CECILIA 2050

OPTIMAL EU CLIMATE POLICY

Choosing Efficient Combinations of Policy Instruments for Low-carbon development and Innovation to Achieve Europe's 2050 climate targets

The Effect of Key EU Climate Policies on the EU Power Sector

An Analysis of the EU ETS, Renewable Electricity and Renewable Energy Directives

Funded by the European Union

SEVENTH FRAMEWORK PROGRAMME

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LIST OF ABBREVIATIONS

CCPT	Carbon Cost Pass Through
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
ETS	Emissions Trading System
EUA	European Union Allowances
FiT	Feed-in Tariff
GW	Gigawatt
GWh	Gigawatt-hour
kWh	Kilowatt-hour
LCPD	Large Combustion Plant Directive
MWh	Megawatt-hour
PV	Solar Photovoltaic
RED	Renewable Energy Directive
TWh	Terrawat-hour
RES-E	Renewable Electricity

EXECUTIVE SUMMARY

This paper assesses the impact of the EU ETS, Renewable Electricity Directive and Renewable Energy Directive on various aspects of the power sector in the EU and selected member states.

- *Electricity Generation* –The EU ETS appears to have encouraged some 'fuel-switching' from coal to gas in some member states (the UK and Germany, in particular), in 2005 and 2006 at least. Delarue *et al* (2008) estimate this reduced EU-wide coal generation by around 2% and 1% in these years respectively, in favour of gas. The increase in renewable generation is a function of increased renewable capacity, with low marginal costs allowing renewable generation to receive preferential dispatch.

- *Electricity Capacity* – The EU ETS is likely to have been a negligible driver in the increasing gas capacity in the EU, and potentially had a negative influence by incentivising investment in coal capacity, resulting from free allocation of permits driving windfall profits. The growth in RES-E capacity is likely to be due almost entirely to targeted support mechanisms and enabling initiatives contained in the two Renewables Directives, with enabling initiatives likely to be as important as the design and detail of the financial support mechanisms employed.

- *Electricity Prices* – The rate of carbon cost pass-through to wholesale electricity spot market prices varies significantly across member states and over time (at all scales), and may be both above 100% and negative. On average however, it is positive and increased wholesale prices against the counterfactual in most instances. Deployment of RES-E as a result of the Renewables Directives is likely to have decreased wholesale prices against the counterfactual, via the merit order effect – but increased retail prices through recovery of support mechanism costs.

- *Electricity Trading* – Both the EU ETS and Renewables Directives are likely to have encouraged additional cross-border electricity trade by working together to increase wholesale price differentials between countries with high and low CO_2 intensities of generation. However, this is limited by the presence of interconnector capacity and the slow implementation of a fully functional internal electricity market.

- *Emissions Abatement* – The EU ETS and Renewables Directives, via the above mechanisms, work in tandem to reduce the emissions intensity of power generation in member states (the first principally via fuel switching, the latter via increasing RES-E

penetration). Whilst overall ETS sector emissions remain unaffected by RES-E installations driven by non-ETS measures (as increased power sector decarbonisation reduces the burden on other EU ETS sectors), the level of the EU ETS cap was set in consideration of this. As such, only overachievement of RES-E targets would produce a detrimental instrument overlap. As fifteen member states were underachieving on these targets by 2010, it is unlikely that this has yet been the case.

In summary, the EU ETS thus far is likely to have relatively little impact on the development of the EU power sector since its introduction in 2005. This appears to be due to a combination of low and volatile prices, leading to a lack of future certainty upon which to base investments, and the practice of free permit allocation preventing the imposition of a 'real' cost to the power sector in Phases One and Two. The Renewables Directives appear to have had a larger impact, and facilitated the significant expansion in RES-E experienced since 2000. However, other factors evidently combine to play a much more decisive role on the development of the EU power system, and in differences across member states. Such factors include fuel prices (particularly the relative difference between coal and gas), domestic resource availability (principally renewable resources, but also fossil fuel), political and public acceptability (particularly concerning RES-E installations, enabling infrastructure and support mechanism costs), and the general economic climate – which significantly impacts electricity demand, the availability and cost of capital for investment in capacity and infrastructure, and political and public priorities. Similarly, other policy measures with a direct or indirect impact on the power sector, such as the Ecodesign Directive, the Energy Performance of Building Directive and Large Combustion Plant Directive, also play influential roles.

1 Introduction

This report discusses the extent to which key climate policies in the EU have influenced the development of the EU's power sector. The discussion is confined to the power rather than the wider energy supply sector, as other sectors such as transport and heating are covered by complementary reports in this series. The discussion surrounds the influence of the EU ETS and renewable electricity support policies, in particular.

The report begins by discussing the development of the EU power sector from 1990 to the present day (or for when the most recent data is available, depending on the specific analysis undertaken), including overall trends in generation, capacity and primary energy source, along with development in electricity markets[1]. Member State examples are also discussed. The influence of the three key EU climate change mitigation policies concerning the power sector - the EU ETS, the Renewable Electricity Directive (RES-E Directive) and the subsequent Renewable Energy Directive (RED) - on power sector developments, are then assessed - first individually, and then by their interaction. Developments in two member states (Germany and Spain) due to national renewable support policies are also described in detail.

Whilst other influences on power sector development, such as non-climate policies and international influences, are not the focus of this analysis, such factors are briefly assessed throughout this report and are summarised in the 'Other Drivers' section.

2 Evolution of the European Power Sector

This section describes the evolution of the European power sector from 1990. It discusses changes in generation and electricity capacity profiles at EU-level and in selected member states, along with developments in electricity markets and CO_2 emissions.

2.1 Electricity Generation

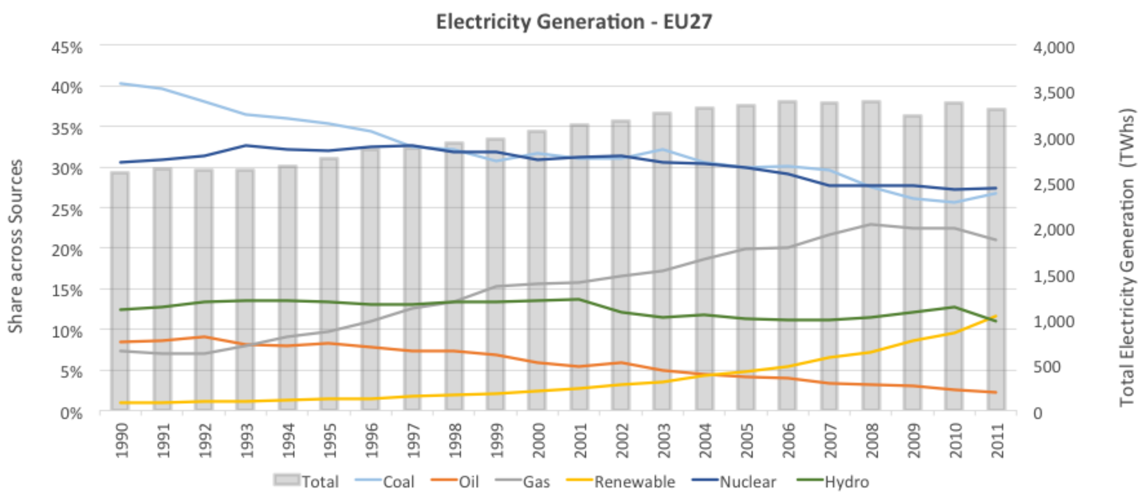
The European power sector has undergone a significant transformation in recent decades. Figure 1, below, illustrates the change in total generation since 1990 (right axis), and the changing profile of the source of this generation (left axis), for the EU27. Total generation increased by 27% between 1990 and 2011; with an average annual increase of 1.5% until 2008. Generation dropped by 4.5% between 2008 and 2009, recovered in 2010, then experienced another slight drop of 2% in 2011. Data is only sporadically available for 2012

[1] As this paper focuses on ex-post analysis of the EU power sector, Croatia (as an EU member state from July 2013) is excluded in any discussion unless explicitly stated.

and 2013 for electricity generation, and shall be discussed where available.

Between 1990 and 2011 the proportion of supply provided by coal and oil decreased significantly, from 40% to 27%, and 8% to 2%, respectively, with each experiencing a relatively linear decline. Despite coal returning to near 1990 levels in 2003 (in absolute terms, but not proportionally), it declined rapidly thereafter – but remained a close second in overall generation, at just under 27% of the total in 2011. The use of natural gas in the electricity mix has experienced opposing fortunes, and increased from 7% to 21% of total generation in the same timeframe. Both the proportion of gas in the electricity supply and absolute generation from gas peaked in 2008, at 23% and 773TWh, respectively, with both aspects decreasing slightly in 2011.

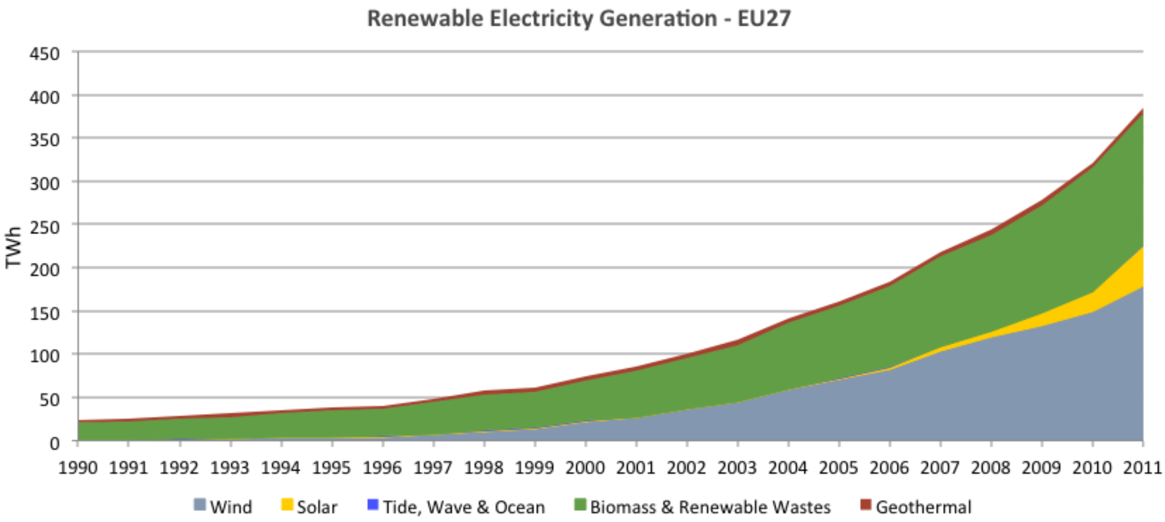
Figure 1 – Gross Electricity Gernation, in Total and by Source (including autoproduction) – EU27 (Source: Eurostat)



Although the share of supply satisfied by nuclear energy decreased from 31% in 1990 to 27% in 2011, overall nuclear generation increased by 14% (from 795TWh to 907TWh – the proportional decrease due to increasing total electricity generation). Despite this proportional reduction, nuclear was still the largest single source of generation in 2011. Electricity from hydropower experiences a similar pattern, with proportional contribution remaining relatively constant (12% in 1990 to 11% in 2011), despite a 13% increase in absolute generation (323TWh to 363TWh).

Generation from non-hydro renewables has increased exponentially however, from under 1% to around 12% of total generation (24TWh in 1990 to 386TWh in 2011) (hydropower is considered separately in order to avoid including pumped-storage from non-renewable electricity). Figure 2 demonstrates the overall trend by renewable source, whilst Figure 3 illustrates additional annual renewable generation by source.

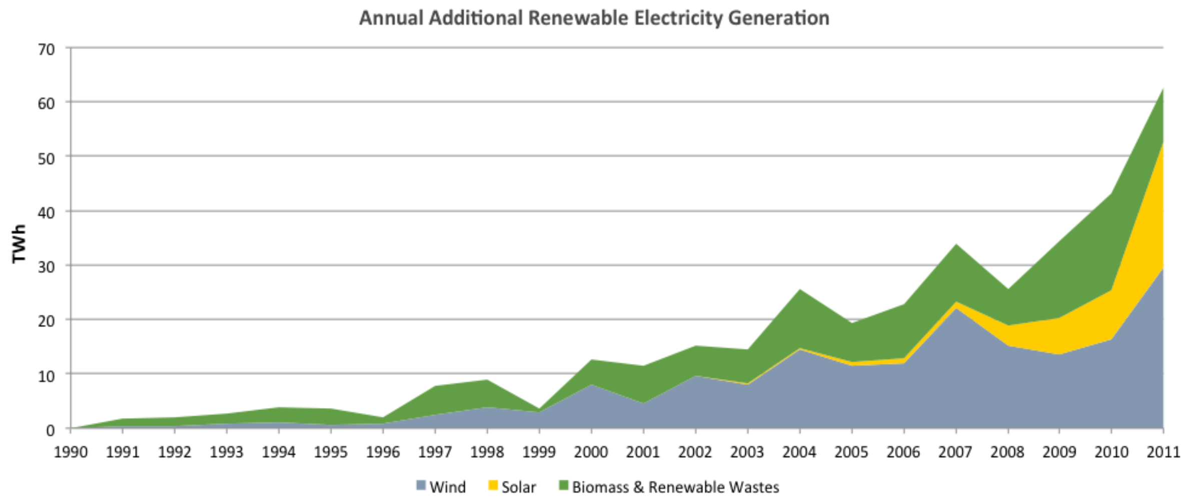
Figure 2 – Renewable Energy Generation Trends – EU27 (Source: Eurostat)



In 1990, generation from biomass and renewable wastes accounted for over 80% of total non-hydro renewable electricity in the EU (0.75% total electricity generation). By 2011, it accounted for less than 40% (but 5% total generation), despite over 750% growth over the same time period. Geothermal power accounted for around 13% of total renewable electricity in the EU in 1990, which decreased dramatically to around 1.5% by 2011, despite an 82% increase in generation. Electricity from tidal, wave and ocean power was marginal in 1990, and has become even more so over time (from around 2% of renewably sourced electricity generation, to under 0.14%).

The most striking trend seen in Figure 2 is the growth of wind power, increasing from 3% (0.78TWh) in 1990 to 47% of total renewable generation in 2011 (179TWh). Electricity from solar photovoltaic has also increased from irrelevance in 1990, to 12% of all renewable generation in 2011 (an increase from 0.012TWh to 46TWh). This growth in solar appears to come in two distinct 'bursts', as illustrated in Figure 3, displaying the first derivative. The first begins in 2001, after which generation from solar increases at an average annual rate of 65%, until 2008, after which annual growth averages around 88%. Solar, along with wind and biomass generation have experienced continuous increases in annual generation since 1990. Tide, wave and ocean and geothermal do not experience such a trend, and are extremely minor in comparison to the three former generation source, and as such are removed from the figure.

Figure 3 – Annual Additional Renewable Electricity Generation – EU27 (Source: Eurostat)



The EU power sector is rather heterogeneous, with Member States exhibiting significant variation. Figure 4 to Figure 11 illustrates the evolution of the power generation profile across selected member states - Czech Republic, France, Germany, Italy, Netherlands, Poland, Spain and the UK.

Figure 4 – Gross Electricity Generation – Total and by Source (including autoproduction) - Czech Republic (Source: Eurostat)

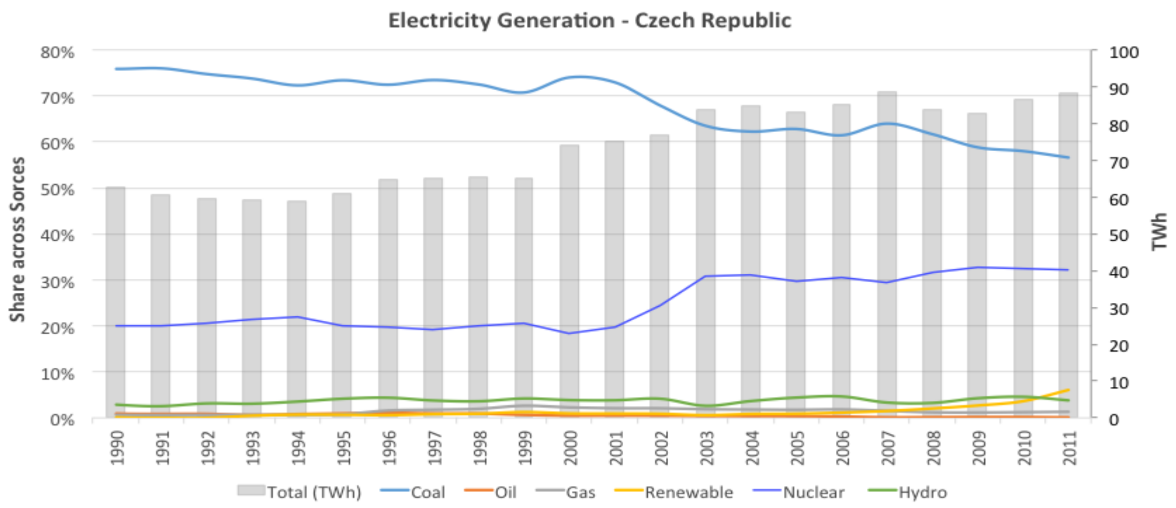


Figure 5 - Gross Electricity Generation – Total and by Source (including autoproduction) - France (Source: Eurostat)

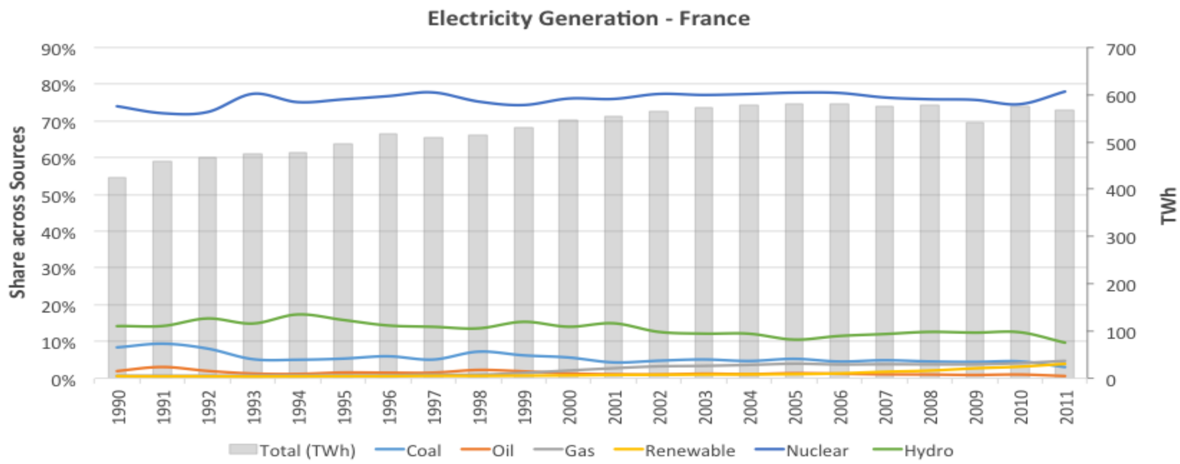


Figure 6 - Gross Electricity Generation – Total and by Source (including autoproduction) - Germany (Source: Eurostat)

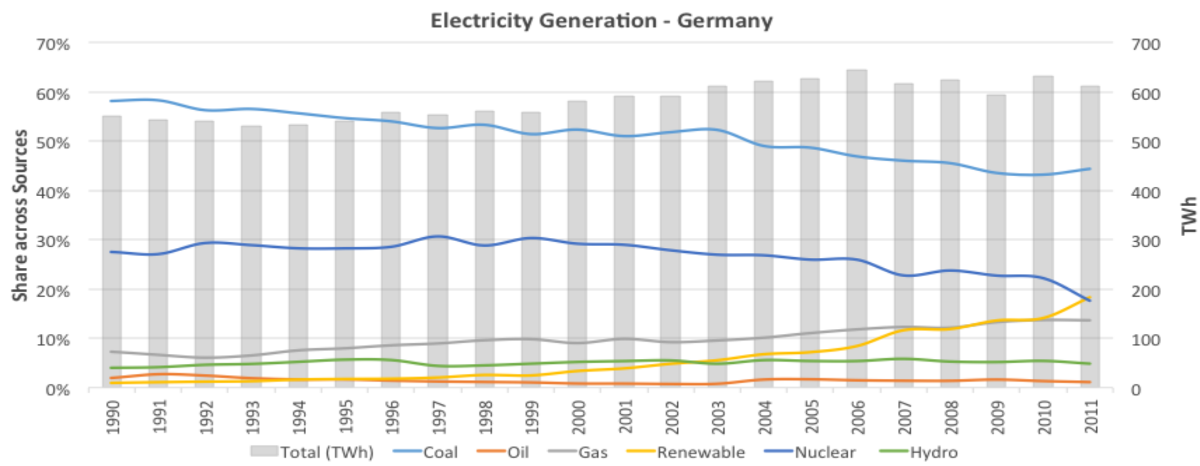


Figure 7 – Gross Electricity Generation – Total and by Source (including autoproduction) - Italy (Source: Eurostat)

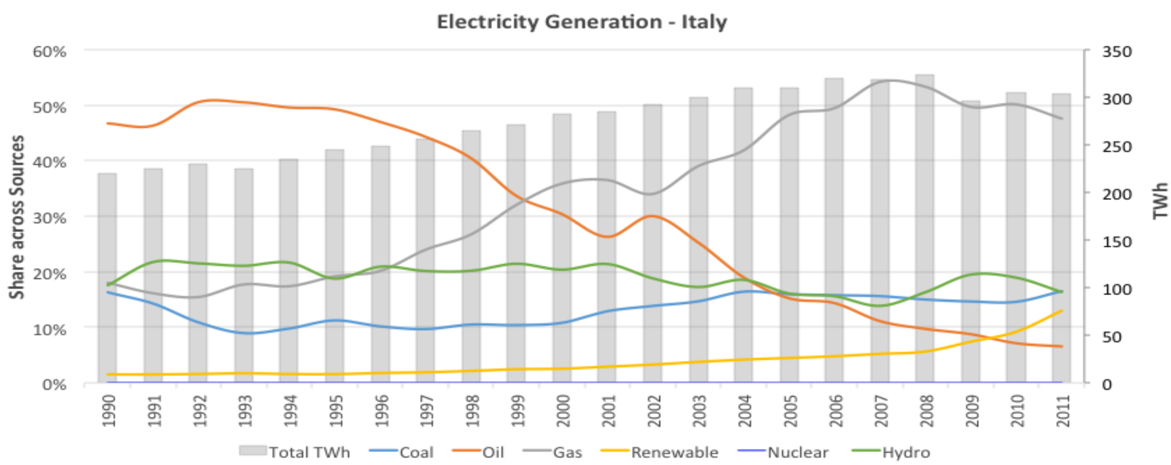


Figure 8 - Gross Electricity Generation – Total and by Source (including autoproduction) - Netherlands (Source: Eurostat)

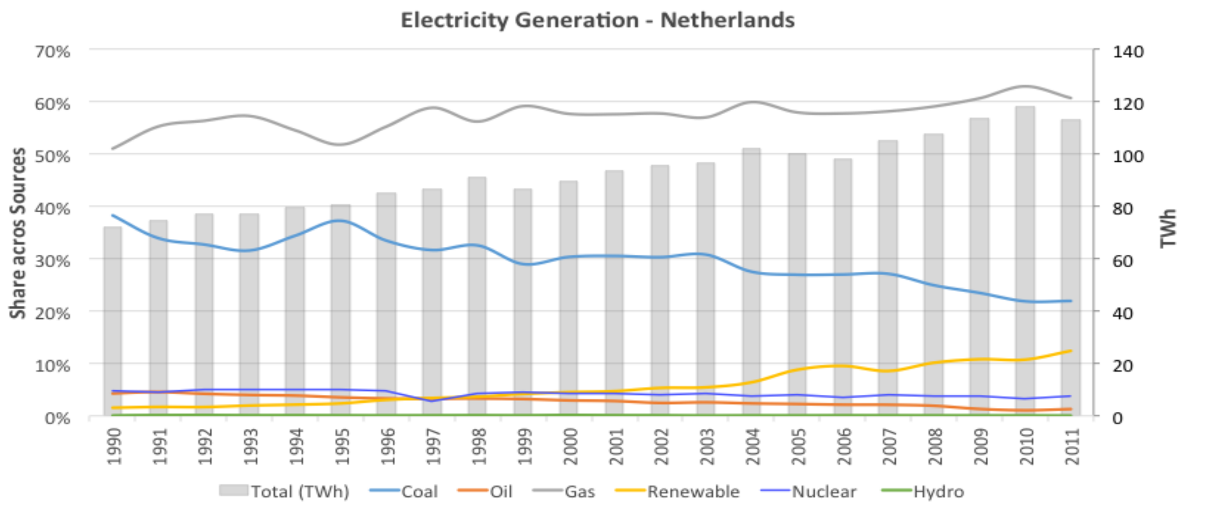


Figure 9 - Gross Electricity Generation – Total and by Source (including autoproduction) - Poland (Source: Eurostat)

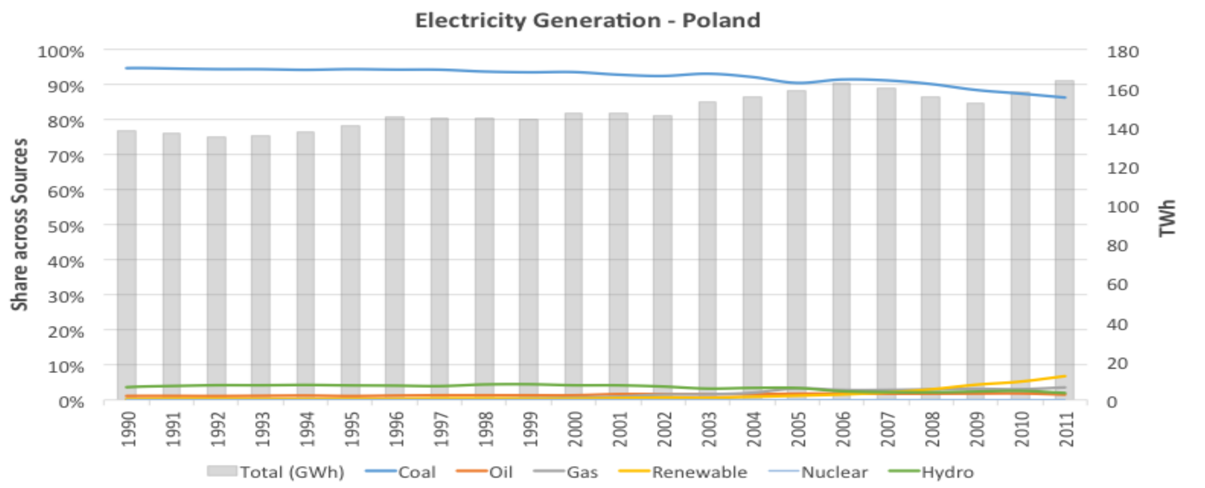


Figure 10 - Gross Electricity Generation – Total and by Source (including autoproduction) –Spain (Source: Eurostat)

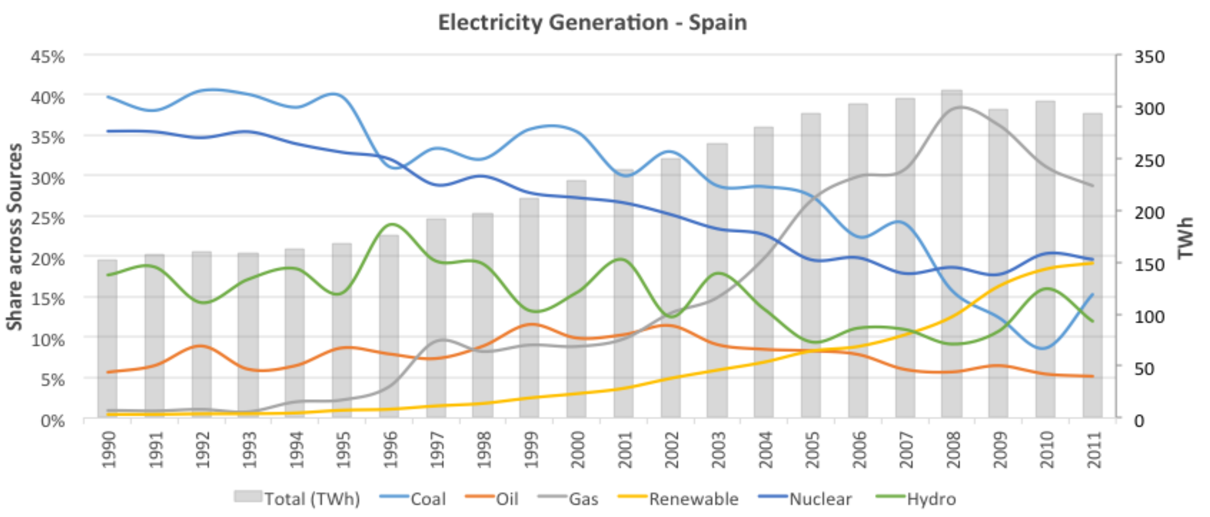
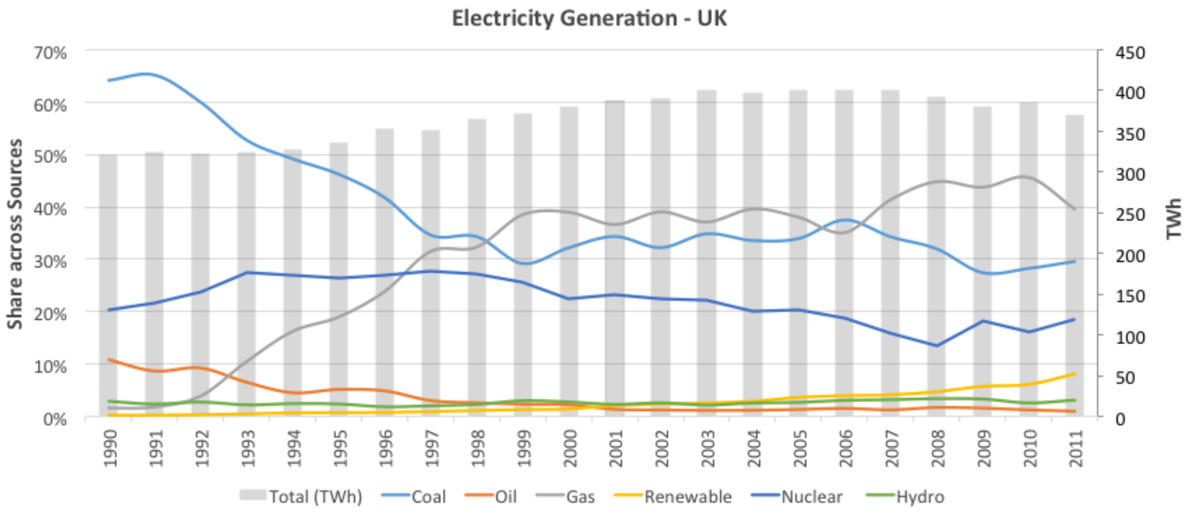


Figure 11 - Gross Electricity Generation – Total and by Source (including autoproduction) –UK (Source: Eurostat)



Each of these countries follows a common trend of continually increasing generation to meet demand from 1990, peaking between 2006 and 2008, before experiencing significant reductions between 2008 and 2009 - varying between 1.3% (Czech Republic) and 8.5% (Italy), with an average reduction of 3.4%. Demand recovered at least partially in 2010, with an average increase in generation of 4%, before experiencing a second (albeit smaller) trough in 2011 (although the Netherlands experiences a peak in generation in 2010, before a 4.4% decrease in 2011). This matches the overall EU trend of a 4.5% decrease in generation in 2009 from 2008, with a recovery of 4.4% in 2010 from 2009 levels. This may be expected, as the eight member states discussed account for around 75% of total EU electricity generation across the time horizon (with Germany, France and the UK alone accounting for 61% in 2011), and thus heavily influence macro trends.

At the EU level coal has shown a steady decrease, both in proportional and absolute terms – however this trend is far from uniform across member states. Whilst the Czech Republic, France, Germany and the Netherlands experienced developments in line with the EU-wide trend between 1990 and 2011, decreasing generation in proportional terms from 76% to 57% (Czech Republic), 8% to 3% (France), 58% to 44% (Germany) and from 38% to 22% (Netherlands), generation from coal in Spain and the UK experienced a much more dramatic decrease, moving from 40% to 15% and 64% to 30%, respectively. The trend in Spain is rather variable over time, with two distinct drops beginning in 1998 and 2008. The UK also experiences two distinct declines, beginning in 1992 and 2007. However, in each case, absolute generation from coal decreases at a much slower rate (with coal-fired power generation in the Czech Republic actually increasing by over 2TWh), yet lags behind the increase in total generation. Similarly, whilst electricity from coal in proportional terms remained relatively stable in Italy (at around 16%), absolute coal generation increased by 40% (nearly 15TWh). Whilst coal is relatively insignificant in French generation in 2011, it accounts for 86% of the Polish electricity mix (down from 95% in 1990), and remains dominant in Germany and the Czech Republic. In all instances except Poland, coal generation increases in 2011 from 2010 levels. This is likely to have continued into 2012 and 2013 - rather dramatically in some instances. In the UK, for example, it has now overtaken gas as the primary generation source once more.

Similarly to coal, there is significant variation in gas trends between member states. Only in Germany and the Netherlands is the 1990-2011 trend in line with the European average, although with very different proportional profiles (moving from 7% to 14%, and from 51% to 61%, respectively) – although with absolute generation in both states approximately doubling (from 40TWh to 84TWh, and from 37TWh to 68TWh, respectively). Gas is the principle generator in the Netherlands by a significant margin – a trend that has only strengthened since 1990. However, Italy, Spain and the UK however have experienced much more significant increases. Italy has seen its use of gas in the electricity mix rise from 18% to 48% (40TWh to 145TWh), overtaking oil in 2000 as the principle generation source. Proportional gas supply peaked at 54% in 2007 (2008 in absolute terms), and slowly decreased to 2011. Gas became the principle supply source in 2005 in Spain (overtaking coal), during it's rapidly increasing presence from under 1% of the mix in 1990 (1.5TWh) to 29% in 2011 (85TWh), via a peak in 2008, at which it accounted for 38% of generation (121TWh). Gas only accounted for around 2% of generation (5TWh) in 1990 in the UK, increasing rapidly to 39% in 1999 (142TWh), overtaking coal as the dominant fuel in the same year. Generation then remained relatively stable until 2006 before increasing to a peak of 46% in 2010 (absolute generation peaked in 2008, at 176TWh), followed by a rapid decrease to 40% in 2011 (147TWh), a trend continuing into 2012 and 2013, relegating to the second largest supply source after coal. The use of gas in the generation mixes of the Czech Republic, France and Poland was, and remains minor (1.3%, 4.7% and 3.5% in 2011, respectively).

The trend in the use of oil for electricity generation is much more homogenous between member states, moving from small to relatively insignificant levels between 1990 and 2011. Italy and the UK were the exceptions to the rule in 1990, with oil accounting for 47% and 11% of generation respectively, decreasing (very significantly in the case of Italy), to 7% and 1% respectively in 2011. Trends in the use of nuclear power in the fourteen member states with such capacity have remained largely stable, on average. Of the member states specifically discussed in this paper only Italy and Poland have no nuclear generation – however only in France has it ever been a majority source (expect briefly in Spain in 1996), growing slightly from 74% to 78% of generation (314TWh to 442TWh) between 1990 and 2011. Whilst nuclear generation also increased over this time in the Czech Republic (20% to 32%, 13TWh to 28TWh), it decreased proportionally in Germany, Netherlands, Spain and the UK – although it increased slightly in absolute generation in all but Germany. In most member states, nuclear is likely to have remained largely static into 2012 and 2013 – aside from Germany, in which the decreasing trend continued.

Whilst there is no use of hydropower in the Netherlands, it is a significant contributor in France, Italy and Spain, generally responsible for between 10% and 20% of generation between 1990 and 2011 - remaining largely stable in proportional and absolute terms (although with significant variation in Spain). Whilst hydropower is used in Germany, the UK, Poland and the Czech Republic, it has accounted for between only 2%-6% of generation. Such trends are likely to have continued into 2012 and 2013.

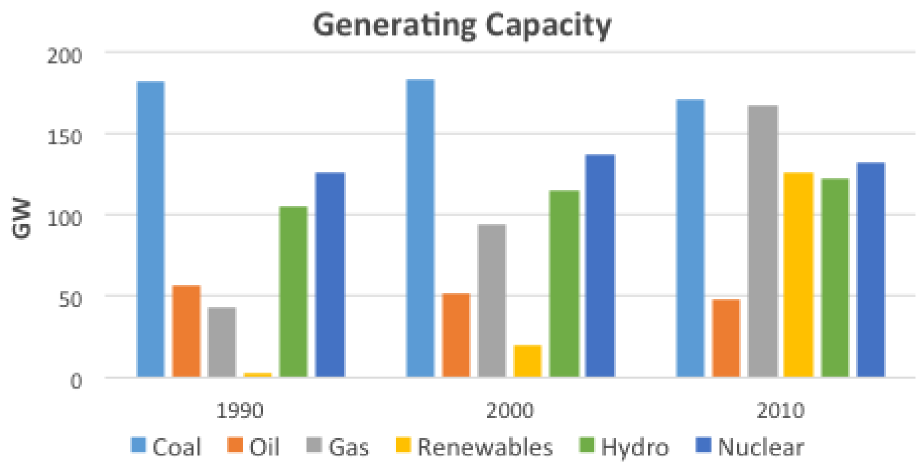
The vast majority of growth across all renewable technologies, particularly in wind and solar, occurred since 2000 – especially in Germany and Spain. These two countries alone accounted for over 60% of solar and 51% of EU wind generation in 2011, with wind power rising to be the largest single generation source in Spain in 2013. Germany accounted for around 29% of all biomass & renewable waste generation in 2011. Generation from biomass & renewable wastes is present in seven of the eight countries selected in 1990, and all countries by 2000. Solar and wind generation is present in only three and five countries respectively in 1990, increasing to six and seven respectively in 2000, and finally to all countries by 2011. Wave and tidal generation is present only in France at a relatively constant level in all three years, whilst geothermal power only has a significant presence in Italy (accounting for over 96% of total geothermal power in the EU in 2011), with Germany the only other country selected with (insignificant) geothermal generation. Returning to the EU level, the trends for both fossil and non-fossil generation seen in Figure 1 are likely to have continued into 2012 and 2013 (although hydro is likely to have recovered from the 2011 dip). The trends in generation for specific (non-hydro) renewable technologies, both at EU and member state levels, are likely to have also maintained their previous trends.

2.2 Electricity Generation Capacity

As may be expected, the EU's electricity generation capacity profile has also undergone significant changes – as Figure 12 illustrates below. Whereas the latest available data for electricity generation was for 2011, comparable data is only available for generation capacity until 2010.

It must be noted that Italy is not represented in this section due to a lack of disaggregated data. Total generation capacity in the EU increased by almost 50% between 1990 and 2010 (approximately 515GW to 770GW), with significant diversification. Oil and coal capacity both experienced a small but steady decline since 1990, although the latter still (marginally) accounts for the largest total capacity. However, gas capacity increased steadily from around 8% to 22% of total capacity, increasing from 43GW in 1990 to 167GW in 2010. Both nuclear and hydro capacities remained largely stable in absolute terms to 2010, and as such decreased slightly in proportional terms, from 24% to 17% (nuclear) and 20% to 16% (hydro).

Figure 12 - Total Generating Capacity - EU27 (minus Italy) (Source: EURELECTRIC, 2012b)



As with generation, the most conspicuous development is the growth in renewables capacity between 1990 and 2010 (and between 2000 and 2010, in particular). Figure 13 breaks down this growth into the key renewable technologies. Whilst geothermal, tidal, wave and ocean capacity remains negligible, and biomass & renewable waste capacity experienced steady increases from 2GW in 1990 to 23GW in 2010, much more striking developments can be seen in wind and solar capacity. Although wind capacity increased from around 1GW in 1990 to 12GW in 2000, it increased much more rapidly over the following decade to 78GW – 61% of total (non-hydro) renewable capacity, and around 10% of total net electricity generation capacity in the EU in 2010 (around 96% in offshore installations (EURELECTRIC, 2012b)). In 2000, solar remained negligible in the capacity mix. However, it grew to 27GW in 2010 – over 3.5% total capacity.

Figure 13 – Total Renewable Electricity Capacity - EU27 (minus Italy) (Source: EURELECTRIC, 2012)

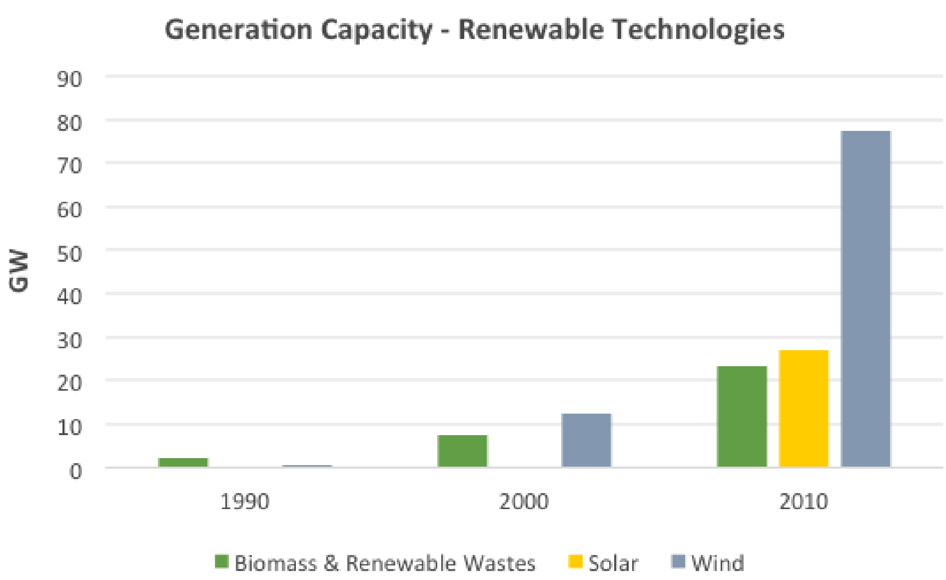


Table 1 - Proportion of Generation and Capacity by Primary Source - EU 27 (Source: EURELECTRIC, 2012b and Eurostat)

	Generation			Capacity		
Primary Energy	**1990**	**2000**	**2010**	**1990**	**2000**	**2010**
Coal	40%	32%	26%	35%	30%	22%
Oil	8%	6%	3%	11%	9%	6%
Gas	7%	16%	22%	8%	16%	22%
Renewable	1%	2%	10%	1%	2%	17%
Hydro	12%	13%	13%	20%	19%	16%
Nuclear	31%	31%	27%	24%	23%	17%

Table 1 illustrates the difference between the proportion of total generation and total capacity across primary energy sources for the EU, over time. First, It is interesting to point out the difference between the growth of generation and capacity, the former growing by around 30% between 1990 and 2010, the later by around 50%. The vast majority of this differential is explained by the increase in renewable capacity which has a lower than average load factor, in particular PV[2]. Hydropower is also subject to resource availability (i.e. rainfall), and thus also varies in generation, both overall (as seen in Spain in Figure 10), and against total capacity. Coal and oil generation reducing faster than their respective capacities may explain the remaining difference. Generation from gas against capacity however experienced the reverse trend, with generation increasing much quicker than overall capacity (whilst maintaining a roughly equal proportion of each), meaning individual plants increased their average output over time. Generation from nuclear and hydro also grew quicker than capacity between 1990 and 2000, but equalised in 2010.

As expected, the significant variation in generation between member states is reflected in their capacity profiles, illustrated in Figure 14 to Figure 20, below.

[2] By comparing the share of individual renewable generation sources in (Figure 2) against respective capacities in 2010 (Figure 13), this becomes clear. For example, solar capacity exceeds biomass & renewable waste capacity, although the latter contributes significantly more generation, due to the more predictable and controllable nature of its feedstock.

Figure 16 - Total Electricity Capacity – Czech Republic (Source: EURELECTRIC, 2012b)

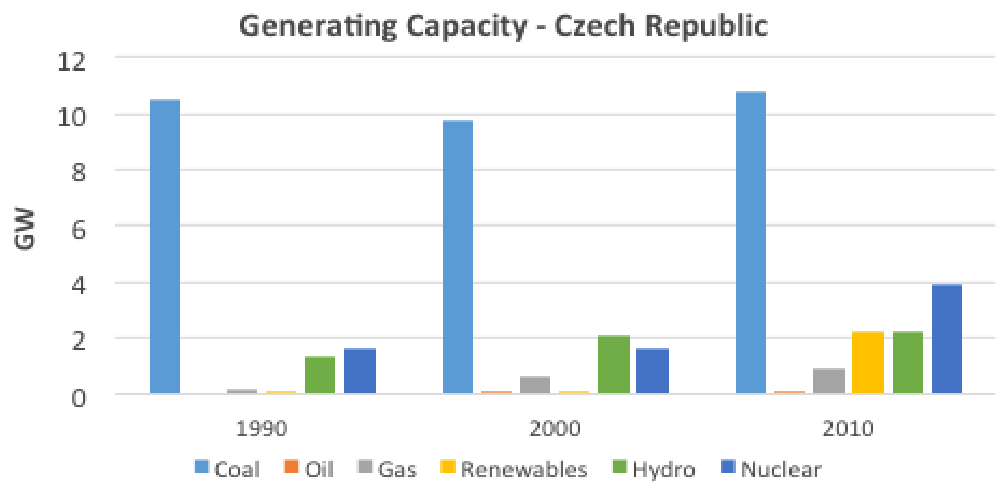


Figure 15 - Total Electricity Capacity – France (Source: EURELECTRIC, 2012b)

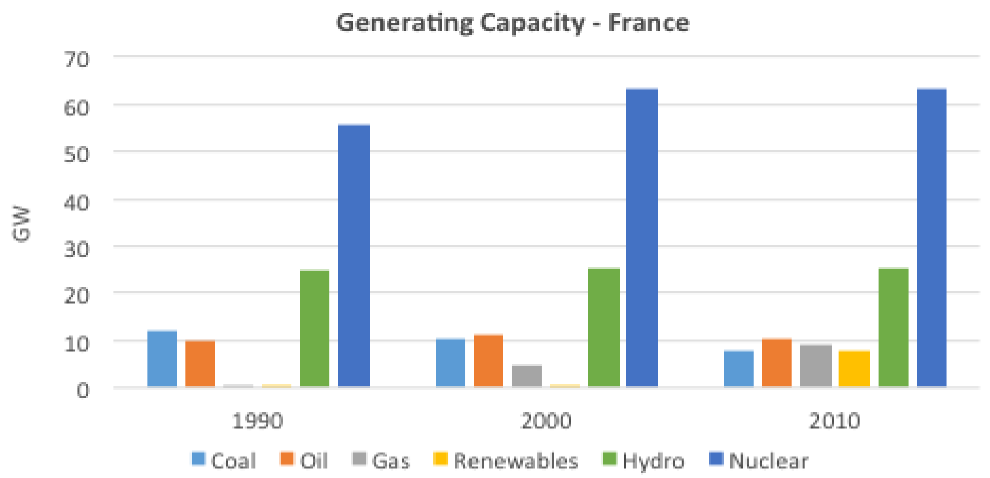


Figure 14 - Total Electricity Capacity - Germany (Source: EURELECTRIC, 2012b)

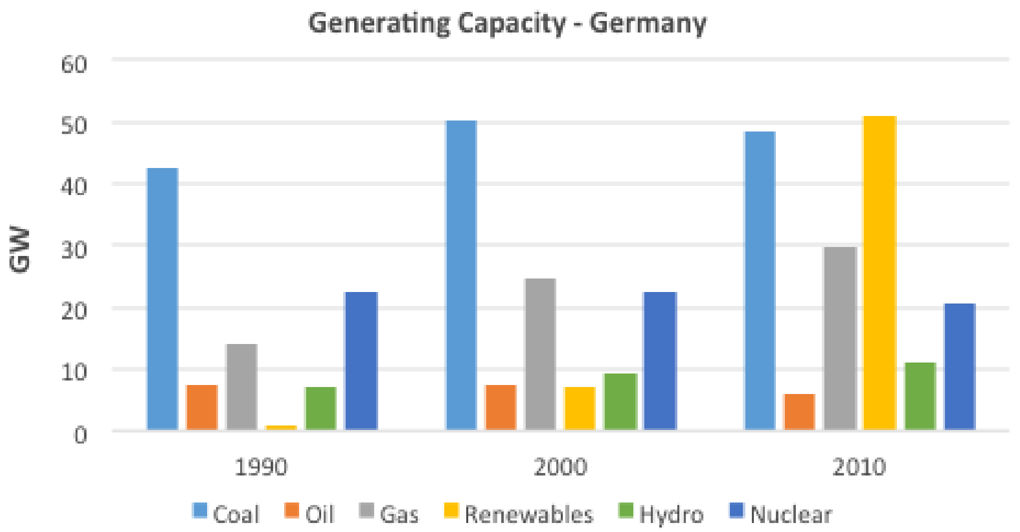


Figure 18 - Total Electricity Capacity - Netherlands (Source: EUELECTRIC, 2012b)

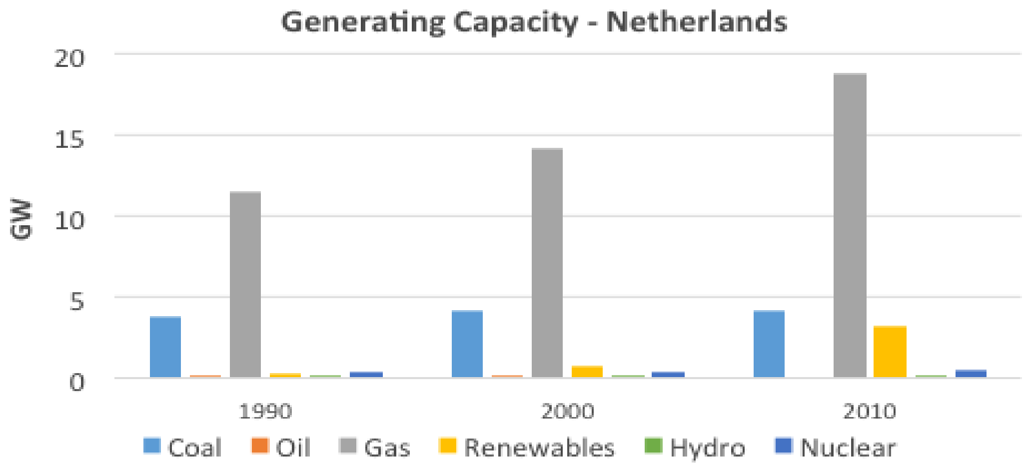


Figure 17 - Total Electricity Capacity – Poland (Source: EURELECTRIC, 2012b)

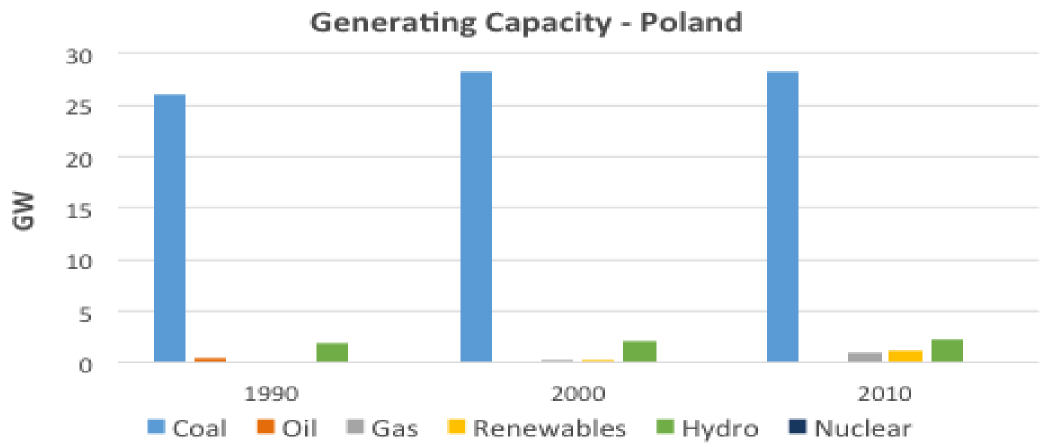


Figure 19 - Total Electricity Capacity - Spain (Source: EURELECTRIC, 2012b)

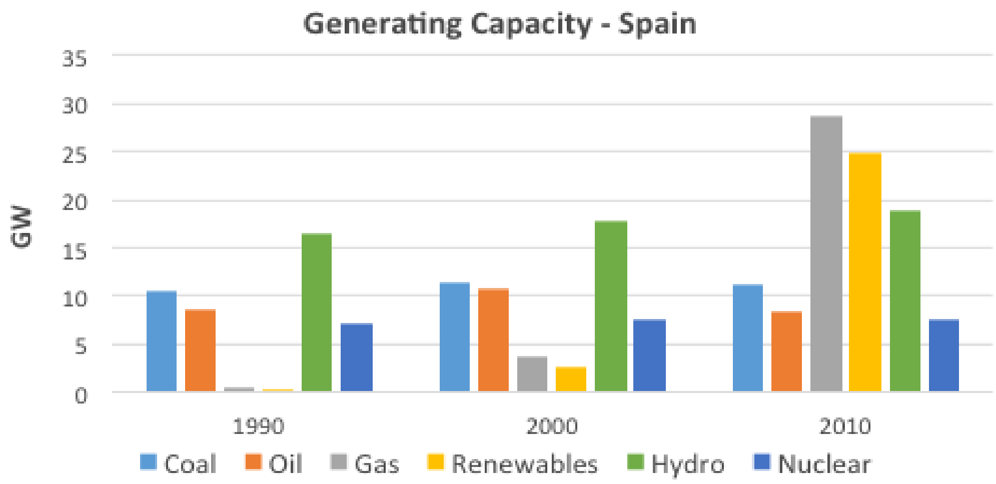
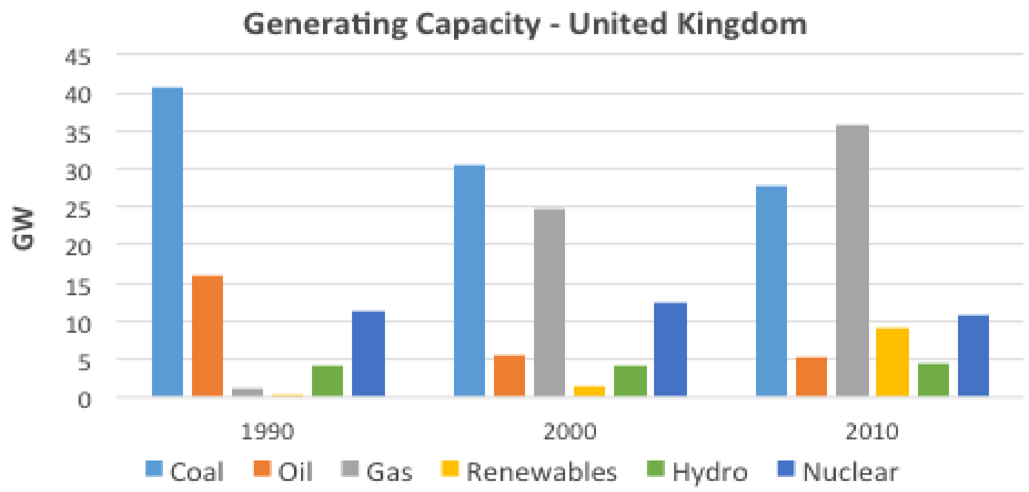


Figure 20 - Total Electricity Capacity - United Kingdom (Source: EURELECTRIC, 2012b)



Coal capacity remained remarkably static across these countries (with the exception of the UK), despite the significant reduction in generation from coal - capacity in Germany and Spain even increased. France, Germany and the UK all follow the EU-wide trend of maintaining some oil-fired capacity, whilst seeing oil generation decline to or maintained at near-negligible levels. Gas capacity in the UK and Spain in particular increased significantly since 1990 and 2000, respectively, facilitating the rapid increase in gas generation they experienced. The Netherlands also increased its gas capacity substantially in proportional terms, but did not experience a significant increase in generation to match. Once again, as with the overall EU trend, hydroelectric and nuclear capacity remains relatively static across these member states (where present).

Figure 21 - Renewable Generation Capacity by Source and Member State - 2010 (Source: EURELECTRIC, 2012b)

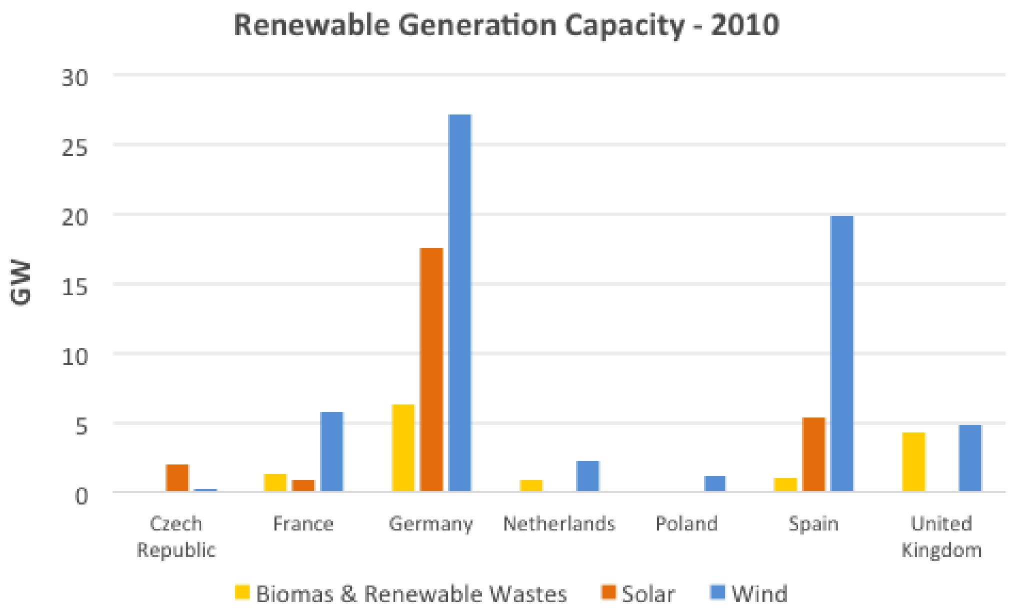


Figure 21 provides a breakdown of (non-hydro) renewable capacity in these member states in 2010. Again, tide, wave and ocean and geothermal are very minor, and as such do not appear in the figure. As would be expected, Germany and Spain hold the highest renewable capacities in wind and solar, and Germany holds the highest biomass & renewable waste generation capacity by 2010. As also might be expected from the above discussion, the proportional division between capacity and generation of these three technologies, for Germany in particular, do not match – with biomass generation providing a much higher proportion of generation than solar, in opposition to their respective capacities. Inter-country proportions of renewable generation appear approximately proportionate to capacity.

At both the EU and Member State level, it is reasonable to suggest the general capacity trends for most technologies continues into 2011, 2012 and 2013. The exceptions to this may be nuclear and gas. In 2011, in the wake of the Fukushima disaster in Japan in March 2011, the German government announced eight of the seventeen operational reactors would be immediately and permanently closed (or rather, not reopened after maintenance), with nuclear energy to be fully phased-out by 2022. As such, 8GW of German nuclear capacity was removed in 2011 (World Nuclear Association, 2013) – nearly halving from 2010 levels (Figure 15), and accounts for the rather significant drop in nuclear generation in Germany in 2011, as seen in Figure 6. The trend of rather rapidly increasing gas capacity is likely to have tapered significantly since 2010, for reasons discussed later in this paper.

2.3 CO_2 Intensity of the European Power Sector

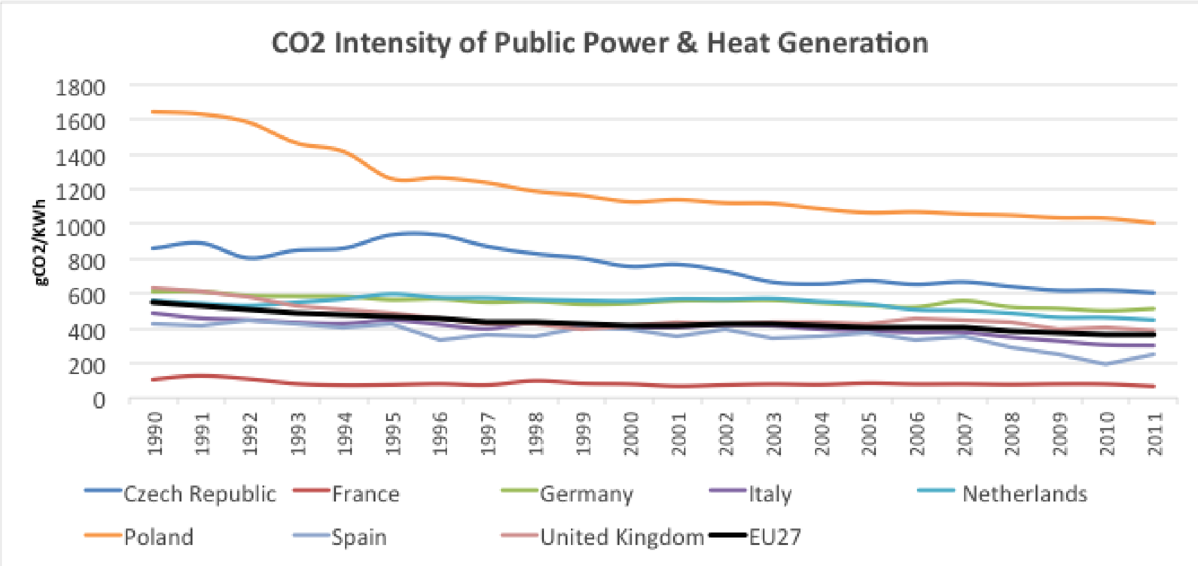
Figure 22 approximates the average CO_2 intensity of gross power generation[3] in the EU27 over time, along with values specific to the representative member states discussed. Emissions from the power sector are a function of both the generation mix and overall demand. Emission intensity is a useful indicator for determining changes over time, as it controls for the latter factor and allows underlying trends to be drawn out.

Most member states have seen a steady decrease in CO_2 intensity over the last two decades, with the EU27 average decreasing by a third, with the exception of Poland and the Czech Republic in the early 1990s. The individual member state profiles presented are reflective of their generation mix over time, as illustrated in Figure 4 to Figure 11. For example, France has a very low CO_2 intensity due to the prevalence of nuclear, whilst Poland has a very high CO_2 intensity due to the prevalence of coal generation. Change in generation efficiency is also important. For example, as the use of combined cycle gas turbines (CCGT) became default for new gas capacity in the early 1990s, overall efficiency of gas plants increased as older plants retired, producing significant impacts in countries with high gas generation.

[3] The emission data used in these calculations also consider public heat generation, but as the vast majority of emissions from these sectors are produced the electricity component, it may be considered indicative of power sector values and trends.

The increase in the use of coal in 2012 and 2013 has raised CO_2 intensity in many countries (with the possible exceptions of Poland and France, which are likely to have altered their generation profile little in 2012 and 2013), and the EU as a whole. However, this would have been at least partially offset by the continued increase in renewable generation. Additionally, such single-year changes are not necessarily indicative of a change in long-term trends.

Figure 22 - CO2 Intensity of Power Generation - EU27 (Source: European Environment Agency, 2013 and Eurostat)



2.4 Market Developments & Other Trends

Electricity Market Structure

The first substantial steps towards the creation of a single, EU-wide internal electricity market came in 1996 with Directive 96/92/EC. This Directive formed half of the '1st Package' of measures (the other half of which aimed to produce a single internal gas market). The package introduced the rules of operation of an internal energy market, with the objective of achieving energy security and supply competition. However, it became clear that an operating framework alone was insufficient to encourage such a market to develop. As such, the European Electricity Regulatory (Florence) Forum was established and first met in 1998, in order to monitor the implementation of Directive 96/92/EC, and to begin addressing barriers to integration (similar processes appeared in relation to the gas market). In addition, in 2002, the European Commission imposed a target of interconnector capacity in each member state to equal 10% of domestic generation capacity, by 2005. The 1996 Directive was replaced in 2003 by Directive 2003/54/EC (part of the '2nd Package' of measures), which contained additional provisions on the harmonisation of national regulatory frameworks and market liberalisation (e.g. 'unbundling' network activities from generation and supply activities, separation of generation and supply accounts, operation according to commercial principles, and non-discrimination between system users), and was complemented by Regulation 1228/2003, which focused on the development of networks and cross-border transmission.

However, it again became clear that significant barriers to the creation of a functioning and effective single internal market still remained, and were too complex to be approached directly at an EU-wide level (e.g. cross-border tariffs and congestion management) (Everis & Mercados, 2010). To overcome this issue, the 11th Florence Forum meeting in 2004 decided to establish seven 'mini-fora' – regional electricity markets centred on existing interconnections, in order to tackle specific regional issues. These were then superseded by the Electricity Regional Initiative (ERI) regions, which largely maintained the existing geographical groupings, listed in Table 2.

Table 2 - Electricity Regional Initiatives

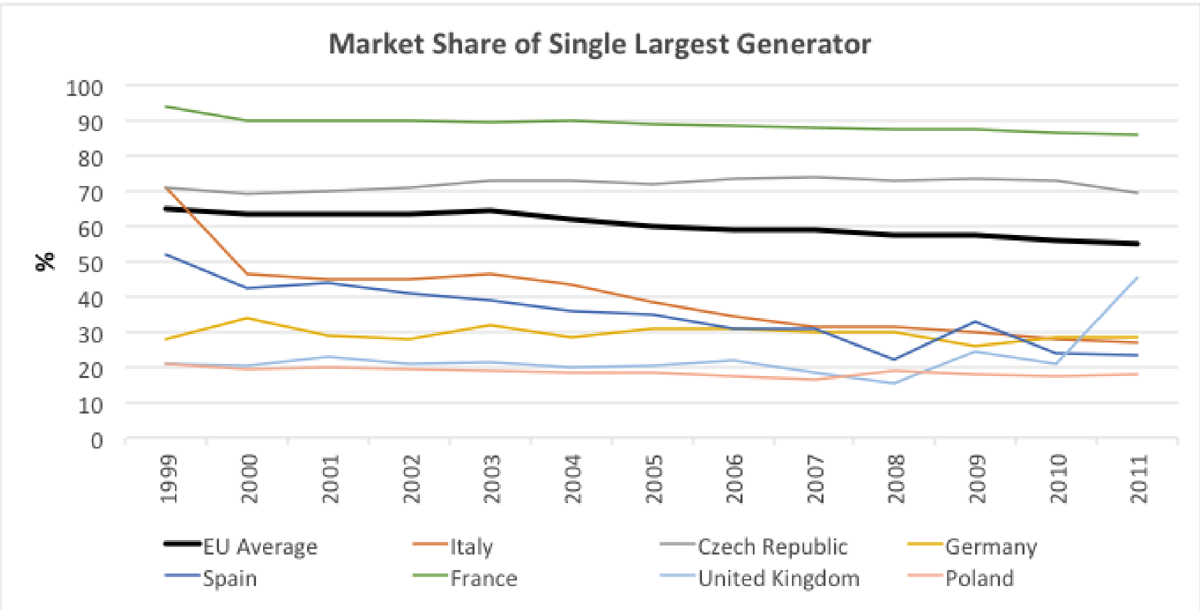
Electricity Regional Initiatives	Member State
Central-West	France Belgium Netherlands Luxembourg Germany
France-UK-Ireland	United Kingdom Ireland France
South-West	Spain Portugal France
Central-South	France Italy Greece Germany Austria Slovenia
Central-East	Germany Poland Czech Republic Slovak Republic Austria Hungary Slovenia
Baltic	Estonia Latvia Lithuania
Northern	Norway Denmark Sweden Finland Germany Poland

The ERIs were established as an interim step to a single internal market, through the involvement of key stakeholders (Member States, European Commission, grid operators, generators, etc.). Whilst most of these ERIs placed a priority upon increasing interconnector capacity, and whilst capacity had increased significantly, by 2010 nine member states had still failed to reach the 2005 interconnector capacity target. The Baltic states, Iberian Peninsula and the UK in particular remain largely isolated (European Commission, 2011).

Despite these problems, significant market liberalisation has been achieved. Almost all European countries once had state-owned electricity monopolies, of which many have now seen far-reaching privatisation, with a division between electricity generators and suppliers, and a freedom of choice for consumers (Aatola *et al*, 2013), spurring competition and generally reducing prices. Figure 23 illustrates the trend in the market share of the single largest generator as an EU average, and across the representative member states discussed[4].

As an EU average, the largest market share for a single firm has decreased from 65% to 55%, but with significant variation between member states (although the generally declining trend remains common). Of the countries selected, France remains the country with the highest market share accounted for by a single generator at 86% in 2011 (EDF), whilst Poland retains the lowest share at 17.8% (PGE).

Figure 23 - Market Share of Single Largest Generator (Source: Eurostat)



Again, significant issues remained in the implementation of the 2nd Package. Many network operators still displayed favour towards incumbent generators (effectively restricting competition), a lack of independence for national regulators remained (or even a lack of a

[4] Data for Netherlands, and pre-1999, are not available.

nominated regulator), and a lack of freedom of choice for consumers persisted (European Commission, 2007). This lead to the adoption of Directive 2009/72/EC, part of the '3rd Package', which introduces new and strengthens many exiting provisions to tackle these issues, and sets the aim of a fully functioning internal electricity market by 2014. Whilst the deadline for transposition was March 2011, by June 2011, no member states had yet notified the Commission of having done so (European Commission, 2011).

Domestic and Industrial Electricity Prices

A theoretical key benefit of electricity market liberalisation is the encouragement of competition and consequential reduction of prices. Figure 24 and Figure 25 illustrate changing electricity prices for domestic and industrial consumers in the EU over time, exclusive of taxes and other levies[5], (inclusive of transmission and distribution charges), as a proxy for changing regional wholesale market costs.

Both average EU domestic and industrial prices generally increased from 2003 to the end of 2012, particularly from around 2005 (although as these values are nominal, the gradient in real terms will be shallower). Both data series experience a peak, followed by a slight drop, before slowly recovering. For domestic prices, this pattern begins in 2008, and in 2009 for industrial prices. It is clear that there is some significant variation between member states for both price series, but with industrial prices appearing more volatile. Broadly speaking, there is little correlation between relative differences of domestic and industrial prices between member states, although French domestic and industrial consumers experience the lowest prices (pre-tax), with Spanish consumers experiencing well above average prices in both series (pre-tax). Whilst the trends show an increase in prices, the trend may have been steeper without liberalisation efforts.

[5] Prices are nominal, and do not consider inflation. For Figure 24, prices are for Band DA (consumption below 1,000KWh/year). For Figure 25, prices are for Band IA (consumption below 20MWh/year). Pre-2008 member state data is not presented due to a change in data collation and methodology. EU Average tracks only EU member states at the time (e.g. EU15 in 2003, EU25 in 2004-2007, and EU27 from 2008 onwards). 'a' and 'b' denote first and second halves of the calendar year.

Figure 24 - Domestic Electricity Prices (excl. Taxes and Levies) (Source: Eurostat)

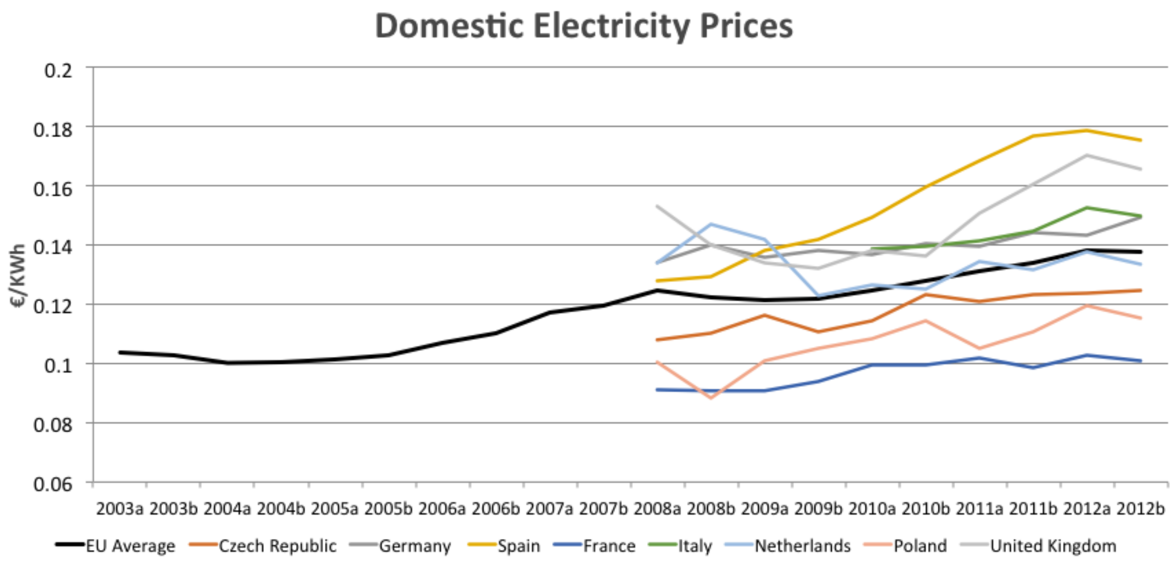
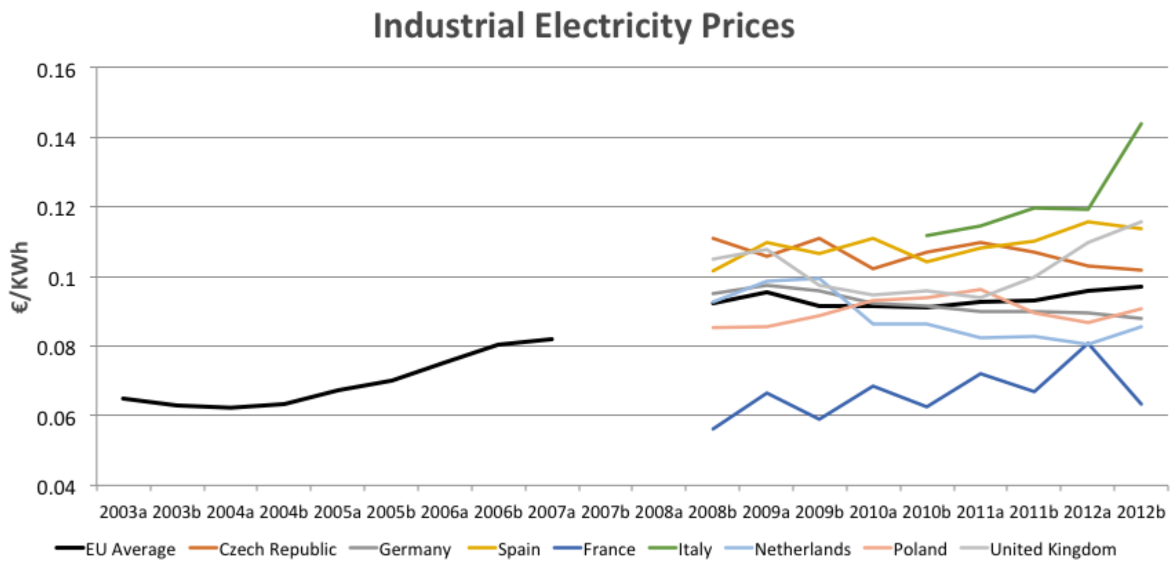


Figure 25 - Industrial Electricity Prices (excl. Taxes and Levies) (Source: Eurostat)

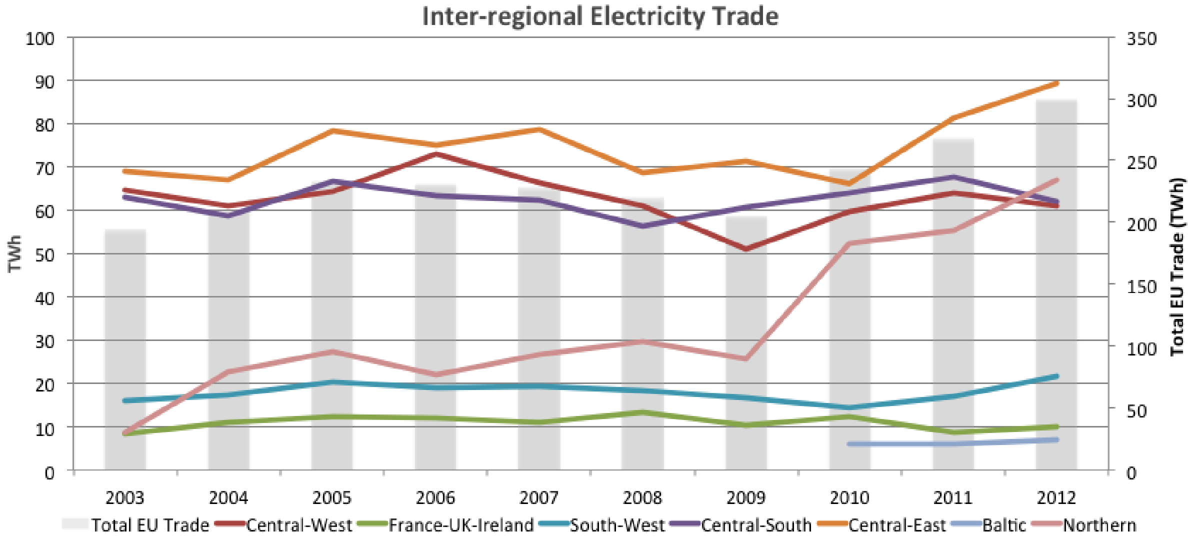


Electricity Trading

Although the slow construction of physical interconnector capacity is the largest barrier to the advancement of the single integrated market[6] (Aatola *et al*, 2013), significant capacity has nevertheless come online since efforts for a single electricity market began. Figure 26 illustrates changing electricity trade volumes within the European markets listed in Table 2**,** since 2003.

[6] As reflected in the persistent power price differences across countries, as seen in Figure 24 and Figure 25. In a fully-functional single market, convergence to a single price would be expected.

Figure 26 - Electricity Trade in the EU and Regional Markets (Source: ENTSO-E)



Overall electricity trade in the EU increased from 194TWh in 2003, to nearly 300TWh in 2012[7], with trade increasing to a peak in 2005, before declining to 2009 and subsequently rapidly increasing to 2012. There is a clear divide in trade volumes between the regions. The 'Central-East', 'Central-South' and Central-West' regions experience the highest trade, largely stemming from the presence of Germany in all three markets. The 'South-West', 'France-UK-Ireland' and 'Baltic' markets are relatively minor in comparison (particularly the latter), as may be expected from a continued lack of significant interconnector capacity, although the 'Nordic' market appears to experience a significant increase in trade volumes between 2009 and 2010 - overtaking all but the 'Central-East' region in total trade in 2012. A proportion of this increase (around 30%) is due to the addition of Finland to the data, with the remainder likely due in large part to low reservoir levels, stifling generation from hydroelectric installations across the region (a significant contributor to total generation), leading to cross-border trade to meet demand (Energy Markets Inspectorate, 2011).

[7] Cyprus and Malta are not included due to a lack of interconnection. Estonia, Ireland, Finland, Latvia, Lithuania are not included until 2010, due to a lack of data. Non-member state Norway is included as part of the 'Northern' power market.

3 The EU Emissions Trading System (EU ETS)

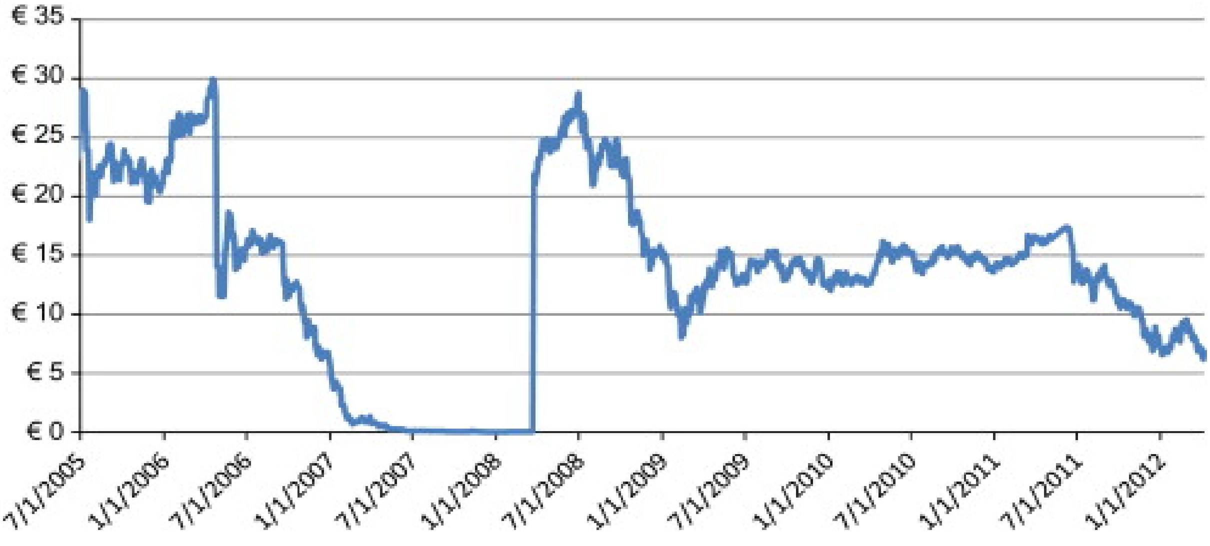
3.1 A Brief Introduction

The EU Emission Trading System (EU ETS) is the world's only large-scale, multi-country, multi-sector emissions cap-and-trade scheme, and has the objective of reducing emissions within the EU (plus Norway, Iceland and Lichtenstein) from upstream primary energy consumption (including electricity generation) and industrial processes - initially in order to achieve Kyoto Protocol targets. It currently covers around 50% of the EU's CO_2 emissions (40% of total GHGs), and was established in October 2003 by Directive 2003/87/EC, with effect from 1st January 2005. It is composed of three initial 'Phases':

- Phase 1 (2005 – 2007) – initial 'learning-by-doing' phase;
- Phase 2 (2008 – 2012) – revised monitoring and reporting rules, stricter emissions caps and additional combustion sources, aviation covered from 2012;
- Phase 3 (2013 to 2020) – Harmonised EU allocation methodologies, centralised CO_2 cap and additional GHGs and emission sources, and increased auctioning.

By capping and issuing emission permits (European Union Allowances (EUAs)), which are traded between obligated sectors and installations, an explicit carbon price is generated. This additional cost burden on emission-intensive processes and practices should encourage the uptake of abatement actions. It would be expected that the higher the carbon price, the stronger the signal to switch to low-carbon practices, determined by the shape and profile of the marginal abatement cost curve (MACC). Figure 27 illustrates the evolution of the EUA spot price from the beginning of the EU ETS in 2005, to mid-2012.

Figure 27 - Trend in EUA Price (Source: Venmans, 2012)



It is immediately clear there has been significant volatility in the EUA price since the beginning. In the first two Phases, all member states were required to submit a National

Allocation Plan (NAP), which determined the number of EUAs to be grandfathered (issued for free) to obligated installations. In Phase 1 and 2, only 5% and 10% of EUAs were permitted for auctioning, but only 0.13% and fewer than 3%, respectively, were (Ellerman, Convery & De Perthuis, 2010). In Phase 1, despite the Commission correcting 15 NAPs and reducing the originally proposed cap by 290MtCO_2/year (-4.6%), EUA availability exceeded total verified emissions in each year of the Phase. In April 2006, when the first verified emissions were published, the spot price collapsed from €29.20/tCO_2 on Monday 24th April, to a closing price of €13.35/tCO_2 on Friday 28th April. As the 'banking' of allowances between Phases 1 & 2 was not permitted, a further price collapse occurred, ending at €0.08/tCO2 by the end of Phase 1 in 2007 (Venmans, 2012). With the issue of oversupply removed at the start of Phase 2, demand for the new EUA vintage returned prices to €27/tCO_2 by July 2008. This dipped to below €10 at the beginning of February 2009 due to the global financial crisis, which reduced demand for ETS sector outputs (and consequential emissions). The price recovered and remained stable at around €15 between April 2010 and April 2011, before dipping to around €7/tCO2 in April 2012, in response to the European sovereign debt crisis (Venmans, 2012).

The price subsequently reduced to below €5, and has remained consistent at this level into Phase 3 (banking of allowances was permitted between Phases 2 & 3, preventing a repeat of near-zero prices experienced at the end of Phase 1). Phase 3 saw the introduction of National Implementation Measures in place of NAPs, which must follow a centralised allocation methodology. A key development is the requirement for full auctioning to the power sector (with some derogations), with other sectors receiving a mixed proportion of grandfathered and auctioned allowances based on a 'benchmarking' approach, which considers 'carbon leakage' and competitiveness issues. The Phase 3 cap decreases annually between 2013 and 2020 at a rate of 1.74% of the average annual EUA allocation in Phase 2. As such, the 2020 cap will be 21% lower than the 2005 cap – in line with the EU's Climate and Energy Package targets. Discussions continue regarding options for structural improvement of the EU ETS, aimed at reducing the building allowance surplus, and producing a higher and more stable carbon price.

Although emissions in the EU ETS sectors have remained below the cap and reduced over time (total verified emissions in 2012 were around 7.3% below 2005 levels (European Environment Agency, 2013)), it does not necessarily follow that this reduction is entirely attributable to the EU ETS. Laing *et al* (2013) summarised the literature attempting to understand the contribution of the ETS to emissions reductions against the counterfactual, and concluded that the EU ETS produced emission savings in Phase 1 of 120-300MtCO_2 (40-80MtCO_2/year), equal to 2-4% of total capped emissions in that Phase (little comparable literature has been produced for Phase 2, largely due to the lag in data publication).

3.2 Abatement of CO_2 Emissions in the Power Sector

The power sector accounts for over half of EU ETS emissions, and therefore plays a key role in producing abatement. Indeed, the perception that more low-cost abatement opportunities are available in the power sector (and the lack of exposure to international competition) lead many member states to place the burden of abatement entirely on this sector, by allocating fewer allowances to it relative to other sectors, and against projected counterfactual emissions. This is also part of the reasoning for the switch to full auctioning in Phase 3 for this sector (Jaraite & Di Maria, 2012).

Table 3 lists ex-post studies of emission abatement in the power sector, categorised by the assessment approach used (power system models, econometric regression analysis and hybrid models). It must be noted that whilst trend extrapolation (see Annex I for a brief discussion) is particularly popular methodology in assessing the impact of the EU ETS, no studies could be found in the literature using this approach specifically for the impact on the power sector.

Table 3 - Studies Estimating Abated CO_2 Emissions in the Power Sector

Model	Study
Econometric Models	Widerberg and Wråke (2009) McGuinness and Ellerman (2008)
Power System Models	Delarue *et al* (2008) Ellerman and Feilhauer (2008)
Hybrid Models	Schumacher *et al* (2012)

Econometric approaches have the advantage of being able to consider a significant number of variables, including fuel prices and weather conditions, and are able to calculate demand endogenously - although the extent to which some effects (such as instances of short-run fuel substitution) can be captured by these linear models, is unclear. Power system models are an advanced and reliable way to assess emission abatement in the power sector, as they consider a high level of technological detail. Typically, such models calculate the dispatch of the whole power plant fleet in response to demand, fuel and carbon prices. However, factors such as demand profiles must be calculated exogenously. Hybrid approaches combine econometric and power system approaches, with obvious benefits, but with compromises individual to the specific model. Table 4 describes the results of the studies in Table 3 that employ econometric and power system model approaches, whilst Table 5 describes the power sector abatement achieved according to the hybrid approach used by Schumacher *et al* (2012).

Table 4 – Estimated Emissions Abated by the EU ETS - Econometric and Power System Models

Study	Area	Abated Emissions[8] MtCO$_2$	%	Time Period	Approach
Delarue *et al* (2008)	Europe	35	2.3%	2005	Power System Model
		20	1.3%	2006	
	UK	16	7.5%	2005	
		8	3.7%	2006	
Ellerman and Feilhauer (2008)	Germany	8.3	2.1%	2005	Power System Model
		4.8	1.2%	2006	
		0.1	0%	2007	
McGuinness and Ellerman (2008)	UK	17	8%-12%	2005	Econometrics
		17	8%-12%	2006	
		0.9	0.4%	2007	
Widerberg and Wråke (2009)	Sweden	0	0	2004-8	Econometrics

Table 5 - Power Sector CO$_2$ Abatement in the Power Sector Against the Counterfactual - Estimated by Two Hybrid Approaches (Source: Schumacher *et al*, 2012)

Area	Year	Tier II	Tier III
Denmark	2005	9.5%	5.6%
Denmark	2010	5.3%	3.9%
Czech Republic	2005	10.0%	13.4%
Czech Republic	2010	8.0%	8.0%
Germany	2005	8.3%	4.9%
Germany	2010	6.4%	3.8%

Delarue *et al* (2008) estimate abatement in the EU-wide power sector due to the EU ETS in 2005 and 2006 at 35MtCO$_2$ and 20MtCO$_2$, respectively (around 2.3% of counterfactual emissions in 2005, and 1.3% in 2006). In 2005, this equals over 50% of the mid-value of the range for total annual EU ETS abatement in Phase 1 provided by Laing *et al* (2013), above. This estimate is achieved by using the 'E-simulate' power system model to represent electricity generation dispatch on an hourly basis at the power plant level, over an annual

[8] Except for McGuiness and Ellerman (2008) results, the percentage values are calculated by the authors of this paper as the reduction from approximate counterfactual emissions (actual verified emissions for all combustion installations (Source: European Environment Agency, 2013), plus abatement estimate). As such, values calculated are conservative and may only be considered as indicative.

cycle. The model is organised into a number of European 'zones', which may trade electricity. The estimate of abatement generated by the EU ETS by the model depends not only on the price of allowances, but also on the load level of the system and the ratio between natural gas and coal prices. This is likely to be a relatively robust estimate of abatement in the power sector at the EU level, but the authors expect the true value to be towards the upper end of the estimate, as the E-Simulate model does not capture effects such as reduced demand for electricity or improved power plant efficiency in response to a carbon price.

It is clear from the literature that abatement is likely to have occurred unevenly across member states. Ellerman and Feilhauer (2008) estimate cumulative abatement between 2005 and 2007 (Phase 1) in the German power sector to be between 13.2MtCO_2 and 56MtCO_2 – the lower of which is around 1% of total German counterfactual emission estimated for EU ETS sectors. The upper value derives from a 'top-down' approach using trend extrapolation on emission intensity of GDP (an upper bound estimate as it is assumed that other factors, such as fuel prices and renewable energy policy, remain the same – where in reality it is likely that some abatement may be attributed to changes to these factors, rather than the EU ETS), whilst the lower estimate also stems from the use of E-simulate to create a counterfactual. E-simulate also provides annual estimates of German power sector ETS abatement for Phase 1, as tabulated in Table 4 (although due to lack of data, the 2007 estimate is calculated via additional assumptions). As with Delarue *et al* (2008), Ellerman and Feilhauer (2008) estimate the highest attributable emissions abatement to be in 2005, decreasing significantly in 2006, and whilst the former study does not provide an estimate of 2007 ETS-attributable abatement, the latter estimates the impact of the ETS on German power sector emissions to be virtually non-existent (however, this estimate may not be considered as robust as the 2005 and 2006 results).

Schumacher *et al* (2012) also produced estimates for German power sector abatement attributable to the ETS (along with the Czech and Danish power sectors), for 2005 and 2010, using a hybrid model. The so-called 'Revised Tier 2' approach aims to compute the change in electricity demand against an increase in electricity prices as a result of the pass-through of ETS costs to the consumer. This change in demand is then converted into change in emissions by determining the specific marginal power plant called upon to cover the increase in demand in the counterfactual. The 'Revised Tier 3' approach builds on this by linking a macro-econometric model (E3ME), a dispatch model (PowerFlex) and power sector investment model (ELIAS). The 'Revised Tier 3' approach also isolates the impact of the EU-ETS by considering the impact of other key policy instruments (primarily the Renewable Electricity Directive, but also the CHP Directive). Due to the more comprehensive and calibrated methodology employed by the latter approach, the authors believe these results are likely to be more representative of reality. Similarly, the 'Revised Tier 3' results for

Germany are likely to be more representative than the author-calculated proportional abatement achieved, based on Ellerman and Feilhauer (2008), for reasons described.

McGuinness and Ellerman (2008) use an econometric approach to separate the impact of changes in relative fuel EUA prices on the utilisation and emissions of coal and natural gas plants in the UK. As Table 4 indicates, a central estimate of around 17 $MtCO_2$ of ETS-attributable abatement is estimated in both 2005 and 2006 (equal to between 8% and 12% of the calculated counterfactual), with under 1 $MtCO_2$ estimated for 2007. The authors provide confidence intervals of between 13.2 $MtCO_2$ and 21.2 $MTCO_2$ for 2005 and between 13.7 $MtCO_2$ and 20.7 $MtCO_2$ in 2006. For 2007 however, the confidence interval includes zero, which means no ETS-attributable abatement in 2007 is possible (with the upper estimate at 4.4 $MtCO_2$). McGuinness and Ellerman's (2008) estimate for 2005 abatement in the UK power sector is similar to Delarue *et al*'s (2008) estimate of 16 $MtCO_2$, although the latter study's estimate for 2006 abatement (8$MtCO_2$) is around half of that provided by the former. As discussed, this is likely to be a conservative estimate. However, the authors believe an estimate of 17 $MtCO_2$ abatement in the UK in 2006 resulting from the EU ETS alone is likely to be an optimistic estimate (regardless of the confidence intervals provided), with a true value expected to be lower than experienced in 2005. As such, it is likely the true value lies between 8 $MtCO_2$ and 17 $MtcO_2$. For context, verified EU ETS emissions in the UK were 243 $MtCO_2$, 251 $MTCO_2$ and 257 $MtCO_2$ for 2005, 2006 and 2007, respectively.

Widerberg and Wråke (2009) also take an econometric approach in order to assess changes in CO_2 intensity of the Swedish power sector between 2004 (pre-ETS) and 2008. Fossil fuel prices, biofuel prices and the status of hydropower reservoirs (significant in Sweden's electricity mix) are considered in setting the counterfactual and determining ETS-related emissions abatement. They found no statistically significant link between EUA price and changing CO_2 intensity of generation.

As with overall estimates of emissions abatement attributable to the EU ETS, few studies have thus far attempted to estimate power sector abatement since the end of Phase 1 (2007). The Phase 1 studies, however, produce a general consensus of abatement peaking in 2005, decreasing in 2006, before virtually ceasing in 2007. This is an expected result, which follows the evolution of the carbon price illustrated in Figure 27. As such, whilst the estimates for 2007 abatement presented less robust than 2005 and 2006 values, very little abatement is indeed likely to have occurred. The following section explores the mechanisms by which abatement is likely to have happened, and examines whether and to what level this is likely to have continued into Phases 2 and 3.

3.3 Impact of the EU ETS on the EU Power Sector Profile

3.3.1 Electricity Generation

Fuel Switching

It is clear from the studies discussed above (and the wider literature), that the primary contributor to power sector abatement attributable the EU ETS is via 'fuel switching', primarily from coal to natural gas. Available electricity generation capacity is brought online to meet demand based on short-run marginal costs of generation (merit-order). The EU ETS alters the relative cost of using different fuel types (the majority component of marginal generation costs), by adding a cost component that reflects the CO_2 emissions of different fuels when utilised. As natural gas has just over half the specific CO_2 potential per unit of electricity generated (KWh) than hard coal (and around a third that of lignite), the marginal generation cost of gas-fired plants become relatively lower (all else being equal – although gas-fired generation also has a higher thermal efficiency than coal), leading to a higher utilisation of gas-fired plant over coal, against the counterfactual.

Switching to renewable capacity does not occur, as the marginal costs of renewable generation, including hydropower (but except biomass and waste), are essentially zero, and thus capacity is brought online when available in almost all instances, regardless of the carbon price[9]. Nuclear plants also have low marginal generation costs and provide significant baseload generation when present, and thus generally have little spare capacity. In addition, they are not able to ramp quickly or flexibly to meet peaking demand.

In their EU-wide study, Delarue *et al* (2008) calculate that the EU ETS was responsible for an average of around 2% reduction in coal-fired generation in 2005 across the EU (around 20 TWh), and around 1% in 2006 (around 10 TWh) – replaced by gas-fired generation, producing approximately 90% of the attributable emissions savings cited in the previous section (with the remaining 10% accounted for by inter-state electricity trade, discussed below). However, as might be expected, this average masks significant variation across time (at various scales), and member states. The majority of abatement occurs in the summer months, during the weekend and overnight. This may be explained by the fact that fuel switching can only occur when there is spare capacity to switch to. In the winter months and during weekdays, electricity load peaks, leaving relatively little capacity unutilised. At times of lower demand (summer and weekends), there is idle capacity in the system, so there is a choice between either bringing coal or gas-fired generation online. This choice would then be taken based on the short-run marginal costs, which reflect fuel prices, the efficiency of the plant, and the carbon price. This effect at the seasonal resolution is highly pronounced

[9] Although, a clause of the Renewable Energy Directive also requires preferential grid access to RES-E generation over conventional. This is discussed later in this paper.

(in 2005 in particular), with substitution peaking at around 4% in July, but barely occurring between November and February. The daily differential is also marked, with rates of substitution at weekends almost double those on weekdays, on average.

Presence of gas-fired capacity is also a key explanatory variable for the spatial variation experienced (although, this is also heavily guided by the abatement potential in each member state). Delarue *et al* (2008) conclude that the majority of the fuel switching experienced (and therefore abatement) occurred in the UK, with Germany a distant second. This might be expected, as the UK has one of the most liberalised power markets in Europe (McGuiness and Ellerman, 2008). Whilst both states have large coal and gas capacity (see Figure 15 and Figure 19), around half of Germany's capacity is CHP, and therefore typically not readily available for switching[10].

Ellerman & Feilhauer (2008), Schumacher *et* al (2010) and McGuiness & Ellerman (2008) support this finding. Ellerman & Feilhauer (2008) note the same seasonal and daily trends at EU-level discussed above for 2005 and 2006, for Germany. When fuel switching occurs, it typically switches between 2% and 12% of counterfactual coal generation to natural gas (in 2005). Although a full year's worth of demand data was unavailable at the time of calculation, the authors assume very little to no fuel switching occurred in 2007. McGuiness & Ellerman (2008) state that their estimates of abatement in the UK are sourced entirely from coal to gas substitution driven by the EU ETS. They estimate that coal generation decreased between 16% and 18% against the counterfactual in 2005 and 2006, with natural gas increasing by 19% to 24% over the same period. In 2006, coal generation increased overall at the expense of gas to become the largest generating fuel in the UK (see Figure 11), which means that without the EU ETS, this increase would likely have been much more dramatic (although this was partially driven by other factors, discussed later).

Whilst Delarue *et al* (2008) conclude that fuel switching also occurred in France and Poland in 2005 and 2006 (and Italy in 2005), rates are significantly lower. 90% of electricity demand in France is satisfied by nuclear and hydropower (Figure 5), and thus leaves little coal generation to switch from. Poland's electricity demand on the other hand is satisfied almost entirely by coal (Figure 9), but has very little gas capacity to switch to (Figure 18). Similarly, Schumacher *et al* (2012) finds that no switching occurred in Denmark due to the high share of inflexible CHP plants (both coal and gas). The lack of a link between the carbon price and CO_2 intensity of electricity generation in Sweden, discussed above, is likely to be at least in part due to the high proportion of hydro and nuclear power, and the use of coal and gas in CHP generation units (Widerberg & Wråke, 2009).

[10] With CHP generation there is typically a local buyer that depends on the steady supply of heat produced (usually an industrial installation), and thus generation must continue even if the economics for the power produced would suggest the plant should be ramped down.

Schumacher *et al* (2012) also find that in the Czech Republic in 2005, fuel switching did occur at a rate of around 5%, but from lignite to slightly less CO_2-intensive hard coal, rather than from coal to gas. Such an effect was also observed in Germany in Phase 1 (alongside coal to gas switching) by Convery *et al* (2008). This study also finds evidence that the EU ETS may have influenced the increase use of biomass generation (co-fired with coal) in Germany and the UK. Kautto *et al* (2012) also support the finding that the EU ETS has a 'tangible' effect on biomass utilisation, but find it difficult to disaggregate the impact of the EU ETS from other policy instruments, and suggest it rather amplifies the effect of these alternative instruments.

Each of the studies discussed track the occurrence of fuel switching with the carbon price – i.e. relatively significant effects occur in 2005, with the effect reduced but remaining in 2006, with 2007 estimates (where available), producing little to no abatement or fuel switching[11]. Again, this is to be expected. However, whilst coal utilisation may have reduced in favour of gas against an estimated counterfactual, this does not indicate that coal use is reducing in favour of gas in absolute terms as an impact of the EU ETS. Delarue *et al* (2008) indicates that whilst the availability of gas capacity to switch to is an important component, the second, more important factor is the underlying market price of the fuel. In order for a 'switching point' to emerge, the marginal cost of generation differential between coal and gas must be lower than the carbon price as applied to each of these fuels, in order for the merit-order to change. Thus far, and as would be expected for some time to come, the ETS price is eclipsed by the underlying fuel price. Indeed, McGuiness & Ellerman (2008) estimate that an increase in the carbon price of €1 / tCO_2 leads to a decrease and increase in coal and gas utilisation of 0.8% and 0.9% respectively in the UK, whereas an increase of 0.1 in the ratio of relative cost of coal to gas is associated with a 5% and 6% decrease and increase in coal and gas utilisation, respectively. Delarue *et al* (2008) illustrate their point by summarising that whilst the relationship between the carbon price, fuel switching and abatement may be observed for any given hour, the relationship is lost when aggregated into days, weeks, months and years – showing that other confounding factors (namely load, indicating available gas capacity, and fuel prices), are at work.

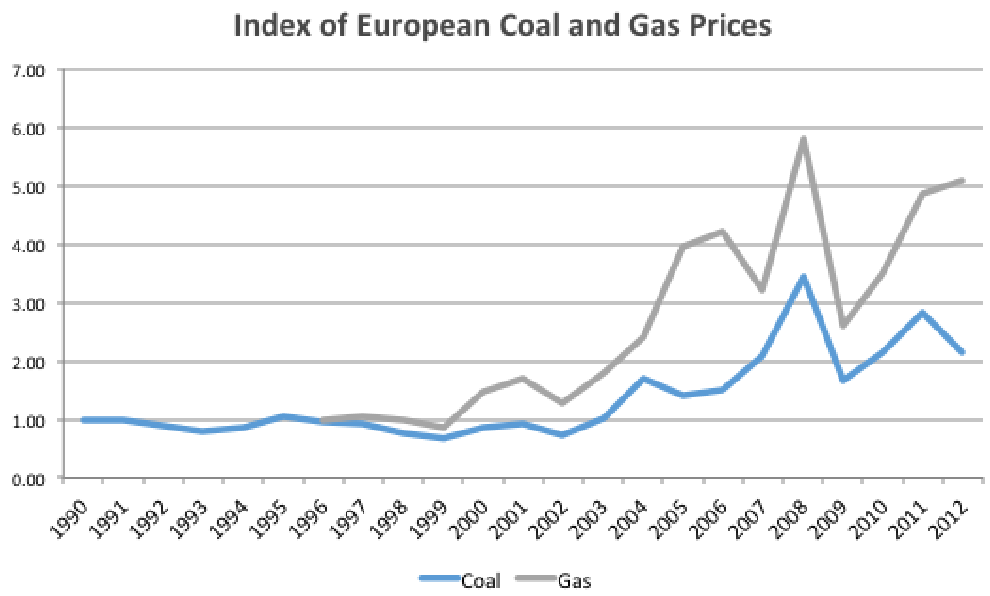
Figure 28 illustrates the change in coal and gas prices[12] from 1990 for coal and 1996 for gas. It is clear that the general trends are closely matched, with gas rising proportionally higher

[11] With many other abatement options (e.g. efficiency measures), the abatement effect remains once the measure has been taken – regardless of changes in the carbon price. Will fuel switching however, the abatement effect is transient.

[12] Coal data represents the change in the Northwest Europe marker price (hard coal). Prices from 1990-2000 are the average of the monthly marker, 2001-2012 are the average of weekly prices. Gas prices represent UK NBP prices. The nature of the European coal and gas markets means these prices are generally representative of EU-wide prices over time (with the exception of 2006, as explained in the text) – although gas prices across Europe generally vary more than the more integrated hard coal market.

over time, with some divergence in 2005 and 2006, before both peaking in 2008 due to robust global oil demand (especially from China and India). Oil prices heavily influence gas prices in Europe, and thus a parallel peak was experienced (Marvin, 2012). Prices subsequently dropped in tandem with decreasing demand into 2009 as a result of the global financial crisis, before recovering and experiencing a second divergence into 2012. The reduction in coal prices in 2012 is a result of plummeting coal demand in the U.S. (driven by domestic shale gas exploitation), increasing coal supply to the EU. Gas prices increased with decreasing European domestic production, and increasing reliance on imports (despite decreasing demand). These divergent trends continued into 2013, with coal prices declining to 2010 levels, whilst gas prices increased to roughly equal the 2008 peak (DG Energy, 2013).

Figure 28 - Index of European Coal and Gas Prices (Source: BP, 2013)



As the gas data illustrated in Figure 28 is based on UK prices, the 2006 value is likely to be higher than the European average for that year, as technical issues with a gas interconnector from Belgium restricted supply (producing the anomaly in the gas and coal generation trends seen in Figure 11). However, a small divergence in coal and gas prices was still generally experienced across the EU. All else being equal, it would be expected that a small increase in coal generation would have occurred as a result – in countries that have spare coal capacity to bring online. In fact, as seen in Figure 1, coal and gas generation generally flattened at the EU level, with carbon intensity of generation dipping (slightly) below the trend for 2005 and 2006 (Figure 22). It is therefore reasonable to suggest that the EU ETS in 2005 (in particular) and 2006, when the carbon price was relatively substantial, whilst broadly unable to achieve a reduction in coal generation, generally maintained pre-existing levels across the EU in a context which would otherwise is likely to have seen an (albeit modest) increase in coal utilisation. This 'dampening' effect would be expected to be most prominent in coal-intensive economies (within the limits of available spare gas capacity), with Figure 4, Figure 6 and Figure 9 for the Czech Republic, Germany and Poland, bearing this out.

With the carbon price dropping to near zero in 2007, it is indeed probable, as stated by other authors, that very little to no fuel switching occurred as a result of the EU ETS during this period. Few ex-post studies exist on this subject for 2008 onwards. Whilst this paper is not able to produce quantified estimates of continued fuel switching, it is again reasonable to suggest that some attributable switching occurred until 2011 for those countries that previously experienced this effect, when a reduced differential between coal and gas prices is likely to have remained within the range for a reduced carbon price to hold influence. It is unlikely, however, that the increased use of coal in 2012 and 2013 due to the even more significant price divergence was tempered to any extent by the even lower carbon price signal experienced over this time.

Despite a lack of evidence in the literature, it might be expected that some switching away from oil-based generation in Italy and Spain would have occurred as a result of the carbon price. Whilst this cannot be verified in this paper, it remains likely that as with other fossil fuel generation, other factors such as the oil price, pre-existing policy and legislation have played a much more significant role in oil-fired generation than the carbon price – evidenced by the pre-EU ETS decline (in Italy, in particular – Figure 7).

Electricity Prices and Other Impacts

In the production of any good, increases in production costs are expected to pass through to the prices paid by final consumers. Such common sense logic stands for the generation of electricity, and for the functioning of any economic instrument in environmental policy. However, there are a number of complicating factors in the pass-through of carbon costs. These relate to the degree of competition in the power market, the markets for fuels used as inputs to electricity generation, the objectives of generators (be it profit maximisation or any other long-term strategy), the elasticity of the demand curve and its shape, and the technology used by the marginal generator.

The wholesale power spot market price is determined by the marginal costs of the marginal generator[13]. This includes the impact of the EU ETS on the marginal producers. Leaving aside complications related to the technology used by the marginal producers, under perfect competition, and with a low price elasticity of demand (as is generally the case for

[13] The central feature of spot electricity markets is the matching procedure of supply bids from generators and demand bids from customers (end-use supply organisations). This procedure builds the supply and demand curve for power, the intersection of which defines the market price. As long as the generator receives the market clearing price and collusion or strategic bidding is prevented, the optimal bid for each generator is the marginal cost of generation.

electricity), the carbon cost pass-through (CCPT), defined here as the change in wholesale power price resulting from a change in CO_2 price, is expected to be (almost) 100% at all times, as firms have little ability to absorb the additional cost (Gulli & Chernyavs'ka, 2013). Under imperfect competition, CCPT can be higher or lower than 100%, depending on whether demand curve is linear or isoelastic (i.e. linear in logarithmic terms), as firms maximise profits either by increasing the pass-through rate (and absorbing reduced demand) or reducing pass-through rate (and absorb reduced margins). Table 6 provides a list of studies that have produced empirical results for CCPT rates on spot markets across various years and member states.

Table 6 - Carbon Cost Pass-Through Estimates in Member States (Source: Guilli & Chernyavs'ka, 2013)

Country	Study	Methodology	Period	Average	Peak	Off-Peak
Finland	Honkatukia *et al* (2008)	Econometric VEAC & AR-GARCH	2005-2006	0.5 - 1.0		
France	Solier and Jouvet (2011)	Econometric Autoregressive	2005-2006		0.17 - 1.75	0.65 - 1.05
	Solier and Jouvet (2011)	Econometric Autoregressive	2008-2010		-0.49 — 0.27	-0.46 - 0.21
Germany	Bunn and Fezzi (2008)	Econometric VEAC	2005-2006	0.52		
	Solier and Jouvet (2011)	Econometric Autoregressive	2005-2006			
	Solier and Jouvet (2011)	Econometric Autoregressive	2008-2010		-0.66 - 0.48	-1.29 – 0.15
Italy	Chernyavs’ka and Gulli (2008)	Load Duration Curve Approach	2006 (North)		1.5 – 2.1	0.8 – 1.3 (Midmerit) 0.9 – 1.1 (Very off-peak)
	Chernyavs’ka and Gulli (2008)	Load Duration Curve Approach	2006 (South)		-0.1 – 0.5	1.7 – 2.1 (Midmerit) 0.9 – 1.1 (Very off-peak)
	Chernyavs’ka and Gulli (2008)	Load Duration Curve Approach	2006 (Whole)		1.1 – 1.5	1.2 – 1.5 (Midmerit) 0.9 – 1.1 (Very off-peak)
	Solier and Jouvet (2011)	Econometric Autoregressive	2005-2006		-0.64 – 1.05	-3.56 - -0.03
	Solier and Jouvet (2011)	Econometric Autoregressive	2008-2010		-6.39 – 1.23	-5.43 – 1.01
Spain	Solier and Jouvet (2011)	Econometric Autoregressive	2005-2006		1.29 – 2.03	-0.18 – 0.67
	Solier and Jouvet (2011)	Econometric Autoregressive	2008-2010		-2.98 – 3.43	-0.76 – 4.24
Netherlands	Solier and Jouvet (2011)	Econometric Autoregressive	2005-2006		0.33 – 0.79	-0.30 – 0.99
	Solier and Jouvet (2011)	Econometric Autoregressive	2008-2010		-4.36 – 4.56	-0.74 – 0.53
United	Solier and Jouvet (2011)	Econometric Autoregressive	2005-2006		0.83 – 1.12	0.57 – 1.66

Kingdom	Solier and Jouvet (2011)	Econometric Autoregressive	2008-2010		2.83 – 3.69	-0.97 – 0.37
	Bunn and Fezzi (2008)	Econometric VEAC	2005-2006	0.3		

It is immediately clear from Table 6 that any estimates of CCPT rates vary significantly depending on the very specific conditions under which they are being assessed (e.g. peak and off-peak, and the exact structure of the market in the specific country under examination), but also the methodology employed to conduct the analysis. Estimates for CCPT rates on the spot market are extremely varied across member states and over time. Additionally, it is also clear that many studies produce different values for peak and off-peak hours, and such values may be negative or more than 100% CCPT. One study containing such variations, and the most comprehensive study considered, is by Solier and Jouvet (2011). This study assesses CCPT across a range of countries (France, Germany, Italy, Spain, Netherlands and the UK), and across Phases one and two. In a market with imperfect competition and high market power (which characterises all power markets in Europe and elsewhere, to different degrees[14]), CCPT rates higher or lower than 100% can be explained by the shape of the demand curve. Generators following a strategy different from profit maximisation – e.g. a profit target, consisting of a constant profit whilst minimising price volatility, can explain negative rates in imperfectly competitive markets. This is more likely to occur in peak hours if allowances are allocated for free – as they were in Phase 1 and mostly in Phase 2.

Profit targets may be pursued over simple maximisation for various reasons, including the achievement of a perceived ‘equitable’ profit margin, and the risk of regulatory intervention (such as price controls) (Guilli and Chernyavs’ka, 2013). Solier and Jouvet (2011) agree that negative rates depend on the level of free EUA allocation, but also the level of over-allocation, and estimate negative CCPT rates of up to -6.39 in Italy over peak hours, between 2008 and 2010. However, this study defines CCPT as a change in market spread (profit) due to the ETS. Such an approach may be suitable in markets for which prices are set based on average generation costs, and although in markets based on marginal costs a change profit in is linked, it is not the same as CCPT (Guilli & Chernyavs’ka, 2013). It is worth mentioning that some econometric studies, including Solier and Jouvet (2011), assume perfect competition, which is difficult to reconcile with the oligopolistic structure of most European markets. Bunn and Fezzi (2008) and Honkatukia *et al* (2008), which produce estimates of average CCPT in Germany and the UK and Finland respectively, are examples of the wider literature in which perfect competition is assumed, and thus also misrepresent the true nature of their objective markets.

Although these approaches are able to consider a significant number of variables such as fuel costs, temperature and generation capacity, they also assume that power prices are set by a single marginal technology (gas, for all studies considered here) with a generic profile, and do not consider the fact that the real marginal technology may change on an hourly basis (Guilli and Chernyavs’ka, 2013).

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[14] Market power consists of many components, of which market concentration is key. A crude indication of market concentration, and by extension market power, may be found in Figure 23, which illustrates the market share of the single largest generator as an average across the EU, and for each of the selected member states.

The non-econometric approach, as employed by Chernyavs'ka and Gulli (2008) for Italy, is able to consider a high time resolution along with the actual technological mix, available capacity in the market and market power; although this approach is unable, unlike an econometric approach, to provide precise CCPT values – just a range. The main finding of Guilli and Chernyavs'ka (2013) support the theoretical suggestion that market power reduces CCPT in peak hours, although this is not a common conclusion in the literature.

CCPT rates are only one factor determining the impact of the EU ETS on wholesale electricity prices, but the overall CO_2 intensity of generation, and therefore the total cost burden applied by the EU-ETS for a given CCPT, is a significantly more important component. Whilst both Figure 24 and Figure 25 indicate increasing end-consumer (retail) power prices at the introduction of the EU ETS in 2005, a direct causality to the EU ETS cannot necessarily be drawn. This is particularly the case considering that both figures indicate increasing power prices even after the carbon price crash in 2006-2008. As with fuel switching, other forces have significantly more influence over power prices than the EU ETS. The break in the EU-level power price trends in 2008, for example, is likely to have been a result of the global financial crisis and a resulting drop in power demand (which appears to have overwhelmed the influence of increasing coal and gas prices at the same time, as seen in Figure 28). Additionally, the economic crisis is also likely to have reduced the influence of the EU ETS further still, as a reduced power demand produces reduced emissions, further reducing the carbon price (as seen in Figure 27, after the initial spike in 2008 at the beginning of Phase 3).

Gulli (2013) suggests that the now lower carbon price also suffers from reduced pass-through. This is supported by Solier and Jouvet (2011), who produce more negative, and generally more wide-ranging CCPT results for the Phase 2 years of 2008-2010, than the Phase 1 years of 2005 and 2006. Such a difference cannot be explained directly by the model outputs, but must be interpreted using theoretical analysis. Negative values in Phase 1 are attributed to EUA oversupply, however this cannot explain the higher prevalence of such values in Phase 2 (Guilli and Chernyavs'ka, 2013). Gulli (2013) attribute this instead to the reduction in power demand, leading to reduced market power and, consequently, the prices at which generators are able to place bids.

As the CO_2 intensity of generation varies significantly across member states (Figure 22**)**, it would be expected that countries with higher CO_2 intensity (e.g. Poland) would see their prices rise significantly in comparison to countries with a low CO_2 intensity (e.g. France), at the same levels of CCPT (but not negative), and regardless of the carbon price (although the effect would be felt most keenly with higher carbon prices). Therefore, the EU ETS would be expected to exert an opposing force on price to that of an increasingly integrated electricity market (which would be expected to produce an increasingly convergent electricity price) (Aatola *et al*, 2013). As is clear from Figure 24 and Figure 25**,** any significant convergence is not yet happening. In fact, it appears as if prices are more divergent in 2012 than 2009 (although according to Aatola *et al* (2013), this is more convergent than the 2003-2008 period, due to increased interconnector capacity). It is possible that the EU ETS has had some influence on this, but the effect is likely to be minor, and again, considerably less influential than other factors such as changes in underlying fuel costs in respective member states. Another factor, however, is the presence of price controls in some member states – which may also place upper limits to CCPT rates. In 2010, nineteen member states continued to regulate domestic electricity prices (including France, Italy, Poland, Spain and the Netherlands), with sixteen maintaining controls for non-domestic prices (including France, Poland and the Netherlands). Whilst price controls themselves do not infringe the requirements of the *aquis*, when imposed they must be proportionate and limited in time (European Commission, 2011). Infringement proceedings are on going for a number of member states that remain in breach of these conditions. Weather conditions also play a role in determining power prices (particularly in countries with a high hydropower resource), and will be discussed later in this paper.

Despite the ability of free allocation to produce negative CCPT rates, any positive CCPT from a grandfathered permit represents 'windfall' profits for generators, as confirmed by several studies in the literature. Abrell *et al* (2012) estimate an overall positive impact on profits for firms in the electricity and heat sector in 2004-08, whilst Venmans (2012) concludes that Phase 1 windfall profits across the EU are likely to have €19-25 billion per year. Sijm *et al* (2006) estimated windfall profits in the Dutch power to be at least €300 million per year in 2005 and 2006. In addition, Koch and Bassen (2012), Oberndorfer (2009) and Veith et al (2009) analyse the share price of listed companies. These authors found that Investors understood that the EU ETS had thus far increased revenues of the European power sector through free allowance allocation in the first two Phases.

Electricity Trading

If the power price differential between member states has indeed increased as a result of the EU ETS, an increase in cross-border trade would be expected, with the flow increasing from countries with low CO_2-intenties to those with high CO_2-intensities, and vice-versa (conditional on the presence of physical transmission capacity and market power in respective trading partners (Aatola *et al*, 2013)). Delarue *et al* (2005), using the 'E-Simulate' model, found this to be the case, and estimate that around 10% of total EU-wide ETS-attributable emission reductions came through changes to electricity trade, against the counterfactual. The breakdown of estimated EU-ETS-induced trade and associated abatement presented by this study is reproduced below (Table 7):

Table 7 – Estimated Electricity Trade and Associated CO_2 Abatement Induced by the EU ETS (Source: Delarue *et al*, 2005)

Electricity Trade	2005		2006	
	TWh	$MtCO_2$	TWh	$MtCO_2$
France to Germany	3.98	1.86	1.64	0.75
France to Benelux	0.5	0.18	1.36	0.48
France to the UK	-0.23	-0.1	0.85	0.39
Germany to Benelux	-3.65	0.41	-2.12	0.22
Poland to Germany	-1.01	0.35	-1.07	0.38
Poland to Central Europe	-1.15	0.42	-0.67	0.24
Other (10 minor flows)		-0.1		-0.31
Total		3.00		2.15

The effect is particularly evident in the increase in French exports, and the decrease in German and Polish exports against the counterfactual. However, an ETS-attributable increase in trade from France to Germany of 3.98TWh and 1.64TWh in 2005 and 2006, respectively, accounts for nearly 25% and 10% of total trade between these countries in these years (both net and gross, as trade from Germany to France is relatively insignificant). As total trade in 2005 is only around 5% higher than 2004 trade volumes, it is likely that the values provided in Table 7 are overestimating the effect of the EU ETS on electricity trade.

Nevertheless, it remains likely that the EU ETS has had some impact, and bears at least some responsibility for the 2005 trading peak and subsequent decline in trade seen in Figure 26. However, it is unlikely, due to the low carbon price experienced since early 2009, that the EU ETS is a primary (or even significant) driver behind the subsequent rapid increase in trade since 2009.

3.3.2 Electricity Capacity

It is clear from the above section that the EU ETS is likely to have had at least some impact on the electricity generation profile in the EU. However, these impacts are short-term and not indicative of long-term, systemic effects. For this, attention must be paid to the influence of the EU ETS on generation capacity in the EU and member states. The EU ETS has the ability to influence power sector investments in reduced-CO_2 and CO_2-free generation capacity, but only if carbon prices are of a suitable level, and the resulting cost liabilities are integrated into investment plans. According to Hoffmann (2007), NEF (2009) and Rogge *et al* (2011), this final point was found to be the case for most companies in the European power sector (83% according to the latter study, including the 23 largest EU generators), and investment appraisal under a number of carbon price scenarios was found to be standard practice.

Fossil Fuel Plant Retrofitting

Before investment in new capacity is discussed, the potential influence of the EU ETS on existing capacity should be examined. Hoffman (2007) finds evidence that the EU ETS spurred efficiency retrofits (e.g. improved heat exchangers) in Phase 1 to selected existing fossil fuel plants in Germany (coal and gas). Whilst efficiency in absence of a carbon price remains beneficial, and the measures concerned are cheap with a quick payback period (typically 1-5 years), the introduction of additional cost tipped the balance for some measures to be cost-effective that previously were not. Efficiency retrofits also increase plant life expectancy, although one respondent in the study stated that retrofits are only carried out on plants with over two years remaining lifetime, in order to allow the cost to be recovered. Another driver to this, however, was the so-called '15% malus rule' in Germany, which stated that for plants below a given (fuel-specific) efficiency would receive 15% fewer free allowances from 2008 onwards. Although this rule was eliminated before it entered into force, the study finds it was a critical driver in retrofits, once the carbon price had reduced significantly in 2006 and 2007. Hagberg and Roth (2010) found that the probability of adopting carbon abatement technologies in the Swedish energy sector (not just power) in response to the EU ETS averaged at around 32% in Phase 1, although the results vary significantly between the different models used in the study. Additionally, a study by Jaraite & Di Maria (2012) computes changes in productivity of fossil fuel generation in the EU over Phase 1, using an index that considers (amongst other things), 'technological change', defined as an increase in the overall production frontier. They came to the conclusion that whilst the pricing of carbon via the EU ETS lead to a shift in the technological (production) frontier, generous permit allocation almost entirely removed this effect. They cite a perceived laxity of the policy by individual actors, or by firms trying to 'inflate' their emissions in an attempt to influence Phase 2 allocations, as potential reasons for this. Any technological change that remains is the product of increasing relative gas capacity and improved efficiency of individual plants, however the study is unable to disaggregate between these two components.

The literature provides little other evidence regarding retrofits, either at EU-level, in specific member states, or in Phase 2 onwards. In Phase 1, it appears that any influence the EU ETS had on retrofitting measures were relatively minor, likely due to a combination of a low carbon price in 2006 and 2007, over-allocation of permits in some member states, and free allocation. Again, the exact extent of the effect is likely to have varied by member state. As these actions are longer lasting than simple fuel switching, longer-term expectations of the carbon price and operation of the EU ETS is also likely to have had a significant influence. It was the expectation of stricter allocation rules in Phase 2 for Germany was 'critical' in investing in retrofits in 2006 and 2007 (Hoffman, 2007). The brief return of a carbon price above €20/tCO_2 at the start of Phase 2 is therefore unlikely to have spurred significant additional retrofit investment in most member states, which retained 100% free allocation. The following return to a low price, and the ability to bank surplus allowances from Phase 2 into Phase 3, thereby maintaining a low price for the foreseeable future (although preventing a repeat zero price), is likely to have produced relatively insignificant investments in retrofitted technologies for existing fossil fuel capacity.

New Fossil Fuel Capacity

A primary driver for deciding upon investment between different technologies for new capacity is the relative difference between the Levelised Costs of Electricity (LCOE).

Figure 29 - Levelised Cost of Electricity (Source: DECC, 2012) (Converted from Pound Sterling to Euro at a rate of 1.2)

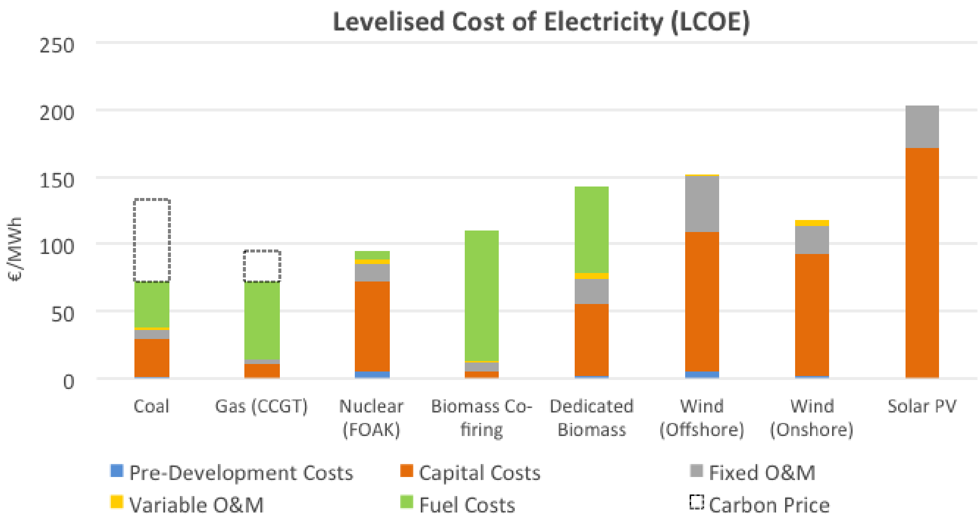

Figure 29 illustrates the LCOE (the average cost per unit of electricity generated across the lifetime of the installation), for the UK, for a project beginning in 2012 (DECC, 2012). LCOE includes the key components of capital costs, fixed and variable operation and maintenance (O&M) costs, and fuel costs (along with pre-development costs, and decommissioning and waste costs for nuclear – the latter of which is excluded from the above figure but are projected at €2/MWh (DECC, 2012)), across the lifetime of the plant or installation against expected total electrical output. Whilst these costs will vary over time and between member states, Figure 29 is generally representative of proportional contributions to LCOE and relative differences between technologies, as of 2012. As might be expected, coal and gas[15] hold the lowest LCOE (excluding carbon costs), with fuel costs a much larger proportion of total cost in gas-fired than coal-fired plants, (i.e. around 80%). As the marginal costs of gas are higher than that of coal in the absence of a (significant) carbon price (as seen in Figure 29), the competitive position of coal remains higher in power markets than Figure 29, which indicates an approximately equal life-cycle cost, might suggest.

[15] The coal values given are an average of Advanced Super Critical with Flue Gas Desulphurisation (ASC with FGD), and Integrated Gasification Combined Cycle (IGCC) plants. The gas values refer to Combined Cycle Gas Turbine (CCGT) plants.

The function of the EU ETS price, as discussed, is to place additional cost on generation based on relative emissions. Figure 29 indicates the effect of the projected carbon price over the lifespan of coal and gas projects beginning in 2012, based on UK government carbon price projections (£25 in 2020, £70 by 2030 and £200 by 2050 – with linear interpolation in between (DECC, 2009)). Whilst these levelised cost estimates are likely to have altered to some extent since the EU ETS began, and each individual investor and generator will have used their own projections of carbon price evolution, the data serves to illustrate the point that investment in gas-fired capacity is likely to appear more economic than coal in light of a significant carbon price. Between 2000 and 2010, whilst coal capacity slowly declined at EU level, gas capacity nearly doubled (95GW to 167GW). Although the carbon price is factored in to investment decisions, it does not necessarily follow that the EU ETS was the primary, or even a significant driver in this trend – especially considering that the carbon price thus far has largely not been significant.

Indeed, Schumacher *et al* (2012) found that the EU ETS did not have a significant effect on either the magnitude of investment in new fossil fuel capacity in Denmark, the Czech Republic or Germany between 2005 and 2010, or the type of fossil fuel capacity invested in. Ellerman *et al* (2010) concur, and find that planned investment in new coal capacity had not diminished since the introduction of the EU ETS. However, Pahle *et al* (2011) disagree, and in fact argue that the 'dash for coal' seen in Germany over the last decade, whilst not initiated by the EU ETS (rather, a combination of factors including the need to replaced closing nuclear and political support for coal), was spurred on and sustained by it. As with other member states, free allocation meant that higher-emitting plants received a higher share of free EUAs, generating windfall profits, and providing a perverse incentive to invest in coal rather than gas. Such an influence is likely to have occurred in other member states, although evidence is lacking in the literature. It would be reasonable to suggest, at least, that the intention to tip investment in favour of lower-emitting technologies as a result of the carbon price was dulled or even removed in Phase 1, by this effect. As such, it is likely that the EU ETS was at best insignificant, if not an obstacle for the expansion in gas capacity experienced between 2000 and 2010 (or more specifically, from 2005 and the introduction of the EU ETS). Although, it is not clear what the impact of the announcement in December 2008 that all EUAs to the power sector would be auctioned from Phase 3 might have had. It would be expected that the perverse incentive would be removed in anticipation of a 'real' carbon price and removal of windfall profits, however no empirical evidence for this could be found in the literature.

However, NRF (2009), whilst acknowledging the existence of this perverse incentive, find evidence of early retirement of some coal and lignite plants in the EU induced by the EU ETS, in the context of the Large Combustion Plant Directive (discussed in Section 6). Whilst in the absence of the EU ETS it may have been cost-effective to retrofit these plants in order to meet the requirements of this Directive, the carbon price rendered this uneconomic, and therefore closure was decided upon.

As capacity changes are primarily a function of changes in demand, or the need to replace closing capacity, the EU ETS may only exercise influence within these confines. Investors in new capacity must make projections on how the components of the LCOE value may change over the lifetime of the plant. This includes the carbon price, but also fuel costs – the latter of which (in addition to projections of electricity demand and price, and the incidence of other policy priorities and initiatives), is considered significantly more important in investment decisions than EU ETS liabilities (Rogge *et al*, 2011, NEF, 2009). Predictability of opportunities and liabilities is key to making efficient investment decisions (Egenhofer, 2007), and despite the certainty of the EU ETS emission cap until 2020, uncertainty regarding future prices and the specific design of future Phases (including allowance allocation methodologies), remain. These uncertainties are exacerbated by exogenous influences such as the rate of economic growth, which impacts demand. Fuel costs are also relatively uncertain, and as they form a larger liability overall, hold more influence in decision-making. Additionally, aspects such as resource availability (domestic, regional and international) are often assessed to provide further grounding for price projections, as was the case in increasing investments in coal capacity in Germany (Hoffman, 2007).

Fuel costs were certainly a reason behind rapid expansion of gas capacity (and generation) seen between 1990 and 2010 (Figure 12). However, power market liberalisation, the shorter lead-time afforded by gas plants over coal and (especially) nuclear, and the significant improvement in efficiencies bought by new CCGT technologies all contributed significantly to this development. Honore (2011) confirms that in Spain these factors, coupled with dramatic increases in electricity demand driven by rapid economic growth lead to the significant expansion of gas capacity, particularly between 2000 and 2010 (Figure 18) - accounting for around 35% of total EU gas capacity expansion during this time. In the case of the UK, which drove gas capacity expansion in Europe between 1990 and 2000 (46% of total gas expansion) (Figure 19), the development of North Sea domestic gas reserves played a considerable role.

Other Electricity Capacity and R&D Investment

Whilst the EU ETS doesn't directly influence generation from renewable electricity, at a high enough carbon price the LCOE values would alter in favour of investing in renewable capacity. It is clear that renewable capacity has indeed increased dramatically over the past few years, however the literature widely concludes that the carbon price generated by the EU ETS has not induced investment in renewable capacity in the EU[16] (Schmidt *et al* (2012), Hoffman (2007), European Commission (2013)). However, the incidence of biomass co-firing capacity was found by NEF (2009) to be 'clearly' positively impacted by the EU ETS, at least in the first Phase.

[16] Although Figure 29 suggests that offshore wind is now more economic than coal installations, the data assumes a rather robust carbon price evolution, which is unlikely to be shared by generator calculations. Additionally, the graph does not consider the effects of allocation methodologies, as discussed above.

Similarly to renewables, at a high enough carbon price additional nuclear capacity becomes economically attractive over fossil fuel investments (and as seen in Figure 29, often at a lower cost than other renewable options – although this might be open to contention). It is reasonable to suggest that the EU ETS has had minimal, if any influence over trends in nuclear capacity since its introduction (Figure 12 shows that nuclear capacity in fact declined slightly between 2000 and 2010, and declined further still to 2013). Non-economic factors exert significant, if not decisive influence over plans to construct new, or even decommission existing, nuclear capacity. Such factors are discussed further in Section 6.

As a desired impact of the EU ETS is to encourage the development of low (or at least, lower) emitting generation sources than the counterfactual, it might be expected that an anticipated additional future cost burden may lead to dynamic efficiency – innovation in existing and new technologies and behaviours in order to reduce future liabilities. To this end, Rogge and Hoffmann (2010) assessed the effect of the EU ETS on four 'building blocks' of innovation systems, namely 'knowledge and technologies', 'actors and networks', 'institutions' and 'demand' in the German power sector. The EU ETS was found to have positively influenced the innovation system of power generation technologies in Germany in several areas, most notably RD&D in CCS – a finding confirmed by NEF (2009) and Rogge et al (2011a), for the wider EU. However, a study by Abadie and Chamorroo (2008), on the basis of a real option framework concluded that up to 2007, electricity producers in Spain did not have a significant financial incentive to invest in CCS development. Hoffman (2007) also finds that the EU ETS has only been of very limited relevance for R&D decisions, with EU research programmes likely to be the largest driver (in Europe), pointing to the fact that most long-term CCS R&D programmes began pre-EU ETS. The authors are inclined to agree with the findings of the latter two studies, as CCS is not yet proven at commercial scale, and at current and projected EUA prices (and uncertainty surrounding the specific designs of future Phases), it is unlikely to act as a significant incentive to invest in CCS R&D – even with the removal of grandfathering to the power sector in Phase 3. Rogge *et al* (2011a) supports this position, and states that the expected CO_2 price level, the size of future markets and the scheme's predictability are of utmost importance for RD&D decisions.

The impact of the EU ETS on innovation has also been assessed through analysing objective measures such as patent counts, and more subjective metrics such as innovation scores. Calel and Dechezlepretre (2012) conclude that as a consequence of the EU ETS, obligated sectors (not just power sector) increased their low carbon patenting by 36%[17]. Martin et al (2012) concluded that most obligated firms (70%) engage in "clean process innovation" – defined as formal or informal R&D aimed at curbing emissions and/or energy consumption. A smaller

[17] Calel and Dechezlepretre (2012) employ a matched difference-in-difference framework to assess the difference between the pre and -post introduction behaviour of firms across EU ETS sectors. The authors' match EU ETS firms to non-EU ETS firms on the basis of turnover, country and sector the firms belong to.

proportion (40%) is also pursuing “clean product innovation”; i.e. R&D aimed at developing products that can help customers to reduce their emissions[18]. However, it is not clear from these studies to what extent these studies are representative of the power sector. It is likely, as concluded above, that much of the patenting and innovation activities relate to the non-power EU ETS sectors.

[18] Martin et al (2012) use a score assigned by the researchers to each of about 800 firms though structured interviews.

4 The Renewable Electricity and Renewable Energy Directives

4.1 A Brief Introduction

Renewable Electricity Directive (2001/77/EC)

Directive 2001/77/EC on the promotion of electricity from renewable energy sources in the internal electricity market (Renewable Electricity Directive, or RES-E Directive hereafter), aimed to increase the penetration of renewables[19] in the EU's electricity mix to an indicative target of 21% of gross electricity consumption by 2010 (reduced from 22.1% with the 2004 EU enlargement), rising from 12% in 1997, in order to contribute towards the achievement of Kyoto Protocol targets and support energy security (Ecofys, 2012). This EU-wide target was to be achieved through indicative targets at a member state level (ranging from 6% renewable electricity in Belgium, to 78.1% in Austria). Member states were required to adopt and publish a report every five years, detailing annual targets for the subsequent ten years, taking account of these indicative national targets set out by the Directive, along with the measures that have or will be taken to achieve them.

By 2010, electricity from renewables accounted for only 19.9% of EU gross consumption, missing the 21% objective (Ecofys, 2012). Fifteen member states failed to achieve their targets (European Commission, 2013). A primary explanation for this was the presence of 'indicative' rather than 'binding' targets, at Community and member state level. Whilst the Commission was able to apply infringement penalties on member states when published targets were set below indicative levels set in the Directive without explanation, or member states failed to take 'appropriate steps' to achieve them, penalties were not applicable to member states that simply failed to reach their non-binding targets (Johnston, 2010).

Renewable Energy Directive (2009/28/EC)

The failure to meet the 2010 target, coupled with the increased level of ambition reflected by the 2008 EU Climate and Energy Package (the '20-20-20' targets), led the Commission to formulate Directive 2009/28/EC on the promotion of the use of energy from renewable sources (Renewable Energy Directive, or 'RED' hereafter), which replaced the RES-E Directive. The RED aims to achieve a share of 20% of EU gross final energy consumption from renewables (extended from just electricity) by 2020, delivered via legally binding member state level targets, tabulated below (Table 8).

[19] Renewable energy sources (RES) considered by the Directive are: wind power (onshore and offshore), solar power (PV and solar thermal electricity), geothermal power, hydropower, wave power, tidal power, biomass and biogas (landfill and sewage gas).

Table 8 - Renewable Energy Directive - Member State Targets (Source: Directive 2009/28/EC)

Member State	Share of Renewable Resources in Gross Final Energy Consumption, in 2005	Target Share of Renewable Resources in Gross Final Energy Consumption, in 2020
Austria	23.3%	34%
Belgium	2.2%	13%
Bulgaria	9.4%	16%
Czech Republic	6.1%	13%
Denmark	17%	30%
Germany	5.8%	18%
Estonia	18%	25%
Ireland	3.1%	16%
Greece	6.9%	18%
Spain	8.7%	20%
France	10.3%	23%
Italy	5.2%	17%
Cyprus	2.9%	13%
Latvia	32.6%	40%
Lithuania	15%	23%
Luxembourg	0.9%	11%
Hungary	4.3%	13%
Malta	0%	10%
Netherlands	2.4%	14%
Poland	7.2%	15%
Portugal	20.5%	31%
Romania	17.8%	24%
Slovenia	16%	25%
Slovak Republic	6.7%	14%
Finland	28.5%	38%
Sweden	39.8%	49%
United Kingdom	1.3%	15%

Each member state must follow an indicative trajectory for renewable penetration to meet their 2020 targets[20], which also includes a sub-target of 10% renewable energy in surface transport by 2020, as an average across all modes, applicable to all member states. Member states are required to adopt National Renewable Energy Action Plans (NRAPs) detailing existing and planned renewable support mechanisms employed to comply with these targets, alongside indicative targets for the electricity sector, amongst others. NRAPs must also include details of implementation of other key provisions of the RED. These provisions include ‘enabling initiatives’, such as the development of transmission and grid infrastructure, intelligent networks and storage facilities (including member state interconnections), guaranteed access to the grid for renewable installations (and priority dispatch for these installations), and the removal of administrative barriers to renewable development (e.g. planning processes).

[20] This trajectory implies that by 2011-12, member states should be 20% of the way towards their individual target (compared to 2005); by 2013-14 30%; by 2015-2016 45% and by 2017-18 65%. RES-E should provide about 35% of the EU’s power by 2020 (European Wind Energy Association, 2012).

4.2 The Impact of the RES-E Directive and RED on the Profile of the EU Power Sector

4.2.1 Implementation by Member States

Each member state has an individual approach to supporting the development of renewable electricity (and wider energy, outside the focus of this paper), tailored to individual circumstances and other national priorities, such as employment and regional development. The main support mechanisms employed are (European Commission, 2008):

- **Quota Obligations** – Governments impose an obligation on consumers, suppliers or generators to source or generate a certain proportion of their electricity from renewables. This is usually facilitated by tradable 'green certificates', which are issued for units of renewable generation, and may be traded between obligated entities (creating a market value), to meet and demonstrate compliance with quota levels.
- **Tendering** – Governments announce a tender for the provision of a certain amount of electricity from a given technology, and competitive bids are submitted by generators or suppliers to provide this.
- **Feed-in Tariffs (FiTs)** – Government-regulated, often technology-specific tariffs paid to generators per unit of renewable electricity generated and exported to the grid. Broadly speaking, the objective is to set tariffs at the differential between the average LCOE of conventional generation and the renewable technology concerned (see Figure 29), to equalise investment incentives. In order to achieve this, tariffs are usually guaranteed for 10-20 years.
- **Premium Tariffs** – Premiums tariffs are bonuses paid to renewable generators on top of the electricity market price. Premium tariffs, differently to feed-in tariffs, allow electricity demand to be reflected in remuneration, and part of the market risk to be borne by RES-E generators.
- **Subsidies and Loans** – Finance to overcome barriers of high initial capital costs, often differentiated by technology, installation size and type of applicant. Loans are often long-term and low-interest.
- **Fiscal Incentives** – Usually tax exemptions or reductions applied to the activities of a renewable electricity generator.

Table 9 - Renewable Electricity Support Mechanisms Across Member States (Source: RES Legal, 2013)

Member State	Quota Obligation	Tendering	FITs	Premiums	Subsidies/ Loans	Fiscal Incentives
Austria						
Belgium						
Bulgaria						
Czech Republic						
Denmark						
Germany						
Estonia						

Ireland						
Greece						
Spain						
France						
Italy						
Cyprus						
Latvia						
Lithuania						
Luxembourg						
Hungary						
Malta						
Netherlands						
Poland						
Portugal						
Romania						
Slovenia						
Slovak Republic						
Finland						
Sweden						
United Kingdom						

Table 9, above, highlights the instruments active in member states, at the time of writing. Latvia currently has no active support mechanism for new renewable electricity capacity – the existing feed-in tariff is closed to new entrants until 2016, and is undergoing revisions (RES Legal, 2013). It is clear that the most common approaches are FiTs and subsidies/loans for renewable installations – often in combination (with FiTs as the primary instrument). Due to different resource potentials and technology costs, combinations of approaches are often employed to encourage development of the full range of technologies (European Commission, 2008). For example, the UK (broadly speaking), uses a quota system to encourage large-scale investments (>5 MW) in all RES-E technologies, and FiTs to encourage smaller installations (<5 MW). Loans are available to cover capital costs of domestic installations (under the 'Green Deal'), and renewable electricity is exempt from a tax on electricity consumption (Climate Change Levy).

In 2000, no member state had more than one 'major' RES-E policy instrument in place, with few supplementary policies. By 2011, the average number of RES-E support instruments across member states was three (Kitzing *et al*, 2012). Although Table 9 represents support measures active at the end of 2013, and whilst many member states have altered as well as added to the instruments employed over time (e.g. Denmark has previously used both tendering and FiTs), many member states rather alter the details of existing measures to improve performance and react to developments in the market (e.g. reducing capital costs), and have done so frequently since their introduction.

4.2.2 Impact on Renewable Electricity Generation and Capacity

As discussed, RES-E capacity and generation has increased dramatically since 1990, and especially since 2000. An approach taken by both the general literature and official assessments by the European Commission is to attribute this growth (from 2001, at least), entirely to national RES-E support mechanisms and enabling initiatives, which are assumed to have been solely introduced to satisfy the RES-E and Renewable Energy Directives. Whilst the first connection is reasonable (increasing RES-E capacity and generation is a result of national support measures of some form), it is perhaps disingenuous to assume all support measures and initiatives in the EU, and therefore all additional RES-E installations, are a result of these two Directives. Whilst the majority of measures may be reasonably associated, each of the EU15 in 2000 already had some form of support measures or initiatives in place (although only ten had 'major' support instruments) (Kitzing *et al*, 2012), driven by their own national (rather than the supranational EU) agenda. It also cannot be known if other member states may have followed suit, irrespective of EU-level initiatives. Other economic instruments and policy and political objectives, at both national and EU level, which do not have RES-E promotion as a direct objective, may have also played a role and are discussed in Section 6. However, this section will continue with the generally reasonable assumption that the majority of installations across the EU since 2000 are a direct result of measures introduced or strengthened by these Directives (via national measures).

Support Mechanisms

Although the variety of support mechanisms currently selected by each member state is relatively limited, the detailed design of these instruments varies significantly. As such, the impacts of individual measures have been highly divergent. Wind capacity, which has seen the largest growth in absolute terms since 2000, has 22 member states currently providing support - primarily through feed-in tariffs (RES Legal, 2013). FiTs are commonly cited by the literature as the most effective support mechanism for RES-E development, primarily because they provide long-term financial certainty upon which investment decisions may be taken (Butler and Neuhoff, 2008). As illustrated in Figure 21, Germany accounted for around 35% of total installed wind power capacity in the EU in 2010, and around 25% of total wind power generation. Spain accounted for 25% of wind power capacity in 2010, and 30% of generation. Both Germany and Spain use FiTs as their main support mechanism for wind power, and are often cited as best-practice examples for FiT implementation. As may be implied, non-best practice implementation would likely lead to a lower deployment of a given technology. For example, the Austrian FiT scheme appears to set rates too low to stimulate even minor additional deployment of onshore wind, and budget limitations have meant any investors that still wish to invest have remained on a waiting list (Ragwitz *et al*, 2012). Indeed, it appears stability (e.g. tariff levels, budget, and access criteria) is a critical factor in effectiveness of support mechanisms, regardless of type ((European Commission (2009), del Rio and Tarancon (2012)).

France, which accounted for 7% of total EU wind capacity in 2010, also employs FiTs as its key instrument in supporting investment. The UK however, which accounted for 6% of capacity in 2010, uses a quota obligation. The literature generally concludes that this policy instrument is not as effective as a FiT, as it inherently presents a higher risk to investors (Butler and Neuhoff (2008), Alishahi *et al* (2012)).

However, numerous other factors influence the growth of wind (and wider RES-E) capacity. The available wind resource, for example, is clearly a key driver or limitation for the development of wind capacity, regardless of the support mechanism. The Czech Republic and the Netherlands, for example, have among the lowest wind resource in Europe (although the latter has a relatively high installed wind capacity), whilst Germany, Spain, the UK and France hold amongst the highest resource potentials (European Environment Agency, 2009). An apparent characteristic of well-designed FiT appears to be the inclusion of a 'stepped' tariff, in which the level of the tariff offered depends on the specific resource condition of the individual installation. In Germany, this is based on a 'reference yield', defined as the output over five years of an installation from a 'reference wind turbine', which is located at a site with an altitude of thirty meters and a wind speed of 5.5m/s. if a turbine produces at least 150% of this reference yield in the first five years of operation, the tariff level is reduced for the remaining fifteen years of support. However, for every 0.75% below the reference yield achieved in the first five years, the higher starting tariff will continue for additional an additional two months. As such, the development of wind power is encouraged in sites with less than optimal conditions (Ragwitz *et al*, 2012). Stepped tariffs for wind power also occur in the Netherlands, Portugal, Denmark and France. Such an approach helps in a fuller exploitation of the available resource, and when used in a member state with a high potential, significant deployment may be expected (in absence of other barriers)[21]. Alongside Germany, this may be a partial explanation for the relatively strong growth of wind in France, and the high deployment in Netherlands in the face of a low wind resource. Whilst other factors affecting wind and wider RES-E deployment will be discussed later in this paper, it is important to note that the RES-E Directive only became applicable to Poland and the Czech Republic upon accession to the EU in 2004. This is likely a key reason for these states exhibiting the lowest RES-E capacity amongst the member states selected and discussed.

Solar capacity, which experienced the second largest absolute growth for a RES-E technology between 2000 and 2010, receives support from all member states, again primarily via FiTs (except Latvia, for new installations). Once again, Germany and Spain account for the largest proportions of installed capacity and generation in the EU, at over 17 GW capacity (66% of the EU total), and 5 GW (20% of the total), respectively. Once again, the design of the FiT in these two countries is largely responsible for this growth. The introduction of FiTs in Italy, France, Czech Republic and the UK, along with Portugal and Slovenia have all led to a strong stimulation of previously insignificant markets for solar PV (Ragwitz *et al*, 2012).

[21] However, such an approach is less efficient, as overall costs increase. The most efficient approach would be to encourage development in the most appropriate sites only, but this in turn reduces deployment, and thus efficacy of the instrument.

Electricity capacity from biomass and renewable wastes, which saw the third largest growth, also hold FiTs as the main support instrument across member states. However, only 60% of electricity generated from solid biomass in 2010 was produced in countries where FiTs are primary RES-E support mechanism (including Germany) – a low value compared to other technologies (EurObserv'ER, 2011). As with wind, the UK primarily uses a quota obligation system to encourage power from biomass, which has shown to be equally as successful as FiTs in this context, as the high share of fuel costs in total generation renders the investment security provided by FiTs less relevant (Ragwitz *et al*, 2012).

Generation and capacity for hydropower, geothermal and tidal and wave have remained relatively stable from 1990 to the present day (and stable in insignificance for the latter two technologies) for a variety of reasons including resource availability (e.g. not all member states have suitable coastlines, or sit above suitable geothermal resource), cost uncertainties and other barriers, of the kind discussed below. Indeed, whilst resource availability and potential, along with the level of support provided by a support mechanism are significant drivers or barriers to different types of RES-E development, the specific design of a support mechanism, along with the regulatory, economic and political environment within which it operates, is often more important (del Rio and Tarancon, 2012).

Enabling Initiatives

Analysis of member states' most recent progress report on RED implementation produces the conclusion that progress in removing barriers to RES-E deployment is limited and slow, with many member states failing to address this aspect in the progress reports entirely (European Commission, 2013).

- *Administrative Procedures*

Concerns regarding administrative procedures particularly surround the slow progress in introducing and processing online applications to access support schemes, administrative time limits for planning and permitting decisions, and the lack of transparent approval processes. Most member states still require multiple permissions and permits to be granted, with only Greece, Portugal, Denmark, Italy and the Netherlands operating a nationwide 'one-stop-shop' or single permit approach (although some states, such as Germany and Sweden, have such processes in place for certain technologies or at a sub-national level). Planning consent for installations remains a significant issue in some member states. This is often linked to the public (and therefore political) acceptability and attitude towards such installations. Although the majority of EU citizens are pro-renewables (71% 'very positive' about the use of wind energy in their country, for example), this varies by member state, and often comes in the form of local opposition, or 'NIMBYism' (Not In My Back Yard). Indeed, this is often a key factor impeding the granting of planning permission for wind installations (often the target of the most severe opposition – particularly onshore) (del Rio and Tarancon, 2012). This is particularly the case for the UK, in which it is often cited as the largest barrier to additional RES-E capacity (Butler and Neuhoff, 2008), but also France (del Rio and Tarancon, 2012). Public acceptance of RES-E technologies in Germany is very high, and although there is evidence to show that a very high proportion of the projects that do not go ahead in Germany are a result of a refusal of planning permission, this is much less of an issue than the UK, for example (Butler and Neuhoff, 2008).

- *Grid Connection*

Whilst member states have made progress on rules for grid access for renewable installations, significant issues remain (European Commission, 2013), and continue to present another key hurdle to RES-E deployment in some countries (del Rio and Tarancon, 2012). A study by Zane *et al* (2012), which reviewed barriers to RES-E integration to the grid across the EU27, identified around 40 issues presenting barriers, with all member states experiencing at least one. The most common were long lead times and delays, and a lack of grid capacity, with seventeen member states experiencing these. The third most common issue was the presence of complex or inefficient administrative procedures (as discussed above, and linked to issues of long lead times and delays). The cost of connection also presents a major barrier in nine member states. Additionally, some countries (such as the UK), provide time-limited grid connection offers under some circumstances, whereas other (such as Germany), guarantee access to renewable generators. Coupled with effective and efficient administrative procedures, Klessmann *et al* (2008) suggest this is a major factor in the rapid RES-E growth seen in Germany. Other issues discussed in relation to the creation of the internal electricity market, such as the incidence of priority connection for incumbent generators, is also a factor in some member states (European Commission, 2009).

- *Priority Dispatch*

Although only nine member states have implemented the requirement for RES-E generation to be given priority for dispatch in law (RES Legal, 2013), the low marginal costs of renewable generation means it naturally experiences favourable dispatch conditions in competitive markets. However, most member states reserve the right to refuse RES-E access to the grid in the interest of grid stability and management (as permitted by the RED). Whilst the relatively low penetration of RES-E in most member states has not yet proven this to be a significant barrier, this is likely to change in the future. In Germany however this issue is already occurring (Zane *et al*, 2012), although clear rules pertaining to grid curtailment have likely prevented this from becoming a significant barrier to development.

- *Development of grid infrastructure*

The European Commission (2013) also concludes that progress has been made in reforming electricity infrastructure, however remaining insufficiencies are already considered a decisive barrier to the integration of RES-E generation. Zane *et al* (2012) find that of the EU27, only three countries exhibit a grid infrastructure and management approach (e.g. grid expansion plans, rules governing sharing and bearing of costs), favourable to RES-E integration (Finland, Ireland and Portugal), with nine providing negative conditions (including the UK, France, Poland and the Czech Republic), with the remaining fifteen found as neutral. Thus far, a lack of suitable grid infrastructure is cited as a barrier to RES-E deployment in ten member states (including the Netherlands and Czech Republic). This is likely to become a more significant issue in future, with at least eleven member states found to be not considering the requirements of RES-E sufficiently in long-term development plans (Zane *et al*, 2012). These issues are interlinked with issues experienced in the creation of the internal power market, where transmission capacity across national boundaries remains a key barrier.

The level and design of support mechanisms, along with varied implementation of rules and requirements surrounding administrative procedures, priority dispatch and development of grid infrastructure and management, have and continue to strongly guide the deployment of RES-E in different member states. However, yet other factors exert influence. One such factor is the electricity price. Higher prices typically encourage investment in all types of capacity, including renewables[22] (Arasto *et al*, 2012) – for which the cost for support mechanisms are reduced (see discussion below). Such logic explains why Jenner *et al* (2013) find a negative correlation between nuclear generation (which typically yields low wholesale prices), and solar PV development across member states (e.g. France)[23]. This is linked to changing power demand. Increasing demand requires increasing capacity, and thus improves the investment climate for all capacity. Additionally, the general condition of the economy in respective member states determines both their attractiveness for investments, and the presence of available capital. Other factors, such as the presence of a highly skilled workforce and subsidies and other advantages for conventional generation, are also important factors for investment attractiveness (del Rio and Tarancon, 2012).

4.2.3 Electricity Market and Other Impacts

Emissions Abatement

It is often argued that any instrument that reduces power sector CO_2 emissions in the EU, such as the RES-E and Renewable Energy Directives, has the unintended consequence of reducing the effort required under the EU ETS, producing inefficiencies (Frondel *et al*, 2010). However, the expected abatement from the increasing renewable penetration as a consequence of the RED and its predecessor was considered in the cap-setting exercises for

[22] Although, this incentive is much reduced in countries with a fixed FiT, for which a changing power price is largely irrelevant to the RES-E developer.

[23] However, other explanations are likely to also play a role. A very high share of centralised nuclear produces an inflexible power system, and is ill-suited to the integration of intermittent RES-E. Additionally, if these nuclear installations are state-owned, the generation of competition from small-scale RES-E may not be a priority.

the different Phases under the EU-ETS, with the European Commission (2008) estimating that more than half of the 20% renewable energy target (by 2020) would be achieved in EU ETS sectors, with much of this drawn from the power sector. As such, only overachievement of this proportion would lead to inefficiencies between instruments. Thus far, as fifteen member states failed to meet their RES-E targets in 2010 (European Commission, 2013), it is unlikely that such an effect has yet occurred.

However, this only applies once the EU ETS came into force in 2005 - whereas the RES-E Directive was applicable from 2001. Any RES-E capacity installed as a result of this Directive between 2001 and the end of 2004 would have produced emissions abatement. Whilst there are no estimates in the literature attempting to produce quantified estimates of the pre-EU ETS abatement, the relatively small increase in RES-E generation between these years (from 86TWh in 2001 to 142TWh in 2002, or 2.7% to 4.3% - see Figure 2), is likely to have led to limited abatement – even under the unlikelihood that this increase could be attributed to the RES-E Directive in its entirety.

Wholesale Electricity Prices

As renewable technologies exhibit low marginal costs, and have guaranteed grid access in some countries, electricity from renewable sources has the first rank in the merit order, in which all power sources are ranked according to their short-run marginal cost of generation. As such, with increasing RES-E penetration, the supply curve shifts to the right, reducing wholesale electricity prices (the ‘merit-order effect’) (Moreno and García-Álvarez 2010). Wurzburg *et al* (2013) summarise seventeen empirical and simulation studies that focus on this issue around the world, and confirm the appearance of this effect in most situations. Wurzburg *et al* (2013) also summarise the literature attempting to quantify this effect in EU member states (specifically Germany, Spain, Denmark, Netherlands, Ireland and the Nordpool power market (Norway, Denmark, Sweden and Finland)). When the results of these studies are normalised to a common measure (change in wholesale price, measured in €/MWh, as a result of an additional GWh of renewable generation), the highest price effects were detected in the smaller member states, such as Denmark, the Netherlands and Ireland (between -€1.33/MWh in Denmark to -€9.90/MWh in Ireland, per additional GWh of renewable generation), with the larger markets (i.e. Germany and Spain), exhibiting between -€0.24/MWh and -€3.99/MWh, per additional GWh of renewable generation. This may be explained by the relative size the power markets in these countries. 1 GWh of renewable generation in Germany, for example, is a much lower proportion than in the Netherlands. As such, the expected effect would be very different. When these values are corrected for this, average values range from -€0.02/MWh in the Nordpool per percentage point of total generation accounted for by renewable generation, to around -€0.8/MWh in Germany. Although the general literature in this field is rather small, the majority of studies have focussed on the impact in Germany and Spain (14 of the 18 EU-focussed studies found by

Wurzburg *et al* (2013)), as they account for the largest renewable generation for individual member states. These two countries will be discussed in further detail in the next section.

It would be expected that this effect would be felt most keenly at peak hours. As increasing penetration shifts the supply curve to the right, displacing less cost-effective (e.g. fossil fuel) plants from the baseload to peak load. This then prevents even less cost-effective plants from being utilised when demand peaks. This also has the benefit of reducing peak-hour price spikes. Such an effect has indeed been found in the empirical literature (Jonsson *et al*, 2010).

Negative prices on the wholesale spot market have also occurred in some member states. This occurs when inflexible generation (such as nuclear and coal generation), meets low demand in the presence of significant renewable generation. Inflexible generators submit negatively priced bids to allow them to remain generating, as the process of shutting down and restarting such plants is often more expensive. This will be discussed further in the specific case of Germany and Spain, where such a phenomenon, although still relatively rare, is likely to have occurred most frequently. However, reduced wholesale (and negative) prices such may only be temporary, as lower prices reduce the long-term price signal and thus may deter future investments, bringing about a subsequent increase in electricity prices due to restricted supply.

Support Mechanism and Other Costs

Across the majority of member states, the costs associated with operating RES-E support mechanisms are recovered via the pass-through of supplier's costs to consumers (in addition to wholesale prices and other levies), increasing retail prices (CEER, 2013). Table 10 tabulates the total RES-E Support expenditure for eighteen member states (both in absolute terms, and per MWh of total final electricity consumption), along with the support level paid per MWh or renewable power that is supplied to the grid, calculated as the weighted average across all RES-E technologies per member state.

Table 10 - Support Mechanism Costs in Different Member States in 2010 (Source: CEER, 2013)

Member State	Weighted Average Support Level (all RES-E) (€/MWh)	Total RES-E Support Expenditure (€m)	RES-E Support Costs per unit of final electricity consumption (€/MWh)
Austria	50.91	378	6.17
Belgium	126.12	729	8.75
Czech Republic	113.37	488	8.23
Estonia	53.55	42	6.01
Finland	6.12	16	0.19
France	86.19	1,511	3.40
Germany	115.60	9,512	17.98
Hungary	101.89	247	5.81
Italy	112.17	3,427	10.38
Luxembourg	99.76	14	2.11

Netherlands	76.70	690	6.46
Norway	9.17	15	0.12
Portugal	55.84	752	15.07
Romania	55.00	37	0.90
Slovenia	49.57	36	2.97
Spain	87.98	5,371	20.61
Sweden	27.98	483	3.68
United Kingdom	126.17	1,438	4.38

As discussed, and as evidenced in the first column of Table 10, support levels vary widely between different member states and technologies (particularly for wind) (CEER, 2013). Total expenditure on RES-E support is highest in Germany and Spain in 2010, as would be expected, along with the highest expenditure per MWh of total final consumption. However, what might be unexpected is that neither Germany or (particularly) Spain provides the highest support levels, with countries such as the Czech Republic and Italy exhibiting comparable financial support. This gives further evidence to the importance of the design of the support scheme, rather than simply the level of support.

Theoretically, a quota obligation system is more cost-effective than a FiT system, as the pre-defined quota should be met at least cost, since – in contrast to the FiT – there is no way how producers can reap excessive profits; if the quota market functions, any cost degradation for renewables should be reflected in lower levels of support. However, Butler and Neuhoff (2008) found that this is not the case when comparing the UK quota system and German FiTs, finding a lower cost per unit of RES-E generation delivered in Germany. They explain this first by suggesting that the financial certainty provided by FiTs reduces regulatory and market risk, and thus the cost of capital. A second component is the finding that stronger competition exists in Germany between wind turbine producers and constructors than in the UK – opposite to what might have been expected. As these are the stages of the value chain that contribute most to the total cost of a wind installation, increased competition here has a strong impact on total cost (Butler and Neuhoff, 2008).

It is unlikely that this finding can be applied to all member states applying FiTs and quota systems respectively, because as suggested, the German scheme is often cited as best-practice design (along with the Spanish scheme). Best-practice components generally act to ensure the incentive to invest is present, but support costs, which are mostly passed-through to electricity bills, are as low as possible. Examples are (Ragwitz *et al*, 2012):

- *Stepped Tariff* – As discussed above, tariffs are varied according to the local resource, and are applied in the Netherlands, Portugal, Denmark, France and Germany. At the same as encouraging development in areas of lower resource availability, it also prevents excessive profits to installations in high-resource locations.

- *Tariff Degression* – The tariff received depends on the year the installation begins operation, with rates decreasing over time to reflect (and incentivise) technological improvements and cost reductions. This may come in the form of a fixed regular reduction, or introduced ad-hoc after a regular review process (introducing an element of risk to investments). Among others, Germany, Greece, Slovenia, Spain and the UK currently employ tariff degression for some or all technologies.

- *Growth Caps and Corridors* – Some countries, including Spain, place caps designed to limit the level of installed capacity over a given time, defined either by capacity or level of support cost. Whilst this ensures overall costs are managed, it reduces investment stability. Other countries however, including Germany for solar PV, set growth 'corridors' to manage costs. This involves defining the level of capacity a member state would like to see installed over a given timeframe. If growth is in line with expectations, the normal tariff degression would apply. If capacity growth is lower than expected, the degression is reduced. If growth is higher than expected, tariff degression is increased. However, the higher the frequency of overshoot and adjustment, the lower the investment stability.

4.3 Member State Implementation and Impact - Germany

4.3.1 Support Mechanism Development

Germany's feed-in tariff approach to RES-E development has undergone a number of modifications since it was first introduced (Diekmann *et al*, 2008). The first incarnation of the German support policy (the Stromeinspeisungsgesetz – 'StrEG'), entered into force in 1991. Utilities became obliged to accept and remunerate RES-E at a rate up to 90% of the retail electricity price, which was considerably higher than the cost of conventional electricity generation to utilities (de Vries *et al*, 2003). The StrEG was amended in November 1997 to limit the renewable purchase obligation of each utility to 5% of its total deliveries. The upstream network company reimbursed costs above this threshold until it also reached the 5% ceiling in its grid. After the liberalisation of Germany's electricity market in 1998, the tariff paid to RES-E generators declined considerably due to falling electricity prices.

As such, the policy was amended in 2000 to tackle the falling RES-E investment incentive, but also in light of the fact that the 5% threshold was quickly approaching for a number of upstream networks. This second incarnation (the Erneuebare-Energien-Gesetz, or the 'EEG'), guarantees stable feed-in tariffs for up to twenty years, providing considerable certainty to RES-E investments. As discussed, both a stepped tariff and tariff degression applies across technologies (1% to 6.5%, depending on the technology), along with rates differentiated by technology. Tariff rates were modified in 2004, 2009 and 2012 for a number of technologies. The EEG also provides guaranteed connection to the grid, along with priority dispatch for renewable generation. A 2004 amendment committed Germany to increase the share of RES-E to 12.5% in 2010, and at least 20% by 2020 (Mendonca and Corre, n.d.).

The EEG was amended twice in 2012, largely in response to the on-going decline in the cost of RES-E technologies, the considerable deployment of PV and the related increase in the size of the EEG surcharge, which is passed to consumers via electricity bills. The two amendments tackled these issues by reducing the tariff for onshore wind and PV generators, and accelerating the degression for biomass, onshore and offshore wind, geothermal and PV. In the case of PV, additional reductions apply to the rate when the expected PV capacity expansion band (growth corridor) is exceeded, with reduction for the following three months based on newly installed capacity in the preceding months. The adjustments take place every three months. Another result of the 2012 amendments was to introduce a 'market premium' option, in order to encourage RES-E generators to behave more like conventional producers. Under this option, RES-E generators can choose to sell directly into the spot market and obtain additional revenues through a premium, which is inversely related to the average monthly spot price.

Revisions of the EEG have been met with criticism from the RES-E industry. Diekmann *et al* (2012) provide a measured discussion of these concerns. Other reactions have been more positive. For example, Gipe (2013) points out that Germany has codified a more aggressive RES-E target (between 35% and 40% of supply within the next decade), than in the previous law - further cementing Germany's commitment to renewables. More details on the rates paid under the StrEG and the EEG across time can be found in a number of reports such as Anon (2013d), Fulton and Capalino (2012) and Scherer and Butler (2013).

In addition, in 2010, the German government introduced its plans for the 'Energy Concept', which aimed to reduce emissions by 80% by 2050 from 1990 levels, and to achieve 80% of electricity consumption from renewables, also by 2050 (along with other objectives). Ambitious interim targets were also imposed. The introduction of the Energy Concept came shortly before the Fukushima disaster in 2011, which prompted the permanent closure of eight of Germany's nuclear reactors, discussed previously. This nuclear phase-out policy, whilst maintaining the targets and objectives of the Energy Concept, has become known as the '*Energiewende*'.

4.3.2 Impact on Wholesale and Retail Prices

Wholesale Prices

Figure 30 below illustrates the average annual wholesale spot market price in Germany for both baseload and peak hours[24], between 2005 and 2013. The trend over time generally matches what might be expected when considering the price trends of coal and gas seen in Figure 28**,** and that of the carbon price as seen in Figure 27.

[24] Data gratefully received from RWE-npower.2013 data excludes December.

Figure 30 - Average Annual Wholesale Spot Market Prices

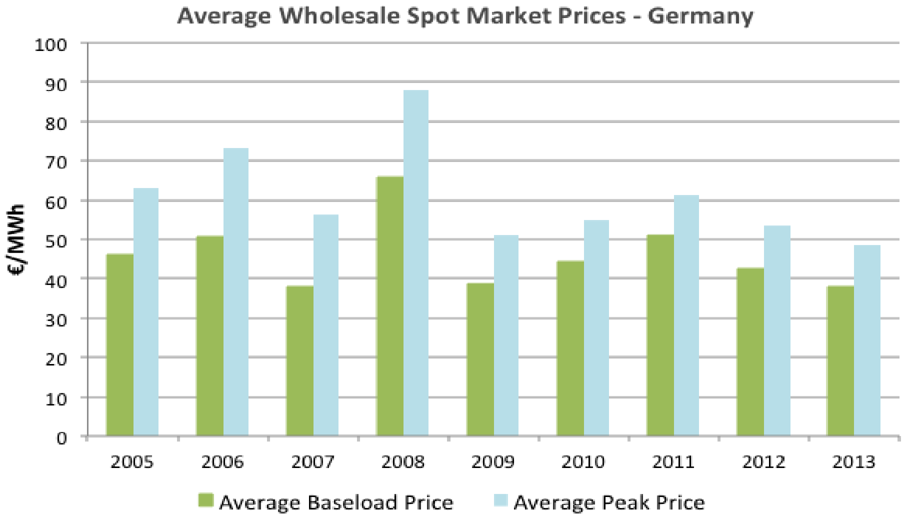

Table 11, below, replicates the tabulation completed by Wurzburg *et al* (2013), summarising the results of the existing literature on the impact of RES-E on wholesale spot market prices in Germany, against the counterfactual. Although only around 25% of Germany electricity is traded on the spot market (Pietz, 2009), these spot prices form the basis of prices for other contracts, and therefore may be considered representative of general price changes (Tveten *et al*, 2013).

Table 11 - Change in the German Wholesale Spot Market Price Resulting from RES-E Penetration (Source: Wurzburg *et al*, 2013)

Study	RES-E Coverage	Period	Change in Wholesale Price per ad. GWh of RES-E Generation (€/MWh)	Change in Wholesale Price per % of RES-E penetration (€/MWh)	Absolute Change in Wholesale Price based on annual total RES-E Generation (author calcs.) (€/MWh)
Bode and Groscurth (2006)	All	~2005	-0.50 - -0.60	-0.35 - -0.43	-2.51 - -3.09
Neubarth *et al* (2006)	All	2004-2005	-1.89	-1.34	-9.07 (2004), -9.63 (2005)
Senfuss *et al* (2008)	All	2001	-0.94	-0.63	-2.45
		2004	-0.60	-0.42	-2.84
		2005	-0.86	-0.61	-4.38
		2006	-1.34	-0.97	-8.17
Senfuss (2011)	All	2007	-0.77	-0.56	-6.52
		2008	-0.71	-0.52	-6.18
		2009	-0.71	-0.48	-6.53
		2010	-0.55	-0.39	-5.51
Traber and Kemfert (2011)	Wind	2007-2008	-0.80	-0.58	-6.75 (2007), -6.89 (2008)
Weber and Woll (2007)	Wind	2006	-1.15	-0.84	-7.08
Weigt (2009)	Wind	2006	-1.78	-1.30	-10.95
		2007	-2.30	-1.68	-19.56
		2008	-2.83	-2.05	-24.35

It is clear from the results displayed in Table 11 that the studies investigating the merit order effect in Germany report largely consistent results, despite varied approaches. The range varies between -€0.35/MWh to -€2.05/MWh per percentage point of RES-E generation, although the majority of studies produce results under -€1/MWh. A reason for the relatively high estimate provided by Neubarth *et al* (2006) at least, is the use of an univariate approach, which may produce biased results (Wurzburg *et al*, 2013). Additionally, results do not vary significantly across time, and whilst two of the multi-period studies suggest an increase in the effect, the third (Senfuss, 2011), calculates a reduction. The estimated absolute reduction in wholesale spot prices range from €2.45/MWh to €24.35/MWh, with an average of €7.91/MWh. Given that wholesale prices (for baseload) have mostly moved between €35 and €60 in recent years, the effect of RES-E is indeed significant. Thus, the expansion of RES-E supply – together with falling prices of CO_2 allowances and other factors – is one of the key drivers behind the falling wholesale prices, which had peaked at more than €80 Euro (baseload) in 2008, and which have since fallen to €35 in early 2014.

Wurzburg *et al* (2013) also conduct their own analysis for the combined German and Austrian market, and find a similar result at approximately -€7.6MWh between July 2010 and July 2012 (with a value of -€1/MWh per GWh of RES-E generation). However, as the average of the studies cited in Table 11 includes studies that may be producing an unlikely high value (e.g. Neubarth *et al*, 2006 and Weigt, 2009), it is likely this average value (and therefore the results from Wurzburg *et al* (2013)), present an upper bound estimate. The latter study also concluded that the significant reduction in nuclear capacity in 2011 did not impact the size of the merit-order effect.

Table 12 - Estimated Average Annual Reduction of Wholesale Spot Market Prices in Germany due to RES-E Generation

Year	Average Estimated Reduction in Wholesale Prices (€/MWh)	% Reduction from Average Wholesale Spot Price	Total Value of RES-E induced Wholesale Price Reductions (€m)
2005	-4.90	8%	-
2006	-8.73	12%	-
2007	-10.94	19%	-
2008	-12.47	14%	-
2009	-6.53	13%	3,100
2010	-5.51	10%	2,800

The first column in Table 12 provides an annual average of the studies cited in Table 11**,** between 2005 and 2010. Using this and data from Figure 30, the second column estimates the average percentage reductions estimated to have occurred in wholesale spot market prices in Germany, resulting from RES-E penetration. The average reduction on wholesale spot market prices between 2005 and 2010 is estimated to be around 12%. However, for the reasons discussed above, this is likely to be towards a higher-bound estimate[25]. The right-hand column tabulates total estimated monetary savings from wholesale price reductions[26] (BMU, 2012).

In September 2008, the EEX for the first time allowed the possibility to submit negatively priced bids. By December 2009, 86 hours were observed with negative prices, with 19 significantly negative (<€100) - the most significant being -€500/MWh on 4th October 2009 (Nicolosi, 2010). According to data from RWE-npower, negative average daily prices for baseload delivery has occurred five times since September 2009 - two days in 2009, two days in 2012 (all in October or December), and once in 2013 (in June). However, the available data does not provide hourly-level detail, and thus more granular analysis may not be performed.

In summary, whilst the impact of RES-E generation has been significant in terms of reduced wholesale prices (and the occurrence of negative prices, to an extent), the effect thus far appears to not be as significant in Germany as is sometimes reported. However, the effect and potential consequences for investment signals are likely to become more pronounced over time, as RES-E penetration increases further.

Retail Prices

It is clear when comparing the values for total savings from reduced wholesale prices in Table 12 against the total costs of the German RES-E support mechanism in Table 10, that the costs have thus far outweighed the savings (by an estimated €6.7bn in 2010) - as might be expected. These costs are recovered via the 'EEG surcharge' – a levy added to the electricity bills of almost all consumers. However, the burden imposed by the surcharge is markedly different across consumer groups. Electricity-intensive firms, for example, may call upon a special hardship rule that considerably reduces the value they are required to pay[27] – whilst benefiting in greater measure from the decrease in the spot price described above, as the wholesale price tends be a higher share of their bills (Bode and Groscurth, 2006). According to Bode and Groscurth (2006), the price change for consumers affected by the hardship clause and inelastic demand could be as high as 10% when RES-E is about 15% of total generation. Figure 31 shows the total value of EEG payments made over time, along with the EEG surcharge applicable to households.

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[25] Additionally, these values must be seen as indicative only, as the values calculated as annual average values for estimated reductions in wholesale prices are based on values themselves calculated through different methodologies and data sources.
[26] However, it does not necessarily follow that these savings are passed-through to the final consumer.
[27] The largest consumers are effectively exempted. For annual consumption above 1GWh, electricity-intensive firms pay 10% of the surcharge. For consumption over 10GWh only 1% is liable, and for over 100GWh, a maximum of 0.05ct/KWh is levied.

When delivering price reduction in the wholesale spot market, RES-E deployment caused a corresponding increase in the costs of the feed-in mechanism, in order to bridge the gap between the spot price and the guaranteed support rate. In addition, as the levy is not paid by the most-electricity intensive sectors this increase burden falls disproportionally only on households, commerce and non-exempted industry. The need to increase cost recovery may be seen in from the rapid increase in the EEG surcharge seen in 2009 onwards in Figure 31, however it must be restated that overall changes in wholesale prices over time is not entirely, or even very significantly, influenced by RES-E generation.

Figure 31 Total Amount of Fees and amount per kWh bornne by households implied by the EEG and previous German renewable policies (Source: BMU, 2012 and Frondel *et al*, 2012)

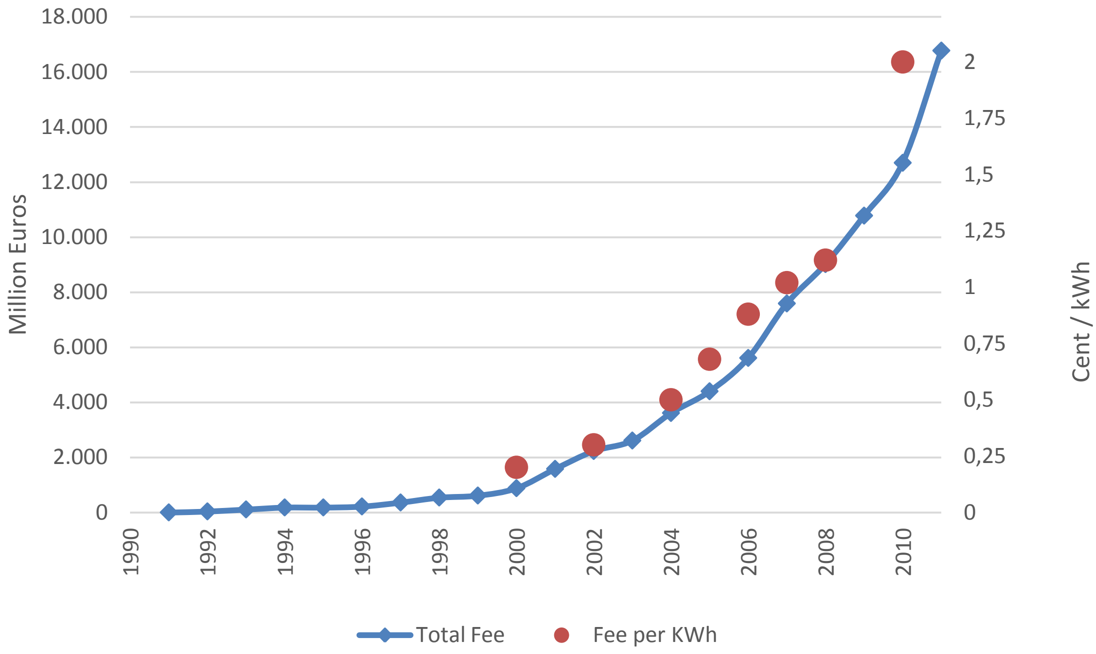

Table 13 - Estimated Net Change in Domestic Electricity Retail Prices in Germany

Year	Average Estimated Reduction in Wholesale Prices (€cent/KWh)	EEG Surcharge (€cent/KWh)	Estimated Net Change in Household Retail Price (€cent/KWh)
2005	-0.49	0.68	0.19
2006	-0.87	0.88	0.01
2007	-1.09	1.02	-0.07
2008	-1.25	1.12	-0.13
2009	-0.65	1.13	0.48
2010	-0.55	2.0	1.45

Table 13 combines the estimated impact of RES-E on wholesale prices with the EEG surcharge to estimate the net impact of RES-E deployment in Germany on domestic electricity retail prices between 2005 and 2010. The most noticeable results are the negative values in 2007 and 2008, which suggest RES-E deployment in Germany had a negative direct cost to households in these years. However, these calculations are rather basic and are based on three key assumptions that may bring this result into question. Firstly, the estimated reduction in wholesale prices is likely to be an overestimate for 2006 and 2007 (along with 2005 and 2008), as the average value used includes two studies which produce estimates nearly an order of magnitude higher than most other studies. Secondly, this calculation assumes that suppliers pass on all the cost saving from a reduced wholesale price to customers. And finally, domestic users must also pay VAT on the EEG surcharge (19%), which is not included in this calculation. As such, the actual cost is likely to be higher than presented above for all years, and also positive in 2007 and 2008. Additionally, the costs are likely to have risen rather substantially since 2010 in tandem with the EEG surcharge, which has increased rapidly and substantially to 6.42€ct/KWh for 2014 (BEE, 2013).

4.3.3 Economic and Social Impact

When taking account of crowding-out effects, Hentrich et al (2004) finds a negligible impact on employment in Germany as a result of RES-E penetration and proportion, whilst BEI (2003) finds negative long-term employment effects. Similar results are attained by Fahl *et al* (2005), Pfaffenberger (2006) and Hillebrand *et al* (2006). On the other hand, BMU (2006) estimates a positive net employment effect - 56,000 jobs by 2020. However, this critically depends on foreign trade in RES-E technologies, an assumption also noticeable in Lehr and Luz (2011). Frondel *et al* (2010) is fairly critical of this assumption, noting the negligible or even negative net exports of PV in recent years due to unprecedented competition from cheaper Asian products. The PV trade balance is much brighter according to Diekmann *et al* (2012), in which the authors point out that there is still a boom in exports by German mechanical engineering companies, as they build a substantial proportion of the new photovoltaic production facilities in Asian countries, despite the decreasing share of the PVs produced in Germany. Additionally, of course, the manufacture of PV modules forms only part of the labour and value added – installation, maintenance and grid integration for example are also labour-intensive, and cannot be exported.

Table 14 below reports the effects of the EEG policy on gross investment and employment, as reported by official publications (BMU, 2012). Based on the discussion above, the numbers in the table may be considered an upper bound for impacts from RES-E support in Germany, as they are gross figures that are by definition higher than net effects. The gross effect on employment is computed through accounting-based procedures based on turnover, and comprises both direct and indirect employment.

Table 14 Economic and Social Impacts of the German Renewable Policy (Source: BMU, 2012)

Year	Gross Investment	Gross Employment	
	Billion Euros	Total	Attributable to EEG
2004	6.8	160,500	98,000
2007	10.8	277,300	172,700
2008	12.8	322,100	207,300

2009	16.5	339,500	225,000
2010	25	367,400	262,100
2011	20.1	381,500	-

4.4 Member State Implementation and Impact - Spain

4.4.1 Support Mechanism Development

The Spanish Feed-in Tariff (also known as the 'Special Regime') was introduced in 1994, whilst administrative procedures and conditions to access the Special Regime were developed in 1998. Although some of the characteristics of the support mechanism have been modified over time, notably in 2004 and 2007, the policy has always maintained two alternative incentive payments for RES-E generators: a fixed tariff for each technology; or a premium for each technology paid on top of the electricity market price (Schallenberg-Rodriquez and Haas, 2012). In both instances generators initially sold electricity generated to distributors, who paid the premiums but passed them to the market regulator (Comision Nacional de la Energıa) and, finally to consumers (del Rio Gonzalez 2008). From 2004 onwards, RES-E generators were given the choice between selling their electricity directly to the market or to the distributors, although the former was encouraged. When the electricity spot market price spiked in 2005 and 2006 (see Figure 32), the premium option became much more profitable than the fixed FIT. The unexpectedly high revenues accruing to RES-E generators ultimately led to the Government changing the details of the policy. In 2007 the level of RES-E support was decoupled from the electricity market price and tied to the Consumer Price Index (CPI). A cap-and-floor system for RES-E support levels was also introduced (del Rio Gonzalez 2008). In 2011, the previously generous tariff for solar PV was cut substantially, followed by the decision to introduce a temporary suspension of the policy for new systems installed after 31st December 2012 - in order to tackle the significant budget deficit created by the continued success of the scheme, despite the criticism of the European Commission. A radical change in Spanish policy was announced in July 2013, in which feed-in tariffs will be substituted with capital investment subsidies for new and existing capacity. The guiding principle is a 7.5% pre-tax profitability target across the lifecycle of all renewables plants (Anon 2013b). Details on the policies such as the cap-and-floor values as well as the fixed FIT and the premium can be found in a number of articles, including Anon (2013c) Gonzalez (2008), Moreno and Garcia-Alvarez (2011), Schallenberg-Rodriquez and Haas (2012).

4.4.2 Impact on Wholesale and Retail Power Prices

Wholesale Prices

As with Germany, Figure 32 below illustrates the average annual wholesale spot market price for Spain[28]. Disaggregation into baseload and peak prices is not required, as peak trade volumes are largely negligible. Again, the general trend is as would be expected (and looks remarkably similar to German baseload wholesale prices, despite different economic fortunes and the fact that the two electricity systems are not directly linked).

Figure 32 - Average Annual Wholesale Spot Market Prices in Spain

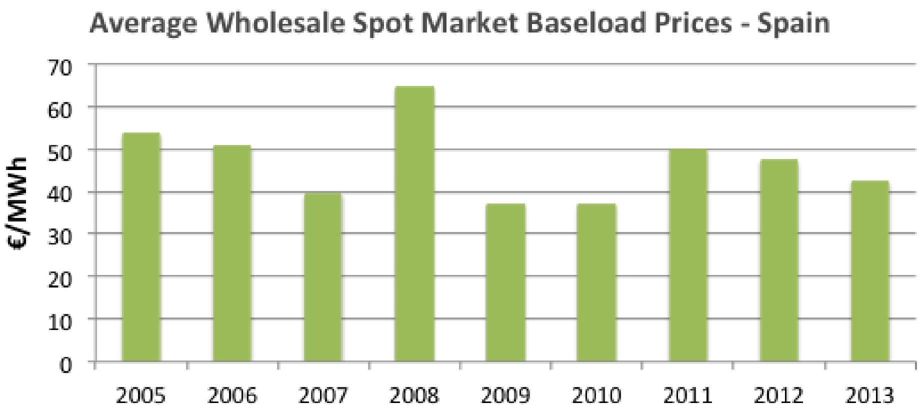

Table 15, below, replicates the tabulation completed by Wurzburg *et al* (2013), summarising the results of the existing literature on the impact of RES-E on wholesale spot market prices in Spain, against the counterfactual. Again, this may be considered representative of price changes across all contract products.

[28] Data also provided by RWE-npower. Again, values for December 2013 are excluded.

Table 15 - Change in the Wholesale Spot Market Price in Spain resulting from RES-E Penetration (Source: Wurzburg et al, 2013)

Study	RES-E Coverage	Period	Change in Wholesale Price per ad. GWh of RES-E Generation (€/MWh)	Change in Wholesale Price per % of RES-E penetration (€/MWh)	Absolute Change in Wholesale Price based on annual total RES-E Generation (author calcs.) (€/MWh)
Gelabert *et al* (2011)	All	2005	-3.80	-1.13	-9.36
		2006	-3.40	-1.04	-9.20
		2007	-1.70	-0.54	-5.56
		2008	-1.50	-0.48	-6.00
		2009	-1.10	-0.32	-5.22
		2010	-1.70	-0.54	-9.95
Gill *et al* (2012)	Wind	2007-2010	-2.15	-0.67	-6.90 (2007), -6.38 (2008), -10.92 (2009), -12.35 (2010)
Saenz de Miera *et al* (2008)	Wind	2005	-2.99	-0.89	-7.37
		2006	-1.83	-0.56	-4.95
		2007	-3.88	-1.26	-12.98

Again, it is clear that the results of these studies are largely similar, perhaps more so than the German-focused studies - again despite divergent approaches. The range varies from -€0.32/MWh to -€1.26/MWh per percentage point of RES-E generation, with absolute changes in wholesale spot prices ranging from -€4.95/MWh to -€12.98/MWh, with an average of -€7.75MWh – remarkably similar to the average for Germany discussed above.

Table 16 - Estimated Average Annual Reduction of Wholesale Spot Market Prices in Spain due to RES-E Generation

Year	Average estimated reduction in wholesale prices (€/MWh)	% reduction from average wholesale spot price	Total Value of RES-E induced Wholesale Price Reductions (€m)
2005	-8.36	13%	4,574
2006	-7.07	12%	2,255
2007	-8.48	18%	3,698
2008	-7.19	10%	4,919
2009	-8.07	18%	4,836
2010	-11.15	23%	4,848

Again, the first column in Table 16 provides an average of the studies cited in Table 15**,** between 2005 and 2010. Using this and data from Figure 22, the second column estimates the average percentage reductions estimated to have occurred in wholesale spot market prices in Spain, resulting from RES-E penetration. The average reduction on wholesale spot market prices between 2005 and 2010 is estimated to be around 16% - higher than the (upper-bound) estimate for Germany. This might be expected, as Spain has experienced a slightly higher proportional penetration of RES-E, and the Spanish merit-order curve is likely to have a steeper tail, given the relatively high share of oil and gas plants. The right-hand column tabulates total estimated monetary savings from wholesale price reductions to end-end users (APPA, 2011).

Daily average zero prices have occurred only twice since 2005, both in 2013. No daily negative prices have thus far been authorized, although the data available does not allow the presence of hourly negative price to be investigated.

As with Germany, whilst the impact of RES-E on wholesale prices appears significant, it is not as severe as commentary often suggests. However, as with Germany, the effects are likely to become more pronounced over time.

Retail Prices

Support mechanism costs are recovered via a supplement on consumer's bills, proportional to their consumption. However, the rate applied to bills does not appear easily disaggregated from other components of the Spanish electricity bill. As such, the cost of the support mechanism by unit of electricity consumed cannot be calculated from the data available.

4.4.3 Economic and Social Impact

APPA (2011) computed the impact of RES-E deployment on the Spanish trade balance, direct and indirect contribution to GDP and employment. These results are reproduced in Table 19. Although the authors provided no methodological information, it is likely that an accounting-type methodology was used. Arregui et al (2010) find similar values for employment via four methodologies (a survey of companies, in-depth interviews with experts, case studies and analysis of accounts and reports). According to Arregui et al (2010), direct and indirect jobs in 2010 related to RES-E were 68,737 and 44,758, respectively, its sum being close to the value in Table 19. A similar figure is also reported by Moreno and García-Álvarez (2010).

Table 17 - Economic and Social Impacts of the Spanish Renewable Policy (Source: APPA, 2011)

Year	Trade Balance	Contribution to GDP				Employment		
	Export – Imports	Direct	Indirect	Total	Total	Direct	Indirect	Total
	Million 2010 Euro	Million 2011 Euro	Million 2011 Euro	Million 2011 Euro	% of GDP			
2005	n/a	3,182	1,824	5,006	0.49%	46,339	39,223	85,562
2006	851	3,463	1,993	5,456	0.51%	49,785	40,443	0,228
2007	1,075	3,610	2,172	5,782	0.52%	53,222	42,062	95,284
2008	1,299	5,016	3,265	8,281	0.67%	75,466	56,159	131,625
2009	768	6,366	3,350	9,716	0.81%	59,303	57,911	117,214
2010	690	6,876	3,304	10,180	0.94%	54,925	56,802	111,727
2011	730	6,740	3,504	10,244	0.95%	54,193	64,464	118,657

5 Interaction between the EU ETS and Renewable Electricity and Renewable Energy Directives, and Other Drivers

EU ETS and RES-E Directive/RED Interaction

Extensive literature exists regarding the overlap of an ETS with RES-E support measures and targets. Taking a textbook approach for when an ETS covers multiple sectors alongside power generation (as the EU ETS does), any simultaneous measures to support RES-E does not produce additional emissions abatement overall, as the additional abetment in the power sector is offset by an equivalent burden reduction in the non-power sectors (as the overall ETS cap remains the same). The same emissions abatement is then achieved at higher cost than with an ETS alone, producing static inefficiency. Although the abatement delivered by RES-E support was considered in EU ETS cap setting exercises, meaning that emission reduction activities only overlap if RES-E targets are exceeded (unlikely to have occurred so far, as fifteen member states failed to reach their 2010 target (European Commission, 2013)), the combination of these instruments still produces static inefficiency, since an economy-wide ETS is the benchmark for static efficiency. However, the presence of a separate RES-E instrument may be justified by encouraging dynamic efficiency; incentives for R&D and innovation to reduce long-term abatement costs. Arguably this is not achieved by an ETS with a lack of predictability in either price or operational mechanisms, leading to investment uncertainty both overall, and on a sectoral basis. Additionally, levels of support afforded to RES-E technologies through dedicated support mechanisms are usually much higher per KWh than the cost of carbon per KWh added by and ETS, even in the presence of a significant carbon price (e.g. €30).

An objective of the EU ETS is to encourage investment in lower-carbon generation capacity than might otherwise have been developed. However, it is clear that largely due to the method of free allocation employed in Phases 1 and 2, this effect was negligible, and possibly negative (investment in new high-emission capacity such as coal was incentivised in some member states through additional profitability, although it is likely that any additional plants built in this time were already planned and simply brought forward). Although there is evidence to suggest the EU ETS did have a positive impact on the incidence of biomass co-firing (at least in Phase 1) (NEF, 2009), there is little evidence to suggest it incentivised investment in RES-E capacity. Indeed, all interviewees in Hoffmann (2007) emphasized that investments in RES-E in Germany are not a result of the EU ETS, but of the German feed-in tariff (under the RES-E/RE Directives) - a conclusion confirmed by Schmidt *et al* (2012) and Rogge *et al* (2011), who state that the shifts toward renewables in Germany would not have occurred if there had been no feed-in tariffs, making investments profitable at low risk. Market players expected that the impact of the EU ETS would be rather low up to 2020, compared to fuel prices and technology-specific policies such as feed-in tariffs (NEF, 2009). Additionally, whilst there is evidence to suggest the EU ETS spurred at least some low-carbon

R&D efforts, Hofmann (2007) discovered that technology-specific policies are among the most relevant decision factors for power generators to decide on RD&D plans. Four years later Rogge et al (2011b) came to an analogous conclusion.

Although the EU ETS and RES-E/RE Directives appear to have had different influences on investment in new capacity, both instruments appear to act in concert in reducing the CO_2 intensity of actual generation, through altering the merit-order for dispatch in member states. RES-E generation, present as a result of the RES-E/RE Directives, is dispatched first due to very low marginal costs (and by legal requirement, although this is not formally implemented in most member states). The EU ETS (in times of a sufficiently high carbon price, at least) alters relative marginal costs, favouring generation capacity with a relatively lower CO_2 intensity, and pushing the more CO_2-intensive capacity out of the market (particularly at times of low demand, and in member states with substantial gas capacity). However, the low carbon price experienced since the middle of Phase Two appears to have reduced the incidence of such fuel switching.

Although, the process by which this joint effect occurs produces opposing impacts on the wholesale price of electricity in member states. Whilst an increasing presence of RES-E reduces the average wholesale spot price (and may create negative prices when permitted), the EU ETS acts to increase it. Table 18 presents an indicative comparison of the respective effects of these two influences as annual averages, for Germany and Spain.

Table 18 - Impact of RES-E and EU ETS on Wholesale Spot Prices in Germany and Spain

Year	Average Reduction in Wholesale Prices		Average annual EU ETS cost		Average Annual Change to Baseload Wholesale Prices	
	Germany (€/MWh)	Spain (€/MWh)	Germany (€/MWh)	Spain (€/MWh)	Germany (%)	Spain (%)
2005	-4.90	-8.36	12.77	9.01	21%	1%
2006	-8.73	-7.07	7.84	5.03	-2%	-4%
2007	-10.94	-8.48	0.28	0.17	-22%	-17%
2008	-12.47	-7.19	7.84	4.31	-7%	-4%
2009	-6.53	-8.07	6.69	3.29	0%	-11%
2010	-5.51	-11.15	6.51	2.51	2%	-19%

The first two columns are reproduced from Table 12 and Table 16, whilst the second two columns are calculated using estimated CO_2 intensity of generation (Figure 22), total generation for each year, and approximated average CO_2 prices for each year (Figure 27), assuming 100% pass-through. Although, as stated, these values may only be considered indicative[29], aside from 2007 (when the average EU ETS price was extremely low) it appears

[29] Firstly, the values in Figure 22 are themselves approximations, for reasons described in the text. Perhaps more importantly however, the assumption of a consistent 100% pass through of the EU ETS (opportunity) cost is a gross simplification, for reasons also discussed in the text. Additionally, as the wholesale spot price is set by

that the total cost burden of the EU ETS has often counteracted or even exceeded the influence of RES-E generation on reducing wholesale prices. The final two columns indicate the indicative net effect of these two influences on baseload wholesale prices, against the counterfactual. However, the reduction in the carbon price from mid-2011 to consistently below €5/tCO_2 from early 2012, coupled with the continued increase in RES-E penetration in these countries, has lowered the wholesale price over time. In member states with a lower RES-E penetration, and consequently often with a higher CO_2 intensity of generation, the effect is much more likely to be a net increase in wholesale prices. However, such member states shoulder a lower cost burden from RES-E support mechanisms, providing at least some counterbalance to overall changes in retail electricity prices.

As discussed, it is likely that the EU ETS has facilitated additional cross-border electricity trade (at least in the presence of a significant carbon price), driven by a change in relative wholesale prices between member states. It is likely that the effect on wholesale prices by RES-E generation enhances the effect of the EU ETS on cross-border trade patterns (and vice-versa), by producing a steeper price gradient between states with low RES-E deployment (and therefore generally higher CO_2 intensity and carbon costs, against the counterfactual), and those with high RES-E deployment (and therefore generally higher CO_2 intensity and carbon costs, against the counterfactual).

Other Drivers

A number of other drivers of the development of the European power sector over recent years, aside from the EU ETS and the RES-E/RE Directives and intricacies in the implementation at member state level, have been discussed already. In summary, these are:

- *Fuel Prices* – The cost of (fossil) fuel is a significant, if not primary driver in shaping the profile of the power sector, in terms of capacity, investments and wholesale prices. The cost differential between coal and gas is a particular driver.

- *Local Resource Base* – Whilst the presence of domestic fossil fuel reserves has shown to be a driver for investment (and is linked to relative prices), local renewable resources are a more prominent factor. Relative differences in solar or wind resources between member states, for example, significantly influences the economics in deploying related technologies. The presence of a hydroelectric resource also appears highly influential, significantly impacting generation and wholesale prices in Spain and Scandinavia, in particular.

- *Political and Public Acceptability* – Public acceptability, and political stances and decisions

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the marginal plant, for a truly correct calculation, the CO_2 intensity and generation of the marginal plant must be known. As this is not known, the average CO_2 intensity provides an adequate proxy in this instance.

which flow from it, are a significant influence. In Germany, for example, the decision to permanently close eight nuclear power stations in 2011 and phase out the remaining nine by 2022 was a political decision (Knight, 2011). The *Energiewende*, which sets an overarching goal of 80% renewable energy in Germany by 2050, is also a political commitment. Such clear, long-term commitment to renewables and emissions reductions may have a larger impact on power sector transformation than the details of the specific instruments employed to realise it (Schmidt *et al*, 2012). Whilst NIMBYism produces significant deployment barriers in some member states, general levels of public acceptability and support also likely has an influence on the profile of RES-E investments – both in terms of volume (i.e. the level of acceptable cost burden from support mechanisms), and type. For example, by the end of 2010, private citizens owned over 40% of renewable capacity in Germany (not just RES-E, but excluding pumped hydro), mainly through co-operatives, with energy companies owning just 13.5% (mainly hydroelectric stations) (Buchan, 2012). This is in stark contrast to most other member states, in which energy companies own the vast majority of installed capacity, illustrating the level of public buy-in to renewables in Germany.

- *Economic Circumstances* – The importance of the broad economic situation to the power sector has become clear over the past few years. The most obvious influence, as discussed, is the deep reduction in electricity demand that began in 2009, at the onset of the global financial crisis (Figure 1). The availability and cost of finance to invest in new capacity (both conventional and renewables), has also been highlighted as a driver. A final key influence, which feeds-in to the above, is the political and public acceptability of support mechanism costs, at a time of relative economic hardship. These three factors substantially alter the investment climate for the power sector.

Other policy measures also have a direct or indirect impact on the power sector. For example, it is curious to observe that annual increases in electricity generation illustrated in Figure 1 slowed down well before the financial crisis, with annual generation between 2006 and 2008 remaining largely equal. In other words, the financial crisis appears to have impacted on an already-unfolding demand reduction. Larsen (2012) ascribes this (at least in part) to the impact of efficiency measures, such as the Ecodesign Directive, the Energy Performance of Buildings Directive and other member-state level measures. The 2006 Energy Services Directive (replaced the Energy Efficiency Directive in 2012) is unlikely to have had much of an impact on the 2006-2008 trend, due to the time of its implementation and its apparent lack of efficacy.

The Large Combustion Plant Directive (LCPD) (2001/80/EC) aims to reduce emissions of acidifying pollutants, particles and ozone precursors from large combustion plants with a rated thermal input greater than 50MW – including fossil fuel power plants. The LCPD imposes SO_2, NO_x and dust emission limits on plants licensed on or after 1st July 1987 (with stricter limits for plants licensed on or after 26th November 2002). Plants licensed before 1st

July 1987 must also achieve 'significant' SO_2, NO_x and dust emission reductions by 1st January 2008, either by meeting the emission limits for plants licensed after this date, or through a national emission reduction plan (NERP) that achieves overall emissions reductions calculated on the basis of these limits. However, Article 4 of the LCPD allows plants to 'opt-out' of compliance, under the provision that these plants are not operated for more than 20,000 between 1st January 2008 and 31st December 2015, after which these plants are not permitted to generate.

At of the 6th January 2014, 228 plants across the EU have opted out, with the UK holding the largest proportion of opted-out plants in relation to total capacity. By this date, eight of the 228 opted-out plants have reached the 20,000-hour limit, and have stopped operating (whilst a further four have exceeded the limit – all in Malta) (European Environment Agency, 2014). It is likely that the plants that have reached this limit would have likely continued operating in absence of this legislation, and that a substantial number of the remaining 'opted-out' plants have reduced their operation over time in response. As discussed, there is evidence that the EU ETS rendered the cost of upgrading certain plants to meet emissions targets uneconomic, and thus were submitted to the 'opt-out' list (NED, 2009).

6 Conclusions

This paper assesses the impact of the EU ETS, Renewable Electricity Directive and Renewable Energy Directive on various aspects of the power sector in the EU and selected member states.

- *Electricity Generation* – Whilst the proportion of electricity sourced from coal, oil and nuclear has decreased over time, the use of gas and particularly renewables has increased since 1990, and particularly since 2000. The EU ETS appears to have encouraged some 'fuel-switching' from coal to gas in some member states (the UK and Germany, in particular), in 2005 and 2006 at least. Delarue *et al* (2008) estimate this reduced EU-wide coal generation by around 2% and 1% in these years respectively, in favour of gas. The increase in renewable generation is a function of increased renewable capacity, with low marginal costs – and, in some MS, legal obligations – allowing renewable generation to receive preferential dispatch.

- *Electricity Capacity* – As with generation, gas and renewable capacity has increased dramatically over time. Coal, oil and nuclear capacity have also decreased along with generation proportions, but not to the same extent. The EU ETS is likely to be a negligible driver in the increasing gas capacity, and potentially had a negative influence by incentivising investment in coal capacity, resulting from free allocation of permits driving windfall profits. However, there is evidence to suggest the EU ETS did drive some efficiency retrofits in existing plants. The growth in RES-E capacity is likely to be due almost entirely to targeted support mechanisms and enabling initiatives contained in the two Renewables Directives, with enabling initiatives likely to be as important as the design and detail of the financial support mechanisms employed. However, it cannot be known which countries would have continued or introduced measures and removed barriers to deployment in absence of these Directives.

- *Electricity Prices* – The rate of carbon cost pass-through to wholesale electricity spot market prices varies significantly across member states and over time (at all scales), and may be both above 100% and negative. On average however, it is positive and likely increased wholesale prices against the counterfactual in most instances – evidenced by estimates of windfall profits received by generators in receipt of free allowances. Deployment of RES-E as a result of the Renewables Directives is likely to have decreased wholesale prices against the counterfactual, via the merit order effect. In Germany and Spain, the average reduction is likely to have been up to around 12% and 16% between 2005 and 2010 respectively, against counterfactual prices. Indicative calculations suggest that aside from the ETS price crash in 2007, the price driving effect of the EU ETS may have largely cancelled out or even exceeded the dampening effect of RES-E on wholesale prices (In Germany, in particular). The reduction in EU ETS price to consistently below €5/tCO2 from early 2011 onwards is will have reduced this effect, however (or may have even reversed it, when considering the significant drop in baseload wholesale price in Germany from 2008 levels). When considering retail prices, the effect of these two directives certainly increases consumer prices, as the RES-E support mechanism costs are most often recovered via levies on electricity bills.

- *Electricity Trading* – Both the EU ETS and Renewables Directives are likely to have encouraged additional cross-border electricity trade by working together to increase wholesale price differentials between countries with high and low CO_2 intensities of generation. However, this is restricted by limited interconnector capacity and the slow implementation of a fully functional internal electricity market.

- *Emissions Abatement* – The EU ETS and Renewables Directives, via the above mechanisms, work in tandem to reduce the emissions intensity of power generation in member states (the first principally via fuel switching, the latter via increasing RES-E penetration). Whilst overall ETS sector emissions remain unaffected by RES-E installations driven by non-ETS measures (as increased power sector decarbonisation reduces the burden on other EU ETS sectors), the level of the EU ETS cap was set in consideration of this. As such, only overachievement of RES-E targets would produce a detrimental instrument overlap. As fifteen member states were underachieving on these targets by 2010, it is unlikely that this has yet been the case.

In summary, the EU ETS thus far appears to have relatively little impact on the development of the EU power sector since its introduction in 2005. This appears to be due to a combination of volatile and often low prices (leading to a lack of future certainty upon which to base investments), and the practice of free permit allocation in Phases One and Two. The Renewables Directives appear to have had a larger impact, and facilitated the significant expansion in RES-E experienced since 2000. However, other factors evidently combine to play a much more decisive role on the development of the EU power system, and in differences across member states. Such factors include fuel prices (particularly the relative difference between coal and gas), domestic resource availability (principally renewable resources, but also fossil fuel), political and public acceptability (particularly concerning RES-E installations, enabling infrastructure and support mechanism costs), and the general economic climate – which significantly impacts electricity demand, the availability and cost of capital for investment in capacity and infrastructure, and political and public priorities. Similarly, other policy measures with a direct or indirect impact on the power sector, such as the Ecodesign Directive, the Energy Performance of Building Directive and Large Combustion Plant Directive, also play influential roles.

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Annex A

Ex-post evaluations of the CO_2 impact of the EU ETS based on trend extrapolation have been particularly popular ion the aftermath of the EU ETS introduction. This approach consists of:

- analysing trends of relevant variables prior of the introduction of the policy;
- building a counterfactual by extrapolating these trends;
- measuring abated emissions by subtracting observed emissions from the counterfactual.

Although the main advantage of this method is its simplicity, shortcomings may be identified based on the assumptions in the analysis. In particular, it is assumed that:

- past trends would have continued in the absence of the introduction of the policy;
- contemporaneous occurrence of two events, i.e. introduction of a policy and abatement of emissions, implies causation;
- introduction of the policy is the only factor responsible for changes in the trends.

Although most if not all of these shortcomings apply to any methodology using the past as a guide for the future, their importance is inversely related to the complexity of the model or the number of factors used in the analysis. The criticisms above seem particularly limiting in the case of trend extrapolation, as some of the studies in the literature are based on a very simple framework, where Business As Usual carbon emissions are a function of emissions in a reference year adjusted for the growth in economic activity and the decline in the carbon intensity

[illegible]

Trend Extrapolation suffers from the fact that a number of factors likely to influence emissions are not incorporated in the analysis, namely weather, the energy price and the price of any other production factor. Most of these studies, for example, Ellerman and Buchner (2008) and Ellerman and Feilhauer (2008), are applied to all the sectors covered by EU ETS and therefore may also be affected by changes in the relative importance of the sectors.