drax

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Electric Insights Quarterly

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Contents

Electric Insights was established by Drax to help inform and enlighten the debate on Britain's electricity. Since 2016 it has been delivered independently by a team of academics at Imperial College London using data courtesy of Elexon, National Grid and Sheffield Solar.

1. Headlines

The start of 2021 saw unusually cold weather coupled with plant outages, which created very tight supply margins throughout January. Despite Britain still being under lockdown, insufficient capacity was expected to be available to meet demand, leading to some of the highest power prices in two decades. We compare Britain's situation to the blackouts which swept through Texas at the start of the year due to extreme weather.

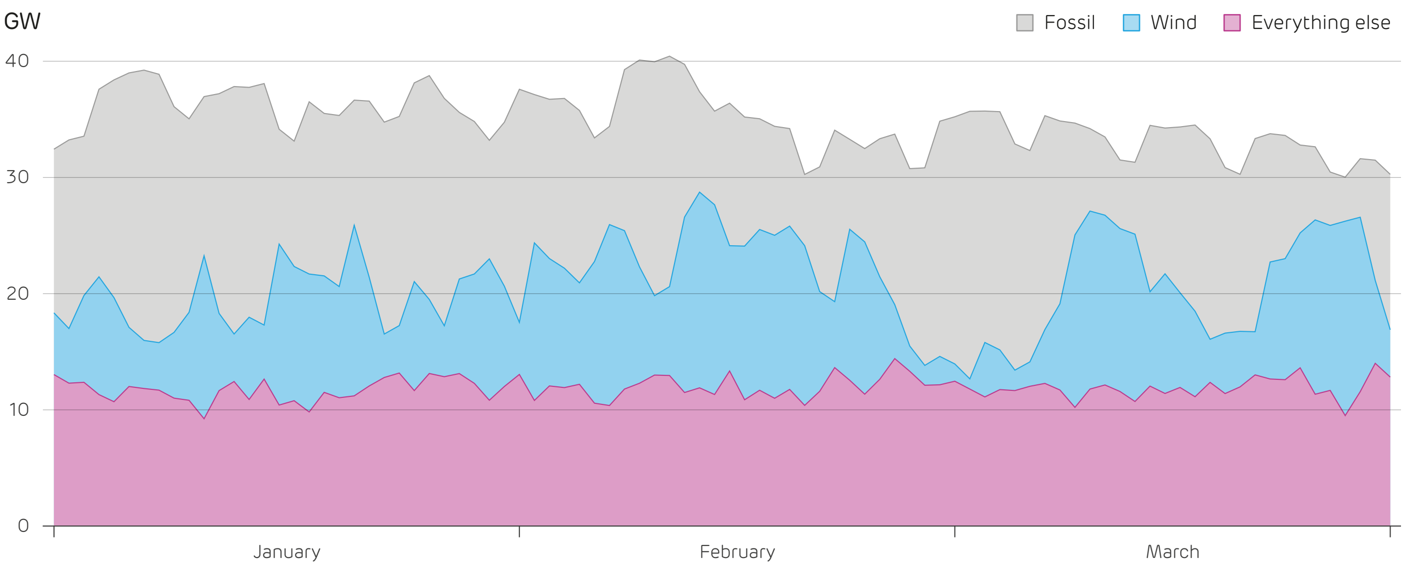
A new interconnector to France came online in January, increasing Britain's capacity for trading power with neighbours by 20%. Imports hit an all-time record high, even though the Dutch interconnector was unavailable for much of the quarter due to prolonged outages.

Commercial power generation ended one of Britain's remaining coal power stations, leaving only two stations now in regular operation. At the same time, biomass output hit a record high, peaking at over 3.8 GW for the first time as plants ran flat out when capacity was scarce. We look at the history of Britain's transition from coal to biomass, and the future of moving towards negative-emissions biomass with carbon capture and storage.

Wind power contributed heavily to Scotland achieving 97% renewable electricity generation in 2020, and Britain's wind farms produced record power output this quarter, reaching over 18 GW for the first time. However, March saw the longest 'cold calm spell' in over a decade: for 11 days straight wind farms operated at just 11% of their rated capacity. Dealing with extended wind lulls could be biggest challenge we face in fully decarbonising Britain's electricity system.

Gas power stations picked up the slack, which contributed to gas generation being up 20% on this quarter last year. This highlights the need for flexible backup in the power system. While burning gas without capturing the CO_2 is a viable solution for now, it will not be possible to rely on unabated fossil fuels for balancing in future if the UK is to hit its net zero targets. We explore the options Britain has for balancing wind variability in future.

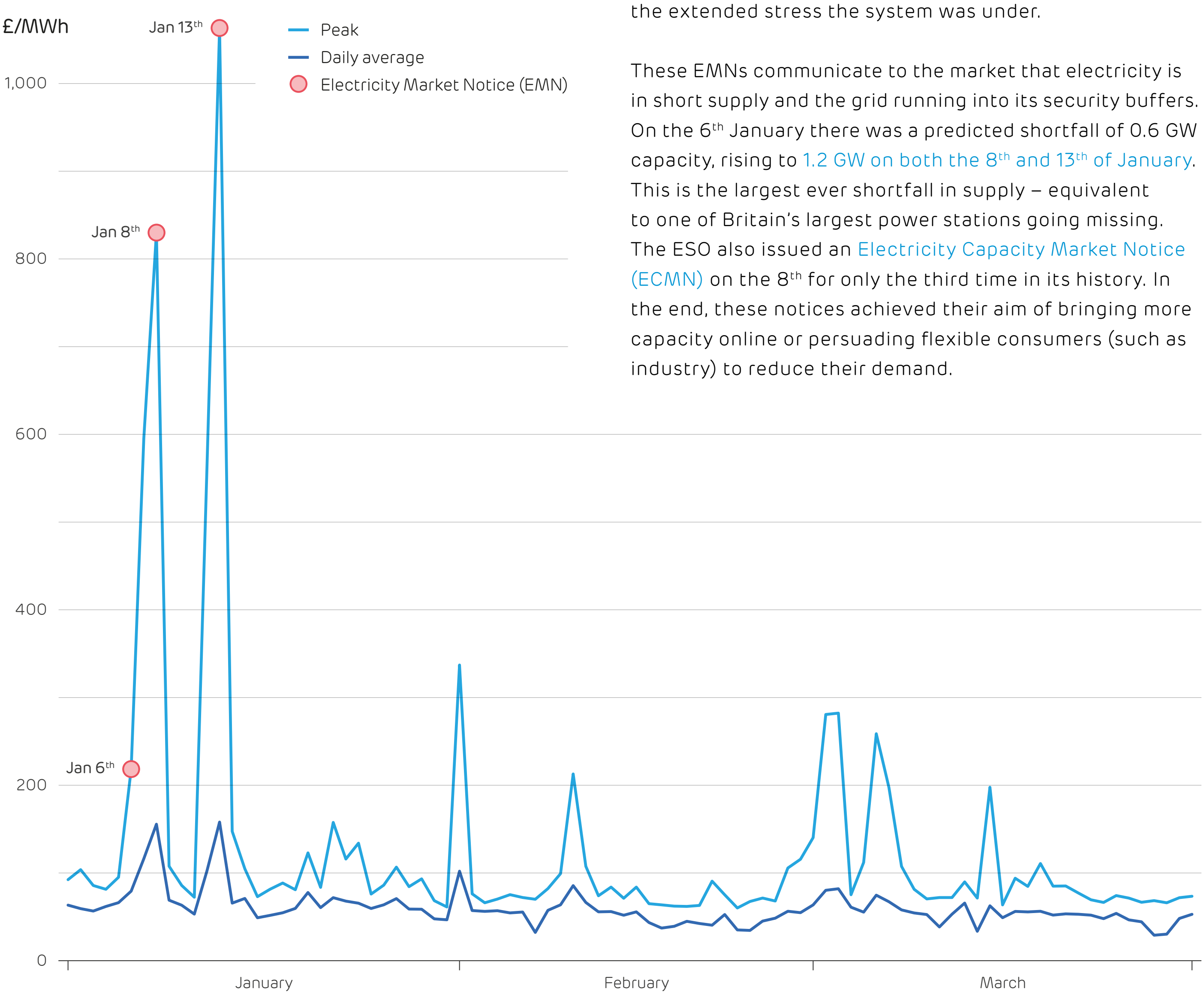
Summary of Britain's electricity generation mix over the first quarter of 2021



2. Cold weather and tight margins

The Texas blackout dominated the newspaper headlines in February. An 'arctic outbreak' plunged south from Canada, sending temperatures down to as low as –22°C, more than forty degrees below typical February temperatures. Electricity demand surged as people tried to stay warm, but at the same time as gas and wind power stations shut down because of the extreme conditions. Blackouts affected 4.3 million Texans, with some lasting for 3 days, and at least 31 lives were lost. Power prices spiked to $8,800 per MWh on February 17th in Dallas and Fort Worth – almost 200 times their normal level. Some households on variable rate tariffs were hit with bills over ten thousand dollars, and three utility companies have already declared bankruptcy.

Daily average and maximum electricity prices on the British day-ahead market in Q1 2021

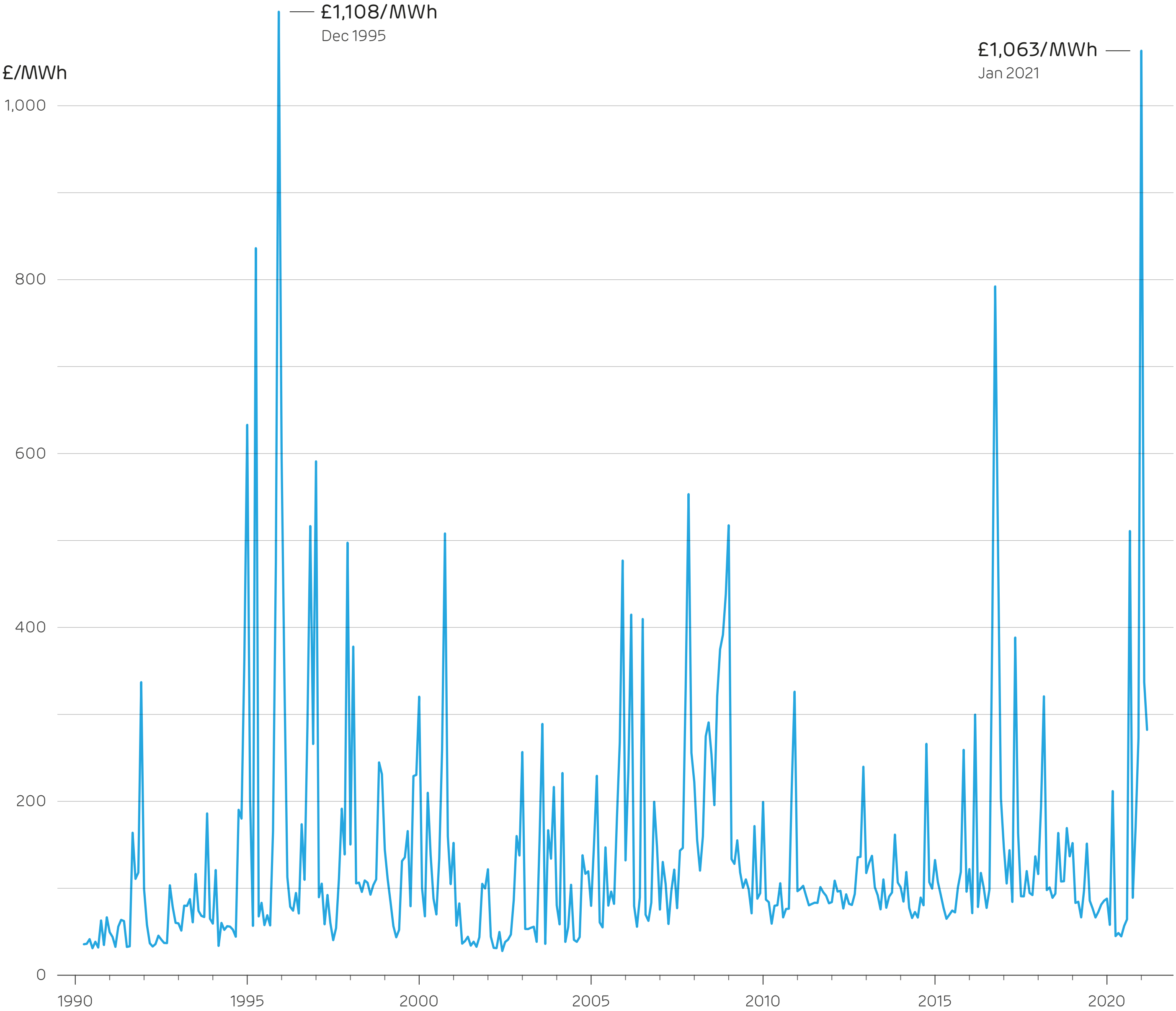


Closer to home, Europe was hit by its own polar vortex, creatively dubbed 'The Beast from the East 2'. After seeing the coldest January since 2010, temperatures in February fell to a low of –23°C in Braemar (Aberdeenshire). This pushed electricity demand up by 15% compared to the surrounding weeks due to increased heating load. Demand pushed above 48 GW for the first time since 2019, despite the country still being under full lockdown.

This increased demand came at an inconvenient time, as nuclear outages were prolonged through winter, and the Dutch interconnector (which normally supplies a steady 1 GW to Britain) was also offline. This left the market 'tight', meaning short of capacity. National Grid ESO (electricity system operator) issued three Electricity Margin Notices (EMN) in January alone, making six in total for this winter. The last such notice was issued back in 2016, highlighting the extended stress the system was under.

These EMNs communicate to the market that electricity is in short supply and the grid running into its security buffers. On the 6th January there was a predicted shortfall of 0.6 GW capacity, rising to 1.2 GW on both the 8th and 13th of January. This is the largest ever shortfall in supply – equivalent to one of Britain's largest power stations going missing. The ESO also issued an Electricity Capacity Market Notice (ECMN) on the 8th for only the third time in its history. In the end, these notices achieved their aim of bringing more capacity online or persuading flexible consumers (such as industry) to reduce their demand.

The highest wholesale power price seen in each month since the British electricity market began



The shortfalls did not lead to any blackouts, but did cause the highest power prices of this century. Day-ahead market prices rose to £1,063 per MWh on January 13th, their highest since 1995 (when they were driven up by capacity payments that were abolished in 2001). While this is 25 times higher than the average price over the past year, extreme prices are not passed on to households directly as they are in Texas.

Britain's power system did not suffer the same catastrophic failure as in Texas for many reasons. While they share some similarities (high shares of wind power, limited connection to neighbouring power systems), the UK suffered much less severe weather, and is more accustomed to winter storms and so is better prepared for them.

Wind turbines are weatherised so they can continue operation when temperatures fall below freezing, and gas supplies come from the North Sea pipelines and via ships which are unaffected by cold weather, compared to on-land gas rigs in Texas which froze over.

However, the Texan experience helps to remind us about the interdependency of energy services. Going forward with our decarbonisation we must ensure that the resilience of the energy system to extreme weather events is designed into the transition to net zero. This might provide an argument for decarbonising household heating systems with a mix of hydrogen and electric heat pumps, as the 'all electric' future provides a single point of failure.

3. Britain's transition from coal to biomass to BECCS

Britain moved one step closer to its 2024/25 target of phasing out coal power completely, while biomass generation hit new record highs. On the 5th of March Drax announced that it had ceased commercial power generation from coal[1] after 47 years at the UK's largest power station. This leaves just two coal power stations operating in Britain, as 85% of the country's coal fleet have retired over the last ten years.

Meanwhile, biomass power stations reached new records, generating 3.81 GW on the 27th of March. Biomass output is likely to grow further as a new biomass-powered combined heat and power unit at Teesside is expected to come online later this year.

Global leadership

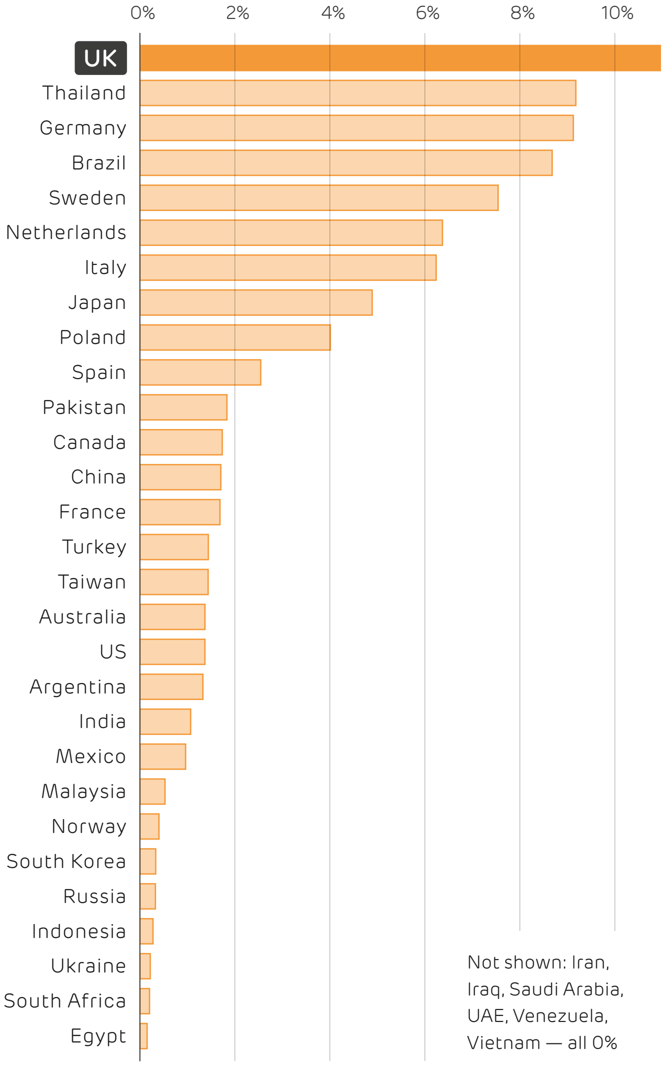
Currently, biomass supplies 2% of the world's electricity, though this share is higher in Europe, having grown five-fold since 2000 to hit 6% in 2020.[2] One explanation for this comes from countries such as Denmark and Sweden, which have extensive municipal electricity and combined heat and power production.

Another reason is the UK. Our share of electricity generation from biomass has tripled over the past decade, hitting an all-time high of 11% in 2020.[2] This means the UK has the highest share of electricity production from biomass of any large country (ones with over 100 TWh/year electricity demand).

The UK pioneered large-scale use of biomass for electricity generation, contributing to its world-leading success in decarbonising electricity over the last decade. This position means the UK has also played a major part in developing the science-led sustainability criteria that govern the use of biomass.

The transition from coal to biomass to BECCS (bioenergy with carbon capture and storage) outlines the versatility of biomass for electricity generation to contribute at each stage of the decarbonisation journey. In a high-coal system (the UK's past), biomass conversions allow for rapid carbon reductions whilst utilising existing infrastructure and preserving the reliable functionality of firm, dispatchable power. In a high-renewables system (increasingly the UK's present), biomass offers flexibility services, including inertia and grid balancing. This helps the overall system to integrate variable renewables and lowers grid management costs. Finally, looking to the future, BECCS offers the possibility of negative emissions, which the Climate Change Committee describe as "a necessity" for net zero and beyond.

Share of electricity generated from biomass in 2020 across all countries worldwide which consume more than 100 TWh of electricity per year[2]



1 These units will still operate in the capacity market until they are fully decommissioned in 2022, meaning they could be called upon to provide peak capacity at times of system stress.
2 Data from Ember's Global Electricity Review.

Looking to the past

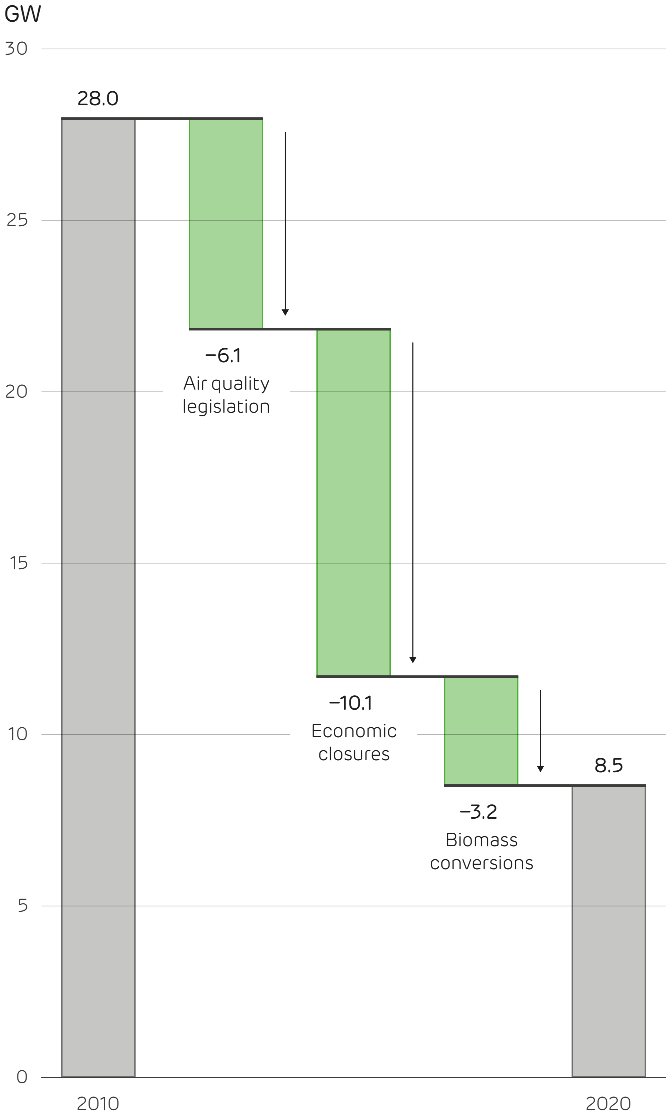
Coal dominated Britain's electricity generation until just a decade ago. However, since 2018, Britain has produced more electricity from biomass than it has from coal. There are three main reasons why Britain's coal plants closed down.

Clean air legislation forced older plants to close if they did not fit equipment to capture harmful sulphur and nitrous oxide emissions. Secondly, many plants closed on economic grounds, either because they were reaching the end of their design life and the cost of maintaining them outweighed the revenue they could bring in, or they could simply no longer compete in the market. A key factor in this was government policy raising the cost of emitting carbon so coal plants became more expensive than gas. With demand falling and renewables taking a larger share, there was simply no room left for them to make a profit.

When these units retired they needed to be replaced by a clean electricity source that could provide baseload generation, producing electricity when it is needed. However, research shows that in addition, these coal retirements also led to a 30% increase in output from natural gas plants (37 TWh extra in 2019).[3]

The third source of coal plant closures was conversion to biomass. Although they represent the smallest share of capacity (with 3.2 GW converted), they have delivered greater carbon savings because not only did they reduce the amount of coal burnt, they replaced it with a low-carbon source of electricity. Coal to biomass conversions therefore limited – rather than increased – gas generation. Comparing 2012 to 2019, they reduced carbon emissions by 10 $MtCO_2$ per year, slightly more than achieved by the 8 GW of onshore wind farms installed in that time.[3]

The change in coal power station capacity over the last decade and main categories of coal plant closures



3 R Green and I Staffell, 2021. The contribution of taxes, subsidies and regulations to British electricity decarbonisation. EPRG 2105.

Looking to the future

National Grid ESO's Future Energy Scenarios see biomass playing an increased role in coming decades. Current unabated biomass (where emissions from generating electricity are offset by regrowing it) plays a key step towards the deployment of BECCS (bioenergy with carbon capture and storage) from the late 2020s.

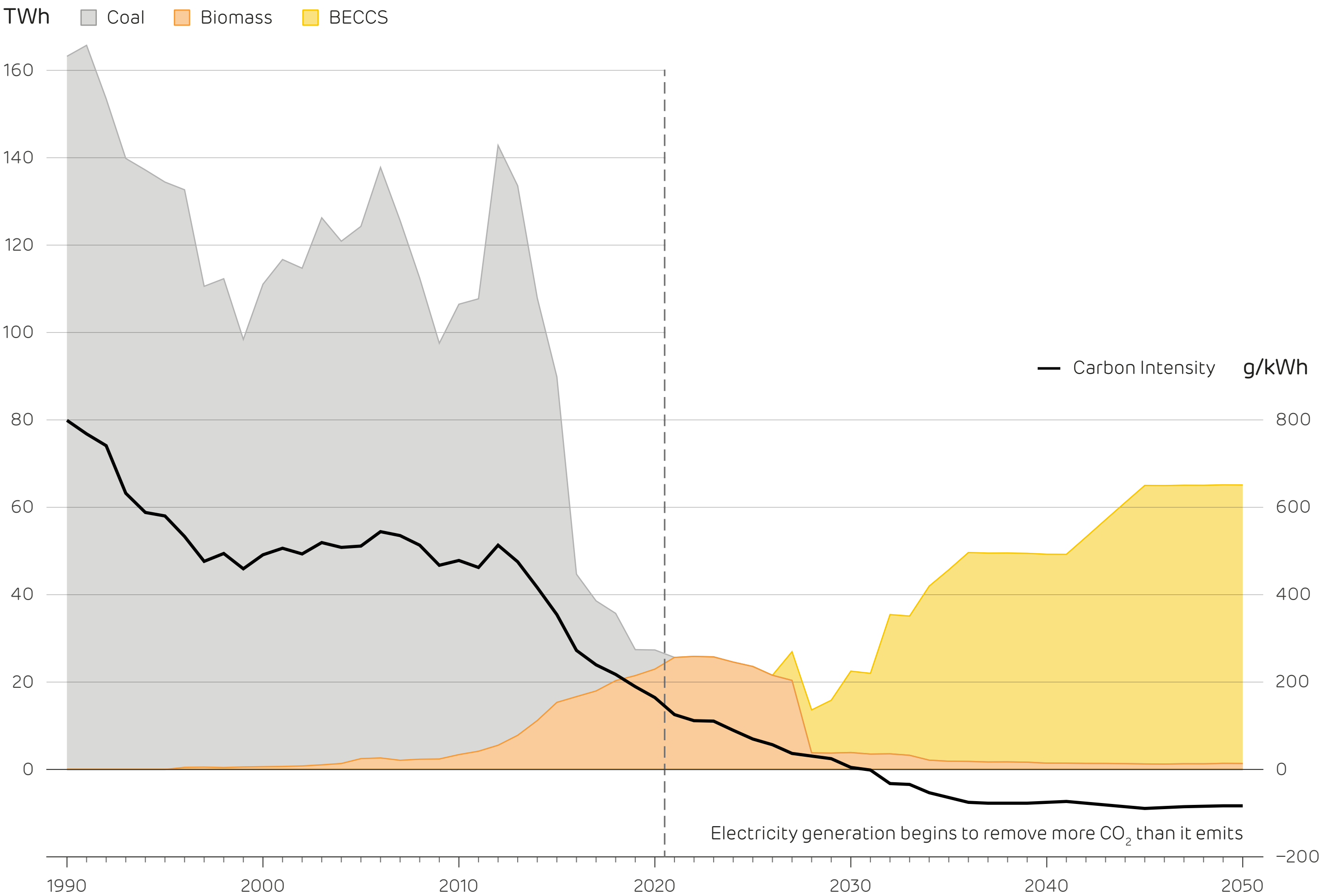
Bioenergy (the 'BE' in 'BECCS') operates by growing and continuously regrowing plants that are then used for energy. The carbon emitted during energy generation is reabsorbed by the regrowth of the plants, meaning net-zero emissions. Supply chain emissions are then counted on top of this in accordance with a strict sustainability governance regime, hence Electric Insights considers biomass as producing 121 grams of CO_2 per kWh of electricity.

If emissions from the power station are instead captured and locked away underground (the 'CCS' in 'BECCS'), the plants being grown and regrown actually remove carbon from the atmosphere, over and above simply offsetting the bioenergy emissions. Therefore BECCS as a whole can deliver negative emissions as part of a major energy source.

The deployment of BECCS means annual carbon emissions from electricity generation could fall negative as early as 2030 in National Grid's scenarios. My the mid-2030s, BECCS could be removing 40 $MtCO_2$ per year from the atmosphere, comparable to total annual emissions in 2020.

The IEA remarked in 2018 that "modern bioenergy is the overlooked giant of the renewable energy field". With the potential for sustainable expansion and the use of carbon capture to deliver negative emissions, this could take a more visible role in the UK's future.

Annual electricity generation from solid fuels in Britain and the average carbon intensity of electricity, shown over the past three decades and the next three decades according to National Grid's "Leading the Way" future energy scenario

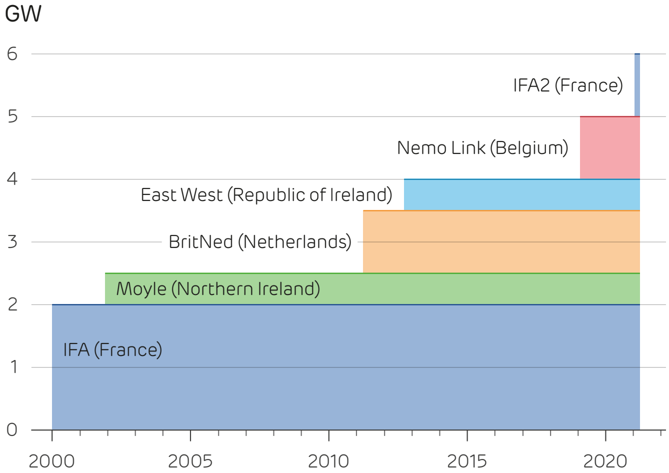


4. IFA2 goes online

A new power link between the UK and France went online in January, meaning Britain's interconnector capacity has doubled over the last decade to 6 GW. IFA2 is one of Britain's two undersea connection to France, coming some 60 years after the first link was built, and 35 years after that was replaced by IFA (which still operates today). The £700m IFA2 project, jointly owned by National Grid and RTE (their French equivalent), spans 130 miles under the English Channel to connect Portsmouth with Caen in Normandy.

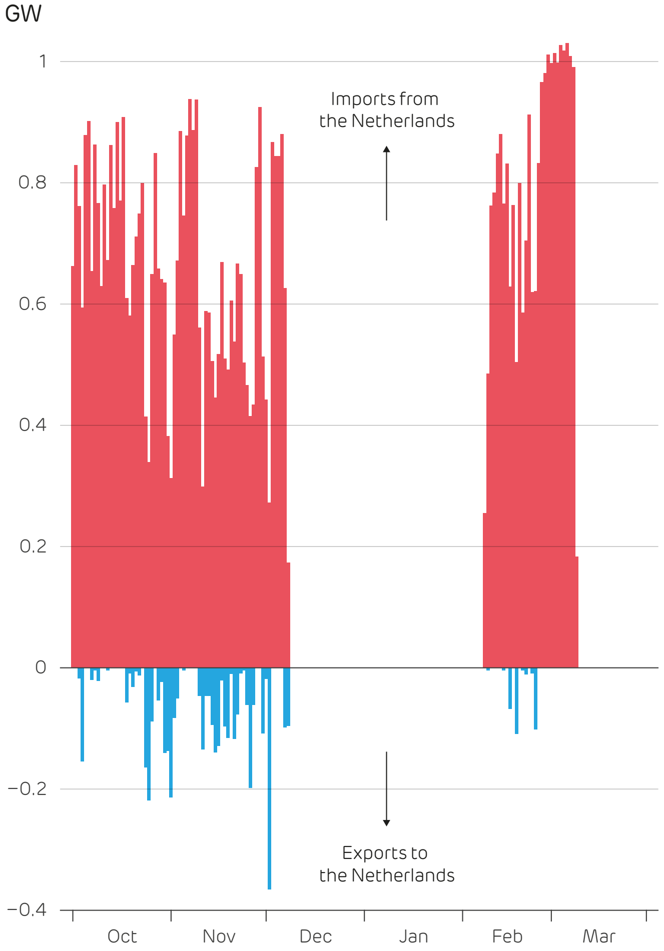
After some early teething troubles, the new link has imported 20 times more power than it exported since it went into operation on January 22nd. Imports of electricity to Britain rose to new record levels, although they could have been higher still.

Installed capacity of interconnectors in Great Britain over the last two decades



Despite very good historical reliability, the BritNed cable between Britain and the Netherlands was out of action for most of the quarter: from mid-December through to mid-February, and again since mid-March. As a result, Dutch imports were down 60% and exports down 90% compared to the first quarter last year. Cable faults are responsible for both outages, being found on December 8th last year (and taking three months to repair) and again on March 9th this year (with an estimated two months to repair).

Daily trade over the BritNed interconnector during the past six months



There were initial reports that the end of the Brexit transition period led to reduced trade over the interconnectors to Ireland at the start of this year, sending power prices rocketing. The UK left Europe's Internal Energy Market on the 31st December 2020, which increased friction for trading. However, it appears this was only a short-term blip — trade fell by 40% between December 2020 and January 2021, but then recovered completely in February. Over the first quarter of this year, trade with the Irish power market was 1% higher than the average during 2019-20.

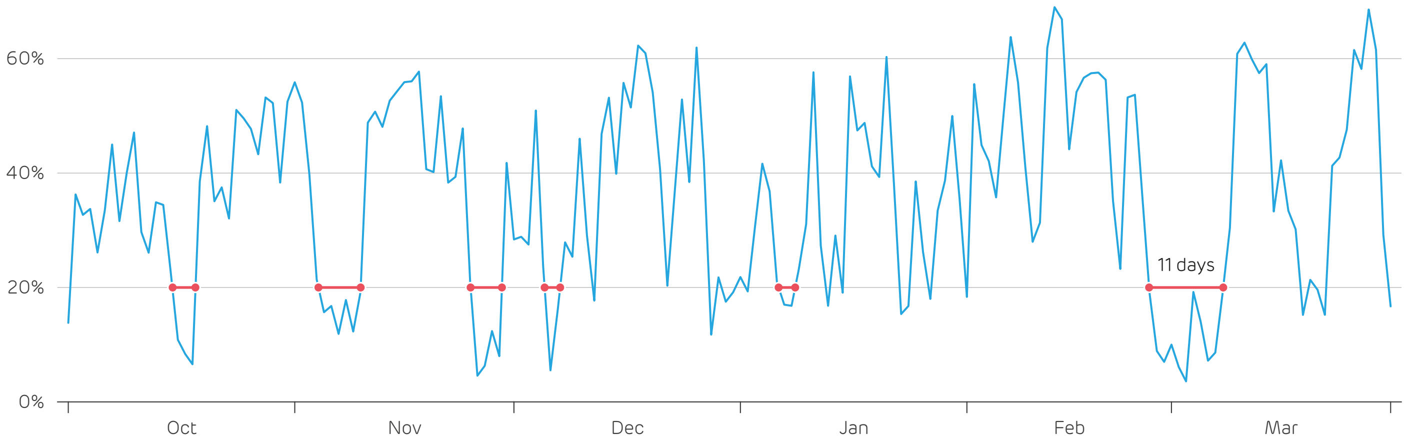
Work on a third interconnector to France will begin later this year, and links to Norway and Denmark are currently under construction. These will begin to be shown on the Electric Insights webpage in the coming months. With these and the return of the Dutch interconnector to service, Britain is set to source an increasing share of its power from abroad in the coming years.

5. When the wind goes, gas fills in the gap

At the start of March Britain experienced its longest spell of low wind output in more than a decade. For more than a week calm weather covered the country. Wind farm output fell to as low as 0.6 GW on the 3rd of March, in sharp contrast to the 18.1 GW delivered later on that month. Power prices were typical for the time of year, suggesting that the system wasn't particularly stressed though.

A prolonged period of low wind and low solar power output has been coined in German as a 'Dunkelflaute' (*dunk-el-flout-eh*) — a dark wind lull. The event at the start of March was the longest Dunkelflaute that Britain has experienced in the last decade. Between the 26th of February and the 8th of March the capacity factor[1] of the national wind fleet did not go above 20%. Its average over these 11 days was just 11%, less than a quarter of their average in the month either side.

Britain's wind farm capacity factor over the past six months, highlighting times when it fell below 20% for more than a day



Both the frequency and duration of these events matters. Looking back over the Electric Insights archives, this was the longest cold-calm spell that Britain has experienced in over a decade. February 2010 also saw 11 days with wind capacity factors never going above 20%. However, back in 2010 most of Britain's wind farms were onshore and so average capacity factors were lower. Also, the impact of low wind speeds was barely noticeable back in 2010, as Britain's wind capacity then was one-sixth of current levels.

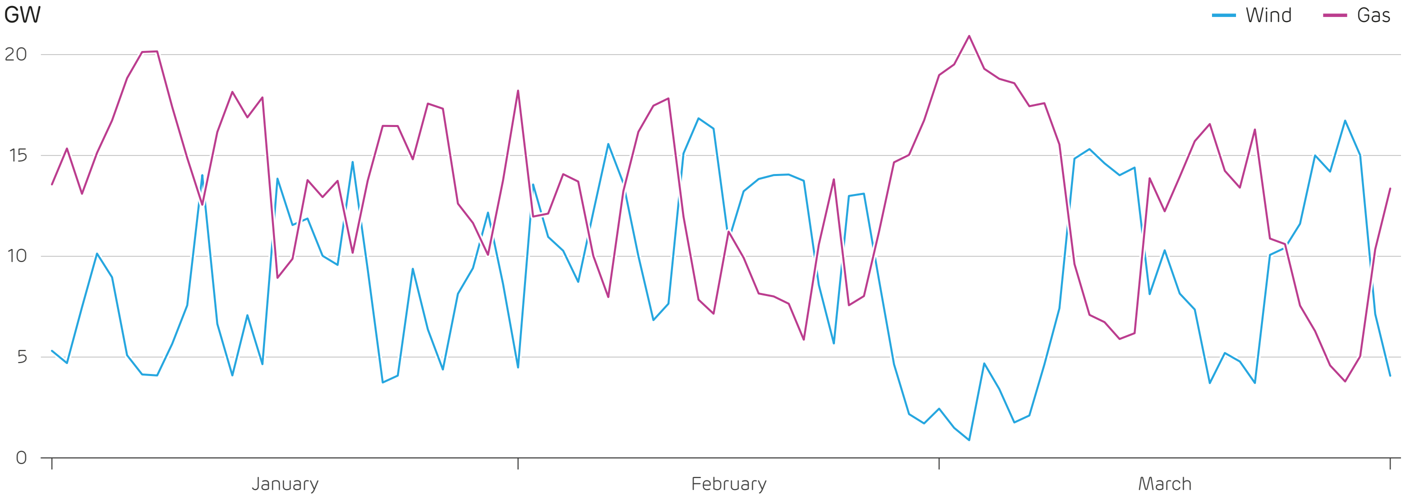
Based on longer records of historical wind speed data from Renewables.ninja, the March Dunkelflaute could be expected roughly once every 20 years, statistically speaking. Prolonged low-wind periods should be accounted for when designing Britain's energy system security, and they should not be seen as a 'black swan event' which cannot be anticipated.

The power system coped in March because the shortfall in wind was made up by fossil fuels, particularly the 28 GW of gas power stations. Fossil fuels peaked at a 73% share of all electricity generation on the 6th of March. While coal and biomass stations ran at close to full output to help, Britain's nuclear output actually fell to its lowest this year during the low-wind period. Nuclear output dropped to just 3.6 GW, 30% below its average for the quarter, as maintenance outages continued to affect the fleet.

1 Power output as a fraction of total installed capacity.

The output from Britain's wind farms is almost exclusively balanced by gas power stations. Throughout the quarter their outputs were the mirror image of one another, performing an elaborate dance to keep the system balanced. For every GW that wind output falls, gas output rises by 0.84 GW. When all other generation sources are combined, their output only varies by 10% around their average of 13 GW across the quarter.

Daily average output from wind farms and gas power stations during Quarter 1 of 2021



The UK's ambition to reach net zero would prohibit the use of (unabated) gas power plants for such long periods. While a variety of clean flexibility options could replace gas, the scale and duration of wind droughts may rule many of them out.

The lull in March saw a deficit of over 10 GW of wind capacity compared to the surrounding weeks, and some 2,300 GWh of energy. In comparison, the UK's largest storage facility – the Dinorwig pumped hydro plant in North Wales – stores just 9 GWh. Battery storage systems are ideal for providing peak power, but their duration (and total energy storage) is limited. Over 10,000 of the world's largest battery storage systems would be needed to cover the shortfall, occupying a space the size of Liverpool city.[2]

Interconnectors can help, but these weather patterns tend to affect the entire north-west of Europe, meaning our neighbouring countries would also be short of capacity. Flexible demand may be insufficient for a different reason – households and industries may be willing to turn down their consumption for a few hours at a time, but doing so for over a week straight is another matter. This restricts the options for dealing with large-scale weather variability to longer-duration storage or low- and zero-carbon fuels such as biomass and potentially hydrogen in the future. The four biomass domes at Drax Power Station hold enough fuel to generate 600 GWh of electricity, showing the scale that storable fuels can attain.

Weather variability will play an important part in the planning and operation of Britain's future energy system. The recent power outage in Texas highlights the cost of overlooking extreme weather risks (noting that it was gas generation rather than wind which drove this crisis). Securely managing wind variability will likely require policy and market innovations, not just technical fixes.

2 Based on a 6,500 m² footprint estimated for the South Australia battery farm.

6. Capacity and production statistics

Electricity production from gas rose 20% from this time last year, driven by lower wind output and continued nuclear outages. It was by no means a bad quarter for wind farms – their productivity was typical for winter at 37% – but this was much lower than during the unusually stormy start to 2020.

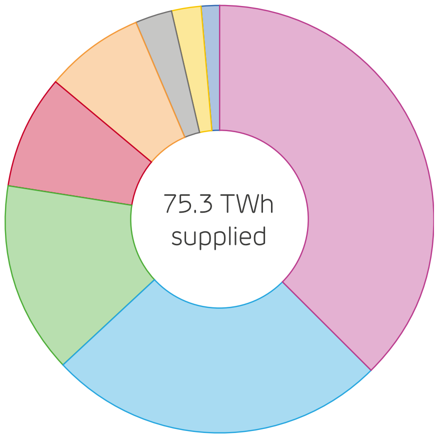
Britain's nuclear reactors on the other hand ran at just 53% capacity factor during the quarter, when ideally they should be running 24/7. Their utilisation was only slightly higher than that of gas power stations.

Demand was almost the same as Q1 last year, as the demand reductions from the country being under lockdown were offset by it being on average 1 degree colder.

Both biomass and coal power stations hit a peak of 100% capacity factor during the quarter, meaning every station was running at full power at the same time. This is highly unusual for coal, which was called on extensively during periods of tight margins in January.

Britain's remaining coal capacity fell by one quarter as Drax announced the end of commercial operation for its two remaining coal units in Yorkshire. This leaves two coal power stations remaining – West Burton A and Ratcliffe on Soar, both in Nottinghamshire, due to close in 2022 and 2024.

Britain's electricity supply mix in the first quarter of 2021



	Share of the mix
Gas	37.6%
Wind	25.6%
Nuclear	14.4%
Imports	8.6%
Biomass	7.5%
Coal	2.7%
Solar	2.2%
Hydro	1.3%

Installed capacity and electricity produced by each technology [1 2]

	Installed Capacity (GW)		Energy Output (TWh)		Utilisation / Capacity Factor	
	2021 Q1	Annual change	2021 Q1	Annual change	Average	Maximum
Nuclear	9.5	~	10.8	−1.5 (−12%)	53%	65%
Biomass	3.8	+0.1 (+4%)	5.6	+0.5 (+10%)	68%	100%
Hydro	1.2	~	1.0	−0.5 (−35%)	40%	96%
Wind	24.4	+0.9 (+4%)	19.3	−4.0 (−17%)	37%	74%
– of which Onshore	13.7	~	8.7	− 2.2 (−20%)	30%	73%
– of which Offshore	10.7	+0.9 (+9%)	10.6	− 1.8 (−14%)	46%	88%
Solar	13.2	+0.1 (+1%)	1.7	−0.3 (−14%)	6%	63%
Gas	27.6	−0.5 (−2%)	28.3	+4.9 (+21%)	48%	86%
Coal	3.8	−1.4 (−27%)	2.0	−0.9 (−31%)	20%	100%
Imports	6.0	+1.0 (+20%)	7.2	+0.5 (+7%)	58%	97%
Exports			0.7	−0.1 (−14%)	6%	61%
Storage discharge	3.1	~	0.5	+0.1 (+12%)	7%	61%
Storage recharge			0.5	−0.0 (−5%)	7%	76%

1 Other sources give different values because of the types of plant they consider. For example, BEIS Energy Trends records an additional 0.7 GW of hydro, 0.6 GW of biomass and 3 GW of waste-to-energy plants. These plants and their output are not visible to the electricity transmission system and so cannot be reported on here.
2 We include an estimate of the installed capacity of smaller storage devices which are not monitored by the electricity market operator. Britain's storage capacity is made up of 2.9 GW of pumped hydro storage, 0.6 GW of lithium-ion batteries, 0.4 GW of flywheels and 0.3 GW of compressed air.

7. Power system records

March the 28th was a record-breaking day for Britain's power system. Wind farms produced more than 18 GW for the first time. Over the whole day renewables produced two-thirds of the country's electricity demand, pushing fossil fuels to their lowest ever share of electricity generation, under one-eighth of the day's electricity.

January also saw the highest power prices in over a decade, averaging £71/MWh for the month. On the 8th real-time prices hit a record £4,000/MWh, and on the 13th day-ahead prices (which are normally much smoother) peaked at over £1,000/MWh for the first time in over two decades.

The tables below look over the past decade (2009 to 2021) and report the record output and share of electricity generation, plus sustained averages over a day, a month and a calendar year.[1] Cells highlighted in blue are records that were broken in the first quarter of 2021. Each number links to the date it occurred on the Electric Insights website, allowing these records to be explored visually.

Wind – Maximum

	Output (MW)	Share (%)
Instantaneous	18,120	60.9%
Daily average	16,844	53.4%
Month average	12,346	34.1%
Year average	7,817	24.9%

Solar – Maximum

	Output (MW)	Share (%)
Instantaneous	9,680	33.1%
Daily average	3,386	13.6%
Month average	2,651	10.0%
Year average	1,372	4.4%

Biomass – Maximum

	Output (MW)	Share (%)
Instantaneous	3,831	16.8%
Daily average	3,316	12.9%
Month average	2,849	8.8%
Year average	2,216	7.1%

All Renewables – Maximum

	Output (MW)	Share (%)
Instantaneous	25,790	69.5%
Daily average	20,786	66.3%
Month average	16,030	44.3%
Year average	11,896	37.9%

Gross demand

	Maximum (MW)	Minimum (MW)
Instantaneous	60,070	16,934
Daily average	49,203	23,297
Month average	45,003	26,081
Year average	37,736	30,709

Demand (net of wind and solar)

	Maximum (MW)	Minimum (MW)
Instantaneous	59,563	6,605
Daily average	48,823	9,454
Month average	43,767	18,017
Year average	36,579	21,520

1 The annual records relate to calendar years, covering the period of 2009 to 2020.

Day ahead wholesale price

	Maximum (£/MWh)	Minimum (£/MWh)
Instantaneous	1063.27	–72.84
Daily average	197.45	–11.35
Month average	71.12	22.03
Year average	56.82	33.88

Carbon intensity

	Maximum (g/kWh)	Minimum (g/kWh)
Instantaneous	704	18
Daily average	633	61
Month average	591	141
Year average	508	172

All low carbon – Maximum

	Output (MW)	Share (%)
Instantaneous	32,688	89.7%
Daily average	27,282	82.5%
Month average	23,276	65.4%
Year average	17,930	58.3%

All low carbon – Minimum

	Output (MW)	Share (%)
Instantaneous	3,395	8.3%
Daily average	5,007	10.8%
Month average	6,885	16.7%
Year average	8,412	21.6%

All fossil fuels – Maximum

	Output (MW)	Share (%)
Instantaneous	49,307	88.0%
Daily average	43,085	86.4%
Month average	36,466	81.2%
Year average	29,709	76.3%

All fossil fuels – Minimum

	Output (MW)	Share (%)
Instantaneous	2,369	8.8%
Daily average	3,789	12.1%
Month average	7,382	27.8%
Year average	11,336	36.1%

Nuclear – Maximum

	Output (MW)	Share (%)
Instantaneous	9,342	42.8%
Daily average	9,320	32.0%
Month average	8,649	26.5%
Year average	7,604	22.0%

Nuclear – Minimum

	Output (MW)	Share (%)
Instantaneous	2,488	8.1%
Daily average	2,665	10.3%
Month average	4,232	12.9%
Year average	5,397	17.2%

Coal – Maximum

	Output (MW)	Share (%)
Instantaneous	26,044	61.4%
Daily average	24,589	52.0%
Month average	20,746	48.0%
Year average	15,628	42.0%

Coal – Minimum

	Output (MW)	Share (%)
Instantaneous	0	0.0%
Daily average	0	0.0%
Month average	0	0.0%
Year average	499	1.6%

Gas – Maximum	Output (MW)	Share (%)
Instantaneous	27,131	72.6%
Daily average	24,210	61.3%
Month average	20,828	54.8%
Year average	17,930	46.0%

Gas – Minimum	Output (MW)	Share (%)
Instantaneous	1,556	4.9%
Daily average	3,071	9.5%
Month average	6,775	19.9%
Year average	9,159	24.6%

Imports – Maximum	Output (MW)	Share (%)
Instantaneous	5,827	19.1%
Daily average	4,985	15.5%
Month average	3,796	10.6%
Year average	2,850	8.6%

Exports – Maximum	Output (MW)	Share (%)
Instantaneous	–3,870	–14.3%
Daily average	–2,748	–7.9%
Month average	–1,690	–3.9%
Year average	–731	–1.9%

Pumped storage – Maximum[2]	Output (MW)	Share (%)
Instantaneous	2,660	7.9%
Daily average	409	1.2%

Pumped storage – Minimum[2]	Output (MW)	Share (%)
Instantaneous	–2,782	–10.8%
Daily average	–622	–1.7%

2 Note that Britain has no inter-seasonal electricity storage, so we only report on half-hourly and daily records. Elexon and National Grid only report the output of large pumped hydro storage plants. The operation of battery, flywheel and other storage sites is not publicly available.

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