltage management spend.

We committed to providing more transparency on our trading decisions and, as part of that, to provide more information on our reactive power requirements for voltage management. We publish overnight voltage requirements for voltage management at the week-ahead stage. We have also published a document explaining how we manage the voltage requirement to help the industry understand this better.

Costs

National Grid ESO have taken a number of measures to reduce costs to consumers, but high wholesale prices will offset this leading to overall higher costs. The table on the right gives a current indication of likely trajectories for the different balancing and constraint costs in terms of volume of actions, cost per action and total cost we expect over summer 2022 relative to last summer.

Area	Volume of actions	Cost per action	Total cost	
Thermal[1]	↑	↑	↑	Costs are likely to be higher in summer 2022 than 2021. This is partly due to managing the volume of constraints this summer, but mainly driven by the significant increase in the gas price, increasing the cost of replacement plant (those generators instructed to run to replace generation that is constrained behind a constraint boundary).
Restoration	↑	↑	↑	Costs are likely to increase incrementally to account for assurance activities and new services that will include capital contributions and testing.
Frequency	↓	↑	↑	Similar technical requirements, although less total actions as many of these are now taken at a system wide level. High market prices are likely to lead to an overall cost increase though.
Stability	→	↑	↑	Technical requirements are likely to be similar to last year. High market prices are likely to lead to an overall cost increase although this is partially offset by sites procured through Phase 1 of the Stability Pathfinder.
Voltage	→	↑	↑	Technical requirements are likely to be similar to last year, however high wholesale prices are likely to lead to a net increase in cost.
Overall	→	↑	↑	In general, operational challenges will be similar to last year but high prices will drive the costs of balancing actions up.

1. Whilst these outage related constraints may be set by thermal limits, they also have the potential to be set by locational voltage or stability constraint limits

Appendix A/ Demand definitions

There are a range of different types of electricity demand, the differences between these are presented here.

	Term	Definition	Note
Types of demand	GB Customer demand	Sum of all demand used within GB. Total demand requirement for GB.	This includes demand offset by embedded generation on the distribution networks and is similar to the demands quoted in FES.
	Transmission demand	Sum of all generation that flows through the GB Electricity Transmission network to meet internal GB demand or exports out of GB.	These are the demands typically presented in the Summer and Winter Outlook.
	National demand	Sum of all generation that flows through the GB Electricity Transmission network to meet internal GB demand, excluding electricity used to power large power stations	
	Triad demand	Transmission demand minus exports out of GB. Used to determine the days on which Triads have occurred	
Types of outturn	Operational outturn	Uses all real-time metering feeding into NG ESO live systems	
	Settlement metering outturn	Uses metering from Elexon settlement metering which is then reviewed by all parties so anomalies can be resolved. For generation this only includes plant that participates in the Balancing Mechanism (BM)	
	Normal or Weather Corrected outturn	Operational outturn adjusted to provide the equivalent demand under average weather conditions	
	Average Cold Spell (ACS) outturn	A measure of hypothetical maximum demand over some period (usually an entire winter period) based on all the possible weather variation that could have occurred over the period. The ACS outturn is the value that, based on all the hypothetical weather variation, had a 50% chance of being exceeded. It is the average value of the maximum demand.	This is used in the Winter Outlook when considering supply margins.
Types of forecast	Operational forecasts	Forecasts based on using detailed meteorological forecasts when available (out to 14 days ahead) or average weather conditions (beyond 14 days ahead)	
	Normal or Weather Corrected forecasts	Forecasts based on using average weather conditions (beyond 14 days ahead). All longer range forecasts are on this basis	These are the forecasts presented in the summer and winter outlook.
	Average Cold Spell (ACS) forecast	A forecast of maximum demand over some period (usually an entire winter period) based on all the possible weather variation that could have occurred over the period. The ACS forecast is the value that, based on all the hypothetical weather variation, has a 50% chance of being exceeded. It is the forecast for the average value of the maximum demand.	Used in the winter outlook for peak demand forecasting when considering capacity available to meet peak demands during low temperatures.

Appendix B / Record minimum electricity demands in 2020

There are several different types of demand – each with a different definition. The summer of 2020 saw record low demands – but what was the lowest electricity demand in the summer of 2020? This appendix, first published last year, explores this and explains how different types of demand vary.

National demand measures how much generation must be supplied through the transmission network to meet customer demand within GB. Effectively this is the "natural" demand within GB. By this measure the lowest demand in 2020 occurred on 28 June at 05:30. This demand of 13.4 GW was by far the lowest ever seen (the next lowest National demand outside of 2020 was 15.8 GW).

In addition to the customer demand component, there was approximately 500MW of demand from transmission connected generation, known as **station load**. And there were also exports across the international **interconnectors** and demand from **pumped storage** units, totalling 3.8 GW. This means that the total demand to be met by the transmission network was 17.8 GW; this is known as **transmission demand**.

It is standard practice when summer overnight demands are low, that extra demand can be created by instructing pumped storage units to pump or by trading on the interconnectors. This gives the necessary operational flexibility to the Control Room by increasing the total generation required from the transmission network. The amount of this extra demand that can be created depends on the prevailing market conditions and on the state of the pumped storage reservoirs, and cannot be accurately forecast much ahead of real time.

However, the **transmission demand** on 28 June was not the lowest transmission demand in summer 2020. That occurred on 31 May, the weekend after the late May bank holiday. The lowest **transmission demand** was 16.6 GW at 15:00 in the afternoon. The "natural" customer demand at the time was much higher than the lowest, at 16.0 GW, and only 0.1 GW of extra demand was being created through pumping or interconnectors.

It is normal not to take too much action on pump storage units to create higher transmission demand during the afternoon trough because if the storage reservoirs are filled up during the afternoon trough, the same facility might not be available overnight when the risk is greater.

The lowest overnight transmission demand occurred on 10 May 2020, the Sunday of the early bank holiday weekend. The transmission demand was 16.9 GW, 0.3 GW higher than the lowest transmission demand. But the "natural" demand was lower at 15.3 GW; this is low by normal standards, but not particularly low by the standards of 2020. There was 1.1 GW of "extra" demand created by Control Room instructions.

Additional to **national demand** and **transmission demand**, we also publish **weather corrected outturn demand** (that is, demand as it would have been under average weather conditions), and demand forecasts more than 14 days ahead also use average weather conditions. Weather corrected demands are useful for comparing demands between different years because they strip out the variability of weather conditions, and reflect economic, behavioural and technological changes.

Maximum and minimum weather corrected demands do not necessarily coincide in time or date with the equivalent extremes of the outturn demands, as minimum (or maximum) demands occur on days when we can guarantee that the weather is not average. However, in summer 2020 the minimum weather corrected **transmission demand** of 16.2 GW did occur at the same time as the minimum National demand.

When calculating either weather corrected **transmission demand** or demand forecasts based on average weather conditions we do not apply any assumed value for the "extra" demand that can be created by instructing pumps or interconnectors. The amount that can be instructed is too dependent on prevailing market conditions, and the amount that needs to be instructed depends too much on the actual weather conditions as opposed to the average weather conditions.

This means that caution should be applied when comparing season ahead **transmission demand** forecasts (with zero allowance for "extra" instructed demand) to previous years' outturn **transmission demand** (with the actual amount of "extra" generation included). It is always better to compare the seasonal forecast with the weather corrected outturn, so that they are calculated on the same basis.

In conclusion, what was the lowest summer demand for 2020? It was either 13.4 GW or 16.2 GW or 16.6 GW. Which you choose depends on what you want to use the value for.

Appendix C / Relationship between types of demand

This figure shows the relationship between some of the different types of demand discussed on the previous page, but this time based on minimum demands which occurred over summer 2021

The lowest overnight **Transmission demand** occurred on 27 September.. The Transmission demand was 18.4 GW..

Transmission System Demand

The lowest daytime **Transmission demand** was 19.4 GW at 15:00 in the afternoon of 30 May, the Sunday of the late May Bank Holiday weekend

'Natural' Demand

Power Station Demand

Interconnector Exports

Pumped Storage Pumping

National Demand

Increasing Transmission Demand

The lowest **National demand** occurred on 28 June at 05:30. This demand of 16.3 GW was significantly higher than that seen in 2020 (13.4 GW) which due to COVID-19 demand suppression was by far the lowest ever seen.

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

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 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 interconnector 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.

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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.

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 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 Moderation
This pre-fault frequency service is aimed to correct sudden large imbalances between generation and demand due to e.g., erroneous wind forecasts.

Dynamic Regulation
This pre-fault frequency service is designed to correct random but small deviations in frequency around the target of 50 Hz.

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/

Glossary

Eleclink
A power interconnector through the Channel Tunnel to provide a transmission link between the UK and France with a capacity of a 1000MW in either direction of flow

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

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.

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.

Frequency risk and control report (FRCR)
The FRCR is produced at least once annually and sets out the results of an assessment of the operational frequency risks on the system.

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

High summer period
The period between 1 June and 31 August, or weeks 23 to 35. It is when we expect the greatest number of planned generator outages.

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

Interconnexion France–Angleterre 2 (IFA2)
A 1,000 MW interconnector being between the French and British transmission systems commissioned early 2021. 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 other markets including Continental Europe and Ireland. 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.

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

Maximum demand
The highest demand on the transmission system.

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

Glossary

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).

Negative reserve active power margin (NRAPM)
The insufficient NRAPM warning is a request to encourage more flexible parameters from generators and inform participants of a risk of emergency instructions. A NRAPM may be issued if there is insufficient flexibility available to ensure that generation matches demand during periods of low demand. A localised NRAPM occurs where there is a danger that the combination of demand and inflexible generation within a constraint group can exceed the constraint limit of a portion of the network; in both cases there is a risk that the ESO may need to issue emergency instructions to inflexible and non-BM participating plant. Localised NRAPM are more common in the north of Scotland due to the large volume of wind and water generation and relatively low demand.

Nemo Link
A 1000 MW interconnector 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.

OC2 data
Power generation operational data provided under Operating Code No.2 of the Grid Code.

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/.

Optional Downward Flexibility Management (ODFM)
Ancillary service introduced in summer 2020 to help manage periods of low demand on the transmission system

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

Outturn
Actual historic demand operational demand from real time metering

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.

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.

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.

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.

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

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

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

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