

UK INDUSTRIAL ELECTRICITY PRICES: COMPETITIVENESS IN A LOW CARBON WORLD

Professor Michael Grubb and Paul Drummond
University College London, Institute for Sustainable Resources

Report Commissioned by the Aldersgate Group
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PREFACE

UK electricity prices are the topic of lively debate, particularly industrial prices in the context of Brexit and the UK's Industrial Strategy. This report was written as a contribution to that debate by Professor Michael Grubb and Paul Drummond, Senior Research Associate, at the UCL Institute of Sustainable Resources, with extensive and invaluable contributions on the Italian electricity system by our colleague Elsa Barazza.

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Professor Michael Grubb and Paul Drummond

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SUMMARY FOR POLICY MAKERS

This report, based on a detailed analysis of industrial electricity prices in the UK, France, Germany and Italy, considers how the UK government can help deliver competitive prices as the UK transitions to a low-carbon power system. The fact that UK industrial electricity prices are higher than in countries such as France and Germany has been well documented, but this report goes further than previous analysis by considering the drivers behind the evolution of electricity prices and what policy measures can help mitigate unnecessary costs to businesses.

It finds that differences in industrial electricity prices have been driven in particular by the fact that some of our key continental neighbours tend to be better interconnected and engage in more cross-border electricity trading, are more supportive of long-term contracts to reduce prices for electro-intensive companies, take a more activist approach to how network and policy costs are charged to electro-intensive companies, and have integrated renewable energy on their system in a more co-ordinated – and therefore cost-effective – way than in the UK (although UK policy is now improving in this regard).

This report sets out six policy options to provide competitive industrial electricity prices as the UK continues its transition to a low-carbon power system. These recommendations come from the observation that the government should use the technological revolution underway in the clean power sector to minimise system costs, whilst at the same time better integrate the reform of the electricity market with the UK's new Industrial Strategy.

To deliver competitive industrial electricity prices and reduce the gap with prices prevailing in neighbouring continental countries, the government should consider:

1. **Removing barriers to investment in mature renewable energy projects**, based on the recognition that technologies like onshore wind no longer need subsidy if the political risks are minimised (e.g. through long-term contracts). This should be coupled with a resumption of the carbon price escalator, taking effect as coal retires from the UK system in the early 2020s, so that investors have confidence that they will save on fuel and rising carbon costs (with an appropriate compensation mechanism for those electro-intensives where justified, see also #6);
2. **Improving strategic coordination between investments in network and generation infrastructure** to avoid congestion and inefficient network development at all levels, and including review of transmission funding and charging approaches in the light of continental practice;
3. **Ensuring that the UK leaves the EU in a way that retains efficient engagement with the internal energy market and supports continued investment in interconnection with continental grids**, which will help to maintain system security more cheaply as the UK electricity system decarbonises;
4. **Facilitating direct cross-border industrial electricity purchases**, with carbon charged on imports (as in California);
5. Using the 5-year review of the Electricity Market Reform and Capacity Market to **help UK industrial electricity consumers benefit from providing system-related services** such as demand-shifting and frequency support to the electricity system;
6. **Establishing a long-term market of zero carbon and tradeable electricity contracts** to facilitate industry access to low cost and unsubsidised sources of renewable electricity such as onshore wind. Industrial consumers holding these contracts would thereby avoid the carbon price.

EXECUTIVE SUMMARY

Concerns have grown in recent years that UK industry pays too much for its electricity, particularly compared to continental and international prices. Close examination shows a more nuanced picture, but also shows some important differences between how the UK and some of its continental neighbours approach industrial electricity prices and recover costs from different parts of industry and society. At a time where the UK government has published new Industrial, and Clean Growth Strategies and is reviewing the cost of energy, the report highlights the extent to which industrial electricity prices in the UK are different to some of our key continental neighbours (Germany, France and Italy), sets out the key trends that explain those differences, and suggests recommendations to moderate the electricity prices paid by UK industry in the future.

Looking back: Have UK industrial electricity prices been exceptional?

Since 2000, UK wholesale electricity prices have been mainly determined by the cost of operating gas plants built in the 1990s, given the UK's highly liberalised version of electricity markets. Network costs were driven down by a simple regulatory formula. There was surplus capacity, no capacity-related payments, and little investment. Consequently, prices remained low as long as gas prices did – and rose sharply as fossil fuel prices escalated from 2004.

In parallel, the historic tensions between the government drive to introduce renewables and the regulated expenditure on electricity networks also led to congestion on the network, resulting in renewables (mainly in Scotland) paid compensation when not permitted to generate at their full capacity. This approach contrasted with some continental systems, where renewable support policies were better co-ordinated with investment in the overall network infrastructure and were more cost effective.

Between January 2008 and 2012, UK electricity prices for large industrial consumers rose in a way that broadly mirrored the impact of the gas price on the UK wholesale electricity price, and remained close to the EU (and German) average over that period. After 2012, the gap with the continent widened, peaking in 2015, as a result of the following four key factors:

- Changing fossil fuel prices including differentials between gas and coal prices;
- The need for new investment throughout the ageing

UK system, including transmission upgrades, with costs recovered across all UK electricity consumers, which differs from the cost recovery approaches in Germany, France and Italy;

- Exchange rates, with until recently a relatively strong Sterling versus a weaker Euro;
- A more integrated approach to the energy transition in some continental countries including the form and balance of policy costs (e.g. renewables support relative to carbon pricing) and their recovery.

Reported average electricity prices experienced by industrial consumers in the UK in 2016 were 35% above both their level in early 2008, and the EU average (which remained largely stable between 2008 and 2016), but this does not take into account the impact of compensation for low-carbon policy costs in the UK. Compensation schemes in the UK are much more substantial than those in our key continental neighbours for those processes, businesses and sectors able to receive them. Nevertheless, those processes, businesses and sectors outside compensation schemes (or that receive only limited support) face higher net electricity prices compared to their counterparts in many (not all) continental countries.

Much of the UK debate on electricity prices has been at a level of either technical detail, or sweeping (and often questionable) generalisations. However, the way in which the four forces have affected industrial electricity prices – and in particular, differentials with the continent – reflect wider choices in terms of policy and regulatory approaches.

Differences in cost-recovery: the UK philosophy of spreading network and (until recently) policy costs relatively evenly across all consumers has contrasted with the approach taken by our neighbours.

The overall cost of the electricity networks appears remarkably similar across the UK, Germany, France and Italy, but the way in which these costs are recovered differs markedly. The UK philosophy has aimed to recover network costs relatively evenly across all electricity consumers, with industry paying its share broadly based on consumption.

Most other countries recover proportionately more policy costs from (the less electricity-intensive) domestic

and commercial consumers, with much lower charges for large industrial consumers. Most of our continental neighbours recover the costs of ‘environmental’ programmes (mainly for energy efficiency and renewables) with charge rates to industrial consumers more differentiated (and lower than for domestic and commercial sectors), but until 2014, the UK (as with network charges) did not differentiate between consumer groups. The energy efficiency programmes mostly benefited households and the commercial sector, whilst the deployment of renewables was a net cost addition.

Except for the direct Climate Change Levy, the UK government subsequently moved to compensate industry (with direct payments) for many of these costs, pending a move to greater exemptions. **UK gross policy costs (pre-compensation) for energy efficiency and (mainly) renewables are less than in many continental countries – with associated average policy charges to industry in aggregate at about 3/5ths of that in Germany and Italy – but carbon prices are higher.** UK industry exemptions are smaller, whilst compensation payments are far larger (for those receiving them), than in any of our neighbours examined. Over 2018–19, the government plans to shift more from compensation to exemptions, which would reduce electricity prices and help to bring the UK more into line with continental practice.

The ‘renewables paradox’

Although there has been a high initial deployment cost, renewables across Europe are now starting to reduce wholesale electricity prices. Germany’s *Energiewende* has been the world’s most ambitious programme of renewable energy deployment; the large initial investments have led to major cost reductions, in both onshore and offshore renewables. By 2015, renewables contributed over 30% of electricity in Germany and Italy, with France’s electricity generation dominated by low carbon sources such as nuclear and renewables.

Household and commercial consumers pay most of the policy costs. Yet, because renewables cost little to operate, at times of high output (and low demand) they reduce wholesale electricity prices, which occasionally go negative in Germany. The overall impact on wholesale prices is comparable to, and thus helps to offset, the difference between the average policy costs paid by German and UK industry respectively. The wider progress of renewables in Europe (both in terms of levels of deployment and technological maturity)

is starting to reduce wholesale prices more widely and this is already occurring in the UK as renewable capacity grows.

Electricity systems in France, Germany and Italy have had a greater focus on negotiating lower electricity prices for key industries...

Beyond the broad regulatory approaches taken to recover network and policy costs, each of the UK’s three biggest European neighbours have found different routes to moderating electricity prices for their largest industrial consumers.

Although German businesses on average pay more charges (network plus policy costs) than in the UK, Germany extended its charging systems into much finer-grained, negotiated distinctions in the rates that businesses pay depending on sector and consumption intensities.

In France, a huge industrial consortium (known as ‘Exeltium’) negotiated a collective 24-year electricity contract with the nuclear-based *Electricité de France* (EDF), thus buying down the price considerably, **in ways that would be incompatible with the UK’s historic approach to promoting competition between industries.**

In Italy, to deal with generally high industrial electricity prices, the government has facilitated large industrial consumers to engage in “Virtual electricity trade”, buying at cheap (mainly German) prices in return for investments in expanding interconnection capacity.

...within more integrated and forward-looking systems and a different financial environment

The UK electricity market has few contracts with duration beyond a couple of years ahead, thus exposing UK industries more to the volatility of energy prices, in contrast to some of their continental competitors where some power generators and consumers contract much further ahead.

Continental electricity networks are more integrated, and interconnections between Member States are mostly treated as part of the regulated networks. **High levels of interconnection offer policy choices to reduce industrial electricity prices.** In contrast, UK interconnections to the continent have been built and operated more as commercial assets, mediating flows between wholesale markets and with little direct contracting between users and foreign generators.

The UK's emergence from the aftermath of the financial crisis, led by the relative health of its financial services, drove up the £:€ exchange rate, increasing *comparative* electricity prices, while limited interconnection constrained trading to bridge this. Continental industry, by contrast – particularly Germany – has benefited from a strong and integrated industrial base with a supportive banking system, nested within the historically weaker Eurozone currency area.

Against this background, the 2015 peak in exchange rate differentials coincided with peak contracted gas prices and the increase in the UK carbon floor price, all of which combined to make UK industrial electricity, for many companies, amongst the most expensive in Europe. The gap lessened in 2016 as the exchange rate fell, but UK industrial prices remain comparatively high for those without compensation.

UK industrial electricity prices in an era of industrial strategy

In summary, differentials between UK and international industrial electricity prices have been driven by two key factors, in addition to wider macroeconomic (such as exchange rate) factors.

The first stems from the UK historic philosophy of a market-led, cost-reflective and relatively short-term approach to electricity. UK consumers pay the highs (and lows) of gas price swings, and industrial consumers have been expected to pay their 'fairshare' of the overall costs of the UK electricity system. There are few long-term contracts and none negotiated collectively.

Some of our neighbours have taken a more activist approach. They have used network and policy cost recovery in ways designed to protect electricity-intensive industries (Germany), or otherwise fostered long-term collective contracts (France) or cross-border pricing (Italy), leaving key industries as net beneficiaries from network and low carbon electricity investments (whether renewables or nuclear). These reflect societal and political choices around cost recovery, namely whether domestic and commercial consumers should 'pick up the tab' to help shield electro-intensive industry.

The other factor has been an historical incoherence in the UK approach to developing renewable energy.

Reflecting its more market-based approach, the UK initially supported renewables with subsidies (notably, the Renewables Obligation) that left them still exposed to all the uncertainties of wholesale electricity markets, driving up the cost of capital (hence increasing the subsidies required), and without a clear strategy on how much of the cost should be borne by industrial consumers. There was also more emphasis on using market instruments designed to penalise carbon emissions to create the incentive to decarbonise, notably through the Climate Change Levy (CCL) for lighter industry, and the carbon price floor. In addition, significant historical problems in coordination between generation and transmission led to high congestion costs including payments to renewables not to generate (notably vis-à-vis new Scottish wind farms, with Cornish solar PV also 'constrained off').

Some of our continental neighbours have placed more emphasis upon direct support for clean industry (e.g. through feed-in-tariffs) in ways that do not create direct costs for industrial electricity consumers. Germany in particular had a more integrated approach to the transformation of its energy system, including network and industrial strategies.

However, the UK regulatory approach has evolved. UK Electricity Market Reform and the introduction of competitive auctions for Contracts for Difference (CfDs) have created a far more efficient financing of renewables. Coordination mechanisms have improved. Changes to compensate and soon exempt large industrial consumers from renewables support costs now also differentiate between industries more extensively; the carbon floor price with compensation is also a model which is now being followed by the Netherlands, and probably by France.

Looking ahead: Policy recommendations and conclusions

Given this context, we set out specific options the government could consider to ensure that the electricity prices available to UK industry fall and converge with prices in western Europe, and beyond. These policy options could also support businesses that are not strictly categorised as "electro-intensive" but which nonetheless use a lot of electricity.

The Helm Review acknowledged the recent revolution in the cost of energy technologies and systems, stimulated by both continental (especially German)

and UK investments. We remain unclear how his proposal to put the historical UK contracts, which have helped to finance these investments, into a formal ‘legacy bank’ would help to reduce overall impact on electricity prices¹); the case for exempting electro-intensive industry from these legacy costs can be considered independently.

Strategically, we consider the starting point should be to harness the technological revolution underway in electricity so as to minimise overall system costs. **The path to further reduce disparities between UK and continental industrial electricity prices lies in further integrating UK electricity market reform with the emerging UK Industrial Strategy.** In particular we encourage government to consider taking the following steps:

1. Restore an efficient investment framework for the cheapest mature renewables and signal intent to restore a rising carbon price in the 2020s

Launch a full scale review of policy towards onshore renewables, based on recognition that onshore wind no longer requires subsidy providing that political risk is minimised (e.g. through long-term contracts) and that investors have confidence in realising the full value of fuel (including carbon) cost savings. Specific near-term options include a “Pot 1” CfD auction and reform of planning regulations, and a legislated carbon price escalator (with an appropriate compensation mechanism) to take effect as coal is retired from the system. The carbon price would reduce investment risks, whilst this timing would reduce the impact on wholesale electricity prices and allow time to develop options for industrial consumers to access cheap renewables and circumvent carbon prices (recommendation 6).

¹ Unless their financing were transferred directly to the Treasury, which seems unlikely. There is however an economic case for clearly socially-motivated interventions, like support for the fuel poor and associated building upgrades, to be treated as generic ‘public good’ investments funded from the Treasury rather than through energy prices. In the absence of Treasury financing through taxes, any exemptions to electro-intensive industries would inevitably increase the cost to be borne by other electricity consumers, by a few percent.

2. Establish an integrated approach to network development, funding and pricing

Enhanced System Operator Objective(s) to include more coordinated oversight of future generation and network developments at all scales of the system, so as to minimise combined network and congestion costs; consider using carbon price revenues to help fund specifically identified Strategic Wider Works; and review transmission funding and charging approaches in light of continental practice.

3. Continue the cap-and-floor system to support continued growth of interconnection irrespective of transitional uncertainties as the UK leaves the EU

Electricity trade through interconnection helps UK wholesale prices to converge with continental prices, and lowers the cost of maintaining security as the grid decarbonises. The existing regulatory structure for interconnectors is proving effective, and the government should underline its commitment to maintaining close electricity integration with continental Europe and its support for Ofgem’s cap-and-floor returns regime so as to maintain investment momentum in the face of Brexit-related uncertainties.

4. Facilitate cross-border electricity contracting incorporating UK carbon prices

The government should establish a new structure for direct cross-border industrial electricity purchases, which (as with the Californian carbon pricing system) should charge UK carbon prices on purchased electricity, based upon Guarantees of Origin (see section 6).

5. Support industrial involvement in the Capacity Market and other electricity service markets

The value of system-related services like demand-shifting and frequency support is rising, whilst the cost of providing such services from industrial energy users is declining. The government should in particular use the 5-year review of the EMR and Capacity Market with the explicit aim of helping UK industrial electricity consumers to gain from providing these services to the future UK electricity system.

6. Establish a long-term, zero carbon electricity contracts market

For the longer term, foster standardised structures of long-term, tradeable zero-carbon electricity contracts available to business consumers and grounded in the declining cost of unsubsidised renewable electricity sources. Consumers holding these contracts would thereby avoid the carbon price. Balancing and backup costs will be minimised if the renewable energy contracts are aggregated through a 'green power pool', which passes these costs on to the renewable generators, whilst consumers offering demand flexibility and other system services benefit from lower contract prices. The most relevant publicly-governed body (potentially the Low Carbon Contracts Company or an enhanced System Operator) should be charged with examining the steps required for such a system to develop at scale by the mid-2020s alongside resumption of the carbon price escalator.

1. Introduction

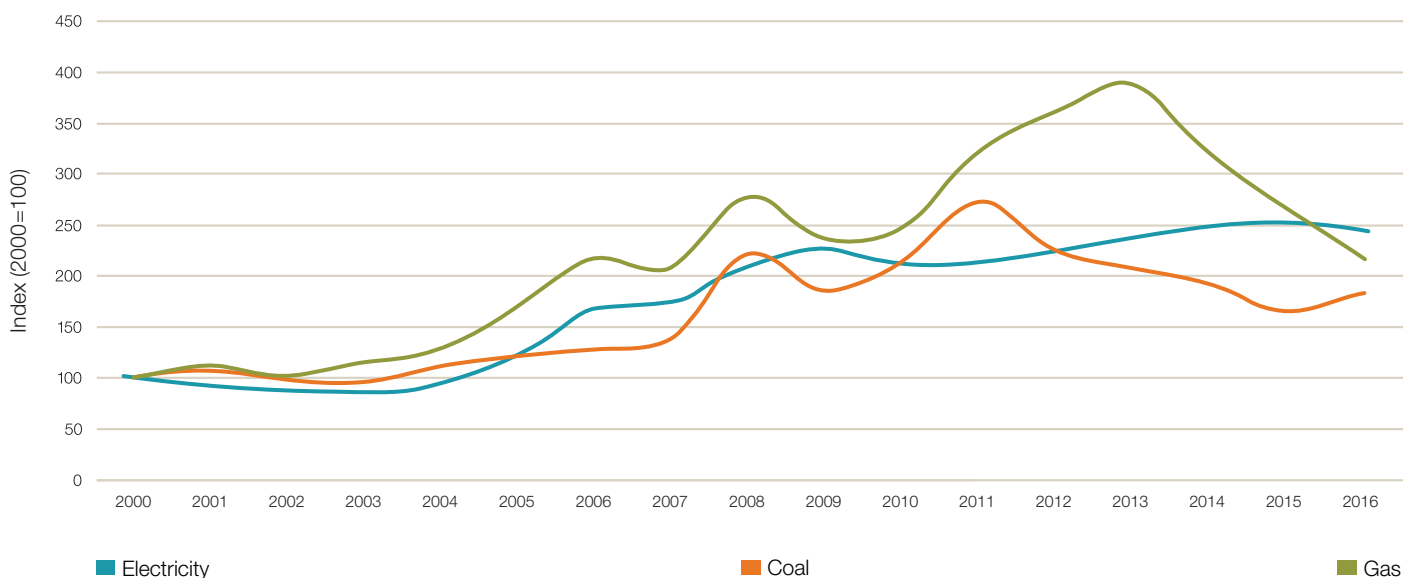
Electricity prices have in recent years become a source of political concern, in part because of the costs involved for some large and electricity-intensive industry and manufacturing sectors such as steel, chemicals, paper and mineral products. As such, electricity prices – which sit alongside consumption as a determinant of total electricity bills – have also featured in the debate about UK industrial competitiveness and industrial strategy, particularly for the most electro-intensive industries.

this is a result of high rates of social and environmental levies placed on the generation and consumption of electricity in the UK. However, recent analysis by the UK’s statutory Committee on Climate Change (CCC) concluded that ‘*differences in low carbon policies cannot explain the difference in electricity prices, which stem primarily from higher wholesale and network costs*’. They also noted that ‘*It is not clear why these costs are higher in the UK than in many comparable countries*’ (CCC, 2017, pg.8).

As illustrated in Figure 1, the price of both gas and coal had by 2008 more than doubled compared with 2000, and UK electricity prices followed the surging in gas price, with a roughly one year lag. Coal prices fell back, as have gas prices more recently, though they remain about double the levels fifteen years before, whilst – following a brief dip after the financial crisis – the average electricity price continued to rise to 2015. As we show below, this contrasts with average trends in the EU where electricity prices have fallen back since the peak of 2013.

It is frequently claimed that electricity prices in the UK, particularly for industrial consumers, are high compared to comparable countries in the European Union and around the world. Some commentators suggest that

Figure 1 – UK industrial electricity, and power producer coal and gas prices, 2000–2016



Note: Indexed, year 2000 values = 100
 Source: BEIS Quarterly Energy Prices, Table 3.2.1

Against this background this report seeks to address four key questions:

- 1) *Are electricity prices faced by industry higher in the UK than other key economies in the European Union?*
- 2) *What key factors determine industrial electricity prices and their components in the UK, and other key economies in the European Union?*
- 3) *How might these factors develop into the future?*
- 4) *What policy options are available to manage electricity prices in the UK, now and into the future?*

Section 2 introduces key data sources for international comparisons on industrial electricity prices, before assessing how prices have developed over recent years in the UK and EU, with a **focus on Germany, France and Italy**. **Sections 3–5** then examine the key drivers behind the components of industrial electricity prices – energy and supply costs, network costs, and taxes and levies – in these countries in 2016, and assesses how they may evolve in the future. **Section 6** discusses policy recommendations to manage industrial electricity prices in the UK. **Section 7** concludes by summarising our answers to the above questions.

2. Industrial Electricity Prices in the EU: data and main

Data sources

Eurostat

Twice a year, EU Member States are required to compile and report data on electricity prices faced by a representative share of domestic and industrial consumers to the European Commission's statistical service, Eurostat. For industrial consumers, average prices are reported for the consumption bands shown in Table 1 (see below):

Prices for a seventh band, Band IG, may also be reported (see Box 1). Prices are reported half-yearly, with key price components also reported for the second half of the year (described below). Reporting requirements under these definitions have been in place since 2007 (before which data were reported under different consumption band definitions).

Other Sources

The UK government's Department for Business, Energy and Industrial Strategy (BEIS) publishes the prices of fuels (including electricity) purchased by the manufacturing industry in Great Britain (GB) on a quarterly basis. Prices are presented across four annual consumption size bands (Small, Medium, Moderately Large and Extra Large²). Government data (BEIS for the UK) forms the basis for national reporting to Eurostat, which publishes these data in both national currencies (where applicable) and Euros.

The International Energy Agency (IEA) also collates and publishes quarterly and annual data on industrial electricity prices, for all members of the Organisation of Economic Co-operation and Development (OECD), through its Energy Prices and Taxes publication. However, only annual values are published, with no disaggregation by size or type of industrial consumer, or by price components. Additionally, data collection methodologies between countries are inconsistent, and for many EU countries, the IEA uses Eurostat data (or a subset thereof).³

We conclude that **Eurostat is the most appropriate publicly-available data source for comparisons of industrial electricity prices across EU Member States**. As with all data sources, some limitations should be noted (Box 1).

Table 1 – Eurostat Industrial Electricity Consumption Bands

Industrial End-User	Annual electricity consumption (MWh)	
	Lowest	Highest
Band IA	–	<20
Band IB	20	<500
Band IC	500	<2,000
Band ID	2,000	<20,000
Band IE	20,000	<70,000
Band IF	70,000	<=150,000

² Annual consumption levels of <880 MWh, 880–8,800 MWh, 8,800–150,000 MWh and >150,000 MWh, respectively.

³ For the UK, France and Italy, prices are an average of all Eurostat consumption bands (with data collected as part of the Eurostat reporting requirement). German data reflects Eurostat Band ID only (IEA, 2017).

trends

Box 1 Eurostat data on electricity prices

EU Member States are responsible for collating and reporting the data themselves, using **data provided by electricity suppliers**. The precise methodology each country adopts can be unclear, and this may limit the data quality and comparability to some degree, **particularly for the division of prices into individual price components**.

Because it represents supplier prices, the price of electricity paid by consumers contracting directly with generators, or from their own generating installations (autogeneration), are not considered.

In addition, **the market share of the electricity suppliers from which data is collected varies significantly** between countries. However, the fact that supplier prices are published (and of course known to market players) means that we consider Eurostat data to be not only the most comprehensive and comparable data available, but sufficiently reliable for the purposes of this study.

The data reports average prices for industrial consumers that fall within each band. **In some countries there may a significant range in specific consumption and prices experienced by individual consumers within each band.**

In particular, the top band (Eurostat Band IG, which mirrors the top BEIS band definition) of industrial consumers with annual electricity consumption exceeding 150 GWh is diverse and complex. There

tend to be many bespoke contracts with confidential terms, limiting the supplier data. Member States are not required to report data for Band IG to Eurostat, but may do so voluntarily. In 2016, only eight Member States did so (including the UK and Italy, and excluding Germany and France). There is great diversity within and between sectors. This includes total and profile of electricity consumption, the proportion of electricity demand satisfied by power drawn from the grid and through suppliers (and thus included within Eurostat data), and the price paid for this electricity. Many extra-large industrial consumers hold and draw upon their own electricity generators to satisfy a proportion of their demand (which hence is not reflected in Eurostat data). For electricity drawn from the grid, they are likely to have individually-negotiated and priced supply contracts. Drawing useful, common insights from Eurostat data for such consumers is therefore likely to be difficult. **For all these reasons, in our main analysis we use the average of the next three largest bands, ID-IF.**

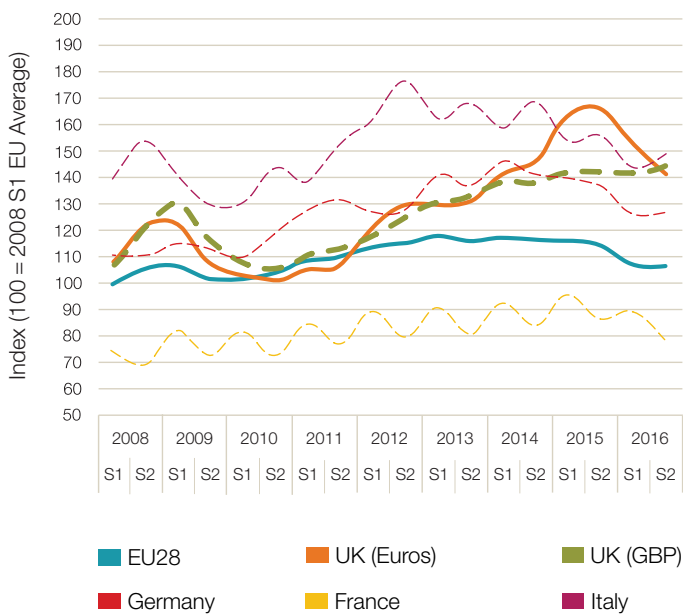
The data reflects the average price paid by consumers at the point of consumption. As such, they include any exemptions and discounts applied to any consumer group before the price is paid. However, **any compensation or refund mechanisms that seek to reduce electricity costs after payment has been made (which as described later in this section, may be significant in the UK) are not included in the data.**

Trends since 2008

Using the half-yearly data (S1 & S2), Figure 2 illustrates the evolution of average (nominal) industrial electricity prices from S1 2008⁴ to S2 2016 for the EU average, the UK, Germany, France and Italy (exclusive of recoverable taxes and levies, such as VAT), using an index with all values set with reference to EU average prices in 2008 S1. In 2008 S1 (Jan–June arithmetic mean) average prices in the EU were €82/MWh for industrial consumers.

The chart shows values averaged across consumption Bands ID–IF, which broadly reflects the large commercial and industrial sector for which consistent Eurostat data are available (Band IG is excluded – see Box 1).⁵ Prices are presented in Euros for all countries and the EU average, and additionally in GBP for the UK.

Figure 2 – Industrial electricity price evolution (index) 2008–2016, UK compared to EU average & key countries



Note: The Figure shows evolution of the average price across consumption bands ID–IF (average), compared to the average EU level in 2008
Source: Author calculations from Eurostat

⁴ Data are presented from 2008 due to incomplete data for 2007.

⁵ In addition, electricity prices in the UK across bands ID–IF have been similar since 2008. In 2008 (S1), prices were £66–68/MWh. By 2016 (S2), prices had increased 43–48.5% in nominal terms, to £98.50–101/MWh. Prices for Band IG followed a similar trajectory, increasing from £60/MWh to £95/MWh.

In 2008 S1, prices in the UK were comparable to the EU average (at around €87/MWh); prices were higher in Germany, Ireland, Italy, Hungary and Slovakia and Cyprus. Figure 2 illustrates that EU average prices remained relatively stable in nominal terms, with average prices in 2016 S2 at around €88/MWh (a ~2% reduction in prices in real terms). Following a sharp peak in late-2008/early-2009, UK prices (in both Euros and GBP) largely mirrored the EU average until 2012 when they began to diverge. By early 2014, UK prices were around 24% higher than the EU average, at around €116/MWh.

What happened after early 2014 depends on whether UK prices are measured in Euros, or GBP.

In GBP, reflecting the pattern of Figure 1, prices have remained relatively stable since early 2014, with little change in the nominal price UK firms were paying on average. However, when denominated in Euros prices appear to increase substantially – peaking at around 50% above the EU average price in 2015 S2 – before returning to 2014 levels by 2016 S2.

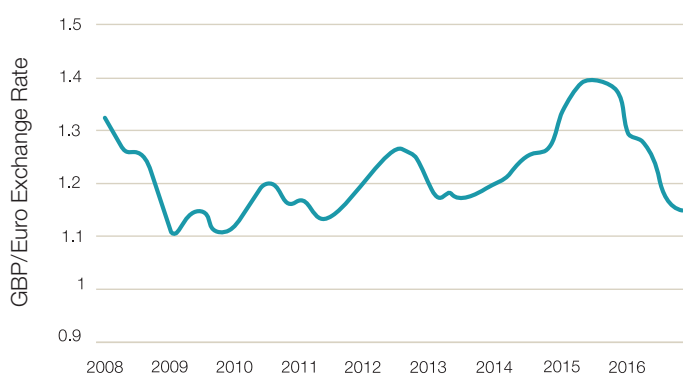
Four main factors explain this pattern:

- The sharp rise (and subsequent fall) in the £:€ exchange rate (Figure 3);
- The residue of exceptionally high gas prices that peaked in 2013, well after the peak of coal prices (Figure 1) which had more impact on continental electricity prices;
- Rapidly expanding investment needs in networks and new energy sources, with costs recovered across all consumers (as detailed in Sections 4 and 5);
- The ramping up of the UK carbon price support rate, which drives up wholesale electricity prices (before compensation) where there is a significant share of coal generation on the system, as described in Section 3.

The impact of exchange rates

Figure 3 shows the bumpy ride of £:€ exchange rates, which fell dramatically after the 2008 financial crisis, before rising as a reflection of growing confidence in the UK economy in contrast to the extended Eurozone crisis, before sharply falling back to post-financial crisis levels (2009–13) following the UK referendum on EU Membership.⁶

Figure 3 – GBP/Euro Exchange Rate – 2008–2016



Source: Eurostat

For industrial companies competing internationally, such exchange rate fluctuations directly affect the relative costs of production; a high £:€ exchange rate increases the comparative production cost (including electricity) of products manufactured in the UK but sold in Europe. Note that this effect is opposite in sign to the (smaller and somewhat delayed) impact of currency fluctuations on UK electricity prices measured in GBP, which reflect dependence of power generation on imported fuels, the cost of which increases with a falling exchange rate.⁷

⁶ Note that the increase measured in GBP since 2008 in Figure 2 also appears significantly bigger than illustrated in Figure 1, largely because prices rose rapidly during 2008 and the base for Figure 2 is first half of 2008 rather than the annual average.

⁷ Domestic electricity prices – as indicated by Figure 1 – are strongly influenced by fuel prices, which depend largely on international markets and hence become more expensive if the exchange rate falls, but with some lag reflecting futures contracts for fuel purchases.

Nevertheless, after the large post-referendum fall in exchange rates (by 2016 S2), **Italy was the only large Member State with industrial electricity prices higher than the UK**, averaged across consumption Bands ID–IF, although **this excludes the role of policy cost compensation mechanisms. As discussed below, such compensation is, for those receiving it, far larger in value in the UK than other European countries.**

Component costs – an overview

For the second half of each year (S2), prices to Eurostat are reported in three components⁸:

- **Energy and supply** – the cost to suppliers of purchasing electricity from generators, plus any operational costs borne by the supplier (excluding those below), and their profit margin
- **Network costs** – the charges associated with recovering the cost of the transmission and distribution networks
- **Taxes and levies** – recoverable (e.g. VAT) and non-recoverable taxes, levies, fees and charges applied to the consumption of electricity for a given consumer, including for social and environmental initiatives and instruments

In 2008 S1, around 70% of average EU industrial electricity prices were ‘energy and supply’ costs, with the remaining 24% and 6% attributable to ‘network costs’ and ‘taxes and levies’, respectively. However, by 2016 S2 the ‘energy and supply’ component reduced to around 59% of price values, with ‘taxes and levies’ increasing to 16%, and ‘network costs’ retaining a 24% share. Whilst the value of taxes and levies has undoubtedly increased, a partial factor behind this shift is also a reclassification of cost elements over time.⁹ In addition, programmes supported by these levies – such as the deployment of renewables – may serve to reduce other components of electricity prices (see Section 3).

⁸ A full definition of what cost elements should be considered under each of these components is provided in Annex II of Directive 2008/92/EC for the years 2008–2016, and in Regulation 2016/1952 for 2017 onward.

⁹ For example, data for the UK from 2015 reclassified the cost of various environmental and social taxes and levies that were previously considered under ‘energy and supply’, to ‘taxes and levies’, to improve comparability with other Member States.

A focus on the UK, Germany, France and Italy

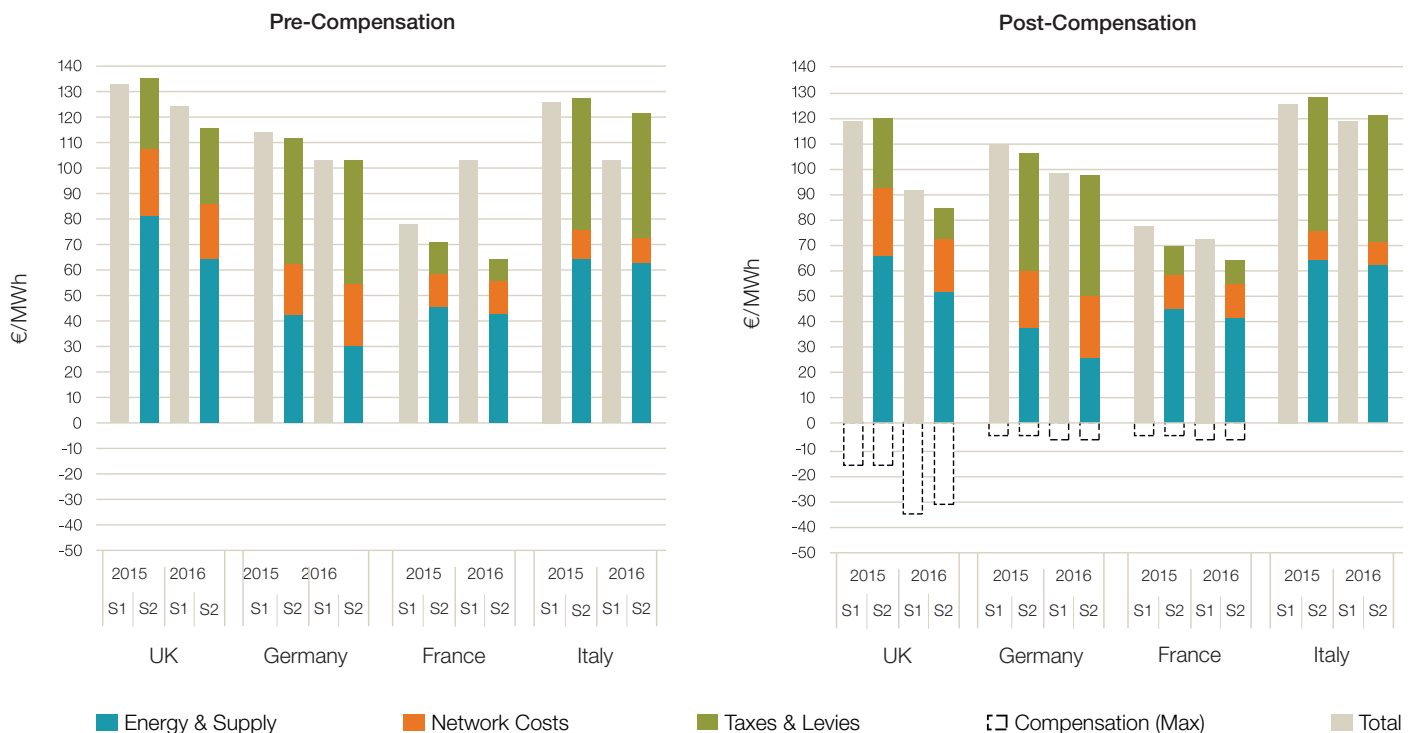
To take a closer look at cost comparisons across the major European industrial economies, this report examines industrial electricity prices in the UK, Germany, France and Italy. These comparator countries are selected due to their large industrial sectors, their proximity, relatively comparable economic and political structures, and the range of prices they represent.¹⁰ Values are presented in Euros for all countries.

Figure 4 presents two panels, exclusive of directly recoverable taxes and levies (e.g. VAT). The first (left) panel illustrates prices (in Euros) reported by Eurostat for the UK, Germany, France and Italy, for 2015 and 2016 (S1 and S2). In line with Figure 2, reported values for the UK are comparable with Italy, but higher than those for Germany and (particularly) France.

The second (right) panel adjusts the data in the first panel to illustrate the potential (*maximum*) effect of ex-post compensation mechanisms available in each country in 2015 and 2016 for eligible firms (under the illustrative assumption that such firms experience these average pre-compensation prices).

In 2015, eligible sectors, firms and processes in the UK, Germany and France were able to recover up to 85% of the cost (80% in 2016) of carbon pricing mechanisms applied to the power sector (and passed through to electricity consumers via wholesale prices). Carbon pricing and associated compensation are discussed further in Section 3 (Energy and supply). In addition, from 2016 eligible firms and sectors in the UK are also able to recover up to 85% of the cost of the UK's renewable electricity support mechanisms, and discussed further in Section 5 (Taxes and levies).

Figure 4 – Industrial Electricity Prices (Band ID–IF Average) – Pre- and Post-Compensation (excluding recoverable taxes & levies)



¹⁰ In this report, data presented for the UK often reflects GB only (excluding Northern Ireland), reflecting the separation between electricity markets in GB and Northern Ireland (which is part of the Irish Single Electricity Market). However, for the purposes of this report, GB and UK may be considered largely synonymous.

UK firms and processes eligible for both carbon pricing and renewable support mechanism cost compensation in 2016 may be in receipt of compensation worth up to €34/MWh, equivalent to 27% of the average electricity price experienced by industrial consumers across Bands ID–IF. **However, this is not equivalent to a 27% reduction in the average effective price.** Relatively few industrial sites in Bands ID–IF will be eligible for both compensation mechanisms, and fewer still will receive the maximum level of compensation possible. In addition, few industrial sites would have experienced electricity prices matching the average values presented in Figure 4 (rates for individual sites may range significantly). **Nonetheless, the value of such compensation mechanisms must be held in mind when comparing electricity prices.**

3. Energy and supply

Key messages

- Increasing penetration of renewables have reduced wholesale prices in the UK, Germany and Italy;
- Low coal prices contribute to low wholesale prices in Germany, however carbon prices and air pollution regulations will drive up these costs;
- Some of the lowest industrial electricity prices have been secured by direct contracting outside of the wholesale market: low electricity prices in France have been guided by long-term, fixed-price contracts, whilst some electro-intensive manufacturers in Italy have special access to low cost generation in neighbouring countries;
- The impact of carbon costs on wholesale prices is likely to remain stable or reduce in the UK as the coal phase-out continues, but increase substantially in Germany, and to some extent in Italy and France;
- Growing interconnection will also help to align UK with continental wholesale prices.

This section examines the drivers and factors that influence the energy and supply cost element of the electricity price across each country. This includes the penetration of renewable electricity, the presence of interconnection with neighbouring markets, differences in the costs associated with the ‘price setting plant’ (specifically fuel costs and carbon pricing), and the use of long-term supply contracts.

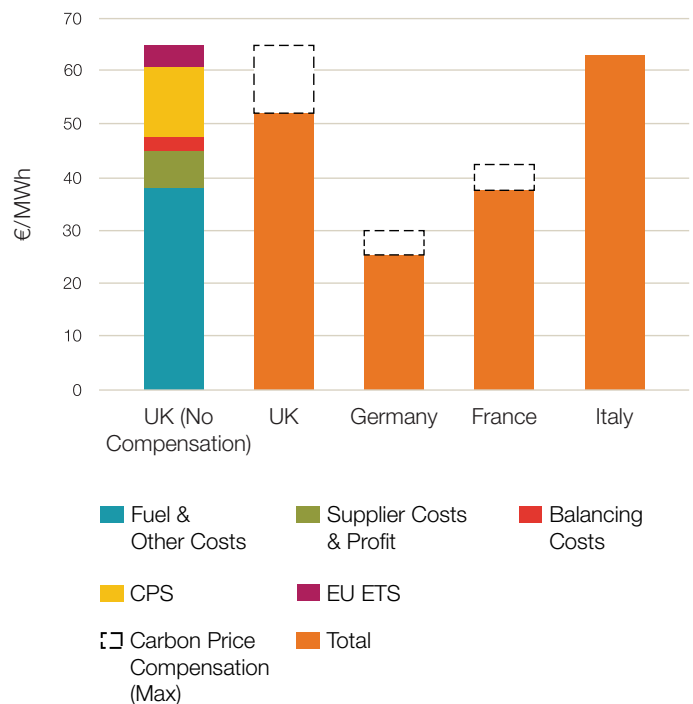
Aggregate comparisons with and without compensation

Figure 5 compares the average Band ID-IF values for the ‘energy and supply’ component of electricity prices for the four countries, in 2016 (S2). The relative contribution of sub-components for the UK are also estimated, along with the value of the maximum potential carbon price compensation for eligible firms and sites in the UK and Germany.

The energy and supply component accounts for an average of €65/MWh on industrial electricity prices in the UK (pre-carbon price compensation). This is comparable to Italy €63/MWh, but substantially higher than pre-compensation rates in France (€42/MWh) and Germany (€30/MWh) (see Box 3).

Of the average €65/MWh energy and supply component in the UK, is it estimated that the majority of energy and supply costs – 60% –

Figure 5 – Industrial price energy and supply components (2016 S2)



results from basic fuel and other costs borne by generators (excluding carbon pricing). Around 4% arises from the proportion of electricity ‘balancing’ costs recovered from consumers, 11% from supplier operational costs and profit margin, and the remaining 25% results from the combined influence of the EU ETS and the UK’s Carbon Price Support (CPS).¹¹ Sufficient data are not available to allow a similar estimated breakdown for Germany, France and Italy, however the following interrelated factors are likely to be decisive drivers behind the values illustrated in Figure 5, and the differences between them.

¹¹ £5.66/tCO₂ and £18.08/tCO₂ for EU ETS and CPS, respectively (see Section 3), assuming marginal plant 50/50 CCGT and coal plant, with average 580 gCO₂ intensity, 100% carbon cost pass-through. Supplier costs and profit assumed at 50% value for overall commercial rate found in energy supplier Consolidated Segmental Reports (note, supplier costs reported by Ofgem for the domestic sector are much higher). ‘Balancing costs’ are average BSUoS values for 2016, and includes costs of both system services (see Footnote 45) and balancing energy (i.e. activated reserve capacity). Although according to Eurostat definitions for price components (see Footnote 8), system service costs should be considered under ‘network’ costs, data submitted by the UK include them under ‘Energy and Supply’. ‘Fuel and Other Costs’ are derived from subtracting above values from the total Energy and Supply average value for 2016 S2. ‘Carbon Price Compensation (Max)’ values calculated using CO₂ intensity of 580 gCO₂/kWh for the UK and 760 gCO₂/kWh for Germany. Aid intensity 85%, benchmark value of 1. GBP converted to Euro with exchange rate 1.16.

What Sets Wholesale Prices? The Merit Order Effect, Fossil Fuel Prices and Renewable Electricity Penetration

In competitive electricity markets, generators are typically brought online according to their position within the 'merit order'; the ranking of available generators according to the price they offer to the market in order to connect a given capacity. Generators are contracted based on ascending price, until connected capacity matches demand. All generators then receive the price of the final connected (marginal) generator for a given contracted period. Competitive pressures mean that generators tend to submit offers at or near their marginal costs of generation, driven primarily by underlying fuel prices (but also any applicable carbon prices and other operational cost). Figure 6 illustrates the concept of the merit order.

Marginal Plants and Fuel Prices

Therefore the cheapest-to-run plants operate first, and electricity wholesale prices are typically set by the marginal costs of the typical final (marginal) generator brought online to satisfy demand (see Figure 6). The wholesale price is dictated mainly by the price of the input fuel and associated carbon cost of those plants (see below). The dominant marginal generator depends on available capacities of different generation options – including renewables and interconnection – and their relative positions in the merit order stack.

In Germany, hard coal (anthracite) plants are the dominant price-setting generators¹². In 2016, the fuel-only cost of hard coal generation in Germany was around €22/MWh.¹³ Combined Cycle (natural) Gas Turbines (CCGTs) dominate marginal generation in Italy.¹⁴

In both, renewables and imports (particularly of French nuclear) through interconnectors – plus cheap lignite in Germany and hard coal in Italy – populate the majority of the stack below. In 2016, the fuel-only cost of CCGT generation in Italy was around €30/MWh.¹⁵

CCGT has also been the typical marginal generator in the UK in since the 1990s, with nuclear, renewables, interconnectors and hard coal populating the merit order stack below. However, the 2015 increase in the Carbon Price Support rate as part of the UK's unilateral Carbon Price Floor (described below), means that hard coal has been increasingly pushed to the price-setting margin. As such, the fuel-only cost of the typical marginal generator in the UK in 2016 was around €28/MWh.¹⁶

In France, nuclear and (non-flexible) hydroelectricity dominate generation, with excess at times of low demand exported to neighbouring countries. Relatively limited hard coal and CCGT capacity¹⁷ is often the marginal plant at times of high-demand, however such demand is often also satisfied by flexible hydroelectricity and interconnection imports. As such, domestic fossil fuel generators (and underlying fuel prices) are less influential at setting wholesale electricity prices in France (however, fossil fuel plants influence the price at which electricity may be imported from neighbouring markets). In addition, **many industrial consumers in France receive a high proportion of their electricity at a fixed price**, reducing the influence of fossil fuel prices on final industrial electricity prices further (see 'Long-term supply contracts', below).

¹² Germany had over 29 GW of hard coal capacity in 2016 (15% of total capacity), accounting for 16.5% of generation (See Footnote 22).

¹³ Average coal price of €75/tonne (Source: BP, 2017). Average thermal efficiency of 42% assumed, as a mix of efficiencies of old and new coal plant (Platts, 2017).

¹⁴ Both the UK and Italy have around 30GW CCGT capacity, around 38% (DUKES Table 5.7) and 30% of total capacity, respectively. Data on installed capacity and generation by type for each EU member state may be found on the ENTSO-E Transparency Platform.

¹⁵ Average gas price of \$4.93/mmbtu (Source: BP, 2017). Average thermal efficiency of UK CCGT plants in 2016 (49.5%) are used (Source: DUKES, Table 5.10).

¹⁶ Assuming price-setting plant is 50% CCGT, 50% hard coal. Average coal price of €75/tonne and gas price of \$4.69/mmbtu used (Source: BP, 2017). Plant efficiency of 49.5% and 35% for CCGT and coal, respectively (Source: Dukes Table 5.10).

¹⁷ 2.9 GW (2.8% of total) and 6.1 GW (5.8% of total) in 2016, respectively (see Footnote 19).

The impact of renewable energy

Generators of renewable electricity typically have zero fuel costs (e.g. wind and solar), and thus near-zero marginal costs. As such, when available they are typically first in the merit order. For a given level of demand, this displaces more expensive marginal (price-setting) generators at the end of the merit order, thus reducing the clearing price. Consequently as renewable electricity penetration increases, wholesale electricity prices decrease – the merit order effect.

Figure 6 – Conceptual illustration of the Merit Order and Merit Order Effect

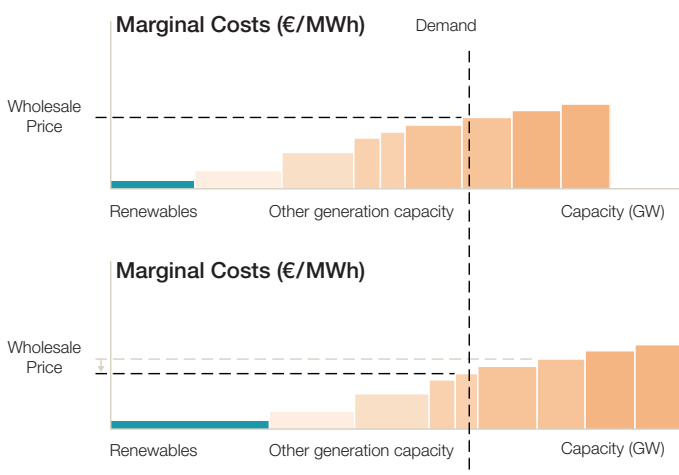
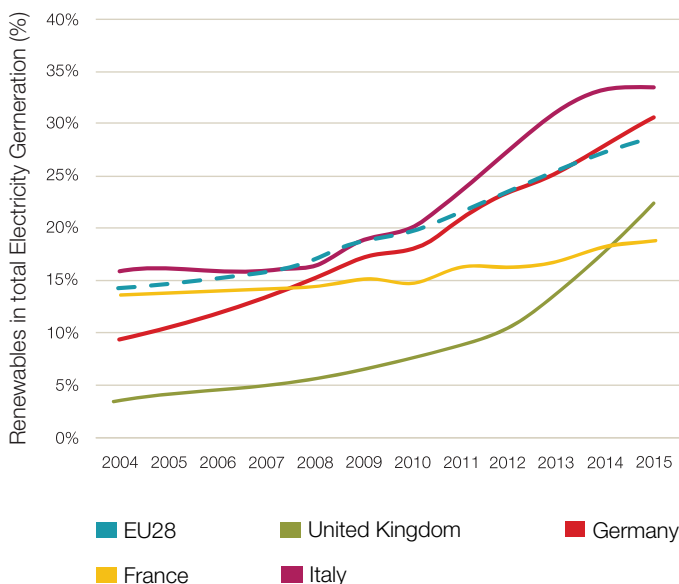


Figure 7 – Renewable Electricity Generation



Source: Eurostat

Figure 7 illustrates the evolution in renewable electricity generation, as a proportion of total generation, for each country (and the EU average) from 2004 to 2015. The CCC (2017, p.24) estimate that due to the rapid increase in renewable generation in the UK, particularly wind and solar PV, **the merit order effect in the UK reduced average¹⁸ wholesale electricity prices by around £6/MWh (€7/MWh) between 2004 and 2016.** Cludius *et al* (2014) calculate that rapid renewable penetration in Germany (again primarily from wind and solar PV) induced a €10/MWh reduction in average prices in 2012, and estimate values of €14–16/MWh for 2016. For Italy, Clò *et al* (2015) find that wind and solar PV collectively reduced average wholesale prices by around €16/MWh in 2013 (a value likely to have remained stable, following a plateau in renewable generation illustrated in Figure 7). As such, through the merit order effect, **renewables have reduced average wholesale electricity prices substantially in the UK, Germany and Italy.**

In France, the majority of renewable generation is flexible hydroelectricity, almost all of which was constructed before 1990 (Lubek & Wakeford, 2015, pg.3), and is deployed at times of relatively high demand to balance the system (with nuclear dominating the remainder of generation). Installation of and generation from other renewable sources in France in recent years, principally wind and solar PV, have been minimal (as illustrated in Figure 7).¹⁹ This, coupled with the low marginal cost of the majority of existing generation (nuclear and hydro), means the merit order effect of renewables is likely to have been minimal in France to date.

Overall, the **fuel-only costs (exclusive of carbon prices and other marginal costs) of the dominant price-setting marginal plant were substantially lower in Germany and France than in the UK and Italy in 2016.**

¹⁸ Specific impacts will vary significantly over time due to the availability of intermittent generation, variation in demand, and the characteristics of the displaced plant.

¹⁹ A combined capacity of 1.8 GW in 2016, <2% of total capacity.

Interconnection and Access

Physical interconnectors allow for the cross-border trade of electricity. Interconnection allows for improved energy security of supply, and for price arbitrage between markets. Interconnectors may be considered domestic pseudo-generators, particularly for the UK; they are able to connect a given capacity to the market at a given price. When and whether they are utilised depends on demand, and their position in the merit order.

GB currently has four active interconnectors, to France (2 GW), Netherlands (1 GW) and the Irish SEM (2 x 0.5 GW). In 2014, this equated to around 6% of the UK's domestic generation capacity.²⁰ Compared to other EU Member States this is relatively limited, with only seven of the twenty-eight being less interconnected. France and Germany had about 10%, whilst Italy has interconnection at about 7% of domestic generation capacity,²¹ but also operates a 'Virtual Interconnector' policy for large energy intensive industry (See Box 2)

Box 2 The Italian 'Virtual Interconnector' Policy

Introduced in 2010 and currently continuing to 2021, the 'virtual interconnector' mechanism allows large energy-intensive companies in Italy to purchase electricity at the (lower) baseload wholesale price of neighbouring countries, in return for co-financing a series of new physical interconnectors with Austria, France, Switzerland, Slovenia, North Africa and Montenegro. This electricity is supplied by 'virtual shippers'; energy suppliers in Italy purchase power in neighbouring markets, and sell generation to the equivalent domestic capacity (2.5GW in 2016) to electricity-intensive companies, at the same price. Virtual shippers and specific capacity are contracted through annual auctions operated by the Italian TSO (Terna), with prospective shippers submitting bids typically at a value equal to the spread between (lower) baseload prices in a given neighbouring country, and the (higher) market prices in Italy for the year ahead, plus a profit margin. Such contract costs are recovered from electricity consumers.

²⁰ This subsequently reduced to around 4.5% in 2016, due to an increase in domestic generation capacity including renewables. In 2016, the UK had over 60GW of 'firm' generating capacity, and a rapidly rising share of renewables (Figure 7).

²¹ See Commission Communication COM (2015) 82, on 'Achieving the 10% electricity interconnection target'.

Due to extensive nuclear generation and relatively low wholesale prices (illustrated in Figure 5), France is typically one of the world's largest net exporters of electricity. Net imports of electricity to the UK from France were equivalent to the interconnector importing electricity continuously at 85% and 79% in 2014 and 2015, respectively²² (though this dropped to 56% in 2016 due to various converging but likely temporary factors²³). Net imports from the Netherlands are also near maximum capacity.²⁴ **The currently low level of interconnection constrains the ability to import low-cost electricity to the GB market,** and also limits the ability to minimise the integration costs of intermittent renewable generation.²⁵

In 2014 the European Council established a requirement that all Member States should achieve interconnection capacity equivalent to at least 10% of domestic generation capacity by 2020, and proposed a target of 15% by 2030. At present, seven new interconnectors for the UK with a total 7.3 GW capacity are contracted to come online by 2022 (including 3.4 GW with France²⁶), meaning the UK's total interconnector capacity will increase to over 12% (assuming total domestic UK capacity remains roughly constant). Further interconnectors are also in the planning stages (see section 6).

²² Data on annual electricity imports and exports, upon which these values are based, may be found in Table 5.6 of 'Energy Trends', published quarterly by the UK government.

²³ Including nuclear safety tests in France that began in the summer of 2016 and continued into 2017, reducing French nuclear capacity by a third (EC, 2016a), and damage to the France-GB interconnector in November 2016 which reduced its capacity by half until March 2017 (EC, 2017b).

²⁴ Equivalent to importing continuously at 83% capacity. Trade through the two interconnectors to the Republic of Ireland is minor (see Footnote 14).

²⁵ Interconnection allows excessive domestic generation from intermittent renewables to be exported to neighbouring markets, reducing the risk of negative prices and curtailment costs, and vice versa, reducing the need for additional domestic 'back-up' generation capacity.

²⁶ The remainder is composed of interconnectors to Belgium (1 GW), Norway (1.4 GW), Denmark (1 GW) and Ireland (0.5 GW) (Ofgem, 2017a).

Increasing interconnection will tend to converge prices²⁷, with National Grid (2014) estimating that each additional 1GW interconnector capacity could reduce UK wholesale prices by 1–2%, depending on the evolution of the cost and merit order of the domestic generation profile, **with reduced costs for intermittent renewables integration and energy security benefits additional to this.** However, at present it is unclear what inter-market arrangements, such as for intra-day trading, will be in place once the UK leaves the EU. Arrangements that increase trading complexity and reduce integration compared to existing circumstances may increase the cost of importing electricity from the continent, and constructing and operating interconnectors that enable it (Froggat *et al*, 2017).

Whilst greater interconnection is likely to reduce UK wholesale prices, reduce the cost of integrating renewables, and enhance UK industrial access to low cost generators on the continent, a significant concern will be if continental generators do not have a similar carbon price. This might enable them to undercut UK generators, without paying the carbon price (or saving CO₂); our recommendation #4 suggests how this should be addressed. Overall, maintaining a regime that favours the construction of interconnectors and electricity trading across borders must therefore be a priority as the UK leaves the EU.

Prospects for wholesale prices

The dominant, price-setting generators in the future will depend on a confluence of factors, including the retirement profile of existing generating capacity, the profile of newly-built capacity to replace it (and to satisfy additional electricity demand), and the relative marginal (fuel and carbon) costs that determine the merit order.

²⁷ Although evidence for this phenomenon is generally positive, different studies and methodologies produce varied results on its validity and extent (Mezősi *et al*, 2016).

The proportion of electricity generated from renewables in the EU and its Member States will continue to increase, driven by a combination of EU and national climate policy and renewable energy targets²⁸, and the rapidly reducing cost of renewable electricity (see Figure 12), **and is likely to continue to reduce average wholesale electricity prices.** However, continued growth in intermittent renewable generation increases the need for reinforcement and greater flexibility of the electricity network, and increases wholesale price volatility, leading to additional system balancing and other service costs (see Section 4).

In the UK, coal capacity has been closing rapidly due to a combination of age, economic viability, and air pollution standards, with the government committing to close all remaining capacity by 2025. Italy has also committed to phasing out its remaining coal capacity by 2025 (MSE, 2017), with France setting a phase-out target of 2022 (Seitz & Höfling, 2017). **These developments mean that CCGTs are likely to remain the price-setting plant in Italy, and regain this status in the UK.**

No coal phase-out commitment has been announced for Germany, which added a net 2.2 GW of coal capacity between 2011 and 2015 (Shultz & Schwartzkopff, 2015). However, as discussed below, increasing carbon costs (coupled with the cost of complying with air pollution requirements²⁹) will drive up the cost of coal generation in the coming years, which Gray and Watson (2017) suggest **will render virtually all coal-fired plants in the EU unprofitable by 2030.**

²⁸ The EU's Renewable Energy Directive (2009/28/EC) sets binding national targets for the proportion of final energy consumption to be obtained from renewable sources by 2020, culminating in a 20% EU-wide target. An EU-wide target of 27% has been set for 2030. Targets originating from Member States include the UK's legally-binding objective of an 80% reduction in GHGs by 2050 (from 1990 levels), established by the 2008 Climate Change Act. Increasing penetration of renewable electricity will be key in achieving these targets.

²⁹ 13.5 GW in 2016 from over 23 GW in 2012. The Large Combustion Plant Directive (2001/80/EC) (succeeded by the Industrial Emissions Directive (2010/75/EU) in 2016) imposed SO₂, NO_x and dust emission limits on plants licensed on or after 1st July 1987, to be achieved by 2016. Plants may 'opt-out' of compliance under the provision that they are not operated for more than 20,000 hours between 2008 and 2015 (after which they must close). In 2017, tighter requirements were set, based on 'best available techniques', which must be achieved by 2021. Gray & Watson (2017) estimate around 70% of existing coal capacity in the EU is currently non-compliant with these new standards.

It is notoriously difficult to project energy commodity prices, and thus the potential influence on average electricity wholesale prices. Gas prices seem particularly uncertain: from the peaks of over 60p/therm during 2011–2013, they had halved to 30p/therm by January 2016 – but then climbed back over 50p/therm by the end of the year and averaged close to that (with wide fluctuations) during 2017. For policy appraisal purposes, the UK government (BEIS) projects a range between 40–80 p/therm by 2030, with a central estimate of 62p/therm in 2030 (BEIS 2016a).³⁰ Developments are therefore subject to great uncertainty.

However as discussed above, renewable and interconnection capacity is likely to expand in all countries, levelling wholesale prices and displacing the most expensive generators.

Carbon Pricing

Carbon pricing is typically recommended by economists as the most efficient way to tackle climate change. All members of the European Economic Area (EEA) participate in the EU ETS, a mechanism that caps CO₂ emissions and allows trading of emission allowances to set a common price on CO₂ emissions from electricity generation and industrial processes. In 2016 (S2), the EU ETS carbon price was an average of around €5/tCO₂, adding an additional €4/MWh and €1.9/MWh to the marginal cost of hard coal and CCGT generation, respectively.³¹

³⁰ Future contract prices may be found on the Intercontinental Exchange (ICE) website.

³¹ Assuming CO₂ intensities of 800 gCO₂/KWh and 380 gCO₂/KWh, respectively.

Given the weakness of the EU ETS, in 2013 the UK government introduced a Carbon Price Support (CPS), initially intended to set a Floor Price to underpin the EU ETS and enhance the price signal in the power sector for a shift toward lower carbon capacity investment and generation. From April 2015, the CPS rate has been set at £18/tCO₂ (€21/tCO₂), adding a further €17/MWh and €8/MWh in marginal costs to hard coal and CCGT generation in the UK in 2016, respectively.³² The CPS has been largely responsible for pushing coal to the price-setting margin in the UK in 2015 and 2016 (and greatly reducing emissions in the process), as discussed above.³³

As carbon prices are levied on generators, the costs are passed through to wholesale prices, and subsequently to final consumers.³⁴ The EU ETS Directive allows countries to compensate electro-intensive industries for the impact of the carbon price on electricity costs. Of the four countries examined, only Italy does not provide compensation to industrial consumers for such costs. Eligible electricity-intensive processes in the UK are also eligible for compensation for the costs for its CPS.³⁵ See Box 3 for details of such compensation mechanisms.

Although any discounts or exemptions applicable to industrial consumers in advance of payment for electricity are reflected in Eurostat data, **any mechanism that provides “ex-post” compensation (i.e. after a user has paid for electricity) for the cost of electricity price components (or elements thereof) are not included in the Eurostat data**, as illustrated by Figure 4.

³² CPS rate of £18/tCO₂ applicable since April 2015 (previously £9.55/tCO₂ from April 2014, and £4.94/tCO₂ from April 2013). See previous footnote for assumed CO₂ intensities.

³³ The combination of the EU ETS and CPS placed hard coal plants, particularly those of relatively low efficiency, above CCGT in the merit order stack. This led to a complete absence of coal generation in the UK for the first time since 1882, for four hours on the 10th May 2016 (Ofgem, 2016), a phenomenon which has occurred frequently since. In 2012, the year before the CPS was introduced, 49% of generation was coal-based.

³⁴ However, the specific rate of pass-through will vary between generators, and across time and markets (See Huisman & Kilic (2015) for an overview of pass-through rates of the EU ETS carbon price in the UK and Germany).

³⁵ For a summary of the UK Carbon Price Floor, including its most recent developments, see Grubb and Newbery (2018)

Box 3 Carbon Price Compensation

Compensation mechanisms for indirect carbon costs must abide by EU State Aid guidance, issued in 2012.³⁶ The guidance allows firms within sectors and sub-sectors deemed ‘Energy-intensive and Trade-Exposed’ (EITE)³⁷ to receive compensation (‘aid intensity’) of up to 85% of such costs in 2013–15 reducing to 80% in 2016–18, and 75% in 2019–20.³⁸ The actual level of compensation received depends on performance against sector-specific efficiency ‘benchmarks’ – highly efficient industrial sites (operating at the benchmark level) may receive the maximum compensation available, with those performing at lower efficiencies receiving proportionally less.³⁹

Indirect carbon costs are calculated using the price of EU ETS permits for delivery during the period in question, and a country-specific CO₂ intensity factor, based on the CO₂ intensity of marginal generators. These factors are stated in 2012 State Aid guidance, and are fixed until 2020. Permissible compensation arrangements for post-2020 are so far undecided.

The 2008 economic crisis combined with several other factors led to a large surplus of allowances in the EU ETS system, depressing prices. **Various reforms have been adopted and proposed in order to reduce this surplus and strengthen the price, which if fully implemented, are projected to lead to a price of around €30/CO₂ by 2030.⁴⁰ If this is achieved, carbon-related costs in coal-based Germany will increase substantially** (and as described above, along with air pollution requirements, potentially render coal generation economically unviable). Carbon-related costs would also likely increase in Italy and France (along with other EU ETS participants), but to a lesser degree.

Carbon pricing in the UK: prospects

It is unclear whether the UK power sector will remain part of the EU ETS once it withdraws from the EU. However, the UK government’s 2017 Autumn Budget stated that the combination of the EU ETS and CPS ‘will continue to target a similar total [currently prevailing] carbon price until unabated coal is no longer used’ (HM Treasury, 2017, pg.37). The implication is that whether or not the EU ETS price recovers, or whether the UK leaves the system entirely, the total carbon price for the power sector in the UK will remain relatively static at around €25/tCO₂ until 2025, with the CPS – or equivalent – adjusting as required. Moreover, because gas generation is less than half as carbon-intensive than coal, **the impact of a fixed carbon price on GB electricity prices will decline as UK coal capacity continues to close.**

³⁶ ‘Guidelines on certain State Aid measures in the context of the greenhouse gas emission allowance trading scheme post-2012’ (COM 158/4)

³⁷ Electricity costs at or above a proportion of Gross Value Added (GVA), and trade with third countries at or above a proportion of trade within the EU market, in the following combinations: 10% and 10%, 20% and 4%, and 7% and 8%.

³⁸ Individual firms within these sectors must also demonstrate that indirect carbon costs would increase their production costs by at least 5% as a proportion of their GVA to qualify.

³⁹ For sectors with no efficiency benchmark value available, a ‘fallback’ value of 0.8 is applied.

⁴⁰ See EC (2017a) for an overview of the adopted and proposed reforms, and their status. See EC (2016b) for EU ETS price projections.

Long-term Supply Contracts: the French ‘Exeltium’ consortium

Large electricity consumers may negotiate long-term contracts with electricity suppliers or generators to supply electricity at preferential, often fixed prices, in order to minimise risks associated with a variable price.

By far the biggest example is ‘Exeltium’; a consortium of 27 companies from electro-intensive industries in France, which in 2007 signed a take-or-pay⁴¹ contract with vertically-integrated generator-supplier EDF for a 311 TWh electricity supply over a 24-year period. In exchange, the consortium would provide a €4 billion up-front payment, and an ongoing proportional price based on industrial risks regarding the nuclear industry, including historic and future development costs. The total price was fixed at around €50/MWh.

Due to difficulties in financing the up-front payment in the wake of the economic crisis, the contract was split into two phases. The first phase, beginning in 2010, would deliver 148 TWh over 24 years for an up-front payment of €1.75 billion. When this phase began, this supply satisfied around a third of all industrial sites concerned. The second phase, due to begin in 2011 and which would deliver the remaining 163 TWh over the same time frame, was delayed due to concerns over the competitiveness of the mechanism. A key reason for this was the introduction of the *Accès Régulé au Nucléaire Historique* (ARENH) mechanism at the end of 2010, through which EDF is required to make up to 25% (100 TWh) of nuclear electricity available to competitors at a fixed rate, in order to stimulate competition between suppliers. The fixed rate was initially €40/MWh, and increased to €42/MWh in 2012. In 2014, it was agreed that the contract between Exeltium and EDF would be amended to allow a flexible price linked to wholesale market changes, and that would reduce the cost of nuclear industry risk borne by the consortium. The price was reduced from €50/MWh to €42/MWh, in line with the ARENH value.

However, many of France’s nuclear fleet are approaching the end of their lifetimes, and must soon be extended, and eventually decommissioned, at significant cost (and replaced with other generation capacity, discussed in Section 5). **EDF estimates a cost of €55 billion to extend the lifetime of the nuclear fleet by 10 years.**⁴² In addition, **the French government estimates costs of €300 million to decommission each GW of nuclear capacity** (however, this falls below estimates by other EU governments for decommissioning costs, with Germany and the UK estimating €1.1 billion and €2.7 billion, respectively) (EC, 2016c). These costs must be paid by largely state-owned EDF, and subsequently recovered through increased electricity prices, or as majority shareholders in EDF, the taxpayer.

The Exeltium experience illustrates several factors, relevant to possible future options in the UK as we discuss in Section 6. **There is, in principle, a natural alignment between the cost structures of capital-intensive, low running cost generators** (in this case, nuclear), **and the interests of large industrial customers for long-term predictable power prices.** Second, bulk purchase can increase their leverage in negotiations and can secure low prices. Third, however, terms may need to be subject to renegotiation in the light of large unexpected changes in circumstances, and the larger the deal and investments at stake, the more likely that governments may have to be involved.

⁴¹ EDF is committed to making the electricity available, whilst the Exeltium consortium is required to pay regardless of actual consumption.

⁴² Although the French Court of Auditors estimates this may rise to €100 billion by 2030, including operating costs (Berthelemy & Duquesnoy, 2016)

Energy and supply costs – conclusions

The 'energy and supply' component of the electricity price is mostly driven by wholesale electricity prices, which are in turn driven by the fuel and carbon costs of the marginal plant. With near-zero marginal costs, the increasing penetration of **renewables in the UK, Germany and Italy have reduced wholesale prices substantially**, by reducing demand for the most expensive generation options. Germany, France and Italy are more interconnected, and the UK's growing interconnection – assuming the construction of new interconnectors and their operation is not hindered – will aid convergence with continental prices, through further import of lower-cost generation.

The typical marginal plant in Italy is natural gas CCGT, hard coal in Germany, and a combination of both in the UK. **The relatively low price of coal compared to natural gas is likely a significant factor behind the reduced wholesale prices experienced in Germany.** Projecting the evolution of natural gas and coal prices, and thus their relative influence on respective wholesale prices in the future, however, is uncertain. **EDF, which owns and operates the nuclear fleet dominant in the electricity mix in France, holds a long-term contract with a consortium of industrial companies to supply a significant proportion of their consumption at a relatively low and largely fixed price.**

Carbon prices in the UK are significantly higher than those on the continent. **In the UK, Germany and France, eligible industrial consumers are compensated for up to 80% of the cost of carbon on wholesale prices until 2019, and 75% to 2021.** Recent and planned reforms of the EU ETS, and recently announced plans for the total carbon price applied to the power sector in the UK (and the pending introduction of floor prices in some continental countries) means that **in the medium-term the impact of carbon costs on wholesale electricity prices is likely to remain stable and potentially reduce in the UK, but increase significantly on the continent.**

4. Network costs

Key messages

- *Network tariffs in each country generally reduce with increasing voltage, capacity of connection, and level of consumption;*
- *The overall costs of networks appear remarkably similar across UK, France, Germany and Italy, but the way the costs are recovered varies widely;*
- *The costs of electricity (particularly transmission) networks are spread significantly more evenly between consumers in the UK than in Germany, France and Italy, where smaller (e.g. commercial) businesses and domestic consumers compensate for reduced tariffs for industry;*
- *The evolution of total network costs in each country depends on a range of factors, although the distribution of costs between different network users in the future remains largely a decision for regulators and policy makers.*

Network charges are complex. Different generators and consumers utilise networks to different degrees depending on scale, time and location. Once networks are built, there is no general economic principle to determine how the costs should best be recovered. With a competitive generation market, generators may need to be paid not to generate (“constrained off”) if networks are inadequate.

Transmission system operators (TSOs) and distribution network operators (DNOs)⁴³ usually operate high voltage transmission and (mostly) low voltage distribution networks, respectively, as natural monopolies. As such, regulators set limits on the revenue that may be generated through network tariffs, which should reflect the cost of building, maintaining and operating networks, and allow for a profit margin (within a largely pre-determined range).⁴⁴

⁴³ A TSO is responsible for ensuring the balance between electricity supply and demand on the transmission system in real time. They may or may not be the same as the Transmission Network Operator(s) (TNO), responsible for maintaining capital stock, however for the purposes of this report they are assumed to be. At this distribution level, DNOs are typically similarly responsible for maintaining capital stock only. Although the transition to Distribution System Operators (DSOs) is gathering pace, they may be considered DNOs for the purposes of this report.

⁴⁴ Such ‘cost reflectivity’ requirements are set by the EU’s Electricity Directive (2009/72/EC), amongst others.

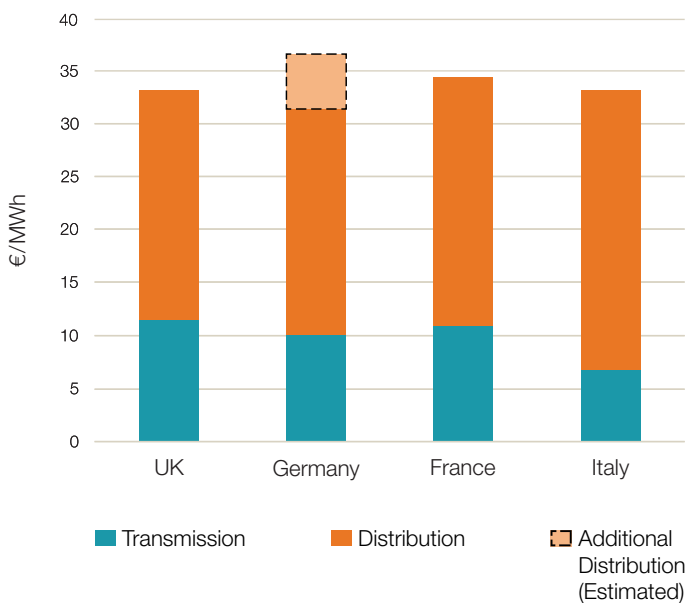
In GB, allowed revenue is governed by the RIIO (Revenue = Incentives + Innovation + Outputs) framework, with RIIO-T1 governing transmission network revenue for the period 2013–2021, and RIIO-ED1 governing distribution network revenue for the period 2015–2023. The government is currently consulting on the design of the subsequent price control framework.

Figure 8⁴⁵ illustrates approximate allowed revenue for TSO and DNOs in the UK, Germany, France and Italy, per unit of electricity consumed in the country, for 2015/16. It is immediately clear that by this measure, total network costs (which are considered as equivalent to total allowed revenue for the purposes of this study), are similar across all four countries, at around €33–36/MWh. In the UK, Germany and France, transmission accounts for around 30% of these costs (and around 20% in Italy), including system services⁴⁶, with the remainder being distribution-related costs.

⁴⁵ Revenue data for the UK (GB) taken from Ofgem (2017c,d), with 2016 average BSUoS value added. For Germany, data provided by BNetzA for all TSOs, and the 150 DSOs with more than 100,000 customers (or those in states with a contract with BNetzA). It is assumed that the remaining 625 DSOs, managed at State level, have an average of 5% of the income of the average of the 150 for which values are reported (‘Distribution (Estimated)’). Values are for 2017, but assumed to be static from 2015/16 for the purposes of this estimation. Revenue data for France sourced from CRE (2013a,b), with DSO estimates covering ENERDIS only (>95% total distribution). Revenue data for Italy sourced from company annual reports. For France and Italy, remaining DSOs assumed to have same average revenue per unit of electricity consumption. For Germany, France and Italy, values inclusive of system service costs, but exclusive of balancing energy delivered. For the UK, values inclusive of both system service costs and balancing energy delivered. Electricity consumption values for 2015 sourced from Eurostat.

⁴⁶ System services include the contracting of reserve capacity, congestion management, voltage control, arrangements for ‘black start’, and other actions necessary to maintain system security. It excludes the cost of activating reserve capacity.

Figure 8 – Estimated allowed network revenue per unit electricity consumption (2015/16)



The majority of expenditure by network operators is on capital equipment.⁴⁷ Operators typically use a combination of debt and equity financing to fund these investments, each of which comes with a cost of capital (i.e. interest and dividend payments). The combined cost of capital the operator receives is its ‘weighted cost of capital’ (WACC). In setting allowed revenues, regulators must make an assumption on the likely WACC a TSO or DNO is likely to receive. An overestimated WACC is cited as a key driver behind what some commentators believe are ‘excessive’ profits for network operators in the UK, though this is disputed.⁴⁸

47 For example, 77% of planned expenditure on transmission by the UK’s National Grid for 2013–2021 is capital expenditure (National Grid, 2014b).

48 Wild (2017) calculated an average profit margin of 10% across all energy (electricity and gas) network operators, and ECIU (2017) estimated profit margins of 25–39% for electricity DNOs. However, network operators dispute these data and methodologies used to calculate these figures; for example, see ENA (2017a) for a riposte to the values produced by ECIU (2017).

Despite the similarity in overall allowed revenue per unit of electricity consumed in each country, network tariffs applied to industry vary relatively substantially. As illustrated in Figure 4, average network costs in France and Italy (€14/MWh and €10/MWh, respectively) are around half those experienced in the UK and Germany for Bands ID–IF (€21/MWh and €24/MWh, respectively).

Three key factors interact to explain these differences: how network costs are recovered between generators and consumers (both customers of electricity networks); the size of the customer base over which network costs are recovered; and the design of individual network tariffs, which determine how costs are divided between different types of consumer.

a) Division of costs between generation and demand

Both generators and (usually indirectly) consumers of electricity make use of the electricity transmission network, and contribute to the costs of its construction, maintenance and operation. In an effort to establish a common regulatory approach to transmission charging, EU rules adopted in 2010 set a limit on transmission costs that may be recovered from electricity generators. For most countries, this limit is €0.5/MWh generated. However, for the UK, this rate is €2.5/MWh.⁴⁹ The remainder must be recovered from consumers.

This means that in 2015/16, 24% of transmission network costs in the UK were recovered from generators, with the remaining 76% recovered from consumers (reducing to 16% recovery from generators in 2016/17).⁵⁰ In contrast, France recovered only 3% of transmission-related costs from generators in 2015/16, whilst Germany and Italy recovered all costs from consumers.⁵¹ Costs associated with the distribution system are recovered from consumers in all cases.

49 Regulation 838/2010 also provides exceptions for Denmark, Sweden and Finland (maximum rate of €1.2/MWh), and Romania (maximum rate of €2.0/MWh).

50 Historically, the €2.5/MWh limit allowed 27% of transmission system costs in the UK to be recovered from generators. However, a combination of increasing costs, increasing interconnection capacity (which are exempt from transmission charges) and reducing value of the limit in real terms is expected to reduce this proportion to around 10% by 2020/21 (Energy UK, 2016, pg.7). This value excludes system service costs.

51 In total, 14 EU Member States recover no transmission costs from generators (ENTSO-E, 2017, pg.9)

To at least some degree, costs charged to generators may still be passed on to consumers, generally in undifferentiated ways.

b) Size of chargeable consumer base

The traditional model for an electricity system is large-scale, centralised (fossil fuel and nuclear) generation, which delivers electricity to (most) consumers first through the high-voltage transmission system, and then through lower voltage local distribution networks. Successive system costs are compiled and paid by the final consumer through tariffs. However, a significant proportion of renewable electricity capacity is small-scale and connected directly to distribution networks (known as ‘embedded’ generators).⁵²

In one respect, this may be seen as a benefit to the system. Electricity from embedded generators helps to satisfy (self or other) demand on the local distribution network, reducing the need to draw power from the transmission network. This reduced (net) draw from the transmission network also reduces transmission tariff liabilities to the distribution network, supplier or consumer; avoided costs which may in turn be paid to the embedded generator.⁵³ Distribution-level network charges (and other taxes and levies) may also be charged (at least in part) on a net consumption basis (consumption minus export). Collectively, such avoided costs and payments are known as ‘embedded benefits’.

With increasing total network costs and embedded generation, the value of embedded benefits in GB between 2011/12 and 2015/16 increased from £309 million to £560 million.⁵⁴ Over the same time, in Germany, the value increased from €1.06 billion to an estimated €1.56 billion (BNetzA, 2016) – equivalent to around 8% of total network costs in each country. Under existing charging arrangements, these values are projected to continue increasing. As embedded generating capacity increases, costs must be recovered from a decreasing consumer base. This results in a positive feedback, whereby increasing network tariffs incentivise further deployment and use of embedded generation. Following a consultation on options to address embedded benefits, in 2017 Ofgem announced that the value of avoided (demand side) transmission tariffs that may be paid to embedded generators is to be substantially limited, from around £47/kW at present, to between £3/kW and £7/kW, to be phased in between 2018 to 2021.⁵⁵

c) Network tariff design

The design of network tariffs varies substantially between countries. Tariffs may vary by type of consumer, and based on one or more of the following factors: consumer location, consumer characteristics, type and size of grid connection, and profile of electricity consumption.

United Kingdom

In GB, separate tariffs apply to the use of the transmission and distribution systems, with rates for each based on voltage and capacity level of the consumers’ connection to the grid, time and location of consumption. System service costs are recovered through a separate tariff.

⁵² Between 2012 and 2016, the capacity of embedded generators in the UK increased from 14.5 GW to 28.8 GW (15% to 29% of total domestic generation capacity, respectively). Renewables accounted for 67% and 88% of total embedded generation, respectively. (Source: DUKES Table 5.12)

⁵³ The extent to which such payments are made varies. For example, in the UK, it is dependent on the specific agreement between generator and supplier. In Germany however, the DNO must pay the generator a rate equal to the avoided network charge (BNetzA, 2016). In addition, generators with a capacity below 100MW in the GB are exempt from generator-side transmission costs (discussed above).

⁵⁴ This includes avoided TNUoS, BSUoS and DUoS tariff charges, transmission and distribution losses, Assistance for Areas with High Distribution Costs (AAHDC) and Capacity Market Supplier Charges (Pace et al, 2016, pg.16).

⁵⁵ This is a reduction in the TNUoS demand residual only. For more information on options and associated impacts of different options for embedded benefit reforms in the GB, see Ofgem (2017b).

Transmission (or 'Transmission Network Use of System' – TNUoS) tariffs recover the cost of installing and maintaining the transmission network, for three TSOs.⁵⁶ For half-hourly (HH) metered (i.e. commercial and industrial) consumers,⁵⁷ TNUoS tariffs are based on the 'Triad'; the three HH settlement periods with highest electricity system demand (and separated from each other by at least ten full days) between November and February, inclusive (determined ex-post). The average demand of HH consumers across the Triad is then subject to a location-specific tariff (from £29.58/kW in Northern Scotland, to £51.96/kW in South-West England in 2017/18), to produce the total annual transmission charge due for that site. If a HH site does not consume any electricity from the grid across the Triad, no TNUoS charges are due. Commercial and industrial sites therefore face a locational and temporal price signal, and are incentivised to site themselves in areas of low demand, and to consume electricity outside periods of peak demand.⁵⁸ However, Triad periods are becoming more difficult to predict, due to flattening demand profiles resulting from triad avoidance strategies (e.g. switching to autogenerators). Although a desired result of the Triad approach, this in turn may increase transmission costs for industrial consumers that fail to avoid the Triad.

Non-half hourly (NHH) metered (typically domestic) consumer TNUoS charges are based on average consumption between 16:00 and 19:00, throughout the year, with a location-specific tariff (from £42.26/MWh in Southern Scotland, to £74.75/MWh in South-East England in 2017/18).

The cost of day-to-day balancing of the system (system services and balancing energy) is recovered from both generation and demand in equal proportion⁵⁹, by the Balancing Services Use of System (BSUoS) Tariff, calculated daily as a flat tariff (per MWh) across all users.

⁵⁶ National Grid Electricity Transmission plc (NGET) for England and Wales, Scottish Transmission Power Limited for Southern Scotland, and Scottish Hydro Electric Transmission plc for Northern Scotland and the Scottish islands. NGET also acts as the single System Operator (SO) across the whole network.

⁵⁷ Any consumer with a connection above 100 kVa must use a half-hourly meter.

⁵⁸ This 'smooths' electricity demand across the network and across time, reducing the need for additional investment in generation or transmission infrastructure.

⁵⁹ Interconnectors are exempt from BSUoS tariffs.

Distribution (or 'Distribution Use of System' – DUoS) tariffs, which recover the cost of operating distribution networks, also vary by location (across the 14 DNOs operating across GB), and by time. The highest tariffs are applied to consumption in the 'Red' time band (typically hours of highest demand), with the lowest applied in the 'Green' time band (typically hours of lowest demand). The 'Amber' time band tariffs are applicable at all other times.⁶⁰ However, tariffs are also differentiated between HH and NHH consumers, and by whether the connection is low, high, or extra-high voltage.⁶¹ NHH consumers typically only pay for consumption during the 'Red' band, and usually at rates lower than those applied for 'Red' band HH consumption. Tariffs for HH high voltage consumers are usually substantially below those low-voltage HH consumers, particularly for consumption in the 'Red' band. Extra-high voltage consumers, however, usually only pay for consumption in the 'Red' band (at individually applicable, but typically lower, rates), or through a (substantially higher) fixed meter and capacity charge only.⁶² Both HH and NHH consumers also pay a (varied) daily meter charge, with HH consumers also liable for daily fixed capacity charges.

⁶⁰ Typically, the 'Red' band falls on weekday evenings, with the 'Green' band falling on weekday nights and weekends (with the 'Amber' band applying at all other times). However, the specific hours vary between DNO region. The differential between tariffs due for consumption in each band also varies significantly between regions.

⁶¹ Low voltage = <1kV, high voltage = 1kV to 22kV, extra-high voltage = >22kV

⁶² These are general conclusions, but specific values within and between consumers with different connection voltages vary substantially across DNO regions.

Germany

In Germany, consumers receive a single tariff (including system service costs) depending on voltage level, annual consumption volume, and location. Costs of higher-voltage (i.e. transmission) networks are paid by networks of successively lower voltages (i.e. distribution networks), and passed through to consumers. Four TSOs⁶³ operate across Germany, alongside 875 distribution companies (DNOs, many of them local municipalities).

Consumers pay both a fixed capacity charge and a charge per unit of consumption, with the rates offered for a consumer in a given location based on voltage level (and thus the value of accumulated costs, which increase with decreasing voltage level), and whether annual consumption is expected to be less or greater than 2,500 hours. Consumers with expected consumption >2,500 hours are subject to a high fixed capacity charge, and a relatively low consumption charge, whilst the reverse applies to consumers with expected consumption <2,500 hours.⁶⁴ This is based on the probability that large users are likely to contribute to peak demand on the network to a significantly greater degree than smaller consumers. Metering and billing charges are also due.

Consumers in rural locations and in the east of the country tend to face higher charges than those in rural areas and in the west of the country, for two principal reasons. The first is age of the network; in the west of the country, much of the cost of capital investment in the existing network has been recovered. In the east, however, much of the cost of network expansion and reinforcement after reunification in the early 1990s must still be recovered (although this situation will reverse over time, as infrastructure in the west requires replacing). The second relates to the size of the consumer base; the east of the country (and rural areas) has a lower population density than the west (and urban areas), and reduced industrial production than at reunification, reducing the number of consumers over which network costs may be distributed (BNetzA, 2015).

⁶³ TenneT, covering the centre of the country from the border with Denmark in the north and Austria in the south, 50 Hertz, covering the north-east, AMPRION, covering (primarily) the west, and TransnetBW, covering the south west of the country.

⁶⁴ For EHV consumers with >2,500 hours consumption, over 80% of the network tariff is fixed capacity charge, with the reverse true for low voltage consumers with consumption <2,500 hours (BNetzA, 2015).

Consumers with annual consumption >10 GWh (middle of Band ID in the Eurostat classification) may apply for individual tariff rates, with a maximum discount on standard tariffs of 80% (annual consumption >7,000 hours), 85% (annual consumption >7,500 hours) or 90% (annual consumption 8,000 hours) available. These discounts are funded by the Electricity Network Access Ordinance Surcharge, discussed in Section 5.

France

In France, the structure and level of network tariffs (TURPE) are based principally on the consumer's voltage and capacity of connection, and time of consumption. Tariff rates are applied equally across the country, and include the cost of system services. A single TSO operates in France (RTE), with a single DSO (ENERDIS) managing over 95% of the distribution network.

For connections at transmission voltage levels HVB1 (50–130kV) and HVB2 (130–350kV), consumers pay a fixed annual capacity charge, and a variable charge based on actual consumption across five pre-defined time periods (which take into account time of day, day of the week, and season).⁶⁵ Variable charges are highest in the time period of typically greatest electricity demand, and vice versa. Consumers in these voltage ranges may select one of three tariff options, with different weighting to the fixed and variable components. Consumers connected at the extra-high voltage HVB3 level (350–500kV), pay a fixed capacity charge and a single consumption rate, without time differentiation.

⁶⁵ Off-Peak (09:00–11:00 & 18:00–20:00 on December–February weekdays), Mid-Peak Winter (07:00–09:00, 11:00–18:00, 20:00–23:00 on December–February weekdays, and 07:00–23:00 November & March weekdays), Off-Peak Winter (23:00–07:00 on weekdays and all day on weekends in November & March), Mid-Peak Summer (07:00–23:00 on April–October weekdays), and Off-Peak Summer (23:00–07:00 on weekdays and all day on weekends April–October).

Consumers connected to the distribution system at medium voltages (HVA1 and HVA2, at 1–40kV and 40–50kV, respectively) may choose from three tariffs. The first mirrors the approach applied to HVB1 and HVB2 connections, with five pre-defined time periods of varied charges (excluding the option for different weighting between fixed and varied tariff components). The second tariff option sets eight pre-defined time periods.⁶⁶ In both instances, time periods are set according to local conditions. The third option mirrors the approach applied HVB3 connections, with no time differentiation. Consumers with low voltage connections (<1kV) may also receive different time-differentiated tariffs.⁶⁷

Generally, both fixed and variable charges are higher for consumers connected at progressively lower voltages (although the specifics vary depending on choice of available tariff⁶⁸), with rates for consumers connected at HVA1 and HVA2 including the upstream costs of the transmission network. All consumers are also liable for other fixed costs, such as transmission grid access management and metering (either directly or indirectly via the DNO, depending on connection level).

From 2016, certain industrial consumers are able to apply for specific tariff reductions based on their total consumption, profile of use and electro-intensity, as in Table 2.

Table 2 – Network cost discounts available in France

Qualification Criteria	Discount Rate		
	Not Electro-intensive ⁶⁹	Electro-intensive ⁷⁰	Hyper Electro-intensive ⁷¹
Group A			
>10 GWh/year consumption, >7,000 hours			
>20 GWh/year consumption, off-peak grid utilisation rate >44%	5%	45%	80%
>500 GWh/year consumption, off-peak grid utilisation rate 40–44%			
Group B			
>10 GWh/year consumption, >7,500 hours			
>20 GWh/year consumption, off-peak grid utilisation rate >48%	10%	50%	85%
Group C			
>10 GWh/year consumption, >8,000 hours			
>20 GWh/year consumption, off-peak grid utilisation rate >53%	20%	60%	90%

66 Similar to those outlined in Footnote 65, but with Mid- and Off-Peak hours for March and November, and July and August, disaggregated.

67 For those with a connection >36 kVA, a ‘long duration’ tariff with five time periods, or a ‘medium duration’ tariff with four time periods, may be selected. For those with a connection <36 kVA, a ‘short duration’ (no time differentiation), ‘medium duration’ (two time periods), and a ‘long duration’ (no time differentiation) tariff may be selected. All tariffs have both fixed and variable elements.

68 Values for 2nd half 2016 may be found in CRE (2016a,b)

69 Consumer does not meet criteria outlined in Footnotes 66 and 67.

70 Electricity consumption >2.5 kWh/€ GVA, trade-intensity >4%, annual consumption >50 GWh.

71 Electricity consumption >6 kWh/€ GVA, trade-intensity >25%.

Firms must also introduce an Energy Performance Policy to qualify. Although these discounts are applicable for electricity consumption in 2016, firms had until 30th April 2017 to apply for them to be effective for their 2016 and 2017 consumption.⁷² As such, it is unlikely that these discounts are considered in the data presented in Figure 2, Figure 4, and Figure 9.

Italy

In Italy, the structure and level of network tariffs depend on the consumer's connection voltage and capacity. Separate tariffs recover costs for transmission and distribution, metering, and system services, all of which are applied equally across the country. A single TSO operates in Italy (Terna), with 135 DSOs (although just four DSOs account for 95% of distribution, with one (Enel Distribuzione) accounting for 86%).

Transmission (TRAS) tariffs have two components. The first (TRASp) is a capacity charge, applicable only to consumers with high voltage connections (>380 kV), with a flat rate of €18/kW/year in 2016. The second component (TRASe) is paid by all consumers, with those connected at a low voltage (<1 kV) paid a rate of €6.8/MWh in 2016, and those at medium voltage (1–35 kV) paying €6.35/MWh. Consumers connected at high voltage paid over 90% less, at €0.62/MWh.

Distribution tariffs have three components. The first is a fixed rate per meter point, ranging from around €4.73/year for low voltage consumers in 2016, to €404/year for medium voltage consumers, and €19,740 for high voltage consumers. The second component is a capacity charge, with a value of €28.57–31.77/kW/year for low-voltage consumers in 2016, and €26.88–€34.12/kW/year for medium-voltage consumers. High voltage connection consumers are not liable for capacity charges. The third component is a charge per unit of consumption, with a value of €0.62/MWh for most low-voltage consumers in 2016, €0.46–0.59/MWh for medium voltage consumers, and €0.2/MWh for high voltage consumers. Consumers with a very high voltage connection (>150 kV) are not liable for consumption charges.

The UC3 and UC6 tariffs recover the cost of system services. The UC3 rate for low voltage consumers in 2016 was €2.33/MWh, reducing to €0.81/MWh and €0.10/MWh for medium and high voltage consumers, respectively. The UC6 rate in 2016 for the majority

of low voltage consumers was €0.11/MWh. Medium voltage consumers paid a flat rate of €204, and a zero-rate applied to high voltage consumers. Metering and billing costs are recovered through the MIS tariff, which ranged from €19.25/year in 2016 for low voltage, €233/year for medium voltage, and €1,256/year for high voltage consumers.

Network costs – conclusions

Network costs recovered from individual consumers depend on whether any costs are allocated to generators, the number of consumers that may be charged, network tariff structures, and the presence and value of targeted discounts. Generally, **effective network tariffs reduce in all countries with increasing voltage and capacity of connection, and level of consumption.**

Unlike other countries, industrial consumers in GB experience both locational and temporal price signals. **Whilst in France time-differentiated tariffs are pre-defined, in GB the time at which consumers are charged for use of the transmission network is determined ex-post, reducing the ability to plan effective avoidance strategies ahead of time (an increasingly prevalent issue).** Whilst in Germany areas of high demand may experience lower charges due to a larger charging base, incentive-based tariffs mean the opposite is true in GB. In addition, **where Germany and France provide targeted discounts on network tariffs to large and electricity-intensive industry of up to 90%, no such specific provisions are available in GB or Italy (although in Italy, tariff rates reduce very substantially for high voltage consumers).**

⁷² For more details, see MEST (2017).

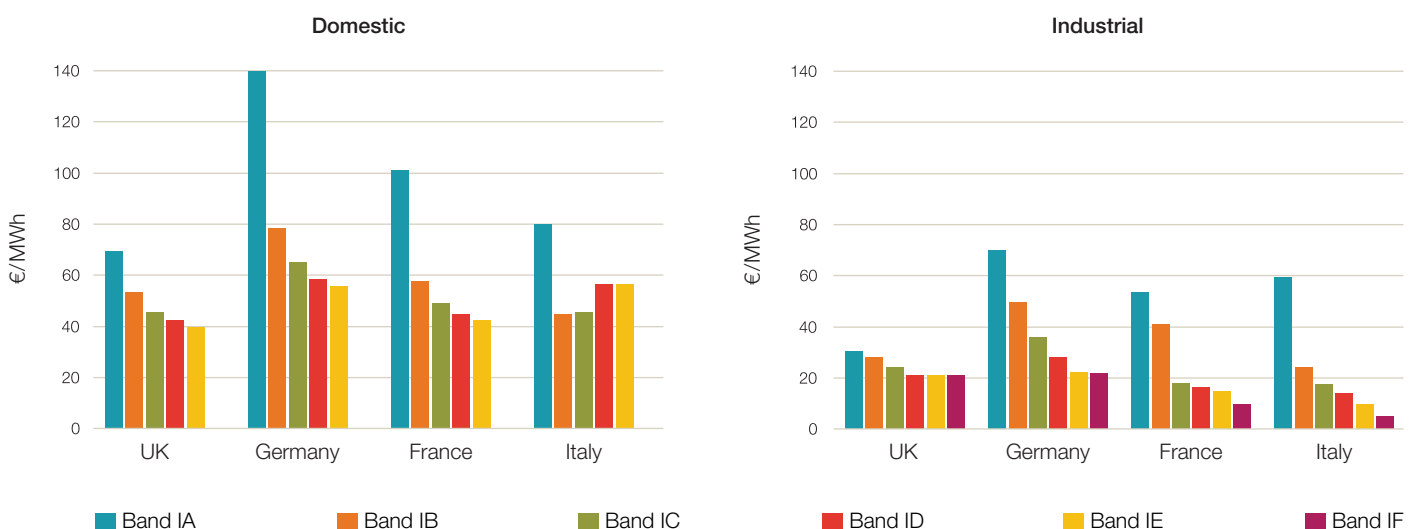
Although it would be expected that consumers connected, for example, directly to the transmission network experience lower network costs than those connected to the distribution network (as fewer costs accumulate), the above factors combine to mean that **the costs of electricity (particularly high voltage transmission) networks are spread significantly more evenly between consumers in the UK than in Germany, France and Italy, where small and domestic consumers compensate for reduced tariffs for large and electricity-intensive industry**, as illustrated by Figure 9.⁷³ Assigning a proportion of transmission costs to generators in GB is likely to contribute to this, however the value of embedded benefits is likely to have the opposing effect.

Total network costs in future will depend on network capacity and balancing requirements, dictated by the profile of both generation and demand. National Grid (2017a) project peak electricity demand in GB to increase by 0.5–8.4% by 2030 across four Future Energy Scenarios, indicating a relatively modest expansion in network capacity. This will be influenced by, amongst other factors, existing capacity ‘headroom’, the relative location of future generation capacity and demand centres (including how much capacity is embedded and used for autogeneration),

the evolution of ‘smart’ networks and demand-side response, and how the networks are managed (for example, the evolution of DNOs to become Distribution ‘System’ Operators, allowing for flexibility services to compete alongside traditional investment⁷⁴). Increasing penetration of intermittent renewables is likely to increase the cost of balancing the system, although analysis by Hepstonstall *et al* (2017) suggests this is also likely to be modest in GB for at least 30% renewable penetration, at less than £10/MWh (€11.30/MWh). Future price control frameworks will also play a role, for example in determining the profit margin of network operators.

Network cost recovery from different network users will depend on the future division of costs between generation (including interconnectors) and demand, and the penetration of embedded generation and associated benefits. Proportional costs recovered from demand in the UK are expected to increase over time under current restrictions (although it is yet unclear what arrangements may be in place once the UK exits the European Union). By contrast, new arrangements for reduced embedded benefits is likely to reduce average tariff rates in the UK. The distribution of costs between different network users in the future remains largely a decision for regulators and policy makers.

Figure 9 – Network costs across countries for domestic (left panel) and industrial (right panel) electricity consumption



Data source: Eurostat

⁷³ Domestic annual consumption bands are: Band DA (<1MW), Band DB (1MW–2.5MW), Band DC (2.5MW–5MW), Band DD (5MW–15MW), and Band DE (>15MW). UK values exclude system service costs.

⁷⁴ See ENA (2017b) for an assessment of economic implications of DSOs in the UK in future.

5. Taxes and levies

Key messages

- Recovering the cost of renewable support mechanisms is the key driver behind the taxes and levies rate in each country; taxes and levies are on average substantially higher in Germany and Italy, than the UK;
- The largest industrial consumers receive discounts or compensation for such costs in all four countries (paid for by other electricity consumers or taxpayers), but such provisions are more aggressive in Germany, France and Italy, for some large and electricity-intensive industrial consumers;
- Although the deployment of renewable electricity will continue in each country, the cost of new support is decreasing dramatically due to falling technology costs and competitive support mechanisms.

Figure 10 presents the average taxes and levies electricity price component for industrial consumption bands ID–IF for each country, with an estimated breakdown of the specific taxes and levies that comprise these values, and the magnitude of the maximum value of available taxes and levies cost compensation in the UK for eligible sectors, firms and processes.⁷⁵

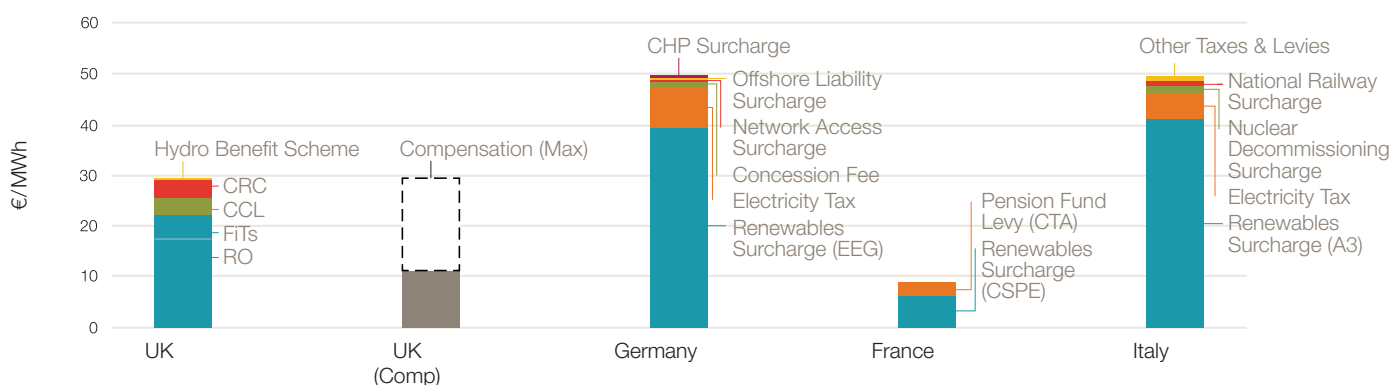
Across Bands ID–IF, in 2016, average firms in the UK experienced taxes and levies worth around €30/MWh (pre-compensation), whilst those in Germany and Italy averaged around €50/MWh. In France, the charges averaged just €9/MWh. In all four countries, the major part is recovering the cost of renewable electricity support mechanisms. The difference between German, Italian and UK levels is larger than (and hence at least offsets) the impact of their renewables in reducing wholesale electricity prices (Section 3).

United Kingdom

The cost of the UK’s Renewables Obligation (RO) and Feed-in Tariffs (FiTs)⁷⁶ accrue to electricity suppliers, who in turn recover these costs from consumers. For 2016, the average values of these pass-through costs to all consumers were around £15/MWh (€17.50/MWh) for the RO and £4.5/MWh (€5.24/MWh) for FiTs⁷⁷, comprising over 75% of the total taxes and levies value presented in the first column of Figure 10.

In response to the concerns about UK industrial electricity prices, the recovery of such costs has changed substantially in recent years. From December 2015, firms in an EITE sector with electricity intensity above 20% (see Box 3), may receive up to 85%

Figure 10 – Taxes & Levies Estimated Breakdown 2016 (S2)



Data source: Eurostat, average Bands ID–IF, excluding directly recoverable taxes and levies (like VAT)

⁷⁶ The RO obligates electricity suppliers to source an increasing proportion of their electricity from large scale renewables. The RO closed to new capacity in March 2017, and was replaced by CfDs. FiTs support the installation of small scale renewables (<5MW).

⁷⁵ See country-specific discussions below for data and key assumptions behind these estimates.

⁷⁷ Data provided by Department for Business, Energy and Industrial Strategy (BEIS).

compensation of the estimated pass-through costs of the RO and FITs (as illustrated in the second column in Figure 10).⁷⁸

From 2018, these firms will receive an exemption, rather than compensation, for up to 85% of these costs of the RO (and in 2019 for FITs, pending State Aid approval). Whereas current compensation is paid by the Department for Business, Energy and Industrial Strategy (BEIS) – and thus, general taxation – these exemptions will instead be funded through increased pass-through costs to non-exempt electricity consumers.⁷⁹ Costs for the ‘Contracts-for-Difference’ (CfD) instrument (successor to the RO) and Capacity Market are not included in Figure 10, as in 2016 these were negligible.⁸⁰

The two remaining taxes and levies of note⁸¹ are the Climate Change Levy (CCL) and the CRC Energy Efficiency Scheme (CRC).⁸² The CCL is a tax on the non-domestic consumption of electricity (and other fuels). Firms in EITE sectors are eligible for a 90% reduction on the standard rate if they have entered into a Climate Change Agreement (CCA) with the government.⁸³ The CRC is a form of carbon tax for large but less energy-intensive organisations (both companies and public sector)⁸⁴ but after the 2018/19 financial year, the CRC will close and be replaced by an increase in the standard rates of the CCL. The discount rate for firms

⁷⁸ See BEIS (2017) for further information.

⁷⁹ BEIS (2017b) estimate a resulting annual average electricity bill increase of £2.30 for the average household, £160 for small commercial consumers, £6,700 for non-exempt medium-sized industrial consumers, and £62,900 for non-exempt large industrial consumers (between 2017/18 and 2027/28).

⁸⁰ A generator with a CfD is paid the difference between the ‘strike price’ – a price for electricity reflecting the cost of investing in a particular low carbon technology, awarded through competitive auction, and the average market price for electricity in the GB market. If the market price exceeds the strike price, the generator pays the difference. The Capacity Market awards payment through competitive auction for the availability of electricity capacity for an agreed period, in order to maintain security of supply.

⁸¹ The Hydro Benefit Replacement Scheme is a fixed levy of £0.2/MWh on suppliers for each unit of electricity sold to (and passed through to) all consumers in GB, in order to assist with the high cost of electricity distribution in the North of Scotland.

⁸² Formerly the Carbon Reduction Commitment.

⁸³ The standard CCL rate for electricity in 2016 was £5.59/KWh (€6.5/MWh). CCAs are voluntary agreements made between UK industry firms or associations to reduce energy consumption and CO₂ emissions to agreed targets. Current CCAs operate from 2013 to 2023. In Figure 9, it is assumed that 40% of consumers are eligible for both the CRC and full CCL rate, and 60% are in receipt of a CCA, with 90% CCL discount and CRC exemption.

with a CCA will increase to 93%, to ensure the reduced rate paid by qualifying firms does not increase as a result of this reform.

Figure 11, adapted from CCC (2017), illustrates the reduction in taxes and levies applied to UK industrial consumers at increasing scales of electricity consumption, in 2016.

Germany

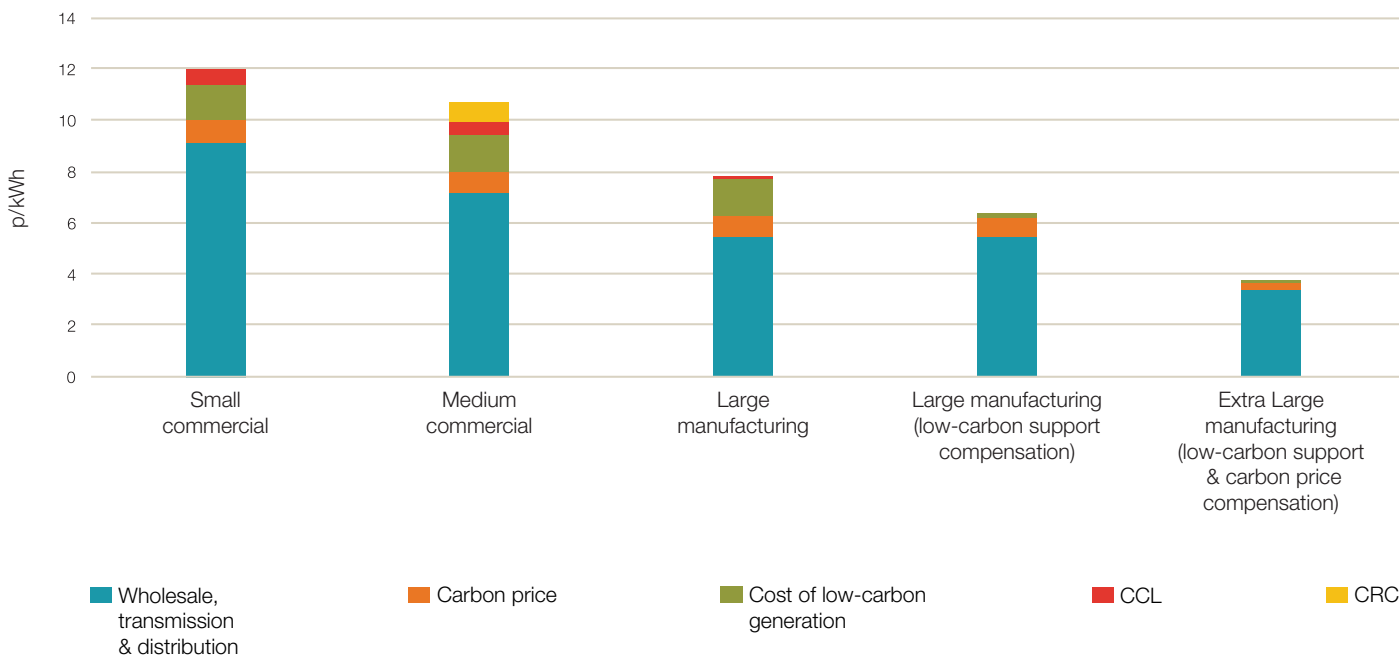
The cost of renewable electricity support mechanisms under the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, or ‘EEG’), is recovered through the EEG Surcharge on electricity consumers. In 2016, the standard EEG surcharge rate was €63.54/MWh. **Industrial consumers that are part of an EITE sector (See Box 3), with an individual electricity intensity above 14% or 17%, may receive a discount of 80% or 85%, respectively.** In addition, the surcharge is capped at a level equal to 4% GVA for all consumers with electricity intensity below 20%, and at 0.5% GVA for all consumers with electricity intensity above 20% (however, minimum surcharge rates of €0.5/MWh for non-ferrous metal producers, and €1.0/MWh for all other industrial consumers, also apply). Such discounts are financed through otherwise increased rates on other electricity consumers. In Figure 10 the EEG rate is an average of €40/MWh, accounting for 80% of the total industry taxes and levies value in Germany.⁸⁵

The German electricity tax (*Stromsteuer*), accounting for over 15% of the total value for Germany in Figure 10, is applied at a flat rate of €20.50/MWh for most consumers, with a reduced rate of €15.37/MWh for industrial consumers. However, industry may receive

⁸⁴ The CRC operates as a tax on CO₂ emissions from energy consumption, but levied at the company rather than facility level (unlike the CCL or EU ETS), designed to ensure adequate monitoring, attention and comparison at the top level of companies across their facilities’ energy and emissions; specifically, it applies to non-domestic sectors with annual consumption over 6 GWh, but not in receipt of a CCA. Participants have the option of paying a ‘forecast’ price at the beginning of each year, or a higher ‘compliance price’ at the end of each year. In the financial year 2016/17, the forecast price was £16.10/tCO₂ (€18.75/tCO₂), whilst the compliance price was £17.20/tCO₂ (€20/tCO₂).

⁸⁵ The value remaining after subtracting the applicable values for the remaining taxes and levies for industrial consumers in Germany, from the total average taxes and levies value for Bands ID–IF.

Figure 11 – Overall electricity and policy-related costs for different classes of UK industrial consumers in 2016



Source: CCC (2017)

further discounts (up to 90%) depending on the level of pension contributions paid by an individual company.⁸⁶

The remaining four taxes and levies applied to industrial electricity consumption in Germany together comprise an estimated 5% of the rate presented in Figure 10.⁸⁷ This includes the Electricity Network Access Ordinance Surcharge (*StromNEV Umlage*), which finances the reduction in network tariffs for industrial consumers (see Section 5). All consumers

must pay this surcharge, of which the standard rate was €3.78/MWh in 2016, for the first 1 GWh consumption by all consumers on an annual basis.⁸⁸ The rate applied to consumption above 1 GWh reduces to €0.5/MWh for most consumers, but reduces further to just €0.25/MWh for manufacturing firms with electricity costs exceeding 4% turnover (many of which will also qualify for the network discounts this levy funds). At least some industrial consumers may receive discounts on the standard rate on each of the remaining three taxes and levies (as reflected in Figure 10), under varied conditions.

86 In Figure 10, it is assumed that the average consumer receives a 50% discount on the standard rate.

87 The Concession Fee (*Konzessionsabgabe*) is a levy on the use of public space for network infrastructure. The standard rate for industrial consumers is €1.1/MWh (higher for other consumers), although industrial consumers with an annual average electricity price under an annually-defined threshold (€126.9/MWh in 2016), are exempt. The CHP Surcharge (*KWK-Umlage*) funds the installation of combined heat and power (CHP) systems. The base rate is €4.38/MWh, with annual consumption exceeding 0.1 GWh of either €0.4/MWh or €0.3/MWh (for industrial consumers with electricity costs <4% or >4% turnover, respectively). The Offshore Liability Surcharge (*Offshore-Haftungsumlage*) funds the costs of service compensation in the case of interference or delay in the connection of offshore wind farms. In 2016, for annual electricity consumption <1 GWh, a rate of €0.28/MWh applied. For consumption over >1GWh, the rate increased to €0.38/MWh, aside for consumers in the manufacturing industry with electricity costs equal to >4% turnover, for whom the rate reduced to €0.25/MWh.

88 Increasing to €3.88/MWh 2017, but reducing to €3.70/MWh in 2018 (Netztransparenz.De, 2017).

France

Only two levies are applied to the electricity consumption of industrial consumers in France. The first is the CSPE (*Contribution au service public de l'électricité*), which recovers the cost of renewable electricity support mechanisms.⁸⁹ The standard rate is €22.50/MWh. This relatively low value is due to the relatively low penetration of non-hydro renewables in France. **However, an objective of the French Energy Transition is to reduce nuclear power from 75% to 50% of generation by 2025, to be replaced in part by substantial investment in new renewable capacity, including €7 billion between 2018 and 2022 alone.**⁹⁰

Industrial consumers may receive substantial discounts on the CSPE, depending on their specific characteristics. For industrial consumers, and where the cost of the CSPE would equal or exceed 0.5% GVA, rates may be as low as €2/MWh (for consumption >3 KWh per unit GVA).⁹¹ For consumers in 'highly trade-exposed' sectors⁹² with energy intensity >6 KWh per unit GVA, the rate reduces further to €0.5/MWh. For firms with annual consumption over 7 GWh, the total cost of the CSPE is limited to the equivalent of 0.5% GVA, or €627,783 per site. The rate in the chart is equivalent to an average rate of €7/MWh, and accounts for over 75% of the average taxes and levies value for French industrial consumers presented in Figure 10.⁹³ Such discounts are funded by otherwise higher rates for other electricity consumers.

The second levy applied to industrial electricity consumption is the CTA (*Contribution tarifaire d'acheminement*), which contributes to pensions for energy sector employees. For all electricity consumed through the distribution network, the standard rate is

equivalent to 27.04% of the fixed-rate components of the relevant network tariffs (see Section 4). For consumers connected to the distribution network at or above 50kV, or directly to the transmission system, a rate of 10.14% applies.⁹⁴

Italy

The costs of the Italian renewable electricity support mechanisms (*incentivi alle fonti rinnovabili e assimilate*) are recovered through a charge on electricity consumption ('A3' tariff). In October 2016, the standard tariff rate for domestic consumers with a connection of 3kW or less was €33.44/MWh for up to 1,800 kWh of annual consumption, rising to €72.73/MWh for consumption exceeding 2,640 kWh (with the latter rate applying to all domestic consumption for connections above 3kW). **Commercial and industrial consumers pay progressively reduced rates, based on their connection voltage and with increasing annual electricity consumption.** Those connected at a low voltage paid a flat rate of €67.63/MWh or €62.45 (depending on power capacity), for all consumption. The rate for medium voltage connections for consumption up to 8 GWh each month was €51.29/MWh. For consumers with a high voltage connection, a similar rate was charged for the first 4 GWh consumption per month, with a rate of €27.96/MWh applied to consumption in the range 4–12 GWh per month. Any monthly consumption above these levels for medium and high voltage connections were not charged.⁹⁵ The rate in the chart is equivalent to an average rate of €39/MWh, and accounts for over 75% of the average taxes and levies value for Italian industrial consumers presented in Figure 10.⁹⁶

The second levy of note is an electricity tax applied at a standard rate of €22.7/MWh for the majority of domestic consumers. For non-domestic consumers, a reduced rate of €12.50/MWh applied for the first 200 MWh/month (2.4 GWh/year) consumption. For

89 Alongside subsidised electricity prices for low-income consumers, and power supply to overseas territories not connected to the local grid.

90 Announced as part of the French government's 'Great Investment Plan 2018–2022', published in September 2017.

91 For electro-intensive consumers with consumption of 1.5–3 kWh per unit GVA, the rate is €5/MWh. For those with consumption <1.5 kWh per unit GVA, the rate is €7.5/MWh.

92 25% trade intensity (see Footnote 71)

93 This value is the remainder once the average CTA value is subtracted from the total taxes and levies rate (see Footnote 89).

94 The average rate is assumed as €2/MWh, the midpoint of the range given by Grave et al (2015, pg.15).

95 Most non-domestic consumers must also pay an additional flat annual charge of between €114.51 and €156.39 in 2016.

96 The value remaining after subtracting the applicable values for the remaining taxes and levies for industrial consumers in Italy, from the total average taxes and levies value for Bands ID–IF.

consumers with a maximum consumption of 1.2 GWh/month (14.4 GWh/year), a rate of €7.5/MWh applied to the remainder. For consumers with consumption rates above this, a fixed value of €4,820 applied to all consumption above the first 200 MWh/month.⁹⁷

Industrial electricity consumers in 2016 were liable for various other levies, which collectively comprise an estimated average of around 6% of the value of total taxes and levies due – all of which afford progressively reduced rates for large electricity consumers in the non-domestic sector.⁹⁸ Such reductions were financed through otherwise higher rates on lower consumption levels.

Since 2013, electricity-intensive consumers⁹⁹ connected at the medium and high voltage levels in Italy have been eligible for compensation for the costs of the 'A' tariffs, in proportion to their electricity intensity, ranging from 15% (with electricity intensity of 2–6%) to 60% (with electricity intensity >15%). Such compensation is financed by the 'Ae' tariff (*copertura delle agevolazioni per le imprese a forte consumo di energia elettrica*), payable by all other consumers. However, the Ae tariff was suspended for 2016 (but reintroduced in 2017), and only compensation for 2013 and 2014 has so far been paid, pending a decision from the European Commission on the mechanism's

⁹⁷ The value in Figure 9 assumes annual electricity consumption of 76 GWh, spread evenly over 12 months.

⁹⁸ The Nuclear Decommissioning Surcharge ('A2' Tariff, *Oneri per la Messa in sicurezza del nucleare e compensazioni territoriali*) covers the cost of decommissioning nuclear power plants. The standard rate for most domestic consumption in 2016 was €4.87/MWh. The National Railway Surcharge ('A4' Tariff, *Regimi tariffari Speciali per la società Ferrovie dello Stato*) finances subsidies to the national railway system. The standard rate for domestic consumers in 2016 was around €1/MWh. The R&D Surcharge ('A5' Tariff, *Alla ricerca di sistema sostegno*) funds power sector-related research and development. The standard rate for most domestic consumers in 2016 was €0.59/MWh. The 'Electricity Bonus' Surcharge ('As' Tariff, *copertura del bonus elettrico*), finances subsidies to low-income and vulnerable domestic consumers. The standard rate for most consumers and consumption is €0.35/MWh. For each of these tariffs, values reduce to zero for large industrial consumers for monthly consumption >12 GWh. The UC4 tariff supports electricity companies with fewer than 5,000 customers, and had a standard rate of €0.27–0.58/MWh for domestic consumers, reducing to €0.20/MWh and €0.10/MWh for medium and high voltage consumers, respectively. The UC7 tariff covers the cost of measures to promote end-use energy efficiency, with a flat rate of €0.20/MWh for all consumers. The MCT tariff finances territorial compensation measures for sites hosting nuclear power facilities, with a flat rate of €0.18/MWh for all consumers. All values applicable from 1st October to 31st December 2016. The tariff structure in Italy has undergone significant reform for 2018 onward – See EC (2017c) for information.

compliance with State Aid guidelines. A positive decision was reached at the close of 2017, meaning compensation for these years became available for payment from 1st January 2018.

Taxes and levies – conclusions

Large, electricity-intensive consumers in each country may receive substantial discounts on or compensation for the costs of renewable electricity support mechanisms, as well as other taxes and levies.

In the UK, this means that in 2016 the effective minimum level of taxes and levies due to qualifying firms was around £3.66/MWh (€4.26/MWh)¹⁰⁰ – more than 75% lower than the average rate presented in Figure 9. Calculating such a rate in the other countries examined is difficult, however, as in **Germany, France and Italy, renewable electricity cost recovery mechanism rates for large or electricity-intensive consumers are either capped to an absolute value, a value equal to a GVA threshold, or fall to zero over a given consumption level.** Such limits, along with those applied to other taxes and levies, means that effective rates may continually decrease with increasing consumption. **In all countries, the value of discounts and compensation are recovered either by higher rates on other electricity consumers, or by the taxpayer.**

Although the deployment of renewable electricity is likely to continue (and potentially accelerate) in each country, the cost of support mechanisms is likely to decrease in the medium term, driven by a combination of rapidly reducing technology costs, a shift from traditional support mechanisms (such as feed-in tariffs) to more market-responsive and competitive instruments (such as feed-in premiums and auctions), and as existing support contracts begin to expire.

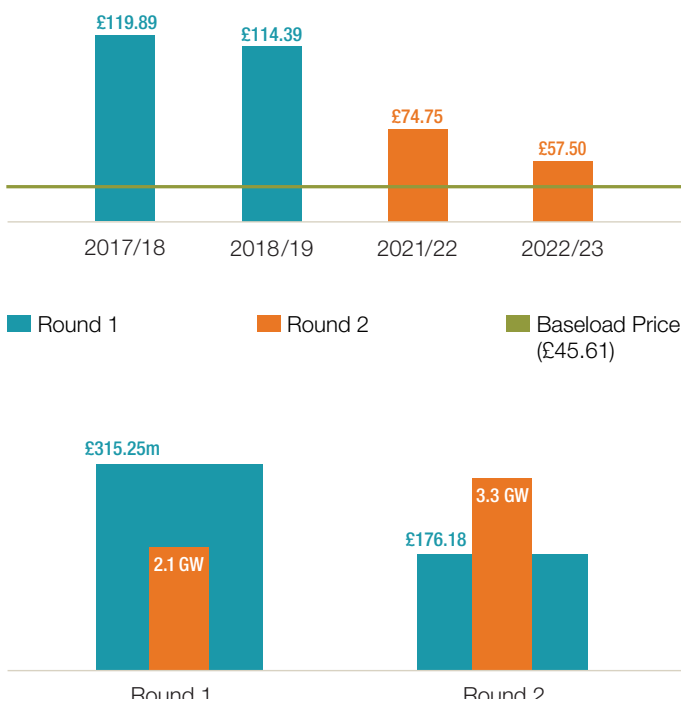
⁹⁹ Electricity consumption >2.5 GWh/year, with electricity costs >2% GVA.

¹⁰⁰ Assuming 85% discount on the pass-through cost of RO and FITs, 90% discount on the CCL standard rate, and exemption from the CRC.

Figure 12 illustrates the evolution in the strike price for offshore wind under the UK’s CfD instrument (left panel), reducing from a minimum value of £119.89/MWh in the allocation Round 1 (for delivery in 2018/19), to just £57.50/MWh in the 2017 allocation Round 2 (for delivery in 2022/23). The left panel illustrates an increasing capacity contracted for a reducing value between the two rounds. These strike prices are already substantially below the UK government’s 2016 lower bound projection for levelised costs for projects commissioned in 2030 (£85/MWh) (BEIS, 2016b). Some offshore wind auctions in continental Europe in 2017 cleared with ‘zero subsidy’, though these generally do not pay transmission charges and had guaranteed grid access.

As shown in the next section, onshore wind is probably the lowest cost form of electricity generation that may be built in the UK, with levelised costs at or below prevailing wholesale prices, meaning **it could be subsidy-free, and even potentially generate income that would reduce the existing costs of the CfD, recovered from electricity consumers**¹⁰¹ (ECIU, 2017). However, despite continued expansion in other EU Member States (including Germany and France), new onshore wind development has been excluded from renewable investment mechanisms in the UK since 2015.

Figure 12 – UK Contract-for-Difference offshore wind strike prices, contracted volume, and total value



Source: Adapted from National Grid (2017b)

¹⁰¹ Baringa (2017) estimate that a strike price for new onshore wind would be less than £50/MWh for capacity delivered in 2021–23, a value that would generate a net payback to the CfD scheme of £18 million (present value) over the lifetime of contract, for 1GW contracted capacity.

6. Policy recommendations

For those industries without compensation UK industrial electricity remains amongst the most expensive in Europe. Our analysis suggests why the gap is likely to narrow in the future, but the government's ambition is to go well beyond this.

The CCC's projections in 2016 suggested that energy costs will still rise considerably to 2030, due to their assumptions of both rising gas prices – a view questioned in the Helm Review – and rising policy costs – a view which recent auctions, of both firm capacity and renewables (both much cheaper than expected), also calls into question.

The system context, national and international

Wholesale prices remain the main component of industrial electricity prices. Whilst in recent years coal has been pushed to the price-setting margin of UK generation, this will recede as coal is phased out and wholesale prices in the UK electricity spot market will again be set mainly by gas prices. Overall, the enquiry by the Competition and Markets Authority concluded that the GB wholesale market is competitive (though it expressed more concerns about the retail market for domestic and other small consumers).

Especially with the decline of North Sea output, the price of gas depends largely upon international developments. There is no robust way of knowing how the interplay of reserves, rising global demand, and the politics of the US, the Middle East, Russia and Asia in particular may play out to affect future gas prices. Given political and economic uncertainties, exchange rates may also remain volatile.

These factors are largely beyond our control (and as noted in Section 3, official projections of gas prices by 2030 span a factor of two). However, expanding renewables deployment, using the auctioned contracts of the UK's Energy Market Reform, will tend to push the more expensive coal and gas plants off the system and thus bring down wholesale costs, as well as starting to reduce the wholesale market's dependence on gas. The load to be met by flexible plant will become more, not less, variable, increasing the importance of smart controls and storage.¹⁰²

¹⁰² Note that we thus seem a long way from the disappearance of the wholesale market envisioned in the Helm Review due purely to the rise of asset-based energy generation (like renewables). The wholesale market would at minimum remain an important interface in the management of the system and play an important role as a price marker.

Given this context, in this section we set out specific options the government could consider to ensure that the electricity prices available to UK industry fall and converge, at least, with prices typical across western Europe.

The starting point is to harness the technological revolution underway in electricity so as to minimise overall system costs.

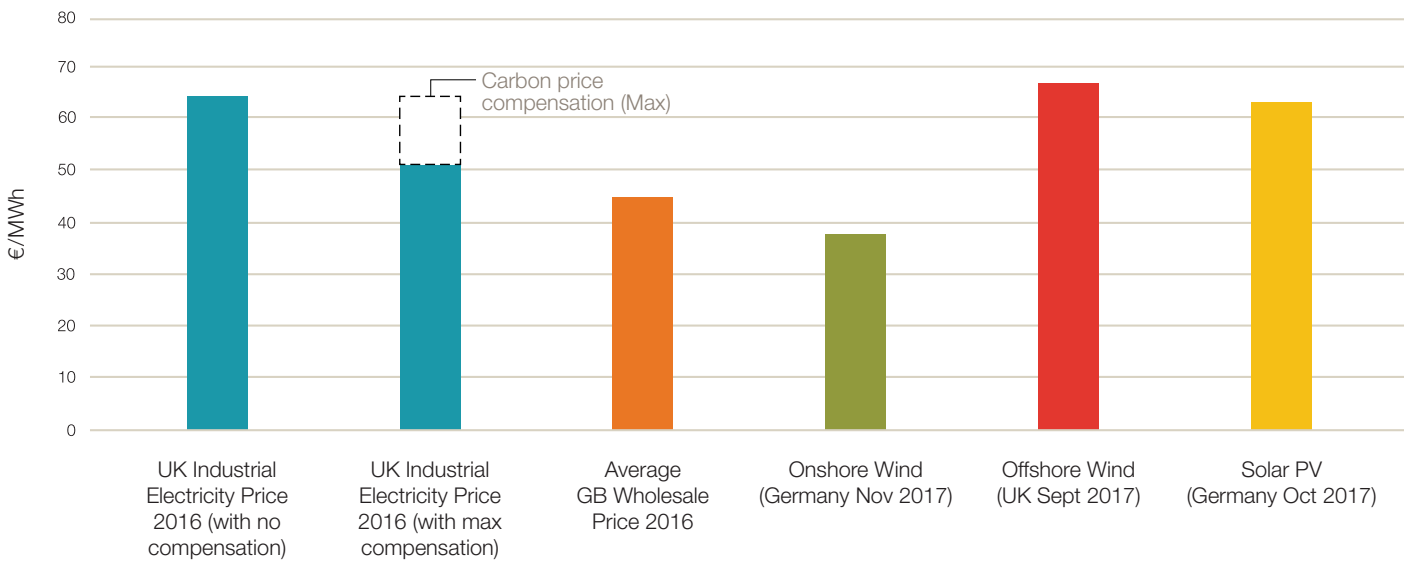
1. Restore an efficient investment framework for the cheapest mature renewables and signal intent to restore a rising carbon price in the 2020s

Launch a full-scale review of policy towards onshore renewables, based on recognition that onshore wind no longer requires subsidy providing that political risk is minimised (e.g. through long-term contracts) and that investors have confidence in realising the full value of fuel (including carbon) cost savings. Specific near-term options include a "Pot 1" CfD auction and reform of planning regulations, and a legislated carbon price escalator (with an appropriate compensation mechanism) to reduce policy-related investment risks, timed alongside the coal phase-out.

Clearly, the overall economic costs of the UK system will be lowered by maximising use of the cheapest energy resources, particularly from clean sources which will contribute to meeting UK carbon targets and for which a carbon price would not increase generation costs. **International experience has underlined that for a windy country like the UK, the cost of onshore wind energy can be significantly below the price of industrial electricity, given a non-discriminatory planning environment and investor confidence.**

Figure 13 shows that the most recent contracted prices for onshore wind and PV in Germany (which is less windy than many UK regions) are below UK industrial electricity prices, whether with or without compensation; the wind price is even below UK wholesale prices. Even offshore wind energy, long considered one of the most expensive renewables, was in the most recent UK auctions contracted at a cost comparable to UK industrial electricity prices.

Figure 13 – Recent renewable energy prices compared to UK electricity prices



Sources: Wholesale and renewable prices: BNetzA (2017a, b), Ofgem (2017e). For UK industrial electricity prices, see Section 3.

From a cost perspective it is doubly unfortunate that all mature renewables have been caught up in the policy ban on what is now probably the UK’s cheapest bulk power source. The drop in price of mature renewables especially onshore wind suggests a reasonable basis for a review of policy.

In the context of the existing wholesale market, enhanced renewables deployment will bring forward the point at which existing highly efficient gas plants become the main wholesale price-setter. This would reduce wholesale prices, but could further increase price volatility and hence market risk if renewables investment is expected purely on the basis of the wholesale market; as summarised in Box 4 and recognised in developing the Electricity Market Reform (EMR), this is an inefficient approach which risks deterring investment in renewables even when they could offer lower (and in terms of their own costs, more certain) prices.

Renewables already pay balancing costs, and at present, ‘backup’ costs as represented by the Capacity Market amount to only a small fraction of investment costs; in Recommendation 6 we suggest how to ensure that unsubsidised renewables evolve to pay their system costs efficiently as the capacity grows further.

One obvious route therefore would be to hold another “Pot 1” auction of contracts-for-difference, which would lead to net benefit and reduction of electricity bills, consistent with the implications of Figure 13.¹⁰³

Second, to enhance investor confidence and thus lower the cost of renewables investment in the longer term, the government should clarify its intention to restore the carbon price escalator, to within the range recommended by the High-level Commission

¹⁰³ Aldersgate Group submission to the Call for Evidence on the Helm Review: “Providing a route to market for such technologies through another Pot 1 auction of market stabilising CfDs (defined as a CfD contract capped at the level of support given to conventional power generation such as new gas power plant) should be a priority under the new Control for Low Carbon Levies, in which we note that “in order to ensure the lowest costs for consumers, new levies may still be considered where they have a net reduction effect on bills and are consistent with the government’s energy strategy”. A recent study from Baringa (2017) for Scottish Renewables found that if a 1 GW Pot 1 auction took place in 2018/19, this would deliver exclusively onshore wind projects at a clearing price of £49.4/MWh in real 2017 terms. The study estimated that contracts would pay back to the consumer over their lifetime, with the Low Carbon Contracts Company receiving a net payback of £18 million on a present value basis (real 2017 terms, using a public sector WACC discount rate of 3.5%).”

Box 4 Risk and financing costs in the electricity transition

Gas turbines have short build times, and relatively low capital costs, with the main costs being the gas burned to produce electricity. Zero carbon sources are very different, with most of the costs related to the capital costs of construction and installation. Once solar panels are installed, or wind turbines are built, costs are low: there is no fuel, only operation and maintenance (O&M) costs. This has two crucial implications:

- As explained in Section 3, such renewable sources tend to operate as baseload, ahead of fossil fuel sources, because they are cheaper to run and need to produce whenever available to recover the cost of capital; by displacing the most expensive-to-run fossil fuel plants, this reduces wholesale electricity prices
- The cost of capital is all important to developers of low-carbon electricity and is crucial to determining the cost of, and our ability to move towards, a low-carbon electricity system.

The cost of capital to generators depends on the balance between debt and equity financing, market conditions, and the risk and uncertainty related to the returns on investment. The latter depend upon the future electricity price, along with any additional support policies. In competitive wholesale electricity markets, such as that which exists in the UK and EU, the wholesale price is set by fossil fuel generators.

This means that **the price at which a low-carbon investor can sell its product in the wholesale market bears no relation to its own costs.** It depends instead upon the volatile prices of coal,

gas and carbon faced by the fossil fuels generators (Roques, Nuttall et al. 2006). In economic terms, zero carbon sources are 'infra-marginal', but in the absence of other measures will receive a price set at the margin over which they have no control – and limited capacity to predict.

This potentially raises the cost of capital, increasing overall costs and reducing incentives to invest. Doubling the cost of capital (discount rate) from 5% to 10%, for example, increases the overall cost of capital-intensive generation, such as nuclear and wind, by around 50%.

Recognition of these factors was central to the inclusion of long-term contracts in the UK's Electricity Market Reform and the cost reductions which have ensued, with Newbery (2016) estimating that the auctioned contracts have reduced the weighted average cost of capital by around 3% – saving an estimated £2bn/yr on the cost of capital associated with the UK energy transition.

Consequently, we support the Helm Review's conclusion that any future market design cannot simply rely on a wholesale electricity market as the main incentive for low carbon investment, whatever the carbon price. This economic logic implies (a) that 'subsidy free' does not obviate the need for contract auctions (Recommendation 1) and (b) underpins Recommendation 6 to develop a longer term contracts market suitable for low carbon investment whilst taking account of 'system costs'.

on Carbon Pricing,¹⁰⁴ particularly after coal is largely phased out during the early-mid 2020s. **This is because the move from coal to gas as the main wholesale price-setter would more than halve the impact of a carbon price on the electricity price; also the gap with continental carbon prices is set to narrow on a similar timescale (Section 5).**

Restoring the carbon price escalator on this timescale will not only reflect environmental costs and support low carbon investment. **It would also increase the economic signals through the wholesale market for effective use of electricity storage, to help maximise the efficient use of renewables as their impact on system operation grows, and lay the foundations for the move to a private sector-led low-carbon contracts market (Recommendation 6) which would enable industry to avoid the carbon price through direct contracting,** whilst taking appropriate account of system costs.

Until then, the mechanisms for compensating electro-intensive industries for the impact of carbon prices should be regularly reviewed to ensure they provide proportionate support to the industries that most need them, taking into account the introduction of other supportive policies outlined below.

2. Establish an integrated approach to network development, funding and pricing

Enhanced or independent System Operator Objective(s) to include more coordinated oversight of generation and network developments at all levels, to minimise combined network and congestion costs; consider using carbon price revenues to help fund specific identified Strategic Wider Works; and review transmission funding and charging approaches in the light of continental practice.

As noted, overall UK network costs appear comparable to other major countries in Europe, but other countries tend to fund networks (including many offshore connections and interconnectors) through regulated returns, and differentiate network pricing far more. Compared to the intricately negotiated German system, especially, the UK approach has the virtue of simplicity and greater equity across consumers but it is less beneficial to electro-intensive industries.

In the UK, competition in connections to offshore wind farms seems to have helped reduce connection costs (and competition is being introduced for large onshore grid reinforcements), and the cap-and-floor regulation of interconnectors has attracted substantial investment at relatively low financing. However, coordination of generation and investment to minimise costs (including from congestion) and subsequent operation – particularly given long lead times – has been a problem, resulting in the need to pay some wind generation (particularly in Scotland) compensation when its output could not be transmitted south, and discouraging solar particularly in Cornwall as it began to exceed the network capacity.

The present UK approach is good for many purposes, with more competitive pressures and transmission locational pricing signals than continental systems. Coordination mechanisms have also improved. Transmission owners consider proposed generation set out by the System Operator in annual, 10-year-ahead network plans (though renewable energy developments – and technologies for smart network management – sometimes outpace such planning). Ofgem also recently introduced a Network Options Assessment which requires review of plans by the System Operator. Nevertheless, optimising network investment and pricing (regulated activities) with respect to (merchant) generation developments remains a challenge, particularly when changes are

¹⁰⁴ If carbon pricing is to help shape non-discriminatory investment in clean power sources, it needs to rise strategically to a level anchored in independent and internationally recognised analysis of the levels required for consistency with the agreed aims of the Paris Agreement. This was the basis of the report of the High Level Commission on Carbon Prices, convened by the World Bank and chaired by Nobel Laureate Joseph Stiglitz and Lord Nicholas Stern (Stiglitz and Stern, 2017).

accelerating at multiple levels of the system – from small-scale distributed resources to very large scale offshore developments.

The Helm Review recommends an Independent System Operator; the Energy Technologies Institute has called for a System Architect; the Oxford Institute of Energy Studies has reviewed literature and detailed the need for more coordination in the energy transition;¹⁰⁵ and Innovate UK's Future Power System Architecture Project (IET 2017) identified 'thirty-five functions that are either entirely new, or are significantly extended from functionality which exists in some form today... which have interdependencies and cannot be delivered independently.'¹⁰⁶ Strengthening objectives for the GB System Operator – and potentially, multiple distribution system operators – to coordinate generation and network developments could further reduce network and congestion costs.

Such coordination might prove particularly important for cost-effective development of North Sea renewables and interconnections, though Brexit might complicate this institutionally. Further locational signals in transmission pricing could potentially aid a more decentralised approach to coordination, though after recent reforms enacted in Project Transmit¹⁰⁷ it is unclear what the practical scope is for further moves towards the traditional economists' prescription of fully 'locational marginal pricing'.

Whilst doubtless efficiency improvements in networks are possible, bigger issues for industrial electricity prices may lie more in "who pays?" Compared to the current regime, two options could be considered.

105 Peng and Poudineh (2017) argue for an institutional structure where 'the government/regulatory authority plays the role of meta-coordinator, matching the adaptation of market-based coordination modules with a hybrid future...'

106 *Future Power System Architecture 2 (IET 2017)*, Project commissioned by Innovate UK and delivered through a collaboration between the Institution of Engineering and Technology and the Energy Systems Catapult. Final Synthesis report <http://www.theiet.org/sectors/energy/resources/fpsa/index.cfm?origin=reportdocs>. They express strong concern about the inadequacy of current institutional arrangements, but avoid using the term "System Architect" in favour of emphasising the need for "Enabling Frameworks".

107 Project Transmit was an Ofgem-led project spanning many years to reform transmission charging arrangements in the UK. After project launch in 2010 the reforms were finally implemented (after judicial review) in April 2016 (<https://www.ofgem.gov.uk/publications-and-updates/ofgem-welcomes-ruling-project-transmit>)

If the investments continue to be recovered from direct network charging, this is primarily a public policy choice on the options indicated in Section 4: the division between generator and consumer charges; the size of the customer base over which network costs are recovered; and the apportioning of tariffs between different types of consumer. As explained in Section 4, the default UK position has been more even payment across customers, compared to some continental systems which weight network cost recovery more toward domestic and other small consumers to alleviate costs to larger industries. **The UK should review transmission funding and charging approaches holistically (including Triad charges) in the light of continental experience.**

Another option could be to use revenues from carbon pricing to help fund network developments – particularly those identified by Ofgem as Strategic Wider Works which may yield wider and longer term benefits than just 'congestion management', in terms of the opportunities and options they open up. Such network development would then still (and rightly) be funded from electricity consumption, but net transfers from electricity consumers to the government would be reduced.

3. Continue the cap-and-floor system to support continued growth of interconnection irrespective of transitional uncertainties as the UK leaves the EU

Electricity trade through interconnection helps UK wholesale prices to converge with continental prices, and lowers the cost of maintaining security as the grid decarbonises. The existing regulatory structure for interconnectors is proving effective. The government should underline its commitment to maintaining close electricity integration with continental Europe and its support for Ofgem's cap-and-floor returns regime to maintain investment momentum in the face of Brexit-related uncertainties.

Continued expansion of the UK's interconnectors will help the UK wholesale market converge with continental wholesale prices, help to manage fluctuations on the UK system and improve security.¹⁰⁸ As noted in Section 4, National Grid estimated that each additional 1GW interconnector capacity could reduce UK wholesale prices by 1–2%, with reduced costs for intermittent renewables integration and energy security benefits additional to this.

UK interconnector proposals and investments have expanded considerably since Ofgem introduced a system which sets both a cap and a floor on the returns available to investors, initially to support an interconnector to Belgium, and subsequently through two interconnector application 'windows'. The existing capacity of 4GW is due to double to 8.4GW with those now under construction, and increase further on the basis of planned projects given regulatory approval.¹⁰⁹

¹⁰⁸ Particularly given the closure of the UK's main existing gas storage facility, and declining domestic production in Europe, there may also be a case for gas storage to help even out seasonal variations (in addition to possible security arguments) but this is beyond scope of the study.

¹⁰⁹ Existing interconnectors – France (IFA 2GW), Netherlands (BritNed 1GW), Ireland (EWIC and Moyle, 500MW each) plus the following interconnectors under construction: Belgium (NEMO 1GW), France (ElecLink 1GW), Norway (NSL 1.4GW) and France (IFA2 1GW). See Section 4 and https://www.ofgem.gov.uk/system/files/docs/2017/06/ofgem_window2_ipaconsultation_june_2017.pdf

This would transform the UK's physical connections, with links to six different countries. It compares to around 60GW of UK 'firm' generation capacity (and up to double that including the renewables peak capacity projected for the mid-2020s by National Grid). The continued expansion of interconnectors would go a very long way to helping UK prices converge with continental prices, along with the wider benefits, providing the UK retains access to efficient trading with the EU after Brexit. However, developers are more cautious given uncertainties around future arrangements. **The government should underline its commitment to maintaining close electricity integration with continental Europe after Brexit and its support for Ofgem's cap-and-trade regime to reduce the perceived risks facing interconnector investments.**

4. Facilitate cross-border electricity contracting incorporating UK carbon prices

The government should establish a new structure for direct cross-border industrial electricity purchases, which (as with the Californian carbon pricing system) should charge UK carbon prices on purchased electricity, based upon Guarantees of Origin.

Access to the cheapest sources of low carbon generation and storage capacity (most obviously, Norwegian hydro) could be particularly valuable in helping to reduce UK electricity prices and manage variability at least cost. Direct contracting with generators in other Member States is the approach being pursued in the EU internal electricity market, though the Italian 'virtual interconnector' policy (Box 2) illustrates an imaginative approach e.g. if finance for adequate interconnection is delayed, or possibly if market access restricted after Brexit.

However, UK generators would be at a disadvantage if carbon-intensive electricity (e.g. German coal through the planned NeuConnect interconnector, in particular) competed in the UK market. Consequently, the UK should consider applying its carbon price to electricity imports, in the way that California applies its carbon price to imports from other US states.

In principle there are at least two options for this. For general trade through interconnectors, the carbon intensity of the source country could be applied. The alternative would focus on specific contracts with

generators abroad, with emissions as monitored and priced under the EU ETS. And specifically, if the UK did foster a market in long-term low carbon power electricity contracts (Recommendation 6), it should seek to include cross-border electricity contracts, with zero-rated carbon prices. The EU electricity system already includes certificates of Guarantees of Origin for low carbon power generation, which should facilitate the implementation of such a system irrespective of the precise nature of the future relationship between the UK and the EU's Single Electricity Market.

5. Support industrial involvement in the Capacity Market and other electricity service markets

The value of system-related services like demand-shifting and frequency support is rising, whilst the cost of providing such services from industrial energy users is declining. The government should in particular use the 5-year review of the EMR and Capacity Market with the explicit aim of helping UK industrial electricity consumers to gain from providing these services to the future UK electricity system.

Despite declining relative consumption, UK industry in 2016 still accounted for 26% of electricity consumption (and the commercial sector another 21%).¹¹⁰ Significant parts of such demand could, in principle, have some flexibility, associated with inbuilt storage (e.g. thermal), more flexible cogeneration of heat and power, and/or other flexibility (e.g. in scheduling of manufacturing activities). Industry also has an estimated 10GW of 'autoproduction' or backup generating capacity.¹¹¹

In a system with growing variability from renewables, these resources potentially have a growing economic value. In principle industries could realise this value from participating in several electricity-related markets, most obviously, the Capacity Market, and markets for frequency response. Yet the Capacity Market was really designed with a view to supporting new generation capacity. Industrial demand management plays a role in 'triad avoidance', but has to date remained a small

component in most other service markets, including the Capacity Market, in which demand-side response rose to 1.4GW out of a total 52.5GW in the January 2016 Capacity Market auction – a far lower proportion than found in some US capacity markets.

This is despite the fact that new information and control technologies, and new electrical applications (like electric transport and associated batteries) are rapidly increasing the scope for, and the cost of, offering such services.

National Grid and BEIS have made attempts to encourage industrial participation in these mechanisms, but largely from the standpoint of electricity system management. The approaching 5-year review of EMR and the Capacity Mechanism, alongside the UK industrial strategy, offers an opportunity to also broaden horizons.

The UK should work with industries also from the standpoint of helping companies to realise the economic value of these services as a way of offsetting their electricity bills, and better understanding the obstacles to their greater engagement. This might lead to greater participation in the existing mechanisms. It might also suggest new and additional approaches – including new ways of bundling such services in new types of industrial electricity contracts, which brings us to our final recommendation.

6. Establish a long-term, zero carbon electricity contracts market

For the longer term, foster standardised structures of long-term, tradeable zero-carbon electricity contracts available to business consumers and grounded in the declining cost of unsubsidised renewable electricity sources. Consumers holding these contracts would thereby avoid the carbon price. Balancing and backup costs will be minimised if the renewable energy contracts are aggregated through a 'green power pool', which passes these costs on to the renewable generators, whilst consumers offering demand flexibility and other system services benefit from lower contract prices. The most relevant publicly-governed body (potentially the Low Carbon Contracts Company or an enhanced System Operator) should be charged with examining the steps required for such a system to develop at scale by the mid-2020s alongside resumption of the carbon price escalator.

110 DUKES 2017, Chapter 5 Figure 5.6

111 Ibid.

As noted, some of the largest electricity consumers (in Band IG) often circumvent the wholesale market, for example through owning their own generating facilities, or through direct ‘power purchase agreements’ with generators. The French Exeltium consortium (Section 3) provides a particular route through which electro-intensive industries have accessed cheap power and reduced risks through the financial efficiency of bulk purchase through long-term contracts. **That model of industrial collaboration (in economic terms, a monopsony) seems inimical for the UK, but the core economic point becomes highly relevant in an age of cheap renewables contrasted with an uncertain and increasingly volatile wholesale market.**

For the reasons summarised in Box 4, a short-run wholesale market is an inappropriate basis for funding renewables investment, which is why the long-term CfD contracts of the EMR have helped to bring such large cost reductions. This does however place government purchase (through auctions) at the centre of the system, with attendant risks particularly as the scale grows further.

A long-term, zero carbon electricity contact market: the basic idea

However, the advent of cheap renewables raises another possibility. **We propose that systems should be established to facilitate a market for long-term, zero-carbon power contracts – a specific, regulated ‘green power’ contracts market, which could operate alongside the mainstream wholesale power market.**

As in the Exeltium consortium, bulk industries which value cost certainty could be major purchasers if the price is attractive. It need not be restricted to such companies, though; some UK companies like BT already buy 100% zero carbon power as part of their corporate sustainability strategy, and in the framework of the Paris Agreement hundreds of major international companies have declared their commitment to rely 100% on renewable electricity by 2030. Domestic supply companies could also buy such contracts, particularly if they wish to target green consumers.

Economic principles

Long-term contracts reduce financing and thereby investment costs in low-carbon electricity sources. A market based on this would be better suited to the

‘infrastructure electricity’ (to use the term of Paterson (2013) that renewables will supply. Long-term contracts for such power could be based on generators’ actual investment costs, rather than short-run wholesale markets, and allow more certainty in repayment, reducing the cost of capital.

Corporate long-term contracts are possible in the current market but take the form of individually tailored power purchase agreements. A contract between an individual buyer and a single power plant involves risks for both sides. A generating company that builds and operates the plant faces the risk of having a single purchaser, while the counterparty depends on that power source, with the inherent risks involved.¹¹² The danger is that these risks inflate the cost of capital above and beyond that financed by alternative instruments, such as feed-in tariffs, that are backed by governments, reducing their effectiveness.

The central principle would be to combine the economic value of long-term contracts for low carbon generators, with the risk-sharing features of markets. The traditional difficulty with such an idea is the potential diversity of such contracts – how would one trade a 15-year contract with one finance and risk structure with another of 20 years and a completely different finance and risk structure? The need for some liquidity in such a contract market structure implies a need for a limited number of standardised contract types, which could then be exchangeable.

Once signed, such contracts would guarantee the price of electricity to be received by the generator for the contract period. However instead of the government being the only counterparty, contracts could be purchased by private companies seeking security for their future electricity prices, taking the form of an

¹¹² If the buyer goes bust, the power plant is exposed – this has been a major reason cited why most generators have not pursued long-term contracts with some of Europe’s major industrial consumers. In a globalising world, and witnessing the struggles of European large and electricity-intensive industry, the longevity of a specific industrial plant is considered too risky to finance a major power plant construction. Conversely, if the contract is focused on a single new power plant, the buyer is exposed if that goes wrong.

Figure 14 – Core differences between ‘traditional’ and ‘emerging’ electricity

	Traditional	New Electricity
Generation	Baseload & flexible	Variable, inflexible & storage (batteries, CHP, hydro, biomass)
	Different price reflecting variable cost	Fixed price reflecting capital outlay
Demand	Variable, inflexible, mostly fixed price	Baseload & seasonal, growing flexibility, differentiated pricing

asset which could be resold at any time (for example if their electricity demand declined).

Binding long-term contracts are illegal in the domestic market, given the rules facilitating switching of suppliers. Individual consumers are most unlikely to be participants in long contracts anyway, but at some scale, preventing or impeding mutually assenting parties from entering long-term contracts can no longer be presented as a way of preventing market abuse, but risks instead impeding another sort of competition – one which might be far better suited to fostering the investments required.

Design issues

For specificity, call it a ‘Green Power (GP) Contract Market’. To support investment, the generator contracts would have to be long term (the 15-year horizon of the CfD contracts appears to be adequate for renewables). A long-term contract on the generator side does not necessarily preclude the ability to trade contracts (which might be particularly relevant as an option on the consumer side). The accounting

framework would need to clearly delineate such GP contracts from the rest of the power system.

Such a differentiation would allow firms holding such GP contracts to claim credit for purchasing zero-carbon power in calculating their carbon emissions. It would provide a much simpler and robust system of accounting for consumers who wish to purchase renewable power. It is thus an extension of market principles – not the reverse.¹¹³ **Creating a tradable contractual structure would be crucial to such arrangements, allowing firms to acquire or divest such contracts as their situations dictate, within prescribed rules that protect the underlying financing requirements.**

Purchasers of these contracts would be paying the costs associated with carbon-free generation – but would avoid the carbon price. However, carbon pricing would remain relevant to the economics of this

¹¹³ Moreover, with some specific low-carbon power capacity linked through long-term GP contracts, this would also facilitate (though not resolve entirely) the dilemma of disincentives under an emissions trading system cap. The cap for a future system, for example, could be explicitly debated in terms of electricity sector emissions net of the volume of GP contracts; such contracts could thus legitimately claim to be contributing to ongoing carbon emissions, by reducing the demand for carbon-based generation and thus facilitating tougher carbon caps on the rest of the system over time.

approach – as the carbon price rises, the relative value of fixed-price GP contracts would correspondingly increase relative to the wholesale electricity market.

*Bundling and system balancing costs:
'two markets' approaches*

Given the variable nature of output from most renewables, the renewables would still require balance and backup services and it is likely that government would still need to oversee the rules and systems for accounting, which could draw on precedents for example relating to the renewables Levy Exemption system under the Climate Change Levy. But this is not dissimilar to some of the roles government plays today in some other markets, and in monitoring fuel mixes of energy suppliers for green certificate accreditation.¹¹⁴

The full benefits from this approach – which draws upon other proposals pointing in similar directions (e.g. Keay and Robinson, 2017) – would derive from fully combining the differences implied by the new forms of generation, with the growing flexibility of many business and other electricity consumers, as simply summarised in Figure 14.

The implication would be for a distinct electricity market, potentially culminating with a 'green electricity pool', designed appropriately to these characteristics, as summarised in Box 5. Renewable energy generators would be accountable for the system costs implied by their variability, but in ways that still allowed for the economic benefits of aggregation. Since the green pool on the generator side would be designed to support efficient investment in renewables, this could offer different contract prices depending upon the nature, location and characteristics of the renewables, relative to the existing portfolio.

On the demand side, business electricity consumers would not only benefit from efficient contracting with cheap renewables, but also avoid carbon prices on

such contracts (though the value of such contracts obviously would rise with the carbon price paid in the wholesale market). They could also gain discounts on contract prices if they could offer flexible demand, responding to the variations of power available through the 'green electricity pool', and thereby reducing the need for the pool itself to buy balancing services from the rest of the electricity system.

Note that none of this implies a sudden and radical change imposed by government. As noted there are already unsubsidised renewable energy contracts to some large (usually commercial) companies. New technologies and business models for demand flexibility and related services are already emerging, and our Recommendation #5 is essentially to accelerate this particularly in relation to industry. An enhanced or independent System Operator – along with distribution system operators – would seem best placed to assess these options, whilst the Low Carbon Contracts Company is closest to the current structure of renewable energy contracts.

Their expertise could usefully be brought to bear on the detailed options, informed by the private sector innovations already occurring. At minimum, government could do much to help a distinct market for 'new electricity' to emerge, by helping to connect these trends and develop standardised systems: systems to help pool renewable energy generation and allocate system costs on one side, matching on the other with business interests to secure predictable and affordable prices, along with the growing value of (and options for) demand flexibility.

¹¹⁴ Suppliers who provided levy exempt tariffs were required to provide balancing of Levy Exemption certificates with energy sold under the tariff. This need not be instantaneous. There is an initial 3 month balancing period. At the end of this period if the energy sold balances, or is less than, the number of certificates held, a new balancing period begins. If the amount of energy sold is greater, the balance is carried forward into subsequent periods, up to a limit of two years, at the end of which any outstanding Levy payments must be settled (HMRC, 2010). The UK's fuel mix disclosure regulations, which requires suppliers to provide information on the mix of different generation types used to produce the energy they sell offers a different model. The fuel mix is balanced over a total of a year, with disclosure based upon total generation mix over that time period (Ofgem 2005).

Box 5 Implementing contracts markets with variability – a ‘Green Pool’

As the contribution of renewables rises during the 2020s, the cost of system services – and notably, backup for periods of low renewables output – will become more important. The Helm Review proposes that renewable energy CfDs should be merged with the Capacity Market, requiring each renewable investor to provide its own backup to provide firm power. However, this would lose the clear benefits of aggregating different (and potentially diverse) supply sources and hence lead to substantial excess capacity and higher system costs.

The changing characteristics of the emerging electricity system as summarised in Figure 14 point to something more fundamental. In some ways, the ‘new electricity’ system emerging with renewables and more active demand side is a mirror image of the traditional system. Many competitive systems are run with an ‘electricity pool’ and many economists still consider this to be a good way of organising traditional electricity markets. To implement a green power contracts market, the characteristics indicated suggest that similar principles could be applied for aggregating demand and supply contracts in a ‘green pool’, but with some of the traditional incentives applied ‘in reverse’ between generators and electricity demand.

On the generator side, such a ‘green pool’ would comprise fixed price contracts with renewable energy generators, potentially differentiated according to e.g. seasonal and peak availability. The pool itself – representing the aggregate of the participating renewable energy sources – would contract with the balancing market to ensure it could provide the power available for the industrial demand-side contracts. The cost of the balancing services would be charged back to the renewable generators – which would thus face short-run balancing costs more efficiently, plus an appropriate level of backup costs. The industrial consumers could negotiate reduced contract prices in return for providing flexible demand (a major evolution from existing interruptible contracts) according to the fluctuating supply availability in the green pool.

This is of course not the only option. A ‘two market’ proposal from the Oxford Institute of Energy Studies (Keay and Robinson, 2017) goes even further and suggests two entirely separate electricity markets, with separated retail markets, and with the ‘as available’ (intermittent) generation market responsible for all balancing through its own, separated, customer base, and no balancing transactions with the traditional electricity market.

7. Conclusions

As explained in the Introduction, we set out to answer four questions relating to UK industrial electricity prices.

Are electricity prices faced by industry higher in the UK than other key economies in the European Union?

Average industrial electricity prices in the UK in 2016 were significantly above the EU average, though this excludes the role of compensations which are far bigger than in other major European economies: namely, for the indirect cost of carbon prices (both the EU ETS and the UK's unilateral Carbon Price Floor) and renewable support mechanisms in the UK. For those companies eligible, such compensation may be worth up to 27% of the average electricity price in 2016 – although relatively few industrial consumers will be eligible for both compensation mechanisms, and fewer still for the maximum value.

Exchange rates are also key in price comparisons. When denominated in Euro, average UK prices appeared to increase by 20% between the end of 2013 and the end of 2015, before returning to 2013 levels by the end of 2016. However, prices as experienced by industry (denominated in GBP) remained relatively stable – a difference explained by a rapid spike and subsequent decline in the £:€ exchange rate.

What key factors determine industrial electricity prices and their components in the UK, and other key economies in the European Union?

Electricity prices may be deconstructed into three components: energy and supply, network costs, and taxes and levies. On average across the EU by the end of 2016, these elements comprised 59%, 16% and 24%, respectively, of reported prices. Whilst UK price components approximately match this EU average, taxes and levies are more dominant in Germany and Italy, whilst energy and supply takes a larger share (of lower overall prices) in France.

Despite the availability of discounts and compensation, levies to recoup the cost of renewable support mechanisms comprise the majority of the taxes and levies component for the average industrial consumer, although the value of this component is substantially lower in the UK than in Germany and Italy. For the largest, most electricity-intensive consumers, discounts and compensation may reduce the value of most taxes and levies very substantially below the average in all countries – although such provisions are most aggressive in Germany, France and Italy.

Such reductions are compensated by other electricity consumers, or the taxpayer.

However, the growth of renewables has substantially reduced average wholesale electricity prices in Germany and Italy over recent years, and (somewhat less and more recently) in the UK, compared to what such prices might otherwise be. For industrial consumers that receive discounts or compensation for the cost of support mechanisms, this is therefore achieved at minimal (and potentially negative) cost. Energy and supply costs in Germany are well below those in the UK, Italy, and even France. Low prices for coal and carbon emissions, combined with the impact of renewables on its wholesale market, all contribute to low German wholesale prices, whilst higher gas and carbon prices, combined with relatively limited interconnection between the GB and continental electricity markets and previously less efficient renewables policies, have contributed to higher UK prices (before compensation). In France, a significant proportion of electricity for industry is delivered through semi-fixed price contracts based on nuclear generation.

Network costs with respect to total electricity demand are relatively consistent across all four countries, however average network tariffs for industrial consumers in France and Italy are significantly lower than in the UK and Germany. This is a result of tariff designs that yield particularly low rates for users with progressively higher voltage and capacity connections and consumption levels, and the use of targeted discounts. However, this means the costs of electricity (particularly transmission) networks are spread significantly more evenly between consumers in the UK than in France, Italy and also Germany, where smaller commercial and domestic consumers must compensate with higher tariff rates or other levies.

How might these factors develop into the future?

Projecting how comparative industrial electricity prices and their components may develop into the future is fraught with difficulty. This may be particularly the case at present, as the UK prepares to leave the European Union, with relevant details regarding the future relationship – and their implications – yet to be determined. However, some likely developments may be distilled.

The deployment of renewable electricity is likely to continue in each country, with policy costs decreasing in line with rapidly reducing technology and support mechanism costs. This is likely to continue to reduce wholesale electricity prices, and if discounts and

compensation mechanisms are maintained, magnify the net benefit to large industrial consumers. In 2018, in the UK, firms will begin to receive exemptions rather than compensation for these costs, improving comparability in reported prices between the UK and other European countries.

A number of new interconnectors between the GB and neighbouring markets are at various stages of development, which would likely help prices converge between these markets. However, it is unclear how post-Brexit arrangements may affect decisions to construct and operate these interconnectors.

Recently announced policy means that the impact of the UK carbon price on electricity prices is likely to remain stable or decrease in the UK, as coal capacity is phased out. With a strengthening EU ETS, carbon-related costs are likely to increase on the continent, and particularly so for coal-intensive states such as Germany. Although an increased carbon price is likely to have limited effect on industrial electricity prices in France, substantial costs are pending for the upgrade and decommissioning of nuclear capacity, and installing replacement generation capacity. Such costs may lead to increased electricity prices in neighbouring continental countries and contribute to a narrowing of the gap between UK and continental prices.

The evolution of total network costs in each country depends on a range of factors, such as the profile of the existing network and future demand, however the distribution of costs between different network users in the future remains largely a decision for regulators and policy makers.

What policy options are available to manage electricity prices in the UK, now and into the future?

Drawing upon these insights, to complement (and in some cases, elaborate on) the recommendations of the Helm Review, we have offered six specific recommendations to help address concerns about UK industrial electricity prices.

These reflect a few underlying themes.

One, most evident in respect of networks development and pricing, is taking an integrated approach. Germany, France and Italy have taken a more integrated and activist approach to the energy transition itself (e.g. closer coordination of generation and networks investment) and between electricity and industrial policy, with a greater differentiation in the

way costs are recovered between large and electricity-intensive industries and less intensive users of electricity, such as commercial and domestic consumers. This informs particularly our Recommendations #2, and less directly, #5.

A second theme concerns greater willingness to help manufacturing industry with long-term strategy, including engagement with the electricity sector and cross-border trading. This is most obvious concerning the French Exeltium consortium contract for industrial power, but also underlies the Italian ‘virtual interconnector’ policy of allowing industries to contract electricity at prices available in neighbouring markets if they contribute to extending interconnection links. This informs our Recommendations on interconnections (#3) and international access (#4).

Both these themes reinforce the third, which is that the energy transition – the investment costs of which have been cast by some commentators as a driver of high electricity prices and a problem for UK manufacturing industry – is now becoming a major opportunity, arising both from the tumbling cost of renewables and the development of smart control and flexible user technologies. These underlie our short term (#1) and longer term (#6) proposals: on increasing the utilisation of cheap renewables at low financing costs (#1), whilst enhancing direct industrial access to these resources and realising the benefits available from providing electricity services of growing value and declining cost (#4, #5, #6). These serve to complete our recommendations on how to harness the energy revolution to the benefit of UK industry.

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