# The contribution of taxes, subsidies and regulations to British electricity decarbonisation

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## Abstract

Great Britain's carbon emissions from electricity generation fell by two-thirds between 2012 and 2019, providing an important example for other nations. This rapid transition was driven by a complex interplay of policies and events: investment in renewable generation, closure of coal power stations, raising carbon prices and energy efficiency measures. Previous studies of the impact of these simultaneous individual measures miss their interactions with each other and with exogenous changes in fuel prices and the weather. Here we use Shapley values, a concept from cooperative game theory, to disentangle these and precisely attribute outcomes ($CO_2$ saved, changes to electricity prices and fossil fuel consumption) to individual drivers. We find the effectiveness of each driver remained stable despite the transformation seen over the 7 years we study. The four main drivers each saved 19–29 $MtCO_2$ per year in 2019, reinforcing the view that there is no 'silver bullet', and a multi-faceted approach to deep decarbonisation is essential.

# Main text

Carbon dioxide emissions from electricity generation in Great Britain have fallen by 66% between 2012 and 2019 – a faster decline than in any other country[1] (see Figure 1). The UK government adopted all the standard policy responses to a negative externality: taxes, subsidies and regulations. Polluters pay a price for carbon emissions, through the EU Emissions Trading System and the UK's Carbon Price Support. Substitutes for fossil-fuelled electricity are subsidised via several schemes supporting renewable generation and energy efficiency. Regulations to reduce acid rain had the effect of closing 40% of high-carbon power stations (11 GW)[2]. The relative contribution of these policies towards decarbonisation is unknown as they happened simultaneously, interacted with one another, and were muddied by exogenous effects such as changing fuel prices and the weather.

In this study, we estimate the emissions reductions that can be attributed to the above changes that took place, along with their impact on wholesale electricity prices and consumption of fossil fuels. We calculate Shapley Values from repeated runs of an electricity dispatch simulation with different combinations of changes activated. The Shapley Value is a concept from cooperative game theory that allocates the benefits created by individual players when they come together in a coalition. We replace "players" by changes to the electricity system, and define "outcomes" as changes in carbon emissions, prices and fossil fuel consumption.

This incorporates all the interactions between drivers, as for example the effect of closing coal plants added to that of (separately) raising carbon prices will differ from the impact of doing both together. In doing so, our method avoids the under- or over-allocation which can happen with current methodologies. We show the relative importance of the changes we document, over the entire period and in each year. Emissions rose in 2013 when coal became cheaper relative to gas, and the steadily rising British carbon price had more impact in reducing emissions than the fluctuating price of European emissions allowances. Among renewable generators, the increase in onshore wind had the greatest overall impact and solar PV the smallest.

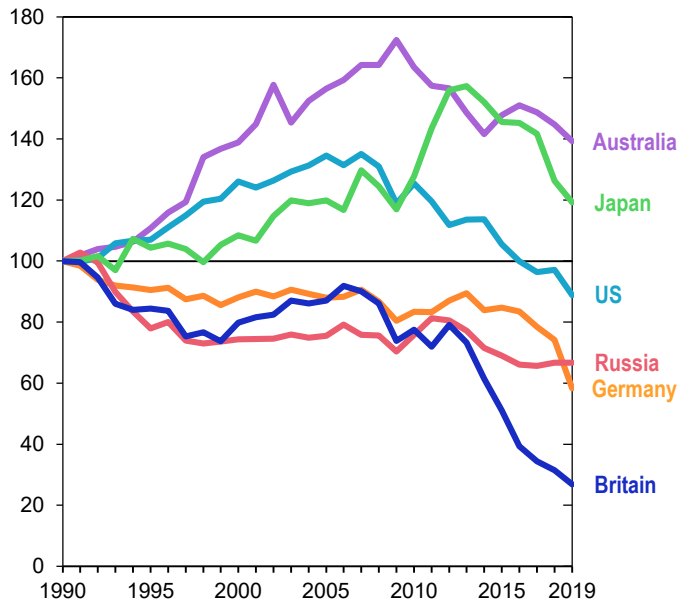


**Figure 1: Normalised carbon emissions from electricity generation in Great Britain and comparable markets.** Total annual emissions (in $MtCO_2$) are indexed to 100 for each country's value in 1990 to show the change over the last three decades. Data sourced from Refs. 3,4.

## Decarbonising British electricity

When the British electricity sector was privatised in 1990-1, over 70% of generation was coal-fired, and much of the rest came from nuclear power. $CO_2$ emissions fell steadily during the 1990s as new entrants and incumbents built gas-fired stations. Renewable capacity expanded under a succession of policies: the Non-Fossil Fuel Obligation held a series of tenders for new capacity; the Renewables Obligation offered tradable green certificates; Feed-in Tariffs were available for small-scale generators from 2010 until 2019, and large ones have been offered Contracts for Differences since 2014. The EU ETS introduced a carbon price in 2005, and this was supplemented by the UK's Carbon Price Support (a tax) from 2013 onwards. That was part of a package of policies that eventually led to a government pledge to phase out coal capacity by 2025; long before that pledge, the EU's Large Combustion Plant Directive (LCPD) forced generators either to invest in Flue Gas Desulphurisation equipment or to retire their coal- and oil-fired plant before the end of 2016, making the choice by the end of 2007.

Several studies have estimated the impact of wind generation on British carbon emissions by regressing half-hourly emissions against contemporaneous wind output[1,5,6], which has become

the accepted methodology. Chyong et al.[7] showed that the relative prices of gas and coal (including carbon prices) affect the marginal emissions savings from wind. The impact of relative fuel prices is also stressed by Abrell et al.[8], who use a machine learning model to estimate the impact of the UK Carbon Price Support on emissions. Using simulation models, Hirth[9] and Mills et al.[10] study the drivers of falling prices in two European and seven US markets respectively, changing each factor in turn, while holding all others at their start-year values. There were sizeable interaction effects in seven of these nine markets, and in one (the Southern Power Pool in the US) they were larger than any of the identified drivers. The British energy regulator, Ofgem, also found interaction effects when assigning emissions reductions to specific policies[11], apparently ignoring the effect of exogenous changes (e.g. in fuel prices). We model the full range of changes and show how the Shapley value treats interaction effects.

## Attributing emissions reductions

We calculate the impact of the various changes to British electricity generation between 2012 and 2019, chosen as the period of greatest change in emissions. We use the simulation model from Ward et al.[12] to estimate counter-factual emissions in the absence of each change and all combinations of them. The model is an enhancement of the merit order stack approach, which finds the electricity generation mix in each half-hour that minimises the variable cost of meeting demand given the available generating capacity, profile of renewable generation, fuel and carbon prices. The standard approach ignores much of the complexity and inter-temporal constraints on operating power systems[13], but our enhancement adjusts generator costs to represent some of their impacts. It yields accurate prices and output shares at the monthly-aggregate level (Figure 2), while its simplicity allows for very rapid calculations.

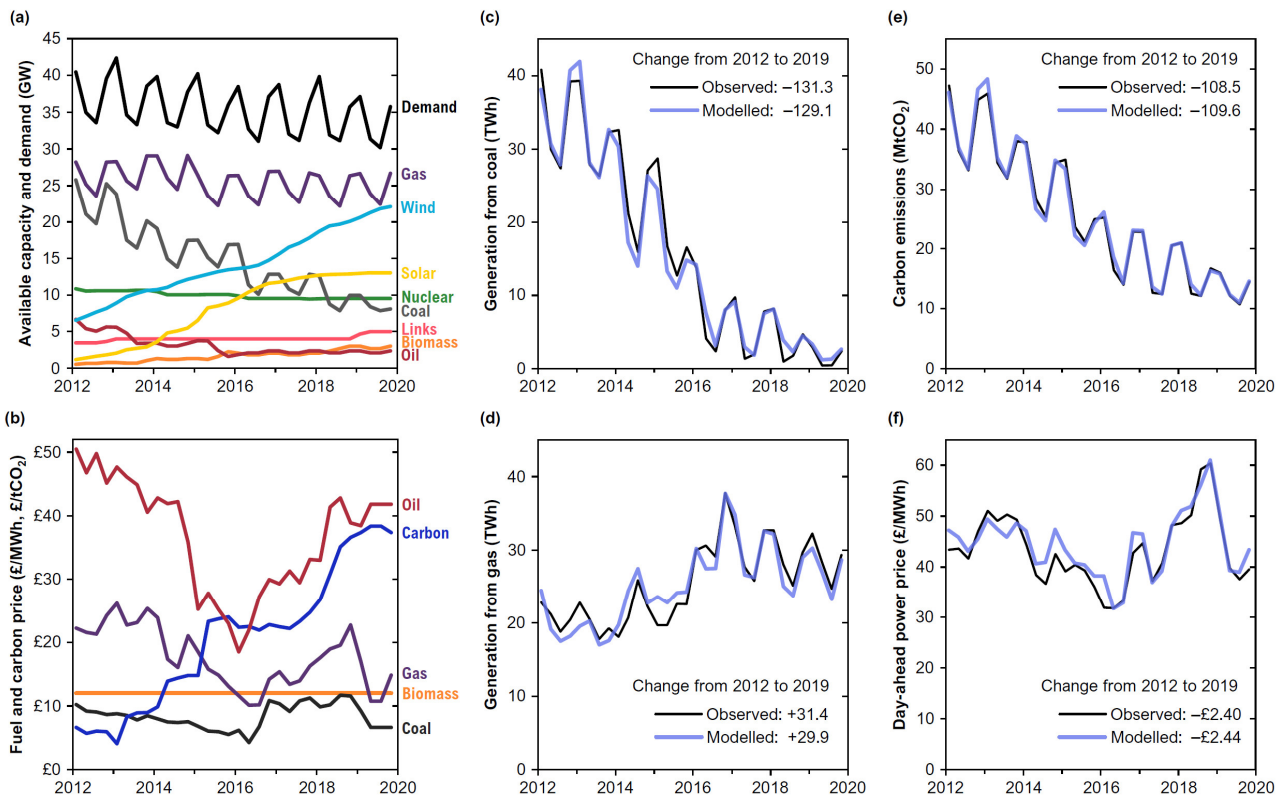


**Figure 2: Model inputs and outputs, showing ability to replicate historic data.** Panels (a) and (b) show the infrastructural and economic inputs to the model, and how their evolution at three-month resolution over the period we study. Panels (c) and (d) show the modelled electricity generation from coal and natural gas when all inputs followed their historical evolution, set against observed outputs[17]. Panels (e) and (f) show the modelled carbon emissions and electricity prices from the same scenario, against historical evolution[17]. The root-mean-square errors on these outputs at three-month resolution were 1.8 and 1.9 TWh for coal and gas generation, 0.99 $MtCO_2$, and £2.40/MWh.

Speed is important as calculating the Shapley value requires us to estimate the emissions from every possible combination of our 14 changes to the electricity system, requiring $2^{14}$ = 16,384 model runs. Each change (model input) was either allowed to vary as it had done over the period (as shown in Figure 2a and 2b) or was held constant at 2012 levels (e.g. wind capacity remained at 6.5 GW). For each combination of changes being fixed or free, the model estimates the dispatch of power stations, and thus the resulting $CO_2$ emissions and power prices in each year from 2012 to 2019.

Calculating the Shapley Value[14] then allows us to quantify the marginal impact of each change, averaged across all possible realisations of the other changes. The Shapley value has a number of attractive properties, not least that Shapley values add up to the overall change in emissions with

no separate interaction term, and these interactions are fairly apportioned between the individual changes.

## Modelling the British electricity system's evolution

Figure 3 shows the underlying simulations from which our results derive. The four panels show the monthly electricity generation mix with different variables held constant at 2012 levels.

Given these simulations, the traditional methodology for assigning carbon emissions to individual changes in generation, fuel prices or taxes is to calculate emissions in a counter-factual scenario with each change in turn, holding all other factors constant. We do this in Figure 4a, showing that this over-estimates the importance of our changes. The sum of the

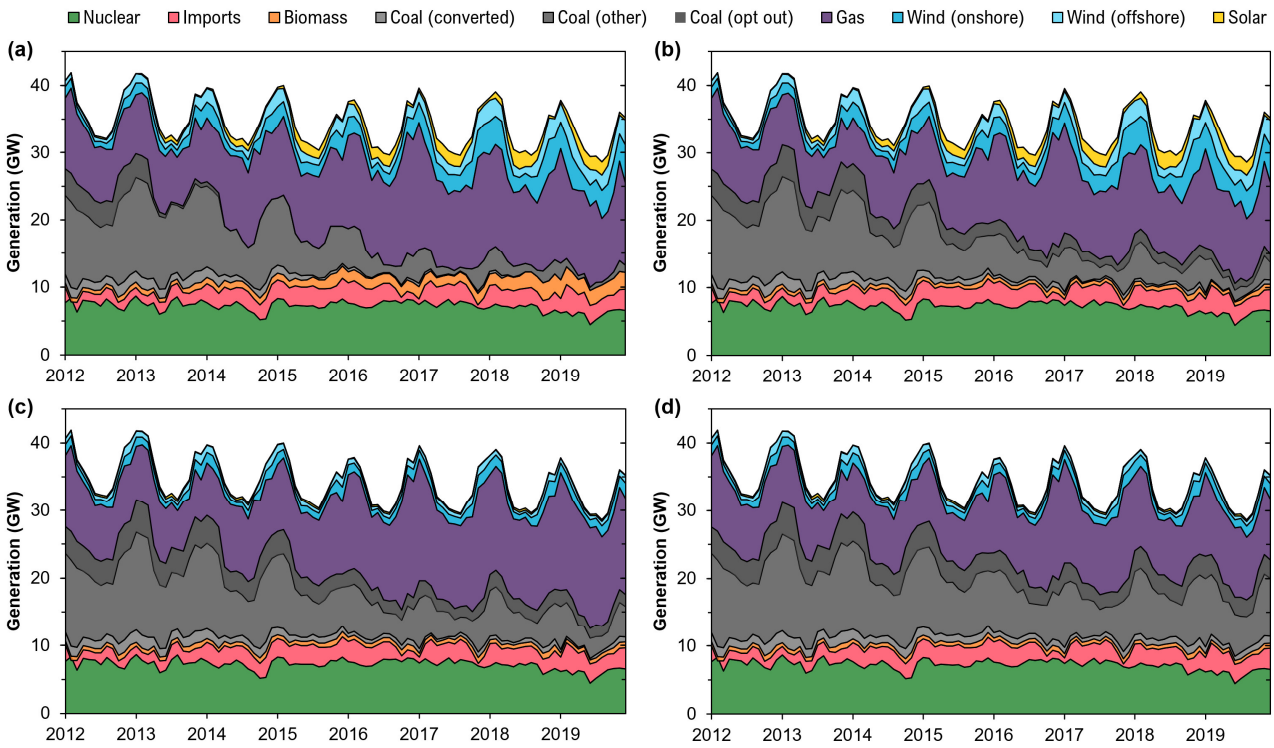


**Figure 3: Electricity generation mix in Britain under different scenarios.** Each panel shows the monthly electricity output from each technology we consider. Different sets of input parameters are held constant at 2012 levels across the four panels: (a) none, as in all variables represent their historic development; (b) the installed capacity of coal power stations, including coal converted to biomass; (c) also the installed capacity of renewable generators, wind and solar; and (d) also the carbon prices (both ETS and CPF).

individual changes is 28.5 $MtCO_2$ (26%) greater than the observed reduction in emissions. Closing coal stations in a system with a low emissions price and little renewable capacity is likely to have a large impact on emissions. The same would be true for adding renewable capacity or a carbon tax, but the effect of doing these after coal capacity has been removed would be smaller.

Figure 4b shows an alternative approach (also adopted by Ofgem[11]) in which we calculate the effect of "everything but" a given change occurring. This has the opposite problem, resulting in a nearly symmetric error of –32 $MtCO_2$ (–29%). Removing a carbon tax from a system which now has few coal plants and many renewable generators has relatively little impact, and so there is again a large interaction effect. For the other metrics we consider, the residuals amount to £6–13 / MWh error on wholesale electricity prices, 50–58 TWh/year output from coal and 48–54 TWh/year from gas power stations.

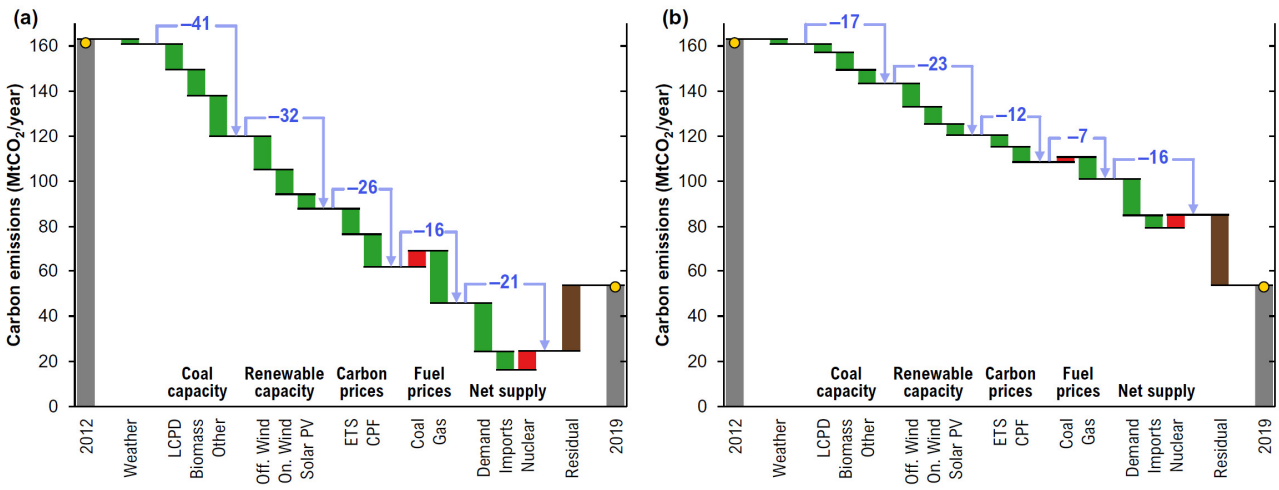


**Figure 4: Waterfall diagrams showing the individual marginal impact of changes to the British power system on carbon emissions.** Substantial residual terms highlight the inability of existing methods to accurately attribute emissions savings. Panel (a) shows individual changes made from the 2012 starting point, with all variables are fixed at 2012 levels except the one labelled. Panel (b) shows individual changes made from the 2019 end point. Change in gas capacity is merged with other coal capacity as it was negligible (<0.2 $MtCO_2$). Grey bars at the far left and far right show the modelled emissions in the start and end years. Yellow points show the actual observed emissions for comparison. Green bars which move downwards indicate reductions due to a change, red bars which move upwards indicate increases. Changes are grouped into broad categories indicated by the bold captions, and the combined savings due to each category are highlighted with numbers above the bars.

Both panels of Figure 4 emphasise the importance of the interaction term for carbon emissions (marked as residual in the figure), which must be added to make the effects of individual changes sum to the overall total.

## The impact of taxes, subsidies and regulations

Figure 5 shows the influence of the fourteen changes we consider on carbon emissions, electricity prices and fossil fuel consumption. When using Shapley values, these attributed impacts sum precisely to the modelled change over the seven years without the need for a residual term. These cumulative changes also correlate well to the historic outturn in each variable, sourced from Electric Insights.[17]

Between 2012 and 2019, annual emissions from electricity generation fell by 109 $MtCO_2$. Actions which reduced the capacity of coal power stations and increased the capacity of renewables had the greatest impacts on emissions, saving 57 $MtCO_2$/year between them. Within this group, offshore wind was attributed the largest individual saving of 13 $MtCO_2$, followed closely by onshore wind (10), coal conversions to burn biomass (10) and Other coal closures (11 $MtCO_2$). Higher carbon prices and lower demand saved 39 $MtCO_2$/year, while changes in fuel prices saved 11 $MtCO_2$. Falling coal prices in isolation would have raised emissions by 6 $MtCO_2$, but this was more than offset by falling natural gas prices saving 17 $MtCO_2$. Finally, the slightly warmer and sunnier weather of 2019 would have saved 2 $MtCO_2$ relative to the 2012 baseline. We tested an alternative methodology of summing the effect of year-by-year changes (as opposed to directly comparing 2019 with 2012), which produces very similar results, typically within 1 $MtCO_2$ or so.

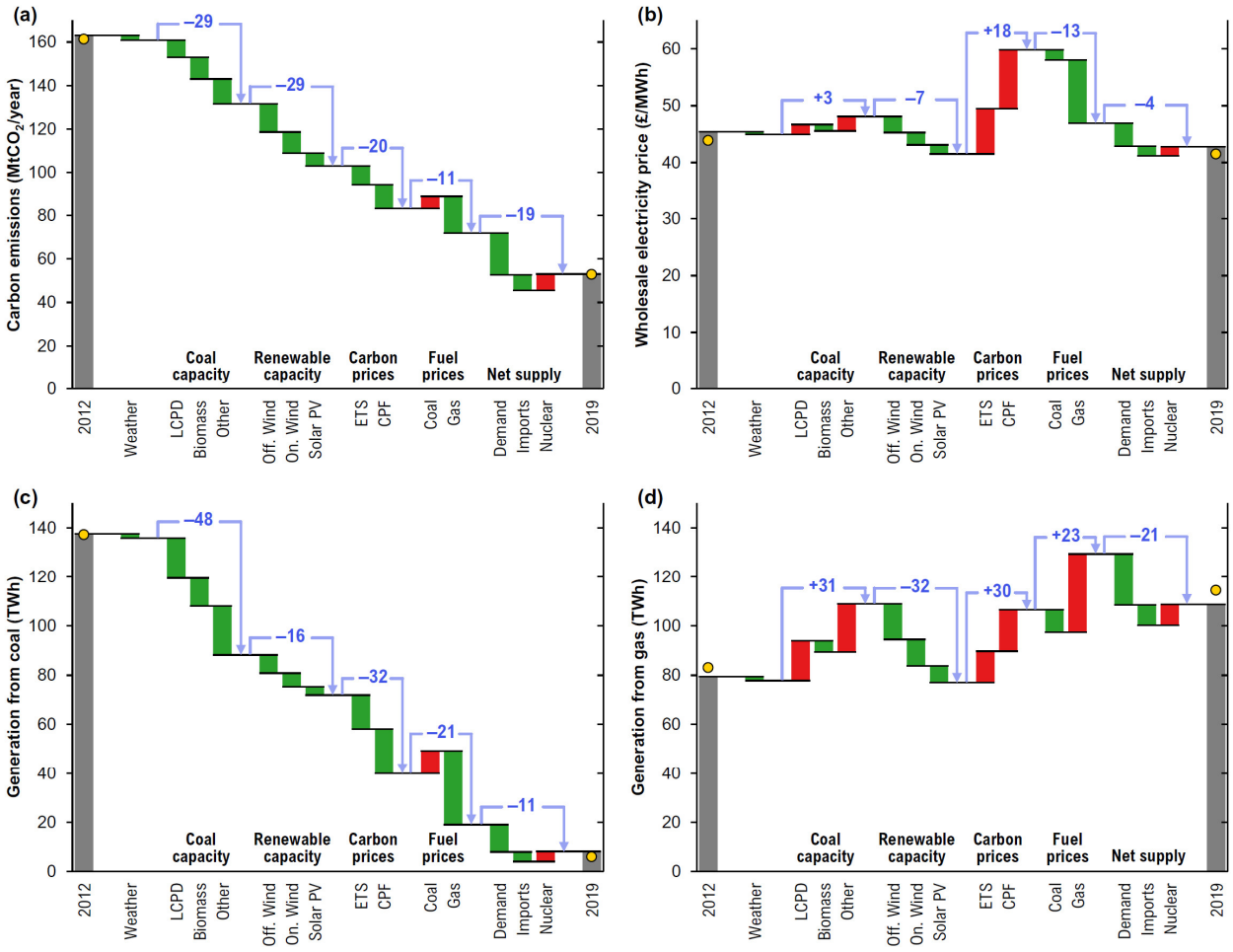


**Figure 5: Waterfall diagrams showing the impact of changes to the British power system on outcomes from 2012 to 2019.** These panels show the Shapley Values, where interaction between changes are accounted for. Panels (a) through (d) show the impact on carbon emissions, power prices, output from coal power stations, and output from gas power stations. Grey bars at the far left and far right show the modelled emissions in the start and end years. Yellow points show the actual observed emissions for comparison. Green bars which move downwards indicate reductions due to a change, red bars which move upwards indicate increases. Changes are grouped into broad categories indicated by the bold captions, and the combined savings due to each category are highlighted with numbers above the bars.

Power prices were similar in 2012 and 2019, as the competing influences of the changes offset one another. Reducing capacity increased prices, while increasing capacity and reducing demand lowered them, as would be expected from microeconomics. Raising carbon prices added £18/MWh (40%) onto wholesale electricity prices, but this was mostly offset by falling prices for fossil fuels.

Closing coal plants led to 48 TWh less generation from coal in 2019, offset by 31 TWh greater generation from natural gas and an increase in biomass output (not shown). The LCPD and

Other closures were met by almost equal increases in gas output, but biomass conversions displaced both 11 TWh of coal and 5 TWh of gas. Increasing the capacity of renewables reduced total output from fossil fuels by 47 TWh, displacing a mix of approximately 2/3 gas to 1/3 coal, which is similar to the mix of fossil fuels displaced by changes in demand, nuclear output and imports.

Raising carbon prices led to 32 TWh of coal being replaced by 30 TWh of gas, with increased output from biomass plants making up the difference. Both fossil fuel prices were lower in 2019 than in 2012, but the price of gas fell by more than coal. The net effect was to reduce coal generation by 21 TWh and increase gas output by 23 TWh, displacing a small amount of biomass output. Adding these effects together, we get a 53 TWh reduction in coal output relative to 2012 and a 53 TWh increase for gas.

Cumulative changes arguably matter more than the end-point changes reported in the figures above, especially with respect to $CO_2$ emissions. Figure 6 shows the time evolution of changes to carbon emissions attributed to each change, and their cumulative impact. This was calculated by running our model from 2012 to each year from 2013–19. Over the seven years we consider, cumulatively these changes amount to 0.503 $GtCO_2$ saved, or ~7.5 $tCO_2$ per capita.

Retiring fossil fuel capacity had the greatest impact due to its early action relative to other changes; it was the only change to have major effects in 2013 and 2014. Falling electricity demand and higher carbon prices were the second and third most influential changes. The carbon savings attributed to many of the changes have accelerated over this period, with the exceptions of solar PV, imports and nuclear. Solar PV levelled off as new installations stalled once government subsidies were cut significantly in 2016. Cumulative savings from nuclear and imports declined in 2019 (i.e. they were in a worse position than in 2012) due to falling nuclear output.

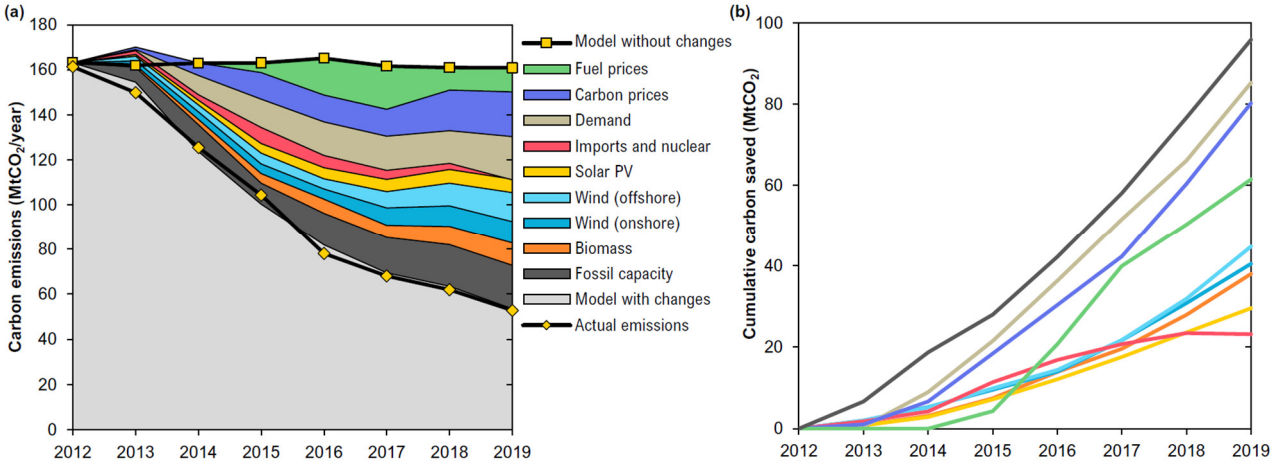


**Figure 6: The time evolution of carbon emissions saved due to each change.** Panel (a) shows the annual emissions from electricity generation, with 'wedges' of emissions savings from each change. Panel (b) shows the cumulative carbon saved by the changes. In both panels, emissions saved are represented by the calculated Shapley values. Selected changes were grouped together for the sake of visibility (coal and gas capacity as fossil capacity, coal and gas prices as fuel prices, imports and nuclear). Full results for the individual changes are given in the Supplementary Information.

# The efficacy of specific actions

For each change, we find the attributed annual carbon savings can be described competently by a linear function of the magnitude of the change. For example, each GW of coal capacity that retired is associated with an additional 1.30 ± 0.09 $MtCO_2$/year saved (adjusted $R^2 = 0.96$), and every £1/$tCO_2$ added to the carbon price is associated with an additional 0.65 ± 0.03 $MtCO_2$/year saved (adjusted $R^2 = 0.99$). Figure 7 shows a selection of these relationships, and full regression statistics for all changes are presented in the Supplementary Information.

The carbon impact of renewables (Figure 7a) depends upon the technology: for each GW installed, solar PV saves 0.51 $MtCO_2$/year, onshore wind saves 1.26, offshore wind saves 2.04, and biomass saves 4.54. The difference is driven by their relative productivity, with capacity factors over the period of 2012-19 averaging 10% for solar PV, 27% for onshore wind and 38% for offshore wind[15]. Converting coal capacity to burn biomass (counted as low- but not zero-

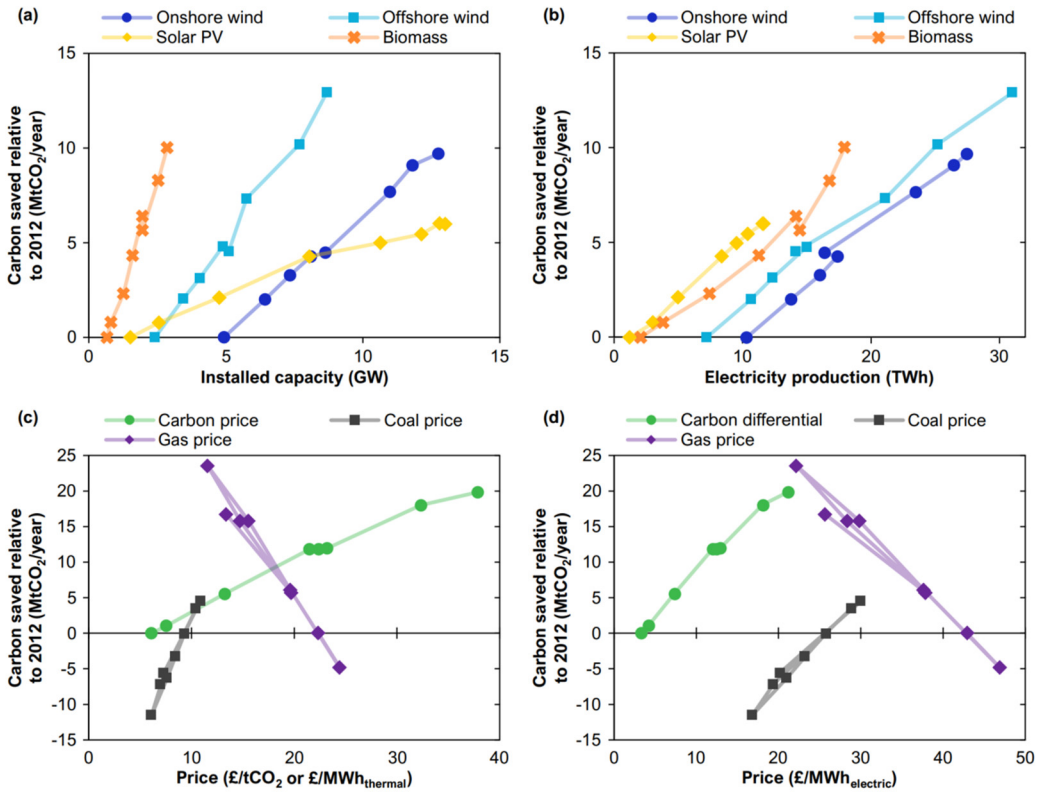


**Figure 7: The correlation between emissions savings and various system parameters over time.** Points represent the annual emissions savings in each year from 2012 to 2019, connected by pale lines to show the evolution. Panels (a) and (b) show the emissions savings attributed to renewable generation technologies, and panel (c) and (d) show the emissions savings attributed to changing carbon and fuel prices. The emissions saved in each year are presented relative to the 2012 baseline, hence the 5 GW of onshore wind already installed in 2012 is attributed zero savings (in panel a), and coal prices below £10 per MWh of fuel yield negative savings, meaning emissions higher than those of 2012 (in panel c). Panel (b) compares renewable technologies normalised by their output, and panel (d) compares fuel and carbon prices normalised by their impact on electricity generation costs. The carbon differential indicates the additional cost added to electricity generation from coal over and above the cost added to generation from gas, due to changes in carbon prices.

carbon) had the greatest impact per GW as utilisation rates were higher than for other renewables, and the output from coal capacity that was otherwise closed was largely replaced by gas generation (with over three times the carbon intensity of biomass).

When these impacts are normalised per GWh of electricity generated they reveal similar magnitudes of carbon saving, indicated by similar slopes in Figure 7b. Solar PV saved 598 $tCO_2$ per GWh, onshore and offshore wind saved 556 and 536 $tCO_2$ respectively, and biomass saved 585 $tCO_2$. Other actions which changed the level of net demand to be met also had comparable effects on emissions. Each GWh reduction in net demand is attributed 592, 619 and 572 $tCO_2$

for demand, imports and nuclear respectively. Our alternative methodology based on year-by-year changes produces broadly similar results, although with greater variation around the trends.

We are following the national carbon accounting convention and exclude emissions from producing the electricity imported by the UK. However, using the average emissions factors from Supplementary Table 1, the increase in imports compared to 2012 would have caused 1.3 $MtCO_2$ of emissions in neighbouring countries in 2019. The average carbon intensity of imported electricity was 223 $tCO_2$ per GWh, although the marginal intensity might well have been higher. Over the whole period, imports saved 37 $MtCO_2$ of British emissions, but caused increases elsewhere of 9.4 $MtCO_2$.

Increasing fuel prices had opposing impacts, shown in Figure 7c. Adding £1 per MWh of chemical energy in coal lowered emissions by 3.25 $MtCO_2$/year, whereas adding £1 per MWh of natural gas raised emissions by 2.11 $MtCO_2$/year. When the fuel costs are translated into the impact on electricity generation cost (by dividing by the average power station efficiencies) they yield almost equal and opposite slopes. Emissions rise by 1.17 $MtCO_2$/year or fall by 1.10 $MtCO_2$/year when increasing the generation cost by £1/MWh for coal and gas respectively. Increasing the price of carbon had a near-uniform impact over the range of £7 to £37/$tCO_2$ experienced between 2012 and 2019, reducing emissions by 0.65 $MtCO_2$/year for each £1/$tCO_2$. Increasing the carbon price by £1.78/$tCO_2$ would raise the cost of generating electricity from coal by £1/MWh more than it raises the cost of electricity from gas[16], and according to our model this would reduce emissions by 1.15 $MtCO_2$/year. It should not be a surprise that this number is neatly between the estimated impacts of an increase in the cost of coal generation and a decrease in that of gas.

## Discussion and Conclusions

In this article, we borrow an old concept from game theory to answer a modern question about how a range of overlapping complementary and conflicting actions influenced carbon emissions, electricity prices and fossil-fuel consumption in Great Britain's power system. The use of Shapley

values requires a well-calibrated model which is rapid enough to run $2^{14}$ calculations but accounts for the interaction between terms, fairly allocating any amplifying or rebound effects they have.

These estimates are attributional rather than causal. They account for interactions between the direct changes we specify; for example, a diminishing effect when coal plants are retired and carbon prices raised (as the carbon price reduces output from fewer stations, or equally the closures are of plants that would have run less intensively). They do not account for indirect, or secondary, relationships; such as that between price and demand, which we take to be exogenous, but would have had time to respond to price changes driven by the changes we study. Therefore, shutting coal plants or raising the carbon price would have caused greater carbon savings than stated here due to the secondary effect of reducing consumption; and had a lower impact on power prices for the same reason. We do not attempt to divide the trend in demand between the effect of energy efficiency policies, changes in overall economic activity in Britain and exogenous technical change. Nonetheless, we believe that our decomposition of the fall in emissions provides useful insight into the relative contribution of the different changes we have identified.

A key message from our case study of Great Britain is that reducing power sector $CO_2$ emissions by two-thirds – a feat which must be rapidly replicated around the world – required a broad multi-faceted approach. Shutting coal power stations, installing renewables, raising the cost of coal and carbon emissions and improving energy efficiency (to reduce demand) all contributed significantly. None of these could have been forsaken, and all worked together to reduce emissions.

The British power system is undergoing a complex and far-reaching transition: in seven years coal was replaced by gas as the dominant dispatchable fuel and renewable energy sources quadrupled their share of electricity supply. Despite this shifting background, we find the carbon impact of each driver we study has been relatively consistent and can be described as a simple linear function of its magnitude. Any action which made electricity more expensive to generate from coal than from gas has a similar impact on emissions, regardless of whether it was driven by exogenous movements in international fuel prices and European carbon markets, or specified changes to national carbon taxes.

Each TWh of electricity that was generated by low-carbon sources (or not consumed due to efficiency and other measures) displaced a similar mix of coal and gas generation and saved a similar amount of $CO_2$, in the range of 573±24 $gCO_2$/kWh. This is regardless of the very different temporal patterns of output from nuclear, biomass, wind or solar. These values could be thought of as 'long-term marginal' abatement factors, which lie centrally in the range of short-term (e.g. half-hourly) marginal emissions abatement identified in previous econometric studies. The long-term stability we identify could provide a simple yet reasonably effective means for estimating the impact of future policy and technology changes.

Building 1 GW of offshore wind reduced British emissions by 2.01±0.09 $MtCO_2$/year at any point during this period, despite the rest of the system decarbonising (which could diminish its marginal impact). However, if a system enters a new regime (as may now be happening in Britain with the almost complete elimination of coal), then the impact of future changes would be different (and perhaps revealed by prospective studies).

Here we use this technique to understand how policy, investment and economic actions helped in the past. This technique could usefully be applied to historic analyses in other countries, or more importantly to future ones; for example, assessing the role of different options in IPCC scenarios. This potentially offers a more robust way to estimate the 'value' of individual technologies or actions to future decarbonisation, accounting for the complex, and potentially more numerous interactions they have upon one another. This should improve answers to the pertinent question of "how much will *Technology X* contribute to decarbonising our planet?"

# Methods

## Shapley values

We need to go beyond the standard methodology for assessing policy-driven changes in emissions, which is to estimate the change in emissions with and without that policy in place, because the British electricity system was affected by so many changes at the same time. Renewable generation, considered in isolation, would have displaced a higher-carbon mix of fossil fuel stations in 2012 (when gas prices were relatively high) than it did in 2019, when coal stations had largely been driven off the system by carbon prices. Similarly, the potential impact of carbon prices would appear to be greater in 2012 (when 68% of generation was fossil-fuelled) than in 2019, when renewable and nuclear output met 49% of demand.

Our approach adopts the Shapley value, which is a concept from cooperative game theory, used to divide the benefits from forming a coalition among the members (players) of that coalition. It measures the incremental contribution that each player brings to the coalition, averaged over all the possible (ordered) ways in which the coalition could be formed by incrementally adding players. Rewarding people with their marginal contribution is a standard idea in economics, and the Shapley value guarantees that this will exactly allocate the benefits available, which is not necessarily the case when, for example, workers are paid their marginal product.

In its traditional setting, the intuition for the Shapley value can be seen as giving each member of a coalition the gain they create when they join the coalition, averaged over all the possible (ordered) ways in which the coalition could have been formed. In our setting, the Shapley value for change $i$, $\varphi_i$, is given by:

$$\varphi_i(v) = \sum_{S \subseteq N \setminus \{i\}} \frac{|S|!\,(|N| - |S| - 1)!}{|N|!} \big(v(S \cup \{i\}) - v(S)\big) \qquad (1)$$

where N is the set of changes that we consider (listed in Section 0), S is any subset of those changes that does not contain change $i$, and $v$ is the relationship between the changes to the electricity system and the resulting change in outcomes. In this paper, $v$ primarily relates to carbon emissions ($MtCO_2$ / year) from electricity generation, and we also consider variants where $v$

relates to wholesale electricity prices (£/MWh), electricity generated from coal (TWh/year) and from natural gas (TWh/year). The second term in the equation shows the impact of adding change *i* to each possible subset of other changes, while the first term is a weighting factor that counts all the possible (ordered) ways in which that subset could have been formed and then joined by the remaining changes outside the subset.

Our main results compare the outcomes in each year with those for 2012. We start with 2012 input values for all prices, capacities and the overall level of demand, but reflect the effects of the year's weather on demand, wind and solar output. Shapley values are then computed from the differences between this weather-adjusted base case and the outcome with each combination of changes to our fourteen drivers.

We computed an alternative set of results based on year-to-year changes, calculating base scenarios for 2013 with 2012 input values, 2014 with 2013 input values, and so on. For each driver, the overall impact of changes over the whole period equalled the sum of the year-to-year changes. Changes that were concentrated at either end of the period are perhaps over- or under-weighted; the LCPD closures of coal capacity, for example, came early and thus affected a relatively high-carbon system. The year-by-year approach "locks in" this stronger impact, whereas our preferred approach credits it (in Figure 6) for those early effects, but also shows that other changes were reducing emissions later on in any case.

## Model for simulating electricity market outcomes

We employ a model which simulates power station dispatch, prices and emissions in the British electricity market. This calculates the short-run equilibrium (how operations would change) rather than the long-run equilibrium (how investment decisions would change) due to the short timescales involved and to free us from dependence on contentious and uncertain assumptions (such as the time-varying capital costs of different technologies).

We employ a Merit Order Stack, a simple but widely used approach to modelling electricity markets, minimising the variable cost of generation while meeting hour-by-hour demand and ensuring that no generator produces more than allowed by its available capacity. Standard merit

order stack models ignore the interactions between time periods that are driven by start-up costs, minimum loading levels and limited ramping rates. Such interactions mean electricity prices can fall dramatically at times of low demand as inflexible generators try to remain on the system and avoid the cost of starting again when demand rises, or can rise dramatically at times of peak demand when a generator must be brought online for a short time, and thus must recover its incurred costs from limited energy sales.

The Enhanced Merit Order Stack we use reflects this by splitting each type of capacity into tranches. We scale down the variable cost of the first tranches to reflect unwillingness to shut down, and scale up the variable cost of later tranches to reflect higher mark-ups when capacity margins are lower. Coal and gas stations are each given nine capacity tranches, with relative sizes and marginal costs estimated using the procedure described in Ward et al. [12].

The model uses the optimisation:

$$\min_{x_{i,j,t}} C = \sum_t \sum_i \sum_j c_{i,j,t} x_{i,j,t} \tag{2}$$

$$s.t. \sum_i \sum_j x_{i,j,t} = d_t \forall t \tag{3}$$

$$x_{i,j,t} \leq k^A_{i,j,t} \; \forall i, j, t \tag{4}$$

where $C$ is the variable cost of generation over the entire period, $x_{i,j,t}$ is the output from tranche $j$ of capacity type $i$ in sub-period $t$, $c_{i,j,t}$is the per-unit variable cost of output from that tranche (which may vary between sub-periods), $d_t$is the demand to be met in sub-period $t$, and $k^A_{i,j,t}$ is the available capacity of tranche $j$ of capacity type $i$ in sub-period $t$.

The model operates at the resolution of the British electricity market (half-hourly), and is specified plant-wise, meaning that each individual power station is defined by its capacity and efficiency. The model determines the output from fossil-fuelled generators (coal, combined cycle gas turbines, and oil-fired open cycle peaking plants) and biomass generators, subject to meeting demand net of weather-driven renewables, nuclear plants and imports. These three classes of

generation are treated as exogenous because their dispatch decisions are beyond the scope of this model. The availability of renewables (wind, solar PV and hydro) is determined by prevailing weather conditions, and these have near-zero marginal costs so will be dispatched whenever possible. Similarly, the inflexibility and low marginal costs of nuclear reactors means their dispatch is governed by availability (i.e. maintenance and unplanned outages). Trade of electricity depends on the interplay between prices in Britain and its neighbouring markets (France, Ireland, Netherlands and Belgium). Simulating these prices with comparable accuracy would require more computing power and granular data than are available.

## Input data

Time-series data for demand and exogenous forms of supply were used with half-hourly resolution covering 2012–19. Historic metered data for each variable were acquired from Electric Insights[17]. Demand was based on transmission-system demand from National Grid with output from 'embedded' wind and solar panels added back, as detailed in Ref. (1). Output data for nuclear, wind, solar, hydro and trade over each interconnector (France, Netherlands, Ireland and Belgium) were based on data from National Grid and Elexon. Solar PV output was not metered in 2012, and so these data were simulated using the Renewables.ninja model[18], made available via [19].

Fuel prices (for coal, natural gas and oil) were defined at quarterly resolution, taken from BEIS and converted to £/MWh[20]. Carbon prices were also specified at quarterly resolution for consistency, based on daily EU Emissions Trading System (ETS) prices[21], converted from Euros to GBP using market exchange rates[22], and the Carbon Price Floor (CPF) set by the UK government[23].

We modelled each generator unit of a thermal power station in Britain that was over 100 MW, totalling 57 coal, 65 CCGT (combined cycle gas turbine), 17 oil and OCGT (open cycle gas turbine) and 7 biomass. Each unit was defined by its fuel type, capacity and efficiency, using the same data as in Ward et al.[12], kindly provided by Bloomberg New Energy Finance[24]. The evolution of capacity over time was manually sourced from construction and decommissioning

announcements, and cross-checked against aggregate fleet data from Electric Insights[17]. The carbon intensity of each unit was estimated from the carbon content of its fuel (344 $kgCO_2$/MWh for coal, 205 for natural gas and 274 for oil)[1], divided by its efficiency. The fleet-wide average efficiency for coal power stations was 36%, and for gas CCGTs it was 52% (against higher heating value). The carbon intensity of biomass units was taken to be 121 $kgCO_2$/MWh of electricity based upon upstream emissions from fuel processing and transport[1], with legislative requirements for sustainable forestry management assumed to mean emissions from combustion are offset by those from growing feedstock[25].

The data which may legally be disseminated are provided as Supplementary Information.

## Scenarios considered

We identify fourteen changes to the electricity industry that accumulated between 2012 and 2019. A full list of these changes and their values is given in Supplementary Table 2. They are visualised in Figure 2a and 2b.

It is important to remember that we are considering changes relative to the situation in 2012, rather than the absolute impact of (say) all renewable capacity installed by 2019. Estimating absolute impact is an important research question, but it may invalidate the use of other aspects of the industry's situation in 2012 as a counterfactual. The level of fossil-fuelled capacity, for example, changed during the preceding decade, as generators withdrew 5.6 GW of coal capacity and added 7.8 GW of CCGT capacity between 2004 and 2012. Some of these decisions could well have been different, had the 7.2 GW of wind capacity present in 2012 not been built.

We consider four changes to the amount of renewable capacity between 2012 and 2019: onshore wind, offshore wind, solar PV and large-scale conversions from coal to biomass. Small-scale biomass generators are included within the distributed generation that meets part of the demand for electricity without being counted by the transmission system operator. The biomass conversions we include are at Drax, Ironbridge and Tilbury, large coal-fired power stations built by the CEGB. These additions to biomass capacity are matched by reductions in the capacity of coal-fired power stations.

We divide the other reductions in coal capacity in two. 6 GW of capacity was opted-out of the EU's Large Combustion Plant Directive, which meant that it could operate beyond 2007 without installing flue gas desulphurisation equipment, but was limited to a total of 20,000 hours of operation from 2008 onwards, closing by the end of 2015 at the latest[2]. While the broad policy aim of decarbonisation was clear in the mid-2000s, setting the context for decisions on whether to invest in these stations or close them, at least two generators had announced plans to build new coal-fired stations[26], and we believe that it is valid to treat these closures as the result of policy to reduce sulphur rather than carbon emissions. A further 10 GW of capacity was opted-in to the LCPD but closed between 2012 and 2019; we treat these later closures as a separate category. Another EU policy, the Industrial Emissions Directive, was forcing generators to invest in order to reduce nitrogen emissions; the rising carbon prices were reducing coal's share of fossil-fuelled generation, and growing renewable output was eating into the overall amount of that generation. These pressures are likely to make the later coal closures an endogenous result of the other changes we document, but we do not attempt to assign the effect of lower coal capacity on $CO_2$ emissions between these underlying changes. We also account for the effect of the 1 GW of gas capacity added to the system, and 2.6 GW that was retired between 2012 and 2019.

As already stated, changes to nuclear output were exogenous, determined by maintenance and outages rather than economic considerations, as it was in the generator's interest to produce as much output as possible from these relatively inflexible stations with low variable costs, subject to safety constraints. We combine these changes with those to the level of output from hydro stations, which depended exogenously on the available water. Nuclear and hydro made up 21% and 1.2% of supply respectively over the period we study. The level of imports and exports was more endogenous, as changing price patterns (particularly higher prices driven by the UK's carbon tax) changed the incentives for trade. However, in half-hours with large inter-market price differences (possible when interconnectors are at full capacity), prices in the UK could have changed without affecting trade. Our data show that both the Netherlands and France interconnectors operated at full capacity more than half of the time.[17] New interconnectors with Ireland (500 MW) and Belgium (1,000 MW) were commissioned in 2012 and 2019 respectively. We follow the national accounting approach to carbon emissions, ignoring emissions outside

Britain in our model runs, although we do comment on the embodied carbon contained in imports when discussing our results. The discussion is based on the annual average carbon intensity of electricity from each country, calculated using the methods from Ref. 1 and listed in Supplementary Table 3.

Electricity demand fell by 10% between 2012 and 2019. Again, this was a mix of endogenous and exogenous changes: the normal trend improvement in energy efficiency over time was supplemented by the effects of a range of policies; subdued GDP growth (particularly in manufacturing) fed through to demand; carbon taxes raised the price of electricity. The effect of renewables on retail prices is potentially ambiguous: their expansion often depresses wholesale prices (at least until capacity has adjusted) but subsidy costs can outweigh this.

We treat the carbon price in the EU ETS separately from the UK's Carbon Price Support. Again, we are looking at the effect of changes in the ETS price relative to its (low) level in 2012, rather than its absolute level. Our final change is the impact of fuel prices, looking at gas and coal together. The UK is integrated into the wider European market for these fuels, and so we think of these changes as largely endogenous to UK policies.

The level of fuel and carbon prices, and of fossil-fuelled capacity, are simply fed into our model with either the level from 2012 or from the current year. The remaining variables for demand and other types of generation depend upon the weather, which changes from year to year. We use the Renewables.ninja to calculate the hourly output that 2012 wind and solar PV capacities would have produced in each succeeding year based on the prevailing weather. For demand, we took the half-hourly profile of electricity demand for each year (which embodied that year's weather patterns) and rescaled their annual total to the annual total of 2012. This rescaling used the weather-corrected demands, so that the actual demand could still vary between years when fixed at 2012 levels (to embody whether particular years had cold or mild winters). Weather correction was based on the number of heating degree days in each year, calculated using temperature data from Renewables.ninja[19] assuming a base temperature of 15.5°C, and the empirical relationship that British electricity demand rises by 0.82 GW for each degree that temperature falls below 15.5°C, meaning each heating degree day corresponds to 19.6 GWh

additional consumption. When we simulate the historic capacities and demand levels, we naturally use the actual half-hourly data. This means that our simulations and calculations of emissions reductions are carried out relative to a fluctuating baseline that reflects the actual weather seen each year.

## Data availability

The datasets used in this study are available in the Zenodo repository as Supplementary Data, DOI: 10.5281/zenodo.4294015 (https://doi.org/10.5281/zenodo.4294015). This includes the raw data for all results presented here and input data for Figs. 1–7.

The half-hourly time series data for demand, supply and prices used in the model and for validation are available upon request, subject to licensing conditions.

## Code availability

The R and Excel code used to perform the analysis in this paper are available upon reasonable request from the lead contact: i.staffell@imperial.ac.uk.

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## Author contributions

RG and IS each contributed to all aspects of the paper.

## Competing interests

RG and IS provide consultancy to organisations relevant to the British electricity industry, including National Grid ESO, Drax Group, the UK government's Department for Business, Energy and Industrial Strategy (BEIS) and the European Commission. No employee of these or any other commercial or government body had the opportunity to contribute towards or influence the content of this paper.

# Supplementary information

## Supplementary Table 1: Regression coefficients for the carbon impact of each change we consider.

| Unit of change | Emissions ($MtCO_2$/year) | Standard error | Significance | Adjusted $R^2$ |
|---|---|---|---|---|
| Reduce coal capacity by 1 GW | −1.615 | 0.066 | *** | 0.988 |
| (specifically LCPD opt-out) | −1.598 | 0.210 | *** | 0.890 |
| (specifically other plants) | −1.794 | 0.057 | *** | 0.993 |
| Convert 1 GW of coal to biomass | −4.753 | 0.155 | *** | 0.993 |
| Reduce installed gas capacity by 1 GW | +0.538 | 0.084 | *** | 0.851 |
| Increase offshore wind capacity by 1 GW | −2.041 | 0.085 | *** | 0.988 |
| Increase onshore wind capacity by 1 GW | −1.259 | 0.047 | *** | 0.991 |
| Increase solar PV capacity by 1 GW | −0.508 | 0.026 | *** | 0.982 |
| Increase carbon price by £1/$tCO_2$ | −0.646 | 0.030 | *** | 0.985 |
| (specifically ETS prices) | −0.643 | 0.012 | *** | 0.998 |
| (specifically CPF prices) | −0.685 | 0.038 | *** | 0.979 |
| Increase coal price by £1/$MWh_{fuel}$ | −4.062 | 0.192 | *** | 0.985 |
| Increase gas price by £1/$MWh_{fuel}$ | +2.633 | 0.120 | *** | 0.986 |
| Reduce electricity demand by 1 TWh | −0.592 | 0.029 | *** | 0.984 |
| Increase electricity imports by 1 TWh | −0.591 | 0.020 | *** | 0.992 |
| Reduce nuclear output by 1 TWh | −0.572 | 0.009 | *** | 0.998 |
| Increase offshore wind output by 1 TWh | −0.536 | 0.016 | *** | 0.993 |
| Increase onshore wind output by 1 TWh | −0.556 | 0.023 | *** | 0.988 |
| Increase solar PV output by 1 TWh | −0.598 | 0.013 | *** | 0.997 |

**Supplementary Table 2: The fourteen changes to the British power system that we examine.**

| | Metric | Value in 2012 | Value in 2019 | Relative change |
|---|---|---|---|---|
| Coal capacity (Opted-out of LCPD) | GW | 6.1 | 0.0 | –100% |
| Coal capacity (converted to biomass) | GW | 2.4 | 0.0 | –100% |
| Coal capacity (other) | GW | 18.4 | 8.5 | –54% |
| Natural gas capacity | GW | 29.7 | 28.1 | –5% |
| Biomass capacity | GW | 0.0 | 2.4 | ~ |
| Offshore wind | GW | 2.0 | 9.1 | 4.5x |
| Onshore wind | GW | 4.5 | 13.0 | 2.9x |
| Solar PV | GW | 1.2 | 13.0 | 11x |
| Carbon price (ETS) | £ / $tCO_2$ | £6.61 | £19.39 | 2.9x |
| Carbon price (CPF) | £ / $tCO_2$ | £0.00 | £18.00 | ~ |
| Coal price | £ / $MWh_{fuel}$ | £9.90 | £6.99 | –29% |
| Gas price | £ / $MWh_{fuel}$ | £21.22 | £15.30 | –28% |
| Electricity demand | TWh | 319 | 286 | –10% |
| Imported electricity | TWh | 9 | 21 | 2.4x |
| Nuclear output | TWh | 66 | 53 | –20% |

595

**Supplementary Table 3: Carbon intensity of electricity generated in countries which trade with Great Britain ($kgCO_2/MWh$).** Annual average values are presented for each country across all years, but only years in which the relevant interconnector was operational were used. Ireland includes both the Republic of Ireland and Northern Ireland, as these share a single electricity market.

| Year | France | Ireland | Netherlands | Belgium |
|---|---|---|---|---|
| 2012 | 60 | 487 | 482 | 244 |
| 2013 | 57 | 460 | 486 | 219 |
| 2014 | 39 | 449 | 517 | 234 |
| 2015 | 44 | 437 | 535 | 257 |
| 2016 | 47 | 433 | 507 | 193 |
| 2017 | 57 | 392 | 476 | 192 |
| 2018 | 49 | 356 | 501 | 223 |
| 2019 | 45 | 310 | 439 | 183 |