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Rapid fuel switching from coal to natural gas through effective carbon pricing

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Abstract

Britain's overall carbon emissions fell by 6% in 2016 due to cleaner electricity production. This was not due to a surge in low-carbon nuclear or renewable sources; instead it was the much-overlooked impact of fuel switching from coal to natural gas generation. This Perspective considers the enabling conditions in Britain and the potential for rapid fuel switching in other coal-reliant countries. We find that spare generation and fuel supply-chain capacity must already exist for fuel switching to deliver rapid carbon savings, and to avoid further high-carbon infrastructure lock-in. More important is the political will to alter the marketplace and incentivise this switch, for example through a strong and stable carbon price. With the right incentives, fuel switching in the power sector could rapidly achieve on the order of 1 $GtCO_2$ saving per year worldwide (3% of global emissions), buying precious time to slow the growth in cumulative carbon emissions.

Introduction

Global carbon emissions from fossil fuels stand at almost 37 $GtCO_2$/yr and have grown by an average 2.4% per year so far this century[1]. While emissions had stabilised between 2014 and 2016 they appear to be increasing once again[2], intensifying the need to reduce global fossil fuel consumption. Switching away from fossil fuels is recognised as a 'key mitigation strategy'[3] of 'crucial importance'[4] in the transport sector, but switching between fossil fuels in the power sector lacks such recognition[5] as it is incompatible with longer-term deep decarbonisation.

Power sector decarbonisation has received most attention with the rollout of renewables, especially wind and solar, which have grown twenty-fold in the last 15 years to reach 5% of global electricity generation[6]. Carbon capture and storage (CCS) is often considered an essential component of least-cost decarbonisation[7,8]; however, it may take another three decades to achieve a 10% share of electricity generation[9], amid very low expectations for CCS in the current environment[10] after continued delays and cancellations[11]. With cumulative carbon emissions being a major determinant of climate change[12], any early opportunities to reduce emissions within months rather than decades deserve attention. Fuel switching between fossil fuels cannot be a long-term option as electrical generation from unabated natural gas still emits around four tenths that of coal[13]; and if shale gas is used, upstream methane emissions may add a further 25% to its carbon intensity[14].

However, Britain has recently demonstrated the short-term impact of fuel switching. Displacing coal with natural gas reduced per-capita annual emissions by 400 $kgCO_2$ between 2015 and 2016, equal to 6% of national emissions[15]. Given the long-lived nature of energy systems and their endemic inertia, this rate of change is remarkable in the absence of any major accident or disaster. Figure 1 puts these changes in context, against market-led fuel switching in China and the US, renewables deployment in Germany, and incremental efficiency improvements in Poland. The unprecedented deployment of nuclear power lowered French carbon intensity by 40 g/kWh each year for a decade (1977–1986)[16,17]. Fuel switching can proceed faster, but not so far: Britain's carbon intensity fell by 85 g/kWh in 2016, but its potential is close to exhaustion as coal is almost eliminated.

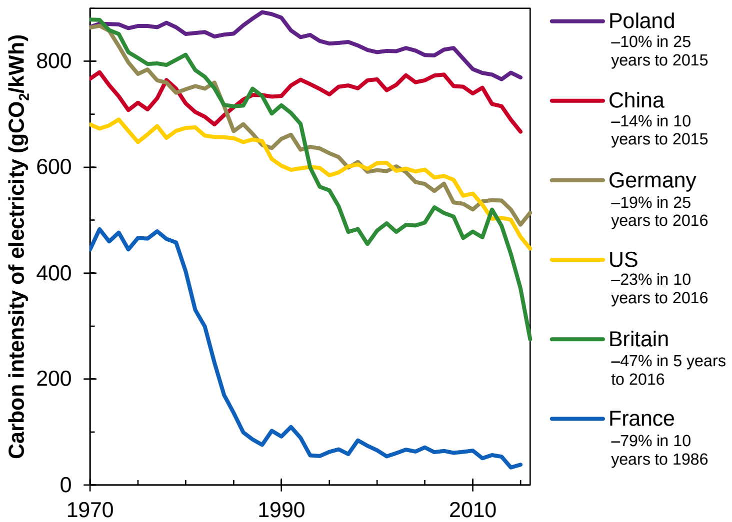

*Figure 1: **Carbon intensity of electricity generation in six countries over the last half-century.** Carbon intensity for gross electricity output (not accounting for losses in transmission and distribution). The legend indicates the depth and duration of sustained reductions in emissions intensity within each country. Data from refs.* [16,17].

This Perspective argues that with the right conditions, both in terms of pre-existing infrastructure and political will, switching away from coal has an important role to play in the rapid early decarbonisation of power systems. This provides immediate benefits to other sectors, which will decarbonise faster through electrification due to lower associated emissions.

Britain's power generation

Coal was the largest source of electricity generation for the first hundred years of Britain's power system. This changed in the early-1990s (Figure 2) when the newly-liberalised market invested in combined cycle gas turbines (CCGTs), for reasons unrelated to carbon mitigation[18].

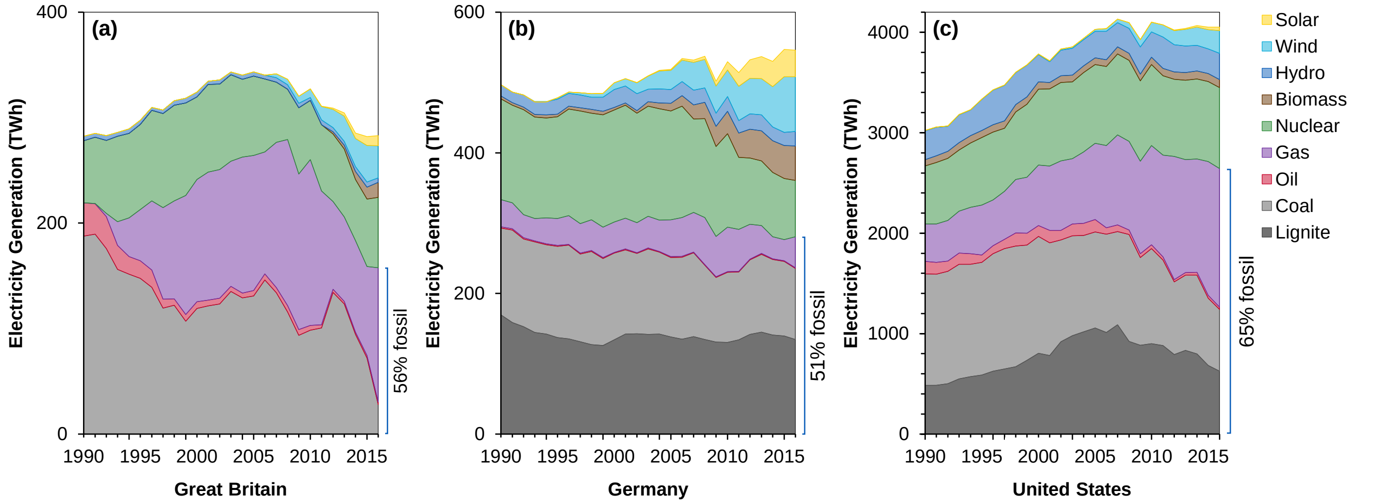

*Figure 2: **Electricity generation by fuel type in three countries over the last 25 years.** Electricity generation over time for **(a)** Great Britain, **(b)** Germany and **(c)** the US. Shares of fossil fuel generation are indicated by the bracketed regions. Imports are not included, waste is included with biomass. Between 2014 and 2016 coal + lignite generation fell by 5% in Germany, 22% in the US and 70% in Britain. Data from refs.* [19,20,56,85].

This 'dash-for-gas' in Britain was not replicated in Germany or elsewhere in Europe, and although termed a 'dash' it took eight years (1991–99) for new gas capacity to be built and halve coal's share of generation[19] from 66% to 34%. Over the last decade, the US has shifted away from coal and lignite[20] as shale gas production significantly reduced the price of natural gas. More recently, the combination of fuel switching and coal plant retirements in Britain has seen coal's generation share fall three-quarters to 9% in just four years (2012–16); helping to halve power sector emissions from 158 $MtCO_2$ in 2012 to 78 $MtCO_2$ in 2016. This fuel switch drove the largest ever annual reduction in British power sector CO_2 emissions[21] of 25 $MtCO_2$ in 2016.

Figure 2 shows that renewable generation expanded rapidly over the last decade to supply nearly a fifth of Britain's electricity. However, the fall in coal generation between 2015 and 2016 was filled entirely by natural gas: coal output fell 46 TWh and gas output increased 43 TWh, while zero-carbon renewables changed by less than 1 TWh due to underlying weather conditions[22]. For context, Britain's switch from coal to gas in 2016 was greater than all other European countries combined[23].

If sustained, this rapid reduction arguably puts Britain well ahead of its near-term carbon reduction trajectory, as it could now beat its carbon targets for 2018-22 within the timeframe of the 2013-2017 carbon budget[24]. However, as power sector emissions are part of the EU Emissions Trading Scheme (referred to as the traded sector), the net UK carbon accounting[25] means that these reductions can be 'exported' from the power sector as a surplus to other parts of the traded sector (*e.g.* heavy industry) potentially in other countries in Europe. Under agreed carbon accounting rules, they cannot be allocated to, or purchased by the non-traded sectors in Britain (*e.g.* domestic transport or heat) to provide additional carbon headroom[26]. Nevertheless, the significant reduction in electricity carbon intensity provides a direct benefit for decarbonising these sectors through electric vehicles and heat.

Britain's commitment to reduce coal power

During the run up to COP21 in Paris, the British government began consulting on the phase-out of unabated coal by 2025[27,28], marking the world's first commitment to abandoning coal power[29]. Although this deadline helps frame the Government's commitment to decarbonisation, there is concern that early power station closures pose an unacceptable security of supply risk. From another perspective, it is felt increasingly important to remove unabated coal as soon as is practical to free up its market share for new, cleaner generation[30].

Scheduling the demise of Britain's coal generation has been eased by the fleet's age (80% are over 30 years old), and tightening air pollution controls such as the Industrial Emissions Directive[31]. Half of Britain's coal capacity (14.3 GW) closed in the 5 years to 2017, and those that remain have historically low utilisation. Coal provided less than 10% (28 TWh) of electrical generation in 2016; a smaller contribution than wind (30.5 TWh) and less than solar generated in Germany (37.5 TWh)[32] over the same year.

Britain is therefore on track to become the first major economy to transition away from coal after centuries of production and consumption (Figure 3). The latter fell to 12 Mt in 2016[33], levels not seen since 1935[34]. The rate of this change is unprecedented; it took 14 years for power sector coal demand to increase from 12 to 28 million tonnes per annum (1936 to 1950), but only 1 year to make the reverse transition (2015 to 2016). Britain could be the first country to leave its coal reserves unburnt in the ground[35], and in November 2017 it set out a global alliance to end coal power generation[36]. This would have been inconceivable to policymakers even a generation ago, when coal, nuclear and oil generation powered the country[18].

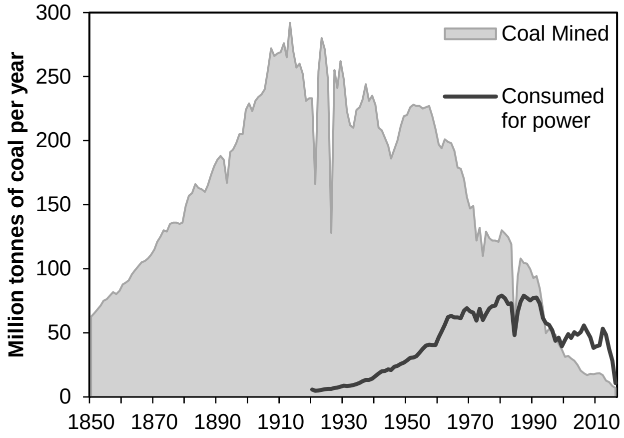

*Figure 3: **Quantity of coal mined and consumed for power generation in Britain.** Power sector data from ref.* [19] *and coal production data from refs.* [33] *and* [34]*.*

Factors that enabled Britain's rapid fuel switch

Britain's experience of fuel switching can be viewed as a policy success, albeit at a rate that was better than anticipated. We suggest four factors were necessary to achieve this rapid fuel switch: first, gas generation plants were already built and had spare underutilised capacity; second, existing fuel supply infrastructure could cope with the increased power sector gas demand; third, the political will was available to intervene in markets to incentivise the switch, penalising coal vs. gas generation via an effective carbon price; Finally, coal and gas prices were sufficiently close so that switching did not inflict large price rises on electricity consumers (a carbon price of £50/t was needed to incentivise fuel switching in 2013, compared to £16/t in 2016)[13].

Renewable generation has also rapidly increased in Britain (Figure 2), lowering emissions over the last decade. However, significant emissions reductions only began in 2013 due to the declining share of coal as carbon prices began to rise, as will be discussed in detail below.

While putting a price on carbon enabled the fuel switch in 2015 to be rapid, the development of this policy and the enabling conditions and the investment in generation and infrastructure for the switch to take place were decades in the making. The EU Large Combustion Plant Directive (2001)[37] and Industrial Emissions Directive (2010)[31] aided in closing half of Britain's coal capacity; while the Climate Change Act (2008)[38] and Electricity Market Reform (2013)[39] laid the foundations for the Carbon Price Support scheme.

Putting a price on carbon

Our view is that the primary driver for coal's substitution in 2015–16 was the higher price placed on carbon emissions. Since 2005 British power stations were subject to the EU Emissions Trading Scheme

(ETS) but it delivered carbon prices that were too weak to drive sustained lower-carbon investment[40–43]. To address this, Britain introduced the Carbon Price Support (CPS) policy in 2013 which required power-sector emitters to pay a top-up price to a Carbon Price Floor (CPF) determined by policymakers[44]. This aims to provide generators with the certainty of a more stable (but higher) price of CO_2 than delivered by the EU-wide market alone.

This CPS policy is still subject to regulatory risk as the floor price can be changed. Its initial trajectory was rising towards £70/tCO_2 in 2030; however, successive announcements have frozen the CPS rate at its 2017 level of £18/tCO_2 at least until 2021. While this suggests diminished ambition in the face of cost sensitivities, it should be compared to an EU-ETS price of approximately €5/tCO_2 throughout 2016.

Debate continues about the floor price[45–47]. Whilst it has been effective in promoting the switch from coal to existing natural gas generation, it has failed to incentivise construction of new low-carbon generation, which continues to require other forms of financial support. The cost to consumers can be roughly approximated from Figure 4a as the gap between the actual electricity price and the estimated cost of the marginal fuel (whichever is more expensive, gas or coal). We estimate the carbon price floor has added in the region of 0.7 p/kWh to retail prices (~5%) during 2016. This rough estimate is indeed comparable to government analysis[48] and estimates for UK industry[49]. This price rise is very modest considering the ~25% reduction in power sector emissions it facilitated in just one year.

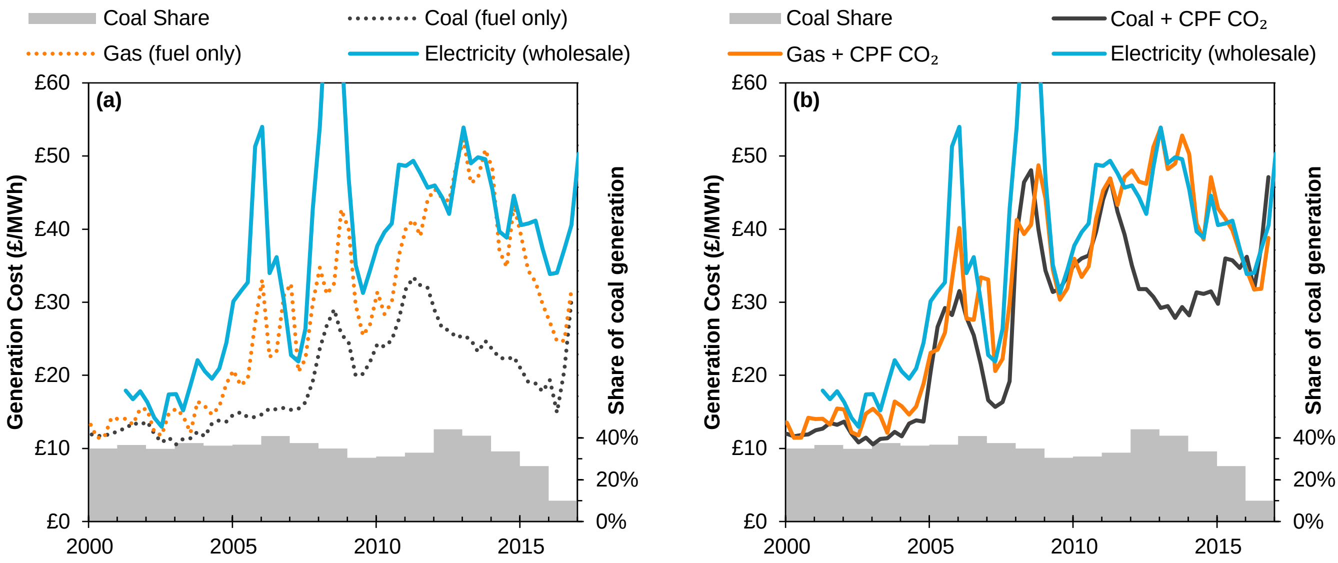

*Figure 4: **Wholesale price of electricity in Britain with the competitive benchmark based on fuel and carbon prices. (a)** Electricity prices compared with the estimated cost of generation from coal and gas with no carbon price. **(b)** The same comparison including the prevailing carbon price (CPF CO_2) in Britain. The solid grey shading plots the share of total electricity generation from coal. Generation cost consists of fuel combusted (divided by conversion efficiency) and carbon emitted (multiplied by carbon price), neglecting other aspects such as maintenance and network charges. Prices and costs have quarterly resolution, the coal generation share has annual resolution. Carbon price data from refs.[44] and [86], fuel price data from ref. [87], electricity price and coal share data from ref. [13]. Electricity prices represent the day-ahead spot market.*

The costs of electricity generation are shown in Figure 4, highlighting the falling cost of gas relative to coal since 2014. However, coal would still be the cheapest form of generation with the European ETS carbon price, despite the sharp rise in international coal prices through 2016 (due to China cutting production by 10%)[50]. Instead, the CPF allowed gas generation to become equivalent or cheaper since the beginning of 2016 and to displace coal's share of generation. In terms of historical precedence, the carbon price in Britain has been raised back to its level in 2008. In the rest of Europe, it remains at just one-third of its peak.

Fuel switching is not unidirectional, and could equally be reversed while coal generation capacity remains available over the coming years, helped by capacity market payments. All this would take is another shift in relative fuel prices or a weakening of the carbon price to increase coal's annual market share.

Leaving the markets to it

Britain's experience shows that liberal markets can rapidly adjust to well-timed well-aimed policy signals. Policy is not an essential ingredient though, as America demonstrates that a confluence of market factors can drive fuel switching alone, albeit at a slower pace.[51–53] Since 2005, natural gas prices have fallen 70% compared to 25% for coal due to increased production and the inability to export shale gas[6] (due to insufficient infrastructure). This has lowered the US average carbon intensity of electricity by a quarter (see Figure 1), with a 5 percentage point swing from coal to gas[20] occurring in 2015, reducing power sector emissions by over 130 Mt[54].

The political landscape changed with the election of President Trump in November 2016, suggesting ongoing tensions between Federal efforts to revive an ailing coal sector, and many State policies that focus on decarbonisation. Carbon pricing at a federal level which would accelerate fuel switching from coal to natural gas is therefore improbable under the Trump administration. The US has a complex range of political drivers from federal environmental regulations impacted by sector lobbying, layered with further political drivers at state level. Within this melange of political and market forces, it is difficult to suggest future levels of fuel switching with any degree of certainty. Federal regulations have switched back and forth to favour different technologies, which suggests the benefit of having legal multi-decadal targets to aim for. Britain is not immune from lobbying and switching regulations back and forth to suit different technologies, but it has pioneered the use of long-term legal targets in the 2008 Climate Change Act[38]. This has kept the long-term ambition on track regardless of the change of policy makers and the political pressure to rescind policies that become unpopular with core voters.

Potential for fuel switching in Germany

Germany is regarded as a champion of renewable energy for its extensive investment in wind and solar power. However, it has had limited success in decarbonising its power sector, with emissions down 15% since 1990, compared to Britain's reduction of 61%. Figure *5* shows that Germany's lack of progress is due to continued reliance on lignite and hard coal for >40% of electricity supply.

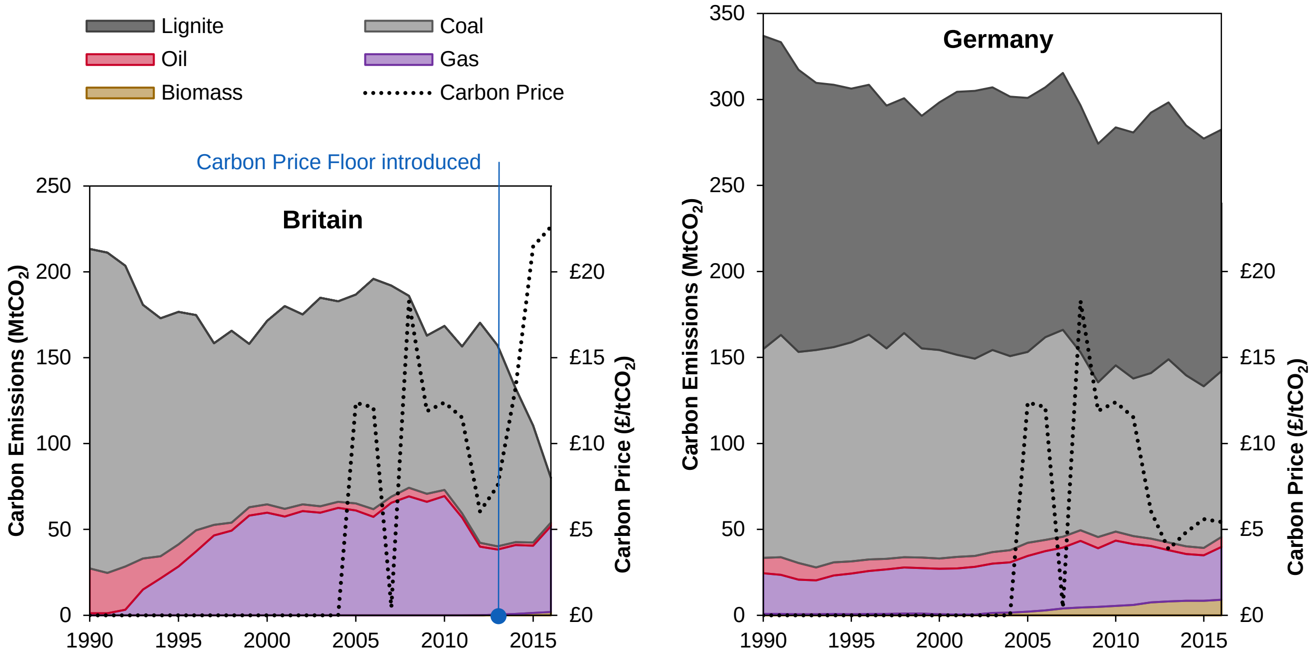

*Figure 5: **Power sector CO_2 emissions by fuel source in Germany and Britain.** The carbon price in each country is overlaid as a dotted line, showing the marked difference since the introduction of the UK's Carbon Price Floor in 2013. It is our view that this was the major additional factor that caused the rapid shift from coal to natural gas generation after 2013. Generation mix data from refs. [19] and [56], emissions intensities from refs. [32] and [13], and carbon prices from refs. [44] and [86].*

Germany is self-sufficient for lignite but imports 89% of its hard coal[55], as its geology makes local production internationally uncompetitive. Import dependency for natural gas is similarly 90%, although only one-sixth of demand is from the power sector as gas is primarily used for heating[56]. Around 15bcm/year (~150 TWh/year) of spare capacity exists in the Nordstream pipeline for increased gas supplies[57], with an additional 55bcm/year (540 TWh/year) if Nordstream 2 is constructed. At a national level, it seems the fuel supply infrastructure has the potential to accommodate significant levels of fuel switching.

However, several factors temper Germany's desire to take this route, not least the security implications of swapping indigenous lignite to imported natural gas. Germany's decision to remove nuclear generation provides an additional challenge: installing 60 GW of wind and solar power in the last decade has done little more than offset the lost output from the 10 GW of retired nuclear power[32]. Both considerations were not applicable to Britain, which has no lignite mines, and, in contrast to Germany, is embracing new nuclear build. Germany is a fascinating interaction of political economy interests, with a lignite lobby that capitalises on security of supply and cost arguments for Germany's energy transition. However, without the development of carbon capture and storage in Germany (which currently seems highly challenging), lignite generation will at some point be impossible to reconcile with decarbonisation targets. Britain's experience shows that Germany's fuel mix could be rapidly changed given their pre-built but underutilised gas generation capacity.

Germany has 24 GW of gas-fired power stations, compared to 28 GW of hard coal and 21 GW of lignite[32]. In recent years, nearly-new gas power stations have been mothballed after proving unprofitable, and eventually exported to the Middle East[58]. This is because gas capacity lies mostly unused, with 18% utilisation compared to 40% for hard coal and 74% for lignite in 2016[56]. An additional 155 TWh of electricity could be produced if this gas generation capacity were utilised at 80%, sufficient to completely eliminate hard coal plus four-tenths of lignite production, which would cut Germany's power sector emissions by around a quarter, or 62 $MtCO_2$ per year.

Greater emissions savings would result from displacing lignite. However, this would increase primary energy import dependency; whereas switching from hard coal to natural gas would simply switch one type of energy imports for another, introducing a different set of risks.

Potential for fuel switching globally

Quantifying a more accurate global potential for fuel switching require a detailed country-by-country analysis of infrastructure, generation, security of supply, demand, prices, and political interests; and will be a valuable area of future work. Nonetheless, the broad order-of-magnitude can be estimated using existing statistics for annual generation and installed generating capacity. We estimate the potential for fuel switching in the 30 largest coal consuming nations (covering 97% of global coal capacity) by compiling the amount of coal and lignite generation in 2015, and comparing this to the additional generation that could come from gas in each country. This is based on existing, underutilised gas generation; disregarding the option of building new capacity. The maximum gas generation potential assumes that combined-cycle gas turbines (CCGTs) could run up to 80% utilisation (limited by availability and downtime), while open-cycle (OCGTs) and steam boiler stations would be limited to 0–40% utilisation (due to economic rationale). Displacing coal with single-cycle (rather than combined-cycle) gas stations would yield half the carbon savings due to their lower efficiency and thus higher carbon intensity. We assume CO_2 emissions of 405 g/kWh for CCGTs and 710 g/kWh for OCGTs, relative to 1025±55 g/kWh for national coal fleets[16]. Sources, details and justification are given in the Methods section.

Figure 6a shows the potential for fuel switching across the OECD and coal-reliant developing countries. Many European countries (including Britain) have over-built power systems with sufficient idle gas capacity to completely eliminate coal, at least at the annual aggregate level. Of the largest coal consumers, Russia and the US could convert 40–50% of their coal generation to gas, but China and India could only displace 6–12% due to the vast scale of their coal fleets.

Poland depends on solid fuels for over 90% of its electricity, and lacks the pre-existing gas plants to take over market share[59]. Japan is still gripped by a capacity shortage in the wake of the Fukushima disaster and shutdown of its nuclear fleet, thus its gas stations are running close to capacity already.

Figure 6b shows that if fuel switching was fully realised in these 30 countries, annual emissions could fall by 0.8–1.2 $GtCO_2$, around 3% of global emissions. Reductions in China, India and Europe amount to 440 $MtCO_2$ per year, and are insensitive to the utilisation of single-cycle plants as these make up only a fifth of their gas fleet. The mitigation potential in the US and Russia is more sensitive to the assumed utilisation, as OCGTs and steam boilers form half their gas capacity.

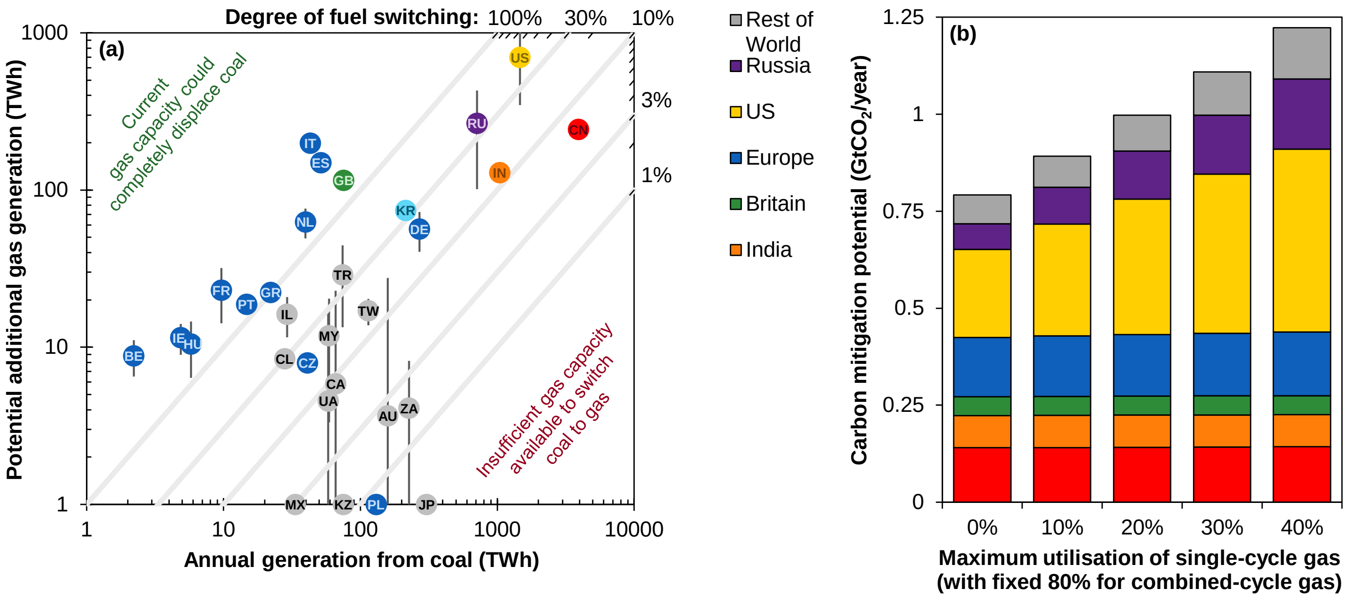

Figure 6: Estimation of the carbon mitigation potential from fuel switching in 30 countries. ***(a)*** *Comparison of output from coal power stations in 2015 with the potential for additional gas generation, if existing combined-cycle gas plants operated at 80% utilisation and single-cycle plants at 20% (with bars showing 0% to 40%).* ***(b)*** *The annual greenhouse-gas emission savings if the identified potential for fuel switching was realised across these countries, showing the sensitivity to the utilisation of single-cycle gas plants. In panel* ***(a)****, countries are identified using their two-letter ISO codes, and diagonal lines highlight the share of coal that could be displaced by gas. Colours are used to group countries into the geographic regions listed in the legend of panel* ***(b)****. The four countries with zero potential for additional gas output (Mexico, Kazakhstan, Poland and Japan) are shown below the axis. Data from sources listed in the Methods section.*

No Silver Bullet

While this analysis is only a first-order approximation (noting the simplifications listed in the Methods section), it suggests that fuel switching in the power sector could provide a significant boost to global decarbonisation. However, fuel switching is no silver bullet, and many barriers can explain why only a small percentage of the estimated potential has been realised thus far.

Fuel switching will change supply-chain and energy security risks, and in many countries would create political tensions by increasing import dependency for primary energy. Although employment in the coal sector has fallen dramatically in many western countries, policies which are seen to further decimate domestic mining industries will face opposition, as seen in America. Over the longer term, politicians must grapple with the consequences of transitioning away from solid fuels; notably how to engage and retrain affected mining communities where coal production is culturally significant, as well as a source of employment.

There are also risks with carbon leakage in highly interconnected markets such as Germany[60,61]. A strong carbon price to promote fuel switching can reduce within-country emissions, but may also shift electricity production (and thus carbon emissions) to areas subject to a lower carbon price. Britain now imports high-carbon electricity from the Netherlands, where coal usage increased 40% and generators pay one-fifth the carbon price. Supranational harmonisation of carbon pricing is needed to avoid the 'offshoring' of power sector emissions. Other considerations, such as the level of methane leakage in the natural gas supply chain must also be carefully assessed[62,63].

Carbon pricing however is not a blanket policy that will work everywhere. In countries that lack the gas infrastructure such as Poland or Japan, raising a carbon price would in the short term be no less blunt than a blanket tax on electricity. In the longer term, a careful balance is needed to redirect how existing infrastructure could be used without going so far as to incentivise building new gas infrastructure and avoidable carbon lock-in. If limiting global temperature rise to 2°C requires no more carbon-emitting electricity generation to be built[64], the distinction between utilising existing gas generation versus investing in additional capacity is of critical importance[65,66].

Conclusions

Switching between fossil fuels can only ever be a temporary stepping stone towards a low-carbon energy system. Its potential is bounded by the scale of existing coal and gas infrastructure, and natural gas is incompatible with deep decarbonisation[67,68] unless carbon capture and storage emerges from its ‘valley of death’[11]. If spare capacity already exists, then fuel switching does not require several years to amount to material emissions savings, unlike other key options (renewables, nuclear, efficiency improvements). The ‘quick win’ is provided simply by using pre-existing infrastructure more effectively.

Britain’s example highlights the effectiveness under certain key circumstances of placing a modest, but stable, £18/tCO2 on carbon, and the speed with which the power sector generation changed in response to such a signal; it switched 15% of its generation mix (45 TWh) in a single year, saving 25 $MtCO_2$. Fuel switching can demonstrably achieve very rapid carbon reductions. In comparison renewables took six years to grow from 4% to 19% of Britain’s generation (a 45 TWh/yr increase), saving approximately[13] 22 $MtCO_2$. It will be at least 10 years before new nuclear capacity will be built in Britain[58], which would require three projects the size of Hinkley Point C to save 27 $MtCO_2$ per year[69] to fuel switch from natural gas (as coal will no longer be in the system).

Fuel switching can also be a cost-effective and convenient form of decarbonisation. If driven solely by market forces it will lower bills; if policy support alters the balance between closely-priced fuels, it can have minimal impact on consumers, as seen in Britain. Natural gas retains the energy system benefits of being a fuel: controllable and dispatchable generation, and extensive storage infrastructure with days to weeks of capacity, rather than minutes to hours for electrochemical and thermal storage[70,71]. Controllable flexibility is increasingly desirable to accommodate greater levels of variable renewable energy generation, especially so if coal generation is simultaneously being retired.

Anthropogenic carbon emissions had almost plateaued in 2016[2]. The next, momentous step – for emissions to decrease – could be catalysed by a concerted global effort to switch away from coal to natural gas. Our initial examination suggests the top 30 coal consuming countries could prevent 1 Gt of CO_2 emissions from entering the atmosphere annually; with a central estimate that 20% of the world's coal could be switched to gas using existing, under-utilised infrastructure (the range is 13% with no OCGT up to 27% with them running at 40% utilisation). This provides an immediate benefit to slow the increase in cumulative carbon emissions, buying all-important time for other sectors to catch up, and providing cleaner electricity with which to decarbonise them. Any effort to front-load emissions reductions will ease the pressure on future generations who are faced with removing emissions from the atmosphere[72]. However, it is vital to cumulative emissions that the gains of early decarbonisation from fuel switching are not squandered by the extended use of gas generation as a substitute for the necessary increase in low-carbon technologies.

The potential for rapid and material global emissions reductions appears to have gone unnoticed thus far; it is about time that the benefits of fuel switching received greater attention.

Methods

Overview. We perform a high-level evaluation of the carbon mitigation potential of switching from coal to gas in the power sector based on statistics for annual generation and installed capacity. The aim is to produce an order-of-magnitude estimate that motivates the discussion around fuel switching in the power sector. A more nuanced approach would form the basis of a more detailed exploration of the potential of fuel switching.

The calculation for a given country can be summarised by four stages:

1. Find the historic annual production from coal and gas plants;
2. Find the installed capacity of gas plants, broken down to combined-cycle and single-cycle;
3. Estimate the maximum potential output from the gas fleet, and thus how much coal could be displaced by gas;

4. Estimate the carbon intensity for the coal and gas fleet, and thus the carbon savings from switching between them.

To summarise, we assume coal stations emit 1025±55 gCO_2/kWh which could be displaced by combined-cycle gas stations producing 405 g/kWh or single-cycle stations producing 710 g/kWh. We assume combined-cycle gas plants could run baseload with 80% utilisation, and test a range of utilisations for single-cycle plants from 0% (not being used at all) up to 40%.

Coverage. We consider thirty countries from the OECD and larger developing nations, which together possess 1900 GW of coal capacity (97% of listed global capacity) and 1100 GW of gas capacity (83%). The choice to study thirty countries was arbitrary (inspired by an anonymous peer reviewer's comments), as a trade-off between tractability and comprehensiveness. The countries are listed in Figure 6 by their ISO codes, and are listed in full in Supplementary Table 1.

Terminology. *Coal* is used as shorthand for both coal and lignite together. *Combined-cycle* is shorthand for combined-cycle gas turbine (CCGT, or also NGCC). *Single-cycle* is shorthand for both steam boilers and open-cycle gas turbines (OCGTs, or also combustion turbines).

Data. The annual electricity generation from coal, gas and nuclear was taken from the IEA[17] for 2015, which was the most recent year available. Nuclear was included to provide a sense check when comparing fossil output to total demand, and when matching capacity and production statistics.

The installed generating capacity was taken from Platts[73] and Enerdata[74] for the end of 2015. The unweighted average was taken across both sources where possible to aim for a comprehensive and unbiased estimate.

Coal capacity was broken down by fuel type: hard coal (anthracite and bituminous), soft coal (sub-bituminous) and lignite; and by the class of steam generator: ultra-supercritical, supercritical and subcritical. Gas capacity was broken into combined-cycle and single-cycle. It was not possible to achieve the same breakdown for electricity production, so it was assumed that each countries' coal and lignite generators operate with the national-average utilisation.

Alignment between the output and capacity datasets was verified by calculating the utilisation of coal and gas plants (and also for nuclear power as a secondary check), ensuring that 100% was not exceeded in any country.

It is regrettable that a full examination of the intermediate data and results cannot be given here, as many of the inputs are derived from commercial sources. Recreating this analysis using open-access data is a logical and important next step[75].

Estimating Potential Gas Generation. We must make an assumption about the maximum utilisation of gas power stations to estimate the potential output from a known capacity. It is unreasonable to assume a power station could operate at maximum capacity all year round, as this ignores the need for maintenance, unexpected outages, and seasonal derating due to ambient temperature.

We assume that CCGTs can operate as baseload generators with 80% utilisation, which equates to 7,000 full-load hours per year. This is based on the median utilisation of nuclear power (traditionally a baseload generator), which was 79% across the countries we consider. The 90th percentile for nuclear utilisation across the countries was 90%. Coal and gas stations were observed with 75–85% utilisation in Japan, South Korea, Taiwan, Mexico, Poland, Netherlands and Portugal. This assumption is slightly conservative compared to the values for CCGT utilisation employed in analysis by the IEA (85%)[76], EIA (87%)[77] and BEIS (93%)[78]. Their mean of 88% implies the potential for fuel switching could be one tenth higher than we estimate.

Single-cycle generators are not assumed to run as baseload as their lower fuel efficiency implies higher running costs. We consider a range of utilisations from 0% to 40% (0 to 3,500 full-load hours), and take 20% as a central value (1,750 full-load hours). We estimate that in 2015, single-cycle generators have around 20% utilisation in Australia, around 40% in Japan and Ukraine and over 60% in Mexico, Malaysia and South Africa.

We cannot directly observe the historic utilisation of single-cycle generators as the production data sources give no distinct breakdown. We therefore estimate their utilisation by assuming that CCGTs cannot exceed 80% utilisation. As a worked example: consider a country with 400 TWh annual gas generation coming from 80 GW of capacity, of which 40 GW is combined-cycle and 40 GW is single-cycle (these figures approximately represent Japan). The overall gas fleet has 57% utilisation. If the CCGTs could run at 100% utilisation they would produce 350 TWh/yr, meaning the single-cycle plants must run at 14% to deliver the annual total. Using our expectation of 80% CCGT utilisation, single-cycle plants must operate at 34% utilisation.

Direct observations are possible for the US gas fleet using Bloomberg data[79]. The average utilisation of single-cycle plants is below 10%, but this is skewed by a large number of inactive plants. One quarter of the fleet has a utilisation of over 20%. For comparison, the EIA assume 30% utilisation for conventional gas combustion turbines[77] and BEIS assume 22% utilisation for OCGTs[78].

We combine the potential output from combined-cycle and single-cycle plants, then subtract off their actual production to give the amount of additional coal that could be displaced. The minimum of this potential extra gas, and the actual output from coal is then taken as the fuel switching potential – given in Figure 6a, and in Supplementary Table 1.

Supplementary Table 2 gives a work-through of the calculation, using stylised numbers that approximately represent Japan, Britain and the US.

Assumptions on Carbon Intensity. We estimate the fleet-average carbon intensity based on each country's installed technology mix. For coal this was based on the relative share of capacity using each fuel and boiler type; for gas it was based on the relative amount of additional output from combined-cycle and single-cycle plants.

For gas, global values from the IEA were used[80] : 405 g/kWh for combined-cycle gas turbines and 710 g/kWh for open-cycle gas turbines (combustion turbines) and steam boilers. These agree with the capacity-weighted averages calculated by Bloomberg within the US[79]: 404 g/kWh for combined-cycle and 711 g/kWh for open-cycle.

For coal, IEA[81] values for each grade of fuel were combined with IEA[82] values for each class of steam generator, to give the matrix of carbon intensities in Supplementary Table 3. All subcritical plants were assumed to be 'new' regardless of their age, to remain conservative in estimating the carbon mitigation potential for fuel switching.

Bloomberg estimate the capacity-weighted average carbon intensity for US coal plants in 2015 to be 965 g/kWh for hard coal, 1020 g/kWh for sub-bituminous coal, and 1075 g/kWh for lignite[79]. Given that the US has a 71:29 mix of subcritical and supercritical plants[73] , these values lie within ±3% of the carbon intensities estimated using Supplementary Table 3.

In summary, our assumptions suggest that displacing 1 TWh of coal generation would save 0.620 $MtCO_2$ using combined-cycle gas, or 0.315 $MtCO_2$ using single-cycle gas. Following on from the examples set out in Supplementary Table 2, the calculation of fleet-average carbon intensity and the mitigation potential of fuel switching are outlined in Supplementary Table 3.

Simplifying Assumptions. Again, it must be stressed that this is a first-order approximation, and the results presented above come with three notable caveats.

No consideration has been made about the time-varying nature of electricity demand. It may not be possible for combined-cycle gas stations to run with 80% utilisation if the profile of demand has significant diurnal or seasonal swings, as their output cannot exceed the country's minimum demand for electricity. This minimum is around two-thirds of average demand in European countries.[83] We found that few countries had enough installed gas capacity for the maximum potential gas output to be more than two-thirds of annual demand, so this may not be a severe limitation. Notable exceptions were Britain, Italy and the Netherlands.

No consideration is given to fuel supply and transportation infrastructure. It may not be possible for some countries to supply the necessary quantity of gas to their power stations in the short-term.

No spatial detail is included within individual countries. The location of gas generators relative to demand centres and transmission infrastructure may limit the output of gas power stations – particularly in larger countries such as the US and China.

Data Availability. The data that support the plots within this paper are available in the Figshare repository, 10.6084/m9.figshare.5827695[84]. As detailed in the Methods section, much of the underlying data is proprietary – and is therefore unable to be shared by the authors.

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