POWERWATCH

The European power industry, 2008-13

1 June 2015

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SECTION 1. EXECUTIVE SUMMARY

Europe's power sector has seen profound changes in recent times. These have been driven in part by policy interventions – clean energy subsidies, carbon pricing and emissions regulations. However the region has also been hit by worst recession since the 1930s, and the US shale gas revolution and coal glut continue to influence commodity markets. In this report we analyse how major policy and market developments have impacted the sector's progress towards decarbonisation by looking at the impact on capacity, generation, investment and emissions over 2008-13[1].

Introduction

- Over the last 30 years, Europe's power industry has been largely powered by fossil fuels – accounting for over 70% of generation in 1980. In absolute terms, generation from these sources continued to grow over the decades.
- EU policy targets to reduce emissions were set as early as 1997, but it wasn't until 2008 that policies to directly promote renewable alternatives moved to the fore. The **European Union**'s 2020 Climate and Energy Package – also known as the 20-20-20 targets – spawned a large number of national renewable subsidy schemes, which together with the EU Emissions Trading System and the Large Combustion Plant Directive were designed to accelerate the decarbonisation of the EU power sector – the region's single biggest source of emissions.

EU trends

- National renewables subsidy schemes were very successful in attracting investment, with a total of $577bn invested and 129GW of renewable energy assets built over 2008-13. This investment drove learning and pushed down costs, with the levelised cost of solar roughly halving over 2009-13 and that for onshore wind dropping 15%. Overall solar and wind capacity increased 164%, generation 158% and power sector emissions across the bloc dropped 15% by 2013.
- In 2008 the global financial crisis pushed Europe into recession. The economic contraction caused EU-28 power demand to fall 5% between 2008 and 2013, and emissions to fall 15% and the EU carbon price to crash. The increase in wind and solar generation from 4% to 10% of the EU-wide total put additional downward pressure on carbon.
- At the same time renewable energy investment was booming on the back of government subsidies that drove a rapid expansion of both utility-scale wind and solar facilities and rooftop solar PV. By 2010 and 2011, however, costs were beginning to balloon and governments began scaling back. Some reformed their renewables support programmes to reduce excessive returns and the rate of future investment, while others made retroactive changes to payments for existing projects, dramatically increasing country risk for investors. Clean energy investment peaked in 2011 at $131bn, subsequently dropping 54% to $60bn by 2013.
- The Large Combustion Plant Directive (LCPD) is on track to successfully close 35GW of emissions intensive coal- and oil-fired capacity by December 2015. The impact of these closures varies by country. The UK is particularly affected due to an ageing coal fleet.

- 1 The report does not include an analysis for 2014 as not all the data was available at the time of writing. Included is a brief discussion of 2014 investment and emissions data.

- Gas plants across Europe have been crippled by weak demand, increasing renewables generation and unfavourable commodity prices. As a glut of cheap coal flooded the market and with no material support from the region's carbon price which has languished below €10 since mid-2011, gas generation fell by 43% over the 2008-13 period, despite a 33GW increase in capacity.
- Although coal and lignite generation fell 4% in the same period, their share of fossil generation increased, from 51% in 2008 to 63% in 2013 increasing the emissions intensity of that part of the European fleet. This was primarily due to clean dark spread which strengthened on the back of low carbon prices, high gas prices and low coal prices.
- This set of complex dynamics meant that emissions varied considerably by country over the period, but the overall trend was downward. Total EU power sector emissions fell nearly 200Mt (15%) over 2008-13. However over 100Mt of that decrease happened in 2009 as a result of the recession.
- In 2014[1], EU investment grew for the first time since 2011, while emissions continued to decline – partly due to an abnormally mild winter. German emissions were down for the first time since 2011.

Country focus – UK and Germany

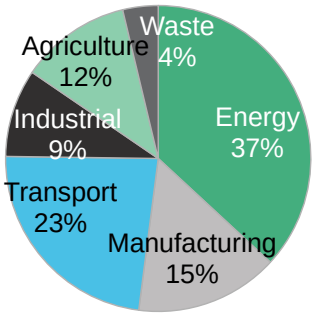
- Nowhere in Europe has the dash for renewables been more prolific than **Germany**. Solar and wind capacity grew 41GW over 2008-13 to 41% of total capacity, but because of its early-adopter status, by 2013 the country had landed its consumers with an annual cost of subsidy of around €20bn.
- The rapid growth of renewables combined with the recession and decline in the cost of coal acted to depress the German power market, with particularly stark implications for gas generators, whose generation dropped 42% over 2008-13. In February 2011 it became unprofitable to run gas for baseload (round-the-clock) power in Germany.
- Together with the accelerated nuclear phaseout, these dynamics called into question the historically stable business model of Germany's large traditional utilities. In 2013 share prices were down around 60% on 2008.
- Germany's decision to accelerate the phase-out of its nuclear fleet following the 2011 Fukushima disaster resulted in a generation gap of around 13% as 6GW of nuclear capacity was taken off-line. Low coal prices meant that by 2012 around half that gap had been filled by coal. As a result, emissions in Germany increased in 2012 and 2013, before dropping again in 2014 due in part to the mild winter.
- In the **UK,** renewables accounted for 14% of generation by 2013, up from just 4% in 2008. Investment was driven by a green certificate scheme, a feed-in-tariff and an additional carbon tax on top of the EU carbon price.
- With dark spreads high on the back of low coal prices and an impending additional carbon tax in the form of the carbon price floor, British coal plants that had opted out under the Large Combustion Plant Directive, rushed through their remaining allocated run hours, pushing emissions up 7.5% in 2012. The carbon price floor started in 2013, improving gas generator competitiveness and bringing emissions back down. Gas generation nevertheless suffered heavily over 2008-13, falling 46%.
- A strong year for offshore wind contributed to a 12% increase in renewables investment in the UK over 2014, far greater than across much of the EU.
- The growing impact of renewables on plant profitability, falling demand and depressed market conditions have provoked questions around the future of the wholesale market in Germany, UK and other major European countries.

SECTION 2. INTRODUCTION

The 2008 agreement of the European Union's 2020 Climate and Energy Package – also known as the 20-20-20 targets – marked the most decisive shift in Europe's energy policy direction in decades. The 20% greenhouse gas emissions reduction target, along with a 20% renewable energy target and a 20% energy efficiency improvement directive provided a framework for national governments to reform their energy strategies. This report looks at the trends in European electricity capacity, generation, emissions and new clean energy investment that occurred following the adoption of the 20-20-20 targets – both the progress achieved as well as some unintended consequences.

Much of the 20-20-20 package's burden fell on the energy industry which made up 37% of EU-28 greenhouse gas emissions in 2008

Figure 1: 2008 EU-28 greenhouse gas emissions by sector



Source: European Environment Agency, Bloomberg New Energy Finance. Note: excludes international aviation.

In 1997 the European Union – then just 15 countries – committed to reducing emissions 8% below 1990 levels by 2008-12 under the Kyoto Protocol. In 2008 the bloc extended its efforts to combat climate change with the 2020 Climate and Energy Package. This set of binding legislation – also known as the 20-20-20 targets – set three key policy objectives to 2020:

- A binding 20% reduction in EU greenhouse gas emissions from 1990 levels
- A binding commitment to raise the share of EU final energy consumption from renewable sources to 20%
- A non-binding 20% improvement in the EU's energy efficiency compared to projected energy consumption

The EU sought to achieve these goals via a raft of measures aimed at incentivising the transition to a low-carbon economy. Much of this burden fell on the energy industry which made up 37% of EU-28 greenhouse gas emissions in 2008 (Figure 1) and where there was most scope for deployment of emissions saving technologies. In addition to reducing emissions, the 20-20-20 targets were also aimed at increasing energy security by reducing reliance on energy imports.

Twenty years of economic growth and rising power demand had seen ongoing growth in conventional and – from a very low base – renewable capacity (Figure 2 and Figure 3). At the start of 2008 demand was expected to continue to rise. For emissions to come down it would require a dramatic ramp-up in the deployment of renewables.

Figure 2: EU-27 net capacity by primary energy, 1980-2009 (GW)

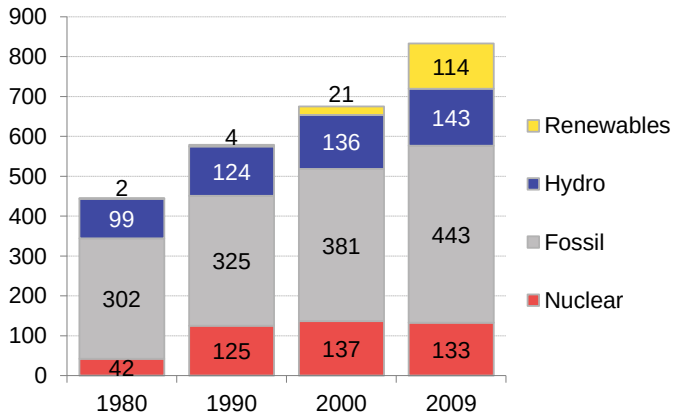
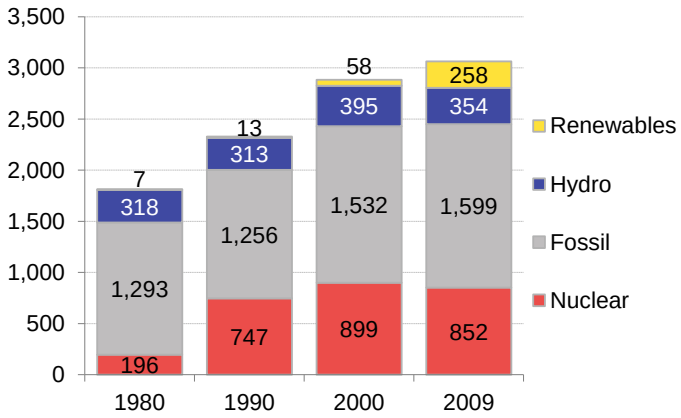
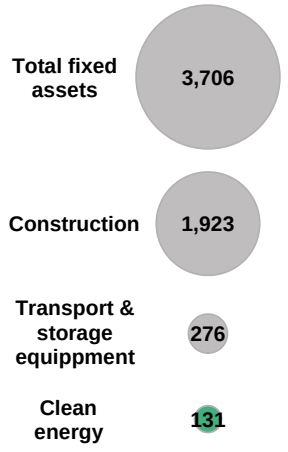


Figure 3: EU-27 generation by primary energy, 1980-2009 (TWh)



Source: Eurelectric. Note: Eurelectric renewables estimates will differ from BNEF figures.

Figure 4: EU-28 fixed asset investment and clean energy investment, 2011 ($bn)



Source: Bloomberg New Energy Finance, Eurostat

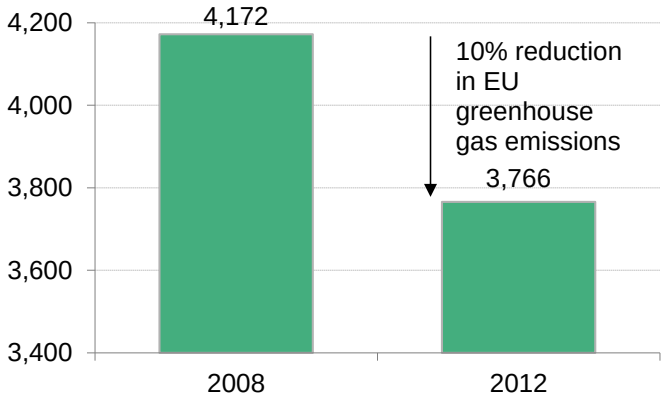
At the national level, support was delivered through feed-in tariffs or green certificate schemes. Where strong incentives were put in place, deployment followed. Early movers such as Spain, Italy and Germany, saw the market respond sharply and their share of renewables increase quickly – much faster than initially expected. At its peak in 2011, European clean energy investment reached $131bn – up more than five-fold on 2004, when Bloomberg New Energy Finance first started tracking investment. Compared with other capital-intensive sectors of the European economy, investment in renewable energy remains relatively small – for example it is just 7% the size of construction sector investment. This means there is still plenty of room for growth, particularly as the finance sector increasingly treats clean energy as an infrastructure asset class, unlocking large sums from more risk averse institutional investors (Figure 4).

In addition, the EU Emissions Trading Scheme (EU ETS) and the Large Combustion Plant Directive (LCPD) were in force, with the aim of directly influencing Europe's power mix away from coal.

Looking back, Europe's policy choices appear to have had some success as far as renewables deployment is concerned. From 2008-13 solar and wind capacity increased 164%, generation 158% and importantly, total greenhouse gas emissions across the bloc dropped 10% (Figure 5). However these policies cannot be viewed in isolation, to do so would be to ignore the significant impact that the 2008 global financial crisis – the worst economic crisis to strike Europe since the Great Depression. As the economy contracted, power demand and emissions plummeted. As emissions fell, the EU carbon price collapsed, and while renewable subsidies saw deployment of wind and solar surge, this further reduced the effectiveness of the carbon market to support gas-fired power generation at the expense of coal (Figure 6).

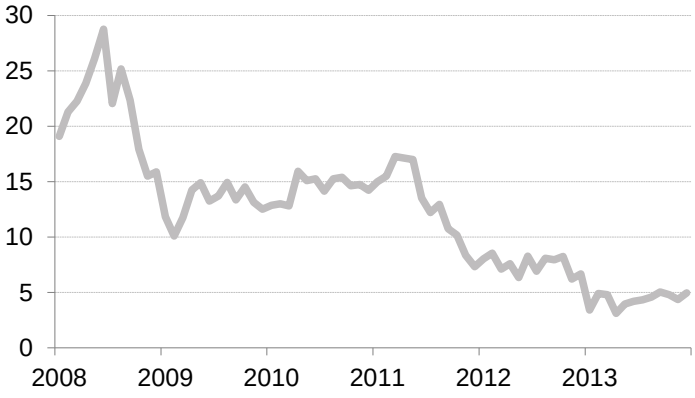
In this report we assess the changes in capacity, generation, investment and emissions in Europe, and the impact of both major policy interventions, and market shocks.

Figure 5: Total EU greenhouse gas emissions (MtCO2e)



Source: EEA, Bloomberg New Energy Finance. Note: Includes emissions from energy, manufacturing, transport, industry, agriculture and waste.

Figure 6: European carbon price, 2008-13 (EUR/t)



Source: Bloomberg New Energy Finance

SECTION 3. EU TRENDS

The EU-wide 20-20-20 targets provided the framework for a shift in the energy system over 2008-13. Clean energy support programmes initiated by European Member States resulted in a 136% increase in renewable capacity over 2008-13 to 223GW, accounting for around 14% of total generation.[2, 3] At the same time the outlook for conventional generation worsened as the financial crisis cut power demand

RENEWABLE SUBSIDIES AND INVESTMENT

In 2009 EU member states agreed to a new framework on supporting the growth of renewable energy production, as part of the 2020 Climate and Energy Package. The 'Renewable Energy Directive' set a target of 20% of renewable energy share in final EU energy consumption in 2020, with 34% of electricity from renewable sources. Legally binding at an EU level, member states are responsible for national implementation, leading to a patchwork of incentive schemes aimed at achieving these goals.

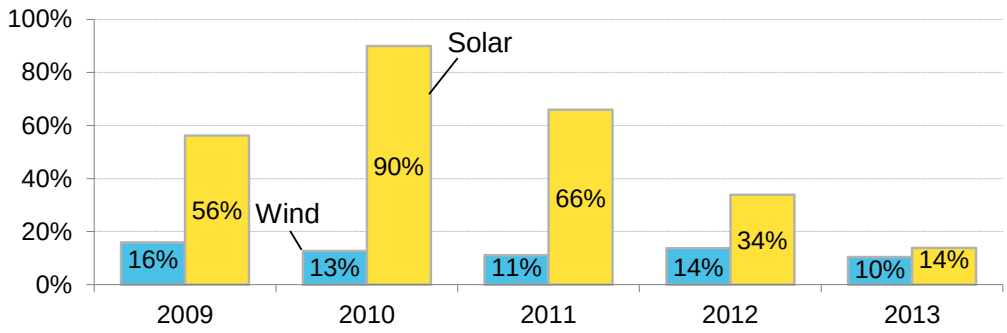
Feed-in-tariffs became the most popular means of support, with Germany and Spain pioneering the measures as far back as 2001. Some countries followed their example (Italy, France, Greece, Czech Republic), others established feed-in-premiums (Netherlands, Denmark) or green certificates schemes (Belgium, UK, Sweden, Poland, Romania).

The subsidies made renewables an attractive option to utilities and investors with high and apparently secure returns. As a result renewables capacity increased at a 19% compound annual growth rate over 2008-13, despite worsening economic conditions as the financial crisis took hold. Overall renewables capacity increased by 129GW across the EU over 2008-13.

Solar was the biggest winner in terms of capacity build with often generous subsidies, ease of installation and appeal of small-scale (rooftop) PV installation attracting utilities and retail investors alike (Figure 7 and Box 1).

Renewables capacity increased at a steady 19% compound annual growth rate over 2008-13, adding 129GW of capacity

Figure 7: Solar and wind net capacity growth year on year (annual % change)



Source: Bloomberg New Energy Finance

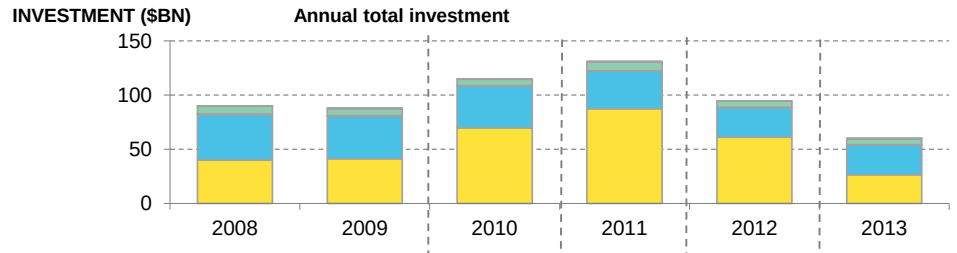
2 EU wide figures include: Capacity (EU-28), Generation (EU-27), Investment (EU-28), Emissions (countries included in the EU ETS, i.e. EU-28 plus EEA/EFTA states

3 Values include estimates for undisclosed deals. Includes utility scale asset finance (1MW+) for all technologies as well as roof top solar (<1MW) investment estimates. Includes investment in the following capacity types: biomass & waste, biofuels, geothermal, marine, solar and wind. Excludes investment in large hydro but includes small hydro investment (<50MW).

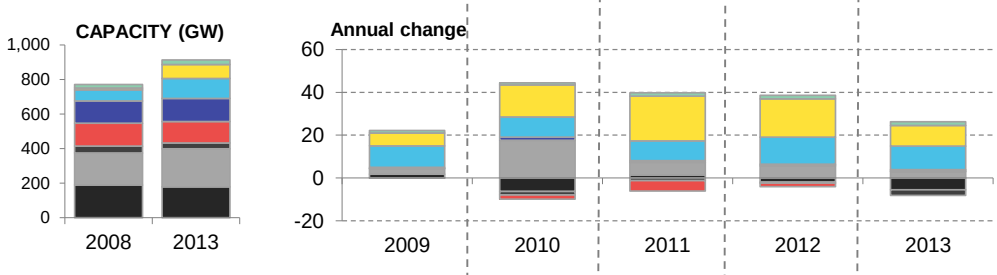
Box 1: EU

Pre-2008	2008	2009	2010	2011	2012	2013
Large Combustion Plant Directive (2001), opt out by 2007, run hours end 2015						
	20-20-20 package sets setting three targets for emissions, renewables and energy efficiency (2008)					
	Phase II of the EU ETS begins (2008)					Phase III begins
		Renewable Energy Directive enters into force (2009)				
					Energy Efficiency Directive enters into force (2012)	

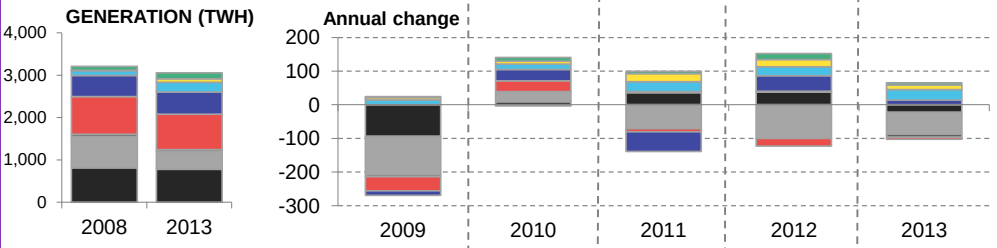
LEGEND: Other, Solar, Wind, Hydro, Nuclear, Oil, Gas, Coal



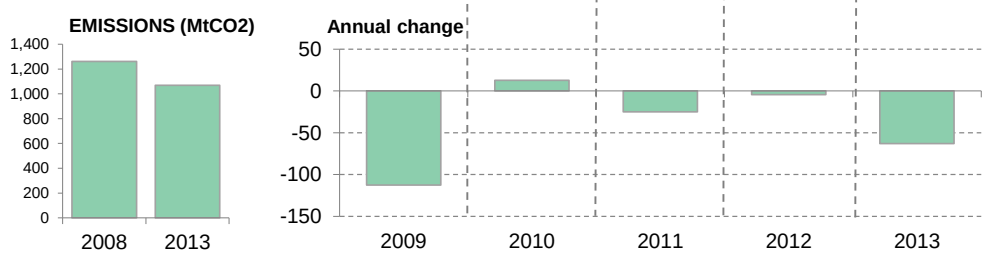
- Renewables investment averaged $96bn/year over 2008-13
- Solar investment dominates the market
- 2012-13 saw a drop in investment in light of subsidy reform, retroactive cuts and a worsening economic climate



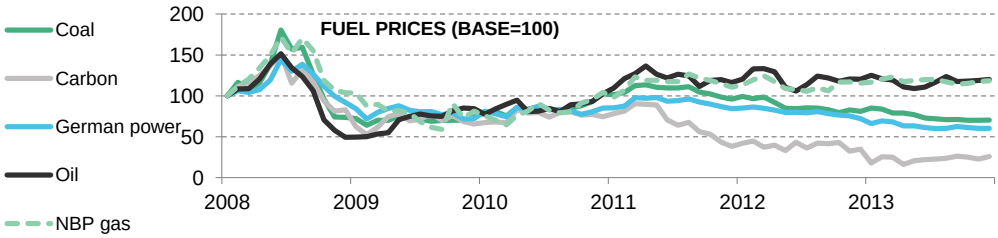
- Net capacity additions totalled 143GW over 2008-13, with renewables (excl. hydro) accounting for 90% of growth
- Over 2010-11 nuclear capacity dropped off 5GW after the Fukushima disaster
- Fossil investment dropped off as plants decided on before the recession commissioned. Closures, some LCPD-led, led to a net fall of 10.6GW of coal and lignite capacity over 2008-13



- 2009 saw an 8% drop in total generation as the financial crisis eroded power demand
- Wind and solar generation grew 158% over the period, picking up as new capacity came online
- Gas plants suffered a 43% decline in generation as low carbon and coal prices leave it uncompetitive with coal and exposed to weak demand and increasing renewables



- 2009's fall in generation was mirrored in power sector carbon emissions which continued to decline to just 1.1Gt by 2013
- As gas was pushed out of the money, emissions intensity of fossil generation grew as coal was favoured over gas
- Increasing renewables penetration further reduced emissions

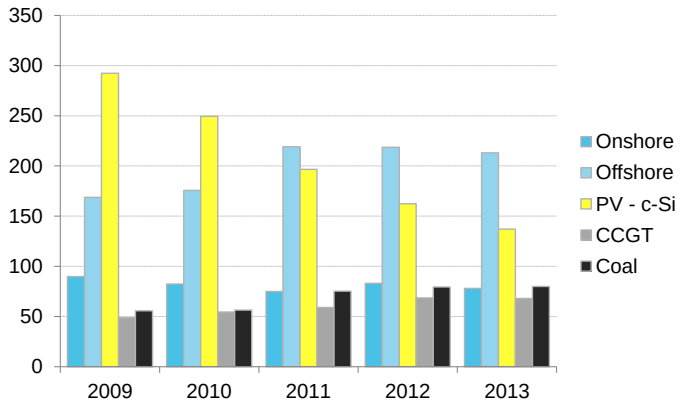


- The financial crisis saw commodity prices crash on weaker demand.
- From 2011, coal and gas prices diverged: coal downwards, gas upwards.
- European carbon dropped a huge 78% over the period.
- The combination of decreasing carbon and coal and increasing gas prices made coal generation more competitive than gas.

Annual growth of solar capacity began to outstrip wind as early as 2009, reaching 90% in 2010. The increasing deployment of solar technology translated into lower technology costs creating a virtuous circle for solar investment (Figure 8). Subsidy-driven uptake consistently beat expectations.

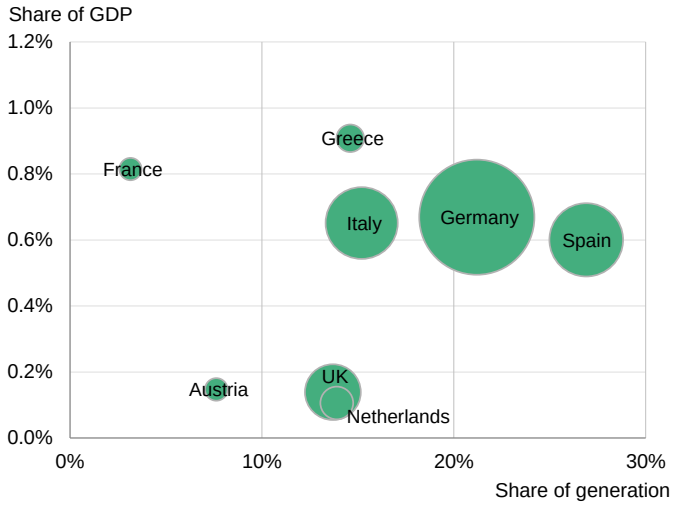
By 2012, however, dramatic cost declines – particularly for solar PV – had resulted in rapid uptake and widespread oversubscription of incentive schemes. Countries with attractive schemes early on such as Spain and Germany saw large investment flows helping to push expensive renewable technologies down the learning curve (Figure 9). Over 2008-12 Germany and Spain saw $141bn and $74bn respectively invested in solar and wind projects, compared with just $46bn in the United Kingdom.

Figure 8: BNEF levelised cost of energy by technology, 2008-13 ($/MWh)



Source: Bloomberg New Energy Finance, Note: LCOEs refer to global average LCOEs calculated in H2 2014.

Figure 9: Cost of renewables subsidies as share of GDP and share of non-hydro renewable power generation, 2013



Source: Bloomberg New Energy Finance, note: bubble size relates to the installed non-hydro renewable capacity (GW).

However economic growth was still weak and contributed to a decline in investment as governments cut budgets to balance their books. Annual investment across the EU dropped 54% from 2011-13.

Across Europe clean energy investment dropped from the 2011 peak of $131bn to just $60bn in 2013

Some governments created new tariff structures, such as FiT tariffs that regularly decreased. These were better at ensuring support levels were in line with and moved in step with the declining cost of deployment, thereby helping prevent the bubble-and-burst scenarios that were playing out all over Europe.

Others, heavily burdened with the soaring cost of renewables support, such as Spain, Greece and the Czech Republic, resorted to retroactively cutting subsidies previously guaranteed to renewable generators. In 2010 Spain – which two years earlier was the largest renewables market in Europe and the biggest solar PV market globally – retroactively cut the number of hours under which existing PV projects were eligible for support, resulting in reductions to project revenue of around 7-30% depending on locations and type of plant according to BNEF analysis. As a result, clean energy investment in Spain crashed to by over two thirds in a year compared with 2011

Figure 10: EU-28 renewables investment, 2008-14 ($bn/year)

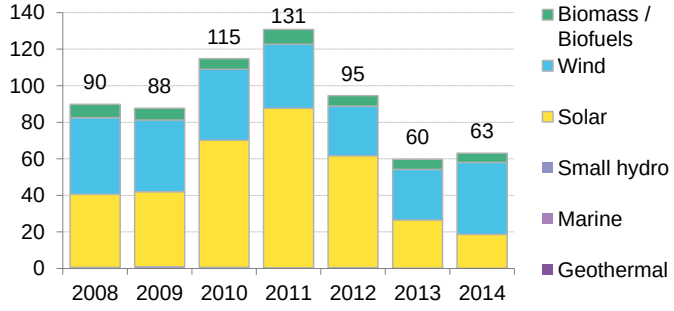
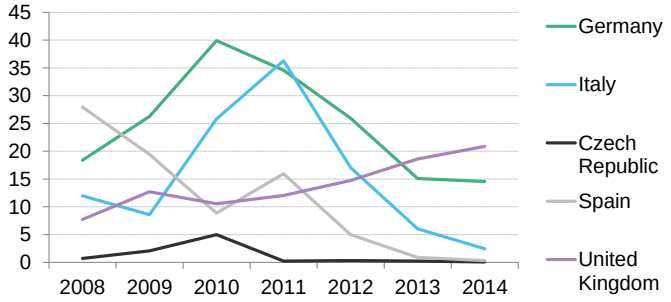


Figure 11: Trends in renewables investment across various countries, 2008-14 ($bn/year)



Source: Bloomberg New Energy Finance.

The Czech Republic's retroactive solar tax, effective from 2011, saw its market for clean energy investment collapse across Europe, and as the financial crisis continued, the fear of more countries cutting support levels retroactively suppressed appetite for clean energy investment. By 2013 investment was just $60bn, down more than 54% from its 2011 peak of $131bn (Figure 10 and Box 1).

2014 saw a mild recovery in renewables investment rising 6% to $63bn as offshore wind saw a burst of activity including the $3.8bn Gemini Offshore Wind Farm- the largest deal of 2014 and largest ever renewable energy asset finance deal ever recorded.[4] In Q4 2014 the top four asset finance deals world-wide were European offshore wind farms (Table 1). On a country-level, Germany ($14.6bn), the UK ($21bn) and France ($6bn) featured relatively stable annual investment levels compared to the previous year. Italy was hit by retroactive subsidy cuts to solar projects, and this contributed to a 60% fall in overall clean energy investment there, to $2bn (Figure 11).

Table 1: Top four asset finance transactions of the quarter Q4 2014.

Project name	Country	Sector	Type of transactions	Capacity (MW)	Value ($m)
Dudgeon Offshore Wind Farm	UK	Wind	Balance Sheet	402	2573
Wikinger Offshore Wind Farm	Germany	Wind	Balance Sheet	350	1712
Sandbank Offshore Wind Farm	Germany	Wind	Balance Sheet	288	1428
Burbo Bank Offshore Wind Farm Extension	UK	Wind	Balance Sheet	258	Undisclosed

Source: Bloomberg New Energy Finance

DEMAND AND THE RECESSION

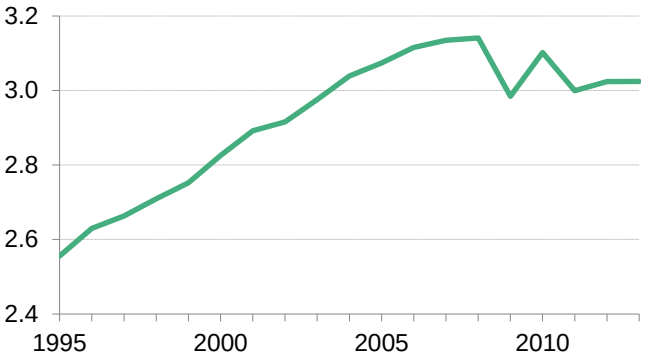
EU-28 power generation fell 5% over 2008-13

The 2008-9 financial crisis hit the majority of European economies. Industrial output fell, dragging power demand down with it. Over 2008-13, EU-28 power generation fell 5% (Figure 12) and with

4 The $3.8bn Gemini Offshore Wind Project was the largest clean energy asset finance transaction recorded by Bloomberg New Energy Finance, since its records began back in 2004.

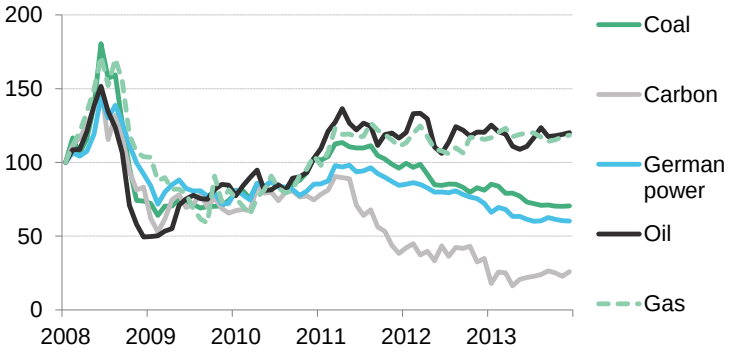
renewables receiving preference for grid access, fossil generators bore the brunt of the demand slide.

Figure 12: Total power demand for EU-28 + Iceland and Norway, 1995-2013 (TWh/yr)



Source: Source: ENTSO-E Bloomberg New Energy Finance

Figure 13: Fuel and carbon prices, normalised, 2008-13 (2008=100)



Source: Bloomberg New Energy Finance. Normalised at 100 as of 1 January 2008.

Early in the period, Europe saw net growth in fossil capacity with almost 10GW added over 2009-10, most of which had reached financial close or was already under construction before 2008. The addition of this capacity in what was already a poor operating environment exacerbated the situation and by 2012-13, net capacity additions had given way to net retirements, with more than 5GW of coal and lignite capacity closed by generators (Box 1).

LARGE COMBUSTION PLANT DIRECTIVE

The Large Combustion Plant Directive, implemented in 2001, required plants to comply with pre-determined limits on NOx and SOx pollution by 2007, or opt-out and receive an allocation of up to 20,000 run-hours to be used no later than December 2015. In total 35GW has opted-out under the scheme,[5] representing around 8% of 2008 EU fossil capacity. Much of this was old and uneconomic, some of it oil-fired peaking generators and most of it coal. The impact of these closures varies by country, with those countries carrying ageing coal fleets such as the UK most affected.

COMMODITY PRICES

Coal and gas-fired power was also strongly influenced over the period by changes in commodity prices. Gas generators were crippled by a perfect storm of falling demand, increasing renewables generation and unfavourable commodity prices. In 2011 coal and gas prices started to diverge (Figure 13). Cheap coal – driven by oversupply caused, in part, by the shale gas revolution in North America and reduced demand compared to expectations (and investment) in Asia – made gas-fired power generally more expensive.

Generation spreads explained
For a fossil fuel power plant, the decision of whether to generate electricity in a given hour depends on whether its short-run marginal cost is less than the wholesale power price in that hour i.e. an operating profit can be made. The wholesale power price in a particular hour is set by the marginal plant – the most expensive plant required to meet demand – while the short run

5 Sandbag, Coal Emissions in Europe, July 2014

marginal cost includes all costs that the plant incurs because of the decision to generate, such as the price of the fuel consumed and carbon emitted, as well as any marginal operating and maintenance costs.

This difference between short run marginal cost and wholesale price is also known as a spread. A positive spread indicates an operating profit per MWh produced. Whilst factors such as a plant's thermal efficiency can affect its profitability relative to others of the same fuel type, the profitability of an 'average' plant is often used to describe the generation economics for a fuel type – usually, coal or gas. The terms 'clean dark' and 'clean spark' spread typically refer to the difference between these marginal costs and the baseload (daily average) wholesale power price, for an average coal and gas plant respectively, where 'clean' refers to the inclusion of a carbon price.

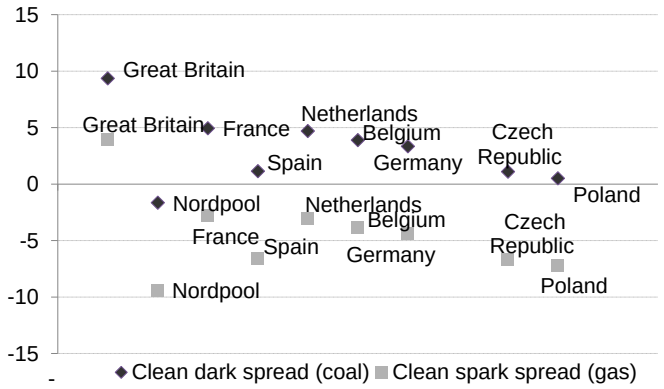
A higher clean dark spread indicates that coal is more profitable than gas, suggesting that coal generation levels (and associated emissions) would be higher. The all-in cost of coal generation has been lower than that of gas across Europe for most of the 2008-13 period, meaning wider dark spreads than spark spreads and therefore a higher carbon intensity of generation.

EU-wide gas-fired power generation dropped 43% over 2008-13

In February 2011 gas generation became unprofitable to run for baseload across most of Europe (Figure 14) and continued to decline through 2013 (Figure 15). Also in 2011 carbon prices more than halved in value to around €6.5/t, further worsening prospects for gas generation (Figure 13) which dropped 11% that year. All this resulted in a 43% drop in generation from gas plants in Europe over 2008-13, despite a 34GW increase in capacity (see Box 1).

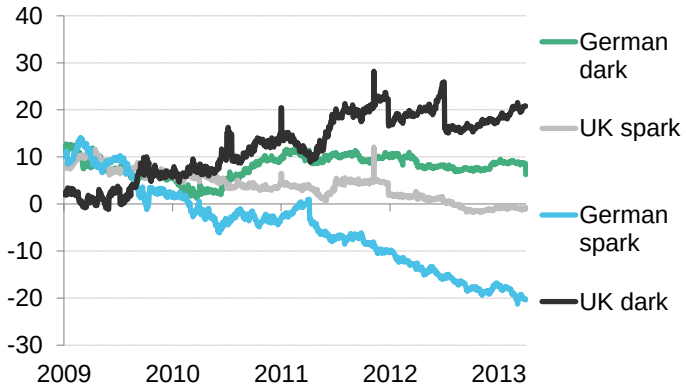
In contrast, coal and lignite generation fell 4% over the same period – in line with a 6% fall in capacity (see Box 1). As gas was pushed to the margin, coal's share of fossil generation increased, from 51% in 2008 to 63% in 2013 – despite the fact both the Large Combustion Plant Directive and EU ETS were in force. Overall the combination of low carbon prices, high gas prices and low coal prices meant that the emissions intensity of fossil generation increased between 2008 and 2013.

Figure 14: European clean spark and dark spreads, February 2011 (€/MWh)



Source: Bloomberg New Energy Finance. Note: spreads calculated as of 25 February 2011

Figure 15: UK and German clean dark and spark spreads, 2009-2013 (€/MWh)



Source: Bloomberg gNew Energy Finance

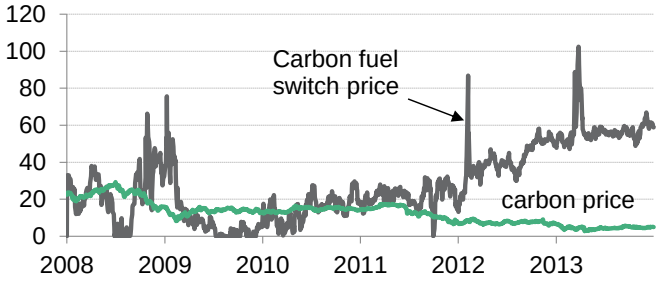
CARBON PRICE SIGNAL

Carbon prices averaged just €14/t over the period 2008-13. Fuel-switching only occurred once, late in 2009

When the second Phase of the EU ETS started in 2008, many assumed that the carbon price would drive fuel switching from coal to gas and help support new gas-fired power stations. The financial crisis and resulting fall in production and emissions left the EU ETS chronically oversupplied with prices falling to an average €14/t over the period 2008-13 and around €8.5/t from 2011-13.

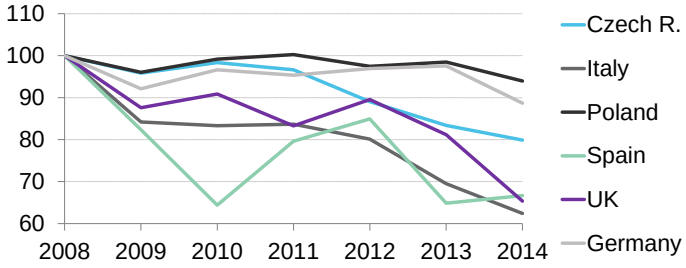
Carbon price-driven fuel-switching was only properly realised in late 2009. This can be seen in Figure 16 where the CO2 fuel switch price dips below the carbon price. In 2013 high gas prices and low coal prices meant the market needed a carbon price of around €45/t to prompt fuel-switching – well above the €5/t traded.

Figure 16: EU ETS carbon price and CO2 fuel switch price, 2008-13 (€/t)



Source: Bloomberg New Energy Finance, Note: fuel-switch price calculated from spot fuel and power prices assuming coal plant thermal efficiency of 36% and carbon intensity of 0.95Tco2/MWh, gas plant thermal efficiency of 49% and carbon intensity of 0.42Tco2/MWh

Figure 17: Country level power emissions, normalised, 2008-14 (2008=100)



Source: Bloomberg New Energy Finance

The drop in carbon prices was driven primarily by the fall in power demand and subsequently emissions, which dropped 15% over 2008-13 (Box 1). However the increase in wind and solar generation from 3.8% to 10% of the EU-wide total between 2008 and 2013, reduced emissions further putting additional downward pressure on prices.

Power sector emissions dropped 15% over 2008-13 on weak demand and increasing renewables

The magnitude of change in emissions varied considerably by country, despite the overall downwards trend (Figure 17). Spain for example saw a huge dip in emissions in 2010 (22%) as the financial crisis crippled the country's economy. Germany however saw less of a fall despite high renewables penetration as it ran more of its coal-fired power on the back of the low coal prices

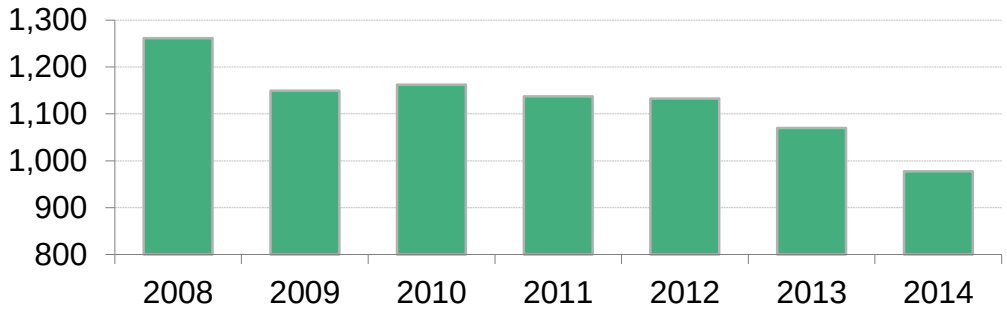
With poor near-term economics for gas fired power and long-term carbon price risk for coal-fired power, there was ultimately very little new investment in firm capacity in Europe after the financial crisis. By 2013 there was talk of a 'capacity crunch' in countries such as the UK, France and Belgium, leading some to implement new capacity payments.

2014 showed the importance of climate variations in dictating trends in power demand and related emissions. Power sector emissions fell 8.6% in 2014 to total around 977Mt. The move was largely precipitated by abnormally warm weather as heating requirements – measures in population-weighed heating degree days (HDD) per year – fell 16%, seeing a 2.5% contraction in total power generation. Coal and gas generation suffered most, declining 17% and 11% respectively, whilst renewables (excluding large hydro) provided an additional 50TWh of electricity – a 10% increase compared with the preceding year. Emissions from coal and gas subsequently fell 16% and 11%, while those from lignite generation increased a modest 4%.

The largest absolute reduction in power sector emissions in 2014 are likely to have come from Germany (down 26Mt/yr or 8.1%) and the UK (down 21Mt/yr or 14.2%), as both countries saw a rise in renewables generation (+8TWh and +10TWh year-on-year) and the largest reductions in total generation (both down more than 25Mt year on year)[6, 7].

The impact of reduced demand via the economic crisis as well as increasing renewables penetration in the energy mix was clearly seen in emissions trends as total EU ETS emissions had already breached the 2020 target by 2014.

Figure 18: EU ETS power sector emissions, 2008-14 (Mt/yr)



Source: Bloomberg New Energy Finance. Note: power sector breakdown according to BNEF classification of installations

6 Emissions estimates based on BNEF calculations on data release by European Commission as of 1 April 2015. Official data had yet to be released.

7 Generation data sources for 2014 include DECC, ENTSO-E, Red Electirca de Espaňa, German Federal Statistical Office, EEX, ISE Fraunhofer. Absolute totals are not comparable with historical BNEF data (2008-13).

SECTION 4. FOCUS ON GERMANY

Nowhere in Europe has the dash for renewables been more prolific than Germany. Solar and wind grew 41GW over 2008-13 to 41% of total installed capacity. Despite the highest penetration of renewables in Europe, an accelerated nuclear phase-out after Fukushima and threats of gas plant closure, Germany remains committed to its 'Energiewende'.

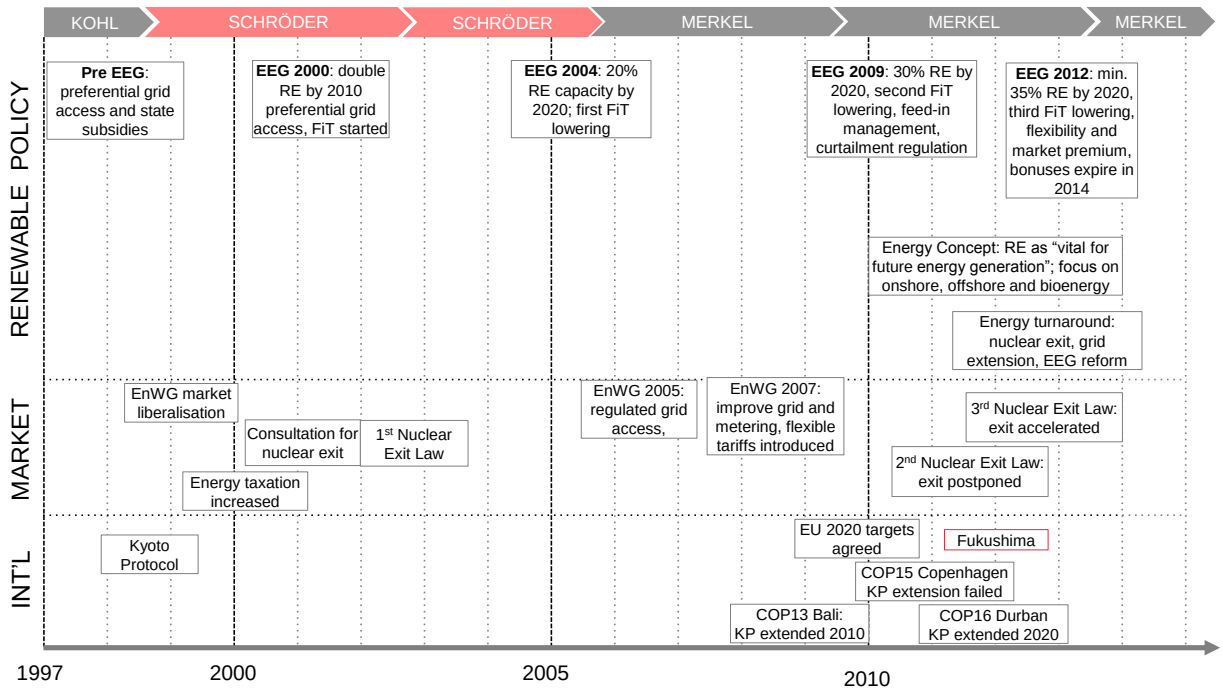
RENEWABLE SUBSIDIES AND INVESTMENT

Germany was an early pioneer in renewables support schemes, setting an objective in 2000 to deploy 52GW of PV capacity by 2020

The country was an early pioneer of feed in tariffs, with the first FiTs for green power dating back as far as the 1991 'Feed-in Act'. This was superseded by the Renewable Energy Act (EEG) in 2000, with a stated aim to deploy 52GW of solar PV capacity by 2020. As an early mover Germany saw renewable capacity – mainly in the form of wind and solar – already account for 29GW in 2008. Over 2009-10 the sector continued to grow with solar receiving $47bn investment and capacity rising 180%.

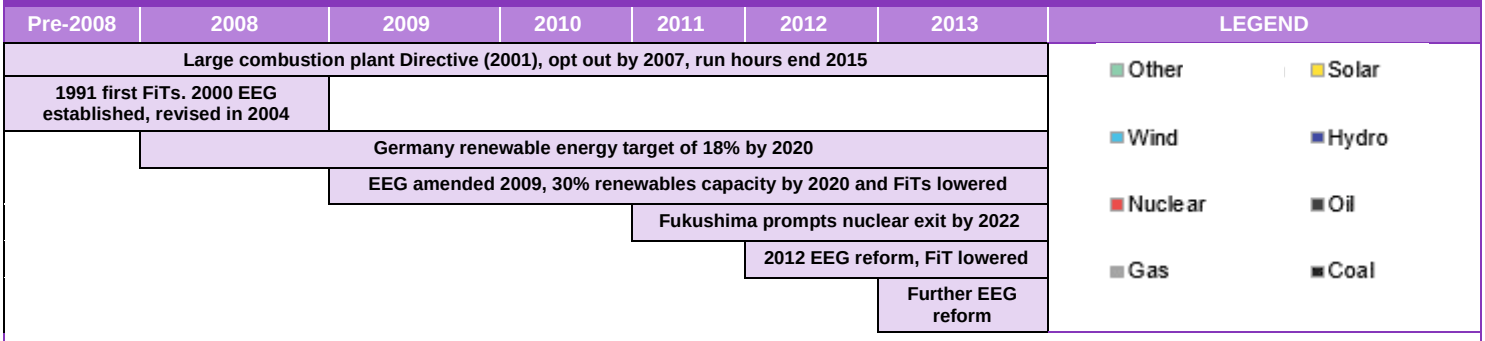
In September 2010 the German government adopted the 'Energy Concept', a long-term strategy for transitioning to renewables and reducing emissions. The concept of the Energiewende (energy transition away from nuclear power towards renewables and energy efficiency) had existed in Germany since 1980 and although plans to phase out nuclear by the 2030s had already been in place, the March 2011 Fukushima nuclear disaster led Chancellor Merkel to dramatically expedite the process (Figure 19). Around 40% of nuclear capacity was closed within a week and a full phase-out scheduled by 2022. It was hoped the Energiewende would also help Germany achieve its lofty climate ambitions set out in 2007 of reducing emissions 40% by 2020 over 1990 levels. The phase-out of nuclear and possibility of increased potential for fossil fuel generation, placed increased onus on policies helping to increase the deployment of low-carbon generation capacity.

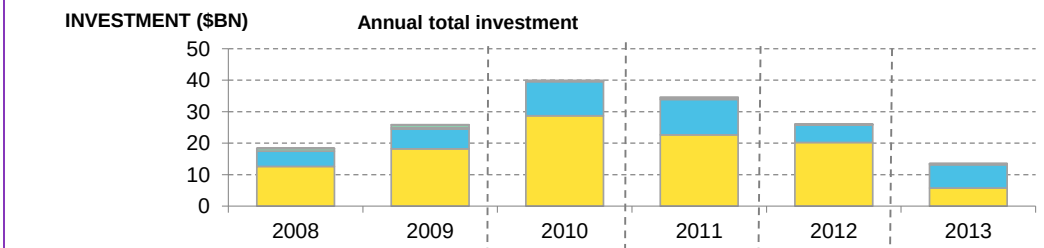
Figure 19: German Renewable Energy Policy, 1997-2013

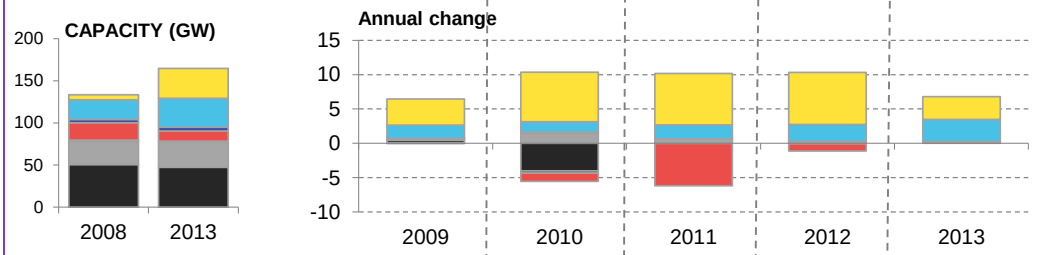


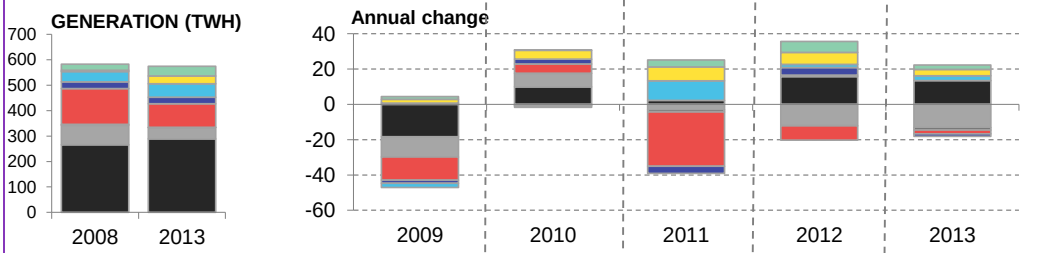
Source: Bloomberg New Energy Finance

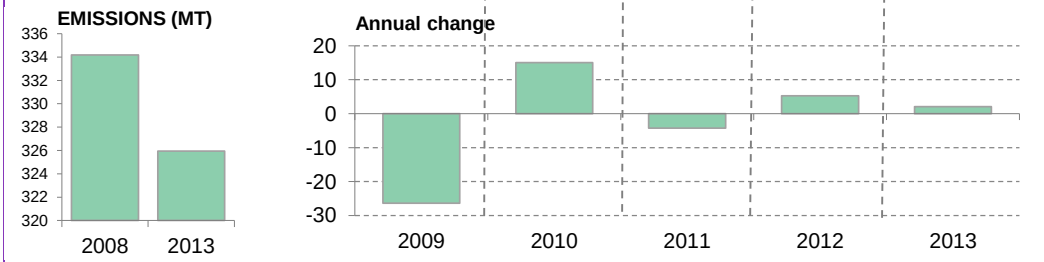
Box 2: Germany

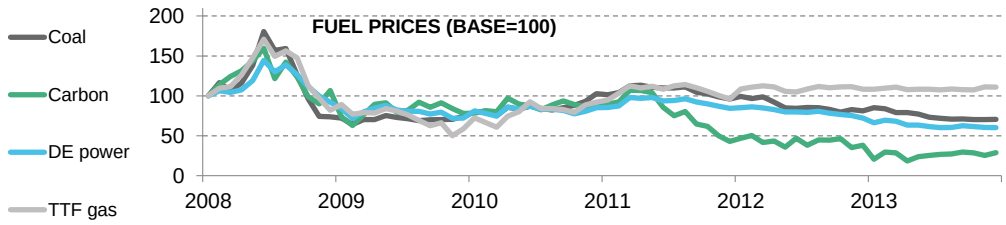






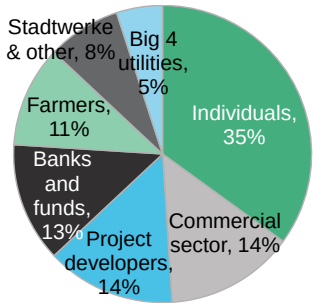






- Germany investment in renewables totalled $158bn over 2008-13.
- Solar investment and installed capacity ramped up quickly 2008-10 as developers and homeowners took advantage of generous FiTs.
- The thirst for PV projects dropped off in the light of tightening margins due to FiT reforms and from 2012 the monthly PV FiT degressions.
- Favourable subsidies for renewables increased their share of German capacity from 25% to 44% over 2008-13 (excl. hydro).
- After the 2011 Fukishima disaster, Germany accelerated its phase-out of nuclear power, closing almost 41% of installed capacity (8.4GW).
- Some years still saw net coal or gas capacity additions as projects decided before the recession came online.
- Total power demand fell just 1.3% over 2008-13, recovering after an initial 7% drop in 2009. The equivalent 2008-13 EU figure stood at 8%.
- Poor spark spreads saw gas generation drop 42% 2008-13.
- Despite increasing renewables penetration, nuclear plants closures and poor gas generation economics meant Germany increased its reliance on coal.
- Emissions fell 2% over 2008-13, with the impact of carbon-neutral renewables and reduced demand stemmed by increasing coal burn in 2012 and 2013.
- With gas frequently out of the money from 2011 onwards, the declining cost of coal generation (decreasing coal, subdued carbon prices) and increasing penetration of zero marginal cost renewables helped depress baseload power prices.

Figure 20: German non-hydro renewable capacity ownership breakdown, 2013



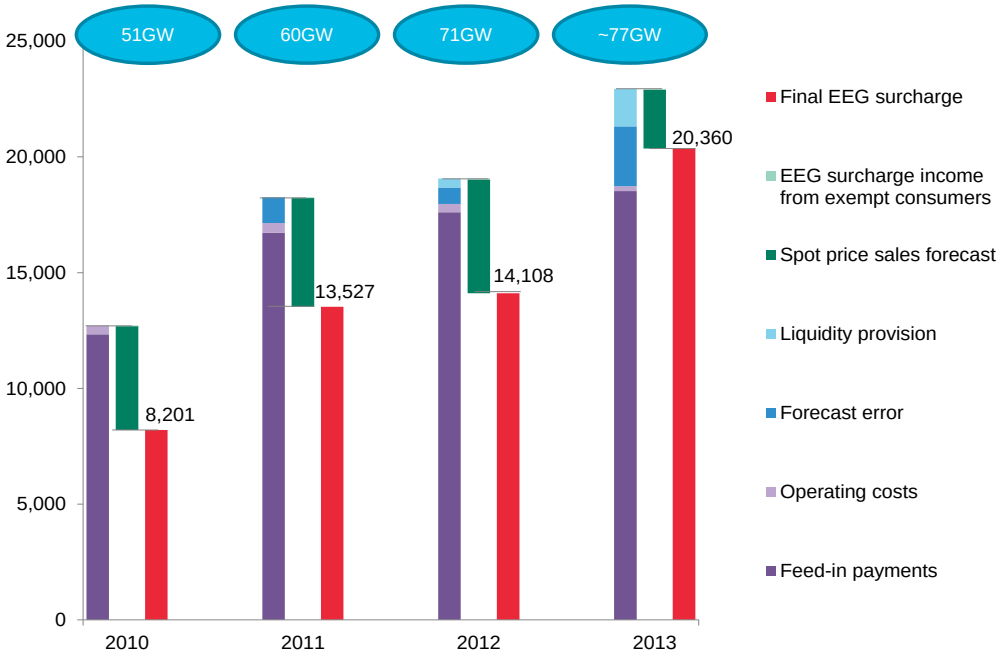
Source: Bloomberg New Energy Finance, trend research

Like in many European countries, renewables subsidies in Germany were more successful at driving uptake than anticipated, with over 7GW of solar PV added each year over 2010-12. Many of the investors came from outside the traditional power sector – by 2013, Germany's Big 4 utilities (E.ON, RWE, Vattenfall and EnBW) only owned 5% of Germany's non-hydro renewables (Figure 20).

As Germany funded its renewables programmes through consumer bills, booming investment – particularly in solar – meant the green power surcharge rose from €2.047ct/kWh in 2010 to €5.277ct/kWh in 2013. Declining wholesale power prices also contributed to the increasing surcharge. This is because the shortfall between power sales and the feed-in tariff renewable generators receive is passed through to consumers under the surcharge.

By 2013, the annual cost of German renewable subsidies had reached around €20bn (Figure 21). With feed-in-tariffs guaranteed for 20 years and continuing investment, German consumers are yet to see the cost of subsidy reach its peak.

Figure 21: Total EEG surcharge collections by component and installed renewable energy capacity in Germany, 2010-13 (EURm)



Source: EEG, KWK-G, Bloomberg New Energy Finance

Note: As the amount of electricity generated from renewables increases, and feed-in tariffs granted to generators deteriorate, the net cost per additional unit (kWh) in 2013 is actually lower than in 2010

After subsidy reforms, annual funds committed for solar projects fell from $28.4bn in 2010 to just $5.3bn in 2013

Aware of this problem, Germany introduced a monthly reduction in its solar PV feed-in tariffs in November 2012. By more closely tracking the rapidly declining cost of solar PV technology, the mechanism resulted in reduced investment in solar projects which fell from $28.7bn in 2010 to just $5.7bn in 2013 (see Box 2). By 2013 the capacity additions for solar had fallen to 3.3GW, the lowest since 2008. After years of trying to better control the rate of solar uptake, 2014 was the first year that solar additions came in below the government's target.

THE RECESSION, COMMODITY PRICES AND THE IMPACT ON UTILITIES

The drop in German generation between 2008 and 2013 was only 2%

The recession led to a 7% drop in power demand in 2009 with generation from coal falling 7% and gas 15% (see Box 2). Power demand ultimately recovered more in Germany than the European average, such that the overall drop in generation between 2008 and 2013 was only 2%.

In addition, increasing renewables uptake pushed the market share of wind and solar from 8% to 15% of generation over 2008-13. This pushed down power prices through the so called 'merit order effect' where wind and solar with zero variable operating costs bid in ahead of coal, gas and nuclear plants, pushing more expensive capacity out of merit. Power prices reached negative territory on a number of occasions in Germany over last 5 years as the system struggled to absorb the significant amounts of generation coming from solar and wind. As well as negative power prices, the increasing prominence of distributed solar PV during daytime hours has shaved peak demand, reducing daytime peak prices and reducing revenues for higher-cost flexible plant.

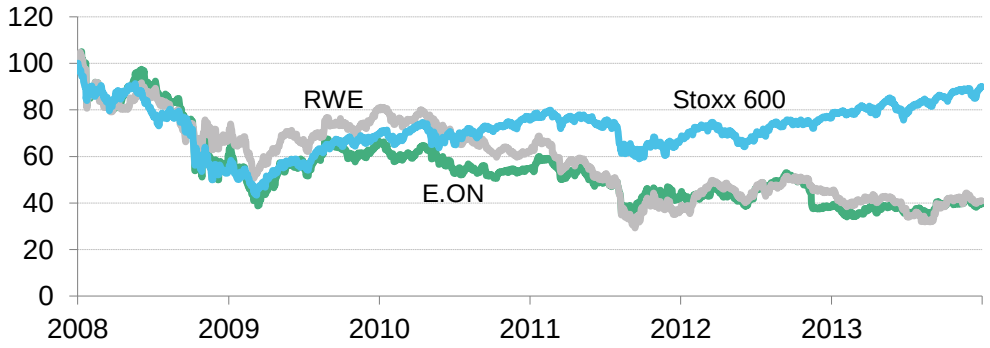
Spark spreads turned negative from 2011 and gas generation decreased 42% over 2008-13

Weak demand, increasing renewables generation and thermal capacity additions resulting from investments made before the financial crisis has left the German power market structurally oversupplied. With so much supply available and cheap coal, gas-fired power was pushed out of the money, with spark spreads turning negative in 2011 (Figure 14). Overall, gas generation decreased 42% between 2008 and 2013.

Although coal generation increased 7% and coal-fired power remained profitable German clean dark spreads still dropped 27% over the period as carbon prices more than halved and coal prices fell nearly 20% as the shale gas revolution in the US created a glut of supply in global coal markets.

These dynamics, combined with accelerated nuclear closures, have put the stable business model for Germany's traditional large utilities under considerable pressure. Once considered the equivalent of low-risk government bonds, these companies started to see their share prices drop relative to the market from 2010 (Figure 22). In 2013 share prices were down around 60% on 2008, while the German benchmark index recovered to around 90% of its 2008 value.

Figure 22: German utility share prices, normalised, 2008-13 (base=100)



Source: Bloomberg New Energy Finance

The depressed market conditions and growing impact of renewables on plant profitability have raised questions around the future of the wholesale market. Not only has the long-term viability of fossil-fuel generators been called into question, but so too the system's ability to provide the price signal needed for new investment in both firm and flexible capacity once the structural oversupply is absorbed.[8] These discussions are ongoing and leading to wholesale market reform, with a

8 Generators have already begun seeking subsidies for unprofitable gas plants in exchange for keeping flexible capacity online. For example, grid operator Tennet TSO GmBH agreed with E.ON

recent policy paper from the government calling for security of supply to be ensured by reforming the 'energy-only' system implementing a strategic reserve, rather than via a UK-style capacity market.[9]

NUCLEAR PHASEOUT AND EMISSIONS

The government was able to shut down some 8GW of nuclear capacity within a week because the market was oversupplied

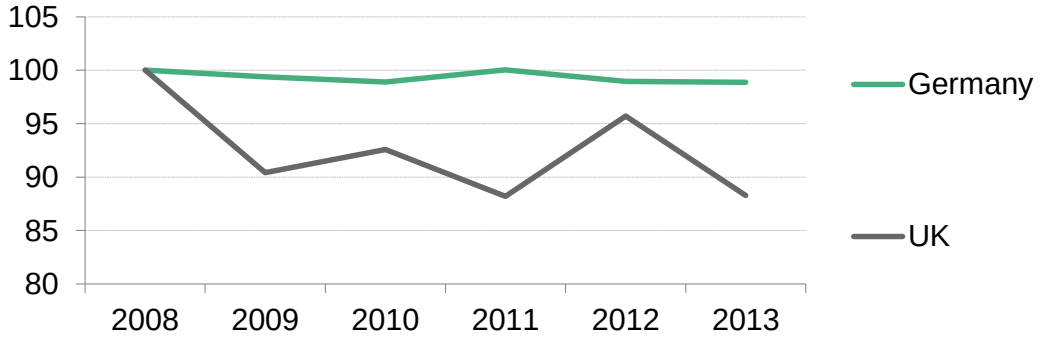
The decision to accelerate the phase out of Germany's nuclear capacity after the Fukushima disaster in Japan provided some respite for the country's gas fleet but ensured emissions stayed high.

Chancellor Merkel's government was able to shut down more than 6GW of nuclear capacity in 2011– which accounted for around 13% of the country's power supply – within a week because the market was so oversupplied. As a result, nuclear output dropped 32% in 2011, relieving some of the pressure on fossil generation – particularly gas – which by this stage had started to see commodity prices turn against it. That meant gas plants were able to continue to generate at 2010 levels of around 70TWh, however by 2012 around half the gap left by nuclear had been filled by coal rising to 48% of total generation, displacing gas. From 2011-13 gas generation's share of total electricity fell from 13% to 8% (Box 2).

Germany's power sector emissions started to rise from 2011 with carbon intensity of power generation staying stubbornly high

The combination of the nuclear shutdowns and favourable generating conditions for coal meant that emissions from Germany's power sector started to rise from 2011 (see Figure 17 and Box 2) with the carbon intensity of power generation staying stubbornly high throughout 2008-13 despite 15TWh (22%) growth in solar and wind generation between 2011 and 2013. This stood in contrast to the UK, where emissions intensity dropped around 10% over the period, albeit with some volatility as coal generation saw upticks in 2010 and 2012 (see Box 3).

Figure 23: Emissions intensity of power generation, normalised, 2008-13 (2008 = 100)



Source: Bloomberg New Energy Finance

to pay a share of fixed costs at their Irsching 4 and 5 plants in exchange for E.ON making the facilities available for regional grid stability.

9 BMWi, *'Eckpunkte-Papier "Strommarkt", 27 March 2015, http://www.bmwi.de/BMWi/Redaktion/PDF/E/eckpunkte-papier-strommarkt,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf*

SECTION 5. FOCUS ON UK

The UK saw renewables account for 14% of generation by 2013, up from just 4% in 2008. A well-developed environment for renewables growth via a green certificate scheme, a feed-in-tariff and additional carbon tax drove investment. More recently, the country has decided to rethink its energy approach in the shape of the 'Electricity Market Reform', including auctions for renewables support a capacity market, and review of the carbon price floor.

RENEWABLE SUBSIDIES AND INVESTMENT

Compared with Germany, the UK was a relatively late adopter of renewables subsidies. The Renewable Obligation (RO) – a green certificate scheme – had existed since 2002, however it wasn't until 2007 that annual renewable capacity additions reached 1GW. By 2011 the UK was adding 3GW or more of renewable capacity per year. Renewables attracted $7.8bn of investment in 2008, growing to $16.7bn in 2013 (Box 3).

Supported by the Renewables Obligation, onshore wind became the most significant renewable technology in the UK accounting for 37% of net capacity additions over 2008-13. Planning and political opposition, as well as industrial policy, meant the government also provided support to the more costly offshore wind sector, which accounted for 25% of additions over the same period.

In 2011, FiT support caused a boom in large solar projects, bringing about $4.5bn in PV project investment

In 2010 feed-in tariffs (FiT) came into force. While these were originally meant for small-scale projects, over-generous support caused a boom in large solar projects, resulting in $4.5bn invested and nearly 1GW added in 2011 (Box 3). This prompted the government to limit FiT support to projects smaller than 50kW. Nevertheless similar solar additions follow in subsequent years, under the Renewable Obligation.

Over the period 2008-13, frequent adjustments to the RO and FiT were made as the government sought to control the cost and prevent the bubble-and-burst effect of over-subsidising and then cutting support. The 2011 solar boom led to an overinflated domestic solar industry that suffered as suffered as support levels were reduced. While the UK has been able to maintain one of the most stable renewable energy investment profiles of all the major European countries, these frequent changes have had an impact on investor certainty. The FiT degression mechanism – whereby FiT support levels are regularly reviewed – was introduced to provide much needed visibility.

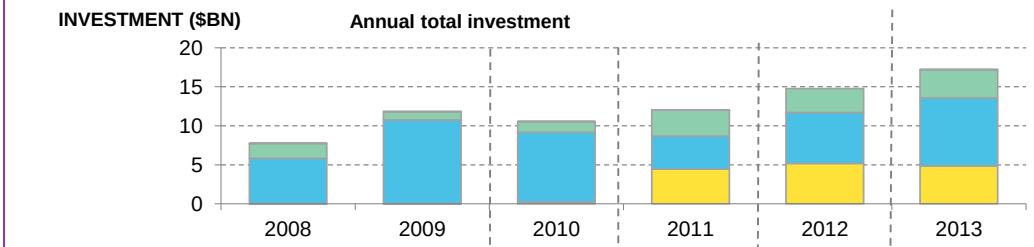
Like other countries that originally opted for green certificate schemes to support renewable energy deployment, the UK is now in the process of replacing the RO with feed-in tariffs and a Contract-for-Difference (CfD) auction process – part of its Electricity Market Reform agenda. Through auctions, the government hopes to reduce subsidies through competitive price setting, as well as being better able to control the amount of capacity added. The UK Levy Control Framework – a budget for current and future total spend on renewables support – creates a ceiling on costs, and provides some guidance on the government's long-term plans.

The phasing out of the RO scheme and phasing in of CfDs contributed to a 12% increase in renewables investment in the UK over 2014, outstripping the growth seen across much of the EU. Wind investment rose a huge 43% to $12.5bn, thanks to a strong year for the offshore wind sector. Three offshore wind farms and one transmission facility secured funding for around EUR5bn in 2014, of which two of the farms via CfDs. Solar developers also rushed to secure financing ahead of the impending cut-off date for ROC eligibility.

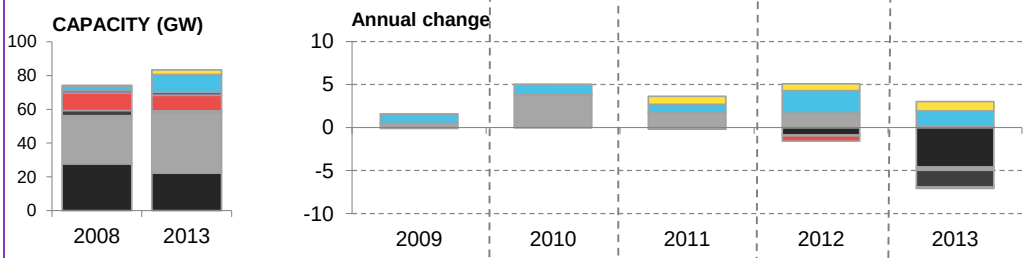
Box 3: UK

Pre-2008	2008	2009	2010	2011	2012	2013
Large combustion plant Directive (2001), opt out by 2007, run hours end 2015						
Renewables Obligation (RO) – green certificate renewable support scheme						
	UK 20-20-20 RE target of 15% by 2020; Climate Change Act (80% GHG reduction by 2050)					
			Small-scale FiTs (degression from 2012)			
				Electricity Market Reform		
					First carbon budget met (22%)	
						Carbon Price Floor: GBP 4.94/t

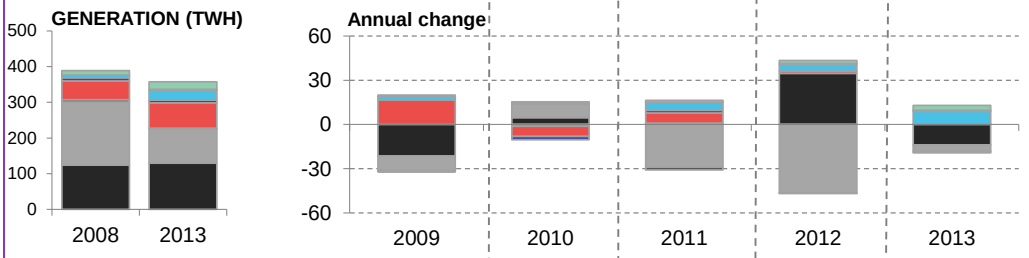
LEGEND: Other, Solar, Wind, Hydro, Nuclear, Oil, Gas, Coal



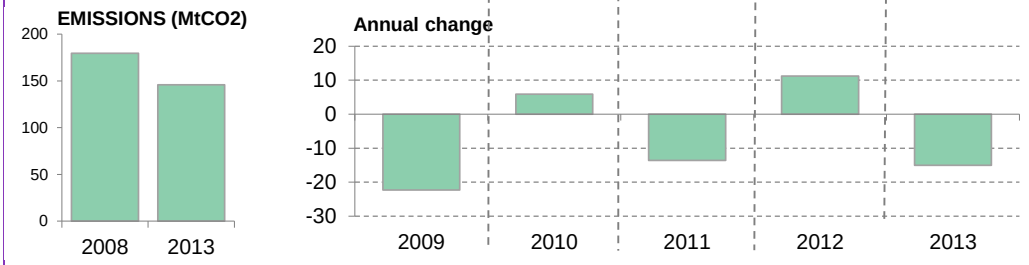
- UK investment in renewables totalled $74bn 2008-13.
- Generous support for solar through FiTs caused a large jump in investment in 2011, which continued under the RO
- The UK was able to maintain a stable investment profile, unlike the rise-and-decline of many other European countries, including Germany.



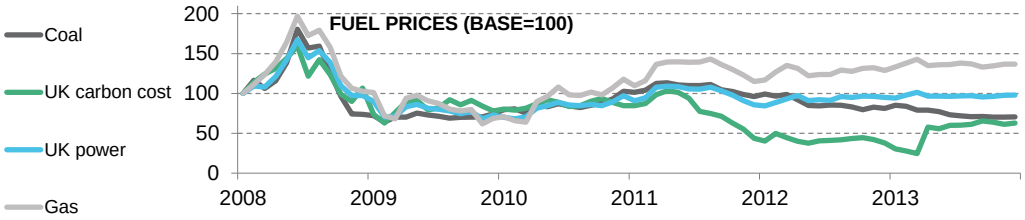
- Impact of LCPD can be seen in 5.5Gt of coal plant closures over 2012-13.
- 7.4GW of already-planned gas capacity was added despite the demand drop caused by the recession.
- Renewables capacity grew 200% over 2008-13
- By 2013 the poor state of gas-fired generator profits had begun to prompt plant closures, with as much as 372MW in 2013.



- Total annual power generation fell 8% as primarily industrial demand never recovered from the 2009 financial crisis.
- Gas generation fell 46% as its economics worsened from 2011 due to low carbon, high gas and low coal prices
- Strong energy margins from 2011 saw coal generation actually increase 4% over 2008-13, leading them to run out their allocated LCPD hours early.



- Although emissions declined over 2008-13, the CO2 intensity of fossil generation increased as coal plants increased run time.
- The rush to burn coal in 2012 caused emissions to rise in that year.
- The introduction of the carbon price floor in early 2013 saw the gap in coal and gas energy margins narrow but was insufficient to change the merit order



- The financial crisis saw fuel prices collapse over 2009-11
- From 2011, the continued demise of coal and carbon prices favoured coal generation.
- Gas generation however continued to remain on the margin often enough to influence (and increase) baseload power prices, further increasing coal generator profits.

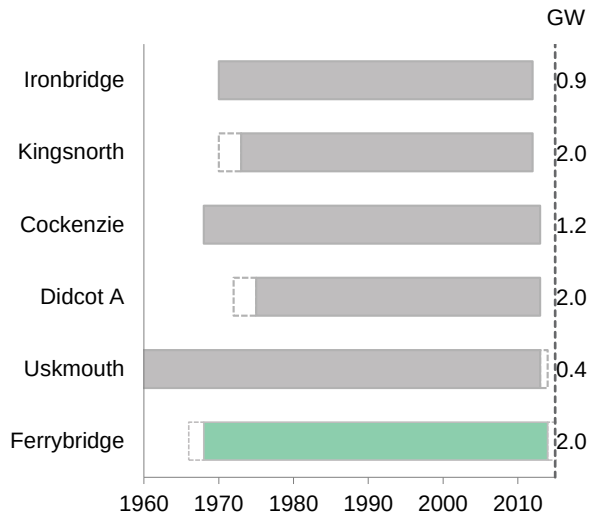
THE LARGE COMBUSTION PLANT DIRECTIVE

The Large Combustion Plant Directive (LCPD) was implemented in 2001 to limit emissions of SOx and NOx from power plants. Plants choosing to 'opt-out' and not invest in special equipment to comply with these limits were given 20,000 run-hours between 1 January 2008 and 31 December 2015.

The UK had more opt-out plants than any other country in Europe including six coal plants (Cockenzie, Didcot A, Ferrybridge 1&2, Ironbridge, Kingsnorth and Tilbury 7-10) and three oil plants (Fawley, Grain and Littlebrook). Of those, only Littlebrook is still open, with most of the coal plants closing in 2013 and 2014 (Figure 24).

The UK had more opt-out plants than any other country in Europe – six coal and three oil

Figure 24: UK LCPD coal opt-out plant lifespans



Source: Bloomberg New Energy Finance. Note: Ferrybridge has two units that are LCPD compliant (1GW total)

ENERGY COMMODITY PRICES

Attractive dark spreads meant that coal-fired generation rose 31% in 2012 pushing emissions up by 11Mt

Coal plants that opted-out of the LCPD used their 20,000 run-hours as quickly as possible closing somewhat earlier than expected as falling coal prices and rising gas prices provided very attractive clean dark spreads (Figure 15 and Box 3). As a result, coal-fired generation increased in 2012 by 31% (34TWh) pushing emissions up 7.5% or 11Mt (Box 3).

Gas generation suffered heavily over 2008-13 falling 46% due to a combination of strong clean dark spreads, increasing renewables generation – in particular wind which quadrupled generation to 8% – and weak demand due to the recession which resulted in an 8% drop in total generation. This was particularly the case from 2011 when gas generation fell 17%, even as new gas-fired power plants were commissioned on the back of investments made prior to the recession – such as Pembroke and West Burton. By 2013 baseload gas plants became uneconomic to run in the UK and the investment case for new gas-fired capacity had all but disappeared.

THE CARBON PRICE FLOOR AND CAPACITY MARKET

The carbon price floor was intended to give a transparent, progressive price signal to move towards low-carbon generation

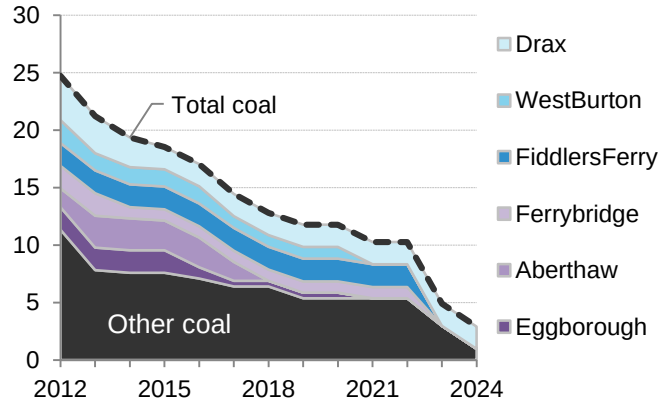
In April 2013 the UK established a carbon price floor as part of its Electricity Market Reform agenda. The carbon price floor sets a target carbon price to be paid by power generators, legislated to rise to GBP 70/t (2009 real) by 2030. In combination with the Emissions Performance Standard, which bans the construction of unabated coal plants from Q2 2014, it is intended to give a transparent, progressive price signal to move towards low-carbon generation.

The carbon price floor started in 2013 with a GBP 4.94/t carbon tax on top of an average GBP 3.83/t carbon price (Box 3). While this is still relatively low, the prospect of a continuously increasing carbon floor price, as well as the sizeable investment that would be required to comply with the LCPD's successor, the Industrial Emissions Directive (IED), suggested that a number of coal plants would be expected to close towards the end of the decade (Figure 25).

The government decided to implement a capacity market as part of the Electricity market reform to bring in new investment

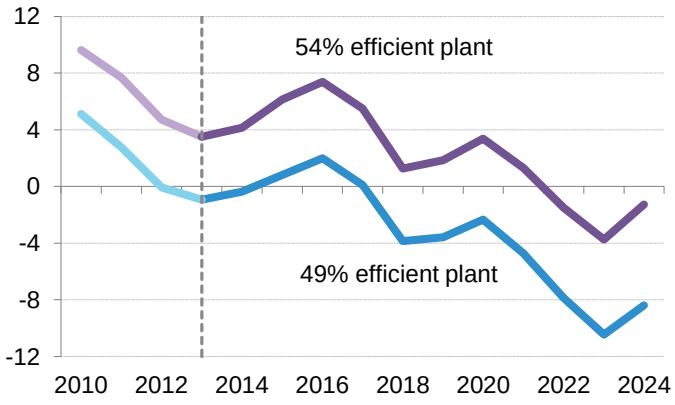
Coal plant closures under the LCPD, plus further retirements in the pipeline on the back of the carbon price floor and the IED was meant to be replaced by new gas capacity. However, negative clean spark spreads mean there is no price signal for such investments (Figure 26). As a result the government has decided to implement a capacity market. In a capacity market, generators are paid for their ability to generate power when called upon in addition to any revenue they receive from selling electricity. The first capacity auction which took place in December 2014, however, was more successful in paying old coal generators to stay open than funding the construction of new gas plants.

Figure 25: UK expected coal closures prior to capacity market (GW)



Source: Bloomberg New Energy Finance

Figure 26: UK clean spark spread for existing (49%) and new entrant (54%) CCGT plants (GBP/MWh)



Source: Bloomberg New Energy Finance Note: Central scenario as per our 2014 GB Power Market Outlook, assumes no capacity market.

SECTION 6. APPENDIX

Table 2: Box 1: EU

		2008	2009	2010	2011	2012	2013
Investment ($million)	Solar	39,990	41,070	69,620	87,211	61,141	26,442
	Wind	41,987	39,127	38,750	35,106	27,170	27,612
	Small hydro	471	783	366	63	351	128
	Biofuels/biomass	7,308	6,480	5,807	8,122	5,737	5,494
	Geothermal	58	139	198	257	168	7
	Marine	12	102	22	84	0	12
Capacity (MW)	Coal	189,365	191,117	184,801	186,190	184,283	178,774
	Gas	185,611	188,096	205,676	211,549	217,161	220,072
	Oil	40,092	40,187	38,477	37,230	36,730	34,033
	Nuclear	131,821	131,788	129,849	124,954	123,313	123,714
	Hydro	129,339	129,928	131,449	132,264	133,059	133,613
	Wind	63,703	73,813	83,208	92,484	105,175	116,154
	Solar	10,676	16,676	31,679	52,565	70,401	80,109
	Other[a]	20,074	21,191	22,125	23,653	25,361	27,052
Generation (GWh)	Coal	813,452	719,272	728,370	764,630	802,322	779,682
	Gas	741,313	626,955	657,045	585,907	486,086	420,537
	Oil	51,735	46,289	42,678	45,643	48,226	40,285
	Nuclear	886,690	844,959	877,105	867,948	844,924	838,699
	Hydro	500,421	487,029	520,833	462,279	508,237	521,841
	Wind	114,971	129,421	145,297	174,871	201,719	233,305
	Solar	7,162	13,971	22,616	46,300	67,702	81,521
	Other[b]	94,914	97,750	108,876	116,090	133,771	139,730
Emissions (MtCO2)	Total	1,262	1,149	1,162	1,137	1,133	1,070

Source: Bloomberg New Energy Finance. Note: EU wide figures include: Capacity (EU-28), Generation (EU-27), Investment (EU-28), Emissions (countries included in the EU ETS, i.e. EU-28 plus EEA/EFTA states)

Table 3: Box 2: Germany

		2008	2009	2010	2011	2012	2013
Investment ($million)	Solar	12,579	18,181	28,693	22,649	20,225	5,730
	Wind	4,867	6,292	10,874	11,242	5,569	7,422
	Small hydro	0	380	0	0	0	0
	Biofuels/biomass	913	979	182	481	138	341
	Geothermal	21	30	180	219	11	7
	Marine	0	0	0	0	0	0
Capacity (MW)	Coal	50,452	50,900	46,887	46,857	47,095	47,279
	Gas	27,326	27,568	28,963	29,610	29,520	29,588
	Oil	1,826	1,842	1,515	1,515	1,515	1,515
	Nuclear	20,486	20,480	19,264	13,101	12,068	12,068
	Hydro	4,139	4,151	4,395	4,401	4,451	4,452

[a] Includes biomass, marine and geothermal

[b] Includes biomass, other renewables and other/unknown fossil-fired generation

		2008	2009	2010	2011	2012	2013
	Wind	23,106	25,023	26,526	28,553	30,992	34,230
	Solar	6,101	9,904	17,103	24,588	32,192	35,496
	Other[a]	5,075	5,310	5,388	5,388	5,769	5,925
Generation (GWh)	Coal	266,015	247,682	257,497	259,701	275,434	288,934
	Gas	76,864	65,379	73,122	70,032	57,856	44,567
	Oil	2,944	3,623	2,928	1,668	2,422	1,111
	Nuclear	140,704	127,660	133,013	102,268	94,218	92,138
	Hydro	26,146	24,291	26,971	22,996	27,309	25,857
	Wind	41,139	38,791	37,800	48,900	50,700	53,400
	Solar	4,428	6,641	11,700	19,600	26,400	30,000
	Other[b]	24,266	25,811	25,997	29,947	36,151	38,664
Emissions (MtCO2)	Total	334	308	323	319	324	326

Source: Bloomberg New Energy Finance

Table 4: Box 3: UK

		2008	2009	2010	2011	2012	2013
Investment ($million)	Solar	35	24	214	4,465	4,999	4,016
	Wind	5,808	11,637	9,088	4,210	6,241	7,946
	Small hydro	0	2	0	0	0	0
	Biofuels/biomass	1,896	957	1,373	3,345	2,940	3,321
	Geothermal	0	0	0	0	0	0
	Marine	0	85	20	30	0	12
Capacity (MW)	Coal	27,705	27,715	27,725	27,683	26,823	22,232
	Gas	28,508	28,971	32,776	34,540	36,234	35,862
	Oil	3,100	3,100	3,100	3,100	2,992	1,050
	Nuclear	10,262	10,148	10,155	10,028	9,412	9,231
	Hydro	1,519	1,526	1,526	1,545	1,545	1,693
	Wind	2,932	4,008	5,163	6,088	8,700	10,489
	Solar	23	27	65	985	1,756	2,837
	Other[a]	2,597	2,658	2,764	3,838	3,971	4,399
Generation (GWh)	Coal	124,381	103,038	107,694	108,571	143,181	129,442
	Gas	176,219	166,498	175,656	146,521	100,073	95,721
	Oil	6,709	5,995	4,803	3,117	3,065	2,544
	Nuclear	52,486	69,098	62,140	68,980	70,405	70,608
	Hydro	9,244	8,926	6,726	8,596	8,251	7,624
	Wind	7,123	9,283	10,180	15,472	19,661	28,433
	Solar	17	20	40	244	1,351	2,036
	Other[b]	12,723	13,870	14,476	15,814	17,805	21,118
Emissions (MtCO2)	Total	180	157	163	150	161	146

Source: Bloomberg New Energy Finance

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