July to September 2017

Electric Insights Quarterly

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Headlines & summary

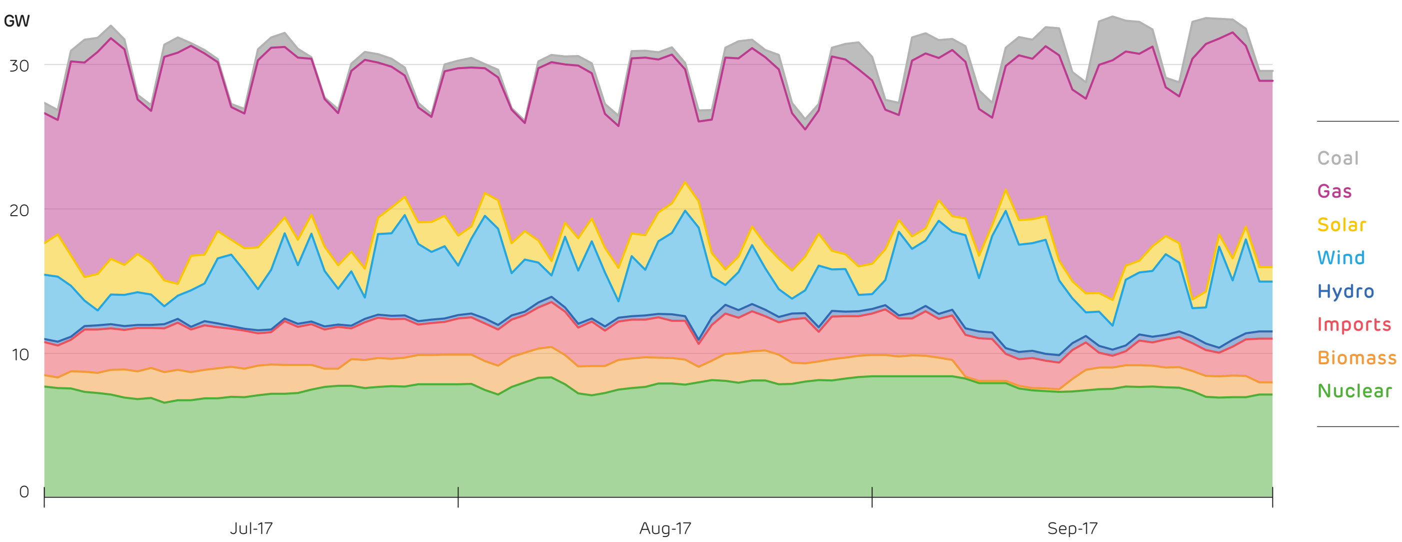
This quarter's issue looks at how Britain's power system decarbonisation compares globally, and how it can be taken further. We unveil the international league table for low carbon electricity in Article 1, which charts the carbon intensity of electricity production across 33 countries. In the last four years, Britain has jumped 13 places to have the 7th cleanest major power system.

National Grid released the world's first grid carbon forecast: predicting the cleanest times to use electricity over the coming 48 hours. Article 2 looks at how this could underpin new services that enable people and businesses to shift when they consume electricity and lower their carbon emissions by up to 25%.

Article 3 charts the growing importance of imports: 9% of Britain's electricity was generated overseas during July and August. But as we import electricity, we export emissions. Britain's power system has decarbonised to the point that imports now raise the average carbon content of our electricity. Article 4 follows on by looking at the future of Britain's interconnectors, and the regulatory uncertainty they face from exiting the European Union.

The last three months were relatively quiet for the power system after several records were broken in Quarter 2. The generation mix was unchanged, and coal output remained at historic lows (see Article 5). Low-carbon sources edged upwards slightly to 55% of the mix despite wind and solar output being down on last quarter (due to the weather), and a week of zero output from transmission-connected biomass plants in September (due to maintenance). Prices were uneventful, with no spikes above £200/MWh, and only 13 hours with zero or negative prices. Article 6 rounds up the statistics for the quarter.

Daily generation mix over the quarter



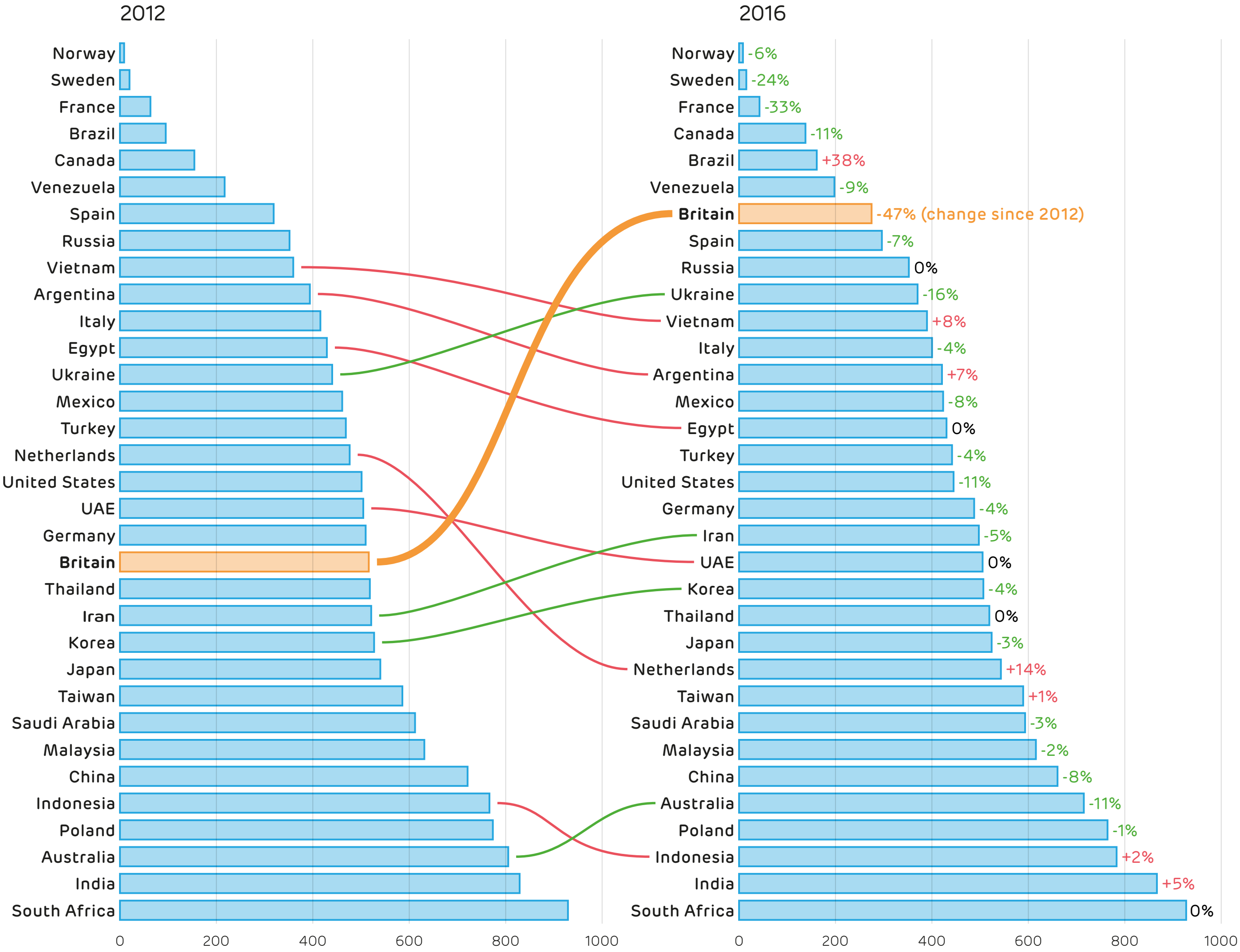
The low carbon electricity league table

In its first year, Electric Insights charted the rapid changes that are cleaning up Britain's power system. Carbon emissions from electricity halved in the last four years thanks to the growth of renewable energy, and the switch from coal to gas driven by the UK's carbon price. But how does Britain's power sector compare to other major countries?

We compiled data on the generation mix and the resulting carbon intensity of the world's largest power systems, and rank them in the chart below. Britain's pace of decarbonisation is unrivalled: the carbon intensity of electricity production has fallen more than twice as fast as any other major country.[2] This comes as PwC report that the UK came top of their 2017 Low Carbon Economy Index.

The low carbon electricity league table for 2012 and 2016.[1] The 33 countries which produce over 100 TWh of electricity per year are ranked by their carbon intensity of production. Lines show countries which have moved by more than one place in the ranking.

Electricity carbon intensity (g/kWh)



1 Compiled using data from: Electric Insights, IEA CO_2 Emissions from Fuel Combustion, IEA World Energy Balances, EIA Electric Power Monthly, Arbeitsgemeinschaft Energiebilanzen, EuroStat Energy Statistics and BP Statistical Review of World Energy.

The energy sector is conservative and usually slow to change as infrastructure has long lifetimes. While Britain's carbon intensity halved, most other countries have only moved by 10% over the last four years.

In 2012, Britain was ranked 20th out of 33. In the four years since, Britain has jumped 13 places to become 7^{th}. The most any other country has moved was 8 places by the Netherlands – and that was in the wrong direction.

While coal generation in Britain fell 80% between 2012 and 2016, it rose by 40% in the Netherlands. Coal usage has increased in the Netherlands specifically as three new coal power stations were built there recently. Another thing that separates these countries is the Carbon Price Floor – Britain charges £23 per tonne of CO_2 versus just £5 per tonne on the continent. Weakening or scrapping the carbon price now could see Britain slide back down the table just as fast as it climbed.

Most countries in the ranking lie in the region of 400 to 600 g/kWh. Four years ago, Britain sat centrally among the mid-table countries from Italy to Saudi Arabia, which are powered by various mixes of coal, gas and nuclear, hydro and other renewables. India and South Africa have the dirtiest power sectors, powered by 75–90% coal. The top six are all under 200 g/kWh, and are either mountainous countries blessed with substantial hydropower resources, or heavily rely on nuclear power (France has 58 reactors).[3]

The make-up of the top six suggests it could be difficult for Britain's electricity to decarbonise much further without a massive shift in either geography or opinion towards infrastructure megaprojects. Nonetheless, Britain's example shows just what can be achieved in four years with a modest price on carbon emissions.

2 Britain's carbon intensity fell by 241 g/kWh from 516 to 275 g/kWh. The next largest fall was 90 g/kWh in Australia (805 to 715 g/kWh). France and Sweden also registered large percentage decreases, but only fell by 21 and 5 g/kWh in absolute terms, as they started with such clean systems.

3 Note that hydro output varies from year to year with the level of rainfall, hence these countries register large changes (in percentage terms) as more or less backup power from fossil fuels is required. 2012 was a wet year for Brazil, so its carbon intensity was unusually low, hence the higher carbon intensity in 2016.

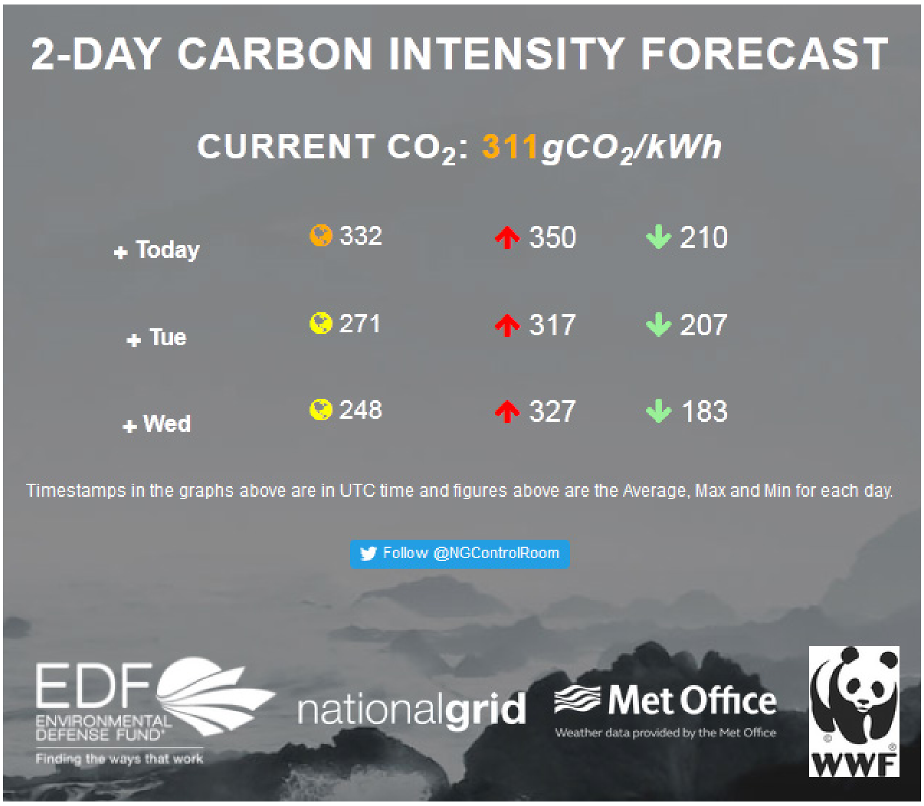
The low carbon forecast*

The world's first low-carbon electricity forecast enables people to use power when it is cleanest. In September, National Grid in partnership with Environmental Defense Fund Europe and WWF launched the carbon intensity forecast, a website that estimates the CO_2 emissions from consuming electricity over the coming 48 hours.

This combines National Grid and Met Office data to forecast the generation mix, and the Electric Insights methodology to estimate the resulting carbon emissions.[4] Carbon intensity data is estimated every half hour, with an accuracy typically better than ±10%, depending on the weather and forecast errors in demand, wind and solar generation.

Turning this information into real-world carbon savings requires people and businesses to be flexible on when they run their appliances (from washing machines and electric vehicles to steel furnaces). The unreliable British weather makes it hard enough to plan when to do the laundry – and very few people will have the time and dedication to routinely check the 'carbon forecast' as well. National Grid therefore provide their forecast through an API[5] that allows developers to build new apps and products to help people and firms optimise when to use electricity. Just as the 'internet of things' means you can now automate your home's heating and lighting, soon you may also be able to control your carbon footprint without thinking about it.

The carbon intensity forecast website, showing the average, maximum and minimum carbon intensity over the coming days



* The views and opinions expressed in this article are those of the authors and do not necessarily represent those of, or constitute an endorsement by, National Grid.

4 The service uses National Grid's latest forecasts for national electricity demand, embedded wind and solar generation, and data from Elexon and the Met Office to forecast carbon intensity for each technology. Emissions are estimated for all large metered power stations, interconnector imports, transmission and distribution losses. See https://github.com/carbon-intensity/methodology for more detail.

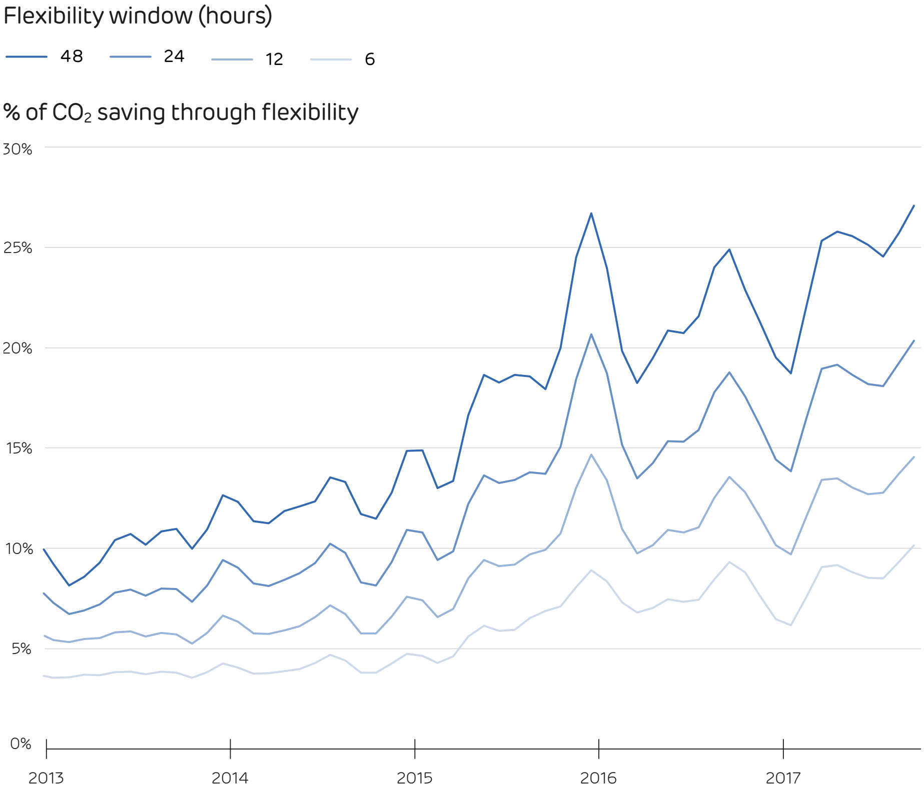
5 API: Application programming interface

It is challenging to estimate the size of 'the prize': how much carbon could be saved from people changing when they consume electricity. On the individual level, delaying your consumption reduces the output of a flexible 'marginal' generator at one time, but increases output from another generator later on. This is likely to be a similar flexible generator (probably gas-fired), as changing when you wash your clothes will not affect when the wind blows.

However, widespread load-shifting across the country would allow low-carbon baseload generators to have longer running hours, and mean less need for diesel and coal peaking plants. It would also smooth out power prices between peak and off-peak times, reducing trading risk for all market participants. Ultimately, this could allow the system to absorb more intermittent renewable energy, thus lowering emissions.

In the long-term, if load shifting altered the average grid mix, this service could lower the carbon emissions from electricity consumption by up to a quarter. The historic Electric Insights data lets us estimate what a perfectly flexible consumer could save by delaying their consumption until the lowest-carbon period. Being flexible over 12 hours would allow electricity to be consumed with 14% lower carbon intensity on average. Extend this to 48 hours and the saving is 25%. These savings are growing as the carbon intensity of Britain's electricity swings more widely with renewables output.

How much carbon could be saved by shifting electricity consumption to the period with lowest carbon intensity? The average CO_2 savings for each month over the last five years, based on the maximum time window for load-shifting.



Importing electricity, exporting emissions?

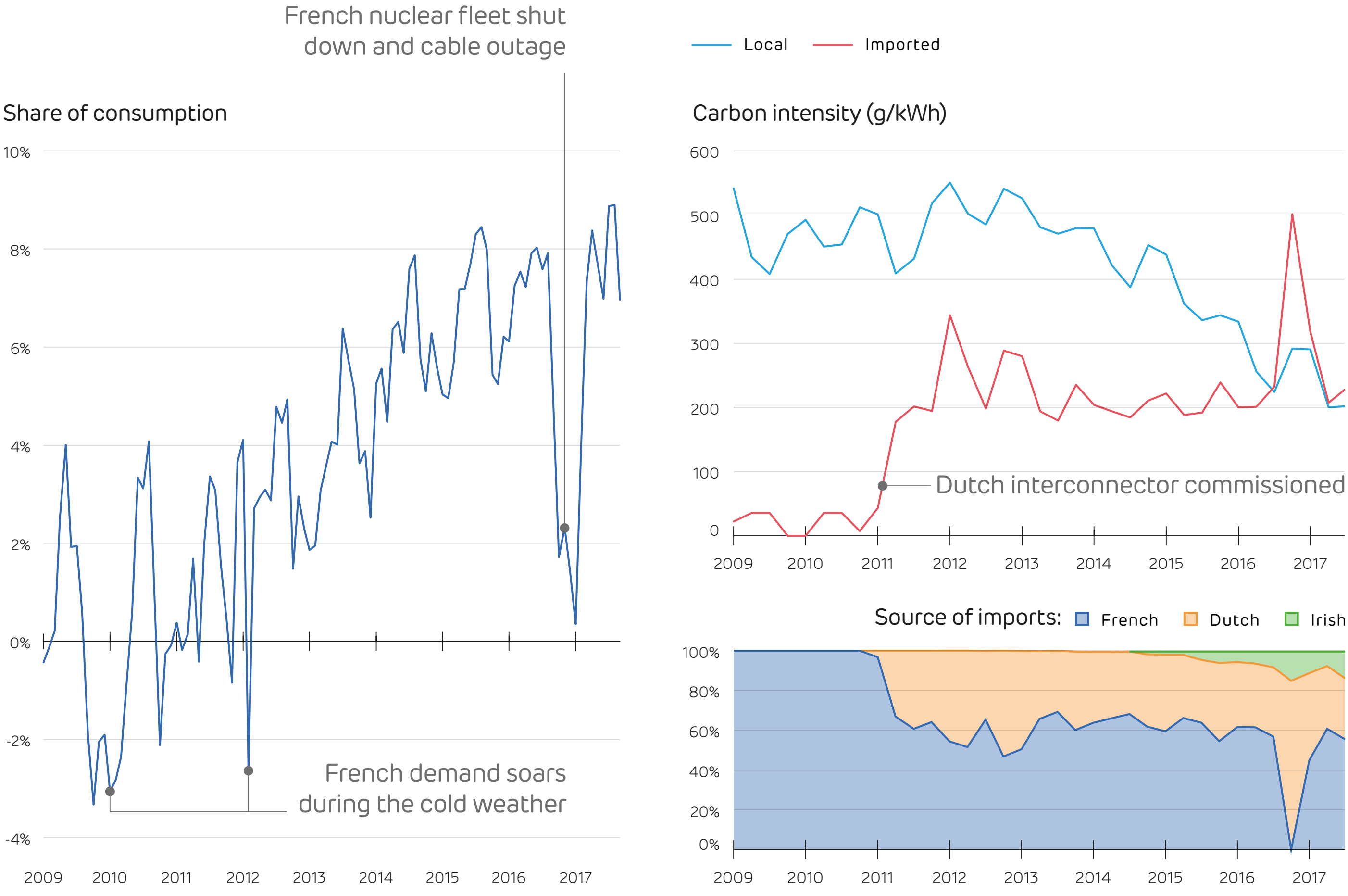
Imports of electricity into Britain are at record highs: 9% of the electricity we used in July and August was generated overseas. Debates around energy imports normally focus on oil from the Middle East or gas from Russia[6]; however, electricity from Europe is becoming ever more significant. In Q3, Britain sourced 5.6 TWh of electricity from abroad, enough to power 7.2 million homes. 60% of this came from France, 30% from the Netherlands and 10% from the island of Ireland.

Even though a smaller share comes from Ireland and the Netherlands, they rely heavily on fossil fuels. So much so that Britain's imports had a 30% higher carbon intensity than locally generated power (314 vs 245 g/kWh over the last twelve months). It is unclear whether these imports actually raised global CO_2 emissions though. We could not have increased output from wind, solar, biomass and nuclear instead of importing; the extra electricity would likely have come from coal and gas.

Imports are expected to become a larger part of the mix in future as more links to France, Norway and Denmark are built. National Grid anticipate that we could import 10–24% of our electricity in just five years' time. We need to ensure this supports the continuing decarbonisation of electricity, rather than simply 'offshoring' our emissions.

6 Note that Britain does not directly import any gas from Russia; the majority comes from Norway and Qatar according to BEIS.

Britain's dependence on imported electricity (left). The carbon intensity of British and imported electricity (top-right). The source of Britain's imported electricity (bottom-right).



The future of Britain's interconnectors

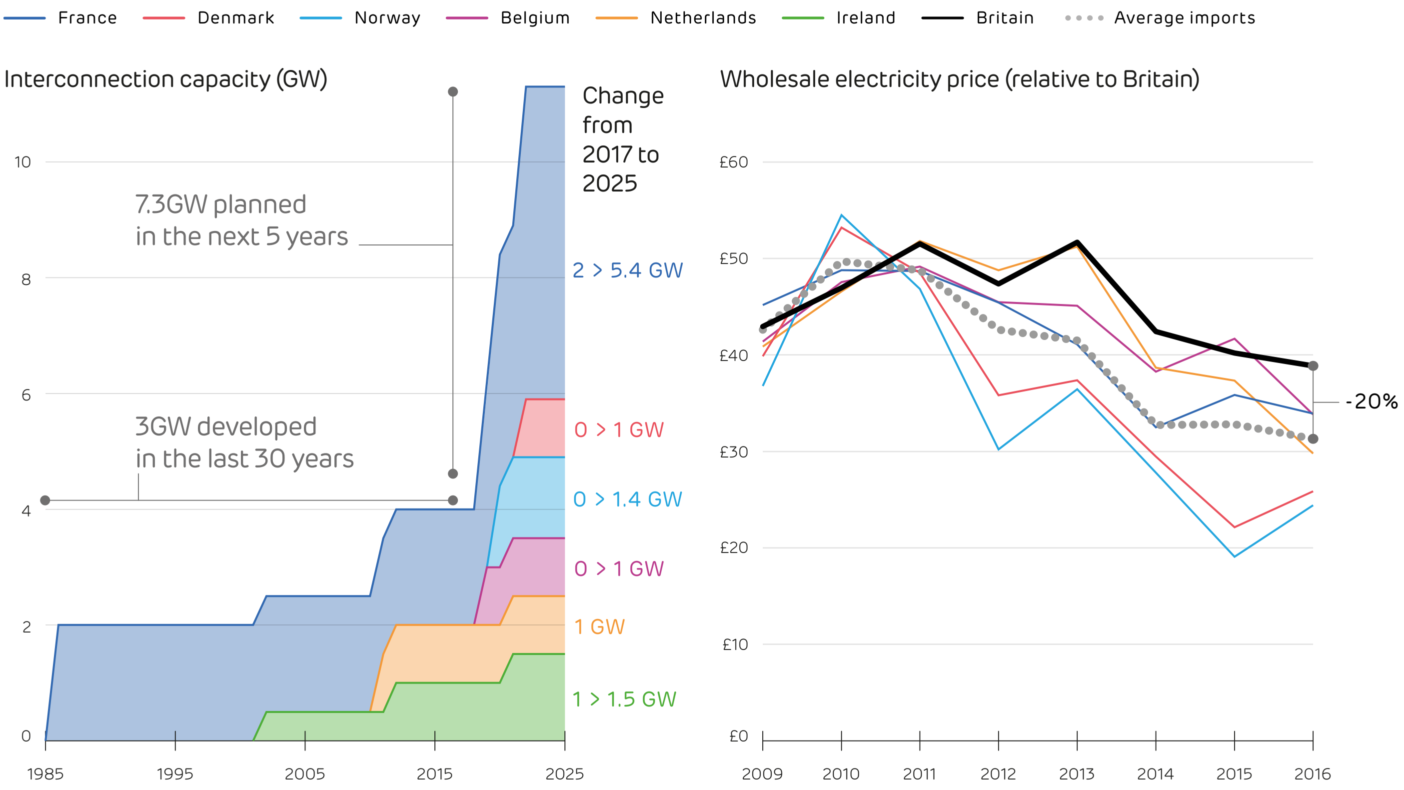
Electricity imports grow ever more important, yet several questions hang over the future of Britain's interconnectors: not least the impacts of Brexit. The UK is part of Europe's internal energy market (IEM) which allows prices to determine how power flows between countries. This future is unclear as participation is based on membership of the European single market, and no specific trade rules have been announced for the post-Brexit energy sector.[7]

Leaving the IEM would revert us back to less efficient interconnector trading. Uneconomic trades (buying dear, selling cheap) could occur up to 20% of the time[8], leading to higher consumer bills[9]. Also, the UK has been the fourth highest recipient of European funds for energy infrastructure, with its interconnectors being awarded 17 out of 195 EU Projects of Common Interest (PCIs) and 12% (£100m) from the European Energy Programme for Recovery (EEPR).

7 GW of new interconnector capacity is planned to be built over the next 5 years, almost tripling the current 4 GW of links (see figure, left). These will provide greater flexibility as weather-dependent renewable sources continue to grow, and greater security of supply whilst coal and nuclear capacity is rapidly retiring. British consumers have arguably benefitted from lower bills as our exporting neighbours have 20% lower electricity prices (see figure, below). Together, these benefits are predicted to reach £500 million per year by 2020[10].

7 UK Government, 2017, The United Kingdom's exit from and new partnership with the European Union.
8 Reuters, 2017, Power market coupling boosts chance of UK-Norway cable – Statnett.
9 UK Parliament, 2017, Leaving the EU: negotiation priorities for energy and climate change policy.
10 Vivid Economics, 2016, The impact of Brexit on the UK energy sector.

The historic and anticipated growth of interconnection capacity to Britain[11] *Electricity prices in these countries compared to in Britain (right)[12]*



11 Ofgem, 2017, Electricity interconnectors.
12 Prices in the Republic of Ireland are not accessible for the selected timeframe, but are likely to be higher than in continental Europe.

However, this has led to Britain importing high-carbon electricity from Dutch and Irish generators. Overseas fossil-fuel generators benefit from an uneven playing field in two ways. British power stations must pay the Carbon Price Floor (£18 per tonne of CO_2) on top of the £5/tCO_2 European ETS price paid by imported electricity. This disadvantage for British power stations will diminish if and when the ETS price strengthens. Applying a levelling border tax on electricity would be administratively difficult, and so Britain's price floor should be maintained to continue our decarbonisation objective.

Secondly, British generators pay to access the national grid (via TNUoS charges)[13], but imported electricity does not. These charges pay for transmission infrastructure, and could instead be paid directly by electricity consumers so that generators don't face different charges depending on their nationality. This may prove easier than requiring European generators to pay TNUoS charges, as it is unlikely the EU would allow a single country to levy charges on European generators.

Together these exemptions give European generators an estimated £10/MWh advantage over domestic generators, around a fifth of the market price. The UK must therefore come up with a feasible way to ensure electricity flows efficiently between borders to keep down costs and carbon emissions. If the markets either side of an interconnector have different charging arrangements, the outcome cannot be efficient.

13 TNUoS: Transmission Network Use of System

Coal output bottoms out

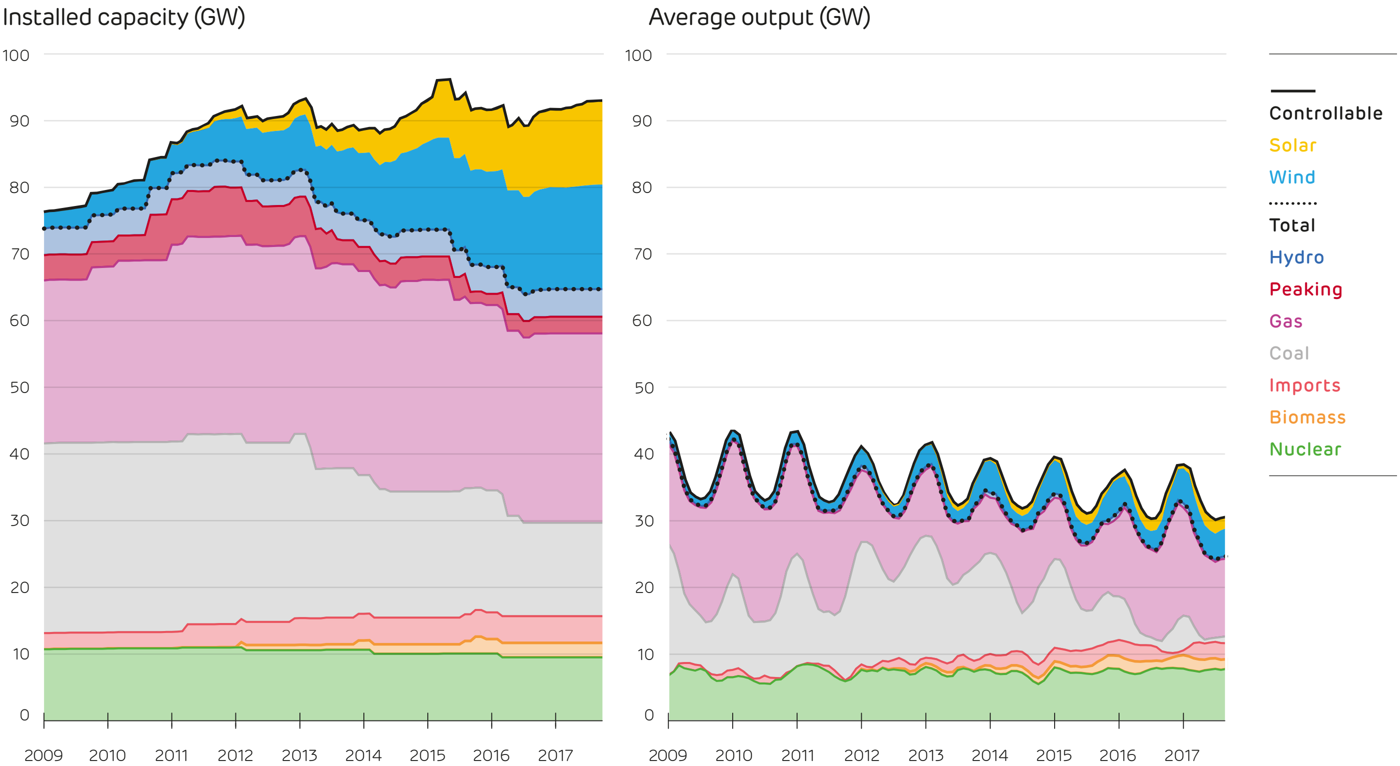
Coal generation remained historically low with just a 1.9% share of generation over the summer. Between April and August Britain's 14 GW of coal stations produced just 0.6 GW on average. This rose to 1.4 GW in September as demand started rising, suggesting that coal is now practically a winter-only fuel used to meet peak demand.

Averaged over this quarter, only 6% of the installed coal capacity was used. However, on the 19th of September 40% of the coal fleet was called upon to produce 5.7 GW. This highlights the need to retain spare capacity for times of peak demand.

Britain's mix of installed capacity and its production have evolved dramatically over the last eight years (see below). Part of coal's decline is due to the wave of retirements over the last five years. Coal capacity fell from 28 GW in 2012 to 14 GW in 2016, either because plants reached the end of their lifetime, became uneconomical, or were forced to close because of clean air legislation.

The amount of controllable capacity (which can be dispatched when needed) has fallen by 20 GW since its peak in 2012, despite total capacity having increased since then. The difference in scale between capacity and output is most obvious for renewables. The 28 GW of installed wind and solar capacity produces less energy than the 9 GW of installed nuclear power.

The capacity mix (left) and output mix (right) in Britain over the last eight years.
Capacity is shown at the end of each month, output is the 3-month rolling average.



Capacity and production statistics

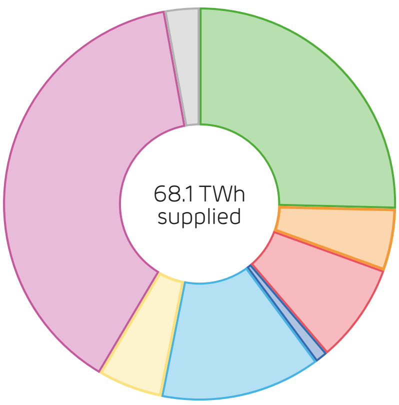
It was an uneventful three months for Britain's power system, looking very similar to Quarter 2. Low carbon sources continued to supply more electricity than fossil fuels, generating 33.5 TWh over the quarter, compared to 30 TWh from gas and coal. Coal formed less than 3% of generation over the quarter. 4 in 5 days saw more output from wind than coal, more from solar than coal, and more from biomass than coal.

The share of low-carbon generation reached a new high of 55.0%, slightly up from 54.7% in Quarter 2. Output from all renewable sources was up on last year, with wind and biomass both increasing by over 30%.

Demand was unchanged from this quarter last year, marking a brief pause in the 1–2% annual decline seen since 2005. Temperatures were 1.3°C lower than this time last year, prompting more demand from electric heating.

Electricity consumption resulted in carbon emissions of 13.6 million tonnes of CO_2, of which 1.3 Mt were produced abroad. The carbon intensity of electricity averaged 202 g/kWh, one-fifth lower than the average over the last twelve months. Total emissions are down from 15.0 Mt in Q3 last year, and 22.2 Mt the year before. The lowest instantaneous carbon intensity was 95 g/kWh, and 250 hours had a carbon intensity of below 150 g/kWh.

Britain's electricity supply mix in the third quarter of 2017



	Output (TWh)	% of mix
Nuclear	16.9	25.4%
Biomass	3.4	5.2%
Imports	5.5	8.2%
Hydro	0.7	1.1%
Wind	8.8	13.3%
Solar	3.6	5.4%
Gas	25.7	38.6%
Coal	1.9	2.9%

Installed capacity and electricity produced by each technology[14]

	Installed Capacity (GW) 2017 Q3	Annual change	Energy Output (TWh) 2017 Q3	Annual change	Utilisation / Capacity Factor 2017 Q3	
					Average	Maximum
Nuclear	9.5	~	16.9	−0.6 (−4%)	81%	89%
Biomass	2.2	~	3.4	+1.0 (+38%)	72%	98%
Hydro	1.1	~	0.7	+0.0 (+2%)	30%	77%
Wind	15.7	+0.7 (+5%)	8.8	+2.2 (+33%)	26%[15]	69%
Solar	12.4	+0.9 (+8%)	3.6	+0.2 (+5%)	13%	67%
Gas	28.4	+0.1 (+1%)	25.7	–3.3 (–11%)	42%	76%
Coal	14.0	~	1.9	−0.4 (–17%)	6%	40%
Imports	4.0	~	5.5	+0.6 (+12%)	63%	94%
Exports			0.0	−0.2 (–95%)	0%	26%
Storage	3.1	~	0.6	−0.1 (–10%)	9%	63%

14 Other statistical sources give different values because of the types of plant they consider. For example, BEIS Energy Trends records an additional 900 MW of wind, 600 MW of biomass and 500 MW of solar, respectively producing 1.4, 1.2 and 0.2 TWh extra per quarter. These plants and their output are not visible to the electricity system and so cannot be reported on here.

15 These are the raw values from National Grid and Elexon, and may differ from other sources (such as BEIS or DUKES) due to which farms are included in the data and the estimation of installed capacity.

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