drax

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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. This report was written by third party authors external to Drax as part of the Electric Insights project. Drax and Imperial College London do not guarantee the accuracy, reliability, or completeness of this content.

1. Introduction

Clean power got a major boost this quarter. The next renewables capacity auction (AR7) opened, with over £1 billion for new offshore wind projects. It offers longer contracts for some technologies and higher maximum strike prices (up 11%), in the hope of attracting more capacity. Renewables and nuclear supplied two-thirds of Britain's electricity in September, and clear skies throughout summer helped solar set new output records, briefly meeting over 40% of national demand. A sunny Saturday in August saw demand met by the transmission system sinking to a modern-era low, as rooftop solar PV meant more power than ever was generated locally.

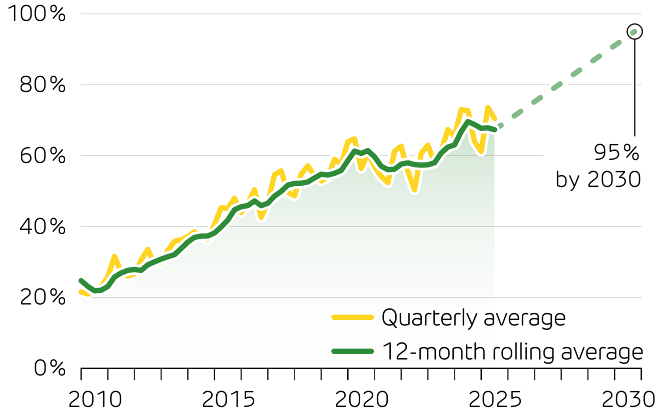
The weather now very much calls the shots, dictating power prices, system balancing and infrastructure stress. Our second article digs into the Royal Meteorological Society's new State of the Climate for the UK Energy Sector report, charting how "dunkelflaute" and storm-driven surpluses affect power prices and security, and what this means for planning over the next decade.

Building the infrastructure to utilise clean power is the other side of the story. National Grid's Great Grid Upgrade is the biggest overhaul to the transmission network since the 1960s. We look at its 17 major projects, from the Eastern Green Links to 'Offshore Hybrid Assets' that aim to cut curtailment and move Scottish wind power to southern demand centres. Flexibility is also booming: Britain's battery storage capacity surged past 6 GW, with hundreds of projects under construction or given the go-ahead. We map the UK's energy storage pipeline, identifying Scotland's Central Belt and England's industrial heartland as hotspots, and discuss the move towards larger and longer-duration storage, such as pumped hydro, thermal and hydrogen.

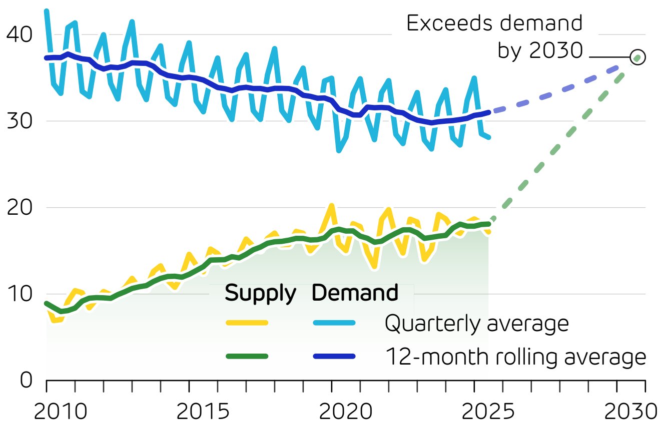
Carbon prices have risen 75% so far this year, after the UK and EU agreed to re-link their emissions trading systems. Our fifth article analyses this shift and its effect on industry, imports and bills. Falling gas prices have muted its impact on electricity generation costs. Ofgem cut the energy price cap for the first time in a year, but the 7% fall in July has been short-lived, as the cap edged back up by 2% in October.

The Government has set three Clean Power 2030 targets, covering the amount of clean electricity produced and overall carbon intensity. Progress towards these has been solid over the past 15 years, but has faltered in the most recent quarter, with the share of clean power falling and carbon emissions rising slightly.

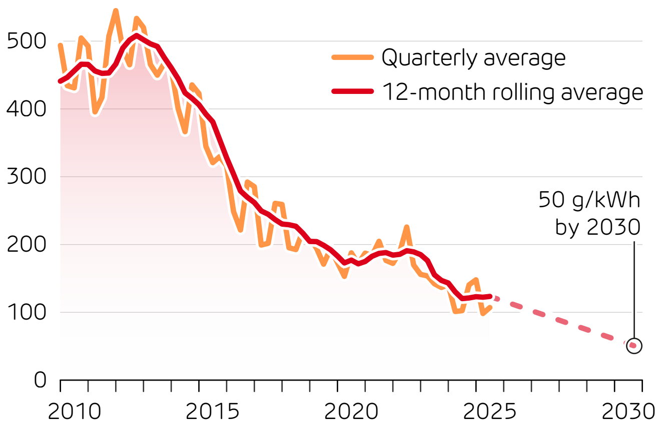
Share of clean electricity generation



(GW) Clean electricity generation



(g/kWh) Carbon intensity of electricity



2. The growing influence of Britain's weather on its electricity

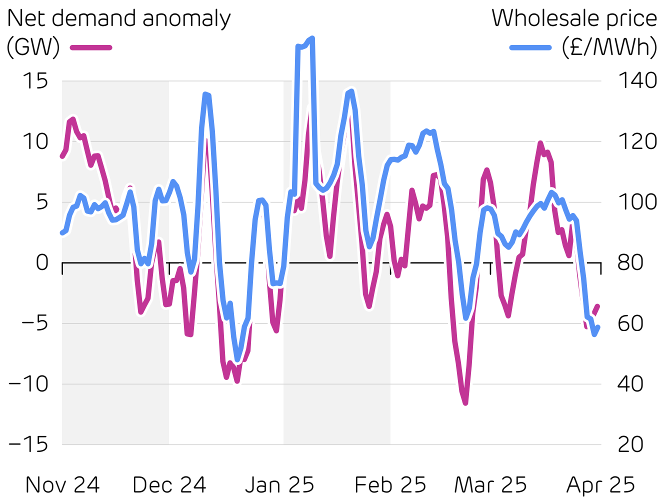
A grey, still Wednesday in January revealed how the weather now calls the shots on Britain's power system. Real-time prices spiked to over seven times the winter average (an eye-watering £2,900/MWh), and the system operator spent £21 million balancing supply and demand that day. The Royal Meteorological Society's latest "State of the Climate for the UK Energy Sector" report shows how weather-driven changes in renewable output and demand drive power prices, and how extreme weather events increasingly impact on our energy infrastructure.

Throughout November 2024, calm and cloudy conditions led to below-average wind and solar generation. Fortunately, the long wind drought coincided with mild temperatures that reduced demand for electricity, muting price impacts. Similar conditions during January 2025 combined with freezing conditions in a so-called "dunkelflaute" event which led to large spikes in the wholesale price. Despite tight margins, there was no disruption to supplies as the National Energy System Operator (NESO) used interconnectors, stored energy and fast-start gas to balance supply and demand.

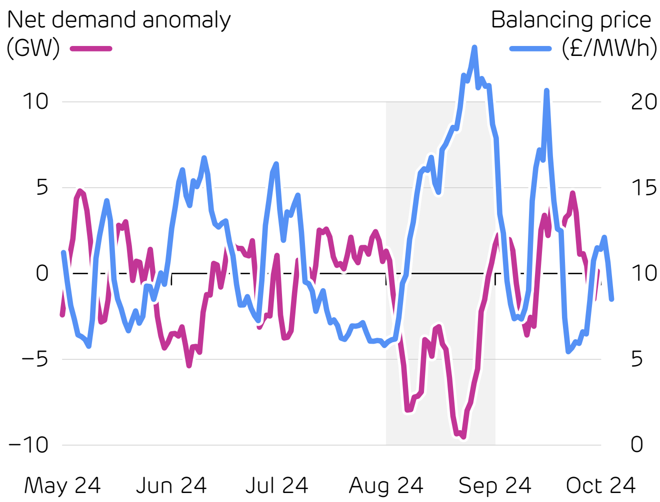
High winds and sunny skies led to the opposite problem in summer. Too much wind and solar generation through August 2024 meant that while wholesale prices were low, keeping the grid in balance was more difficult, and thus more expensive. Wind farms were required to curtail their output extensively, at a cost of over £40 million (the highest monthly total on record). This raises balancing costs which ultimately filter through to consumers.

The weather not only moves prices, but is increasingly damaging Britain's energy infrastructure. Seven named storms hit the UK over the 2024–25 season (April to April). Storm Darragh (6–7 December 2024) left 2.3 million customers without power across Wales and central and northern England, while Storm Éowyn (24 January 2025) left >1 million customers disconnected across Scotland and northern England. Most faults were caused by high winds and/or flooding damage. Localised outages were also caused by extreme rainfall during the summer, and lightning damage during heavy thunderstorms in May.

When renewable output is low and demand is high over winter, wholesale power prices can spike. Net demand refers to electricity demand minus output from wind and solar, and its anomaly means how far net demand deviates from its long-term average.



In contrast, balancing costs can spike during the opposite conditions in summer: when renewable output is high and demand is low.



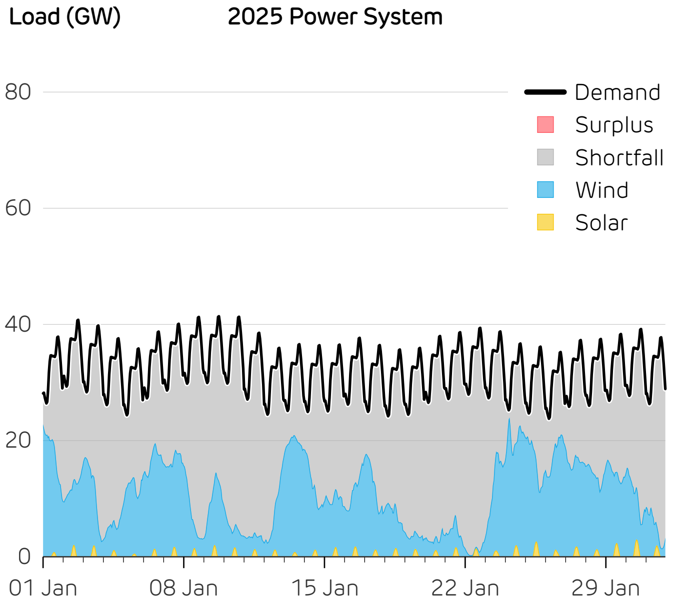
Weather variability will become increasingly important

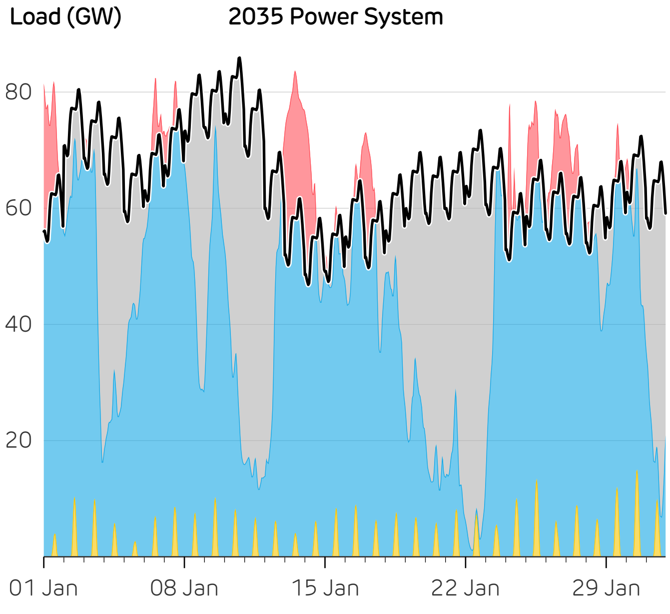
By 2035, wind and solar capacity is expected to more than triple, and electricity demand would be >50% higher as we electrify transport (via electric vehicles) and heating (via heat pumps). The RMetS report tests the resilience of the future power system by modelling how the "dunkelflaute" events of January 2025 would play out. These conditions would be even more challenging for our future clean power system, as higher demand (from electrified heating) would coincide with stalled output from renewables.

Simply building more wind and solar farms is not enough. Even with triple the current capacity, their output would remain minimal on the bleakest days. In 2025 we faced a 35 GW gap between supply from wind / solar and electricity demand, which could be met by the nation's fleet of gas-fired power stations. By 2035 this becomes a 75 GW gap – impossible to meet with our current fleet of power stations. To plug the gap, new technologies are needed: stronger interconnectors, ways to make demand flexible, firm low-carbon generation, and longer-duration types of energy storage, such as pumped hydropower and green hydrogen (see Article 4). One key opportunity for the future power system is the ability to store excess electricity when conditions are favourable (such as on 13 January when it was windy and mild), to be used later when conditions are more challenging (such as the following week when wind output fell close to zero).

Weather's impact on electricity is no longer background noise, it is the driving force behind both prices and outages. As supply and demand become increasingly swayed by the elements, weather-dependent cold, calm, dark spells become the power system's defining tests. The answer is to hedge this risk across both time and space by building in flexibility to harden our power system against future challenges.

The mismatch between demand for electricity and supply from weather-driven renewables during January 2025 (left), and simulated for the power system in 2035 (right). The the red and grey shaded areas show demand net of renewables, which is a core metric that determines how much flexibility is required to 'top up' wind and solar or reduce demand to keep the lights on – the higher the value, the more flexible the system needs to be.



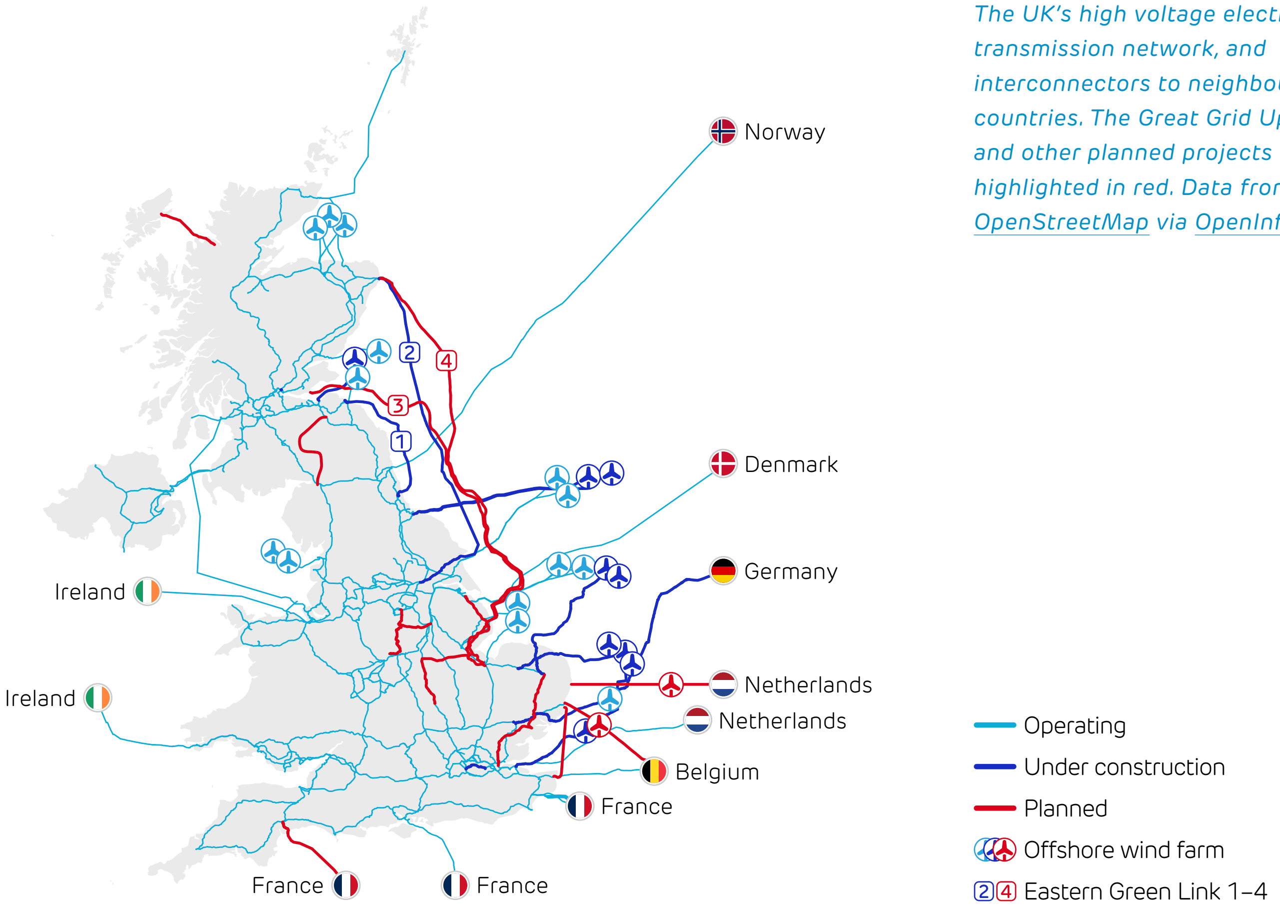


3. The Great Grid Upgrade

Earlier this year, National Grid announced the Great Grid Upgrade: 17 projects that form the largest overhaul since the creation of our modern 'supergrid' in the 1960s. New offshore interconnectors and targeted upgrades to onshore networks, pylons and substations will strengthen the links between Scotland, England and the North Sea to move clean power from where it is generated to where it is needed. At a cost of £19bn, this expansion represents two-thirds of National Grid's planned investments to 2030.

Britain's grid was originally built to transmit electricity from centralised power stations to nearby towns and cities, but the way we produce and use power is changing rapidly. Wind power now provides 30% of Britain's electricity, but is concentrated in windy Scotland and the North Sea, while demand is highest in the densely-populated South East.

Demand for electricity is also set to rise by 50% by 2035 as we turn to electricity for heat and transport, while new AI and data centres come online. This means even more electricity must be shifted around the country. Today, congested transmission lines mean we cannot use all the electricity we generate. This comes at a cost, with consumers paying >£1 billion so far this year to curtail wind farm output that could not be used. With network upgrades, more clean electricity can be used, lowering bills for everyone.



The UK's high voltage electricity transmission network, and interconnectors to neighbouring countries. The Great Grid Upgrade and other planned projects are highlighted in red. Data from OpenStreetMap via OpenInfraMap.

Upgrading electricity networks is like building roads: the more routes there are available, the less likely you will hit traffic on any one route. The Great Grid Upgrade includes four new subsea cables (Eastern Green Links 1–4) to connect Scotland's wind farms to the South and East of England. Other projects include the Sea Link cable from Suffolk to Kent to carry power from the planned Sizewell C nuclear reactor, and reinforcements to various lines throughout the country.

In addition, new interconnectors to France, Belgium, the Netherlands and Germany are planned or under construction, to help smooth out supply and demand over the wider continent. These include Nautilus (to Belgium) and LionLink (to the Netherlands), so-called "offshore hybrid assets", which also connect to offshore wind farms, meaning that power can be sent to whichever country needs it more.

Most of the UK's network upgrades are still in the planning stages, with onshore projects facing strong opposition from local groups concerned about the visual and environmental impacts of pylons. The Norwich-Tilbury transmission line received over 20,000 pieces of community feedback since its consultation launched in 2022, and 40,000 people signed a petition calling for less visible alternatives, resulting in 10% of the line being replaced with underground cables. Similar factors also led to the de-facto ban on onshore wind from 2015–2024, despite it offering the cheapest form of new-build electricity in the UK.

Opposition to new transmission pushes up the cost of electricity, as the alternatives of underground and offshore cables are 4.5 and 11 times more expensive than traditional overhead lines. Extensive delays in planning mean the problem (and cost) of curtailment stays with us for longer. Both the Government and National Grid have rejected large-scale underground cabling, with the Government instead proposing that residents near new pylons receive up to £2,500 off their energy bills over the next decade.

In the short term, the Great Grid Upgrade will mean construction traffic, new pylons on the skyline and billions in upfront costs. But we can learn from the Victorians, who built big with railways and sewer systems that caused disruption at the time, but created a legacy that benefitted the UK for a century since. Rather than continuing to pay to throw clean energy away, then pay again to replace it where it's needed; it is time to build a grid that can see us through for decades to come.

4. Battery storage soars, long-duration storage is next

Energy storage is essential to keep any clean power system running smoothly. Unlike traditional power plants, wind and solar farms cannot be 'dispatched' to meet demand, so storing energy in periods of high renewable output and releasing it when needed is a key pillar of the UK's Clean Power Mission.

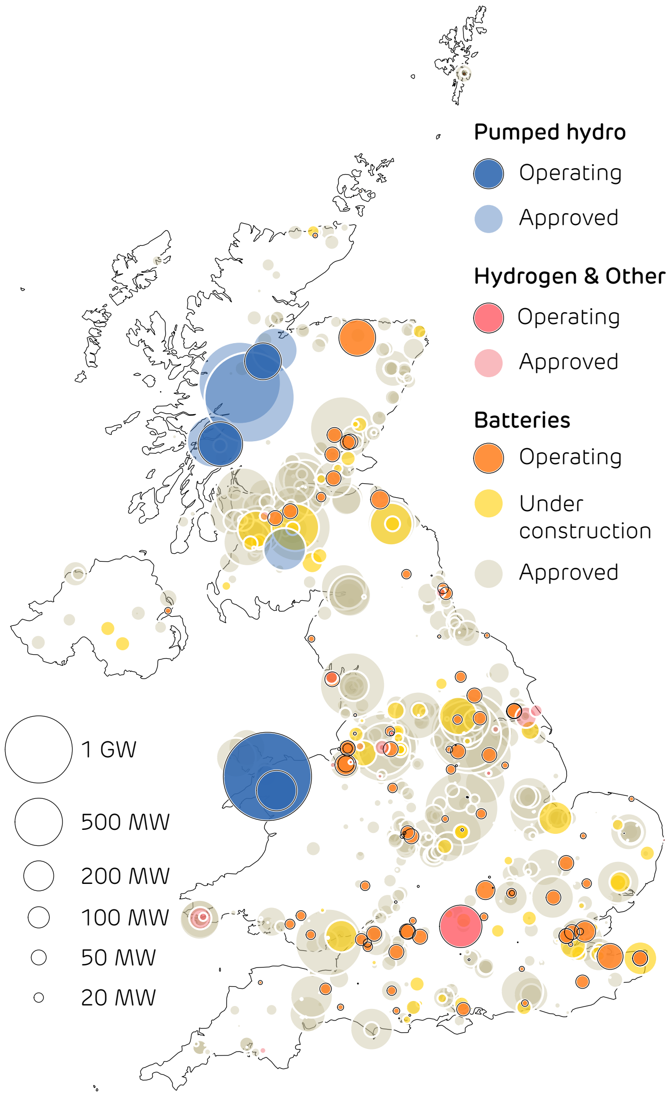
Battery energy storage systems (BESS) are now Britain's largest form of energy storage. They use the same core technology as mobile phones and electric vehicles (lithium-ion cells), but on a much larger scale. Installed BESS capacity has risen sharply over the past decade, from almost nothing in 2015 to over 6 GW today, enough to power 1.3 million homes for a day. BESS operators now make most of their money via arbitrage – buying low and selling high – but they can also "stack" revenues across other grid services (e.g. also providing balancing and frequency response). Falling battery costs and Britain's grid lagging behind renewables expansion have created attractive investments.

The Government expects 23–27 GW of BESS will be needed by 2030 in their Clean Power Action Plan, three to four times current capacity. Industry is well equipped to deliver this, with 45 GW of battery projects consented or under construction. Most existing projects are in England, but Scotland has become a key growth area due to high wind output and tight network constraints (see Article 3).

The UK's largest battery is in Moray, Scotland, with 200 MW of power and 400 MWh of energy capacity, and another 100 MW due to be added in 2026. It was built to ease congestion from nearby offshore wind farms, and could power 50,000 homes for a day. The UK's National Wealth Fund is also planning a £500 million joint venture to deliver 1.4 GW of storage by 2028, with the first projects in Angus, Perth and Kinross.

Batteries can only hold a few hours' worth of electricity. The Moray battery fully charges or discharges in just 2 hours. This means batteries pair well with solar PV's day-night cycle. On the other hand, the UK's wind output varies over days and weeks, while heating demand is highly seasonal. Medium-duration and long-duration storage (MDES and LDES) are needed to support the future energy system and cut our reliance on firing up expensive gas power plants to fill these gaps. The Government anticipates 4–6 GW are needed by 2030 in their Clean Power Action Plan (rising to 11–15 GW by 2050).

The UK's current and future energy storage infrastructure, separated by the class of technology and stage of project development.



The closest we currently have to long-duration energy storage is 2.8 GW of pumped hydroelectric storage, spread across four sites in Wales and Scotland. These use surplus electricity to pump water uphill and release it again to generate electricity when needed. These date from the 1960s to 1980s, and no new pumped hydro has been built in the UK for forty years. A wave of new developments are planned though, with 11 new projects at various stages of development in Scotland and Wales, which could add a combined 10 GW of capacity (200 GWh of energy), one-quarter of Britain's daily demand.

Hydrogen is also a potential option for long-duration energy storage, which could last for weeks or months. Hydrogen can be produced by splitting water using wind or solar power, with the Government targeting 10 GW of low-carbon hydrogen production by 2030. Liquid-air, compressed-air, iron-air batteries, storing heat underground in aquifers, and a whole host of other technologies offer promising options to ride through longer shortfalls in supply.

Unlike BESS, long-duration storage does not present an obvious investment opportunity. Long-duration technologies are more expensive as it is more difficult to store electricity for long periods. They also charge and discharge less frequently (seasonal cycles rather than daily cycles), reducing arbitrage opportunities. Incentives are needed to encourage investment. The Planning and Infrastructure Bill introduced a "cap and floor" scheme to de-risk investments by topping up profits earned by long-duration storage (>8 hours) if they are low (and clawing them back if they are excessive). Applications opened this year and contracted 3–8 GW by 2035. Ofgem has waved a further 77 projects (29 GW) through to the final stage of assessment of the Government's 'super battery' support scheme.

Together with grid expansion and more interconnection, storage is the glue that can hold together abundant renewables and reliable, affordable power. Batteries and long-duration storage solve different problems and need different support. Backing both types of technology, Britain can reduce its reliance on expensive gas, improve energy security, and make clean power dependable year-round.

5. The UK's carbon price surges

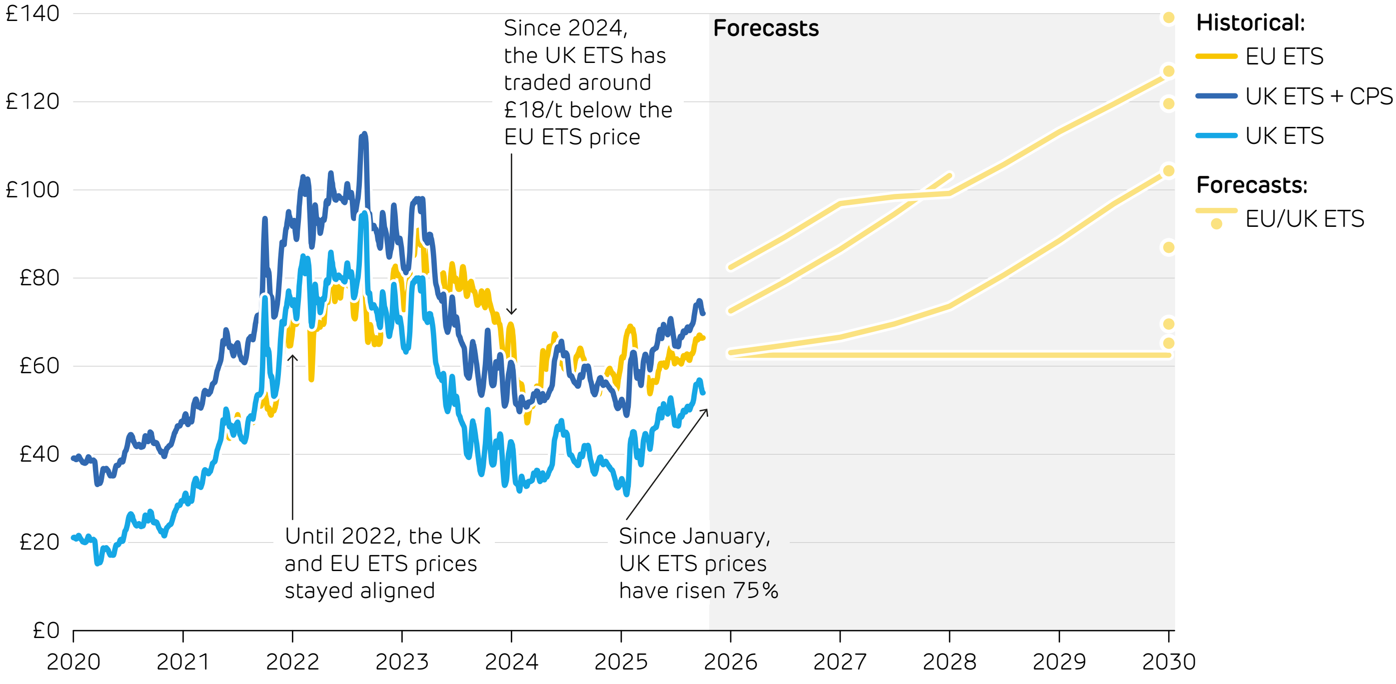
The UK's carbon market, which sets the cost of emitting CO_2, is experiencing a strong rally this year. The carbon price is up 75% since January, pushing up the cost of generating electricity from fossil fuels.

For two decades, the European Union's Emissions Trading Scheme (ETS) has placed a price on emitting carbon, giving companies the incentive to reduce emissions. The UK has run its own carbon market since 2021, separating from the European ETS as part of the Brexit negotiations. Through 2022, UK prices stayed aligned with the much larger European market, as their designs and the strictness of their targets were similar.

UK carbon prices tumbled in 2023, at one point falling to less than half of European prices. The UK's ETS Authority issued more allowances to emit carbon, just as a faltering economy meant actual emissions were lower than anticipated. From 2024, the UK's price settled around £18 per tonne lower than Europe's price. £18 is a special number: it is how much the UK charges in addition to the ETS price for carbon emissions from major power stations.

This £18 'Carbon Price Support' was instrumental in kick-starting the UK's rapid decarbonisation of electricity a decade ago, making coal power more expensive than gas, and making low-carbon alternatives more economically viable. It had a downside though, putting British power stations at a disadvantage against imported electricity. In the first half of 2021, a British gas-fired power station paid £65 for each tonne of CO_2 emitted, but one in Belgium or the Netherlands paid only €44 (£38). In the first half of 2025 this has equalised, with £62 paid in Britain versus €73 (£61) on the continent.

Carbon prices in the UK and Europe, converted to £/tonne. Forecasted prices from OBR, Reuters, BloombergNEF, Enerdata, and Simon Kucher.



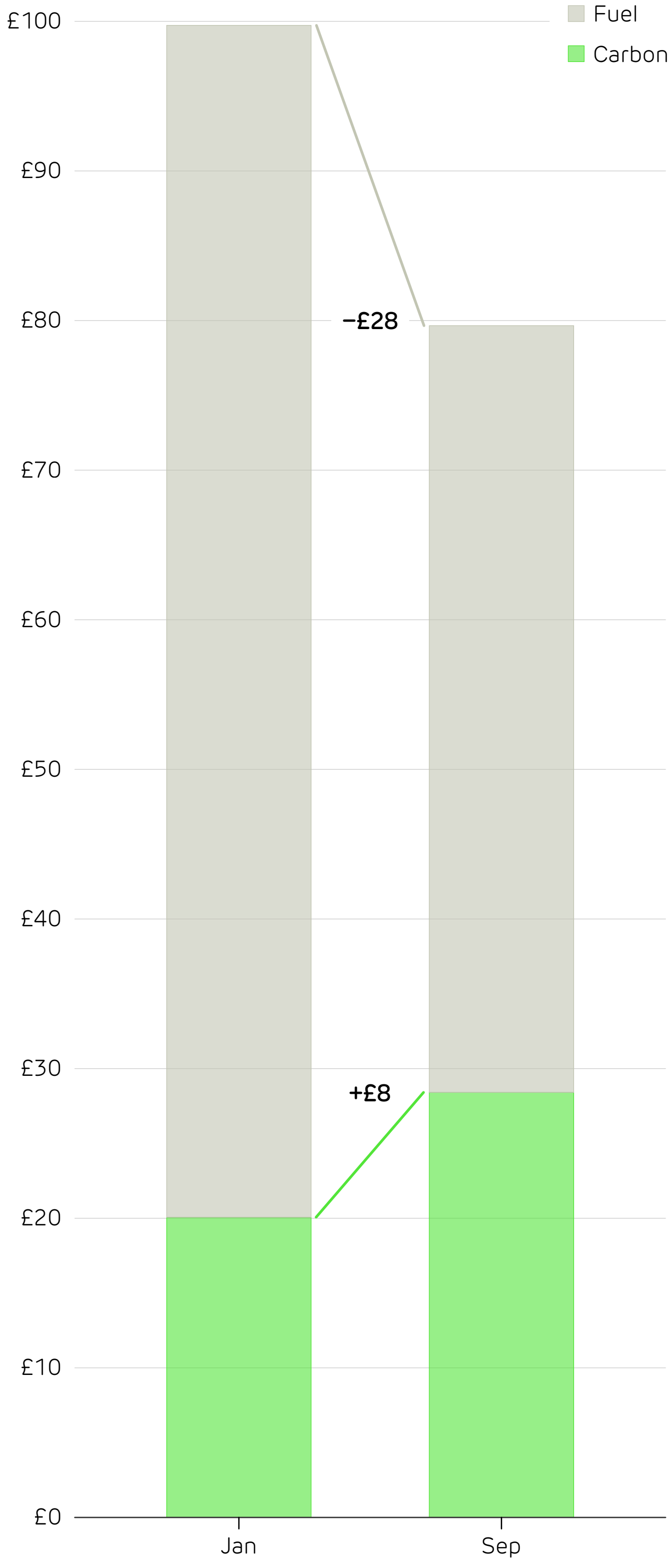
At the end of January this year, the FT reported that talks had begun to rejoin the UK to the EU ETS. The UK carbon price jumped by 13% in a single day. At the UK-EU Reset Summit, both sides committed to take this forwards. Once linked, UK carbon prices would reconverge with those in the EU.

The upshot is that prices have risen by 75% since the start of this year. As every 2.5 MWh of electricity produced from gas power stations produces 1 tonne of CO_2, this is putting upwards pressure on power prices. The rise has been modest though, adding £8/MWh over the last nine months, and has been more than offset by the fall in wholesale gas prices.

Even if European carbon prices stand still, relinking the markets would see UK carbon prices rise by a further 25%. It will reduce red tape though, as British businesses will avoid having to pay Europe's new Carbon Border Adjustment Mechanism (CBAM), which comes into force next year. This will see Europe charge its ETS price on all carbon-intensive imports to the bloc, such as iron and steel, aluminium, fertilisers, and of course, electricity. The link may also add some certainty for businesses, making investments into cross-border projects such as interconnectors look more secure.

Looking forwards, projections for the ETS price point in one direction: up. Analysts see carbon emissions costing anywhere from £60 to £140 per tonne in 2030, as political will to decarbonise ratchets up, and free permits granted to some heavier industries are phased out. This will add further to the cost of generating electricity from gas, but with Government aiming to greatly reduce its share by then, this should have a weaker impact on the prices we pay for electricity.

Changes to the cost of generating electricity from a gas-fired power station in Britain (in £/MWh), between January and September of 2025.



6. Capacity and production statistics

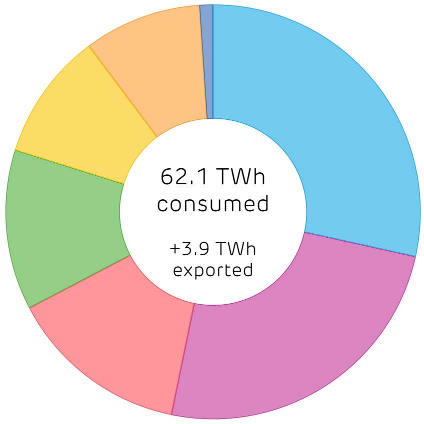
Solar power shone this summer, with output rising 30% year-on-year. Capacity grew by 2 GW over the last twelve months, with projects such as the Cleve Hill Solar Park coming online in Kent. At 373 MW, it is four times larger than any other solar farm in the country, and over the coming months it will be supported by a 150 MW co-located battery.

Greater output from solar, biomass and wind helped to offset nuclear power falling by more than a quarter year-on-year. Britain's nuclear fleet endured new lows, as maintenance and refuelling operations clashed with unplanned faults. Even so, grid emissions stayed near record lows, only slightly higher than summer 2024.

Demand told a different story: reaching 62.1 TWh over the third quarter, up 3.2% year-on-year. This is the fastest pace of growth since 2011, aside from the post-Covid rebound. Electrification continues to accelerate, with battery-electric and plug-in hybrids accounting for one in three new cars sold so far in 2025. Sales were helped by the launch of new models from Chinese carmaker BYD, with the UK now the largest international market for the world's largest maker of EVs.

Finally, 30 September marked the one-year anniversary of Britain's last coal-fired power station being turned off. The power system took its first coal-free year in its stride.

Britain's electricity supply mix in the third quarter of 2025.



	Share of the mix
Wind	28.5%
Gas	24.8%
Imports	14.1%
Nuclear	12.5%
Solar	9.9%
Biomass	9.2%
Hydro	1.1%
Coal	0.0%

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

	Installed Capacity (GW)		Energy Output (TWh)		Utilisation / Capacity Factor	
	2025 Q1	Annual change	2025 Q1	Annual change	Average	Maximum
Nuclear	6.4	~	7.8	−2.9 (−27%)	56%	76%
Biomass	3.8	~	5.7	+0.9 (+19%)	68%	96%
Hydro	1.2	~	0.7	−0.1 (−7%)	25%	72%
Wind	31.9	+1.6 (+5%)	17.7	+1.0 (+6%)	26%	67%
– of which Onshore	14.9	+0.1 (+1%)	7.2	+0.1 (+2%)	22%	54%
– of which Offshore	17.0	+1.5 (+10%)	10.9	+1.4 (+14%)	30%	61%
Solar	19.8	+2.0 (+11%)	6.2	+1.4 (+30%)	14%	72%
Gas	27.6	~	15.4	+1.5 (+11%)	26%	68%
Coal	0.0	~	0.0	~	~	~
Imports	9.2	~	11.7	+0.7 (+6%)	58%	96%
Exports			3.9	+0.9 (+32%)	19%	71%
Storage discharge	3.1	~	0.2	−0.2 (−52%)	3%	100%
Storage recharge			0.2	−0.3 (−54%)	4%	64%

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.

7. Power system records

Summer delivered a string of extremes on Britain's power system. Solar passed the 14 GW mark for the first time on 8 July, leaping above the previous 13.2 GW record. Meanwhile, biomass set a monthly record in supplying 9% of the country's electricity during July. Interconnectors ramped up on 24 August, importing more than 30% of Britain's demand over the day, the highest on record. An abundance of clean electricity on 6 September saw negative prices plunge to a new low of –£99/MWh, as over 23 GWh of wind output had to be curtailed, costing consumers more than £1.1 million. Finally, nuclear generation slumped to its lowest output this century, dipping below 2 GW on 24 September, as a short-lived trip compounded longer unit outages.

The tables below look over the past sixteen years (since 2009) and report the record output and share of electricity generation, plus sustained averages over a day, a month, and a calendar year. Cells highlighted in blue are records that were broken in the third quarter of 2025. Each number links to the date it occurred on the Electric Insights website, so these records can be explored visually.

Wind – Maximum	Output (MW)	Share (%)
Instantaneous	22,545	72.1%
Day average	21,687	61.2%
Month average	14,525	40.4%
Year average	9,414	29.6%

Solar – Maximum	Output (MW)	Share (%)
Instantaneous	14,035	43.2%
Day average	4,909	17.0%
Month average	3,415	11.5%
Year average	1,512	4.8%

Biomass – Maximum	Output (MW)	Share (%)
Instantaneous	3,831	17.0%
Day average	3,547	12.9%
Month average	2,926	9.1%
Year average	2,216	7.1%

All Renewables – Maximum	Output (MW)	Share (%)
Instantaneous	31,698	83.4%
Day average	24,262	71.5%
Month average	18,334	51.7%
Year average	13,476	42.4%

Gross demand	Maximum (MW)	Minimum (MW)
Instantaneous	60,070	16,934
Day average	49,203	23,297
Month average	45,003	26,081
Year average	37,736	29,910

Demand (net of wind and solar)	Maximum (MW)	Minimum (MW)
Instantaneous	59,563	1,365
Day average	48,823	6,292
Month average	43,767	15,229
Year average	36,579	19,389

Day ahead wholesale price	Maximum (£/MWh)	Minimum (£/MWh)
Instantaneous	1,983.66	-99.01
Day average	666.90	-11.35
Month average	353.36	22.03
Year average	198.16	33.88

Carbon intensity	Maximum (g/kWh)	Minimum (g/kWh)
Instantaneous	704	6
Day average	633	28
Month average	591	78
Year average	508	121

All low carbon – Maximum	Output (MW)	Share (%)
Instantaneous	39,126	97.0%
Day average	30,599	90.1%
Month average	23,941	75.5%
Year average	20,058	63.1%

All low carbon – Minimum	Output (MW)	Share (%)
Instantaneous	3,395	8.3%
Day 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%
Day 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	887	2.4%
Day average	1,990	6.2%
Month average	4,831	16.8%
Year average	8,474	26.6%

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

Nuclear – Minimum	Output (MW)	Share (%)
Instantaneous	1,955	5.0%
Day average	2,238	5.9%
Month average	2,964	8.9%
Year average	4,368	13.7%

Coal – Maximum	Output (MW)	Share (%)
Instantaneous	26,044	61.4%
Day 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%
Day average	0	0.0%
Month average	0	0.0%
Year average	179	0.6%

Gas – Maximum	Output (MW)	Share (%)
Instantaneous	27,339	73.4%
Day average	24,906	64.5%
Month average	20,828	54.8%
Year average	17,930	46.0%

Gas – Minimum	Output (MW)	Share (%)
Instantaneous	738	1.8%
Day average	1,874	5.9%
Month average	4,748	16.5%
Year average	8,276	24.6%

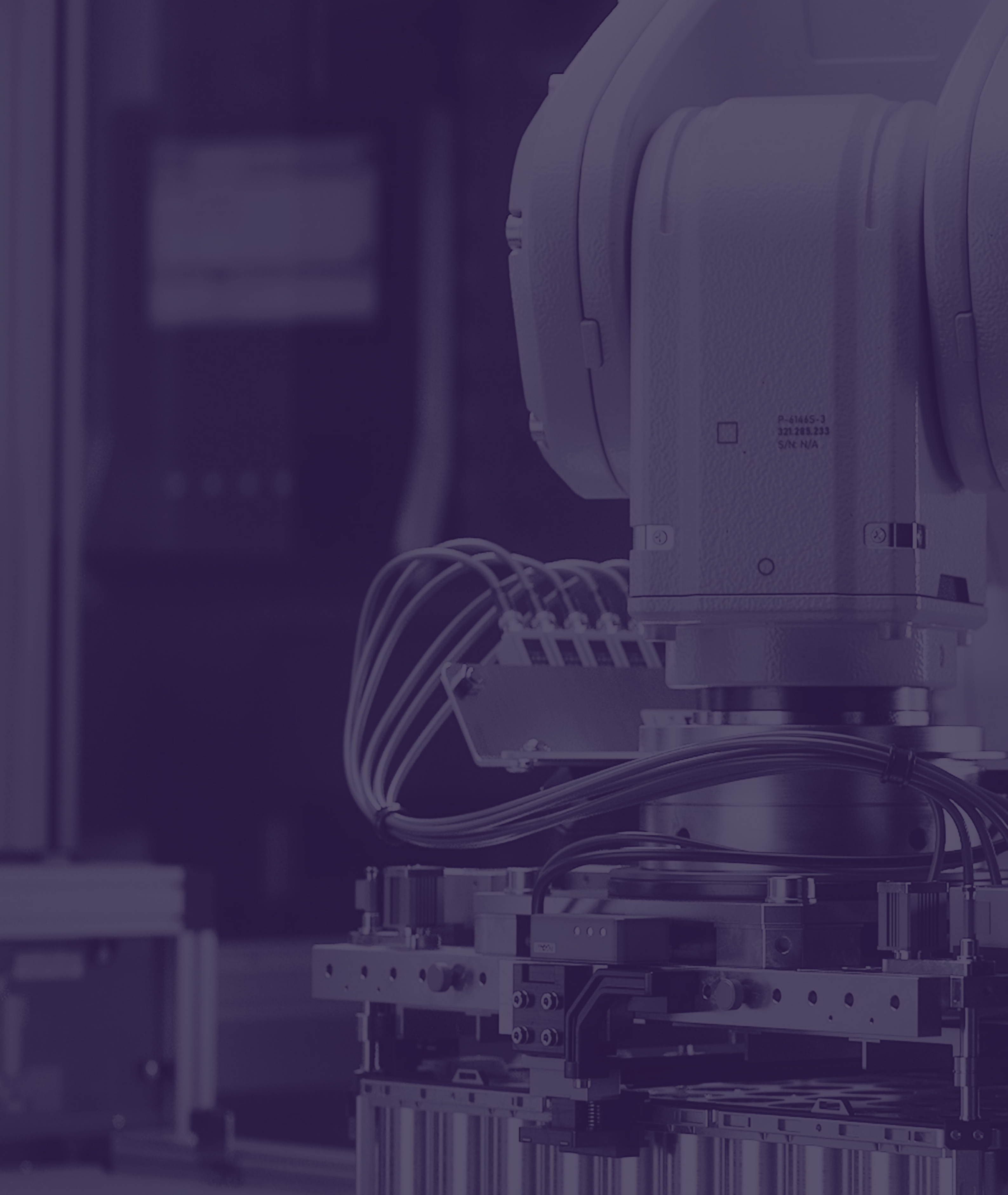
Imports – Maximum	Output (MW)	Share (%)
Instantaneous	8,055	38.4%
Day average	7,299	30.0%
Month average	5,557	20.8%
Year average	4,990	15.7%

Exports – Maximum	Output (MW)	Share (%)
Instantaneous	-5,662	–27.0%
Day average	-4,763	-14.1%
Month average	-3,098	-9.8%
Year average	–731	-5.8%

Pumped storage – Maximum[3]	Output (MW)	Share (%)
Instantaneous	2,660	7.9%
Day average	409	1.3%

Pumped storage – Minimum[3]	Output (MW)	Share (%)
Instantaneous	–2,782	–12.2%
Day average	–622	–4.5%

3 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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