Norwegian School of Economics
Bergen, Spring 2018

COAL-TO-GAS SWITCHING IN THE POWER SECTOR IN GERMANY AND THE UK

ASSESSMENT OF KEY DRIVERS AND PROJECTION OF FUTURE SCENARIOS BASED ON THE EU ETS REFORMS

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I. ABSTRACT

The power sector represents 30% of total greenhouse gas (GHG) emissions in the European Union (EU). Market concentration and use of available technologies combined with a carbon price could trigger drastic GHG emission reductions. In light of this, the EU introduced in 2005 the Emissions Trading Scheme (ETS), a market driven mechanism that sets a price on carbon. Nevertheless, the EU ETS has performed below expectations in generating an effective price signal. Coal represents the main emitting fuel source with about 39% of all EU-ETS emissions resulting from coal power generation. It is undeniable that today fuel combustion plants are needed to maintain a stable power system due to the intermittency of renewable power sources. However, fuel switching from coal to natural gas (referred as “gas” from now on), a less carbon-intensive fuel source, represents a feasible solution to drastically reduce emissions. In this context, the EU roadmap towards 2050 aims for progressive emission reductions as renewable energy gains relevance in the energy mix. This can only be achieved through a progressive transition from coal to gas technologies. Over the last years, the diverging coal and gas economics, have made necessary the role of a carbon price to increase gas competitiveness and allow for a so-called coal-to-gas switch. The German and United Kingdom (UK) power sectors combined represent approximately 30% of the total GHG emissions in the EU. Moreover, their coal-to-gas switching strategies differ considerably. While Germany is a loyal advocate of free-markets, the UK has numerous occasions favoured market intervention. The UK has introduced a carbon price floor and announced a coal-phase out by 2025, while Germany has taken a more passive position letting the EU ETS define the optimum carbon price signal conditions through socio-economic arguments. Recently approved adjustments to the EU ETS may increase the carbon price significantly in the next decade, which could support Germany´s strategy thereby avoiding the social and economic burden of market intervention. On the other hand, if the carbon price signal is not strong enough, Germany would be obliged to introduce stringent policy measures to limit coal power generation. The question over which is a better strategy to support an effective coal-to-gas switch is a topic of debate among the EU member states. This thesis evaluates the key drivers behind the coal-to-gas switching process, compares the situation of Germany and the UK, and analyses different carbon price scenarios up to 2030 in order to project possible coal-to-gas switching outcomes. This will aid in judging which strategy is the most appropriate to accomplish an efficient coal-to-gas switching process, which is crucial for the realization of the 2030 emission reduction targets.

II. ACKNOWLEDGMENT

I would like to express my gratitude to my thesis supervisor Gunnar Eskeland for his support and patience.

Special thanks is also due to Liisa Kelo for her unconditional support and encouragement during the weekends that I have had to spend writing this thesis instead of exploring the beauties of North-Rhine Westphalia with her. Having said that, I am proud of the result of this work and hope it expands the knowledge of the readers about a topic that will be of key importance in energy policy discussions in the years to come.

III. TABLE OF CONTENTS

IV. LIST OF FIGURES

V. LIST OF TABLES

LIST OF ABBREVIATIONS

CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDS	Clean Dark Spread
CHP	Combined Heat and Power
CO2	Carbon dioxide
CPF	Carbon Price Floor
CPS	Carbon Price Support
CSS	Clean Spark Spread
EC	European Commission
ETS	Emission Trading System
EU	European Union
Eurostat	Statistical office of the European Union
GDP	Gross Domestic Product
Gas	Natural gas
GHG	Greenhous Gases
GW	Gigawatt
GWh	Gigawatt-hour
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquefied Natural Gas
MSR	Market Stability Reserve
MW	Megawatt
MWh	Megawatt-hour
p.a.	per. annum
PV	Solar Photovoltaic
RE	Renewable Energy
RES	Renewable Energy Sources
STD	Standard Deviation
T	Metric tonne
TOE	Tonnes of Oil Equivalent
UK	United Kingdom
UN	United Nations

VI. TOPIC AND RELEVANCE

Historically the two highest emitting member states under the EU ETS were Germany and the UK. This was largely due to the vast amount of coal power generation in both countries. However, in recent years a strong divergence between these two countries has taken place. The UK has accomplished drastic emission reductions in the power sector by reducing power generation from coal plants, while in Germany coal power generation is still the dominant fuel source. The aim of writing this thesis is to shed more light on the key reasons behind this divergence and evaluate the different policy approaches and their effectiveness in triggering the necessary coal-to-gas switching process in order to meet the 2030 emission targets.

The power sector offers the largest opportunity to decrease CO2 emission by switching from coal to gas generation. Currently, the replacement of coal by gas plants is one of the key topics in the industry and in policy discussions. A sharp decline in coal prices from 2010 to 2014 drove most of Europe's gas-fired capacity out of the merit order curve. However, falling natural gas prices (in 2015, 2016 and 2017) have to some extent reversed this effect and increased the competitiveness of gas plants. This change in the economic equation has revived discussions about the economics of coal and gas power generation and the adequacy of the current policy measures to support an effective coal-to-gas switching process over the next decade. A comparison between Germany and the UK shows that the path to a low carbon power sector can be approached in different ways through emission restrictive instruments and by implementing national energy policies. Both countries aim to drastically reduce the GHG emissions from the power sector (linked to coal power generation) by applying different political coal-to-gas switching strategies, with different observable results. Thus it makes sense to evaluate the environmental targets of the two countries, the coal and gas power competition and project future scenarios in order to determine which policy approach is more suitable to reach an effective coal-to-gas switching process.

The analysis of the economic and political situation of these countries is crucial to understand the market dynamics. The UK has introduced a carbon floor price due to consistently low carbon prices and has recently announced a coal phase-out by 2025. Germany, on the other hand, has kept faith in the carbon market (EU ETS) and prefers to wait and see the evolution in the markets before taking such a risky political decision. If carbon prices reach a sufficiently high level, no market intervention would be necessary.

Additionally, the EU ETS could gain relevance due to the recently announced corrective measures, which have raised the expectations for higher carbon prices. Until now, the EU ETS has played a discreet role in supporting the coal-to-gas switch. Nevertheless, a significant carbon price increase could definitely favour the competitiveness of gas power generation compared to coal. There is considerable difference of opinion among experts as to which way carbon prices would go. It is therefore important that multiple scenarios be analysed based on different levels of carbon price.

Finally, coal-to-gas switching in the power sector has become a central topic of interest for policy makers and sector participants alike. The favourable economics of coal over the last years has left no doubt about the competitive advantage of coal over natural gas. However, the adjustment of commodity prices due to energy market dynamics and a strong carbon price could change the game in favour of gas power plants. If this is not so, then policy makers will have no choice but to intervene and adjust the economic competition between coal and gas, if they want to meet mutually agreed upon environmental targets. This thesis will shed more light on the need for this political intervention based on the latest assumptions in commodity price forecasts of the World Bank and the development of three carbon price scenarios based on expert predictions.

VII. LITERATURE REVIEW

The basis of this thesis is supported by previous work done by experts on the topic as well as the latest data published by European institutions, regulatory authorities and trading organizations. From a literature standpoint, several authors have tackled this topic approaching it from different angles by making use of diverging quantitative and qualitative methods. The following paragraphs make a cursory review of some of the most relevant literature regarding the topics involved in this thesis.

Cornot-Grandolphe (2014), focuses on the relationship between coal, gas and CO2 prices as key factors that determined the competition between gas and coal in the power sector. In her work, some European cases are analysed in more detail to support her qualitative conclusions. She concludes that policy decisions may affect the coal and gas balance, and that structural reforms to the EU ETS are necessary in order to favour gas power generation. However, she does not look into future scenarios and limits her analysis to a historical perspective.

Delarue, Voorspools and D'haeseleer (2008), develop an electricity generation simulation model to perform simulations on the fuel switching behaviour during the first Phase of the EU ETS (2005-2008), thereby establishing a relation of GHG emissions reductions and carbon price fluctuations. This serves as proof of the positive effect that carbon prices have on the coal-to-gas switching process. However, the calculations performed do not take into account the effect of other potential key drivers, such as regulatory measures, socio-economic factors or commodity price fluctuations, thus providing a limited view of the reality.

Jones and Kleiner (2017), present in their analysis a picture of the recent evolution of fossil power generation, and specify that emission reductions are linked to a decrease in coal power generation. They conclude that a coherent European policy approach is needed to trigger the transition away from coal power generation, thus bringing meaningful CO2 reductions. However, they do not evaluate the different policy strategies applied by countries in the EU and thereby offer no formula to accomplish such a transition.

Pettersson, Söderholm and Lundmark (2012) assess the impacts of liberalization of the energy sector on the fuel switching behaviour in the European power sector. They prove through empirical analysis that the implemented measures had a profound impact on fuel choices, limiting the competitiveness of coal in favour of gas power generation. Further, they use 2004 as the base year to evaluate the impact that different carbon price levels have on the coal (and oil)-to-gas switching process. They conclude that the higher the carbon price, the more gas power is used, supporting the potential impact of the EU ETS. Although the assessment takes into consideration the effect of other relevant factors such as market and policy trends that may be sensitive, this sensitivity analysis is theoretical and based only on a single point in time.

This thesis will attempt to overcome the limitations of the aforementioned research papers. First by analysing historical key drivers affecting the coal-to-gas switching process in two of the most coal dependent economies in the EU, then by performing carbon price simulations based on possible future price trends and finally by assessing the adequacy of the political measures in place to effectively trigger a coal-to-gas switching process.

VIII. RESEARCH METHODOLOGY

This thesis analyses the gas and coal competition in the power sector in Germany and the UK by looking at historic market dynamics in order to evaluate the key drivers affecting the coal-to-gas switching process. Through the evaluation of the current situation and the projection of future scenarios, it will be possible to assess the need for additional policy requirements to trigger an effective coal-to-gas switch in the UK (until 2025) and in Germany (2030). The methodology applied relies on qualitative and quantitative methods.

- The qualitative method is founded on a comparative analysis of both countries' coal and gas power generation mix and the regulatory measures implemented at the national and EU level. First, the current situation around coal and gas generation mix will be described, taking into account the declared environmental targets. The retrospective analysis combines sector specific data from public sources and a wide range of academic/expert reports and articles. This is followed by a narrow analysis of the competition between coal and gas power technologies to identify the key factors that affect the coal-to-gas switching process. This analysis will focus on commodities (coal, natural gas) and carbon price evolution as the key drivers affecting the economic competition of coal and gas. Finally, the significance of recent political measures including amendments to the EU ETS has been explored, paving the way for the quantitative analysis later on. From a political perspective, special importance will be given to the EU ETS as carbon prices could become the key driver affecting the competitive balance between coal and gas in the merit-order-curve.

- The quantitative method relies on an empirical analysis of historical data (2006-2016) for Germany and the UK. The key factors established through the qualitative analysis will set the basis for the different scenario analyses. Three scenarios (best-case, most-likely case and worst-case) for carbon prices will be developed allowing for the projection of the CSS and CDS curves until 2030 and the respective outcomes will be evaluated for each country. Assumptions regarding technological development and carbon price evolution are based on expert projections and reports published by well-recognised institutions. Through simplified Monte Carlo simulations (for the most-likely scenario, 2025) it will be possible to evaluate the likelihood of the obtained outcome considering a reasonable deviation range for commodity prices. This deviation range is grounded on historical market data. Data used for the quantitative analysis has been sourced from public European and global institutions such as Eurostat, ENTSO-E, the World Bank and the national regulatory bodies in Germany (Bundesnetzagentur) and the UK (Ofgem).

The combination of both methods will allow better understanding of the situation in each country regarding the coal and gas power competition and evaluate the effect of different carbon price trends. The obtained results will provide more clarity on the reasons behind the adopted approach in each country and estimate the need for additional political measures.

IX. STRUCTURE OF THE PAPER

This thesis focuses on the electricity generation sector and the potential to switch from emission intensive fuels (coal) to less emission intensive sources (natural gas). The first part will centre on the historical context of climate change and the foundations of the existing economic mechanisms to put a price on carbon. Subsequently, in Chapter 2, European climate action and the accomplishment of Germany and the UK regarding national environmental targets will be presented. Chapter 3 will describe and assess the coal-to-gas switching problem and identify key factors affecting the process. These parameters will then be assessed in Chapter 4 specific to Germany and the UK. Chapter 5 will cover a scenario analysis considering the recently agreed amendments on the EU ETS and the impact of different carbon price trajectories on the coal-to-gas switching process in each country. In this chapter, a set of Monte Carlo simulations will be performed in order to evaluate the uncertainty of the coal-to-gas switching outcomes taking into consideration the fluctuation of commodity prices. The final part consists of a list of key conclusions as well as insights on the need to implement additional policy measures to accelerate the coal-to-gas switch in each country.

INTRODUCTION

Throughout the XX century, humans treated this planet like an endless reservoir of resources with complete disregard for its ability to replenish them. Because of this, our society has become reliant on a production model based on unrestrained consumption of natural resources. The energy needed to sustain this model comes from fossil fuels, which over the last century have been a fundamental pillar on which our economy was built. No one could foresee, however, that this model had a dark secret that could put humanity itself at risk. On innumerable occasions, scientists have raised the issue of climate change and its direct relation to human activity, specifically the combustion of fossil fuels. According to the most recent studies, climate change will continue progressively if we do not change this production model. Consequences that had been predicted are already being observed and will get worse in the absence of a penalty or a strong disincentive to generating carbon emissions. It is crucial to confront the false idea of an inexhaustible abundance of resources and the limitless absorption capacity of the planet in order to find effective solutions that limit GHG emissions.

Historically developed countries have been the main driver of this process, responsible for 80% of accumulated GHG emissions in the atmosphere coming from fossil fuel combustion. Economic development is closely coupled to energy consumption and it will continue growing mainly in developing countries (today approximately 1/4 of the world population consumes 3/4 of total energy). Specifically, the power sector in its role as generator of the electricity that drives industry, households and services represents only 4% of GDP, but is responsible for 30% of total GHG emissions. The concentration level of this sector and high impact on climate change makes it an obvious and important choice for any strategy to reduce emissions substantially by introducing less fossil intensive technologies and/or fuels. The European Union (EU) has set ambitious goals to decarbonise the energy sector as part of its long-term roadmap (until 2050) towards an emission free economy. This has resulted in the implementation of the European Emission Trading Scheme (EU ETS) as a mechanism to "put a price on carbon" targeting the most polluting sectors. In parallel, EU governments are confronted with the question about what is the most effective and politically acceptable formula to move away from coal, one of the most emission-intensive power sources. Whether the recently adjusted EU ETS will suffice to accomplish this task in the cases of Germany and the UK has been evaluated in this thesis.

CHAPTER 1: CLIMATE CHANGE ECONOMICS AND PRICING MECHANISMS

In Chapter 1 the scientific evidence and fundamental economic theory behind climate change and carbon pricing will be presented. This will serve as a basis to build on during the subsequent chapters in which we will delve into concrete environmental policy targets and the drivers affecting the most relevant conventional power sources.

SECTION 1.1: CLIMATE CHANGE

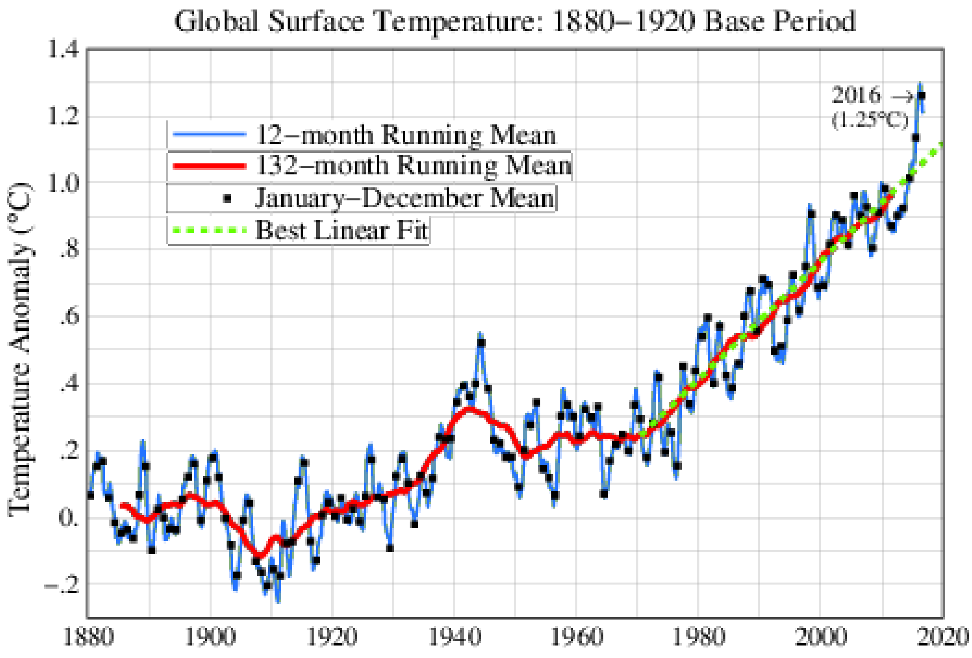
Climate change is a natural process, be it a rise or a fall in temperatures, that has been occurring throughout the 4.600 million years of history in different periods. This process has determined a variation of the terrestrial scene as a result of changes in the atmosphere composition and the so-called greenhouse effect. Scientific studies have shown that only one half of solar radiation reaches the Earth's surface while the other half is reflected by the atmosphere or absorbed by clouds. Of the radiation that reaches the Earth´s surface, one half is reflected preventing the overheating of the surface. The atmosphere creates a natural barrier composed of different greenhouse gases (GHG)[1] that reflects 3/4 of the energy emitted by the Earth back to the surface. This process repeats itself many times resulting in the Greenhouse effect. It is important to note, that without this effect the current average temperature of the earth (15 °C) would be far lower, presumably at -18 °C.

What scientists are warning about is not the Greenhouse effect in itself but the accelerated rise in the average global temperature due to human activity. The massive emission of GHG is altering the composition of the atmosphere leveraging the Greenhouse effect, which results in an increase in global temperature and escalation of natural disasters at a global scale. Several scientific studies argue that the accumulation of GHG in the atmosphere is the cause of accelerated climate change and that severest consequences will be experienced from the middle of this century on. According to official data of the World Meteorological Organization (WMO) the accumulation of GHG in the atmosphere over the last 100 years has resulted in an increase in global temperature of 1 degree (see Figure 1). The scientific community is urging world leaders to act on this issue and stabilize GHG emissions. At current production and consumption rates based on fossil fuel resources combined with

[1] Most important GHG are H2O, CO2, CH4, NOx, ozone and chlorofluorocarbons.

increasing human population, there could be a 6 degree increase by the end of this century (according to the IPCC reports). Among all the scientific evidence arguing that humans are responsible for climate change, the most well-known publications are the Club of Rome, the Stern review, the Nordhaus report, the Keeling curve and the four IPPC reports (Castellanos, 2008).

Figure 1: Global average temperature evolution since 1880



Source: Columbia University. 2017

SECTION 1.2: ENVIRONMENTAL ECONOMIMCS: FAILURE OF THE MARKET

At the beginning of the XX century, the idea of the finiteness of the planet in terms of natural resources started to gain significance, resulting in a new line of economic thought called environmental economics. This movement is based on the fundaments of the Neoclassic theory specifically with regard to the valuation of scarce goods. The Neoclassical theory limits the market to goods that reflect this characteristic, leaving abundant and inexhaustible goods without economic value. The interest in scarce goods generates a trade process between economic agents (maximization of economic value) that enables to determine a monetary value for these goods. Environmental economics is considered to be an evolution of the Neoclassical theory since it includes the environment in the group of scarce goods.

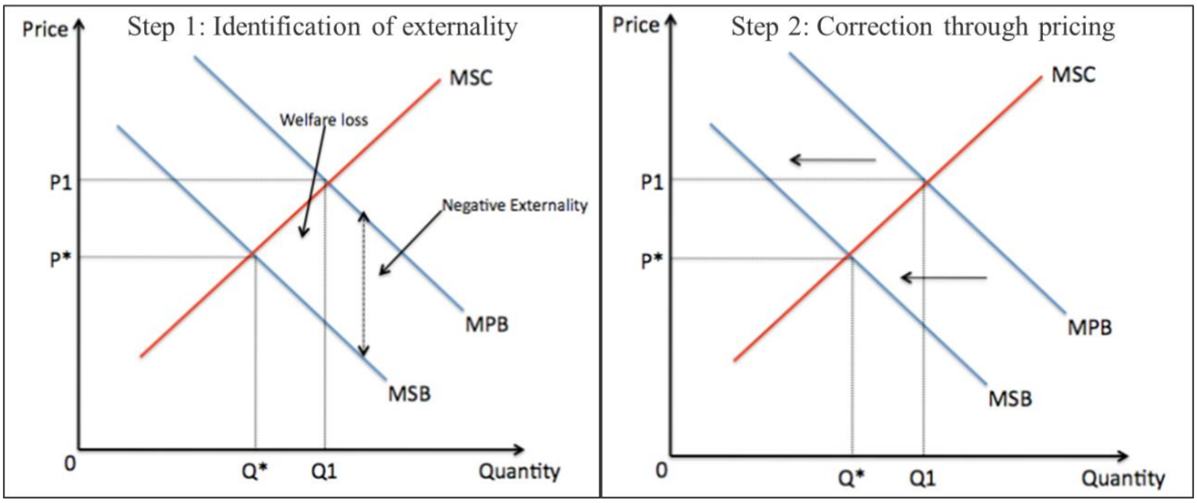
Since the publication in 1972 of a report by Club of Rome presenting the limits of growth, many other scientific studies have evidenced a progressive depletion of natural resources. Even if natural resources are proven to be limited, it is their social profile that hinders their consideration as monetary goods with property rights. To contextualize, the deterioration of the environment represents a subjacent consequence of production process that has been excluded from the economic cost equation. When the market fails to effectively allocate a price for certain goods, it leads to what economists call a failure of the market resulting in externalities. If the transaction between two parties generates harm to a third party, but this harm is not considered in the cost equation, then we are speaking about a negative externality.[2] When speaking about climate change, the third party takes the form of society and the resulting negative externality is defined under economic theory as welfare loss or decrease in social wellbeing (Mochón, 2000).

"Externalities occur when an action of an individual affects other without permission. Location is important for the strengths of the externality but not in case of climate change since it is a global public good." (Kolstad, 2000)

Figure 2 presents a negative externality as the divergence between the marginal social benefit (MSB) function and the marginal private benefit (MPB) function. By not considering the harm to a third party, the intersection between the private marginal benefit (MPB) functions and the marginal social cost function (MSC) attains a higher quantity level (Q1) as it would from a marginal social benefit (MSB) perspective, which includes the cost of the negative externality. Therefore, by setting a value for the negative externality (through market intervention) the MPB function moves towards the MSB function. An effective price allocation means that the optimal equilibrium point (Q*) is attained and the market accounts for the cost of the negative externality.

[2] A positive externality may result from the indirect benefit generated by a transaction. For instance, if a company invests in research and innovation and a third party (society) benefits from the outcome.

Figure 2: Negative externality and correction through pricing



Source: Own development based on the "Economics of welfare" by Pigou

The environmental economics school classifies the emission of GHG as a negative externality, which through economic valuation could be included (internalized) in the market as an additional decision driver. Even if GHG emissions have a limited impact on the current population (although some effects are evident already), it is likely to have disastrous consequences on the quality of life in the near future. These consequences vary from low to high intensity depending on the level of GHG emissions released in the following decades. The increasing awareness to combat climate change has pushed public institutions to implement political measures (nationally and internationally) in order to internalize the social cost of GHG emissions (Chang, 2001).

SECTION 1.3: EXCLUDABILITY AND RIVALRY – ECONOMIC CHALLENGES

Market failure on the consumption side usually refers to the effect on public goods and the need to set a price signal to control its use, a concept known in economics as excludability. In the case of GHG emissions, it is difficult (or practically impossible) to control the emission of GHG for every individual ("bad excludability"). However, it can be controlled for selective individuals, the ones polluting the most by implementing economic measures to change their behaviour. In order to consider emissions as "good excludability", it is necessary to have the technology that makes control feasible and not too costly relative to the resulting social benefits. Cost refers to the administrative task and technological instruments needed to effectively allocate or limit consumption. In the case of GHG emissions, a legal framework could adopt the role of regulator and protector of social value. This means that for a price-system to work properly, rights must be distributed to allow the concept of excludability.

Equally important in climate economics is the aspect of rivalry. Rivalry refers to the situation in which the consumption of a good reduces the availability of this good for another consumer (present or future). In the case of climate change, it is a non-rivaly good since no one can easily calculate the cost of being subject to global climate. However, if we consider the emission of GHG as the exhaustion of the atmosphere´s capacity to maintain a stable global temperature it is a rivalry bad that is detrimental to the future generations (the capacity to remain below the two-degree global temperature increase established by the IPCC as the threshold to avoid catastrophic climatic consequences). This could also be assessed from a social opportunity cost perspective. Since today´s society is reducing the quantity of available atmospheric capacity for future generations, it represents a negative social opportunity cost (Kolstad, 2000).

SECTION 1.4: FUNDAMENTALS OF CARBON PRICING MECHANISMS

The basic problem negative externalities, is that the producer does not consider the damage caused to society since it was never part of the cost equation. Thus, intervention is needed in order to establish a price signal that sets a new optimal behaviour, pareto efficient optimum, for the producer and society. A lack of intervention to control pollution means that the firm accounts a zero (or close to zero) cost for polluting, which leads to not considering the social impact of pollution in the optimal behaviour function (Kolstad, 2000).

The government has two economic mechanisms at its disposal to correct market failure and confront the problem of excludability and rivalry. On the one hand, there is the carbon tax instrument ("the emitter pays"), while on the other, a mechanism to trade emission rights ("the emitter emitting too much, pays"). These two instruments have been at the core of an intense debate between economists over the last decades regarding their efficiency and political appropriateness.

The Pigouvian fees (or pollution tax) is based on the idea that the government intervenes in the market and sets a negative price signal to correct market failure, forcing polluters to pay for every unit of CO_2 equivalent emitted. The introduction of a pollution tax could be an effective solution to internalize the cost of climate change and protect social welfare. The right amount of pollution (efficient level of pollution) is the amount that minimizes total costs (aggregated marginal damages). The government collects compensation paid by the emitter since in the case of GHG emissions exposure to damages is unevenly distributed and cost of control is centralized (Backhouse, 2002).

The Coase theorem is based on the idea of privatizing all social goods through the assignation of property rights that can be traded among private agents. The government distributes property rights making goods excludable and creates a market to trade those rights. This would avoid the appearance of externalities since the cost derived from the externality would be included in the activity of each agent making use of the rights. Consequently, private agents would be incentivised to trade property rights in the market resulting in an efficient distribution of resources. It is necessary to clarify that institutions play an important role in allowing markets to function by allocating resources. Coase argues that if transaction costs are present, it is important that the government distributes property rights efficiently. Furthermore, a progressive reduction of the transaction costs (associated with trading rights to pollute) is crucial as is setting a distribution preference to those parties that have the greatest need for the rights (Coase, 1960 and Kolstad, 2000).

The following table (Table 1) summarizes the pros and cons of both these approaches. It remains open to debate as to which one is better placed to correct the failure of the market. While economists are divided, governments are implementing one or a combination of both depending on economic and social circumstances.

Table 1: Comparison of Pigou and Coase approach (pros and cons)

	Pigou (carbon tax)	**Coase (emission rights)**
Pros	➢ Effective in accomplishing objectives and easy to implement ➢ No problems of negotiation ➢ Standardized tax without sector discrimination	➢ Favours negotiation ➢ Allows for regulation and monitorization of the market ➢ Low operating costs
Cons	➢ High operative costs ➢ Efficiency not granted ➢ Depends on each state national tax policy	➢ Pollution is legitimized ➢ Depends on market variables ➢ Lack of equality among the sectors

Source: Own development based on Chang, 2001

SECTION 1.5: ECONOMIC DEBATE

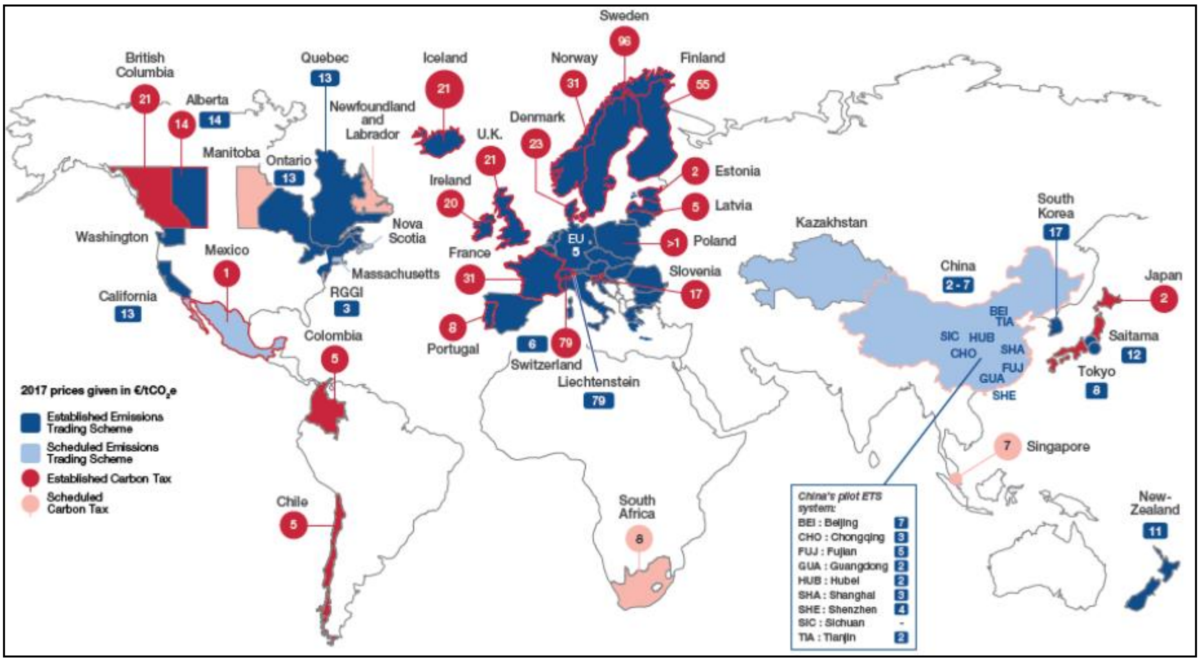
Economists have been involved in an intense debate over which instrument would be more efficient to tackle climate change (fees in form of a carbon tax or subsidies in form of emission rights). Coase published his theory back in 1960, arguing that property rights are an efficient way of allocating social costs and provided an alternative to the Pigouvian fee. Other distinguished economists such as Dales (Pollution, Property and Prices, 1968) and David Montgomery (Markets in Licenses and Efficient Pollution Control Program, 1972) strengthened this theory, by confirming the validity of a model based on a fixed amount of tradable rights for which the market could efficiently determine costs and distribution.

Contrary to this idea, Pigouvian supporters argued that the outcome of both instruments is different, saying that while a fee is efficient in reducing pollution, property rights could take the form of subsidies and generate over pollution (incentivise production). Further, subsidies may allow uncompetitive firms to continue operating due to supplementary financial support. In simple terms, a tax raises average costs while a subsidy lowers average costs with the implications that a subsidy does not allow the market to communicate the real cost of consumption, including the pollution aspect (Kolstad, 2000).

The debate persists in academic circles while governments are taking decisions about which instrument to implement. In fact, a crucial difference between the two instruments lies in the extent of political acceptability. An economic instrument based on allocation of property rights seems to enjoy greater support by emitters than a direct tax. Adding to Coase's argument that it is possible to obtain the same abatement result independently if the polluter is obliged to compensate the victim or the victim compensates the polluter, it has moved the EU Commission to choose a property rights mechanism as the cornerstone of the GHG emission reduction policy. The mechanism developed is the EU ETS and since its implementation in 2005 it has projected a carbon price signal for the most emission intensive sectors (Chang, 2001).

Several countries around the world have also been confronted with the decision of which approach would allow them to attain GHG reduction targets in the most effective way. The current global picture (see Figure 3) presents a balanced preference for carbon pricing mechanisms. The accumulated experience over the years and the results achieved through the EU ETS, known as the largest emission trading scheme in the world, represent a reference point for other countries that are considering the idea of putting a price on carbon.

Figure 3: Map of carbon pricing mechanisms worldwide 2017



Source: I4CE, 2018

CHAPTER 2: CLIMATE CHANGE ACTIONS FOR GERMANY AND THE UK

The EU has taken the role of the leader in the fight against climate change, which is reflected in the targets set for 2050. In this chapter, we will focus on the EU environmental targets taking a closer look into the country specific targets of Germany and the UK. This will allow us to assess if these two countries are on track to accomplish their respective targets paying attention to the power sector. It is crucial to understand the current scenario before diving into more specific topics, where we will analysis the key drivers affecting the coal-to-gas switching process (Chapter 3) and the impact of these drivers on each country (Chapter 4).

SECTION 2.1: INTERNATIONAL NEGOTIATIONS

Scientific evidence about climate change and its disastrous consequences (translated in economic value by some economists such as Nicolas Stern) evoke the need to introduce action at a global scale[3]. A few decades ago, the idea that common problems need to be tackled through collective action, resulted in a cooperative movement driven by the United Nations (UN). This movement succeeded in implementing different international treaties of which the Montreal Protocol in 1987, the United Nations Framework Convention on Climate Change (UNFCCC) in 1992[4], the Kyoto Protocol in 1997[5] and the Paris Agreement in 2015[6] stand out. In terms of involvement, the UNFCCC comprises 186 nations set in an international negotiation framework where cooperative climate action and allocation of responsibilities among nations[7] are discussed.

[3] The Stern review points at the necessity of reducing the concentration of GHG in the atmosphere to 350 parts per million (ppm) being the actual value above 400 ppm (according to the Mauna Loa Observatory, Hawaii) and in a rising trend. No action could lead to 750 ppm resulting in a +5°C according to the evidence found in the IPCC reports.

[4] 197 countries agreed to persue the stabilization of GHG concentrations at a level that would prevent dangerous anthropogenic interference with the climate system.

[5] 55 countries ratified the target of reducing GHG emissions by 5% between 1990 and 2008-2012. The Kyoto protocol covered 55% of developed countries GHG emissions, which included carbon dioxide, methane, nitrous oxide, nitrogen trifluoride, sulphur hexafluoride, hydrofluorocarbons and perfluorocarbons.

[6] Limit global warming below 2°C (aiming for 1.5°C) with the commitment to reach global peaking of GHG emissions as soon as possible and zero-net emissions by the second half of the century. Each of the countries that have ratified the agreement will define their mitigation plan through Nationally Determined Contributions (NDCs).

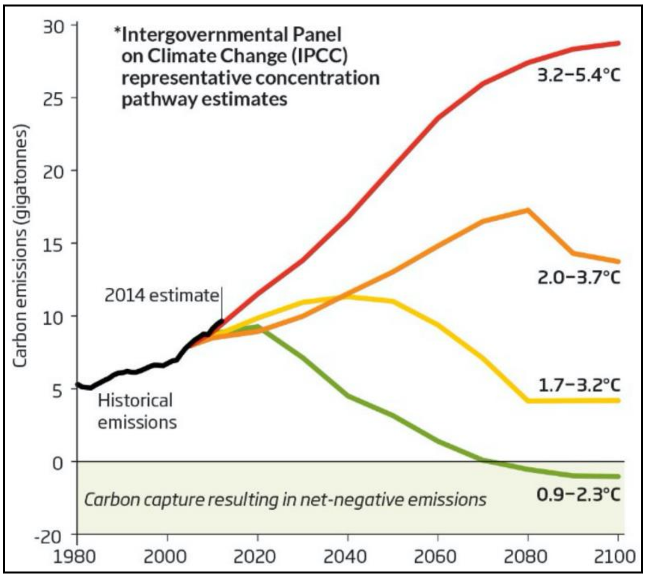
[7] The conference of the parties (COP) takes place every year in a different country to coordinate climate action and evaluate progress made.

Climate Change is a global challenge and entails many uncertainties for policy makers with unequal economic development status. Two ways of thinking have emerged since climate change entered the international political agenda. First, the conventional theory defends that a large collective problem should be handled by a centralized actor. This ideology resulted in the creation of the UNFCCC, to reduce GHG emissions by establishing a collective target (binding agreement). As a consequence of international cooperation and the conviction that global coordinated action reduces the total cost of climate change abatement, the Kyoto protocol was approved. This agreement set binding emission reduction targets for a group of developed countries, leaving developing countries out of the common objective. That is, no targets were set for developing countries. This decision was backed by the principle of common but differentiated responsibility (due to the historical emissions of developed countries) and the principle of the right to economic development (economic and social development is the priority for developing countries) (UNFCCC, 1992).

This approach has proved to be ineffective in addressing the problem since countries generating significant emissions were left out of the agreement (free-rider principle[8]). In the last decades, global emissions have continued to rise at a fast rate, especially due to the economic boom in developing countries. Even though Kyoto was a success in terms of international cooperation and accomplishment of targets, it failed to slow down the upward trend in GHG concentration in the atmosphere. The reasons for this failure were the lack of ambitious targets (to ensure greater participation) and also the absence of key polluters (whether for economic reasons or non-ratification of the protocol). Hence, new and more ambitious political initiatives were required to reverse the trend. According to the Intergovernmental Panel on Climate Change (IPCC), the current carbon emission pathway could result in a global temperature increase of 3.2 to 5.4 degrees (see Figure 4).

[8] The free-rider principel refers to a market failure occuring when individuals take advantage of being able to use a common resource, or collective good, without paying for it. The most common example is the use of public services without paying the shared tax.

Figure 4: Carbon emission pathways and temperature increase rages



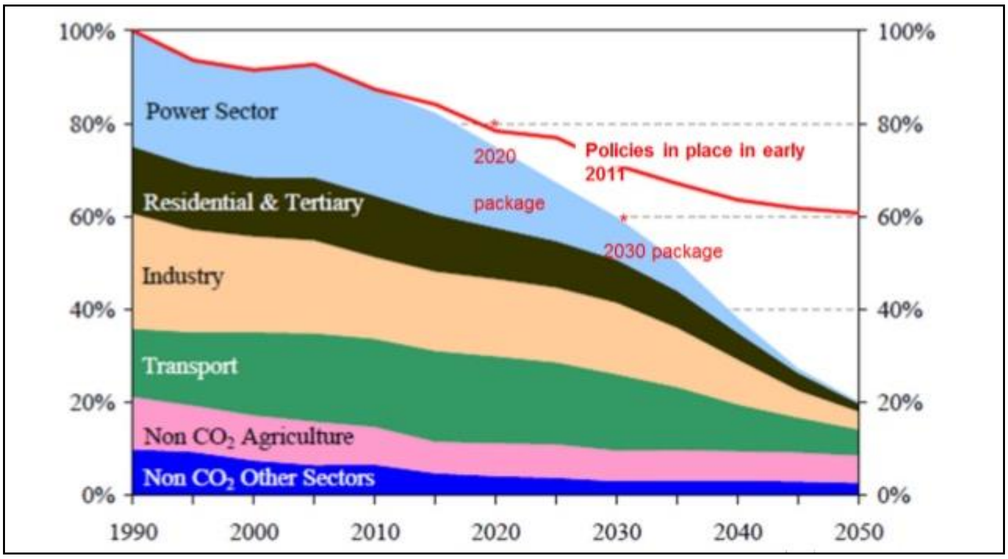
Source: Science Based Targets (SBT) based on IPCC projections. 2016

Due to the failure of conventional theory, a different way of thinking gained momentum, based on the behavioural principle of Garrett Hardin, known as the tragedy of the commons. According to Hardin, individual agents acting independently and rationally follow own self-interest, which makes them behave contrary to the common good of preserving natural resources (Hardin, 1968). The modern behavioural theory recommends a polycentric approach with local initiatives that can be monitored and assessed by national institutions. The Paris Climate Agreement (2015) has permitted to move towards a bottom-up cooperative climate regime[9] where nations set their nationally determined contributions (NDCs) to achieve a common goal of a 2-degree global temperature increase in this century. This means that countries may determine targets and emission reduction instruments that best suit their possibilities. In 2018, 178 out of 197 had ratified the agreement and have already started to implement national tools towards meeting their declared NDCs. Environmental policies are adapted to each nation’s possibilities under an international cooperation framework. The common cooperation will support the exchange of knowledge and technology, the financial aid for adaptation and innovation, as well as set transparency rules and control progress towards the established targets (UNFCCC, 2018).

[9] This approach reminds that of a multi-stakeholder system with a wider acceptance rate among participants.

The climate agreement of Kyoto gave birth to a common European project with the objective of the transformation of the economy towards a sustainable economic model. This commitment led to the definition of the "Low carbon road map 2050" in 2011, which serves as a guide to define environmental targets and policies. This has been especially the case for the power sector, which should undergo a progressive transformation from fossil fuel based to emission free generation by 2050 (see Figure 5).

Figure 5: Low carbon road map 2050



Source: European Commission, 2011

SECTION 2.2: EU'S ENVIRONMENTAL GOALS

The world's top GHG emitting countries have progressively adopted a range of regulations in the form of carbon taxes, emission trading schemes or implicit regulatory actions (as waste or emission standards) in order to limit the effect on climate change. Throughout the last decade, the EU has positioned itself as the global leader in the fight against climate change through the implementation of multiple mechanisms and political measures. The aim is to construct a sustainable economic model that serves as an example to other nations. Assuming this responsibility, the EU has defined three main pillars to concentrate action and policy measures: deployment of renewable energy sources, reduction of GHG emissions and increase of energy efficiency.[10] Under these categories, EU leaders have set ambitious common climate targets to transform the economy throughout the first half of this century (see Figure 6) (Deloitte, 2015).

- 2020: The EU 20-20-20 climate and energy targets approved in March 2007 before the economic crisis aim to cut GHG emissions by 20% compared to the levels in 1990, reaching 20% renewable energy in the total energy consumption mix, and increasing energy efficiency by 20%.

- 2030: In 2014, the European Commission (EC) agreed on a new framework up to 2030 after assessing the 20-20-20 policy accomplishments. The 2030 set GHG emission reductions by at least 40% compared to 1990, reaching 27% renewable energy in the energy consumption mix, and increasing energy efficiency by 30%.

- 2050: the 2050 Energy Roadmap published in 2011 aims to accomplish a low carbon economy with at least 80% of GHG emissions reduction compared to 1990, in this long-term scenario renewable energy share and energy efficiency targets are not defined yet.

Figure 6: European targets for 2020, 2030 and 2050 versus 1990 levels

	2020	2030	2050
Share of Renewable Energy	20%	30%	TBD
Increase Energy Efficiency	20%	27%	TBD
Reduction of Greenhous gas emissions	20%	40%	80-95%

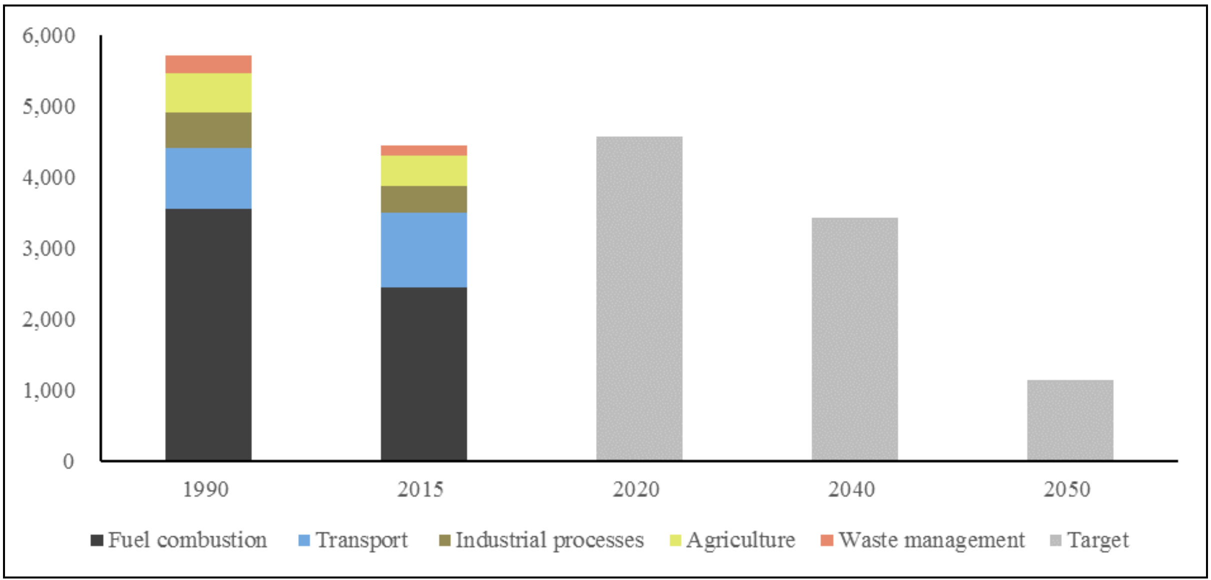
Source: Own development

Considering that the EU is composed out of 28 nations with different states of development, it has been necessary to split the common objectives at a member state level[11]. This has

[10] This division follows the guiding principles covered by the Treaty of Lisbon 2007: ensure energy market performance and energy supply as well as promote energy efficiency, renewable energy generation and network interconnection.

permitted to define objectives based on abatement potential and economic development of each member state.[12] The EU has set ambitious carbon reduction targets affecting all sectors that contribute to climate change. With a particular focus, in drastically reducing the carbon intensity of the fuel combustion sectors, particularly the power sector (see Figure 7).

Figure 7: EU-28 GHG emissions by source sector and targets (thousand tonnes of CO2 eq.)



Source: Own development, data source Eurostat 2018

The EU aims to shift the power sector from fossil fuels to emission free generation granting a sustainable, competitive, affordable and secure electricity supply. It is a fact that electricity represents 20% of total energy consumption, nonetheless it accounts for approximately 30% of total GHG emissions concentrated in a small amount of energy and emission intensive producers. This makes political measures more player-specific and less costly to control (recall the excludability principle of environmental economics in section 1.3). In the following sections, we will focus on the environmental progress of Germany and the UK in regards to the 2020 and 2030 objectives and the resulting transformation of the power sector.

[11] In the Kyoto protocol, the EU appeared as a group and the marginal cost of emission reductions in each country set the basis for the distribution of targets (equi-marginal principle). For this reason, countries such as Germany, UK and Denmark concentrated larger emission reductions than Hungry, Poland or Spain.

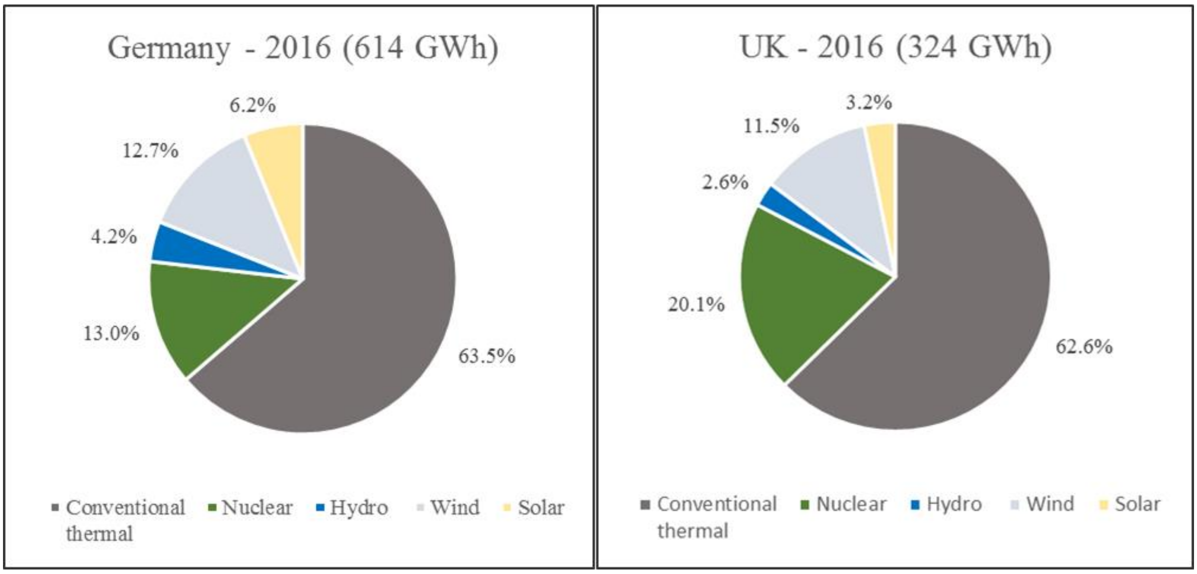
[12] Each state has individual GHG reduction targets agreed in the European Council.

SECTION 2.3: GOALS FOR THE POWER SECTOR IN GERMANY AND THE UK

The following analysis will focus on two countries with the highest level of net electricity generation among the EU member states (2.8 million GWh in 2016): Germany (accounting for 18% of total) and United Kingdom (accounting for 11% of total). The only country with also a double-digit share in total EU-28 net generation is France (accounting for 16%). Since France produces up to 80% of electricity from nuclear sources, it is not a representative case for vast reductions of emissions through the change of fossil fuel power sources (Eurostat, 2018).

Germany and the UK show a similar net electricity production structure with more than 60% coming from power stations using combustible fuels (such as natural gas, coal and oil). This number is way above the EU-28 average of 47.6 % coming from conventional thermal sources. In both cases, the highest share of net electricity generation from renewables is wind energy with over a 12% share followed by solar power (see Figure 8). The proportion of net electricity generated from solar and wind has increased greatly over the last decade as a result of technology improvements and regulatory incentives.

Figure 8: Comparison share electricity generation sources in Germany and the UK (2016)



Source: Own development, data source Eurostat 2018

The EU as environmental leader has recognised the importance of setting ambitious targets and accomplishing them on time in order to encourage other high emitting economies to follow the same path. Derived from the EU-28 targets mentioned before and the responsibility of Germany and the UK as leading economies in the Eurozone, each country has set its own energy and climate agenda (see Table 2 and Table 3).

Table 2: Germany´s energy and climate targets

Targets		2020	2030	2050
Energy Efficiency	Reduction of primary energy consumption versus 2008	20%		50%
	Reduction of electricity consumption versus 2008	10%		25%
	Reduction of final energy consumption in the transport sector versus 2005	10%		40%
Renewable Energy	Share of renewable Energy in final energy consumption	18%	30%	60%
	Share of renewable Energy in electricity consumption	35%	50%	80%
GHG	Reduction of GHG emissions versus 1990	40%	55%	80-95%

Source: Own development out of Energy Concept 2010 and Energy package 2011

Table 3: The UK’s energy and climate targets

Targets		2020	2050
Energy Efficiency	Energy savings versus 2007 business as usual scenario	18%	-
Renewable Energy	Renewable Energy in final energy consumption	15%	-
GHG	EU-wide target for ETS related GHG emission reductions versus 2005	21%	80% vs. 1990
	Non-ETS related GHG emission reductions versus 2005	16%	

Source: Own development out of the various directives mainly Carbon Emission Reduction Target, Renewable Obligation and Climate Change Act 2008

In the following section, the progress of each country in meeting the energy and climate targets will be evaluated.

SECTION 2.4: RENEWABLE ENERGY SOURCES IN THE POWER SECTOR

The defined target on deployment of renewable energy sources has been especially acute in the power sector. This can be seen in the penetration of renewables over the last years. Currently, in the EU-28 the power sector accounts for 40% of total electricity production from renewable sources with continuous capacity additions. This expansion should continue over the next decades aiming to achieve a complete decarbonisation of the power sector by 2050 (Deloitte, 2015).

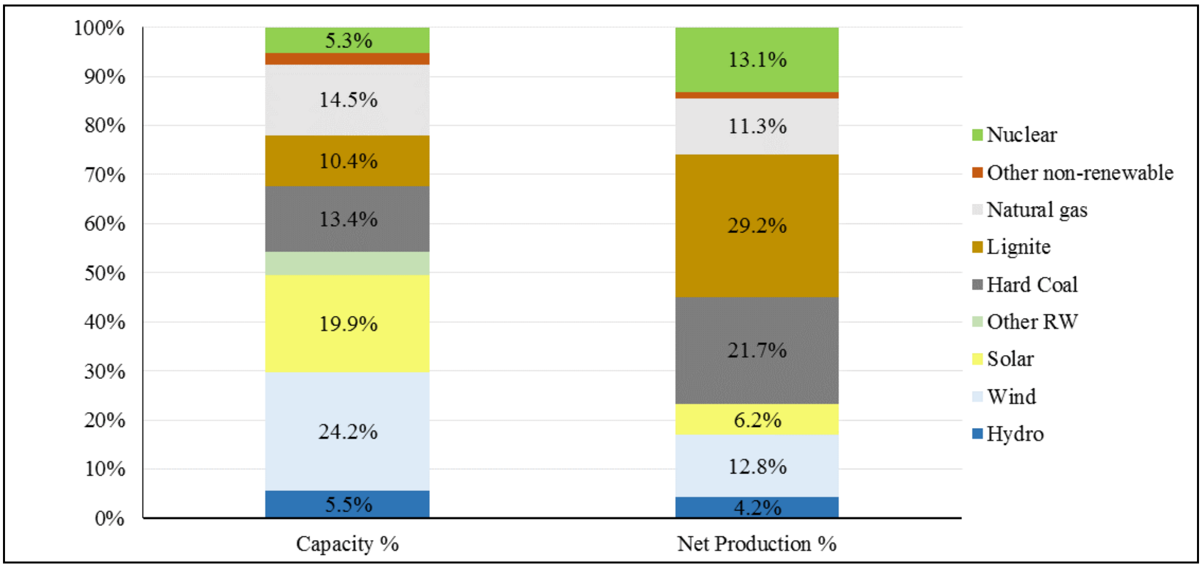
In terms of regulation, the Renewable Energy Directive (RED) sets legally binding targets for each member state consistent with the EU 2020 objective of 20% renewable energy in final energy consumption. Dissimilar potential for development of renewable sources (due to topography, latitude and existing energy mix) and economic development constitutes the main criteria for supporting individual targets. Renewables deployment has been growing at a fast pace in Germany and the UK, due to incentive schemes and technological development that have pressed the cost of renewables down. The deployment of the different technologies is asymmetrical since it depends on favourable natural resources or weather conditions that allow high electricity output. The highest share of renewable technologies in these countries is formed by wind, solar and hydropower.

The progressive increase of solar and wind capacity is reshaping the energy system towards a more decentralized model. This aspect added to the limited prospects of long-lasting energy storage (intermittency challenge), makes network investments necessary to fully integrate RW into the system. Besides network investment, increasing share of renewables in the power mix creates the need for rapid ramp-up generation capacity to secure supply in periods where renewable generation is not sufficient. Today, the only viable solution to cover the intermittency profile of renewable energy sources (RES) is through flexible fossil fuel generation capacity. This, sets an additional challenge as emission intensive power plants need to stay operative to secure power supply and represents an essential aspect when addressing the coal-to-gas switching problematic.

SECTION 2.4.1 GERMAN ACCOMPLISHMENTS

In 2016, Germany had a total installed capacity of 210 GW and a net production of 614,155 GWh. Germany's renewable energy target is 18% share in total final energy consumption and 35% of total electricity generation by 2020. A set of public financial packages have driven the renewable deployment over the last decade. Financial and fiscal incentives such as feed-in-tariffs[13], feed-in-premium[14] or green certificates[15] are the most common instrument used by the government to encourage investors to take part in the energy transition known as "Energiewende". The next figure shows the distribution of total installed capacity compared to the share of power generation in 2016. It is important to note that more renewable capacity is needed than conventional power capacity in order to produce the same amount of power (see Figure 9). This explains why the renewable energy source represent about 50% of total installed capacity but generate 23% of total power demand (Eurostat, 2018).

Figure 9: Germany's power capacity versus power generation 2016



Source: Own Development, data source Eurostat 2018 and Fraunhofer ISE 2018

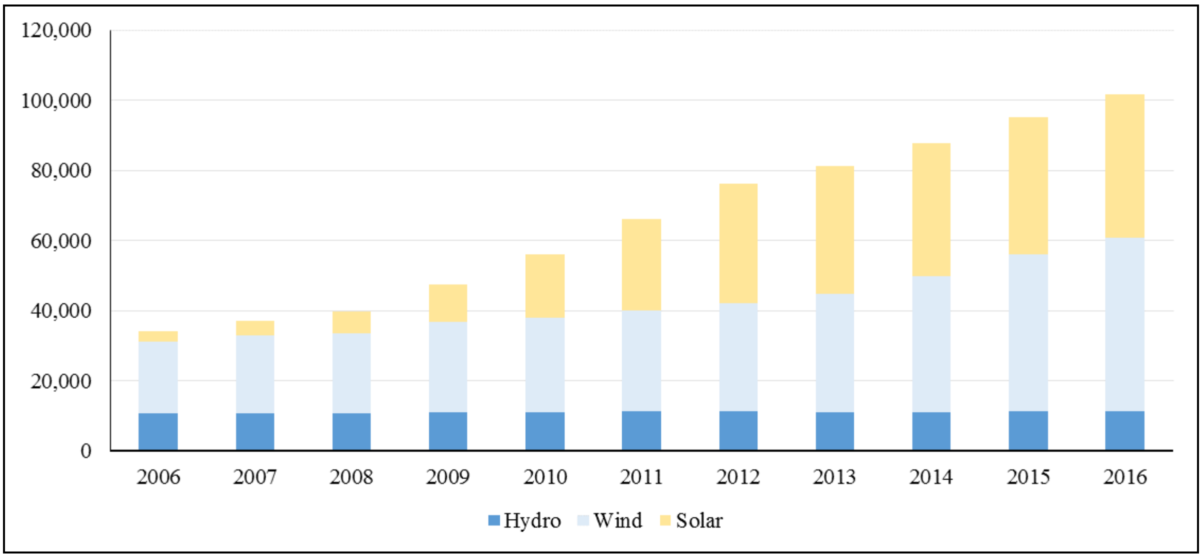
[13] Guaranteed price per MWh of electricity produced for a given number of years.

[14] Add-on incentive on top of the electricity price obtained in the market.

[15] Fluctuating add-on incentive (based on a market of certificates affected by supply and demand) on top of the electricity price obtained in the market.

In the last decade (2006 to 2016), Germany has been able to increase the share of renewables in net electricity consumption from 10% to 23%. Wind power is the most important RES with an installed capacity of 50 GW in 2016 followed by solar, which grew sharply from 3 GW in 2006 to 41 GW in 2016 (see Figure 10). According to Eurostat, Germany is on the right path to accomplishing its target for 2020, thanks to the introduced incentives that triggered the rapid capacity expansion. However, a slow-down of financial support may hamper the good prospects of achieving the 2020 target (Eurostat, 2018).

Figure 10: Germany`s renewable power capacity progress (MW)



Source: Own Development, data source Eurostat 2018

The national commitment is to reach a 60% share of final energy consumption and at least 80% of electricity generation from renewables by 2050. Until a solution is found for the intermittency problem of renewables (due to changing weather patterns), it is obvious that conventional power capacity will be necessary to support the security of supply. Whether the needed back-up energy will come out of coal or natural gas depends on different factors affecting the coal and gas competition (Deloitte, 2015).

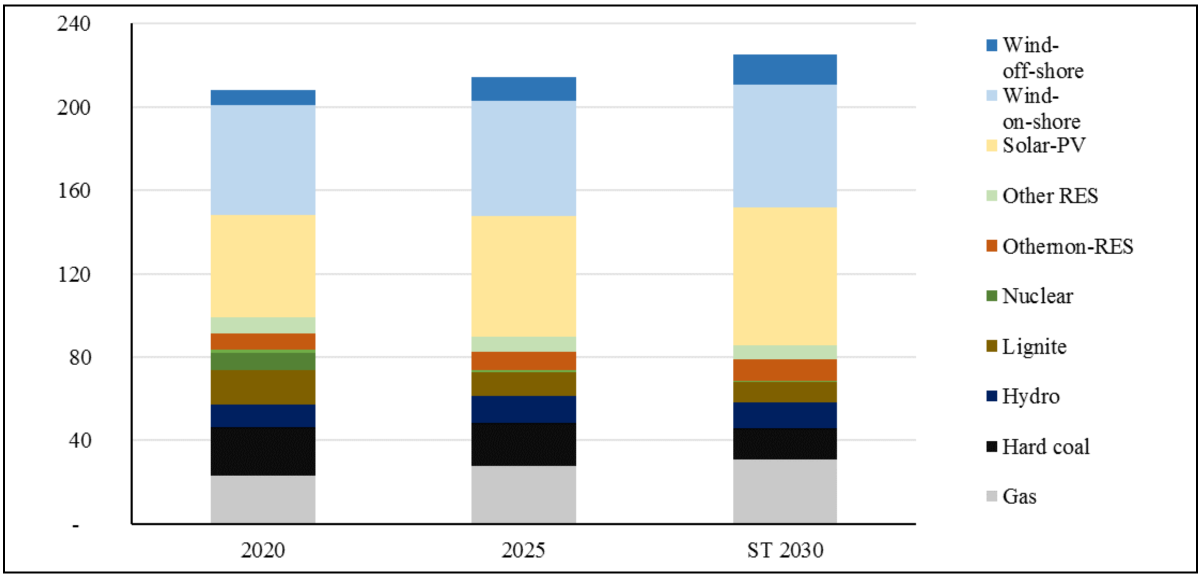
ENTSO-E[16] and ENTSO-G[17] have projected the development of the energy mix up to 2040 for all EU countries (TYNDP scenarios). These projections confirm a more relevant role of

[16] ENTSO-E is the European Network of Transmission System Operators for electricity. It represents 43 electricity transmission system operators (TSOs) from 36 countries across Europe.

[17] ENTSO-G is the European Network of Transmission System Operators for gas.

gas in the German energy mix as the renewable capacity expands rapidly (especially solar and onshore wind) through 2020, 2025 and 2030. These scenarios show that nuclear plants will be phase-out in 2025 and coal (hard coal and lignite) will reduce its total capacity considerably. Figure 11 shows the “best estimate” installed power capacity scenarios for 2020 and 2025; and the “sustainable transition” (ST) scenario for 2030 (Entso-e and Entso-g, 2018).

Figure 11: Germany’s power capacity mix (GW) forecast for 2020 (“best estimation”), 2025 (“best estimation”) and 2030 (“sustainable development scenario”)

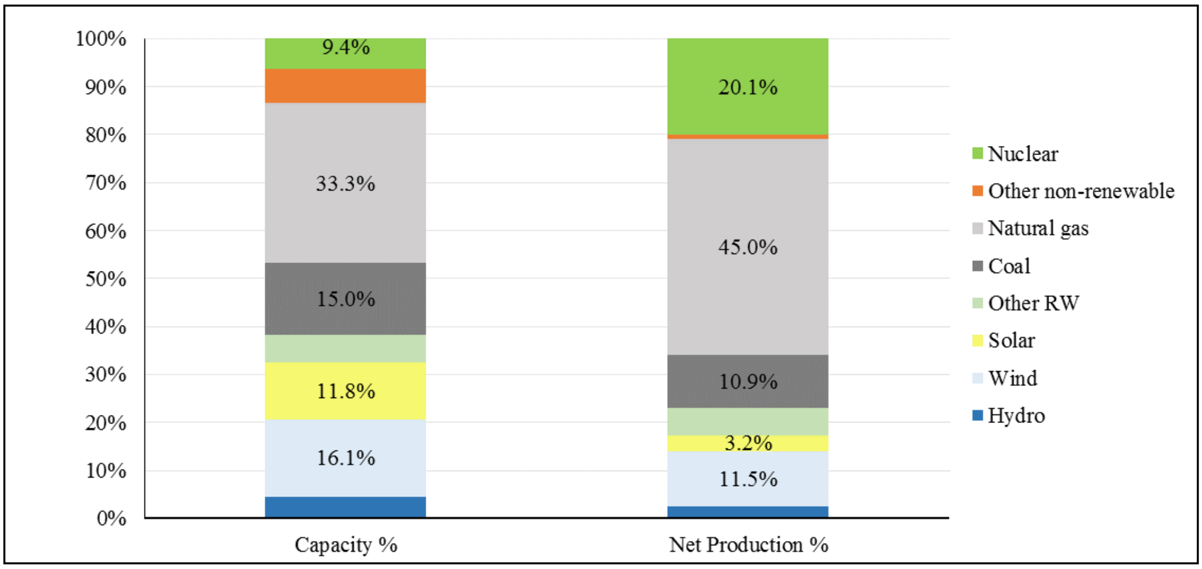


Source: Own development based on Entso-e and Entso-g 2018

SECTION 2.4.2: UK´S ACCOMPLISHMENTS

In 2016, the UK had a total installed capacity of 104 GW and a net production of 324,124 GWh. Renewable power accounted in 2016 for approximately 38% of installed capacity (39 GW) and provided 23% of total electricity generated (75,034 GWh), while 12% came from wind and 3% from solar (see Figure 12) (Eurostat, 2018).

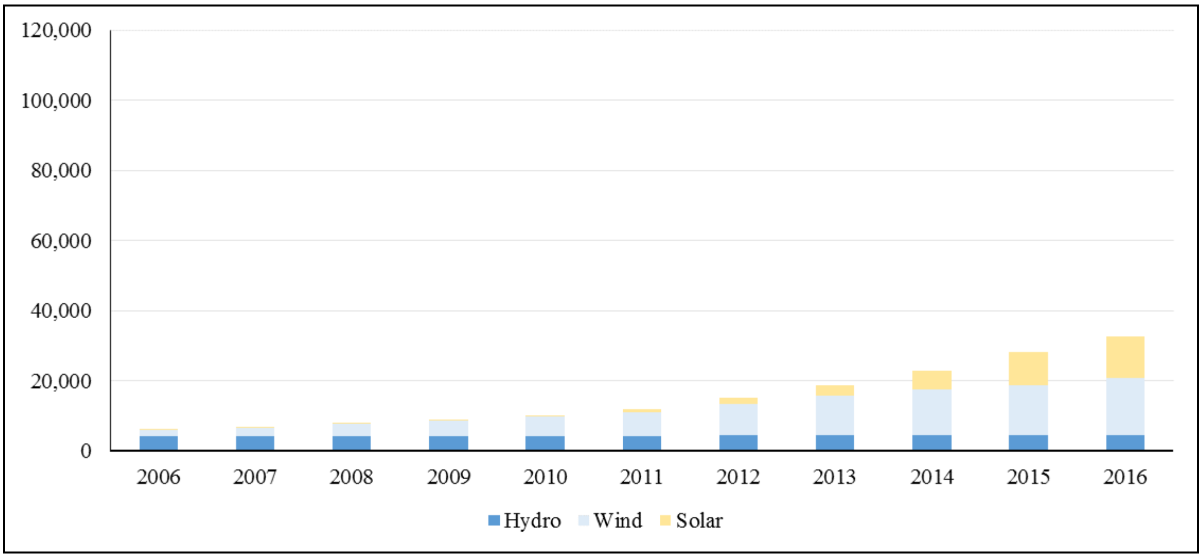
Figure 12: UK power capacity versus net power generation 2016



Source: Own Development, data source Eurostat 2018

In the last decade, (2006 to 2016), the UK has increased the share of renewable in net electricity consumption from 3% to 17%. Wind power is the most important renewable source of electricity production with an installed capacity of 16 GW in 2016 followed by hydro, which has stayed stable due to limited availability with 4.2 GW in 2006 and 4.6 GW in 2016. In 2016, the capacity of renewables increased by 5 GW mainly due to the sharp increase in solar and wind capacity (see Figure 13) (Eurostat, 2018).

Figure 13: UK's renewable power capacity progress (MW)



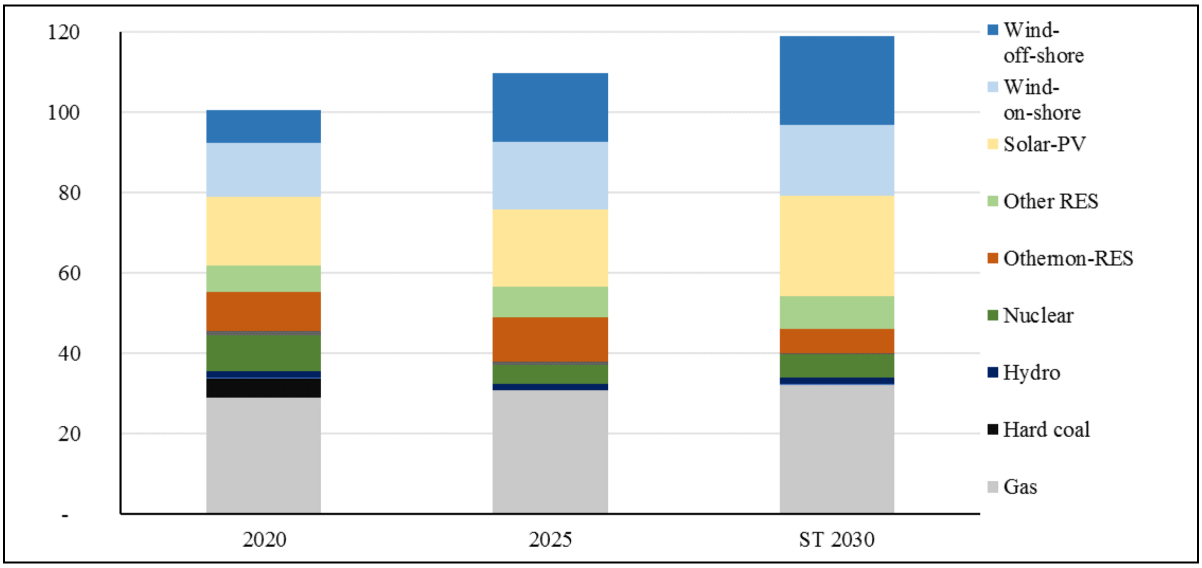
Source: Own Development, data source Eurostat 2018

UK has approved a renewable roadmap, which defines a specific plan to support deployment of offshore and onshore wind, marine energy and photovoltaics. With this plan, the government follows its ambition to reach the 2020 target (15% share of renewables in final energy consumption). Undoubtedly, the observed evolution of the energy mix relies on substantial efforts made by the government through financial support and guarantees benefiting renewable investment. However, according to last published data by Eurostat, the UK is still far from reaching its target and the recent ambitious policies implemented to support renewable development may not have the desired effect before 2020. Furthermore, there are still uncertainties in the sector that need to be resolved in order to accelerate the deployment of renewable energy (Deloitte, 2015).

UK power generation depends highly on fossil fuels, but the steady increase in renewables is pushing traditional combustion out of the merit order curve. Newly added renewable power capacity has raised concerns about security of supply. This has moved the government to implement a capacity market for emission intensive power plants in order to back-up the intermittency of renewable generation. However, this decision is creating controversy, since some high emitting power plants, which are not economically competitive, are seeing their lifetime expanded through this mechanism.

ENTSO-E and ENTSO-G projections on the development of the energy mix (TYNDP scenarios) confirm a more relevant role of gas in the UK energy mix as the renewable capacity expands rapidly (especially wind technologies) through 2020, 2025 and 2030. Hard coal will be phased out in in 2025 and nuclear installed capacity shrinks considerably. Figure 14 shows the “best estimate” installed power capacity scenarios for 2020 and 2025; and the “sustainable transition” (ST) scenario for 2030 (Entso-e and Entso-g, 2018).

Figure 14: UK`s power capacity mix (GW) forecast for 2020 (“best estimation”), 2025 (“best estimation”) and 2030 (“sustainable development scenario”)



Source: Own development based on Entso-e and Entso-g 2018

SECTION 2.5: ENERGY EFFICIENCY IN THE POWER SECTOR

Technology improvements and learning-by-doing effects were the dominant drivers of efficiency gains. Investment in more energy-efficient equipment are the result of compulsory emission standards[18], policies and financial incentives. Energy efficiency saving objectives for primary and final energy consumption have been calculated for the whole EU (not at member state level)[19]. As a result, the EU-28 member states have an indication, but not mandatory targets defined in the Energy Efficiency Directive (Deloitte, 2015).

Energy efficiency savings or gains due to implemented policies are hard to measure and monitor, especially after the economic crisis (it is difficult to isolate the economic recession effect). Thus, it is problematic to establish a direct relation between energy efficiency gains and power generation savings. Additionally, the actions taken are focused principally on energy consumption as a whole (increase in macroeconomic energy productivity mainly in

[18] Sales of electric cars have increase rapidly, driven by government policies. Similarly, for energy services such as residential lighting standards have improved the efficiency of lightbulbs.

[19] Expressed as primary energy consumption (PEC) or final energy consumption (FEC).

the building, industrial and transport sector), not power generation specifically. Looking at the power sector, technological progress has increased the efficiency level of coal and gas technologies allowing for a higher power output and less fuel consumption. However, due to the lack of available data about the efficiency gains achieved in the power sector, this aspect will not be analysed into further detail in this chapter.

SECTION 2.6: EMISSION REDUCTIONS IN THE POWER SECTOR

Out of all the sectors included in the EU ETS, the power sector is the one with highest abatement potential in the medium term[20] due to its concertation, the available low emitting technologies and the inexistent carbon leakage risk. This conditions have pushed policy makers to set ambitious targets and policies specifically for this sector. Each country has its own emission reduction targets aligned with the economic, environmental and social circumstances. However, arising challenges may complicate their realization. The three main challenges shared by all member states are as follows (EEA, 2014):

- Economic recovery: EU economic decline from 2008-2013 resulted in considerable GHG reductions, especially for some countries where electricity consumption dropped considerably[21]. This illusion of emission reductions has moved many member states to relax their efforts. However, the current economic recovery is driving emissions up again, which could disrupt meeting the EU objectives. According to latest released information by Eurostat, in 2017 emissions have increased compared to 2016. Especially in the countries that were more affected by the economic downturn[22] (Eurostat, 2018).

- Nuclear phase-out: The decision of some EU countries to phase out nuclear power completely (Germany) or partially (France, Spain) means that substitutes with similar generation capacity need to be available. The problem that emerges is that nuclear is a

[20] The power sector generates 1,908 MtCO2eq., which constitutes around 40% of total GHG emissions.

[21] Countries worst hit by the economic crisis are Ireland, Greece, Portugal, Italy, Spain and Hungary.

[22] Malta (+12.8%), followed by Estonia (+11.3%), Bulgaria (+8.3%) Spain (+7.4%) and Portugal (+7.3%).

low emitting power source and the phase-out may be substituted by emission intensive power plants (coal) as renewable technologies are not yet sufficiently developed to cover the high amount of nuclear generation. The best example is Germany, where a rapid nuclear phase-out has generated what main experts call the "power gap" ("Stromlücke" in German).

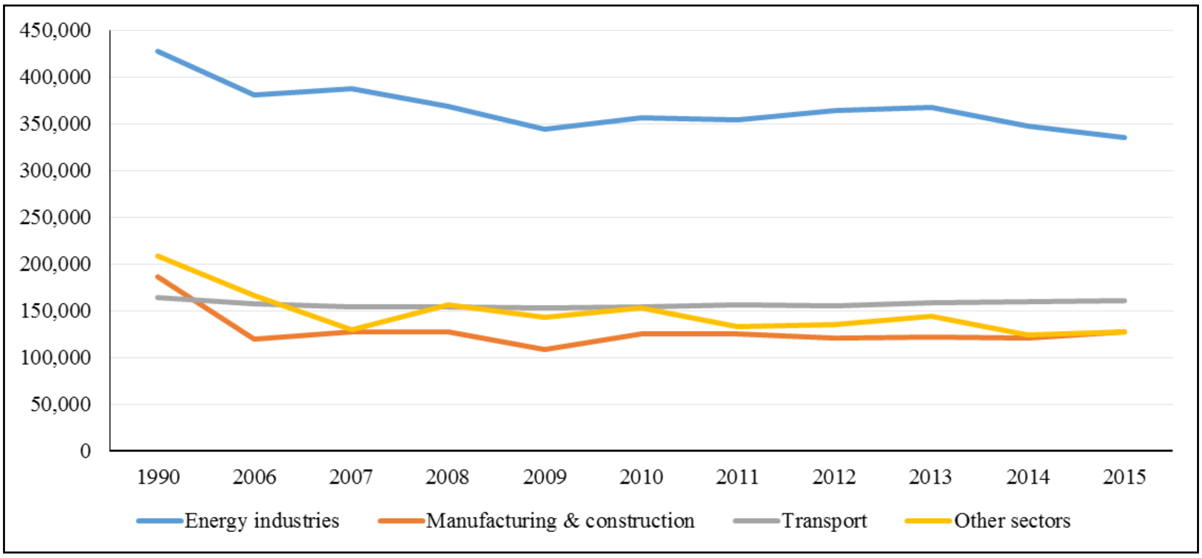
- The coal economic dilemma: Low coal prices, abundant reserves and high amount of generation capacity have set coal in a promising situation in the merit-order-curve. This situation added to a persistently weak carbon price, resulted in an advantageous economic position of coal power generation over the last years. Additionally, coal resources are abundant in Europe, especially in Poland and Germany raising the argument of energy independence (a strategy aspect for many European politicians). This situation has set governments under pressure to delay a coal phase-out decision at the risk of not accomplishing the environmental targets. Particularly difficult, is the decision for countries with a vast power capacity and long history of using coal as a fundamental pillar of the power mix, as is the case of Germany and the UK.

In the following sections, we will analyse the exposure of Germany and the UK to these challenges and comment on the perspectives to accomplish the 2020 and 2030 emission reduction targets.

SECTION 2.6.1: GERMAN ACCOMPLISHMENTS

Germany is the highest CO2 emitter in the EU responsible for 23% of total CO2 emissions in 2017. Emissions have been declining for the last 25 years by 26% compared to 1990 levels (see Figure 15). Nevertheless, emissions increased after 2009 with the first signs of economic recovery and after the country's decision to phase-out nuclear power in 2011, a political move made after the Fukushima accident (Eurostat, 2018).

Figure 15: Germany's historic GHG emissions by sector (thousand tonnes of CO2 equivalent) (1990-2015)

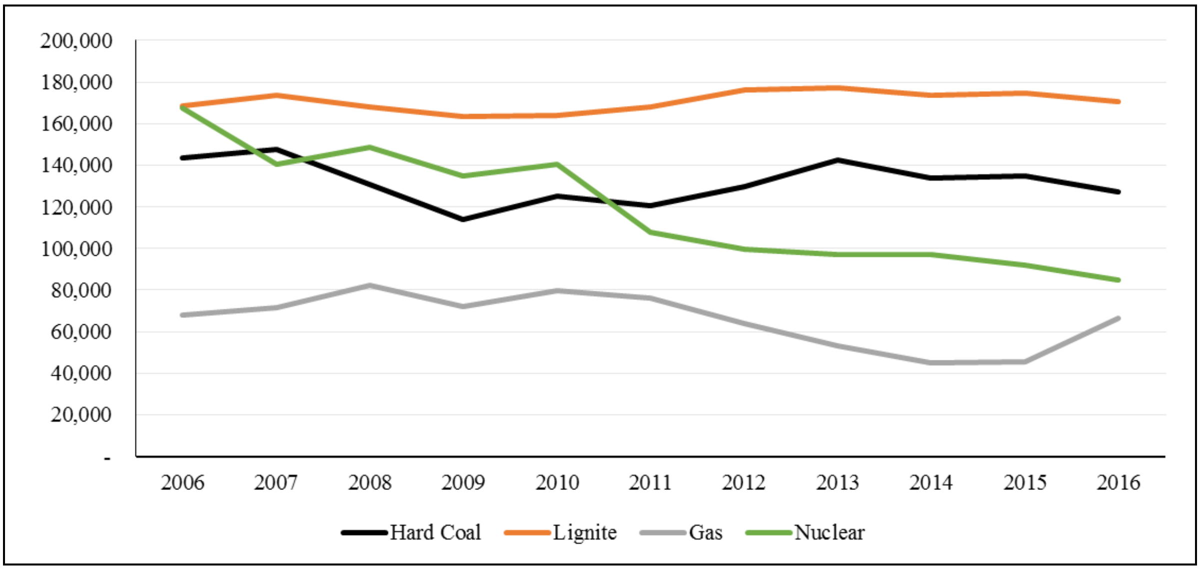


Source: Own development, data source Eurostat 2018

Nuclear plants supplied approximately 23% (167,269 GWh) of Germany's power before 2011. The political decision to phase-out nuclear power progressively until 2022 brings a major transformation to the energy mix affecting energy security and a change in the trajectory of GHG emissions. In 2011, the eight oldest nuclear plants (8.8 GW capacity) were permanently shut down and a plan to close the remaining reactors (9.5 GW capacity) by 2022 is on track. According to recent data, in 2016 nuclear plants generated 80,038 GWh, still 13% of country's net electricity output. In terms of GHG emissions, the nuclear phase-out has led to a rebound of emissions, mainly because coal has taken the role to cover the electricity gap left by nuclear generation. Unsurprisingly, the rapid pace of plant closure, has hampered that ability for renewables to compensate the remaining power gap[23]. This has resulted in an increase of carbon intensive power sources (mainly hard coal), in order to grant the system energy security (see Figure 16). Far from adopting a strategy to reduce coal generation, the situation has obliged the government to approve the build-up of new coal capacity, which creates the risk of locking in carbon emissions over the next decades (Matthes. 2017)

[23] Replacing 97 TWH of nuclear power production would require around 120 GW on new PV capacity, 63 GW of wind or 18 GW of coal power capacity (Deloitte, 2015).

Figure 16: Germany’s gross electricity generation from coal, gas and nuclear in GWh (2006-2016)



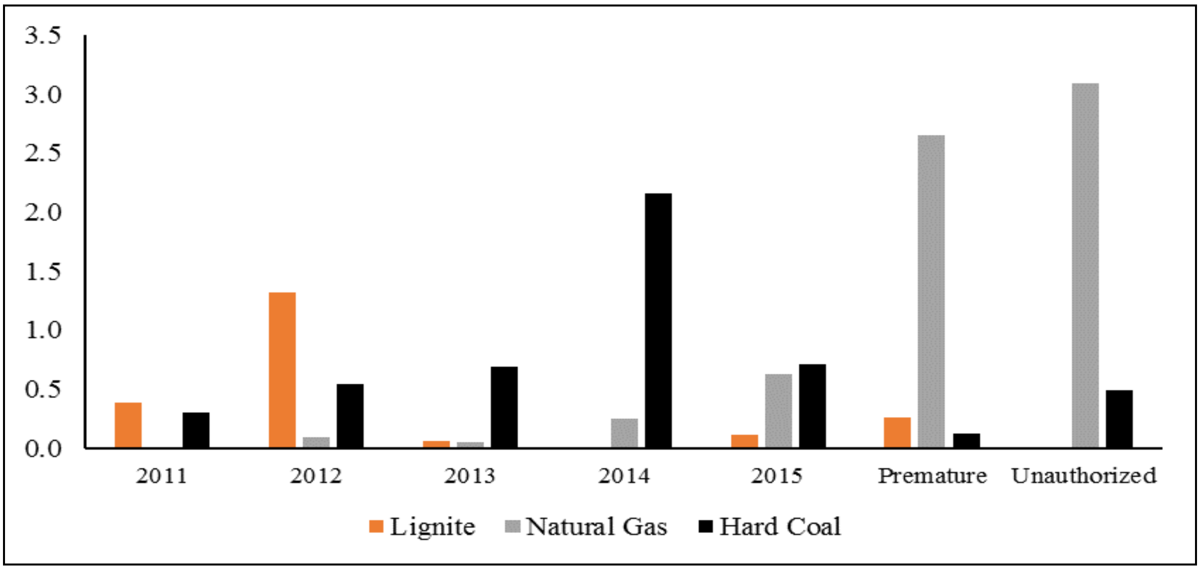
Source: Own development, data source Eurostat 2018

The coal dilemma affects Germany more than other EU member states due to its abundant lignite reserves and its efficient extraction facilities. The long-lasting connection to coal has established a heavy reliance with stable power generation coming from hard coal and lignite (around 50% since 2006) (Eurostat 2018). Since 2011 (until 2016), 10 GW additional coal power capacity has been added to the energy mix. These additions were originally planned to replace inefficient coal plants. However, the nuclear gap in addition to positive economic conditions have favoured that coal power increases its share in the baseload[24]. Further, the competitive advantage of coal has harmed the economic viability of gas-fired power plants to the extent that some plants were prematurely closed or mothballed[25] (see Figure 17) (Bundesnetzagenture, 2017).

[24] Base load represents the power generation covered by power stations, which can consistently generate the electrical power needed to satisfy minimum demand.

[25] Unauthorized closure.

Figure 17: Germany’s plant closure 2011-2015 (capacity in GW)

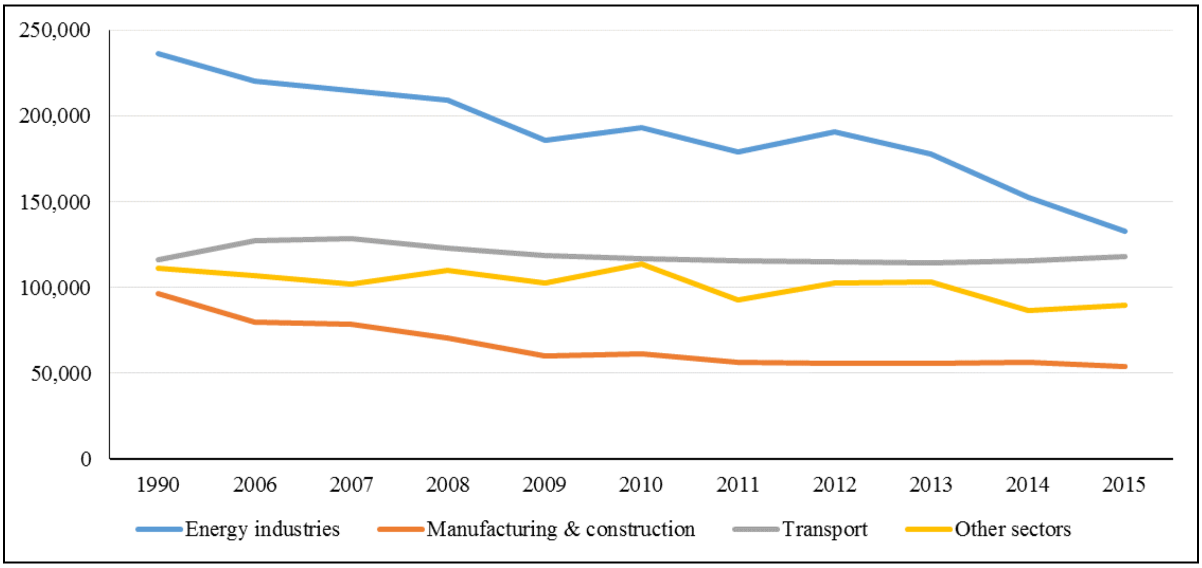


Source: Own development, data source Bundesnetzagenture 2017

SECTION 2.6.2: UK´S ACCOMPLISHMENTS

The UK is the second highest CO2 emitter in the EU accounting for approximately 13% of total CO2 emissions in 2016. However, emissions have been declining for the last 25 years by 30% compared to 1990 levels. Taking into account a rebound after 2009 with the first signs of economic recovery, emissions have been decreasing progressively driven (to a high extent) by the decarbonisation of the energy sector (see Figure 18). The radical transformation of the power sector goes in line with the objective to reduce 80% of GHG emissions by 2050 (see Table 3) (Eurostat, 2018).

Figure 18: UK's historic GHG emissions by sector in thousand tonnes of CO2 equivalent (1990-2015)



Source: Own development, data source Eurostat 2018

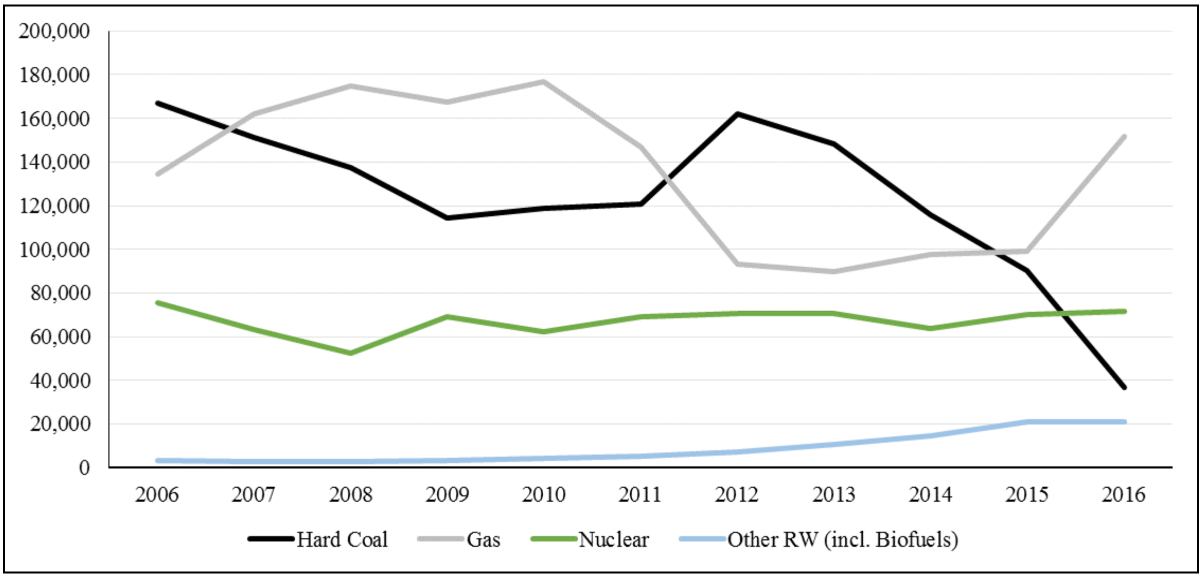
In order to reduce GHG emissions, the government has implemented a series of political and market driven measures over the last years. One of the key objectives is to trigger the replacement of ageing emission intensive power plants with low emission technologies and renewables. Approximately, 20% of existing conventional capacity (nuclear and coal) is scheduled to close down over the next decade. Regarding nuclear power, roughly 7.6 GW will shut down due to decommissioning by 2019 and almost all nuclear reactors (except 1.2 GW) will reach the end of lifetime by 2023. Nuclear power constitutes a key element in the UK's GHG reduction ambitions due to its low emission rate. Therefore, a newly built nuclear plant (3.2 GW) will balance part of the lost capacity[26] ensuring the presence of nuclear power in the energy mix for the next decades.

Coal power generation represented 11% of total net electricity produced in 2016, resulting of a progressive decline over the last decades. Exceptionally in 2010-2012 coal experienced a new momentum after the drastic drop in coal prices and low CO2 emission costs when the combined effect boosted the economics of coal power generation. The share of coal in electricity generation mix reached 44% in 2012 and since then it has steadily declined due to

[26] This nuclear plant will cover approximately 7% of the country's electricity needs (Deloitte 2015).

stricter air quality requirements, the decommissioning of coal-fired mines[27] and the introduction of a carbon price floor. Political measures have countered the economic attractiveness of coal in favour of less emitting fuels sources such as gas or biofuels (see Figure 19). It is very likely that the falling trend will continue in the next years and coal-fired capacity will serve to secure energy supply[28] until its complete phase-out in 2025 (Deloitte, 2015).

Figure 19: UK's gross electricity generation from coal, gas and nuclear in GWh (2006-2016)



Source: Own development, data source Eurostat 2018

The country's electricity capacity coming from coal power plants has decreased significantly since 2010 (-14 GW) as aging emission intensive power plants have been closed down and several plants converted to biomass combustion (considered by the EU as a renewable power sources)[29]. Further, players interested in building new coal power capacity with more efficient technology are having a hard time in getting the permits for construction. In this sense, the government has cancelled more than 14 GW of additional coal capacity projects since 2010

[27] Domestic hard coal extraction is expected to decrease significantly after 2020 as there are no plans to develop new coal mines.

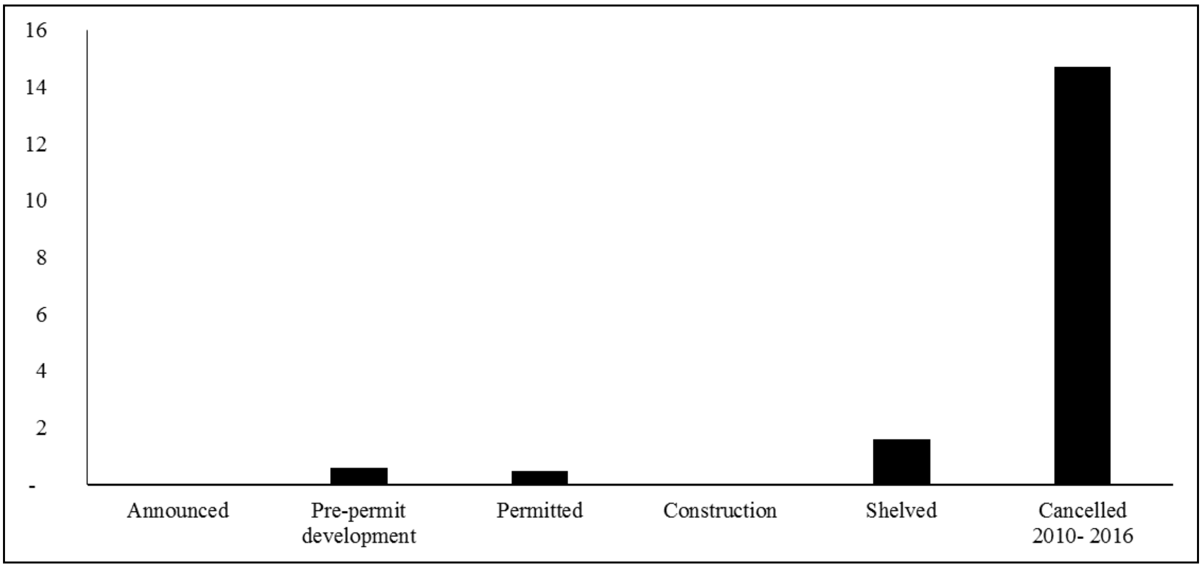
[28] Introduced in 2013, the Electricity Market Reform promotes measures to deliver low carbon energy, security of supply and minimize cost to customers. Two key elements of this reform are the Contracts of Difference (CFD), which promotes long-term price stability for low carbon generation and the capacity market, which pays a reliable retained fee for reliable forms of capacity.

[29] Part of this result can be attributed to the EU Large Combustion Plant Directive (LCP Directive), which will lead to additional closure of coal plants over the next years.

intending to limit the risk of locking in carbon emissions for the next decades (see Figure 20) (Endcoal, 2016).

In order to maintain a capacity level and secure energy supply in peak demand periods the government has introduced a capacity market, which provides an incentive for conventional power generation to keep operating[30]. This measure, aims to avoid the rapid loss of generation capacity from conventional sources, which could increase the risk of outages. From an environmental perspective, this measure could lock in carbon emissions since it extends the lifetime of inefficient, carbon-intensive coal plants, currently unable to be competitive (Deloitte, 2015).

Figure 20: Cancelled coal power capacity additions in the UK by 2016 (in GW)



Source: Own development, data source Endcoal 2017

Referring to gas-fired power, the UK has one of the largest shares of installed capacity, accounting for 33% of total capacity in 2016. The importance of gas is expected to continue to rise as gas-fired electricity plants replace decommissioned coal-fired capacity. However, gas power generation has become more competitive only due to policy mechanisms. Back in 2013, the UK established a carbon price floor in order to prevent the resurgence of coal generation due to low CO2 prices and low coal prices. A stable carbon price would most likely preserve the interest in gas power generation, permitting the accomplishment of drastic

[30] The capacity market aims to secure the availability of approximately 50.8 GW of electricity generation capacity.

GHG emission reduction. Data published by Eurostat reflects that the UK was close to achieving its 2020 GHG emission reduction target, with a 34% decrease in GHG emissions in the electricity sectors in 2015 compared to 1990 (Eurostat, 2017).

In the following chapter, Chapter 3, we will focus on the key factors affecting the coal to gas coal-to-gas switching process, which include: commodity prices, fuel fundamentals, technological progress, regulations and carbon prices. This is needed to understand the position of gas and coal in the European energy mix and will set the ground for a detailed comparison of Germany and the UK in Chapter 4.

CHATER 3: COAL-TO-GAS SWITCHING

Fuel switching gives name to the process of moving from one fuel source to produce energy to an alternative source permitting to attain the same or similar energy output. In the power sector, we refer to coal-to-gas switching as a type of fuel switching, namely when moving from coal or lignite (a CO2 intensive fuel source) to natural gas (a less CO2 emitting fuel source). Coal-to-gas switching has gained importance in the EU over the last decade linked to the growing awareness of climate change and the emission reduction objectives. Gas represents a feasible option to attain drastic emission reductions since it generates less than half the carbon emissions than coal per kWh of electricity produced[31]. Further, the availability of large quantities of natural gas reserves and its high-energy content (similar to the one of coal) has turned gas into a key pillar of environmental regulation. From a regulatory standpoint, an increase in the competitiveness of gas may push coal out of the merit-order-curve, leading to drastic emissions abatement. Many policy makers are aiming to turn gas into the transition fuel that supports the progressive decarbonisation of the European power sector (Gonzalez-Salazar, Kirsten and Prchlik, 2017).

In order to understand the competition between coal and gas in the power sector, first we need to dive into the key factors conditioning the competition itself: such as market trends, technological progress and regulation at a EU and national level. This chapter will delve into the key factors conditioning the coal-to-gas switching process, focusing on the European market.

SECTION 3.1: NATURAL GAS FUNDAMENTALS

Besides its environmental relevance, coal-to-gas switching is an important driver for power prices, load factors, generation margins and obviously, gas demand[32]. As for any commodity market, price fluctuations are a reflection of demand and supply. In Europe, long-term supply contracts with Norway, Russia and Algeria have dominated the gas market for decades, with

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[31] According to a recent study and comparing large power plants in Europe with average effciency level.

[32] In most European countries, gas demand from the power sector is a key driver that shapes the demand curve for the European gas market.

the most suitable transportation option being pipelines (on- and off-shore). The EU has no substantial gas reserves, which obliges to take the risk of being supplied by politically undesired countries. This is especially the case of Russia. An important amount of total gas supply has its origin in Russia and political tensions with this country have escalated over the last years (DNV GL, 2018).

Besides the political risk, transportation costs and infrastructure bottlenecks limit the competitiveness of gas-fired compared to coal power generation. This has been partly overcome through technological development, making it possible today to transport gas over long distances at a reasonable cost in liquefied form, Liquefied Natural Gas (LNG). The surge of LNG allows Europe to diversify its supply sources and obtain gas from a wider number of countries, thereby increasing the availability of gas and pressing gas prices down[33] (World Energy Council, 2016).

Today, there are three main gas markets in the world with different price curves: US-Henry Hub market, Europe-NBP/TTF and Japan-LNG market. The price difference is mainly because of the distance to natural gas reserves (since higher transportation costs increase the final price). For instance, the Henry Hub market (US) reflects the lowest gas price due to the abundant national gas reserves accompanied by highly efficient extraction and transportation infrastructure. While gas prices in Japan are the highest due to the need to import LNG from more distant countries (see Figure 21). In various regions around the globe the relation of abundant resources and low national gas prices[34] have permitted natural gas to become the dominant fuel source in the power industry. Contrary, Europe has no abundant natural gas reserves and gas needs to be imported. Historically Europe has relied on long term contracts indexed to global oil prices with neighbour countries in order to secure supply (some of these contracts are still valid today[35]), which has penalized gas consumptions during high oil price periods. The influence of oil prices is very relevant in the European gas market due to an indexation of up to 50%. From 2013 to 2016, European gas prices experienced a continuous

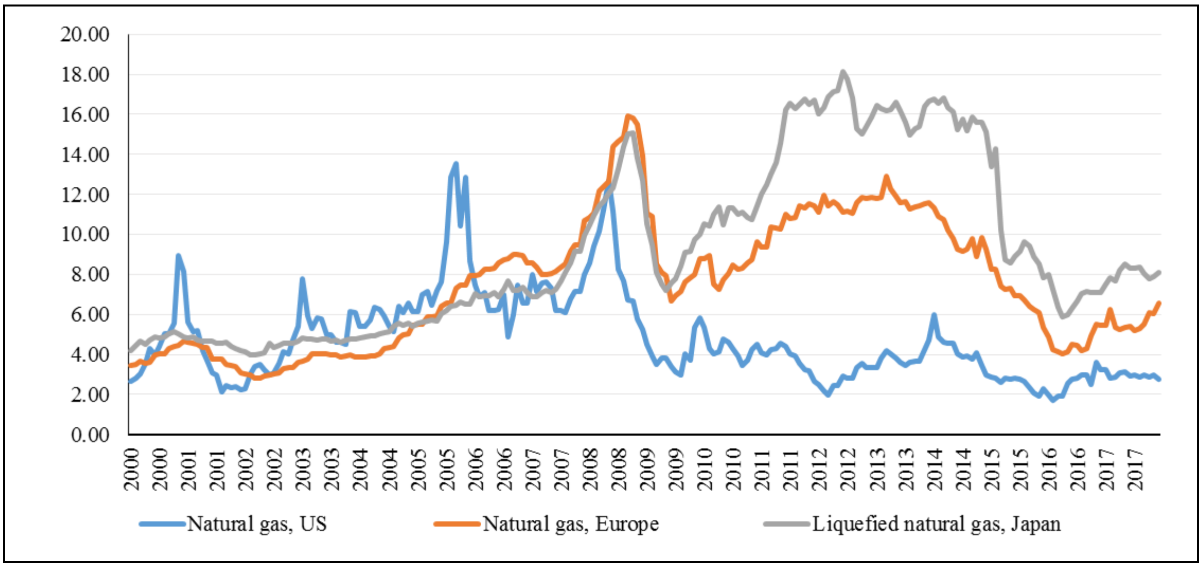
[33] Unconventional gas is entering the global markets as LNG, thereby disrupting the global supplier setting and creating increased competition in regional natural gas markets.

[34] Such as Canada, the Middle-East and Russia.

[35] Some of them running up to 2030.

downward trajectory as a result of increased supply of LNG and low oil prices (Timera, 2017).

Figure 21: Gas price evolution (USD/mmbtu) in the US. (Henry Hub), Europe and Japan (LNG) market (1990-2016)



Own development, data source World Bank and Bloomberg

LNG is affecting EU market prices due to the significant LNG import capacity (transformation infrastructure) built in Europe over the last decades (see Figure 22)[36]. This vast capacity has put Europe in a favourable position to absorb global LNG oversupply. During the last years, an oversupplied global market (low LNG demand in the Asian region and growing global LNG production[37]) has resulted in Europe absorbing the excess LNG supply, thereby pressing European gas prices down. The presence of LNG in European gas markets is expected to grow as world supply is booming (expected to reach 460 BCM a year by 2020)[38]. Increasing LNG supply, flowing through European gas pipelines affects gas prices and subsequently the economics of gas power generation. Experts perceive LNG as a game-changer that could set an end to the traditional oil-indexed contracts and open the path

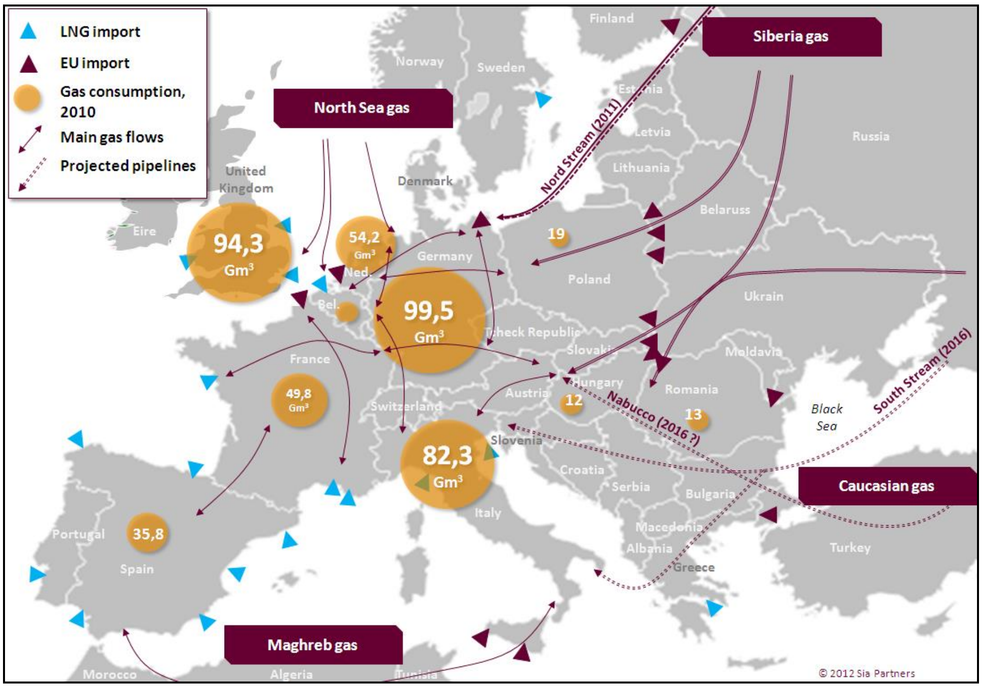
[36] Converts gas from its liquefied form (LNG) transported in bunkers to natural gas fed into the pipeline network.

[37] Particularly in Australia and US.

[38] Currently, Europe has 22 LNG regasification terminals in operation with a total capacity of 216 bcm, which is underutilized (only 20% of capacity in use).

towards a competitive global gas market with persistent low gas prices (DNV GL, 2018 and IEA, 2017).

Figure 22: Gas consumption and supply in key EU member states (2011)



Source: Sia Partners, 2011

SECTION 3.2: COAL FUNDAMENTALS

There are different types of coal with hard coal[39] and lignite (also called brown coal) forming the two main groups. Each group has different energy and water content, causing a dissimilar environmental impact (i.e. lignite has less energy content and is more carbon intensive). According to BGR, global coal reserves[40] were estimated at 1,029 billion tonnes (Gt) by the end of 2015, divided in 712 Gt of hard coal and 317 Gt of lignite. Unlike natural gas, coal reserves are distributed across all continents and extraction does not require high technological investment (BGR, 2016).

[39] Coal used in power production is referred as steam coal (a subgroup of hard coal), which includes anthracite, bituminous and sub-bituminous coal.

[40] Reserves are energy resources, which have been accurately recorded and which can be economically extracted using the current technical possibilities.

In Europe, coal reserves are significant, holding 18.3 Gt of hard coal reserves (80% of the reserves are located in Poland) and 56 Gt of lignite reserves (72% of the reserves are located in Germany). This resource concentration, means that the EU lignite and hard coal production is linked to political decisions in Germany and Poland. A key difference between both coal types is the production (or extraction) process. In Europe, hard coal is obtained from underground deposits, which entails a high degree of complexity for miners to recover. Besides it is a low-quality coal, which makes it energy content wise costly compared to imported coal. Contrary, lignite is mined in open-sites close to the power plants, which keeps production and transportation costs low. From an economical point of view, lignite extraction in Europe is more cost-competitive than hard coal[41] and represents an important energy source for some member states that can reduce their energy dependency. However, lignite is an intensive source of CO2 emissions that needs to be reduced or banned to accomplish the established environmental aims (Euracoal, 2018).

Coal has become the world's second-largest primary fuel, after oil, mainly because of two factors: its abundance[42] and its low capital-intensive supply chain[43]. Over the last century, coal has been one of key levers of economic growth in developed and developing countries. According to the IEA, coal use is driven mostly by the power sector, which represents about 70% of world coal consumption. Opposite to natural gas, hard coal has a global and competitive market (due to its lower abundance lignite is not traded internationally), meaning that prices[44] run almost harmoniously in different regions. Over the last years, global coal demand has decreased primarily influenced by China's decision to lower its dependence on coal[45] and US's shift to natural gas in the power sector triggered by the shale gas boom. This has generated a supply surplus in the international market pushing prices down since 2011 and reaching the bottom line in 2015[46] (see Figure 23). International and national climate policies are penalizing coal usage due to its high carbon content, therefore experts foresee a

[41] Domestic hard coal production struggles with financial losses and cannot compete with cheap international imports. EU Commission has introduced a closure plan for uncompetitive mines by 31 December 2018 with progressive reduction of subsidies.

[42] Coal has the largest reserves of all fossil fuels. Enough to fuel more than 100 years of current world production.

[43] Transport and storage of coal is relatively inexpensive when compared to LNG.

[44] Australia and South Africa are two of the most important markets.

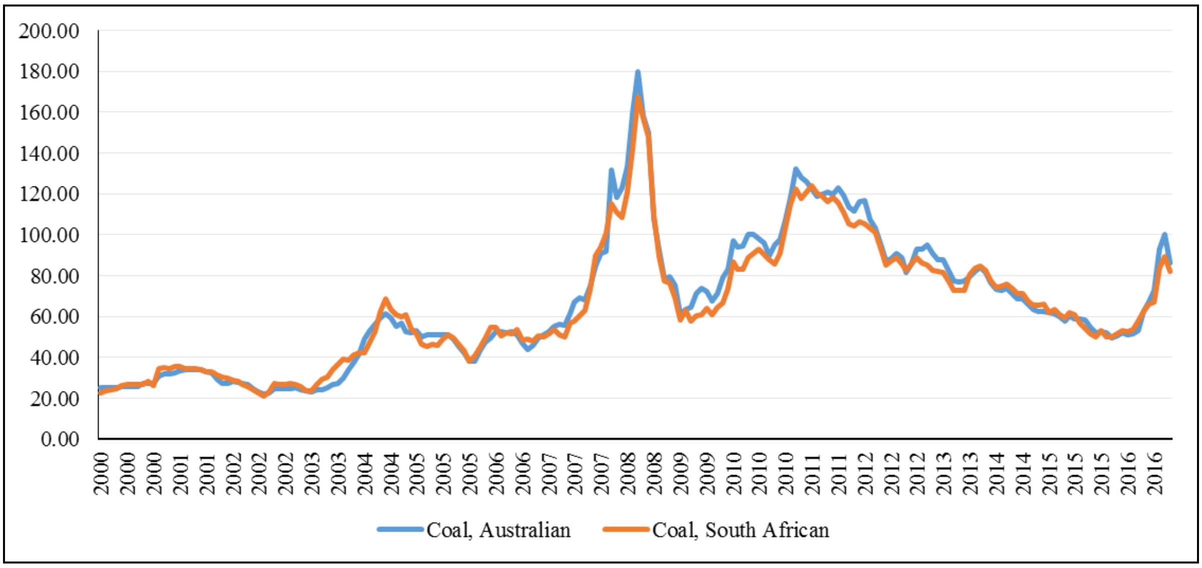
[45] China became the world's largest coal importer in 2011. It now represents almost a quarter of world steam coal imports. Due to its size on the international coal market, China has become a price setter for steam coal affecting the price to European buyers.

[46] Consequently, mining companies were obliged to close their highest cost mines and focus on cost reductions.

continuously oversupplied market and low coal price in the future (World Energy Council, 2016; IEA, 2016 and BP, 2016).

Looking at the main coal consumers, China outshines all the others as it accounts for 51% of total coal consumption[47] (WRI, 2016). Consequently, global prices depend to a high extent on China's market development and government policies. Thus, the announcement of the Chinese government about reducing its share of coal in the energy mix in response to the Paris Climate Agreement, had a wide impact on the market. If China fulfils its objective and reduces its coal imports significantly, the global market will fall into a deep supply glut. In 2016, coal prices have experienced a pronounced rise (64% from January 2016 to December 2016) caused by the reduction in world supply and partial recovery of the demand. The reduction in supply is linked to the closure of 500 million tonnes of Chinese production capacity and the global closure of large-scale mines as a consequence of continual low market prices. On the demand side, global steel production is recovering as the world investment in infrastructure is flourishing[48]. For the European power market, increasing coal prices mean lower margins for coal plant owners, while gas becomes more competitive (Timera, 2017).

Figure 23: Coal price evolution (USD/mt) in Australian and South African market (1990-2016)



Own development, data source World Bank 2017 and Bloomberg 2017

[47] Its coal consumption increased from 737 Mtoe in 2000 to 1,873 Mtoe in 2012.

[48] Steel production is dependent on intensive use of coal, with approximatelly 74% of the steel produced using coal in the steel making process (World coal association).

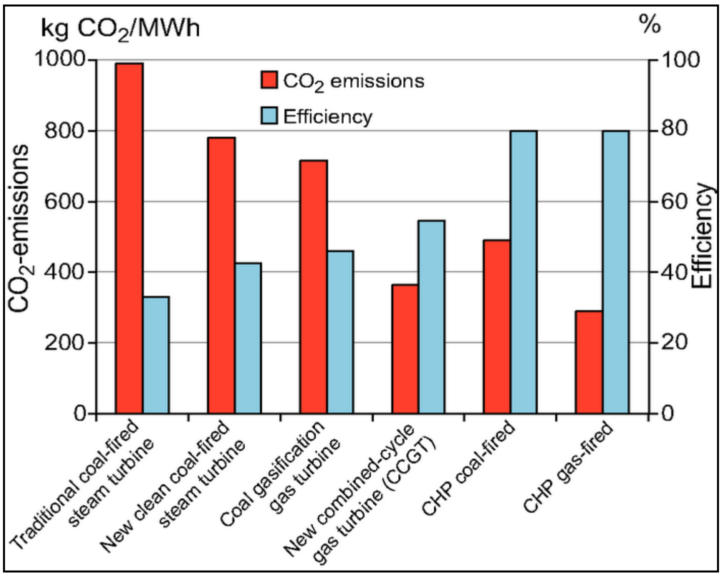
Coal is mostly consumed by the power sector and its use-intensity varies completely across the EU member states. A transparent and well-supplied global coal market has always been of strategic importance for Europe. Mainly because enough coal power capacity grants security of power supply and protects against political risk. Coal has dominated the European power sector for decades due to its availability and technology used to produce vast electricity amounts in a cost-effective manner. However, EU coal consumption has continuously decreased since 1990 (40% less consumption) until 2011 when consumption rebounded. The favourable economics of coal compared to other fuels stimulated a recovery of demand by power utilities (Eurostat, 2017).

SECTION 3.3: TECHNICAL, ENVIRONMENTAL AND ECONOMIC FEATURES

The increasing share of renewables in the energy mix impacts the installation of new conventional power technologies. In order to balance the fluctuations in the power system generated by solar and wind, more efficient coal and gas technologies are needed. However, the systemic need for new high efficient plants conflicts with the economic perspectives of conventional power plants. Mainly because conventional power plant not operating at high capacity factor (or full load), increase their cost per generated unit of electricity. Meaning that to optimize output, a high operating time is required. By reducing the operating time of conventional power plants due to the gap left by renewables (when the sun is not shining or the wind is not blowing[49]), the investment attractiveness in new efficient coal and gas plants shrinks. The dynamics of cost and efficiency are key aspects are for the deployment of new power plants. Energy efficiency refers to the conversion from one form of energy into another, in our case, from fuel to heat and subsequently to electricity. The efficiency rate (percentage) indicates the loss of energy (i.e. heat) during the conversion process. Types of fossil fuel sources combined with available technology attain different efficiency rates. As can be observed in Figure 24, gas power plants with CHP technology allow for considerably higher thermal efficiency than traditional coal steam turbines. It is important to note that the efficiency rate affects the cost competitiveness of a power plant and its emission intensity (EIA, 2017).

[49] Situation also known as “Dunkelflaute” in Germany.

Figure 24: Carbon dioxide emissions and conversion efficiencies of conventional power plants



Source: IPCC, 2007

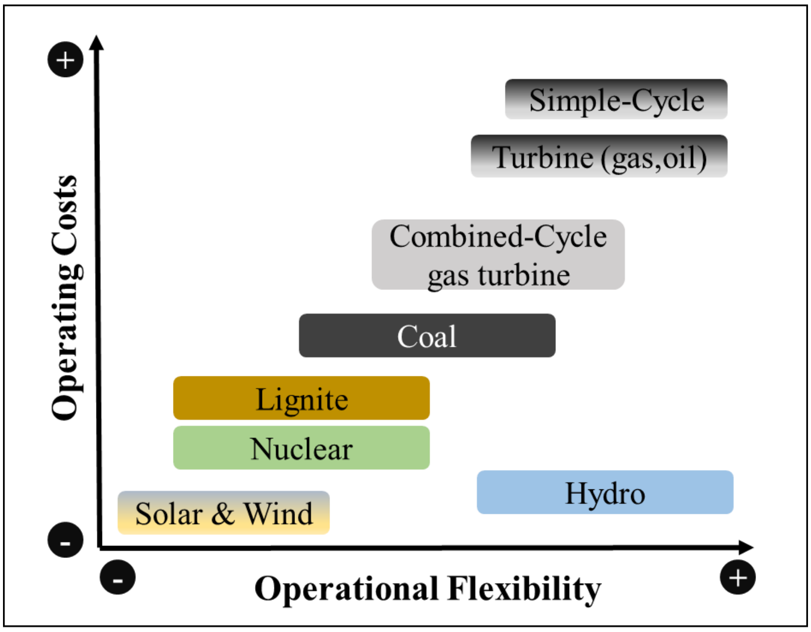
The use of natural gas in the power sector shows obvious technical and environmental advantages over coal. Currently, the most advanced gas power technology is a cycle gas turbine (CCGT) plant, which combines generation of gas and heat. Different from coal plants, which are rooted in conventional combustion. In most of Europe, CCGTs and coal plants compete on a marginal cost basis (short run variable cost) for production share. In general, CCGTs are more efficient and less carbon intensive, but gas is a more expensive resource than coal. Nevertheless, gas technology offers a shorter construction period[50] and a higher flexibility for quick rump up of production.[51] This is especially important considering that flexibility is a necessary component to balance the intermittent generation of renewables, as it helps to cover demand in periods of low renewable output and match the daily peaks in consumption. Plants designed to balance short periods of fluctuating power requirements are called peaking stations (usually gas or oil plants). Peaking stations operate in standby mode, ready to rapidly start operation during a peak in demand. Their high flexibility enables to respond to fluctuating demand. Hydro plants also play a key role during high fluctuation of demand but their availability is limited to grid capacity and natural resources. A further

[50] Construction period typically of 24 to 36 months for gas and 42 to 54 months for coal plants.

[51] For new CCGT plants, time required for hot start-up (after night shutdown) takes less than 30 minutes and approximately two hours for cold start-up.

expansion of hydro capacity is not expected in most of Europe. The following figure (Figure 25) illustrates the relation of operating costs and flexibility for each technology type.

Figure 25: Comparison of energy sources by operating costs and operational flexibility



Source: Own development

Coal power plants are an emission intensive power source (generating more than twice as much CO2 as natural gas), but benefits generally from significantly lower fuel costs relative to natural gas-fired power plants. Furthermore, coal can be transported and stored in a cost-effective way with far less limitations than gas, which needs to be transported in high-pressure pipelines or in the case of LNG, in dedicated supply routes. For many countries, these advantages compensate the higher construction costs of coal fired plants[52] and the lower efficiency rates compared to CCGTs.

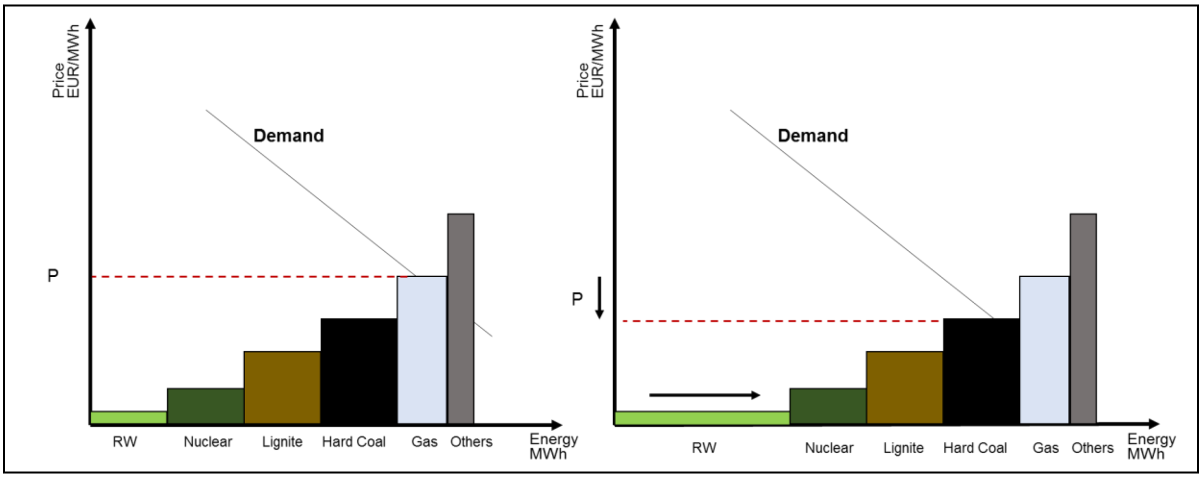
Different types of energy sources cover electricity demand on the market. Each power plant (renewable, nuclear, gas, coal) has marginal costs in terms of usage[53], which determine the dispatch order. In a liberalized market, the power source with the lowest marginal cost, (renewables: solar and wind mainly) have a dispatch preference over the ones with higher

[52] The capital expenditure for a new gas plant is approximately EUR 800/kW compared with EUR 1300-1400/kW for hard coal and lignite in Europe (IEA, 2016).

[53] Fuel costs, CO2 costs, and operation and maintenance costs. Fuel costs dominate the total cost of operation for fossil-fired power plants.

costs. The merit-order-curve centralizes the convergence of the supply and demand curve setting a dispatch order of power generation sources until the demand and supply curve meet. Before the renewable revolution, natural gas production with higher marginal cost compared to other conventional sources was usually the last power source covering the market demand and therefore the price setter. Nevertheless, an increase of low marginal cost technologies in the electricity mix are forcing energy sources with higher marginal costs out of the merit-order-curve. Consequently, gas-fired power plants have been displaced further to the right of the merit-order curve resulting in a decrease in operating hours and in many cases relegated to peak or back-up capacities[54]. In contrast, coal combustion plants with lower marginal costs have maintained their position in the base load and in many countries hard coal has become the new price setter[55]. The following figure (Figure 26) presents the shift in the merit-order-curve due to an increase in renewable capacity (Roldan-Fernandez, Burgos-Payan, Riquelme-Santos and Trigo-Garcia, 2016).

Figure 26: Effect of renewables on the merit-order-curve (gas power is pushed out and electricity price drops)



Source: Own development

As mentioned before, from an economic perspective, new built power plants dealing with limited load factors tend to see fixed and marginal costs increase per unit of output (MWh). As a key fixed expense, capital costs[56] tend to increase with low operating times due to longer

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[54] Initially conceived as base- or mid-load units with about 5,000 operating hours per year.

[55] Since it has a lower marginal cost, the wholesale market price of electricity decreases.

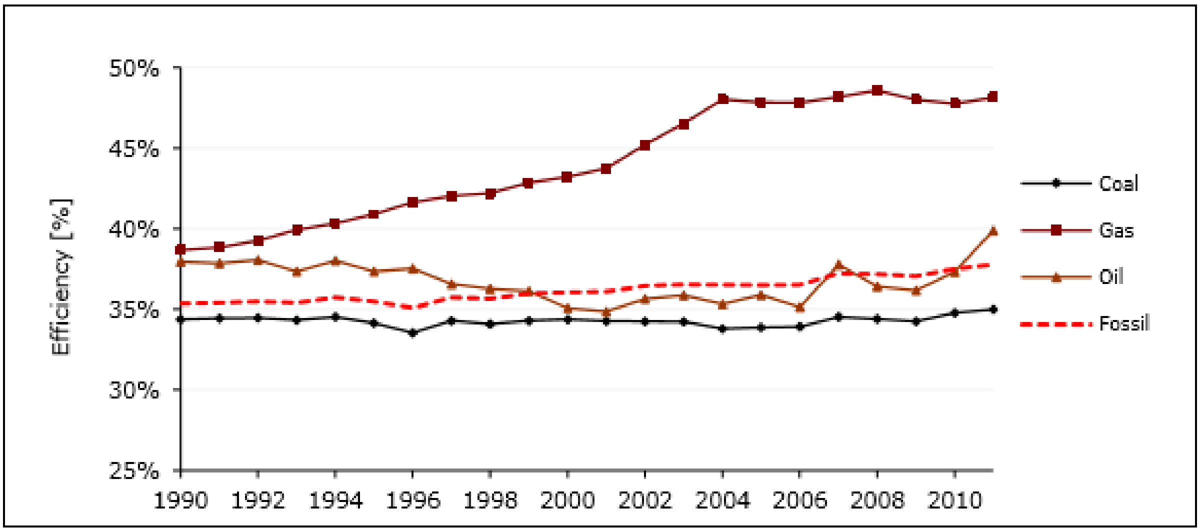
[56] A function of construction labour costs and regulatory costs (in form of permits and approvals).

amortization periods. This is not the case for old plants that have already amortized capital costs. For this reason, the decrease in the load factor has a particularly negative effect on new, high-efficient gas plants, which show a clear cost disadvantage towards old coal plants. Additionally, marginal costs are even higher with low utilisation rates since some variable costs, such as operation and maintenance expenses, stay largely constant irrespectively of use. The low utilisation rate of gas-fired power plants prevents utilities from recovering their investment and even their variable costs. This has led to a situation in which even highly efficient gas plants have experienced a drastic fall in revenues and are at risk of mothball or closure. Investors in conventional technologies are cautious when it comes to put more money in new power plants considering the unfavourable market situation and the political trajectory (DNV GL, 2018).

Technological development has progressed rapidly with modern coal plants, such as USC-PC (ultra-supercritical pulverised coal) plants, achieving considerable lower CO2 emissions and higher thermal efficiency. In terms of thermal efficiency, new hard coal plants can achieve factors of 46% (compared to 38% of older plants) and new lignite plants 43% (compared to 30% of older plants). However, the main throwbacks are that this technology is still highly capital intensive[57] and will stay under the political target due to its high carbon emissions. From a historic point of view, gas powered technologies have seen a steeper increase in efficiency than coal technology. It is difficult to predict if the efficiency rate will increase even further. Considering the historic trajectory, it seems that efficiency gains have reached a maturity level (see Figure 27) (Ecofys, 2014).

[57] Capital costs of USD 1,700 per KW for coal subcritical plant versus USD 500 per KW for a natural gas turbine plant in Europe according to the IEA (IEA, 2016).

Figure 27: Weighted average historic efficiency gains for fossil fuel power technologies (1990-2012)



Source: Ecofys, 2014[58]

As an alternative to conventional fuel sources, stricter regulation is encouraging power generators to choose biomass conversion of some coal plants. Biomass is considered a carbon neutral energy source because it incorporates CO2 during its growing period[59], which is released during the combustion process. Hence, biomass provides an opportunity to reduce large amounts CO2 emissions in the power sector. From a technical perspective, the re-utilization of existing assets (already connected to the grid) through biomass conversion, is feasible. Moreover, biomass is not an intermittent power source, which applies to most renewables. It entails potential to support the accomplishment of the 2020 and 2030 targets, however financial incentives are necessary. Current commodity prices, limited availability of biomass and weak CO2 prices offer blurred perspectives for biomass conversion. Policy incentives vary among countries and biomass-fired power plants are expected to increase their total capacity in the coming years as the technology becomes more efficient and CO2 prices increase. Additionally, a feasible alternative for increasing the efficiency of coal-fired plants is the combination of coal and biomass combustion, a practice called co-firing. Since coal-fired plants generally operate with much higher steam parameters than biomass-fired power plants, the resulting co-fired plant attains a higher efficiency. The main limitation of

[58] Countries considered in the study: US, China, Japan, India, Germany, France, Korea, UK, Nordic countries and Australia.

[59] It is CO2-neutral because it emits the same amount of CO2 during combustion as the plants absorbed during its growth period through the process of photosynthesis.

biomass plants is the availability of biomass material, since supplies are available during harvesting season but scarce during the rest of the time. Furthermore, biomass supplies are widely dispersed and the collection and transport of large amounts of biomass require a well-established infrastructure (transport and storage), which lacks in most countries (Agora, 2017).

An alternative for power generators is the modernisation of existing coal-fired power plants[60], especially considering the capital and time required to build new coal plants. As a response to stricter emission regulations, some power plants have replaced main plant equipment such as boilers and turbines in order to increase efficiency and lower their carbon footprint. Through the introduction of technological improvements, the emissions can be reduced by up to 30%[61]. Further, plants can opt to implement Carbon Capture and Storage (CCS) technology achieving considerable emission cuts. Nevertheless, considering current market dynamics, a capital-intensive technology upgrade entails a high risk for thermal power operators. The renewable deployment will continue reducing the operating hours of conventional power and it could mean that the investment will remain unrecovered (also called "stranded assets"). Under such conditions, many operators are opting for the closure of the oldest coal power plants (Cornot-Gandolphe, 2014).

The availability factor of different power sources is a relevant factor to take into account when speaking about coal-to-gas switching. The availability factor stands for the real amount of time that a power plant is able to produce electricity over a certain period. This factor varies by technology type, design and operation. The availability factor is conditioned by the reliability and maintenance work required by each type of technology. Most thermal power stations, such as coal, geothermal and nuclear power plants, have availability factors between 80% and 90% depending also on the maturity of the technology installed (newer plants tend to have higher availability factors). When comparing average annual availability factors between gas and coal power plants there is no significant difference. On the contrary, renewable technologies presume to have very high availability, close to 100%[62], since the

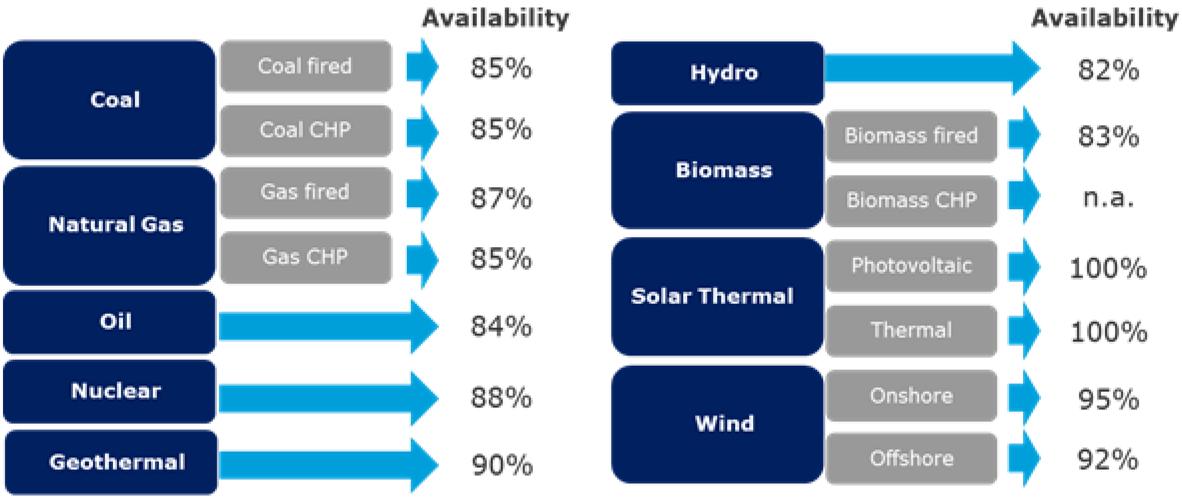
[60] As carbon capture and storage (CCS) technology is not commercially viable.

[61] As can be observed for the new high-efficient plants of Neurath (1.8 GW) and Boxberg (2.4 GW) in Germany.

[62] Wind turbine cannot operate during periods when wind speeds is above a certain limit. Solar, however, can operate almost 100% of the day-time.

maintenance needs are limited and can be carried out during timescales when the environmental conditions are less favourable (see Figure 28) (IEEE Standard Definitions).

Figure 28: Max attainable annual capacity factor or availability



Source: Own development, data sources EIA 2018, IEEE, ESAMP 2012

Note that the availability factor should not be confused with the capacity factor. The capacity factor represents the effective output of a power plant compared to its full output potential. While the availability factor stays constant, the capacity factor of different technologies is constantly changing affected by regulation, market conditions and climate conditions. In Chapter 4, the development of the average capacity factor for coal and gas power technologies will be evaluated for the cases of Germany and the UK.

SECTION 3.4: THE EU COAL AND GAS MARKETS

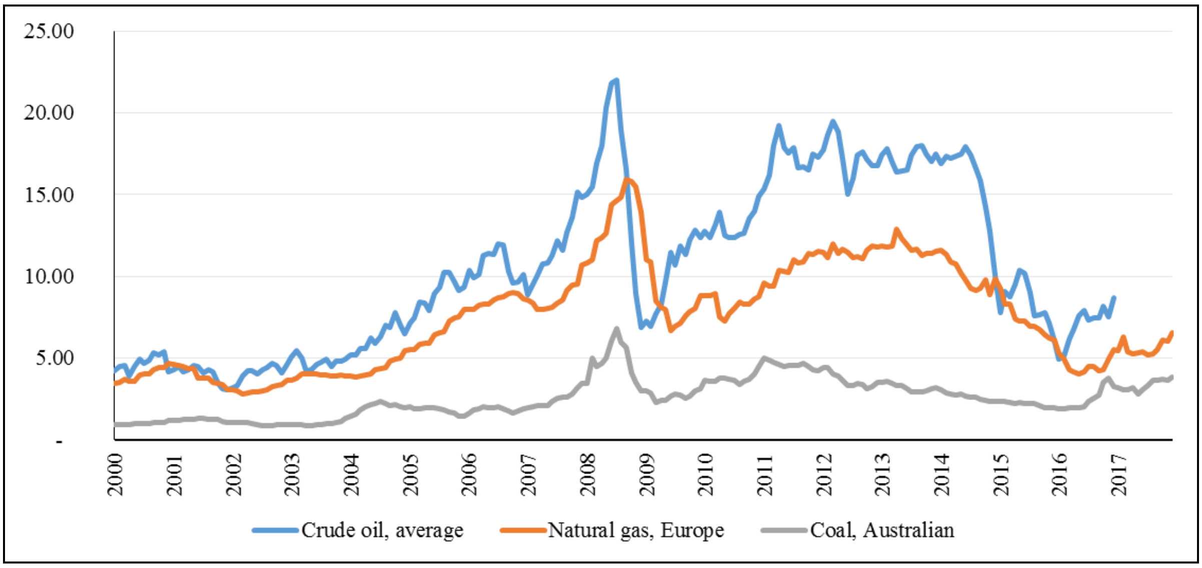
Over the last 20 years the competition between coal and gas power production has been determined to a large extent by fuel and CO2 price dynamics. For instance, in 2009, gas obtained a competitive advantage towards coal (in terms of marginal cost) due to falling gas prices and moderate CO2 prices (approximately EUR 14 per tonne). This marginal cost advantage added to the increasing environmental awareness generated an incentive to build-up new capacity. A few years later in 2011, coal prices and CO2 prices fell drastically as a result of oversupply in both markets. Consequently, coal became more competitive displacing gas out of the merit-order-curve. The economic advantage of coal has augmented over the period 2011 to 2014 due to falling coal prices and the collapse of CO2 prices in parallel to rising gas prices. The effects of increasing gas commodity prices and the fall of electricity prices consequently transformed gas-fired power plants in an unprofitable business (see Figure 29) (Cornot-Gandolphe, 2014).

After 2014 coal's competitive advantage started to weaken. Surprisingly, this time it was not related to an increase in variable costs of coal power generation as coal prices and CO2 prices stayed at a low level. It was more linked to a growing global oversupply of LNG and falling oil prices. These circumstances pressed European gas prices down. Since 2016, the variable cost gap between CCGT and coal plants is small and in some EU member states a new shift from coal-fired generation to gas is taking place[63]. The new reality is that coal is no longer cheaper than natural gas on an energy equivalence basis. The decline in gas prices since 2013 (54% for average spot prices) has changed the pervading competitiveness of coal towards natural gas. Current market conditions are forcing coal power plants to reduce their operating hours and consequently reduce their margins. In previous years, gas-fired plants had to fight to remain profitable but the scene has changed and old coal power plants[64] are at risk of premature shut down due to economic reasons (DNV GL, 2018)

[63] For instance, in 2016 the EU power sector emissions fell by 4.5% or 48 million tonnes, mainly due to coal-to-gas switching.

[64] Coal plants have an average technical lifetime of 40 to 48 years.

Figure 29: Evolution of oil, natural gas and coal prices on an energy equivalence basis (USD/mmBtu[65]) (2000-2017)



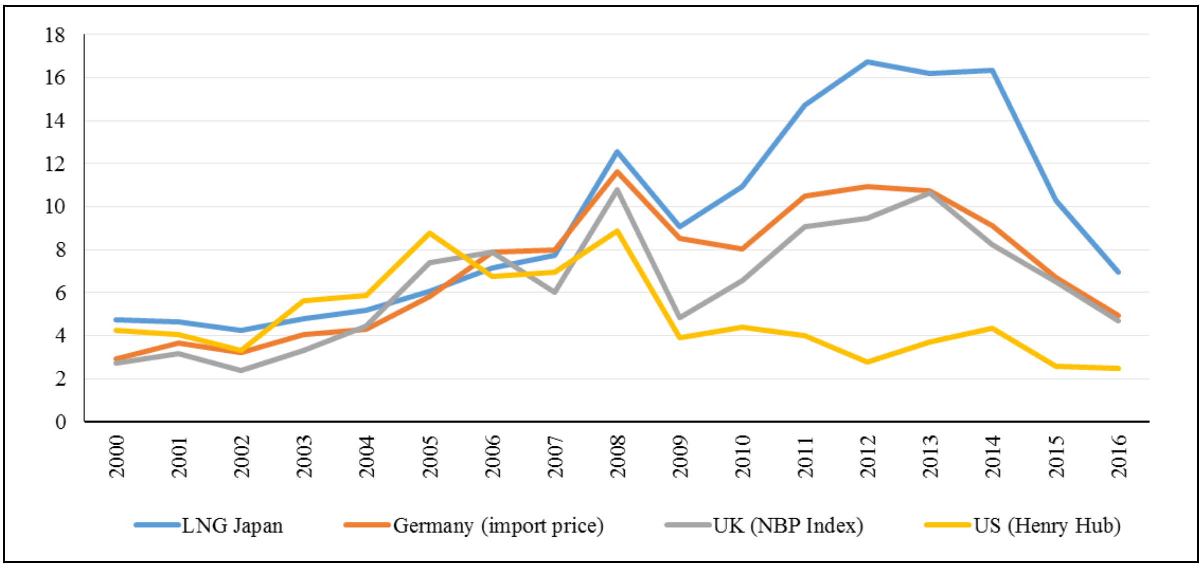
Source: Own development, data source World Bank 2018

Experts forecast persistent low European gas prices over the next years as the Northwest European market (UK, Germany, France, Belgium and the Netherlands) will stay oversupplied. As mentioned before, LNG is set to strengthen its presence in the European gas markets due to increased global production with Europe prepared to absorb the surplus. Additionally, a significant shift away from oil indexation protects European gas prices from correlating to increasing oil prices. This trend would make gas markets more competitive and come closer to the Henry Hub prices (US). While it is very unlikely that the European gas prices will reach the Henry Hub level any time soon, European and US gas prices may begin to close the distance due to LNG supply and cheaper gas coming from Russia[66]. Figure 30 depicts the historical price evolution of gas prices in the different markets (Timera, 2017).

[65] USD/MMBtu: US dollars per Million British Thermal Units.

[66] New gas pipelines crossing the North sea (Nordstream 1 and 2) allow to transport Russian gas through a shorter route comprising therefor less transportation costs.

Figure 30: Evolution of natural gas prices per market (USD/mmBtu) (2000-2016)



Sown development, data source BP report 2017

As we will see in the next chapter with the examples of Germany and the UK, commodity trends have played a fundamental role in shaping the conventional energy mix.

SECTION 3.5: EU REGULATION AND NATIONAL POLICIES ON GHG EMISSIONS

In a coordinated effort to drastically reduce GHG emissions, the EU commission has set air quality standards under the Industrial Emissions Directive to limit emission intensive power generation. Thus, Europe’s dirtiest coal and lignite power stations have until August 17, 2021 to comply with EU air quality guidelines for NOx, SO2 and mercury. The directive offers two alternatives for plant operators: Either accept gradual closure, entitled to operate for a total of 17,500 hours[67] between January 1, 2016 and December 31, 2023; or invest to comply with IED air quality rules by August 2021. In response to the directive, a relevant part of the coal-fired power fleet is implementing emission abatement retrofits to extend the operational horizon. On the contrary, many of the oldest plants prefer to empty their emission budget and accept the premature shut down. This decision is based on the assumption that power plants

[67] 1,500 hours per year is still a 34% load factor over a six-month winter season.

generating 40% more emissions than the emission thresholds, would need to make a substantial investment to comply with the air quality standards. Taking into account the risk of future unfavourable market conditions, there is a high probability that the investment cannot be recovered. Even assuming that abatement improvements could allow coal plant to operate until 2030, a stricter regulatory scenario in the coming years is very likely (IEEFA, 2017).

Apart from emission limitations, the European Parliament's energy committee is trying to reach a consensus, about coal power plants emitting over 550g CO2/kWh not being eligible to receive capacity payments. For now, coal plants are allowed to participate in capacity markets but this could change in the following months, which would diminish even further the future revenue expectations of coal plants. The doubts surrounding this decision rely on one key aspect, whether gas installed capacity would be enough to grant power supply in a rapid coal-phase out scenario. In this regard, the study published by Energy Union Choices, "A Perspective on Infrastructure and Energy Security in the Transition", argues that the existing gas supply infrastructure would be sufficient. This conclusion is based on the fact that the liquefied gas terminals and gas pipelines are underutilized with 32% and 58% of their capacity respectively (Energy Union Choices, 2016). However, it is not clear whether on a country basis, the gas power capacity available today would be sufficient to meet the demand in the next decade. Ageing conventional thermal power units and highly efficient unprofitable gas-fired plants are closing down (or mothballed) and over-capacity could rapidly turn into electricity shortages. Although reserve margins are not at risk, insufficient new projects could derive in a shortage of supply at times of peak demand. The situation is different in each member state and the regulation introduced to confront the problem varies considerably. Many states favour the introduction of capacity markets in order to keep the required conventional power capacity available. In this sense, each member state has the autonomy to structure the coal phase-out in its own way and the impact for the coal (and lignite) fleet may differ considerably between countries. Apart from regulatory directives, the evolution of carbon prices in the EU ETS and the implementation of a national carbon floor will determine to a large extent the future of coal power generation in the European power mix (Cornot-Gandolphe, 2014).

We will shed more light on this issue by looking at the so-called coal-switching channel. When the market conditions (commodity and CO2 prices) are favourable for gas plants, unutilized gas capacity enters the coal-switching price channel. This channel is as wide as installed gas capacity is available to increase output through more operational hours. In Chapter 4 we will analyse in more detail the coal-switching channel in Germany and the UK.

SECTION 3.6: EUROPEAN EMISSION TRADING SCHEME (EU ETS)

In its commitment to fulfil the Kyoto Protocol targets, the EU implemented in 2005 the EU Emissions Trading System (EU ETS). This mechanism was meant to become the cornerstone of the EU energy policy, pushing for a progressive reduction of GHG emissions (CO2 equivalent emissions[68]) by putting a price on carbon[69]. The EU ETS is based on a cap-and-trade scheme, in which emission intensive players trade emission rights. It is based on the polluter based principle (recall Chapter 1) by which the additional cost of CO2 emissions is taken by the emitter, lowering the competitiveness of its production. The idea behind this mechanism is to promote reductions of GHG emissions in a cost-effective manner[70]. Meaning that the market determines the price based on supply and demand forces (no political intervention[71]). In theory, the progressive reduction of the cap creates a scarcity effect of emission rights reflected in the carbon price. The carbon price creates an economic incentive for market players to pursue emission reductions. However, since the EU ETS was introduced (2015), the mechanism has not proven to be effective and various policies aiming to correct flaws over the years have been implemented. The "learning by doing" approach still continues after more than 10 years since its official launch and the question whether the new pile of measures announced by the EU will finally allow the market to become the yearned cornerstone of the climate policy is unclear. In order to understand the EU ETS´s potential to affect the power sector in Germany and the UK (Chapter 4), it is necessary to comprehend its relevance, the causes of the price fluctuations, the current status and the corrective measures recently announced by the European Commission (European Union, 2015).

[68] Different GHG emissions (mainly CO2, N2O, PFCs) can be expressed as CO2 equivalent considering the amount of heat trapped in the atmosphere (quantity known as the global warming potential). Transforming most relevant GHG into CO2 equivalent allows to compare and account different greenhouse gases in one common measure.

[69] The EU ETS was approved after a failed attempt to agree on a carbon energy tax between the member states.

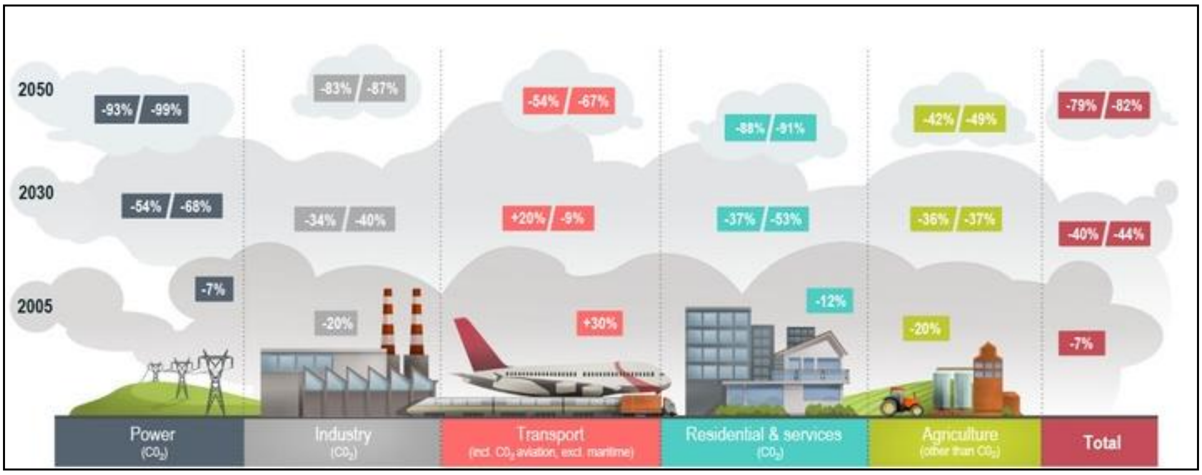
[70] According to the European directive approved in 2003.

[71] From a neoliberal economic perspective, no additional policy would be required to accomplish the climate change targets.

SECTION 3.6.1: RELEVANCE

The EU ETS covers more than 12.000 installations across the most polluting sectors[72] located in the 28 EU member states, Iceland, Norway and Lichtenstein. Translated in total emissions share, the EU ETS sectors account for approximately 41% of total EU GHG emissions. The agreed target is to cut total GHG emission of the involved sectors by at least 21% by 2020 and 43% by 2030 compared to the 2005 levels. These intermediate objectives are lined up with the 2050 roadmap of 80-95% emission reduction (see Figure 31).

Figure 31: Carbon targets by sector until 2050 (compared to 1990 level)



Source: European Commission, 2012

Noting that the share of the power sector and the industrial sector represent 71% and 21% of the total cap respectively (status by 2013), it is clear that the role of the power sector in the reduction of emissions through the EU ETS is crucial. As a matter of fact, by 2030, 70% of EU ETS abatement is expected to come from the power sector[73]. Other sectors have less ambitious reduction objectives due to the carbon leakage risk[74]. Carbon leakage stands for the relocation of emission intensive production plants to other jurisdictions where lower or no carbon price applies. From a competitive standpoint, emission intensive players might see the

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[72] Electricity supply, iron and steel, cement and lime, oil refineries, glass, ceramics, pulp and paper, primary and secondary aluminium, chemicals, non-ferrous metals and aviation.

[73] The CO2 abatement objective for the power sector continues decreasing to -93 to -99 % compared to 1990 by 2050.

[74] The ETS Directive (Article 10a) defines a list of sectors and sub-sector at risk.

relocation as the opportunity to reduce the costs linked to carbon emissions. However, from a climatic perspective, it would mean that emissions are relocated[75] to another region and the opportunity to incentivise these players to reduce emissions vanishes. Sectors sensitive to carbon leakage are more protected under the EU ETS, receiving most of the emission rights for free. This free allocation, however, should decrease over the following years, incentivising a more pronounced decarbonisation in these sectors as well. While carbon leakage risk affects the allocation rules, it must be said that until now no empirical evidence has backed the theory of considerable carbon leakage happening[76] (Jones and Kleiner, 2017).

From a global perspective, the EU ETS is the largest carbon market with vast experience gained over the years. It has served as an example to other countries and has provided many insights for new merging carbon markets around the world. The EU ETS is continuously expanding to new countries[77] and emission intensive sectors (such as aviation[78]) adding to the total covered emission amount (Sandbag, 2017).

SECTION 3.6.2: FUNCTIONING OF THE EU ETS

The EU ETS is founded on the cap and trade approach in which an emission cap puts a threshold on GHG emissions for all sectors covered by the system. The cap is reduced linearly (reduction factor) so that the total emission limit decreases. Specifically, the annual emission cap has decreased by 1.74% p.a. since 2013[79] compared to 2010 (the reference cap). The emission cap is fixed and participants (emission intensive players) can trade emission allowances (one tonne of equivalent CO2 emissions each) guided by market price dynamics. Each installation has an amount of allowed carbon emissions related to its operation that needs to be compensated through emission allowances at the end of each year[80], otherwise

[75] Or even increase due to additional transport needs (new location is far away from customers) and less stringent emission regulation in the relocation country.

[76] An empirical study by the UK government in 2014 fails to find solid evidences of carbon leakage due to the EU ETS.

[77] Recently, after 7 years of negotiations, Switzerland agreed to merge its emission credit system with the EU ETS.

[78] For now, only flights between EU member states are covered under the EU ETS.

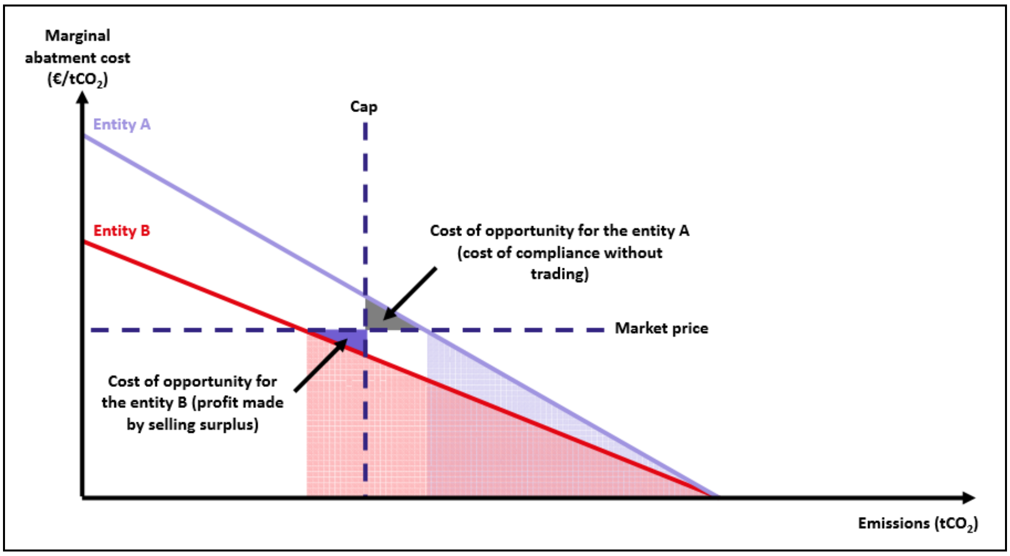
[79] Except for aviation. The emission cap for aviation will stay stable using 95% of the average emissions level observed in 2004-2006. For now, international aviation is exempted from participating in the EU ETS. However, ICAO is developing a global market-based measure for international aviation probably to enter in force by 2021.

[80] Based on the share of the installation´s historical emissions in the sector.

heavy fines are imposed (100 euros per tonne of equivalent CO2 emissions). Based on regulatory categorization, installations either receive free allowances[81] or have to buy allowances in the market to comply with established emission limits. Depending on the emissions generated throughout the year, participants will be in a situation of surplus or shortage of allowances that can be balanced in the market[82] (European Commission, 2015).

The willingness of the players to take part in the market and whether to buy or sell emission allowances, relies on the principle of cost of opportunity. Figure 32 presents this principle. On the one side, entity B has been able to reduce its emissions effectively below its emission cap (holds a surplus in allowances). The accomplished emission reductions are valued at the market price creating a cost of opportunity. On the other side, for entity A, the cost of opportunity is not high enough to invest on emission reduction measures and it is prepared to take the cost of acquiring extra emission allowances in the market. Thus, the additional cost assumed by entity A is transferred to entity B leading to a distribution effect through the market.

Figure 32: Cap and trade system results in distribution effect



Source: Trotignon, 2011

[81] Allowance allocation rules diverge between sectors and protects to some extent sectors at risk of carbon leakage through free allowance.

[82] Since it is an organized market, investors and financial institutions may participate in the market providing it with liquidity. It is important to mention that allowances might also be traded bilaterally between participants. However, this is not the common practice today as it entails higher risks (credit risk mainly) than in the organized market.

It is important to note, that the market price is under constant fluctuation, directly linked to supply and demand. For instance, high prices would be a result of increasing demand for allowances and a reduced availability of allowances in the market. Meaning that the opportunity cost for sellers and buyers is high and therefore costlier emission reductions may become more attractive. In such a scenario, players have a higher incentive to pollute less than their cap and sell the excess allowances.

SECTION 3.6.3: DEVELOPMENT OF THE EU ETS

The EU ETS has gone through different phases since its introduction (Phase 1: 2005-2008, Phase 2: 2008-2012, Phase 3: 2013-2020 and Phase 4: 2021-2030), currently being in the third phase, which will last until 2020. This phase-structure enables to introduce adjustments between phases following the “learning by doing” principle.

Phase 1 (2005-2007): The first phase was a testing phase allowing policy makers and participants to get used to the cap and trade system and consider the cost of GHG emissions in their corporate strategy. It also served to strengthen the basis of a functioning market and attract third parties to provide liquidity and to reduce power concentration. During this phase, overallocation of free allowances[83] led to a high allowance surplus and low carbon prices (European Commission, 2015).

Phase 2 (2008-2012): The second phase gave policy makers a new opportunity to define consistent allocation rules and generate the required scarcity in the market. However, the unforeseen economic crisis led to a reduced industrial production and power demand. The crisis led to an unexpected overallocation and players most affected by the financial crises (low production) had suddenly a vast allowance surplus. Meaning that, companies with allowance surplus could obtain additional benefit through the sale of allowances in the market without implementing any emission abatement measures (defined as windfall profits). During this phase, low demand and high supply drove prices down (see Figure 33) (European Commission, 2015).

[83] Due to excessive protectionism by the member states.

Phase 3 (2013-2020): This phase has not concluded yet. The pitfalls of Phase 2, moved policy makers to introduce adjustments to the EU ETS. The adjustments plus the first signs of economic recovery have pressed prices slowly up (see Figure 33). However, the market is still hampered by a large oversupply of allowances. During this phase, the allocation rules were adjusted to increase the pressure on the power sector, which is not exposed to the risk of carbon leakage. Hence, the power sector stopped receiving free carbon allowances and had to integrate the extra cost of buying allowances in its cost equation. While the economic activity was recovering gradually, additional environmental policies promoted efficiency gains and the implementation of large capacity of renewable energy sources[84]. The effect on the power sector was a reduction in emissions, which circumvented the demand for added allowances. The market continued to be oversupplied and low expectations of political intervention led to persistent low market prices. Since 2015, member states have negotiated to find effective solutions that will allow the market to reduce the supply glut and create the incentive to cut emissions. By the end of 2017 and the beginning of 2018, relevant measures regarding the reduction of the emission cap and the balancing of supply and demand were agreed upon. Market participants are already speculating with the outcomes, which explains the recent boost in market activity and the price increase (Sandbag, 2017).

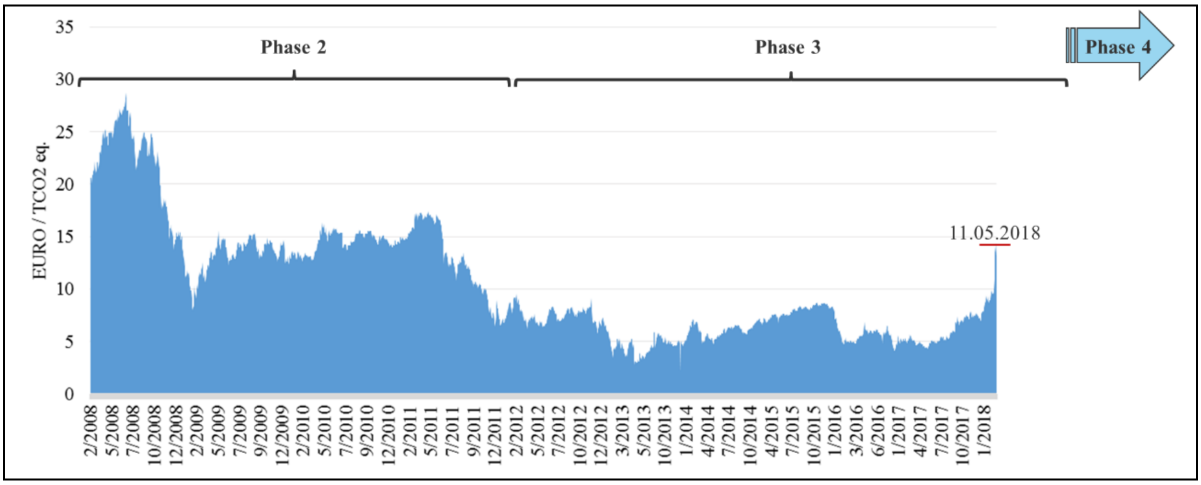
Phase 4 (2021-2030): In an attempt to revive the EU ETS as the cornerstone of EU climate policy, the EC has announced a list of measures for Phase 4 aiming to adjust the flaws identified during Phase 3. As mentioned before, prices have stayed low during Phase 3, which has weakened the role of the ETS in cutting GHG emissions. Policy makers, are optimistic that the new measures will bring the EU ETS back on track generating a relevant incentive for palpable emission reductions.

Figure 33 shows the historic evolution of the market over Phase 2 and Phase 3. During most of time, the EU ETS has presented stubbornly low carbon prices. As can be observed, the price has remained below 10 Euro since the beginning of 2012. This low-price level does not cover what many experts have estimated as the social cost of carbon, since it does not trigger an effective decarbonization of the EU ETS sectors. As can be observed in the same figure, carbon prices are in an upward trend since 2017. It seems that the market is anticipating the effect of the announced amendments before they enter into force. However, it remains

[84] Feed-in-Tariff and Feed-in-Premium mechanisms incentivized vast investment in renewable power generation capacity.

uncertain whether this trend will continue, flatten or fall in the coming years. (On Climate Change Policy, 2018)

Figure 33: Evolution of EUA sport price (2008-2018)



Source: Own development, data source ICE Future Europe and EEX market data

SECTION 3.6.4: EU ETS AND THE POWER SECTOR

The power sector plays a fundamental part in the EU ETS, essentially, because it agglomerates a considerable part of the total EU carbon emissions in a few players. Additionally, it is not exposed to international competition (no risk of carbon leakage) and the carbon cost is passed through to the end consumer. These characteristics have led policy makers to implement stricter conditions for the power sector compared to the industrial sectors. For instance, since the start of the third phase power plants do not receive free allowances and need to participate in auctions to acquire emission quotas (compared to 80% of free allocation in 2013 for the industrial sectors)[85] (European Union, 2015).

The aim of implementing the EU ETS is to price emissions, so that less emission intensive technologies are used. Thus, a rising carbon price would increase the variable costs for conventional power producers, which may lead to a withdrawal from emission intensive power sources (particularly coal), encouraging power producers to shift to natural gas or

[85] The end of free allocation of EUAs has reduced the earnings from coal power generation due to consideration of the additional carbon cost. This can be observed in the case of RWE (with large coal generation capacity), which saw 58% decrease in operating results reported from power generation in 2013 compared to 2012.

renewable technologies. While renewable energy sources are gradually gaining importance in the energy mix, coal and gas generation are in constant competition for share of load, especially the portion that renewables cannot cover (due to climatic and grid limitations).

For now, a persistently low carbon price has not generated a significant incentive to influence investment decisions in low-carbon technologies. Mainly because a strong long-term investment signal in the form of steady high carbon prices has been lacking. From an investor standpoint, before taking any major investment (new plants or technology upgrade) or divestment decision (closure of emission-intensive plants), the carbon price needs to reach a significant level and stay there for a prolonged time. This has raised the debate, about how to reach this stable high carbon price level. Policy makers have acknowledged that the accomplishment of the 2030 emission targets passes indubitably through a significant decrease of coal power generation. According to a recently published study by Sandbag, the impact of the EU ETS on creating an additional incentive towards decarbonisation of the sector has been very limited. In 2016, the coal power emissions still represent 40 percent of all EU-ETS emissions. This situation has moved policy makers to frame and negotiate reforms to the EU ETS that support the creation of scarcity so that prices reach a level that triggers the decarbonisation of the power sector (Sandbag, 2017).

The EC has addressed the EU ETS´s flaws by introducing substantial structural reforms. These reforms aim to create the appropriate setting to boost the role of natural gas in the power mix. However, since the EU ETS is driven by market forces, it is uncertain how this reform will impact the carbon price development. Looking back, with CO2 prices below 10 Euros, no significant change in the competitive balance between coal and gas will happen. In this sense, different studies have tried to set a threshold when gas competitiveness will break even with coal. Experts seem to agree that a carbon price around EUR 30/t would allow gas-fired power plants to edge coal-fired power plants out of the market. However, as we will see in Chapter 5, this threshold varies depending on commodity prices, the state of the conventional power fleet and national regulation among other factors (Evans, 2017).

SECTION 3.6.5: REFORMS AND ADJUSTMENT MECHANISMS

In 2015 the EC, published a legislative proposal to revise the EU ETS for Phase 4 including a fundamental modification of the system of free allocation and new mechanisms in order to create the conditions for a progressive upward trend of the carbon price.

Between 2017 and 2018, the European Parliament and European Council reached a consensus on the EU ETS revisions proposed by the EC. A series of amendments to the EU ETS were approved (European Parliament, 2017). The most relevant are:

- The EU ETS has been aligned with the 2030 EU target of at least 40% emission reductions compared to 1990 levels. The new target of the EU ETS for 2030 (or cap for 2030) is 43% of emission reductions compared to 2005. This reduction of the cap means also an increase in the annual cap reduction factor from 1.74% (38 MtCO2e per year) to 2.2% (48MtCO2e per year). It is estimated that this will reduce the supply of allowances by around 556 million in the period 2021-2030.

- In 2015 the EC approved the implementation of the Market Stability Reserve (MSR), which will be operative from 2019 onwards. This reserve should work as a balancing mechanism between supply and demand by withholding allowances when the surplus is high and releasing them when the surplus is low. The MSR (section 3.6.5) will be describe in more detail further on.

- Adjustments in the distribution rules of free allowances and auctions. The free allocation volume in Phase 4 is planned to be 43%, while the rest (57 %) will be sold through government auctions. Sectors without a significant risk of carbon leakage will see their free allowances share cut gradually from 2026 on.

- Creation of low-carbon funding mechanisms. The "innovation fund" and the "modernisation fund" will finance the transition to a low-carbon economy through the earmark of 835 million allowances (approximately 20 billion euros worth in 2020 according to BNEF's)[86]. A third fund, will manage the free allowances to the power

[86] The "innovation fund" will receive 450 million allowances and will target investment in renewable energy, carbon capture and storage technologies, and innovation in energy-intensive industries. The modernisation fund with 385 million allowances will support energy efficiency and energy system upgrades in Eastern European countries.

sector in the 10 lower-income EU member states in eastern Europe[87]. Due to their economic situation and energy mix (high reliance on coal plants), they will still receive 60% of free allowances. It is important to note that these funds exclude any support to carbon intensity electricity generation such as coal.

- Member states are allowed to voluntarily cancel allowances from their auction share. This measure is limited to the emissions avoided through the closure of power capacity. Taking into account, that some member states are considering or have already approved a coal-phase out before 2030, a cancelation of the linked emission rights avoids market disturbance. This measure makes sense particularly in the case of the UK, where the coal fleet[88] should be phased out by 2025. If related allowances are not cancelled, it could lead to oversupply, with a downward effect on the carbon price.

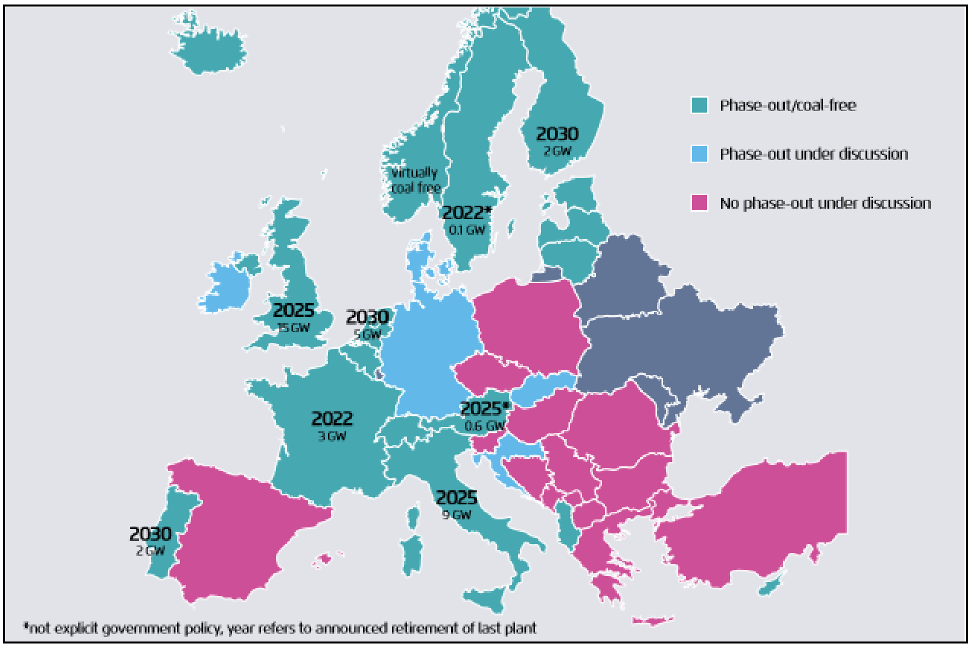
It is important to note, that the EC is committed to the EU ETS as the best way to project an effective carbon signal. For this reason, the “learning by doing” principle will continue through Phase 4, which could lead to a revision of the recently introduced reforms and introduction of new ones.

Besides the measures from the EC, the coal-to-gas switching process will be impacted by policies of each member state as the definition of a coal phase-out deadline (which has been announced by some countries, see Figure 34) or the introduction of a carbon floor price. A price floor linked to the EU ETS would function as a minimum price per CO2 tonne emitted (similar effect as a carbon tax). It would prevent price drops below a certain level. Taking into account the evolution of the EU ETS many countries are contemplating the idea of a carbon floor. For now, the UK is the only member state that has implemented a carbon price floor (back in 2015). As we will see in the Chapter 4, the carbon price floor in the UK has a significant effect on the coal-to-gas switching process (On Climate Change Policy, 2018 and Agora, 2017).

[87] The 10 countries are Bulgaria, Croatia, Czech Republic, Estonia, Latvia, Lithuania, Poland, Slovakia, Hungary and Romania.

[88] Approximately 7% of EU ETS emissions at the beginning of Phase 3.

Figure 34: Coal-phase out decisions in Europe 2017



Source: Agora, 2017

SECTION 3.6.5: THE KEY ROLE OF THE MSR

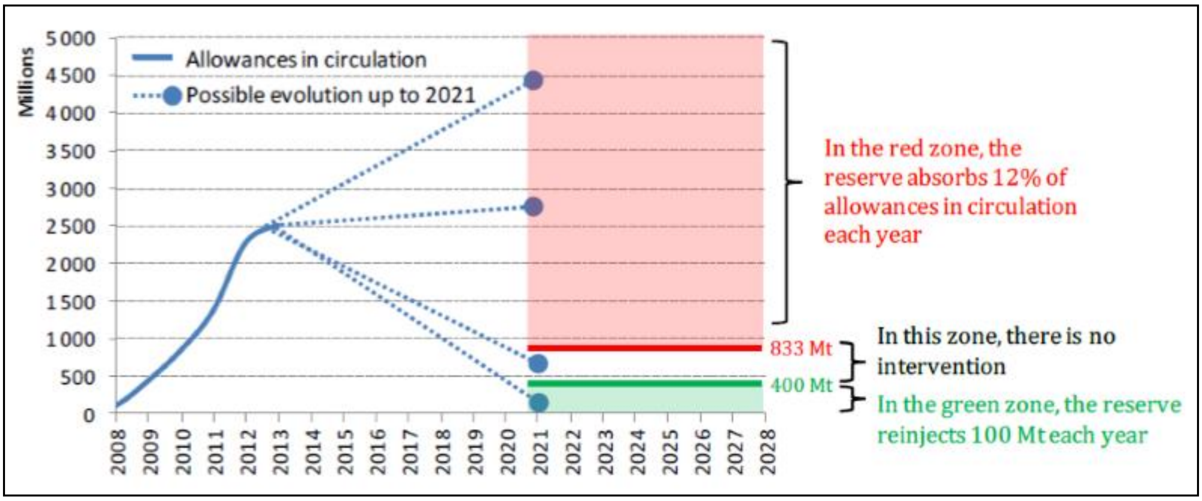
Among all approved measures, most of the lights are focused on the MSR as a potential game changer. The MSR is regarded as a long-term solution to address the surplus of allowances[89] and improve the system's resilience to major market shocks. The implementation is planned for 2019 and it will operate based on an automatic, fully rule-based process[90], gradually removing the surplus allowances from the market, thereby stabilizing supply and demand. The functioning resembles a central bank for allowances that creates scarcity in the system. As observed in Phase 2 and Phase 3, the EU ETS needs a calibration mechanism that counters weak demand acting on the supply side. The MSR permits this calibration function, by restoring the balance of supply and demand. An important detail is that the allowances removed or reintroduced to the market by the MSR, will be deducted or added to the annual auction volumes of each member state (European Commission, 2014).

[89] In Phase 3, the system has accumulated a surplus of 2,080 Mt allowances.

[90] No decision power by the EC or the member states.

Figure 35 presents the functioning of the MSR and paints three possible market situations that would frame the role of the MSR. Each year the surplus will be monitored and depending on the attained surplus, the MSR will function in a different manner. First, if the allowance surplus exceeds the 833 MT limit, the MSR would absorb 24% (until 2023) or 12% (after 2023) of allowances in that year. Second, if the surplus remains between 400 MT and 833 MT, the MSR would stay in stand-by mode. Third, if the surplus falls below 400 MT, 100 MT from the reserve would be reintroduced into the market. Thus, the 400 MT threshold sets the floor surplus that would not require any allowance release from the reserve. According to the EC, these ranges are based on stakeholder insights about the reasonable surplus level that would be needed to allow for a well-functioning market (European Union, 2015).

Figure 35: The functioning of the EU ETS market stability reserve



Source: European Union, 2015

Ideally, the MSR will create a stabilization effect limiting the difference between emissions and allowances, thus enabling prices to behave more consistently. The aim is to gradually accomplish increasing carbon prices and avoiding spikes in both directions. Since the MSR is only meant to balance the market, allowances removed should be reintroduced in the market between 2019 and 2030. However, an exemption applies when the accumulated surplus in the reserve exceeds a limit (the volume auctioned in the previous year). In this case, the excess will be automatically and permanently removed from the market. This is a powerful condition, since it avoids the so called "waterbed-effect", referring to the situation where significant emission reduction in a country allows for higher emission elsewhere in the EU (Agora, 2017).

The EC foresees that the surplus of allowances could reach an equilibrium by 2025 and a stronger price would occur thereafter. Meaning that the MSR will reduce the existing surplus of allowances (approximately 1.7 billion mt) by 1.2 billion mt in the period 2019 to 2022[91] (European Commission, 2016).

The impact of the approved mechanisms on the market is unpredictable since it depends on many unforeseeable variables such as commodity fluctuations, demand-side-risk due to an economic recession and other national and EU environmental policies. In the following chapter, the key factors conditioning the coal-to-gas switching process in the UK and Germany will be assessed, paying special attention to the economics of gas and coal plants. This comparison will enable to create a common ground in order to build the scenario analysis in Chapter 5 and evaluate the effect of different carbon price levels on the coal-to-gas switching process of each country.

[91] Significantly more than the supply cut resulting from the backloading measure in 2014-2016, which removed 900 million tonnes from the total auction volume.

CHAPTER 4: COMPARISON GERMANY AND THE UK

It is important to note that political action and market dynamics vary between EU countries resulting in divergent switching equilibriums. The process towards a less emission intensive power sector can be framed in many ways conditioned by EU climate policies and national policies. In this chapter, we will analyse the current coal-to-gas switching situation in Germany and the UK. The assessment will be focused on the following aspects for each country:

- Underutilized gas power potential
- Commodities effect
- Policy support and investment mood
- Carbon price
- National coal production and socio-economic dependence

Having a clear picture of the coal-to-gas switching situation in each country is key to evaluate the strategy implemented by the respective governments. Further, this assessment creates a solid ground to build the scenario analysis in Chapter 5, allowing to determine if implemented measures and market trends will trigger a significant coal-to-gas switch.

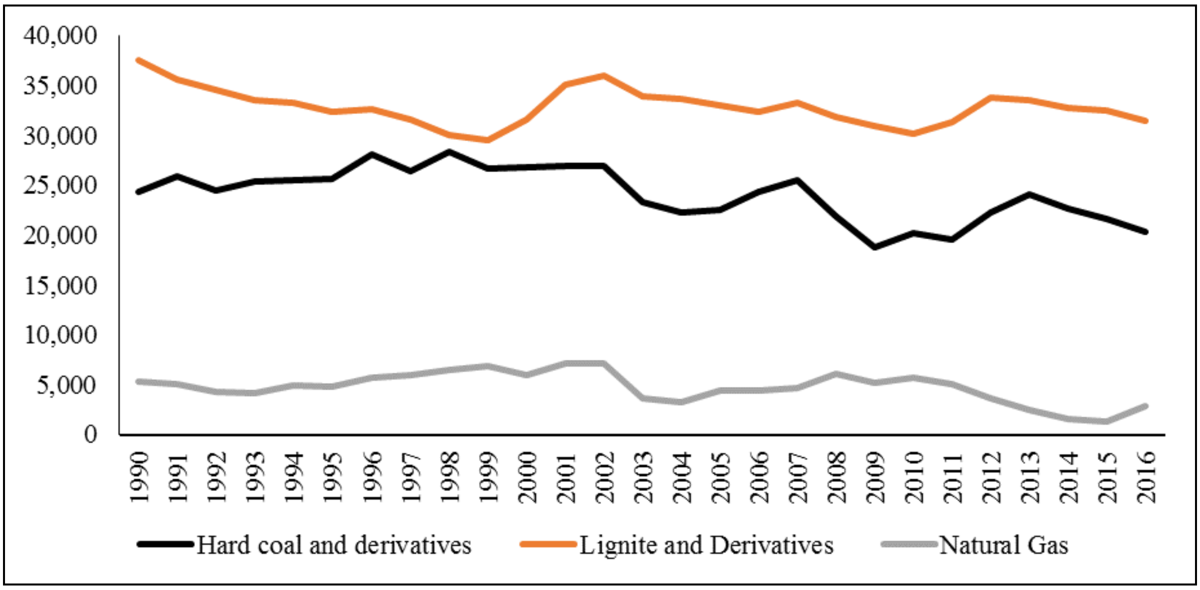
SECTION 4.1: GERMAN CASE

SECTION 4.1.1: UNDERUTILIZED GAS POWER POTENTIAL

Germany is at the core of the European power market and is one of the most difficult European markets for gas-fired plants due to its vast lignite resources and limited market intervention. From 2011 to 2015, hard coal and lignite plants exhibited a marginal cost advantage over gas, leading to a drastic decrease in operating hours of gas capacity. This explains why German gas-fired gross production was only 36,784 GWh in 2015, way below its highest level in 2008 with 82,248 GWh. The fall in natural gas consumption in the power sector went from 6,046 tonnes of oil equivalent (TOE) in 2008 to 1,325 TOE in 2015 (see Figure 36). This indicates that a high switching potential is feasible without the construction of additional gas power capacity. However, a condition sine-qua-non is that the economics of gas become more favourable and no capacity retirement takes place. In 2016, the first signs of gas plants recovery were palpable as gas consumption in the electricity sector doubled (2,852

TOE) compared to 2015, while coal consumption continued its moderate decrease since 2013 (especially in the case of hard coal) (Eurostat, 2018).

Figure 36: Germany's consumption of fossil fuels in the electricity sector in TOE (1990-2016)

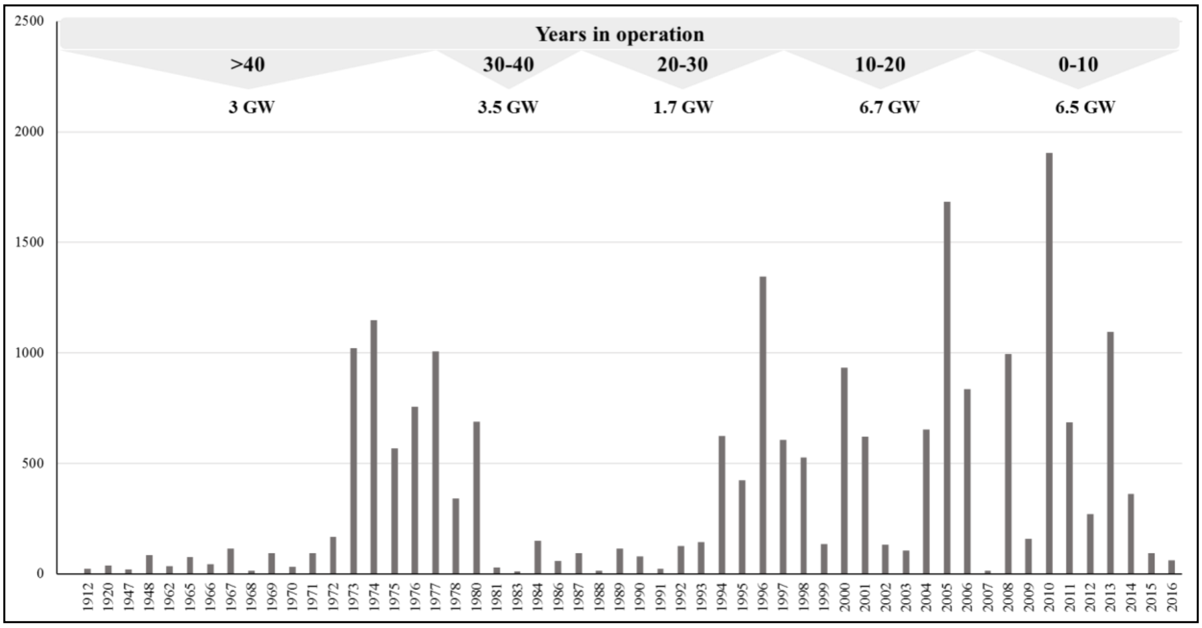


Source: Own development, data source Eurostat, 2018

From 2011 to 2014, the poor economics of gas added to the rapid deployment of renewables, condemned gas-fired plant operators to shorter operating times and very low or even negative margins. This situation triggered mothball and closure of unprofitable plants, particularly between 2012 and 2016, when 0.924 GW of gas-fired power capacity were shutdown, 1.665 GW were temporally shutdown and 0.763 GW were kept online for security supply reasons (accounting for 3.352 GW or 2% of total installed capacity). Old plants with steam turbines or gas turbines technology (less efficient) were closed down first, continuing with the more efficient ones. The persistent negative perspective affected even new plants with an efficiency ratio of 58% (combined cycle technology), which were also forced to shut down[92]. This situation represents a head breaker for supporters of the "Energiewende", who witnessed powerlessly how the market punished efficiency and environmentally friendlier power capacity. According to data published by the German Grid regulator (the Bundesnetzagentur), the gas fleet is noticeably new, as 62% (13.2 GW) of the gas operating capacity is less than 20 years old (see Figure 37).

[92] EON SE announced in 2016 the closure of two new unprofitable gas-fired units.

Figure 37: Historic added operating gas-fired power capacity in Germany in MW (1912-2016)

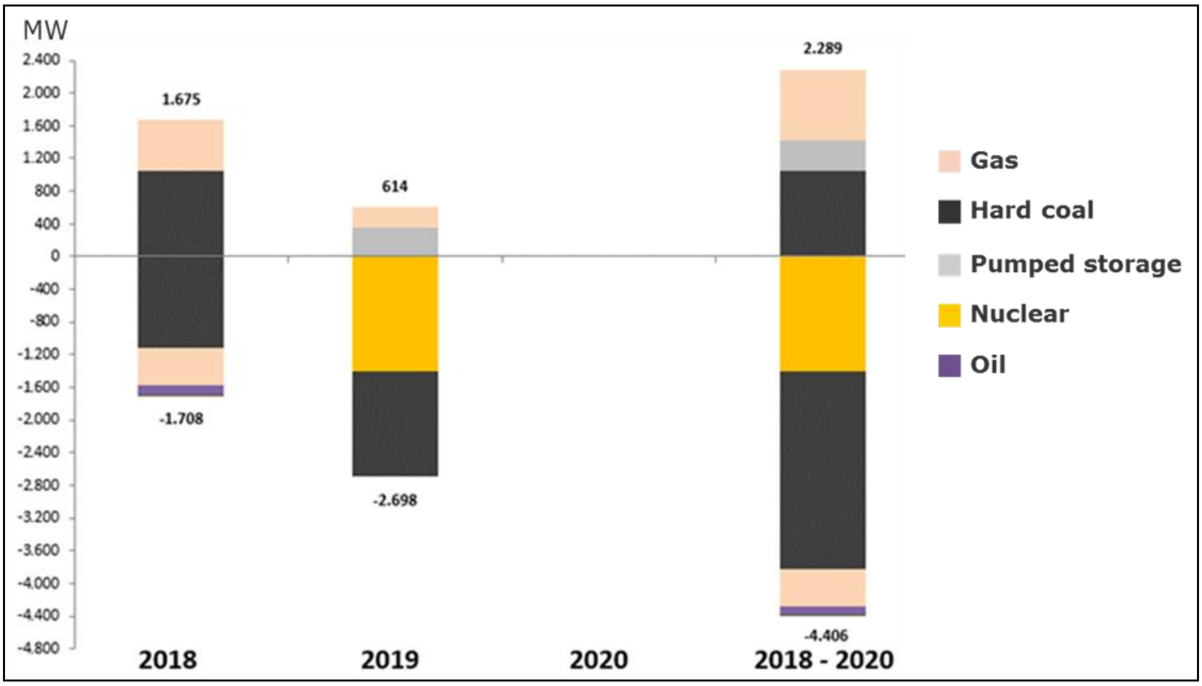


Source: Own development, data source Kraftwerksliste Bundesnetzagentur, 2017

A key problem deriving from this situation is that the continuous closure of high efficient gas plants may increase the energy gap initiated by the nuclear phase-out. The nuclear phase-out has created the need for substitutive capacity, which at first should be covered with conventional and renewable capacity. However, if gas capacity is not competitive enough to stay on the market, the construction of new coal plants is inevitable. This would result in a lock-up effect of emissions for the next decades[93]. The Bundesnetzagentur releases every year the planned capacity additions and retirements for the following years. According to the last published estimation, the net balance indicates a retirement capacity of -4.4 GW (mainly nuclear and hard coal) and a net increase 2.3 GW (gas, hard coal) capacity between 2018 and 2020 (see Figure 38) (Bundesnetzagentur, 2018).

[93] The typical operational life of a coal plant is around 40 to 50 years (IEA, 2016).

Figure 38: Germany's planned construction and retirement of conventional capacity (2018-2020)



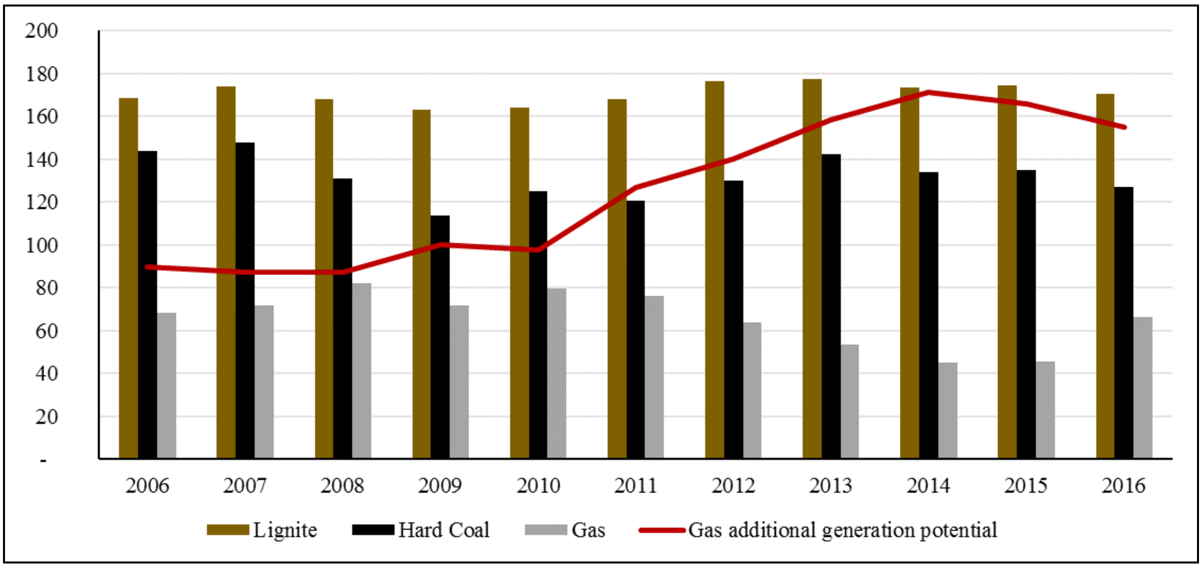
Source: Bundesnetzagentur, 2018

One of the advantages of gas-fired plants is their technical flexibility, which allows to cover peak load and back-up intermittent generation from renewable technologies. However, peak load is not such a delicate issue anymore as RES created an effect of flatter peak demand, due to maximum daily output at peak periods. This applies particularly to solar power generation (which accounted 39,098 GWh net generation in 2016), which reaches its level of max output around noon, matching with one of the demand peaks in Germany. Meaning, that the effect of RES capacity in the system represents less market share for conventional peak plants and therefore shrinking revenues (DNV GL, 2018).

The future picture presented by the "Energiewende" in which renewables will replace generation from nuclear is not accurate, at least not in the medium term. The fact that old coal plant will be retired (due to end life-time) in the next years, makes additional conventional capacity necessary in order to fill the gap. This is particularly important for the southern part of Germany, a region with concentrated industry and seriously affected by the nuclear phase-out. This situation has motivated the German regulator to avoid the closure of 7.2 GW of uneconomical gas-fired capacity declaring them as system-critical. The main concern is the provision of enough power supply at times of low renewable output, which is typically during winter, when calm weather conditions and cold temperatures are the norm. Hence, intermittent renewables capacity needs to be backed-up and from a technical standpoint, gas is the best alternative (GTM, 2018).

The potential coal switching channel in Germany is represented in Figure 39, illustrating the available additional generation potential of gas power plants. It can be observed that the additional gas generation[94] potential could cover the power generation from hard coal and almost lignite, but not of both at the same time. Taking into account that the competitive level of gas-fired plants is closer to hard coal than lignite, a theoretical coal-to-gas switching process would mainly substitute hard coal generation. In order to cover both coal sources (lignite also), significant additional gas power capacity would be need to be built.

Figure 39: Germany's coal-switching channel in GWh (2006-2016)



Source: Own development, data source Eurostat 2018

There is a widespread consensus about the relevance of gas-fired power capacity for the power system. Nevertheless, the substitution of coal generation in the base load depends to a high extent on commodity prices for coal and natural gas.

[94] Formula: Availability factor multiplied by generation capacity minus gross generation.

SECTION 4.1.2: COMMODITIES EFFECT

The prices of coal and natural gas determine to a large extent the sequence of the merit-order-curve for conventional power sources. As explained in an earlier section, coal plants have benefited from marginal cost advantages between 2011 and 2015. However, since 2016 the performance of gas power generation is on an upward trend due to shifts in the commodity markets. Besides the effect of coal and gas prices, the power price plays a key role in determining the profitability of conventional power plants. In Germany, wholesale power prices have fallen significantly due to the vast deployment of renewables (more detail in section 3.3). This has lowered the profitability of all power generators as the price for 1 MWh went down 58% from EUR 65.1/M Wh in 2006 to EUR 37.6/MWh in 2016. In the case of gas-fired power plants, the impact has been particularly notorious due to the parallel rise in gas prices (between 2011 and 2014) and limited operating hours (relegated to the end of the merit-order-curve) (IEEFA, 2017).

The effect of commodity prices on the competitiveness of gas and coal is best represented by the evolution of the clean spark spread and clean dark spread.

The clean spark and dark spread curves are widely used indicators of the profitability of gas power plants and coal power plants. They consider variable production costs (main inputs are fuels and operation expenses), the CO2 equivalent emission cost (determined by the EU ETS)[95] and the average price of electricity (revenue source).

Through the following formulas, the clean spark spread and clean dark spread are calculated:

Clean spark spread (CSS) = [Power price - (Natural gas price expressed in EUR per MWh / Gas plant efficiency rate[96])] - Carbon price from the ETS × gas CO2 emissions factor[97]

[95] The “Clean” part means that the cost of carbon is included in the cost equation.

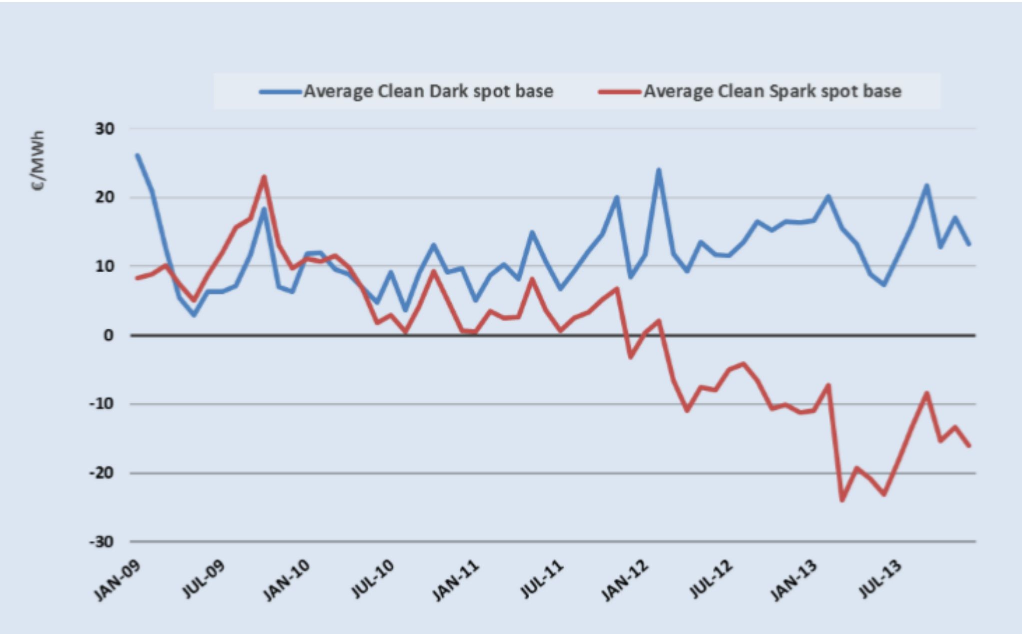
[96] The efficiency ratio refers to the conversion factor from fuel to electricity. For instance, average rate of 50% for gas fleet and 36% for the coal fleet in the UK according to Ofgem.

[97] Emission factor of 0.35t CO2/MWh for gas plants and 0.88t CO2/MWh for coal plants in the UK (Ofgem, 2018) and 0.37t CO2/MWh for gas plants and 0.85t CO2/MWh for coal plants in Germany (On Climate Change Policy, 2018).

Clean dark spread (CDS) = [Power price - (Coal price expressed in EUR per MWh / Coal plant efficiency rate)] - Carbon price from the ETS × coal CO2 emissions factor

The following figure shows the evolution of the CSS and CDS between 2009 and 2013 illustrating the divergence since July 2011 due to rising natural gas prices. Gas plants were pushed out of the market and were only able to obtain negative margins per MWh produced. Contrasting with the CDS (the indicator for the profitability of coal fired electricity), which has remained positive over the same period as a result of low input costs (coal prices and CO2 emission prices). As mentioned previously, the drastic fall in coal prices and the collapse in CO2 prices has enabled the CDS to stay positive even with reduced electricity prices. This is a reflection of the dominance of coal in the German conventional power scene translated to a high share of the base load dispatch (Cornot-Grandolphe, 2014).

Figure 40: Germany's Clean Spark Spread and Clean Dark Spread evolution (in EUR/MWh) (2009-2013)

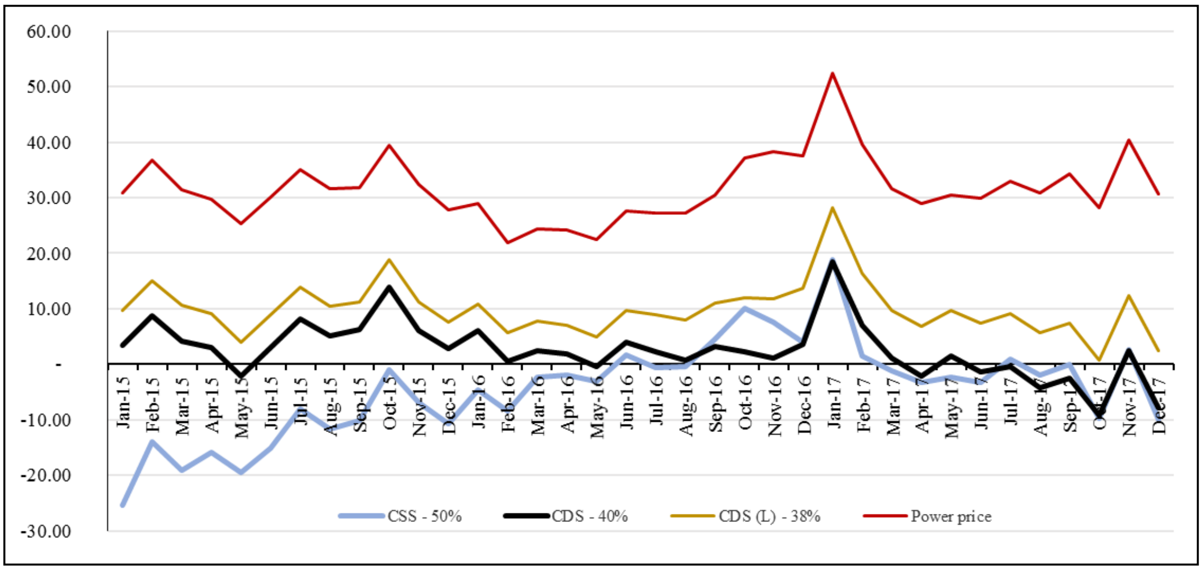


Source: Cornot-Grandolphe, 2014

Since 2015, the wide cost advantage of coal has been losing ground as commodity prices (falling gas price and a slightly increase in coal price) are slowly strengthening the position of gas-power plants. From a commodity perspective, falling gas prices since 2014 and increasing coal prices in 2016 are levelling the marginal cost difference of both fuel sources. Which means that the gas-fired plants are regaining competitiveness and may be able to compete against coal for base load share. However, a continuing fall in European gas price depends largely on how efficiently global oversupply of LNG is absorbed by European markets. This requires favourable regulation that improves the functioning of EU wholesale gas markets, which could translate in more competitive prices (ACER, 2015; Cornot-Gandolphe, 2014 and DNV GL, 2018).

Hard coal plant output in 2017 was 64.7 TWh, down 10% compared to 2016, according to data aggregated by Fraunhofer ISE. Closures of old plants and declining dark spreads are behind the dip. On the contrary, in the same period German gas plants have registered a significant runtime gain. Going up 22% compared to the same period last year (52.1 TWh). Especially relevant is the summer of 2017, the CSS moved ahead of the CDS for the first time since 2011, which increases the pressure on old coal plants not only social and political, but also economical (see Figure 41).

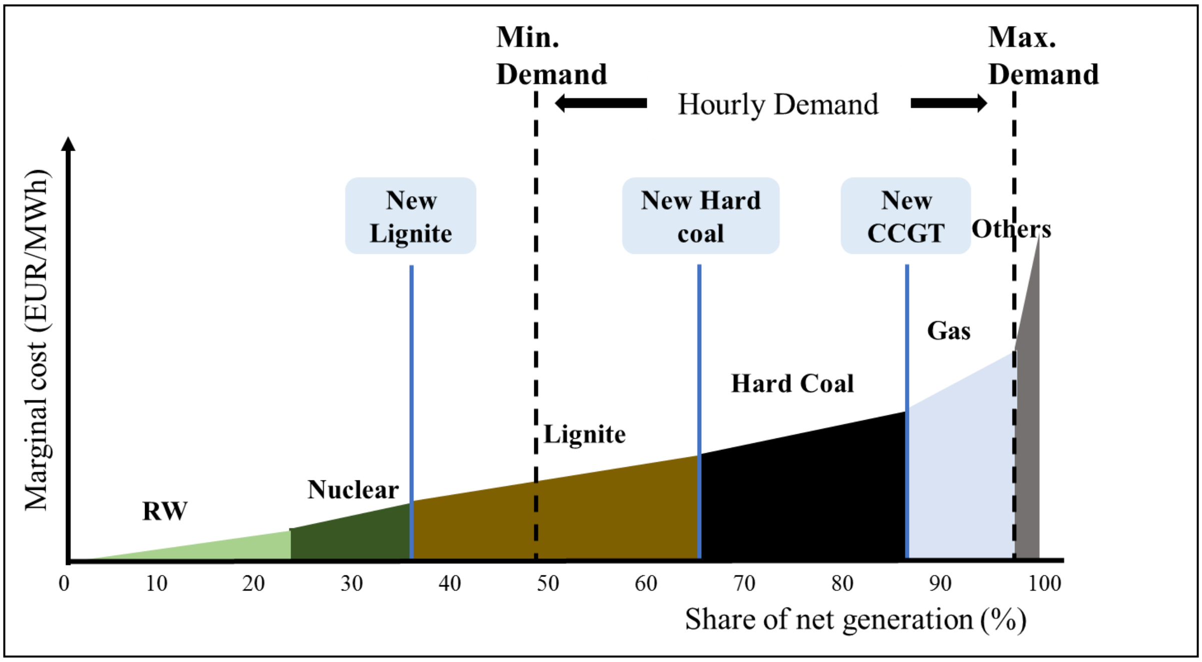
Figure 41: Germany's Clean Spark Spread and Clean Dark Spread evolution (in EUR/MWh) (2015-2017)



Source: Own development, data source ICE Future, EEX, World Bank, Entso-e transparency platform and IPCC

It is evident from Figure 41 that both curves are gradually declining (independent of coal and gas prices). This is due to lower electricity prices triggered by the vast deployment of renewables. Over the last years, Germany has experienced a rapid increase in RES generation resulting from various supporting schemes (such as feed-in tariffs, feed-in premiums, tax credits and auction systems), shrinking installation costs and increasing technological efficiency[98]. However, there is a widespread consensus that the retirement of coal and nuclear in Germany will allow gas plants to become a constant contributor to cover base load supply becoming the price setter even in low demand periods (see Figure 42). Inevitably, this will drive the power prices up.

Figure 42: Merti-order-curve in Germany - net generation share (2016)



Source: Own development, data source Eurostat 2018

SECTION 4.1.3: POLICY SUPPORT AND INVESTMENT MOOD

The German electricity market cannot be described as perfectly competitive, since the four largest electricity producers[99] account for over 76.5% of the electricity production (65% of total capacity) creating an oligopoly (status 2016). These power producers have a wide portfolio of conventional power generation assets accumulated over the last decades. However, investment in conventional power plants has stopped due to low wholesale price predictions and the financial difficulties resulting from the accumulation of stranded assets. With stranded assets, we refer to power plants that are written down because of unprofitable

[98] From 2010 to 2014 decreasing costs per kilowatt hour by 53% and 15% for PV and wind onshore respectively (UNEP 2014).

[99] EnBW, E.ON/Uniper, RWE, Vattenfall and LEAG.

results (low generation margins). Over the last years, utilities reported premature decommission of 3.2 GW of conventional power generation capacity. This amount could have been higher if the government would not have prevented the closure of 4.9 GW additional capacity (Bundesnetzagentur, 2017).

Additionally, the EU environmental standards, such as the Large Combustion Plant Directive, have forced aging coal plant owners to rethink their strategy and seek the most economically interesting option. For plant owners, the economic incentive to invest in depollution equipment in order to cope with new emission requirements (EU clean act) is low. This has pushed various producers to seek alternatives, which consist on running the plants to their maximum operating limit and accept early decommission (2021 or earlier).

The market price dynamics of coal have been a key factor in incentivising the intensive running of coal-fired plants allowing them to keep a stable share of 40% to 50% of total electricity production since 2006. However, this supremacy will very likely shrink as new coal capacity additions will be limited, which will open the base load segment to efficient gas plants. The relevance of gas plants in the base load segment will be further increased given the complete close down of nuclear power capacity by 2022. The following figure shows the planned decommission of conventional plants (including nuclear) and the capacity extension to cover the energy gap left. As can be observed, the region of North-Rhine Westphalia (the most populated state in Germany) will receive a large portion of the new installed conventional capacity, since many aging coal and lignite plants are located in this region (see Figure 43). The government aims to replace part of its old inefficient coal plants with high efficient ones to avoid giving up its vast lignite resources. A sensitive matter, related to energy independence that has become a major issue since the Russian-Ukraine crisis (Matthes, 2017).

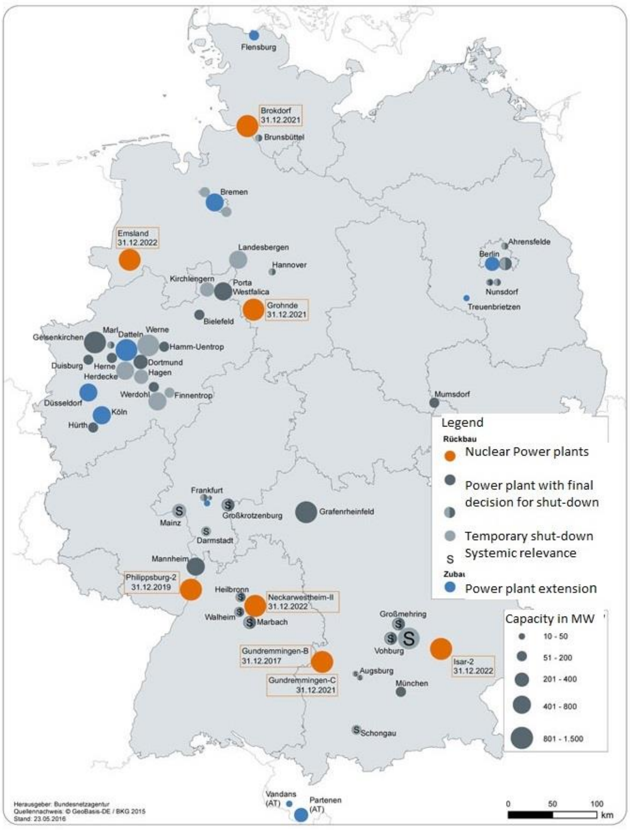


Figure 43: Location of the conventional plant expansions and closures in Germany

Source: Bundesnetzagentur, 2017

Unsurprisingly, the market sentiment on the value of coal and gas plants is pessimistic. Over the last years, the deployment of renewables has displaced gas-fired power plants out of the merit-order-curve. Coal plants have been operating at high loads, but continuous increase in renewable generation is slowly pushing hard coal out from the merit order curve as well. This is especially the case for the ageing coal fleet in Germany, of which 28% (13 GW) is more than 40 years old (considering an average lifetime time of 40 to 50 years in the case of coal plants). In the current scenario, the announced decommissioning of nuclear plants and the unprofitable gas capacity, brings up concerns about security of supply (translated into risk of power shortfalls). Thus, there is a need for renovation of conventional plants (technological upgrade) and construction of new efficient capacity. However, key players responsible for the current infrastructure mix have limited financial means and political incentive to invest in new conventional plants. This explains why the new hard coal unit that will be built in Germany in 2018 will probability be the last one [100]. Furthermore, the economic perspectives for gas and coal are not very attractive to keep newly built power plants online for their entire lifetime. Not even, lignite capacity, which has benefited from a privileged marginal cost situation, is safe from market and regulatory pressure. In this respect, the ministry of Energy has announced a plan to shift 2.7 GW of lignite capacity into the power reserve[101] before 2019 in order to support the climate targets[102] (CEE, 2016 and Bundesnetzagentur, 2017).

The reliance on conventional capacity could further decrease as a result of increases in cross border trade with neighbouring countries and an enhanced grid infrastructure, which would permit the efficient transfer of renewable energy produced throughout the country. The new power sector reality would require power producers to revisit their strategy on conventional assets. In fact, big power utilities have already started to shift their investments from conventional large-scale electricity generation to new business models associated with renewable generation and smart products and services. As an example, two of the main utilities in Germany, RWE and EON, have created new companies to enter the market of

[100] Uniper’s Datteln 4, with a capacity of 1,055 MW.

[101] The plants will be turned off but maintained in running mode in case of power shortages over the next four years.

[102] The power plant operators will receive 1.6 billion Euro in exchange, resulting in 11 to 12.5 million tonnes of CO2 emissions avoided.

renewables, grid and energy distribution. However, this change in business strategy has come after these utilities invested heavily in high-carbon assets leading to considerable financial losses.

Besides low profitable perspectives, conventional power capacity needs to exist even beyond 2050 in order to back up renewable generation. According to Garrelt Duin, the economy minister in the state of North-Rhine Westphalia, this back up capacity should be at least 50 GW source from conventional power sources (Andresen and Zha, 2016).

SECTION 4.1.4: CARBON PRICE

German power plants have been exposed to the carbon price set by the EU ETS since 2005. During the first and second phase (2005-2012), the power sector obtained free allowance, which did not create a strong incentive to reduce emissions. Additionally, the carbon price has remained low, since the end of 2012 to 2018 the average carbon price has been EUR 6.2/mt of CO2 making it inexpensive for coal plants to operate using high CO2 intensive fuels (see Section 4.1.2). Under these circumstances, lignite plants have benefited from a strong economically competitive position in comparison to other fossil fuel technologies, with less CO2 emission intensity but higher fuel prices. The persistent low EU ETS price has opened the debate about the necessity to introduce a carbon price floor that reinforces the price of carbon at a level that drives low carbon investments. According to the last study published by the climate NGO Sandbag, 55% of EU ETS emissions in Germany in 2016 came from coal plants, especially from lignite plants. In fact, 7 out of 10 of the biggest polluting plants in Europe are in German territory (see Figure 44) (Sandbag, 2017 (2)).

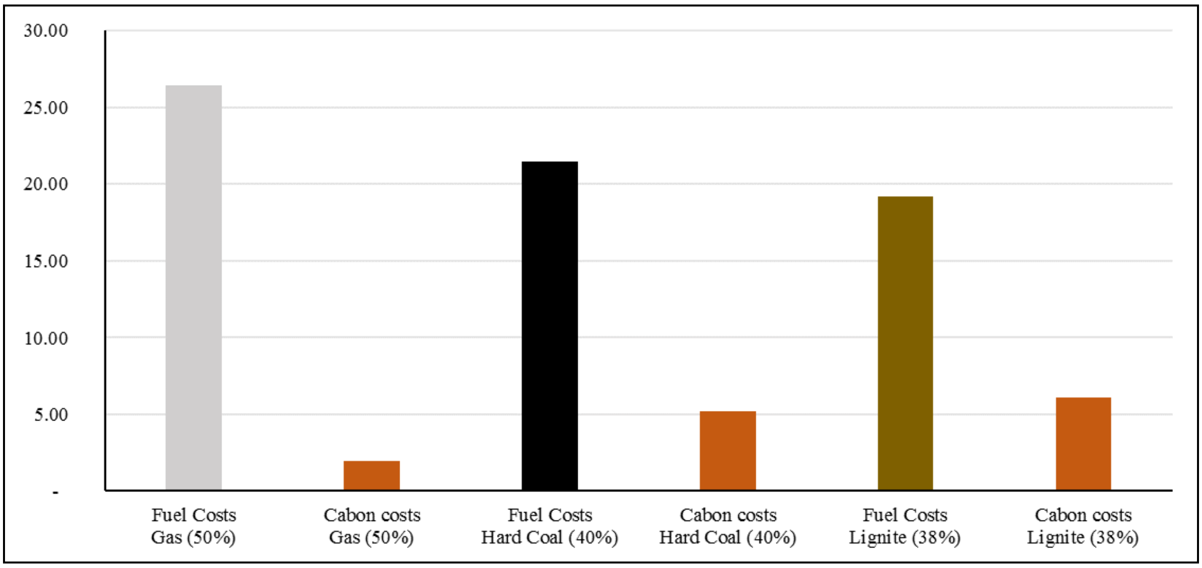
Figure 44: Top 10 emitting installations under the ETS (2016)

InstallationName	RegCtryName	SandbagSector	Fuel	$MtCO_{2e}$
PGE GiEK S.A. Oddział Elektrownia Bełchatów	Poland	Power and heat	Lignite	34.9
Kraftwerk Neurath	Germany	Power and heat	Lignite	31.3
Kraftwerk Niederaußem	Germany	Power and heat	Lignite	24.8
Kraftwerk Jänschwalde	Germany	Power and heat	Lignite	23.8
Kraftwerk Weisweiler	Germany	Power and heat	Lignite	18.7
Kraftwerk Schwarze Pumpe	Germany	Power and heat	Lignite	12.2
ELEKTROWNIA KOZIENICE	Poland	Power and heat	Hard coal	12.0
Kraftwerk Lippendorf	Germany	Power and heat	Lignite	10.8
CENTRALE TERMOELETTRICA DI TORREVALDALIGA NORD	Italy	Power and heat	Hard coal	10.2
Kraftwerk Boxberg Werk IV	Germany	Power and heat	Lignite	9.7

Source: Sandbag, 2017

Germany´s aim to cut national CO2 emissions by 40% by 2020 compared to 1990 levels will not be accomplished. This is due to the stable position of coal in the energy mix. Despite that renewables accounted for 23% of total net power generation in 2016 (rising from 13% in 2010), emissions from the power sector have remained unchanged due to stable output from coal combustion (50% of fossil fuel power generation through coal in 2016). The EU ETS has not proven to be effective in discouraging the operation of old coal plants in favour of newer gas installations. While the first have gained a share in the baseload, modern gas plans have been pushed out of the merit-order-curve. This situation is called the "Energiewende paradox" since rapid renewable deployment has not reduced the total emissions amount. Considering current market conditions, old coal plants will probably run until the end of their operating lifetime and about 8 GW of modern capacity may provide baseload power for many years to come. Therefore, many experts claim that a progressive coal phase out is inevitably linked to a carbon price floor. However, implementing a price floor is a sensitive political decision, especially in Germany where reserves of lignite are abundant and the coal fleet has a strong strategic position in the energy mix as well as the economy (as we will see in a later section). For this reason, the government has avoided any clear commitment on a minimum CO2 price, and prefers to let the market (EU ETS) decide (Clean Energy Wire, 2016).

Figure 45: Fuel and carbon costs for fossil fuel plants EUR/MWh in Germany (2016)



Source: Own development and calculations, data source ICE Future, EEX, World Bank, Entso-e transparency platform

While a national price floor doesn't seem plausible, since it could damage German industrial competitiveness, a minimum price at EU level could be feasible considering the pressure of neighbouring countries: Belgium, Netherlands and France. Netherlands has already announced its intention to implement a carbon price floor of EUR 18/mt of CO2 from 2020 with a progressive increase to EUR 43/mt until 2030. France is also considering the introduction of a floor price as a complement to the EU ETS price, in the form of a carbon tax (as in the UK case, see section 4.2.4). A key consideration when defining a carbon price floor is its impact on the electricity price. Recent calculations performed by Pöyry[103], show that a floor price of EUR 30/mt CO2, would increase electricity wholesale price by around EUR 15/MWh in Germany. The results show that such a floor price would augment the costs of an average coal power plant from EUR 35/MWh to EUR 55/MWh, while costs for an average modern gas plants would only increase from EUR 39/MWh to EUR 47/MWh. This would trigger an effective coal to gas switch granting higher shares of baseload for gas plants. However, the burden of an electricity price increase would be carried out by the economy as a whole, especially power intensive industries. Taking into account that Germany is an industrial superpower in Europe, it appears politically difficult to pass such a measure in the near future (Platts, 2017).

SECTION 4.1.5: NATIONAL COAL AND SOCIO-ECONOMIC DEPENDANCE

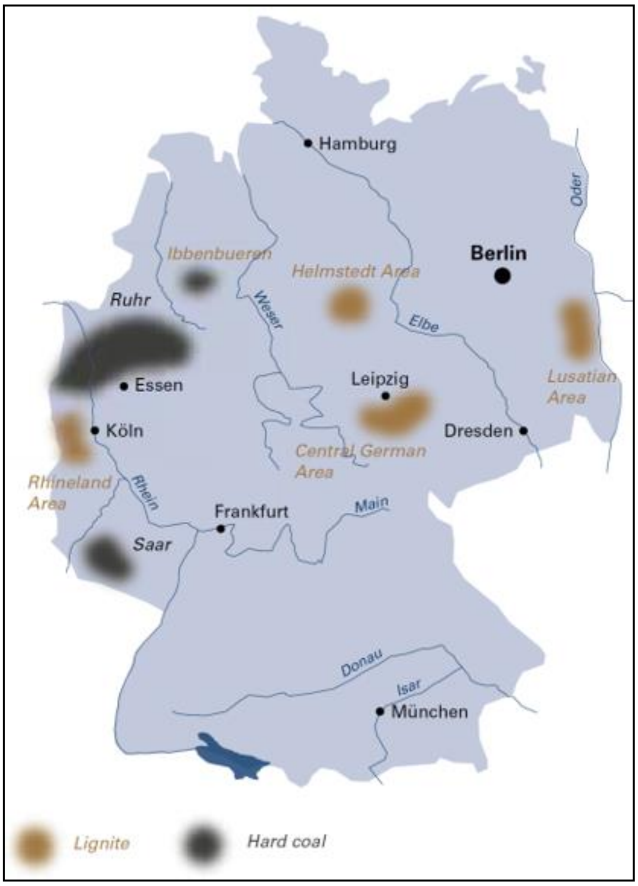
Germany's ongoing dependence on gas pipeline imports (99.3 billion m^3 in 2016) with a considerable part coming from politically risky Russia (46 billion m^3 in 2016)[104], speaks in favour of maintaining its connection to coal as a fundamental piece in the country's electricity mix. In the case of hard coal, Germany has no considerable reserves and is a net importer with 48 million tonnes in 2015 (the largest importer in Europe and the sixth worldwide). Contrary to gas, Germany's hard coal suppliers are well-diversified located in five different continents (AGEB, 2016).

[103] Pöyry Management Consulting.

[104] The other main suppliers from countries without political risk are Norway and Netherlands. However, the supply from these countries is expected to fall over the next years.

Figure 46: Lignite and hard coal production sites in Germany

Source: Euracol, 2018



In the case of lignite, Germany accounts for the third (after Russia and Australia) biggest lignite reserves with 36,212 million tonnes in 2016 and is the largest producer with 178 million tonnes in 2015 from which it consumed 173 million tonnes mainly in the electricity sector. Today, there are three working brown coal mining regions left in Germany, the Rhineland area, the Lusatian area and the Central German area (see Figure 46) (BGR, 2016 and BP, 2017).

Recent German recent history is closely linked to coal production, which played an important role in the country's post-war reconstruction and economic recovery (the so called "Wirtschaftswunder"). Nonetheless, international competition has forced a steady decline in production and jobs since 1990 with only a low portion coming from national mines in the last years[105]. Germany's government signed the "Hard Coal Financing Act" setting 2018 as the deadline to close all remaining hard coal mines, which relied on heavy subsidies. Lignite production, in contrast, is more competitive due to its lower extraction costs in opencast pits[106] and close access to lignite power plants providing approximately 20,000 direct and indirect jobs (15.000 related to lignite mining) (see Table 4). The power sector is the only consumer of lignite with most power plants located next to the mines in order to reduced transportation costs. The low extraction cost, its abundance and the fact that lignite extraction and burning is concentrated in a few regions makes the decision to close

[105] Coal imports have its origins in Russia (34.1%), the United States (16.5%), Australia (16.1%) and Columbia (15.8%) in 2016 (Clean Energy Wire, 2016).

[106] In 2015 the average mining cost of one tonne of hard coal in Germany was EUR 180, compared to EUR 68 from imported hard coal (Clean Energy Wire, 2016).

down the lignite mines politically unpleasant. Besides, mining employees are well organized and represented by a strong labour union (the so-called IG BCE[107]) that will actively defend this sector (AGEB, 2016 and Euracoal, 2016).

Table 4: Employment in the hard coal and lignite sector in Germany (2015)

Employment in Germany - 2015

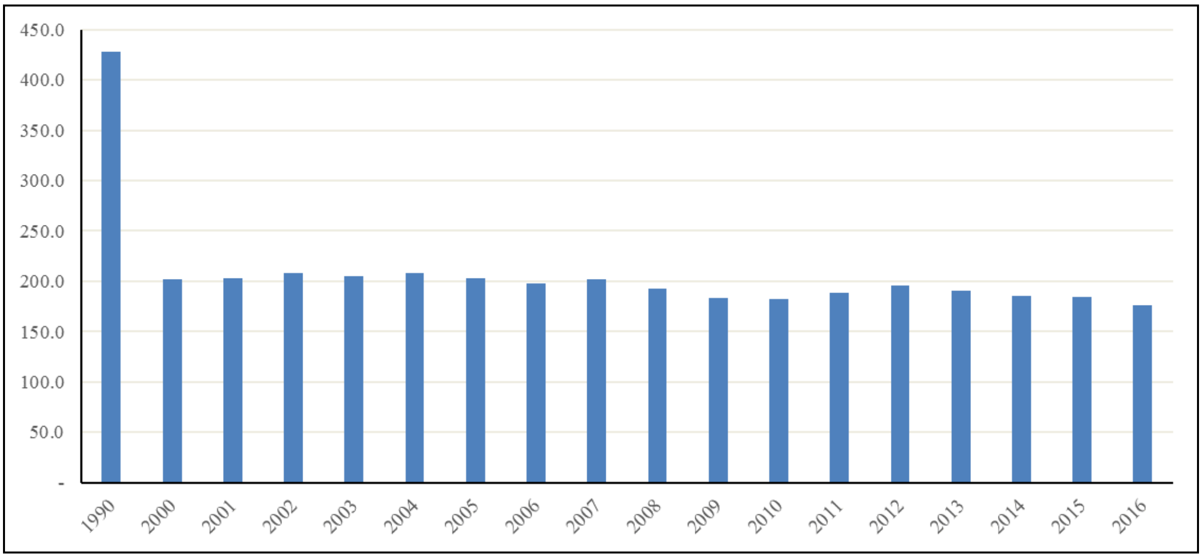
Direct in hard coal mining	9,640
Direct in lignite mining	15,428
Other hard coal related*	15,700
Other lignite related*	5,316

*e.g. in power generation, equipment supply, services and R&D

Source: Own development, data source Euracoal 2016

As can be observed in Figure 47, lignite production has not declined significantly since 2000. Despite its high CO2 emission content, the CO2 price has been too low in order to incentivise a fuel switching process to less carbon intensive sources. This has allowed lignite to maintain a solid position in the base load. In 2016, lignite generated 29% of total electricity output and hard coal 22% (Eurostat, 2018).

Figure 47: Lignite production in Germany in million tonnes (1990-2016)

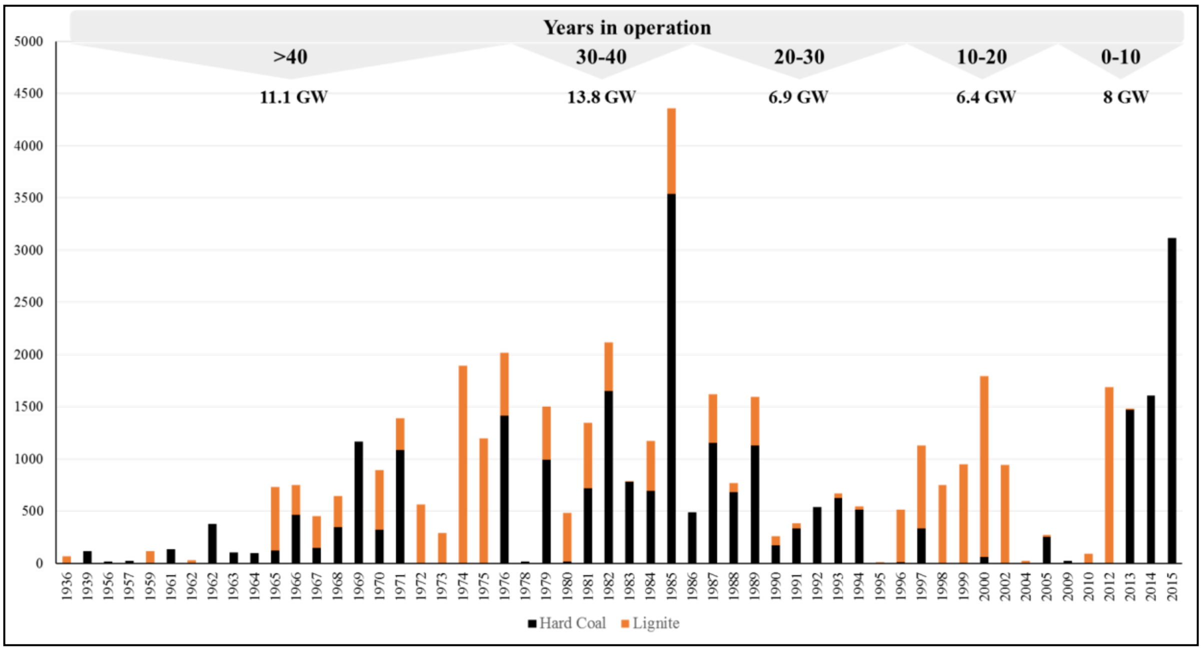


Source: Own development, data source BP 2017

[107] According to IG DGB, plant closures would have a far-reaching effects on the local economy.

During the 70s and 80s, a large expansion of the coal fleet took place (24.5 GW of hard coal and lignite added capacity) leading to today's ageing fleet. Considering an average lifetime of 40 to 50 years for a typical coal plant (IEA, 2016), it means that a significant part of the old coal plants is in the process of retirement. According to the "Bundesnetzagenture", from 2011 to 2016, 6.5 GW of old coal-fired plants were decommissioned and more retirements are expected in the following years. In order to prevent energy shortages, 8 GW of new lignite and coal capacity have been added to the grid over the last 10 years, which has increased the risk of carbon locking (see Figure 48) (Bundesnetzagentur, 2017).

Figure 48: Added hard coal and lignite power capacity (MW) in Germany



Source: Own development, data source Bundesnetzagentur 2017

Apart from the retirement due to age, a pronounced decline of electricity prices and a fast deployment of renewables could set off a wave of premature closures of unprofitable plants. The decommissioning of 2.5 GW of hard coal in 2017 and a planned addition of 2.4 GW to the security reserve in 2019 symbolises a trend of no-return for the coal dominance in the base load[108] Further, as part of the "Climate Action Programme 2020", 2.7 GW of lignite power capacity will be progressively shifted to the security standby reserve until 2023 (Schulz and Schwartzkopff, 2015 and Euracoal, 2018).

[108] Especially disturbing is the case of RWE AG that will never recover its EUR 1 billion (USD 1.1 billion) investment in the Westfalen-D plant.

The political party "Die Grünen" (the Green) intends to accelerate the decommission process by forcing ten coal plants in North-Rhine Westphalia to shut down in the following three years. The political pressure in the national parliament is increasing[109] and CCS technology has encountered widespread opposition throughout the country (due to the undesired carbon underground storage and its high costs). This has reinforced the strategic and political position of gas as the chosen transition fuel. After missing the 2020 emission target, the government will not have any option than defining a plan to phase out halve of its coal fleet by 2030 in order to achieve a 60% cut in emissions. It is therefore, plausible that the government will be forced to introduce new regulation measures if market conditions do not move in the desired direction. However, this doesn´t seem an easy task as strong resistance from economically coal dependent regions is expected (Reuters, 2017).

SECTION 4.2: THE UK CASE

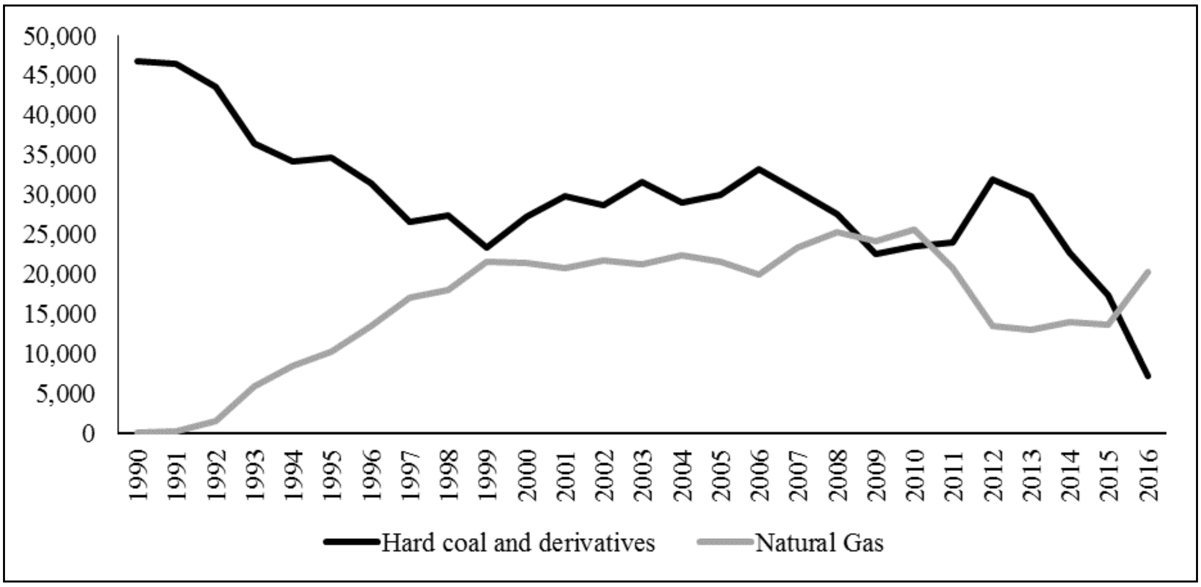
SECTION 4.2.1: UNULIZED GAS PRODUCTION POTENTIAL

UK´s power mix evolution over the last decades has projected a strong reliance on non-domestic fossil fuels. A country that was once mainly powered by coal has experienced a shifting trend towards gas during the 90s due to favourable commodity prices and the increasing concern about air pollution. This triggered a rapid build-up of the gas fleet resulting in a fierce competition between gas and coal for market share. In numbers, coal-fired electricity generation registered a fall from 72% of electricity generation in 1990 (46,840 TOE) to 30% in 1999 (23,253 TOE). In parallel, gas experienced a sharp progress from practically no-use to 21,560 TOE of natural gas consumption in the power sector in 1999. The competition between both sources has been tight with coal leading the battle until 2010 when gas generation achieved its highest load ratio with 64.2% (25,512 TOE) against 38.5% (23,531 TOE) of coal generation. Over the next years, low coal prices progressively gave coal once again the leading position in the base load (in 2013, 58.4% of load against 27.9% of gas). Later on, changing market price trends and policy actions regarding emissions and renewable deployment turned the scene in favour of gas in 2015. A new structural shift

[109] "Die Grünen" have presented a plan in the parliament (Bundestag) supporting a coal-phase out plan until 2037.

happened and since then gas and renewables have been pushing coal into a less and less relevant role in the energy mix. The following graph (Figure 49) illustrates the fuel consumption evolution in the power sector. The natural gas consumption peaked in 2010 (25,512 TOE), which indicates that there is still space for switching potential without the need to build new capacity (Eurostat, 2018).

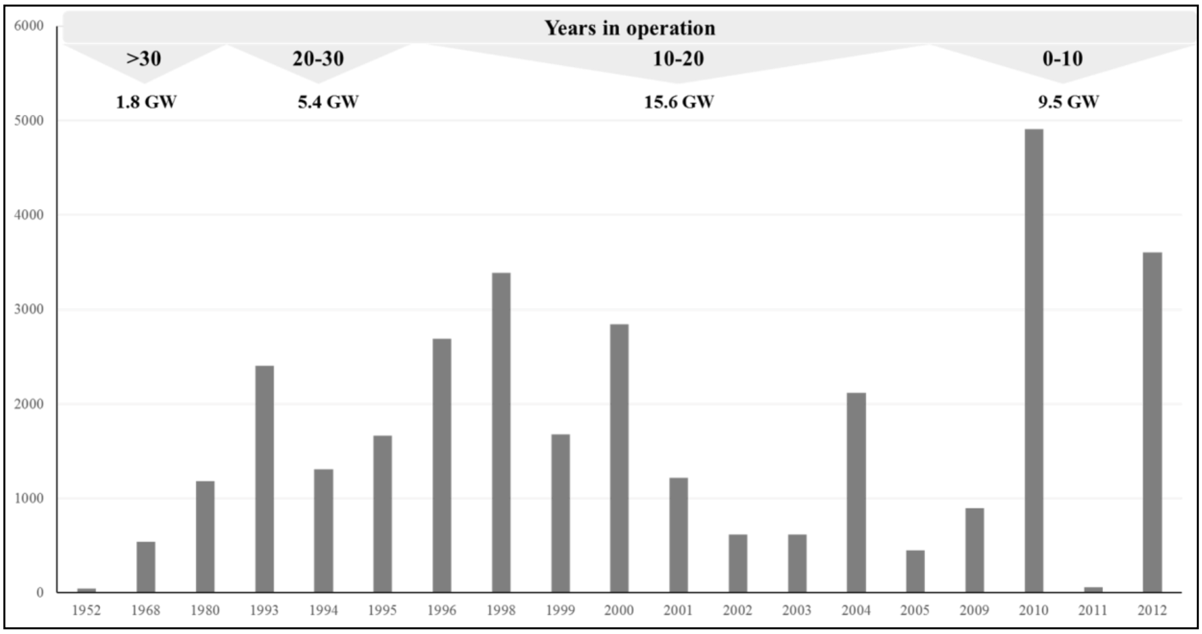
Figure 49: Consumption of fossil fuels in the electricity sector in thousand tonnes of oil equivalent (TOE) in the UK (1990-2016)



Source: Own development, data source Eurostat 2018

According to data published by Ofgem, the gas fleet is relatively new, as 78% (25.1 GW) of the gas operating capacity has less than 20 years of life (see Figure 50). In contrast, the coal fleet is considerably older, with the oldest coal plants close to retirement. Nevertheless, an old power fleet plus negative market conditions could push towards a rapid and early coal-decommissioning phase, setting the security of supply at risk and increasing the need for additional gas capacity (Ofgem, 2016).

Figure 50: Natural Gas capacity in operation in the UK (status May 2016) (MW)

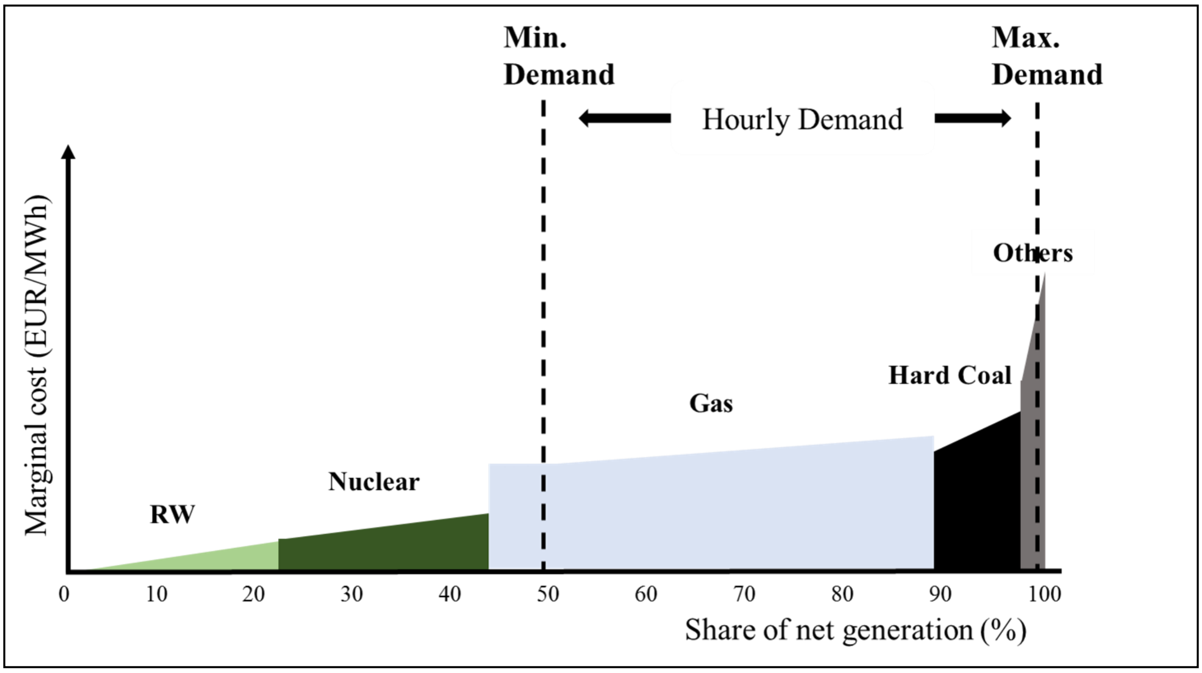


Source: Own development, data source Department for Business, Energy & Industrial strategy 2016

Comparing the position of coal and gas technologies in the merit-order-curve is key in order to understand the coal-to-gas switching potential. As mentioned in an earlier chapter, CCGT plants are a highly efficient technology generating considerably less CO2 emissions than coal technologies. However, CCGT uses gas as a fuel source, which is more expensive than coal. Nevertheless, falling gas prices and a fixed carbon price floor (more detail in the next section) are causing a structural displacement of coal by gas in the merit-order-curve (see Figure 51). New gas plants (with 52% fuel efficiency) have already displaced older coal plants (36% efficiency)[110]. This trend will presumably continue, relying on further drops in gas prices and more stringent policies (Timera, 2017).

[110] CCGT plant technology has developed fast and its competitiveness is constantly increasing reaching 52% of average efficiency for plants build after 2005 compared to 49% average efficiency around 2000 and 47% prior to 1998 (Timera, 2017).

Figure 51: Merit-order-curve in the UK – net generation share (2016)

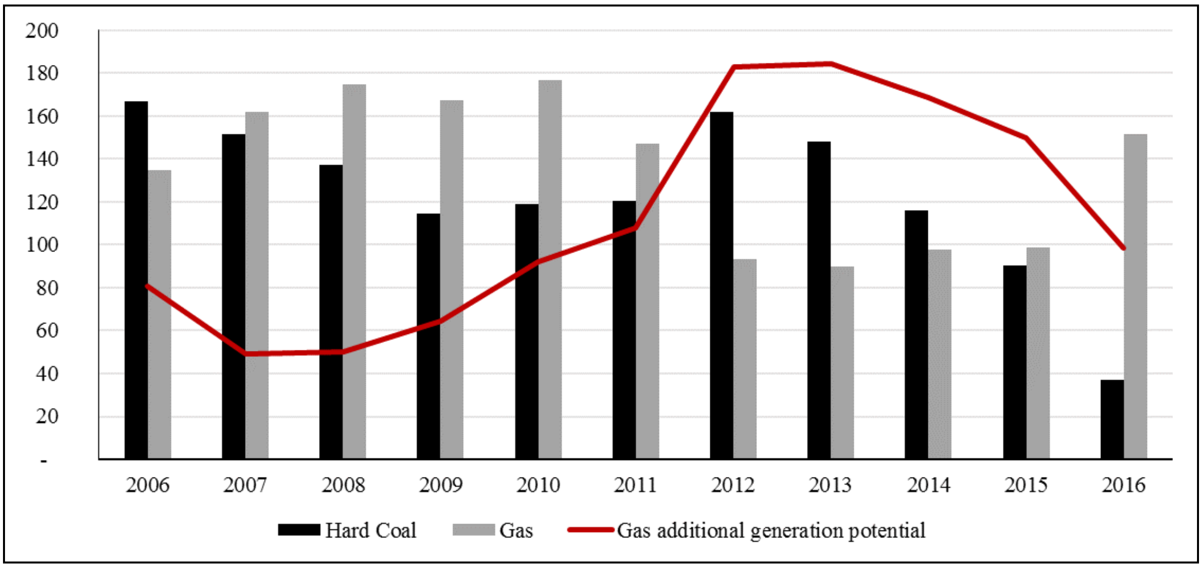


Source: Own development, data source Eurostat 2018

The coal switching channel in the UK shows the available added generation potential of gas power plants (Figure 52). It can be observed that the additional available gas generation[111] potential could have covered the power generation from hard coal since 2012. We can see that in 2016 a significant increase of gas generation pushed hard coal generation out of the base load segment (which explains why the coal-switching channel goes down). In 2016 the coal switching channel is high enough to substitute all remaining generation from hard coal by gas if the market conditions favour this process. Meaning that no additional gas capacity needs to be built in order to phase-out coal completely.

[111] Availability factor multiplied by generation capacity minus gross generation.

Figure 52: UK's coal-switching channel in GWh (2006-2016)



Source: Own development, data source Eurostat 2018

A study published by Greenpeace using DECC[112] data, supports the argument that the existing gas capacity in the UK would be able to fill in the gap of a rapid coal phase-out by 2020. Partly due to new interconnection capacity with neighbouring countries and the mothballed gas capacity (since 2010), which has been put back into operation (approximately 1.3 GW) (Greenpeace, 2014).

SECTION 4.2.2: COMMODITIES EFFECT

The use of the clean spark spread (CSS) and clean dark spread (CDS) is convenient to evaluate the effect of the commodity prices on the profitability of the gas and coal fleet. To recall, CSS (gas plant fleet) and CDS (coal plant fleet) indicates the average revenue that the respective power fleet can expect from generating a unit of electricity during baseload operation. This calculation takes fuel and carbon costs into account. In the UK, the competition between CCGTs and coal plants follow the evolution of the short-term marginal costs build-up out of fuel and carbon expenses. When looking at the CSS and CDS evolution, we can observe that from 2008 to 2015, coal stayed in a comfortable position with a stable

[112] Department of Energy and Climate Change.

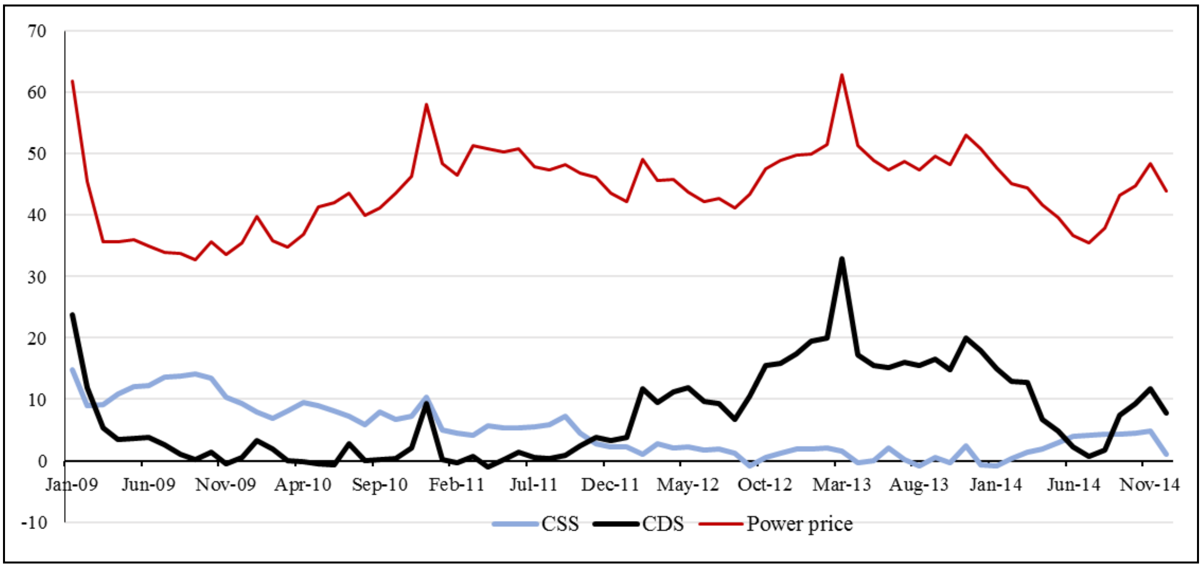
profit inflow. On the contrary, gas generation went through an alarming phase between 2011 and 2014 where high fuel prices pressed down profits to almost zero. The instruments in place to restrict carbon emissions did not work as policy makers expected and coal generation maintained a cost advantage due to low coal prices and EU-carbon prices. Consequently, coal power dominated the conventional power scene until 2015 when the government implemented a carbon floor price to counter the fall in carbon prices. This measure added to stricter emission standards supported a gas resurgence leading to regaining share of the baseload. Data published by the UK regulator (Ofgem) shows that recent commodity price fluctuations are weakening the position of coal generation even further and placing the CSS curve close to the CDS curve (Ofgem, 2017).

The figure below shows the development of the CSS and the CDS curves in Great Britain[113]. Both curves define the average revenue that a power stations can expect from generating a unit of electricity (MWh) during base load operation, after fuel and carbon costs[114]. As can be observed, the CSS was above the CDS since beginning of 2009 and until the end of 2011 due to the low gas prices and moderate carbon prices. From 2012 to 2015 the situation changed triggered by rising gas prices and plummeting carbon prices. This gave coal plants a competitive advantage (high margins compared to gas plants) and gas plants can barely stay profitable with margins close to zero. As can be seen, the electricity price is determined by the lowest standing curve (price setter), resulting in a higher profit difference during times where the CSS and CDS gap is widest.

[113] Geographically, the power market in the UK is divided into two areas: Great Britain and Northern Ireland. Ofgem publishes data separately.

[114] Fixed efficiency rates were assumed for gas-fired plants (50%) and coal plants (36%). Assumption based on Ofgem average efficiency level per power source.

Figure 53: UK's Clean Spark Spread and Clean Dark Spread evolution (in GBP/MWh) (2009-2014)[115]



Source: Own development, data source Ofgem 2017[116]

However, the situation changed in February 2015 when the CSS curve surpassed CDS and kept its upper position from then on. This has to be interpreted as gas-fired power generation being more cost-competitive than coal generation. An effective displacement in the merit-order-curve took place. Furthermore, coal plants (CDS) entered the negative area twice, in February 2016 and April 2017, resulting in losses (negative margin per MWh) during negative months (the revenues earned by coal plants were not enough to cover the operative costs[117]). The reason for the switch between the CSS and CDS is linked to falling gas prices and the introduction of a carbon price floor in the UK. The carbon price floor[118] was introduced in 2013 with a rate equivalent to GBP 4.94/tCO2, increased to GBP 9.55/tCO2 in April 2014 and from April 2015 on fixed at GBP 18.08/tCO2. According to the government this floor level will stay unchanged until 2020 (Matthes, 2017).

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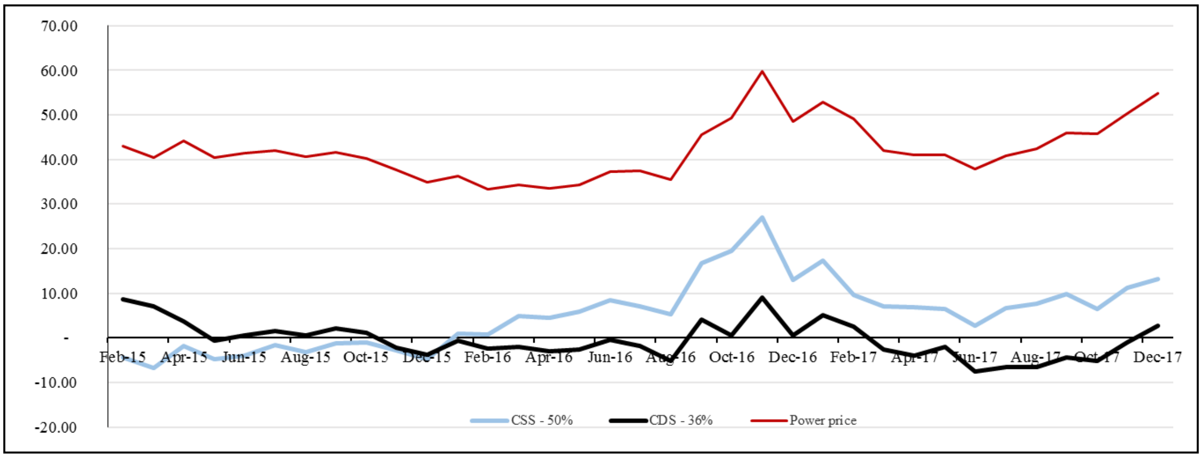
[115] The weighted average emissions intensity according to the Ofgem is 880 gCO2/kWh for coal generation, and 350 gCO2/kWh for gas generation.

[116] Ofgem is the electricity and gas regulator and controls the prices for the system operators.

[117] Not considering other cost as start costs and operation (workforce) expenses.

[118] The carbon price support (CPS) increases the cost of CO2 above the level set by the EU ETS until a limit (floor). The current level of the CPS has the potential to affect the competitiveness of coal plant by improving the economic attractiveness of gas generation.

Figure 54: UK's Clean Spark Spread and Clean Dark Spread evolution (in GBP/MWh) (2015-2017)



Source: Own development, data source Entso-e and World Bank

SECTION 4.2.3: POLICY SUPPORT AND INVESTMENT MOOD

After the deregulation of the power sector back in the 90s, six big private companies[119] have kept a strong position, accounting for more than 60% of the power supply in 2010 and an additional 31 power producers have gained market share progressively. This makes the UK a competitive and relatively disperse market (Deloitte, 2015).

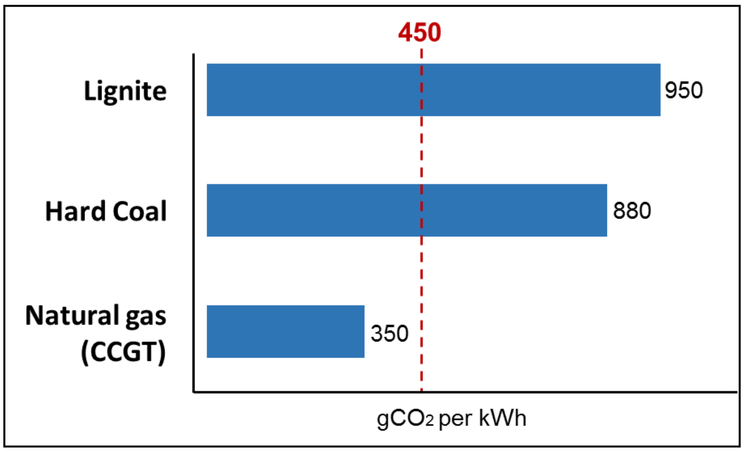
From a regulatory perspective, the Committee of Climate Change (CCC) has set the reduction of coal generation in the power sector as the first priority in order to drive the decarbonisation of the UK economy. This needs to be accompanied in parallel by the deployment of low-carbon power technologies and new business areas that develop out of the new established market structure[120]. On the one side, new incentive schemes have been created to increase renewable deployment, especially of wind and biomass. On the other, various regulatory thresholds on high GHG emitting plants, have lowered their profitability, thus discouraging new investment. The CCC has pressured against unabated coal capacity, leading to prohibit

[119] SSE, E.ON UK, Scottish Power, Centrica, RWE, and EDF Energy.

[120] Demand control, smart grids, efficiency measures, decentralized household power generation are some of the business opportunities that are attracting investment of traditional and new market players.

new coal capacity without CCS in 2009 and the implementation of the Emissions Performance Standard (EPS) in 2013[121].

Figure 55: CO2 emission of new CCGT and Coal plants / Source: Own development



The Emissions Performance Standard limits the carbon emissions of power stations up to 450 gCO2 per kWh of electricity generated. This threshold will be enforced on the 1st October 2025. Which means, that coal power plants need to have installed CCS technology to capture part of the CO2 emitted in order to meet regulatory guidelines (see Figure 55). This threshold will apply to all plants burning fossil fuels and thermal capacity over 300 MW (Sandbag, 2018).

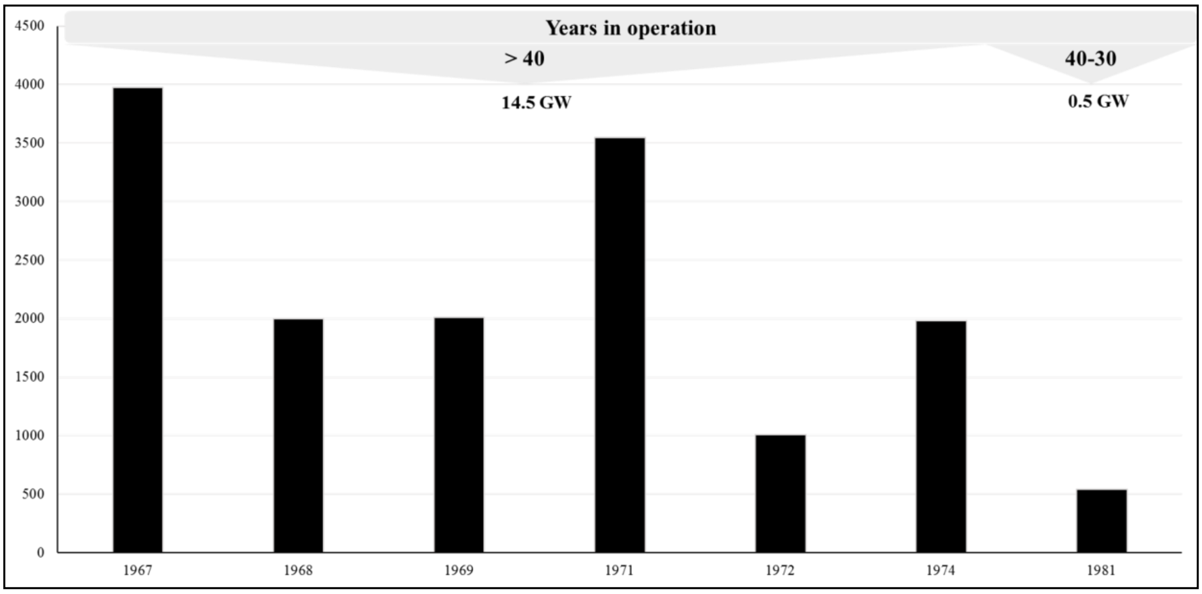
Over the last 30 years, no new coal plants have been commissioned and practically all capacity addition requests have been postponed or cancelled by the regulator, even the ones incorporating CCS technology[122]. In addition, based on regulatory perspectives, finance institutions are reviewing their investment strategy and many have publicly announced the introduction of strict conditions to finance high GHG emitting assets. Difficult financing translates into high debt interests, discouraging investment even further.

The current situation reflects the outcome of regulation: an old and inefficient coal fleet with some of the most polluting plants in Europe accounting for up to 15 GW of capacity (see Figure 56). As the coal phase-out process is underway old coal plants are retiring and new coal capacity additions are being blocked (Ofgem, 2017).

[121] 8.3 GW of coal capacity has been shut down since the implementation of the Large Combustion Plant Directive (LCPD), which restricts the emissions of SOx and NOx emissions mainly.

[122] As of September 2015, two CCS projects are still under active development: the White Rose Oxyfuel coal project at the Drax site in Yorkshire, and the Peterhead post-combustion natural gas project in Scotland.

Figure 56: Coal Capacity (MW) in operation at the end of May 2016



Source: Own development, Department for Business, Energy & Industrial strategy 2016

From the operating side, the future perspective looked dim, as unabated coal generation is sentenced to shut down or transform (implementing CCS technology or converting to biomass sources) the latest by the mid-2020s. Further, in order to meet emission targets, the government introduced two alternatives intending to provide some flexibility and compensation relief to coal plant owners: the Limited Life Derogation (LLD) and the Transitional National Plan (TNP). The first, allows coal plans to operate 17,500 hours until 2023[123], while the second, allows plant owners to operate at low load factors from 2020 on (1,500 hour per year limit on operations, which is approximately 17% of total load factor). The intention behind these alternatives is to avoid lifetime extensions through technological upgrades and secure electricity supply (Department for Business, Energy & Industrial Strategy, 2018).

Over the last years, the government had to deal with an additional concern that could to some extent slow down the coal phase-out process: the close down of aging and the mothballing of gas capacity. This has increased the systemic supply risk; and decreased the flexible response to back up RES penetration. This effect is reflected in the rapid fall of the reserve margin, which grants security of supply (fall from 6% in 2014 to 4% in 2016). Historically, the

[123] For instance, the Eggborough coal plant took this option.

reserve margin was balanced as an investment in new capacity that was economically interesting. Over the last years, the reduced revenue (or even losses) of the gas fleet and the barriers set for new coal plants have discouraged the investment in new base load capacity. This presents a critical issue, as even in a high interconnection scenario, the UK market would still need to add 6 GW of new gas plants by 2035 with most of this coming in the next four years. According to DECC, the required new capacity needs to be reliable, flexible and available to cover the rapid deployment of renewables. Since the market has failed to provide an incentive for capacity investment, the government has opted to implement a capacity market (allocation of capacity contracts through auctions). Capacity contracts[124] represent an additional source of income as conventional power plant owners receive money for making their capacity available to the system in case of unplanned demand spikes[125] (Department for Business, Energy & Industrial Strategy, 2018 (2)).

The capacity market represents tailwinds for gas plants investors too, as it allows mothballed gas plants to restart operations and unlock CCGT projects in the pipeline. The introduction of a capacity market strengthens the long-term confidence of gas assets and stimulates the build-up of the adequate flexible power capacity, as renewables are becoming the most economically interesting option. Capacity contracts are not exclusively directed at gas plants and give coal plant owners an alternative to secure longer lifetime for their assets (however, coal plants are not allowed to receive capacity contracts for beyond 2025)[126]. Meaning that by extending the lifetime of high emitting plants, part of the measures from the CCC are counteracted[127]. For instance, 9.2 GW of the UK's remaining coal plants have secured capacity contracts, which oblige them to operate during the winter of 2018-19 and two of the largest coal plants (West Burton and Cottam) have secured capacity contracts for the period 2018-2021 (see Table 4). In order to be eligible for the capacity market, high emitting plant owners need to upgrade their technology[128] and meet emissions standards. Meaning that more

[124] First auctions took place at the end of 2014 with capacity delivery in October 2017.

[125] Capacity providers are granted with additional payments or financial penalties, depending on whether they exceed their Capacity Obligations (overdeliver) or fail to meet them (underdeliver).

[126] Since 2017 also existing interconnectors (connecting the UK to France and Netherlands) are allowed to bid for capacity contracts. New interconnectors capacity is planned in the near future creating the link to Norway and Belgium.

[127] The capacity market granted financial support to 8.9GW of existing coal plants in its first auction in 2014. The resulting amount for coal plants rises to approximately GBP 178 million extra income in 2018, providing economic reasons to remain in operation.

[128] As done by E.on's Ratcliffe plant (2 GW of capacity) with an investment of GBP 1 bn to comply with IED.

investments will flow towards old coal plants instead of directing it towards more sustainable power sources. The capacity market has already proven its effectiveness as the capacity margin rose from 5.7% in 2016-2017 to 10.3% (or 6.2 GW) in 2017/2018[129] (Platts, 2017).

Table 5: UK's coal plants with capacity contracts from 2017 to 2020

Plant	Operator	Capacity (MW)	IED Decision	Capacity contracts			
				2017	2018	2019	2020
Fiddiers Ferry	SSE	2	Traditional National Plan	YES	YES		
Eggborough	EPH	1.9	Limited Life Derogation	YES			
Cottam	EDF Energy	2	Traditional National Plan	YES	YES		
West Burton	EDF Energy	2	Traditional National Plan	YES	YES		YES
Aberthaw	RWE Power	1.5	Traditional National Plan	YES	YES	YES	YES
Drax	Drax Power	2	Traditional National Plan	YES	YES	YES	YES
Ratcliffe	E.ON Power	2	Traditional National Plan	YES	YES	YES	YES

Source: Own development, data source Ofgem 2017

Another alternative for coal power generators is to switch to biomass. From a governmental standpoint, the conversion of coal power plants to biomass offers the largest potential to achieve the 2020 emission target. The economics of conversion, however, is highly dependent on the availability and price of sustainable biomass[130]. In this context, the government has allowed converted biomass plants to bid for additional economical support (Contracts-for-Difference or CfDs)[131]. By 2023, 12.4 GW of coal capacity may close or convert to biomass, based on the announcements of some big utilities (RWE, SSE and EDF). However, the conversion factor to biomass would need to be very high in order to meet the emission limit of 450 gCO2 per kWh. According to Sandbag estimations, the biomass share would need to reach 52% for the Drax power plant (this percentage can be even higher for older coal plants). Besides, the economics of co-fired plants are not sustainable and would need subsidies in order to stay profitable. Thus, this alternative does not seem very appealing to coal plant owners (Sandbag, 2018).

[129] The capacity contracts are being paid at GBP 6.95 per kW a year to guarantee availability.

[130] Several announced conversions projects of coal plants have been cancelled (for example: RWE's Tilbury coal-fired power plant).

[131] A CfD has a contractually guaranteed fee for power fed into the system (price per unit of electricity). If the price received on the wholesale market is below the fee, the government pays the difference to the generator. It is used as an incentive for RES.

The government is aiming for a complete coal phase-out by 2025 meaning that the remaining 13GW distributed among eight plants needs to be closed over the next years. In order to reach this objective, besides the aforementioned regulatory limitation, economic pressure through carbon pricing is the main strategy for the government. According to analysis of the government, current policies and carbon price levels would be enough to motivate the shutdown of most of the remaining coal capacity leaving only 1.5 GW unabated coal until 2025. This is why there is no intention of implementing further constraints on coal generation ahead of 2025. Additionally, the concern that the rapid coal decommission could jeopardize the security of the electricity supply (risk of shortfall) could even lead to a delay of the 2025 deadline according to the government's last announcement (Department for Business, Energy & Industrial Strategy, 2018).

According to a recent forecast by the government, 6 GW of new gas plants would be needed between 2018 and 2025 to cover the gap left by nuclear and coal decommissioning in the next years. It is hard to believe that renewables alone could cover the gap. The investment required in RES, batteries and grid interconnection would be too high and even then the variable generation of wind and solar could set the supply security at risk during some periods. Further, a recent study by the UK's Environmental Audit Committee (EAC) has exposed that the investment in new green technology in the UK is declining (56% decrease from 2016 to 2017) mainly due to changes in government policy. This clears the way for gas generation as a the most suitable substitute to decommissioning coal capacity. Nevertheless, investors are not very attracted by the idea of building new gas plants as gas is the next candidate on the emission target list. Environmental groups are creating pressure to avoid new combustion capacity entering the system, since also new gas plants would create an emission lockage effect for the next decades (Clean tecnica, 2018).

Besides regulatory measures, carbon prices added to the carbon price floor, have played a fundamental role in the UK coal-to-gas switching process and it is expected that this effect will continue after 2020. In the following section, we will evaluate the effect of carbon prices on the coal-to-gas switching process.

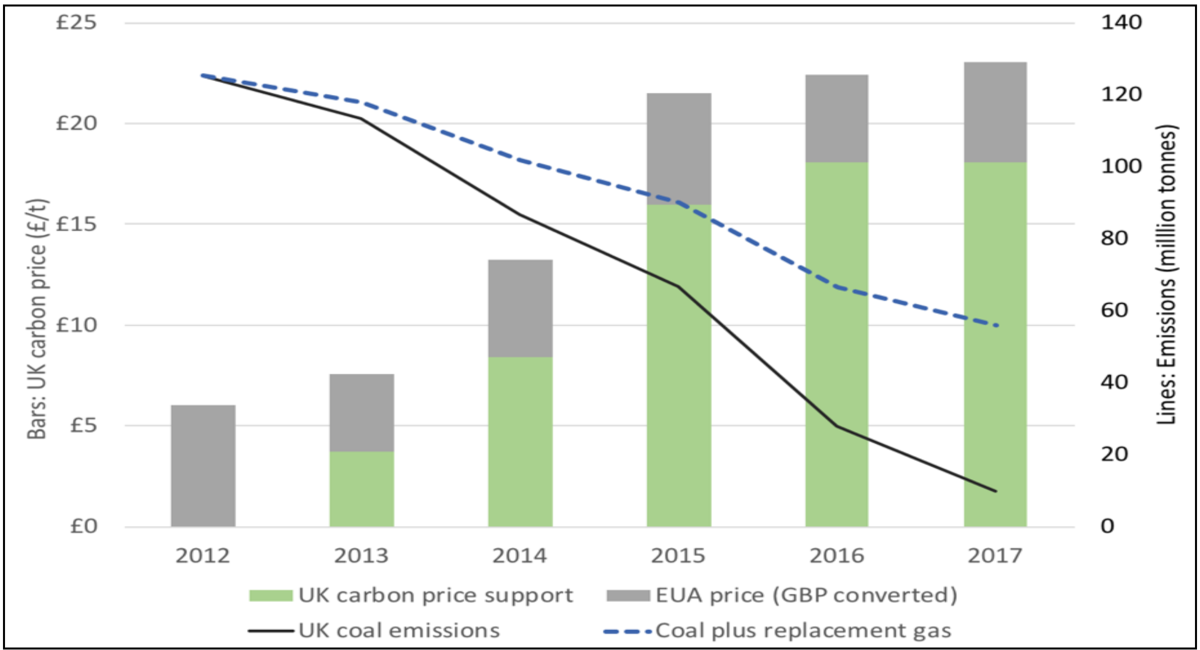
SECTION 4.2.4: CARBON PRICE

The UK has been part of the EU ETS since its implementation in 2005. Since then, the stubbornly low carbon prices have not allowed to create a meaningful signal for the decarbonisation of the power sector (see section 3.6). For this reason, the UK government introduced an additional measure in 2013 to incentivise the reduction of emissions in the power sector, the carbon price floor (CPF). The CPF is calculated as the sum of two parts: the EU ETS price and an additional carbon price support (CPS). The CPF is pre-determined by the government at a level high enough to incentivise emission reductions. While the EU ETS price is a EU wide market-based allowance price, the CPS is a UK carbon tax. The CPF puts a minimum price on CO2 emitted by the power sector and the CPS is periodically adjusted to cope with EU ETS fluctuation (David Hirst, 2018).

The UK government has kept the CPS as a top-up tax since 2013, because the EU ETS price has stayed below the CPF. Given that the carbon price has continued to decrease since the introduction of the CPF, the UK has increase the CPS in various occasions. In 2013 the CPS was set at GBP 4.94. Back then it was not clear that whether the CPS would be needed in the future as no one could predict the development of carbon prices. However, persistent low prices moved the governement to raise the CPS to GBP 9.55 in 2014 in order to meet the price floor target. Later on, in 2015 the CPS was increased again to GBP 18/tCO2 (around EUR 20/tCO2) and frozen at this level until 2021. It is unclear what will be the level after 2021 but the government has given signs that the carbon price floor will continue and that the price level will probably stay at the current level. Which means that in the case the carbon price under the EU ETS rises, the CPS would have to be reduced and vice versa.

Based on the available evidence it is clear that the CPF has played a fundamental role in driving emissions from coal plants down through a rapid coal-to-gas switching process. This process has been more intensive since the CPS doubled from GBP 9 to GBP 18/tCO2 in 2015. In the following figure (Figure 57), we can observe the evolution of the CPF (sum of the EU ETS price and the CPS) and the parallel reduction in emissions linked to coal power plants. However, since gas is not a renewable power source, through coal-to-gas switching the avoided emission from coal plants is decreased to the gas emission level. As mentioned earlier, (on average) a gas plant generates less than half of emission per MWh than a coal plant (On Climate Change Policy, 2018).

Figure 57: The carbon price floor (CPS + EU ETS) and emission reductions in the UK power sector (2012-2017)



Source: On Climate Change Policy, 2018

In the UK, the coal-to-gas switching process is sensitive to fuel prices and the CPF. With low gas and coal prices, the CPF is breaking the balance and pushing coal generation out of the merit-order-curve (7% generation share in 2017 according to the EIA). The government expects that the carbon price will even demotivate traditional energy suppliers from considering investment in upgrades and aiming to secure capacity contracts. This is the reason for not having implemented a legally binding coal-phase out deadline by 2025, but instead a government plan. It has to be noted that the CPF affects the country's domestic fossil-fuelled power plants at different levels. So, even if gas is less affected that coal, it also has to take the burden of increased generation costs resulting in lower profitability, which has lowered the attractiveness of investment in new gas capacity. In this sense, the energy minister recently announced lower expectations regarding new gas power plants being built until 2035 to 6 GW compared to 14 GW of a previous forecast (Department for Business, Energy & Industrial Strategy, 2018 and Quartz, 2018).

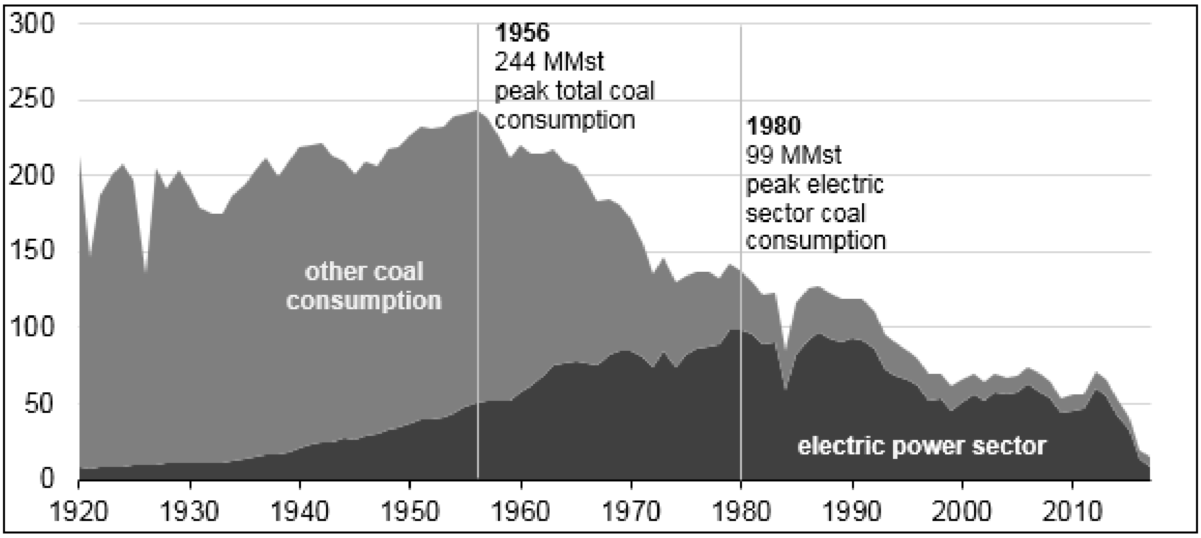
The question that remains open is what will be the future of the CPF after 2021. While the government has stated its intention of keeping the CPF at the current level, the participation of the UK in the EU ETS is not assured due to Brexit. However, the CPF is designed is such a way that if the EU ETS price falls to zero the CPS would compensate this reduction. Therefore, an exit of the EU ETS would not automatically mean that the carbon price mechanism in the UK would be discontinued. What seems more certain, is that the government will probably not increase the CPS further due to the strong criticism receive by some industry and consumer groups complaining about high-electricity bills (David Hirst, 2018).

SECTION 4.2.5: NATIONAL COAL AND SOCIO-ECONOMIC DEPENDANCE

Coal was the dominating fuel source in most of the sectors of the UK´s economy after the Second World War (steel production; industrial processes; heating; transportation and electricity generation). In 1948, the power sector accounted for 15% of total coal consumption, generating 97% of the UK’s electricity. In contrast, by 2015 the power sector held 91% of total coal consumption and produced just 27% of the total electricity. This means that today the power sector sustains almost the entire domestic coal industry. Nevertheless, the domestic coal input represents a small part, since foreign coal supply covered 84% of total coal demand in 2014. Even considering recent plant closures and significant reductions in power generation from coal plants, the UK remains one of the largest coal consumers in Europe (Littlecott, 2015).

The progressive structural decrease in coal relevance is reflected in the shrinking national coal extraction sector (since 1948, 97% of the UK coal mines have been closed). Falling national demand and low international prices have hit the economics of the national mines and consequently triggered an employment downturn from a peaking point of 720,000 miners in 1948 to employing less than 3,000 workers in 2015. The economic and regulatory perspectives seem to be proclaiming the end of the national coal production in a country whose recent historical and cultural pillars were built with coal (see Figure 58) (Littlecott, 2015).

Figure 58: Historic coal consumption in the UK (in millions tonnes) (1920-2017)



Source: EIA, 2018

The strategic importance of coal is part of the past and the remaining infrastructure is under pressure to close down. The government strategy to phase-out coal is based on a combination of regulation and market mechanisms allowing plant operators to plan ahead and develop redeployment programmes for employees. There are around 2,400 jobs at coal-fired power plants as of mid-2016[132]. The impact of closing down the coal sector will not only affect jobs at the power station, but also jobs associated to the supply chains, such as port and rail infrastructure and the coal mining industry (Department for Business, Energy & Industrial Strategy, 2018).

The timeline of progressive plant closure until 2025 will allow for a harmless transition away from unabated coal and avoid sudden large-scale job losses (see Table 5). There are weak economic and strategic arguments in favour of the coal industry and the determination of the government leaves no space for negotiation. Society supports the government in this decision as the coal-phase out will bring improvements in air quality and reduce impacts on human health and the environment.

[132] Mainly in the Yorkshire/Humber region, and in South Wales.

Table 6: Closure of coal-fired power plants under the LCPD

Plants	Owner	Capacity (MW)	Clousure
Kingsnorth	E.ON UK	1940	Closed December 2012
Ironbrige	E.ON UK	940	Closed March 2013. Converted to biomass (700 MW)
Didcot A	RWE npower	1940	Closed March 2013
Tilbury	RWE npower	1020	Converted to biomass (750 MW) in 2011. Closed July 2013
Ferrybridge	SSE	980	Closed end 2015
Cockenzie	Scottish Power	1152	Closed March 2013
Uskmouth SSE	SSE	363	Closed March 2013
		8335	

Source: Own development, data source Ofgem 2017

In order to evaluate if the current regulation will support the coal-to-gas switching process in Germany and the UK, it is necessary to project future market situations (Chapter 5). As we have seen through Chapter 4, commodity prices and the carbon price are key factors that will determine the competition of coal and gas. Thus, a close analysis of the outcomes of different future situations for each country will allow to evaluate how suitable current regulation is to support the effective coal-to-gas switch in the next decade.

CHAPTER 5: ANALYSIS OF THE EFFECT OF DIFFERENT CARBON PRICE LEVELS

In this chapter, we will evaluate the effect of different carbon price scenarios on the coal-to-gas switching process in Germany, -until 2030 and in the UK, -until 2025. The scenario analysis relies on the latest commodity price forecast for gas and coal from the World Bank (2020, 2025 and 2030) and three different carbon price forecasts announced by well-known industry players. The economic competition between coal and gas plants is the driving force (as could be seen in Chapter 3 and Chapter 4) that determines the coal-to-gas switching process. Through the projection of the CSS and CDS curves, it will be possible to evaluate if the current regulatory measures are sufficient to trigger an effective coal-to-gas switching process in Germany and the UK or if on the contrary, additional regulatory measures are needed. The scenario analysis will be complemented by a set of Monte Carlo simulations to evaluate the likelihood of the outcomes for the most-likely scenario in the year 2025 introducing uncertainty on fuel prices (coal and gas). This will provide more information about the probability of gas-fired power plants being more economically competitive than coal at this specific point in time.

SECTION 5.1: ASSUMPTIONS

Three scenarios will be drawn based on different possible paths of carbon price development up to 2030. In the following, the assumptions that will frame the scenario analysis for the years 2020, 2025, 2030 in Germany and 2020, 2025 in the UK will be defined. The assumptions are focused on commodity prices (natural gas and coal), electricity prices and technology average efficiency rates in each country. Due to little difference in gas and coal prices between Germany and the UK, the same price level will be used for both countries. However, average efficiency level and electricity prices diverge between Germany and the UK. The assumptions applied for the projection are the following:

- Commodity prices (natural gas and coal) until 2030 are sourced from the World Bank forecast (May 2018) (see Table 7). The historic commodity prices published by the World Bank have also been used in Chapter 4 to draw the CSS and CDS curves for Germany and the UK. Since prices are provided in USD/mt for coal and USD /mmbtu (U.S. dollars per million British thermal units) for gas, the EIA-conversion-calculator has been used to transform coal and gas prices to

EUR/MWh units (World Bank pink sheet, 2018 and EIA, 2018). More detail about of each fuel assumption is described in the following:

- Regarding gas prices, the World Bank forecasts an increase of gas prices in Europe triggered by reduced production in EU countries and Norway, added to a probable reduction in the global oversupply of LNG. According to World Bank´s calculations, until 2030 the price of natural gas in Europe is expected to increase progressively until it reaches an average USD 8/mmbtu in 2030. Based on own calculation, this price level represents EUR 23.12/MWh (an 42% increase with respect to average prices in 2017, EUR 16.38/MWh).

- On the other hand, according to the World Bank coal prices will shrink considerably over the next decade due to a constantly oversupplied global market and falling global demand. Compared to the 2017 price level (USD 82.72/mt average prices), the World Bank projects a USD 65/mt price level in 2020 and USD 60/mt in 2030. Based on own calculation, the price level in 2030 represents EUR 8.25/MWh (a 28% decrease with respect to average prices in 2017, EUR 11.37/MWh).

Table 7: World Bank commodity price forecast

	Unit	2020	2025	2030
Energy				
Coal, Australia	$/mt	65.0	62.4	60.0
Natural gas, Europe	$/mmbtu	6.7	7.3	8.0

Source: World Bank Commodity Price Data, 2018

- Electricity wholesale prices will adapt to the price setting technology. As a simplified approach, the wholesale power price will be defined at a level where the most competitive thermal generation technology (gas or hard coal)[133] earns back its marginal costs (price setter). In other words, the power prices will allow the CSS or

[133] Lignite is considered and inflexible generation technology designed for baseload operation. Flexible gas turbine combined cycle and flexible coal are designed as mid-merit plants and thus can adjust their generation output (Gonzalez-Salazar, M.A., Kirsten, T. and Prchlik, L., 2017).

CDS curve (depending which one is at a higher position) to stay slightly above the zero level (in the profit zone).

- The efficiency rates of coal and gas power plants are based on the average efficiency of the German and the UK fleet. Average efficiency rates of existing coal and gas plants will increase slightly in the next decade as old plants are progressively retired. It is assumed that no new capacity of gas and coal will be built (renewables and more interconnector capacity will cover the capacity of the retired plants). In order to establish the average efficiency of coal and gas, an average retirement age has been set: 50 years for coal plants and 40 years for gas plants. In the following further detail about the average efficiency rate per technology type and country is given:

    a. Hard coal power generation in Germany: 7 GW hard coal capacity will need to get off-line between 2020 and 2030 due to the end of operating life-time (50 years), which will increase the average efficiency rate to 43% of the remaining coal-plant fleet (40% average efficiency rate in 2017) (Bundesnetzagentur, 2017).

    b. Lignite power generation in Germany: 9 GW of lignite will end its operating life (50 years) between 2020 and 2030, which will increase the average efficiency rate to 40% (38% average efficiency rate in 2017) (Bundesnetzagentur, 2017).

    c. Gas-fired power generation in Germany: 7.8 GW of gas capacity need to get off-line between 2020 and 2030 due to the end of operating life-time (40 years). This means that the average efficiency rate will rise to 55% for the remaining gas plants (50% average efficiency rate in 2017) (Bundesnetzagentur, 2017).

    d. Coal power generation in the UK: The coal fleet in the UK is considerably old with an average efficiency rate of 36%. Due to the announced phase-out, this number is not expected to change over the next years, no technology upgrades are expected and the remaining plants will operate as much as possible until 2025 (DUKES, 2017).

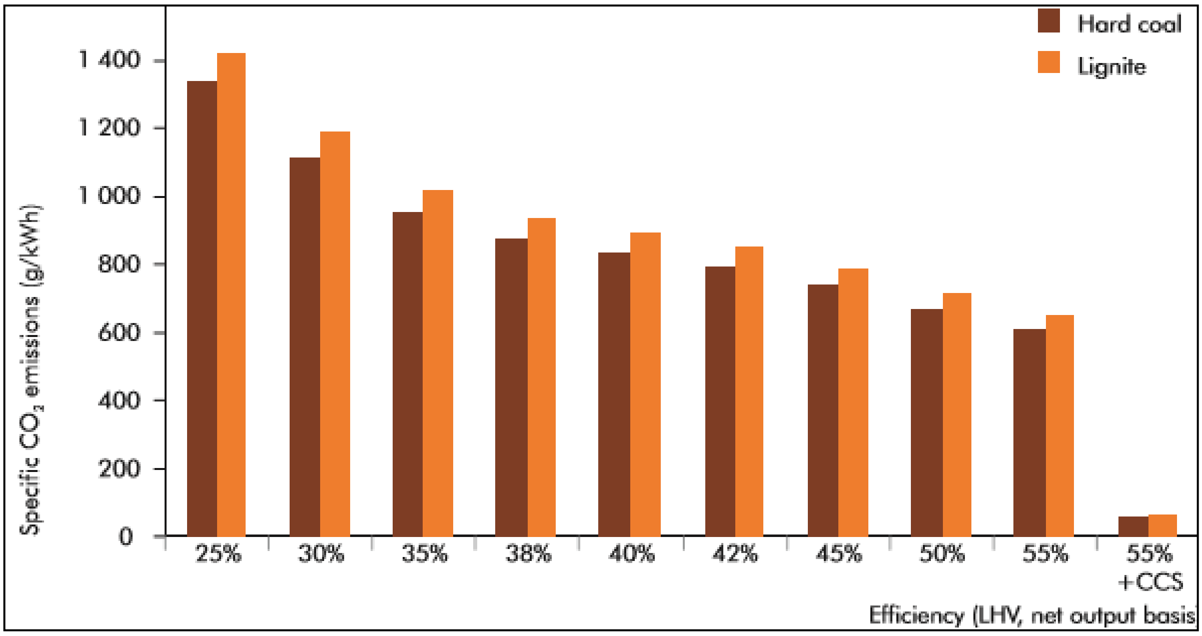
e. Gas-fired power generation in the UK: The gas fleet in the UK has an average efficiency rate of 50%. The expansion of the fleet could continue as old gas plants get decommissioned. However, only 0.5 GW capacity (out of 32 GW) is older than 1980. Therefore, it is not expected that the efficiency rate will increase due to old plant retirements (DUKES, 2017).

- The efficiency rates of existing coal and lignite plants determine not only the heat efficiency, but also the emission factor. An increase in efficiency, leads to a decrease in average emission per unit of electricity generated (KWh). Thus, the average emission factor will decrease as old, inefficient plants are decommissioned. In 2010 the IEA published an estimation of CO2 emission intensity per efficiency level for hard coal and lignite plants. This estimation will be used to decrease the emission factor resulting from the gains in average efficiency (see Figure 59).

  a. For Germany´s coal and gas fleet, an emission factor of 0.32t CO2/MWh for gas plants, 0.80t CO2/MWh for coal plants and 0.90t CO2/MWh for lignite plants is assumed.

  b. While for the UK, an emission factor of 0.35t CO2/MWh for gas plants and 0.88t CO2/MWh for coal plants is used.

Figure 59: CO2 emissions and pant efficiency for hard coal and lignite power plants 2010



Source: IEA, 2010

These assumptions will condition the three carbon prices scenarios, which will be described in detail in the next section.

SECTION 5.2: SCENARIO ANALYSIS

Three carbon price scenarios have been defined based on expert opinions about the possible development of the carbon price up until 2030. These expert opinions diverge considerably in their view about the carbon price trajectory after the approved amendments to the EU ETS (in 2017 and 2018)[134]. The carbon price forecasts range from EUR 15/tCO2eq. to EUR 40/tCO2eq. in 2030, having different effects on the coal to gas transition and therefore their environmental impact. Three categories have been defined to evaluate the effect of different carbon price trajectories on the coal-to-gas switching process: “best-case”, “most-likely-case” and “worst-case” (see Table 8).

[134] The MSR will be active since 2019, while the rest of measures will be introduced at the beginning of Phase 4 (2021).

Table 8: Expert price forecasts after the announcement of the adjustment to the EU ETS (2018)

Future carbon prices (EUR/t.CO2eq.)				
Sceanrio	**Source**	**2020**	**2025**	**2030**
Scenario 1 - Best case	Consultancy Energy Aspects	20	30	40
Scenario 2 - Most Likely case	Bloomberg	15	20	30
Scenario 3 - Worst Case	Sandbag	15	15	15

Source: Own development

A description of the three scenarios follows:

- “Best-case” scenario: In this situation, the announced reforms have the desired impact by the EC and turn the EU ETS into a relevant mechanism to combat intensive carbon emissions in the power sector. During the first half of 2020 the allowance scarcity becomes obvious through the rapid increase in carbon prices. The faster cap reduction and a growing economy solve the oversupply gap and the MSR provides the needed flexibility of the market leading to a strong long-term price signal. In 2025 carbon prices reach the EUR 30/tCO2eq. level and continue the upward trajectory to EUR 40/tCO2eq. in 2030. The consulting company Energy Aspects defends this view (Evans, 2017).

- “Most-likely-case” scenario: A large segment of experts agree that carbon prices will progressively increase during the next decade. The market oversupply will fall as a result of the retirement of allowances by the MSR. However, the balancing of the oversupply will take time and prevent a fast increase in carbon prices[135]. Bloomberg is among the experts defending this view, forecasting a EUR 20/tCO2eq. level in 2020 and close to EUR 30/tCO2eq. in 2030 (Bloomberg New Energy Finance, 2017).

- “Worst-case” scenario: This scenario is justified on the expectation of a continuously oversupplied market, which sentences the EU ETS towards stubbornly low carbon prices. Sandbag is sceptic that the corrective measures will deconstruct the vast accumulated surplus by 2030. The announced measures will

[135] Especially after 2023 when the balancing rate of the MSR will shrink to 12% (the balancing rate from 2019 to 2023 is set at 24%).

result in a slight increase in carbon prices up to EUR 15/tCO2eq. but not more than that because the existing allowance surplus provides a large cushion. According to Sandbag “more needs to be done to create a more appropriate supply demand balance.” (Sandbag, 2017).

SECTION 5.3: SCENARIO RESULTS

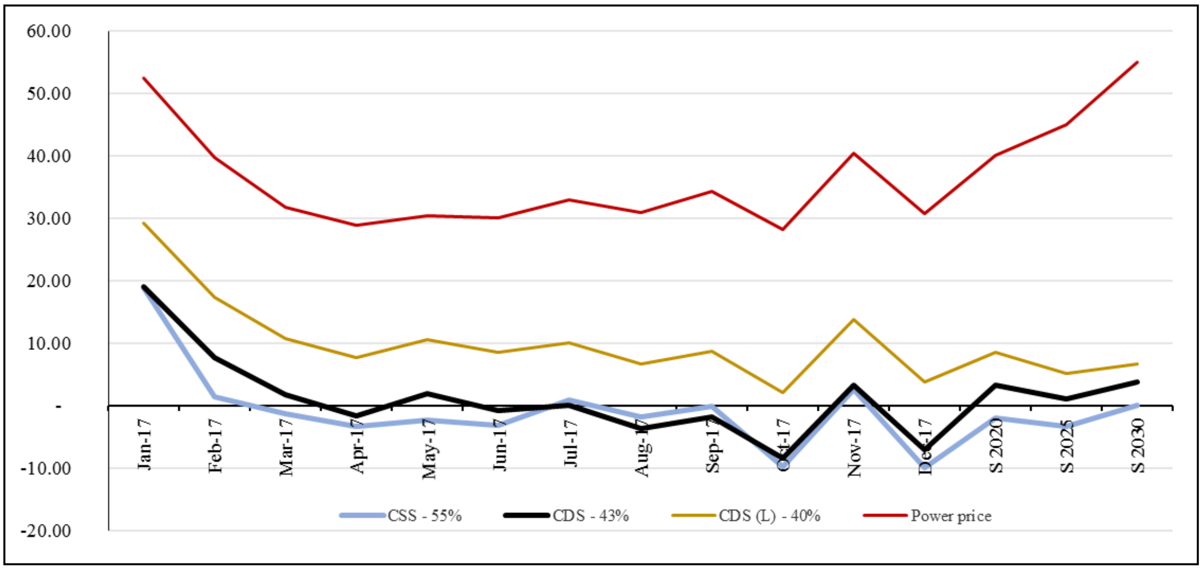
In the following section, the different carbon price scenarios will be combined with the assumptions in order to project the CSS and CDS curves for Germany (until 2030) and the UK (until 2025). In order to provide a sense of continuity and visualize the evolution of the CSS and CDS curves, the year 2017 will be included in the figures.

SECTION 5.3.1: GERMANY SCENARIO RESULTS

Germany´s CSS, CDS (hard coal) and CDS – L (lignite) will be projected until 2030 for all three scenarios described in the previous section.

Germany - Best-case: High carbon price trend (EUR 20/tCO2eq. in 2020; EUR 30/tCO2eq. in 2025; EUR 40/tCO2eq. in 2030)

Figure 60: Germany - Best-case carbon price scenario 2020-2030

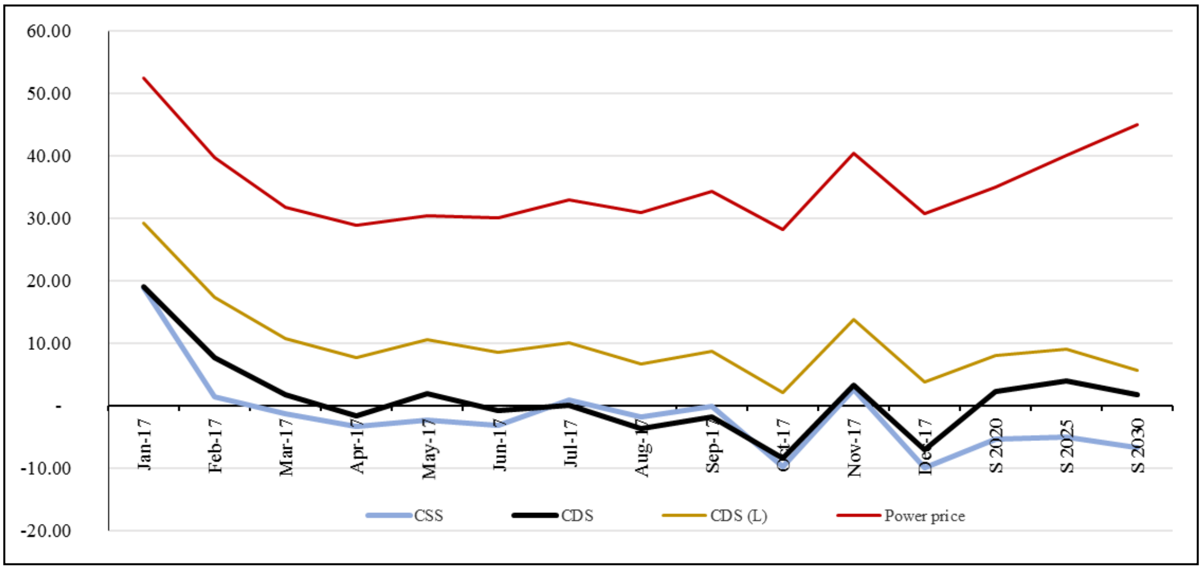


Source: Own development

The results from the best-case scenario (see Figure 60), suggest that high carbon prices will not be sufficient to break the economical superiority of coal in the German power mix. Coal keeps a distance from gas even with rising carbon prices. The reason is that commodity prices forecasted by the World Bank (gas prices have risen 48% with respect to falling coal prices 28% with respect to 2017) counter the effect of sharply rising carbon prices. Interestingly, power prices need to rise significantly (EUR 55/MWh in 2030) in order to keep the hard coal plants profitable (CDS curve on the positive side). Lignite keeps its supremacy, to some extent strengthened through the increase in efficiency and subsequently reduction in emission intensity. Gas can only start recovering its marginal costs at a carbon price of EUR 40/tCO2eq., meaning that gas is relegated to a loss-making position until 2030, which could result in the further mothballing of highly efficient gas plants. The gap between all three technologies seems to diminish as the carbon price rises.

Germany - Most-likely-case: Middle carbon price trend (EUR 15/tCO2eq. in 2020; EUR 20/tCO2eq. in 2025; EUR 30/tCO2eq. in 2030)

Figure 61: Germany - Most-likely case carbon price scenario 2020-2030

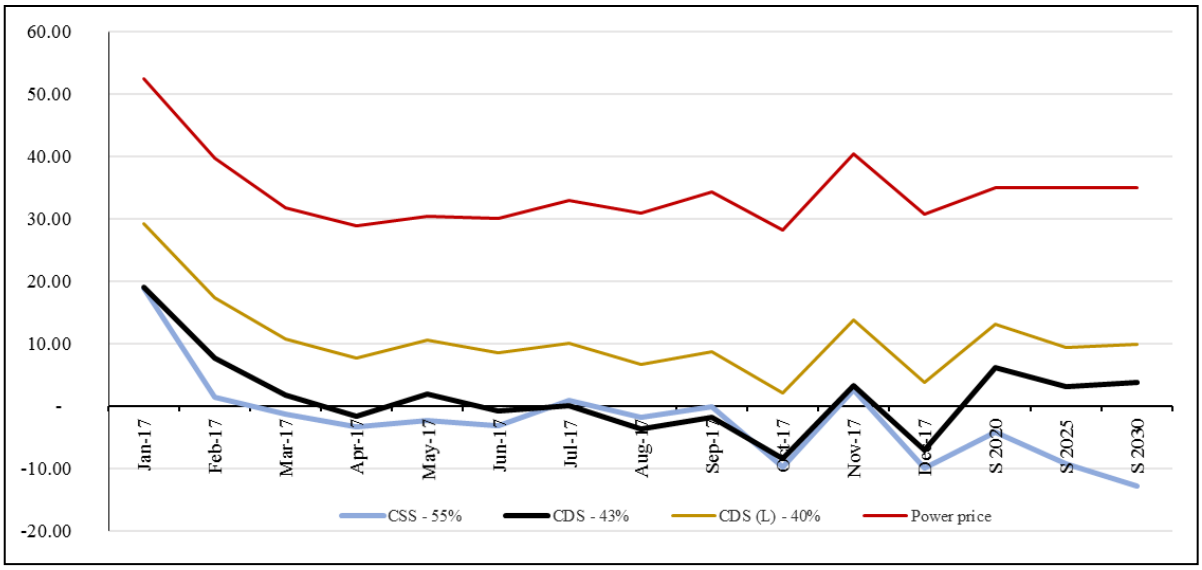


Source: Own development

In the most-likely scenario, lignite and hard coal increase the gap with gas power plants mainly due to the divergent trend of commodity prices and the increase in efficiency of the remaining capacity. Power prices need to rise to up to EUR 45/MWh in 2030 to keep the price setter (hard coal) at the edge of profitability. Gas keeps its loss-making position stable with a considerable distance between the CSS and CDS curve (around EUR 10 additional cost per MWh) (see Figure 61).

Germany - Worst-case: Low carbon price trend (EUR 15/tCO2eq. in 2020; EUR 15/tCO2eq. in 2025; EUR 15/tCO2eq. in 2030)

Figure 62: Germany – Worst-case carbon price scenario 2020-2030



Source: Own development

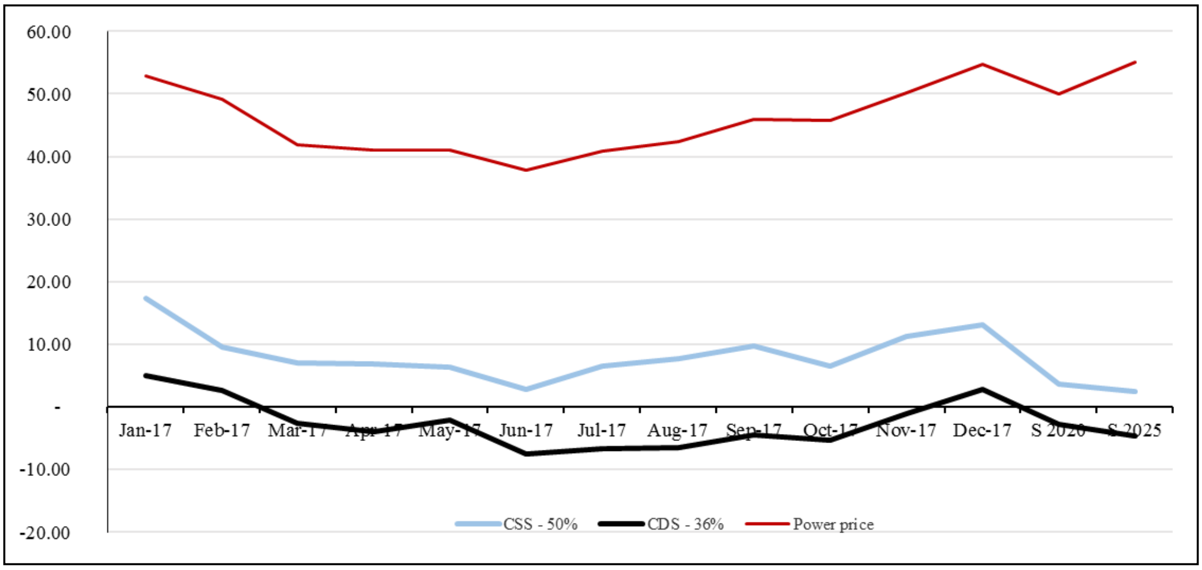
The worst-case scenario, replicates to some extent the situation observed between 2011 and 2014. Rising gas prices, falling coal prices and a low carbon price increase the economic gap between gas and coal plants. The power prices stay stable at a EUR 35/MWh level, while gas power plants sink deeper in the negative side of the figure. This situation suggests a dim future for gas power operators, where many will be forced to operate during peak hours or close down the power plants. Coal stays as the transitioning fuel in Germany, at the risk of not meeting the environmental targets set for 2030 (see Figure 62).

SECTION 5.3.2: THE UK SCENARIO RESULTS

UK´s CSS and CDS (hard coal) will be projected until 2025 for all three scenarios described in the previous section. The probability that unabated coal plants will be still operative after 2025 is very low due to the government coal phase-out announcement.

The UK - Best-case: High carbon price trend (EUR 20/tCO2eq. in 2020; EUR 30/tCO2eq. in 2025) added to the fixed carbon price support (GBP 18.08/tCO2eq.)

Figure 63: UK - Best-case carbon price scenario 2020-2025

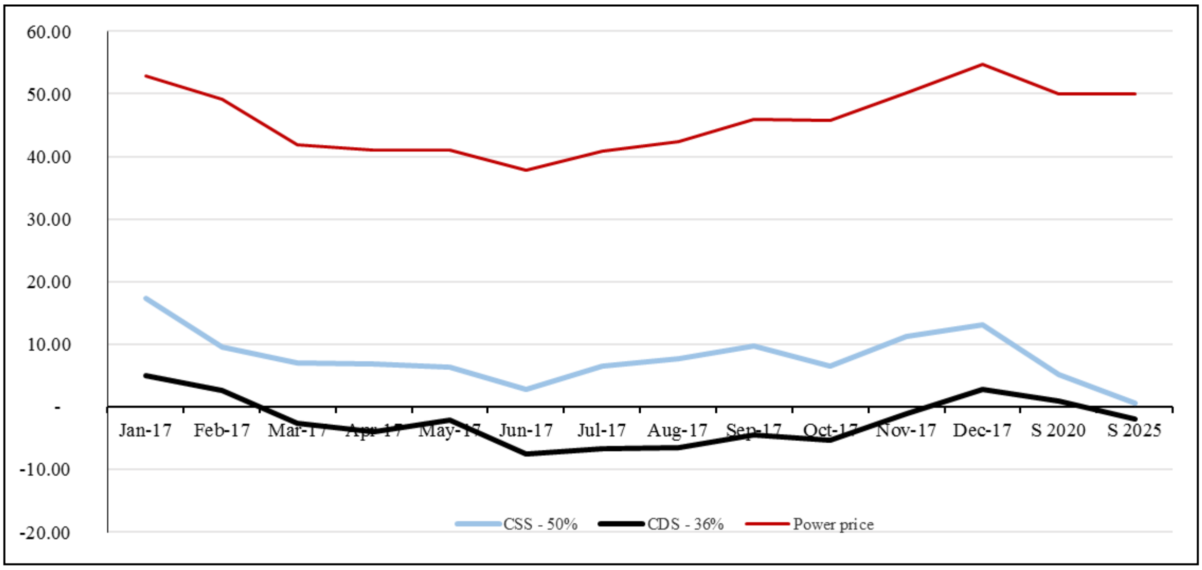


Source: Own development

The best-case scenario confirms the upper position of the CSS mainly due to the fixed carbon price support that has been frozen at a GBP 18.08/tCO2eq. The carbon price support serves as a cushion against unfavourable commodity prices for gas power plants. As can be observed in the figure above, the gap between the CSS and CDS shrinks in 2020 but recovers again in 2025 due to increasing carbon prices (EUR 30/tCO2eq.). As could be observed in the case of Germany, a high carbon price leads to higher marginal costs for the price setter and consequently to higher power prices (GBP 55/MWh). It should be noted that the carbon price support level can be revised by the government and a downwards adjustment could lead to an increase in competitiveness of old coal plants. This situation is however unlikely as the government is determined to set an end to unabated coal power generation by 2025 using the existing economic mechanism (see Figure 63).

The UK - Most-likely-case: High carbon price trend (EUR 15/tCO2eq. in 2020; EUR 20/tCO2eq. in 2025) added to the fixed carbon price support (GBP 18.08/tCO2eq.)

Figure 64: UK - Most-likely-case carbon price scenario 2020-2025

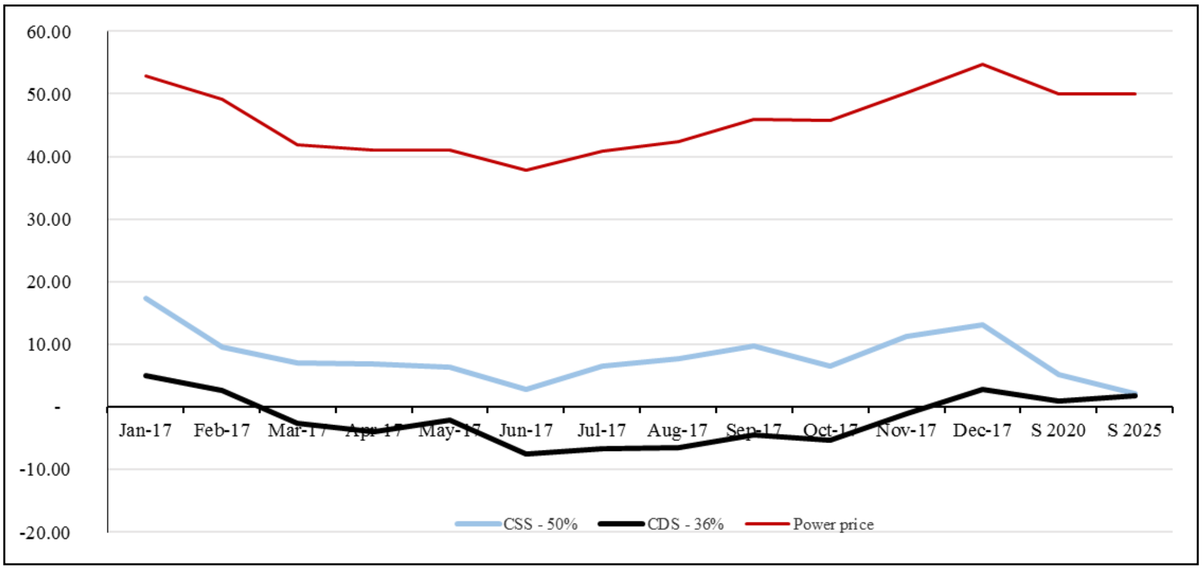


Source: Own development

In the most-likely scenario, commodity trends narrow the gap between CSS and CDS even with a carbon price support in place (see Figure 64). Gas power plants keep a marginal cost difference of around GBP 2.5/MWh (in 2025) with respect to coal plants, which stay in the negative part of the figure. Contrary to the situation in Germany, an average efficiency increase of coal plants due to the retirement of old coal plants will not happen. The remaining coal fleet in the UK is relatively old and investment in efficiency measures is not economically reasonable. It is possible that new gas plants are commissioned in the next years, however the vast gas fleet in the UK makes an efficiency increase only plausible if considerable amount of new capacity is added.

The UK - Worst-case: Low carbon price trend (EUR 15/tCO2eq. in 2020; EUR 15/tCO2eq. in 2025) added to the fixed carbon price support (GBP 18.08/tCO2eq.)

Figure 65: UK - Worst-case carbon price scenario 2020-2025



Source: Own development

The worst-case scenario, suggests that the carbon price stabilizes at EUR 15/tCO2eq. As in the previous scenarios, commodity prices boost the competitiveness of coal and drive the CDS close to the CSS in 2025 (GBP 0.2/MWh difference only). If unabated coal plants would not have to shut down or convert by 2025, a stable carbon price and the commodity trend projected by the World Bank (favourable to coal plants) would lead to a curve switch (gas-to-coal) in 2030, conceding CDS the upper position.

SECTION 5.4: UNCERTAINTY AROUND COMMODITY PRICES (MONTE CARLO SIMULATIONS)

Monte Carlo simulations allow to examine the risk or uncertainty of a specific output by incorporating randomness in the possible deviation of key factors. This allows to create a distribution of possible outcomes and calculate the probability of occurrence. The results presented in the previous section may be conditioned by deviations of commodity prices (coal and natural gas prices). Through the performance of Monte Carlo simulations on a specific result (scenario and point in time), it is possible to picture a full range of possible outcomes for the CSS and CDS. This enables to visualize the uncertainty embedded and thus provides additional information than just looking at a point estimate. Thus, this exercise is complementary to the scenario analysis by allowing to capture the effect of uncertainties surrounding commodity price fluctuations keeping a fixed carbon price (defined by the scenario).

In Chapter 3, the historic of price evolution of coal and gas prices was presented, showing considerable variation among the different periods. This continuous fluctuation is also expected in the next decade subject to supply and demand variations but also geopolitical circumstances. As a way to capture this variation and use it in the analysis, the historic standard deviation (STD) of commodity prices between 2006 and 2017 has been calculated, (29% for natural gas and 32% for coal). The resulting STD will be applied to the World Bank forecasted commodity prices and introduced to the CSS and CDS estimations. By randomly assigning price deviations inside the established valid range (STD) of commodity prices, the CSS and CSS will project a series of possible results for the most-likely scenario. One thousand Monte Carlo simulations (each with a different coal and gas price) were performed resulting in a bell-shaped distribution curve of CSS and CDS results. The resulting picture allows to calculate (and visualize) the probability of a coal-to-gas-switch based on a marginal cost situation (CSS in the upper position compared to CDS). Since the following emission reduction targets are set for 2030 (see Chapter 2), it is reasonable to evaluate the 2025 period in order to determine the need for additional regulatory measures in case the coal-to-gas switch signal is not coming from the market. Therefore, the assessment of 2025 is suitable to assess the coal-phase out strategy in each country. On the one hand, because the UK has announced its intention to phase-out coal plants by 2025. On the other, because Germany´s market based approach may be reconsidered five years before 2030 (still 5 years left for political manoeuvre) if the obtained results by then are not satisfactory.

SECTION 5.4.1: PROBABILITY - GERMANY´s MOST LIKELY SCENARIO 2025

Taking the results from the previous section for the most-likely scenario and the 2025 period (see Table 9) a STD of 29% on gas prices and 32% on coal prices has been applied and one thousand CSS and one thousand CDS simulations have been performed. The results have been distributed in a bell-shaped probabilistic chart (see Figure 66).

Table 9: Germany - Most-likely-case 2025 period

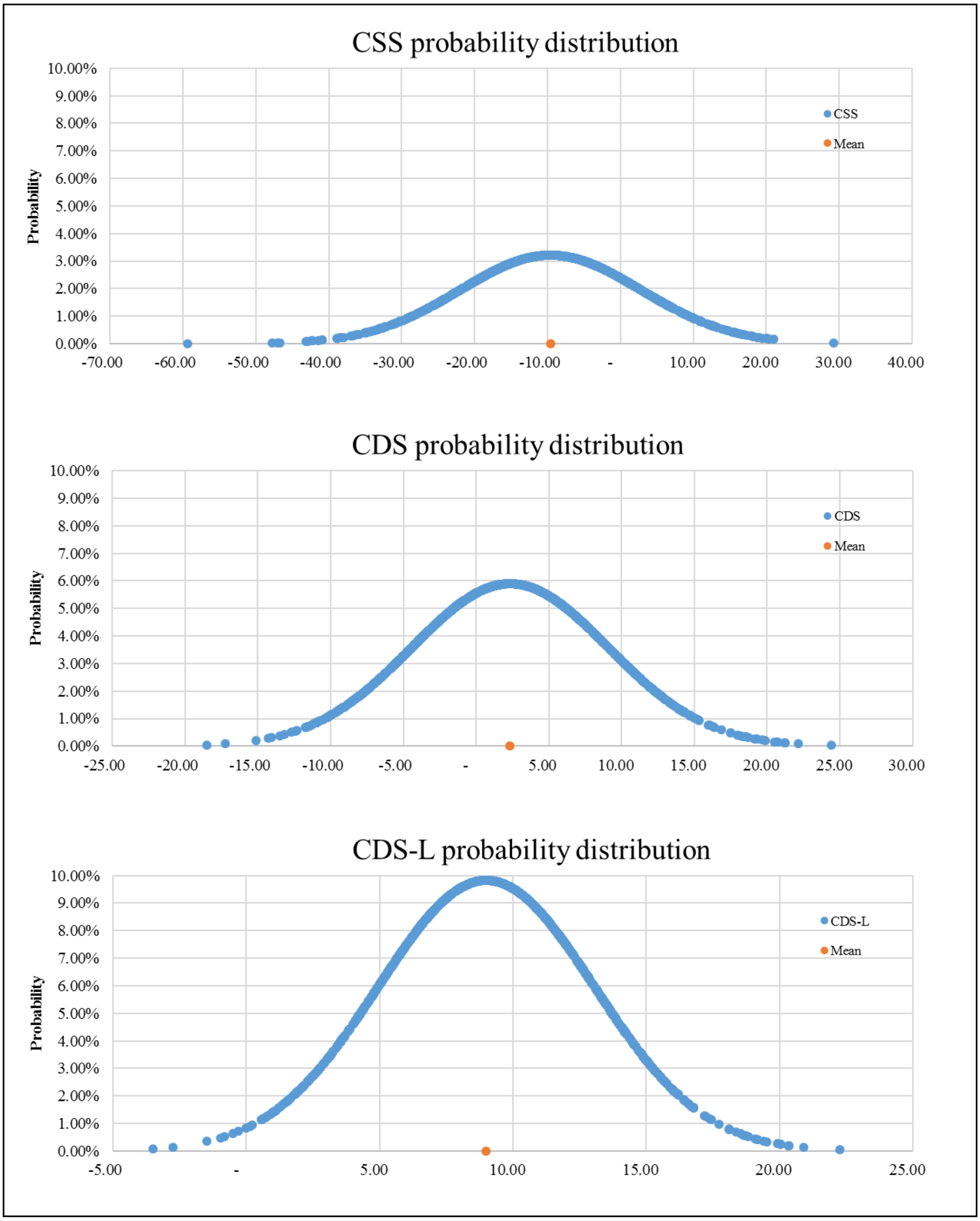
	Power price	**Gas price**	**Coal price**	**Carbon price**	Emission factor gas	Emission factor coal	Efficiency gas plants	Efficiency coal plants
Year	EUR/MWh	EUR/MWh	EUR/MWh	EUR/Ton	%	%	**CSS - 55%**	**CDS - 43%**
2025	40	21.28	8.58	20.00	0.32	0.8	- **5.10**	**4.04**
Standard deviation		29%	32%					

Source: Own development

The obtained results suggest that Germany has around a 21% probability that the CSS curve will be above the CDS curve in 2025. Further, it can be observed from the probability distribution curves below that the CCS results are more spread out than the CDS results justified by the different STDs of gas and coal prices. A 29% STD from the average gas prices (EUR 6.17 /MWh) has a more pronounced effect than a 32% STD on coal prices (EUR 2.75 /MWh). This effect is accentuated by the fact that fuel cost represents approximately 82% of the marginal costs of gas power plants and only 56% of coal power plants in this scenario. Meaning that the fluctuation of fuel costs has a higher impact on the CSS curve than on the CDS curve.

Based on the obtained results from the Monte Carlo simulations, gas plants have a 21% probability to be more competitive than coal plants and a 7% probability to be more competitive than lignite plants. Under this circumstances, gas plant owners would have to decide whether to take the risk of low operating hours or opt for an early plant closure.

Figure 66: CSS and CDS probability distribution, Germany – most-likely-case 2025



Source: Own development

SECTION 5.4.2: PROBABILITY - UK´s MOST LIKELY SCENARIO 2025

Taking the results from the previous section for the most-likely scenario for the 2025 period (see Table 10) a STD of 29% on gas prices and a 32% has been applied on coal prices and one thousand CSS and one thousand CDS simulations have been performed. The results have been distributed in a bell-shaped probabilistic chart (see Figure 67).

Table 10: UK - Most-likely-case 2025 period

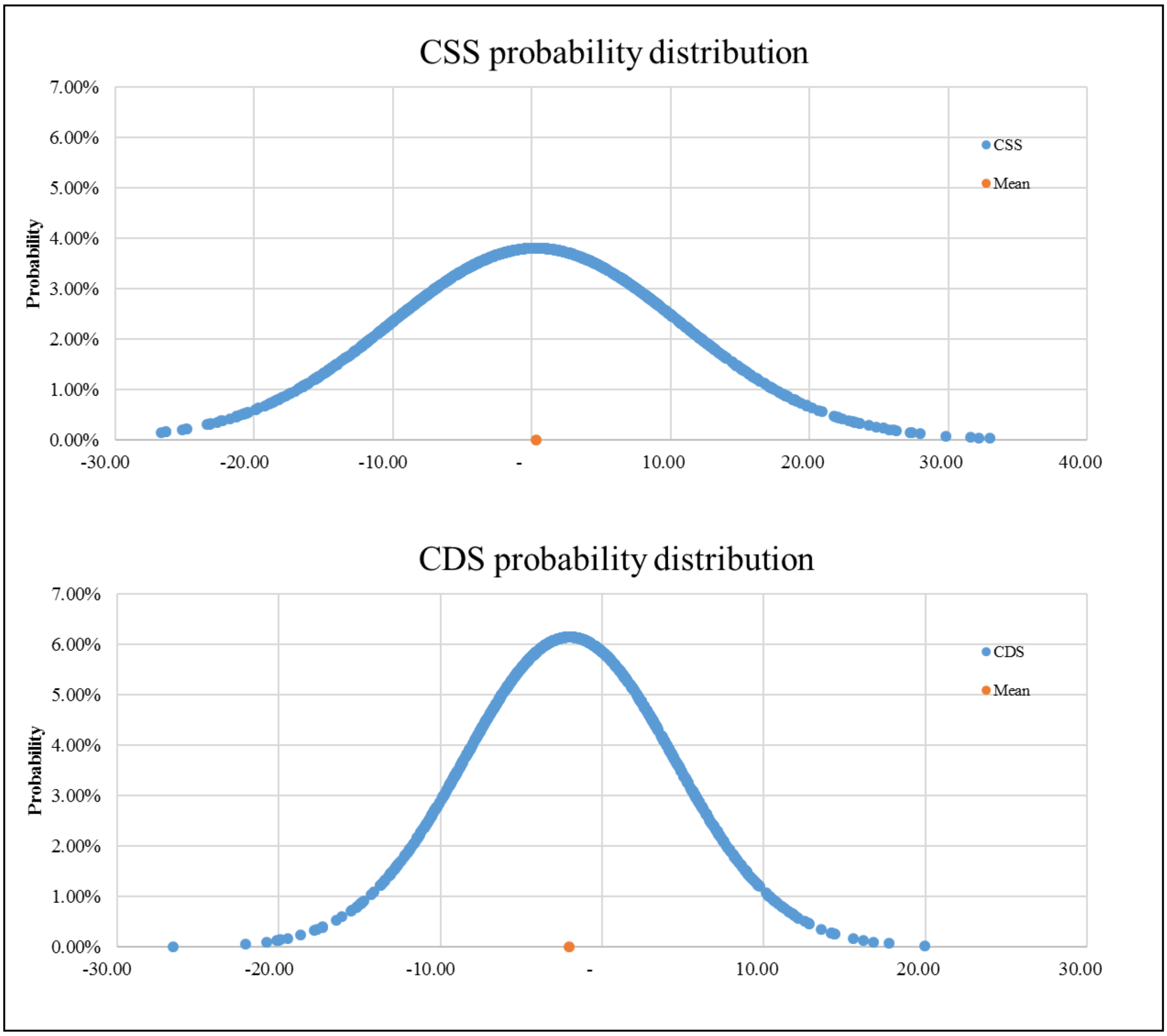
	Power price	**Gas price**	**Coal price**	**Carbon price**	Emission factor gas	Emission factor coal	Efficiency gas plants		Efficiency coal plants
Year	£/MWh	£/MWh	£/MWh	£/Ton	%	%	**CSS - 50%**		**CDS - 36%**
2025	50	18.52	7.47	18.08	0.35	0.88	**0.55**	**-**	**1.96**
Standard deviation		29%	32%						

Source: Own development

The obtained results suggest that in the case of UK with around 57% probability the CSS curve will be above the CDS curve in 2025. Meaning that, with a 57% probability gas plants would be more competitive than coal plants. This probability is too low for a government that is aiming to phase out coal by 2025 with economic arguments.

Further, it can be observed from the probability distribution curves below that the CSS results are more spread out than the CDS results pointing to the effect of the STD of gas prices. A 29% STD from the average gas prices (GBP 5.37 /MWh) has a more pronounced effect than a 32% STD on coal prices (GBP 2.39 /MWh).

Figure 67: CSS and CDS probability distribution, UK – most-likely-case 2025



Source: Own development

SECTION 5.5: FINDINGS

The quantitative analysis in Chapter 5 has provided the following findings about the future coal-to-gas switching situation in Germany and the UK.

- For Germany we can derive the following conclusions:

  a. The CDS and the CDS-L curve) stay in the upper position in all three scenarios with a considerable cushion with respect to the CSS curve. Not even the best-case carbon price scenario (EUR 40/tCO2eq. in 2030) would trigger a coal-to-gas switch from a marginal cost perspective. It becomes clear that unfavourable commodity market developments (forecast by the World Bank) for gas plants would need unrealistically high carbon prices to attain a significant change in the coal-gas competition.

b. Commodity prices play a crucial role in the competition between coal and gas power generation. The effect of fuel prices compounds 86% of the total marginal costs of gas power plants in the most-likely scenario for 2025 (EUR 20/tCO2eq.) compared to 56% in the case of coal power generation. In a situation where commodity prices remain stable, this difference would increase as carbon prices rise above the EUR 20/tCO2eq. level.

c. Through Monte Carlo simulations and focusing on the most-likely scenario in 2025 (EUR 20/tCO2eq.), we could observe that gas-fired plants would be more competitive than hard coal with a 21% probability and only with a 7% probability more competitive than lignite power plants, which suggests that gas plants will continue at the right end of the merit order curve with limited operating hours in the future.

d. A significant increase in power prices would be needed to keep the price setter profitable (CSS or CDS above the zero limit). In the best-case scenario in 2030 (EUR 40/tCO2eq.) the power prices would need to rise to EUR 55/MWh to allow hard coal plants to recover their marginal costs. Therefore, the power price is correlated to carbon price increase. This finding is confirmed by observing the results of the worst-case scenario, where a low carbon price level (EUR 15/tCO2eq.) will not push power prices up.

- For the UK we can derive the following conclusions:

  a. The CSS curve keeps the upper position in all three scenarios. The main reason is the fixed carbon price support (CPS) at GBP 18.08/tCO2eq. A reduction of the CPS could result in a curve switch, especially in the most-likely-case and worst-case scenarios.

b. Favourable commodity prices for coal plants (reduced coal price and increased gas price) reduce the gap between the CSS and CDS curve in the most-likely-case and even close the gap in the worst-case scenarios in 2025. If the projection would continue until 2030, probably a switch between CSS and CDS would take place, triggered by continuous increasing gas prices and falling coal prices. In this sense, the effect of fuel prices compounds 76% of the total marginal costs of gas power plants in the most-likely scenario in 2025 compared to 41% in the case of coal power plants. In a situation where commodity prices stay stable, this difference will increase as carbon prices increase above the EUR 20/tCO2eq. due to the different emission factor of both technologies.

c. Through Monte Carlo simulations for the most-likely-case scenario in 2025, we could observe that gas-fired plants would be more competitive than hard coal in 57% of the cases, which points to a reasonable probability, but not high enough to secure a coal-phase out by 2025. If commodity prices develop more favourably (than the forecast by the World Bank) for coal plants, the coal-phase out based on cost competition could be at risk.

d. The UK would only be exposed to a power price rise in case of a significant carbon price increase, since gas power plants are already in the upper position (price setter) and carbon prices affect the marginal costs of gas plants to a lesser extent than coal plants. For instance, in the best-case scenario power prices would rise to GBP 55/MWh to keep the price setter profitable (CSS above the zero level). It should be noted that that power prices cover also the impact of increasing gas prices. Thus, the power price increase is less correlated to a carbon price increase when the CSS curve is on the upper position.

CONCLUSIONS

Two of the largest EU coal consuming countries, Germany and the UK, have mixed approaches towards phasing out coal power generation through coal-to-gas switching.

In Germany, competition between coal and gas is left to market forces and is not specifically addressed by the “Energiewende”. The fast expansion of wind and solar have pushed gas out of the merit order curve. This has resulted in increased coal consumption by the power sector accentuated by the nuclear phase out. Because of favourable economics of coal, Germany has maintained its old coal-fired plants in operation and even built new, more efficient ones. Further, its vast lignite resources at extremely low price means that emission intensive lignite plants have virtually no competition economically. While CCS may help to decarbonise the electricity mix, it has encountered wide public opposition and the technology itself is not yet mature. Without this alternative, it is undeniable that coal cannot take the role of transition fuel and a drastic reduction in coal power generation is necessary to achieve the emission target for 2030.

In the UK, the energy and climate policy does not encourage the use of coal and has blocked several construction plans for new coal plants. The introduction of a carbon price floor in 2013 penalises coal power generation. The carbon price floor has effectively conditioned the balance between CSS and CDS to the benefit of natural gas. Furthermore, generators with old coal plants will have little incentive to invest in depollution equipment and are progressively closing their plants. As part of the coal phase-out plan, the government has also introduced an emission limit, which will prevent the operation of unabated coal stations beyond 2025. Gas power generation is expected to increase and new gas power capacity is needed due to the closure of coal plants.

The assessment of the coal-to-gas switch situation and the projection of future scenarios for Germany and the UK point to the following conclusions:

First, unabated coal plants emit more than twice as much CO2 per unit of electricity generated compared to gas (the difference is even bigger for lignite plants). Carbon prices affect the profitability of coal generation by raising the marginal costs. The impact becomes more severe as the emission factor of the power plants increases. Thus, coal plants have to pay a higher carbon cost for every MWh produced compared to gas plants.

Second, the increasing need for a more flexible power system due to the penetration of renewables, leaves conventional power technologies in a difficult position. More flexible capacity is needed and coal is not the best placed technology to assume this function. Gas power plants are technically better suited (quick to start and stop) for the future power reality for both base-load and peak-load. Further, gas-fired plants can be used as back-up capacity complementing intermittent renewable energy sources.

Third, the growth of renewable power sources with low marginal costs, has forced the less competitive conventional power source out of the merit order curve and pushed wholesale electricity prices down. For conventional power plants this situation translates into fewer operating hours and diminished revenues, leading to premature closure or mothball of unprofitable plants. This trend is expected to continue as more renewables enter the power generation market.

Fourth, a significant increase in renewable power generation does not automatically result in emission reductions. As we have seen in the case of Germany, the nuclear-phase-out and the favorable energy market for coal power plants has led to an increase in power generation from emission intensive sources (hard coal mainly), offsetting the effect of vast renewable deployment. In the UK, even with a more modest share of renewables, a significant decrease in operation of emission-intensive coal power plants has resulted in considerable emission reductions in the power sector.

Fifth, commodity prices play a fundamental role in the coal-to-gas switching process. Historically, fuel costs for coal plants have been relatively low compared to gas plants. This situation has resulted in an underperformance of gas plants compared to coal. During periods of significant fuel cost difference, a higher carbon price is required in order to compensate for the economic advantage of coal.

Sixth, a low carbon price (below EUR 10/tCO2eq.) has been the norm since 2011, impeding the compensation of the economic advantage of coal. A persistent low carbon price has been the result of the accumulated allowance surplus in the EU ETS derived from the economic recession and the protective overallocation of allowances by member states. Recently, the carbon price has experienced an upward trend (since beginning of 2018) triggered by the recently announced reforms to the EU ETS.

Seventh, competition between gas and coal is not only driven by commodity and carbon prices. Government intervention plays a key role. Taxes on carbon emissions and other national policy measures could influence the competition between coal and gas. As can be seen in the case of the UK, a carbon tax can turn around the competition balance of coal and gas. However, national coal resources and employment linked to the coal activities may hinder political action against the coal sector as can be observed in the example of Germany.

Eighth, current market conditions and political objectives do not create the confidence to invest in new conventional power capacity. Nevertheless, new efficient and flexible capacity will be necessary to support intermittent renewable power technologies. Since the market does not ensure a correct price signal for future investment, recently introduced capacity market could create a meaningful incentive for the construction of new conventional power capacity.

Ninth, the approved reforms for Phase 4 on the EU ETS will probably not be enough to drive the carbon price to a level that incentivises the coal-to-gas switch in Germany. The German government will need to introduce a long-term coal-to-gas switching strategy based on market intervention in order to reduce power generation from high emitting power plants. This is a necessary action to accomplish significant emissions cuts in the power sector and reach the 2030 emission objective. The carbon price needs to reach a high level to reduce the competitive advantage of high emission intensive technologies and make gas plants more economically advantageous. For now, the signal coming from the EU ETS has been weak, which explains the supremacy of coal plants. In light of this conclusion, the German government should pursue the implementation of a set of national measures that aims to address a progressive and ambitious coal-to-gas switching process. The path towards the 2030 emissions reduction objective inevitably passes through the reduction of at least half of the coal power generation fleet.

Tenth, in the UK, national measures are pushing coal power generation out of the merit-order curve (despite low EU ETS prices). The key has been the carbon price floor, which has allowed closing the gap to coal power generation leading to a progressive coal-to-gas switch. According to quantitative analysis, the introduced carbon price floor protects the economics of gas plants against low carbon prices and unfavourable commodity prices. Further, the maximum emission limit set by the UK gives unabated coal plants no option to continue operating after 2025. This implies that a complete coal phase-out by 2025 is very likely unless security supply issues arise. The UK has earned the title of European ‘canary in the coal mine’ when it comes to coal-to-gas switching. The importance of policy interventions has been crucial in this process, granting economic competitiveness to gas even with unfavourable market conditions.

With the insights obtained through the qualitative and quantitative analysis performed in this thesis a statement can be made regarding the most suitable coal-to-gas switching strategy. As we have seen, even the most optimistic carbon price projection appears to be insufficient to close the economic gap between coal and gas plants in Germany. Thus, market intervention seems to be the most reasonable option in order to trigger a sound coal-to-gas switch that enables meeting the emissions reduction target of 2030. The formula applied by the UK, while going against the principle of free markets, has proven to be the most effective approach and should be considered as a serious alternative to a market-driven strategy that does not seem very likely to succeed under the current circumstances.

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