

The energy transition in Europe: initial lessons from Germany, the UK and France

Towards a low carbon European power sector

Professor Natalia Fabra (Joint Academic Director, CERRE, and Universidad Carlos III, Madrid), Editor

Dr Felix Christian Matthes (Öko-Institut, Berlin)

Professor David Newbery (University of Cambridge)

Dr Michel Colombier, Mathilde Mathieu and Andreas Rüdinger, (Institute for Sustainable Development and International Relations - IDDRI, Paris)

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About the authors

Professor Natalia Fabra joined CERRE as a Joint Academic Director in January 2014. She is a Professor in the Economics Department of Universidad Carlos III de Madrid. She is also Research Affiliate at the Centre of Economic Policy Research in London and Associate Editor of the Journal of Industrial Economics. She edits RePEc's New Economic Papers on Regulation. In the past, Natalia has been a visiting scholar at various universities, including the University of California Energy Institute, the *Institut d'Economie Industrielle* (Toulouse), and Nuffield College (Oxford). Natalia works in the field of Industrial Organisation, with emphasis on Regulation and Competition Policy issues. She has worked extensively on the economic analysis of electricity markets. She holds a PhD from the European University Institute.

Dr Michel Colombier is Scientific Director, and one of the founders, of IDDRI (Institut du Développement Durable et des Relations Internationales). Dr Colombier is an agricultural engineer and holds a PhD in Economics. A specialist in energy policy and climate issues, he has served as a member of the scientific panels of the Global Environment Facility (GEF) and the French Global Environment Fund (FGEF). Having worked at the Centro de Estudos de Economia, Energia, Transportes e Ambiente (CEEETA) at the University of Lisbon, he joined l'Agence de l'environnement et de la maîtrise de l'énergie (ADEME), a French government body charged with promoting environmental protection energy efficiency and renewable energy.

Dr Felix Christian Matthes is Research Coordinator, Energy & Climate Policy at the Öko-Institut – Institute for Applied Ecology in Berlin. He is the author of numerous studies and publications on German and international energy, environmental and climate policy. Key topics of his research include decarbonisation strategies for Germany and the European Union, EU energy market development and market liberalisation, energy and emissions projections as well as greenhouse gas emissions trading. Dr Matthes is a member of the Advisory Group to the European Commission on the Energy Roadmap 2050 and has also served as a scientific member of the German Bundestag's Study Commission on Sustainable Energy. From 2007 – 2008 he was a visiting scientist at the Massachusetts Institute of Technology. Dr Matthes graduated as Diplom-Ingenieur from Leipzig University of Technology and holds a PhD in political science from the Free University of Berlin.

Mathilde Mathieu joined IDDRI (Institut du Développement Durable et des Relations Internationales) in 2013 as a researcher, where she has conducted a comparative analysis of national energy transition scenarios and is currently working on European energy and climate policies. After completing her studies as an electrical engineer at the National Institute of Applied Sciences (INSA) in Lyon in 2011, she worked in the field of energy within Areva. In 2012, she obtained a Master's in Public Policy and Environmental Strategy from AgroParisTech-ENGREF. She has also spent time at the Politécnico di Torino (2008) and at the Instituto Tecnológico de Buenos Aires.



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Professor David Newbery is Research Director of the Cambridge Energy Policy Research Group, Emeritus Professor of Applied Economics at the University of Cambridge, and a Research Fellow in the Control and Power Research Group at Imperial College London. He is a Fellow of the British Academy and of the Econometric Society. He was the 2013 President of the International Association for Energy Economics. Educated at Cambridge with degrees in Mathematics and Economics, he has managed research projects on utility privatisation and regulation, electricity restructuring and market design, transmission access pricing and has active research on market integration, transmission planning and finance, climate change policies, and the design of energy policy and energy taxation. Occasional economic advisor to Ofgem, Ofwat, and ORR, former member of the Competition Commission and chairman of the Dutch Electricity Market Surveillance Committee, he is currently a panel member of Ofgem's Network Innovation Competition, a member of the Panel of Technical Experts offering quality assurance to DECC on the delivery of the UK's Electricity Market Reform and the Deputy Independent Member of the Single Electricity Market Committee of the island of Ireland.

Andreas Rüdinger is a Research Fellow at IDDRI (Institut du Développement Durable et des Relations Internationales), specialised in energy and climate policies. He currently leads several projects on the European electricity market and national energy transition strategies. His work focuses on the development and integration of renewable energies and energy efficiency policies. He has published several comparative studies on energy policies in France and Germany. Andreas completed his Master's degree in political sciences at Sciences Po Bordeaux and the University of Stuttgart, Germany.



Executive Summary

The Energy Transition is the set of policies and structural changes aimed at decarbonising the economy. Germany, the United Kingdom and France have taken the lead in implementing national policies to facilitate the Energy Transition. All three countries have set out a range of ambitious targets and policies to cut emissions, deploy renewable resources, and improve energy efficiency: the *Energiewende* in Germany, the *Carbon Plan* and the *Electricity Market Reform* in the UK, and the *Loi sur la transition énergétique pour la croissance verte* in France. With the Paris summit in the background, their experiences show that Europe can contribute to the global fight against climate change by putting in place climate and energy policies from which other countries or regions can learn.

In this CERRE study, we review the early experiences of these three countries with the aim of providing practical guidance. Even though the Energy Transition encompasses several sectors of the economy, we focus on the power sector given its relevance for decarbonising the whole economy. First, the power sector comprises the largest source of greenhouse gas emissions. And second, there is ample scope to reduce them through the use of renewable resources, coupled with other low carbon intensive options during the transition period.

The experience in Germany, the United Kingdom and France shows that the Energy Transition is a lengthy process that requires strong political support, not least because of the often conflicting interests that arise when technologies, social norms, and institutions change. The new technologies have triggered the entry of new market players, which in turn has created an environment favourable to R&D. Participation of a wider range of actors has also proved to be key in securing broader public acceptance towards climate policies. In turn, as financial markets start to factor in the impact of climate policies, some corporations are also starting to change their policies. This should prove decisive to push the Energy Transition forward.

The Energy Transition has put extra pressure on electricity bills. Concerns over the increase in energy costs have led governments to water-down some climate policies. Notwithstanding the high cost of the low carbon investments, this pressure has also been driven by (i) an unbalanced burden share of the costs among the various consumer groups, and (ii) the surge of rents and inefficient costs associated with the implementation of certain climate policies. For the future, it is expected that the Energy Transition will deliver lower costs due to the increased maturity of renewables, the improvements in energy efficiency, and their associated externalities.

The cost reductions achieved by renewables have exceeded all expectations. Part of the success lies in the early roll out of renewables, which rested on technology-specific Feed-in-Tariffs (FiTs). This system has been key in driving R&D efforts in a context in which the EU carbon market has delivered a weak and volatile price signal. However, the FiT system failed to adjust the tariffs in line with cost reductions, not allowing consumers to fully benefit from them.



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The renewable rollout has brought new challenges, such as the need to promote investments in flexible back-up plants. Countries have tried to address this issue in an uncoordinated fashion, which has resulted in a patchwork of different types of capacity mechanisms.

The Energy Transition is faced with large and diverse risks, some of which are unavoidable - both for firms as well as for consumers. Regulation should thus seek to allocate these costs in an efficient manner so as to minimise overall costs. We believe this calls for the use by regulators of long-term contracts for the new investments (both in renewables and in back-up capacity), as the reduced risk exposure for investors should translate into lower risk *premia*. If there is adequate competition among potential investors, auctions for long-term contracts would enable the passing on of these lower *premia* to consumers. In turn, competition through auctions would also reflect the rapid cost reductions as renewable resources approach maturity. This virtuous cycle would be reinforced by reduced regulatory uncertainty, as long-term contracts are less vulnerable to regulatory opportunism as compared to other remuneration schemes. Nevertheless, it is important to stress that long-term contracts are not a substitute but rather a complement of liquid wholesale markets. Indeed, liquid wholesale markets are still needed to facilitate an efficient dispatch and to provide hedging opportunities, while long-term contracts minimise firm's incentives to exercise market power in these markets.

The Energy Transition requires that firms undertake investments in capital-intensive assets with high upfront costs. Evidence has shown that the current regulatory arrangements in power markets are not well suited to induce such investments, not least to set prices in renewables-dominated systems. Good regulations are forward looking: given that low carbon assets are long-lived, it is paramount to already set out the regulatory framework that will be in place both in the short as well as in the medium- to long-run. While there are different views in the regulatory debate – as will most likely be shown by the recent public consultation launched by the European Commission on this issue - we believe that a future-proof electricity market should rest on three pillars:

- Competition *in* the market should be progressively replaced by **competition for the market**, i.e., through capacity tenders run by (or on behalf) of regulators;
- **Long-term Contracts for Differences** for renewables and for back-up capacity, (referenced to the spot energy price), should be used by regulators to de-risk investments, and
- A liquid **wholesale energy market** should be preserved.

In sum, national governments should commit to supporting the Energy Transition with no further delay. This involves putting in place targets and policies leading to an almost carbon-free power sector by 2050. Europe's climate and energy policies are an important complement, but not a substitute for national policies in this area. To avoid damaging investors' confidence, governments should commit to regulatory stability. This is not in contradiction with the need to have rules that evolve during the transition period as long as the course of changes is clearly set and announced in advance. The road ahead is long and windy, but the stakes are high.



Foreword

The proximity of the Paris summit is building up momentum for climate action. Experts repeatedly warn that atmospheric concentrations of carbon dioxide have to be constrained below 400 ppm to avoid an increase in global warming above 2°C. Yet, this concentration, which was first reached in May 2013, has already been exceeded.¹ As governments seek to strike a global climate agreement at the end of the year, very few now argue against the urgent need to decarbonise our economies.

Europe has traditionally led the efforts to tackle climate change. The *2030 climate and energy package*² released in 2014 commits Europe to reducing greenhouse gas emissions by 40% as compared to 1990 levels, to increasing the EU-wide weight of renewables on final energy consumption to 27%, and to improving energy efficiency up to 27% by 2030. The most recent *Energy Union package*³ further reiterates Europe's commitment towards the achievement of environmental objectives, as it advocates for “a resilient Energy Union with an ambitious energy policy at its core”. Europe also aims at becoming the “most energy efficient economy in the world” as well as “number one in renewables”.

Nevertheless, Europe's decreased relevance in the worldwide political arena casts doubts as to whether Europe's climate commitments will be enough to encourage other relevant actors to follow suit. There is, however, one area in which Europe's contribution can be crucial. Committing to ambitious climate targets is paramount, but designing and implementing policies capable of achieving those targets is equally important. There is no magic recipe, nor a single solution for all countries or regions, or for all stages of the decarbonisation process. However, policy experience in Europe can provide important lessons for other countries as they seek to decarbonise their economies. This can indeed be Europe's main contribution to the fight against climate change.

Several European countries – including Germany, the UK and France – have implemented new regulatory instruments to facilitate the transition to a low carbon economy. In this CERRE study, we review their early experiences with the aim of providing practical guidance for other countries and regions. Even though the low carbon transition encompasses several sectors of the economy, the focus will be put on the power sector given its relevance for decarbonising the whole economy.

The study is structured in four chapters. The first chapter (authored by Natalia Fabra) contains an overview of the experiences and main policies implemented in Germany, the UK and France. These experiences provide lessons and allow for the drawing of regulatory suggestions that can be useful for other countries and regions as they seek to achieve a least-cost Energy Transition. The

¹ In May 2015, the Mauna Loa observatory (which provides the most reliable recordings of carbon concentrations) reported carbon concentrations of 404 ppm. See Fowlie (2013).

² http://ec.europa.eu/clima/policies/2030/index_en.htm

³ http://ec.europa.eu/priorities/energy-union/index_en.htm



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remaining three chapters of this study provide an in-depth description of the Energy Transitions in Germany (authored by Felix Matthes), the United Kingdom (authored by David Newbery) and France (co-authored by Andreas Rüdinger, Michel Colombier, and Mathilde Mathieu).



1. Towards a low carbon European power sector, by Natalia Fabra

1.1 What is the Energy Transition?

All goods and services contain energy. When energy is generated through the combustion of fossil fuels, energy consumption generates carbon emissions. Hence, in order to decarbonise our economies, we have (i) to become more energy efficient in order to reduce the energy content of goods and services; and (ii) to rely more heavily on low-carbon energy sources in order to reduce the carbon intensity of the energy consumed. It is thus not surprising that the set of policies and structural changes needed to drastically cut greenhouse gas emissions has received the name of “Energy Transition”.

The Energy Transition is brought about by policy changes and structural changes that take place over a long, and often non-linear, process. In the power sector, these changes encompass massive investments in low carbon assets and infrastructures, as well as new market rules and regulatory arrangements for governing the process. There have been several energy transitions throughout history, including the shift from biomass to coal that took place during the Industrial Revolution, or the shift from coal to oil that took place during the twentieth century. However, the distinctive feature of the current Energy Transition is that it encompasses a combination of various – and not just one at a time - politically-driven changes. For instance, decarbonisation in Europe would be unlikely without the political commitments embodied in the EU climate and energy policy, for the same reasons that the Energy Transitions in Germany, the UK and France have mainly been driven by political decisions.

The Energy Transition in the power sector has brought about changes in corporate structures as new actors have entered the sector, from innovative medium-sized companies to citizens who start producing electricity through small-scale investments in renewables. These changes have already contributed towards the fragmentation of the market structure, leading to a surge of more diverse views in the regulatory debate.

Among the various challenges faced by the Energy Transition, the distributional impacts of the various policies are likely to be paramount as these ultimately affect the public acceptance of such policies and thus their political support. It is beyond dispute that the market arrangements and regulatory policies that are put in place to facilitate the Energy Transition should be efficient. However, the efficiency of such policies cannot be disentangled from their distributional impacts: the most efficient option will not succeed without societal support.

Similarly, the success of the Energy Transition requires irreversible commitments in support of the policies. Otherwise, the often conflicting interests that arise may delay or hamper policy



implementation. Indeed, policy making in Europe has been subject to pressure by some lobby groups, essentially because low carbon policies reduce the profitability of some of the existing power generation assets.⁴ In the power sector, renewables depress wholesale electricity prices and reduce the market share of fossil fuels while, more broadly, some high carbon assets become stranded as a consequence of the climate and energy policies.⁵

The Energy Transition is widely seen as a lever for R&D intensive growth.⁶ As such, it constitutes an opportunity for modernising our economies. As renewable energies are likely to be massively deployed in other parts of the world, early action might allow the European industry to gain and maintain a competitive advantage in this area. The technological spillovers triggered by R&D in low carbon resources may further benefit other sectors of the economy. Concerns remain as to the macroeconomic effects of the Energy Transition, as the need to recover the costs of the low carbon policies put pressure on electricity bills. However, despite the likely rise in energy prices in the short run, the Energy Transition is seen as leverage for competitiveness in the medium to long run as the increased maturity of renewables and energy efficiency investments give rise to future reductions in energy costs.

1.2 The Energy Transition: a regulatory challenge for the power sector

In order to move towards a low carbon economy, all activities - including power generation, transport and heating, among others - must drastically reduce their emissions. For this to be possible, action must come first and foremost from the power sector. The reason is two-fold. First, the power sector comprises the largest source of greenhouse gas emissions. And second, there is ample scope to reduce them through the use of renewable resources, coupled with other low carbon intensive options during the transition period. Decarbonising other sectors is more challenging, as these typically lack the ability to incorporate renewables into their production processes. There will thus be an increased use of electricity in a wide range of sectors, which will have to be at least partly compensated with improvements in energy efficiency.

The 2050 Energy Roadmap for moving to a competitive low carbon economy states that the EU should be prepared to reduce its domestic emissions by 80% in 2050, as compared to 1990. The achievement of this goal thus requires almost full decarbonisation of the power sector. It is beyond

⁴ See Euroactiv, 11 October 2013 "Energy CEOs call for end to renewable subsidies".

⁵ see John Stern's (2013) report on the carbon bubble; the OCDE and the IEA have also expressed similar concerns

⁶ The current EU Commissioner for Climate Action and Energy recently argued that: "We have three times more renewable power per capita in Europe than anywhere else in the rest of the world. We have more than one million people working in a renewable energy sector worth over €130 bn a year and we export €35 bn worth of renewables every year." (Renewable energy progress report, Press release, 16 June 2015). See also the report written by the German Ministry of the Environment (2010).



dispute that the energy sector will have to go through a profound transformation as Europe seeks to achieve this goal. While the Energy Transition is faced with diverse challenges (technical feasibilities, macroeconomic costs, affordability in general or security of supply issues) the most significant challenges result from the regulatory and market arrangements as well as from the distributional impacts of the policies.

The *energy trilemma*, i.e., the triple challenge of making energy supplies sustainable, secure and affordable, is at the heart of the Energy Transition. The energy trilemma has headed Europe's climate and energy policy for the last decade, at least since the European Commission committed in 2007 to the 20-20-20 objectives with the aim of "combating climate change, increasing the EU's energy security and strengthening its competitiveness." The recently approved Energy Union package reiterates Europe's commitment to this triple objective as it sets out a "resilient Energy Union with an ambitious energy policy at its core" as an instrument to "give EU consumers secure, sustainable, competitive and affordable energy".

Yet, even though the policy objectives are clear, their actual policy translation is far from straightforward. How can countries find the right balance between the sustainability, security of supply and affordability objectives? Which are the best available policy options to achieve them? The answer is certainly not easy. Most likely, there is no single correct answer. Experience tells us that one size does not fit all: answers differ because countries differ in their energy mixes, availability of natural resources, public acceptance and political support for the various policy options, or because they are at different stages of the Energy Transition process. This does not mean that one cannot find common lessons. Rather, the various solutions adopted across countries provide an array of valuable lessons for all. The early experiences of Germany, the UK and France – with their national idiosyncrasies – show that this is already the case, as we elaborate next.

1.3 The Energy Transition in Germany, the UK and France: an overview

Germany, the United Kingdom and France have taken the lead in implementing national policies to facilitate the Energy Transition. All three countries have set out a range of ambitious targets and policies to cut emissions and decarbonise their power sectors.

It is difficult to overstate the importance of the power sectors in these three countries. Germany, the UK and France have the three largest power sectors in Europe, together representing almost half of total electricity produced and consumed in the European Union. According to the latest Eurostat statistics,⁷ annual net electricity generation in Germany is the highest in Europe, accounting for 19.2 % of the EU-28 total, just ahead of France (17.7 %) and the UK (11.0 %). Indeed, these three countries are the only Member States with a double-digit share. Their importance

⁷ http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_105a&lang=en



spreads beyond these figures: since these countries are heavily interconnected with other European countries - particularly so in the case of Germany and France⁸ whatever happens in these three countries affects its neighbours.

Table 1: Key indicators (2014 data)

| | Germany | UK | France |
|------------------------------|---------|-------|--------|
| Net Generating Capacity GW | 189,5 | 74,9 | 128,9 |
| of which Nuclear GW | 12,1 | 97,5 | 63,1 |
| of which Fossil Fuels GW | 85,3 | 53,3 | 24,4 |
| of which Renewable GW | 81,5 | 7,9 | 16,0 |
| of which Hydro GW | 10,7 | 4,0 | 25,4 |
| Net Generation TWh | 548,5 | 363,6 | 541,2 |
| Balance Imports- Exports TWh | -35,7 | 19,5 | -65,8 |

Source: ENTSO-E (2015)

1.3.1 Differences and similarities across the three countries

Germany, the UK and France have similarities among them, but also important differences. Among others, they have different initial conditions (regarding e.g. their energy mix), different institutions or governance structures (regarding e.g. the role of independent regulators), different market structures in the power sector (both horizontally and vertically), and their societies have shown different attitudes towards the various energy policy options (regarding e.g. the renewable rollout, or the role of nuclear). These differences have affected the choice and the success of policies towards the Energy Transition.

First, these three **countries differ in their energy mixes**. France sources the largest share of its generation from nuclear, with 75%, while Germany and the UK have the largest shares of coal in the generation mix, with 44% and 39% respectively. This implies that the carbon intensity of France is much lower than in the other two countries. Paradoxically, this favourable initial condition has made the implementation of the Energy Transition policies in France harder, as it has required a more convincing narrative to justify the diversification of energy sources towards renewables. In contrast, the high carbon intensities in Germany and the UK have been powerful drivers for pushing for ambitious energy efficiency and renewables targets.

Nevertheless, the gradual phase out of polluting power stations in Germany and the UK has added complexity to the decarbonisation of their power sectors. For instance, subsidies for the use of domestic hard coal in Germany will not be phased out until 2018. After several months of

⁸ Germany is interconnected with Austria, Switzerland, the Czech Republic, Denmark, France, Luxembourg, the Netherlands, Poland, and Sweden. France is interconnected with Belgium, Germany, the UK, Spain, Italy and Switzerland. The UK is connected to France, Ireland and the Netherlands.



discussions, Germany has recently abandoned its plans for a tax on coal-fired power plants.⁹ In the UK, the recently held capacity auction has awarded capacity payments to two-thirds of the UK's coal plants, making it easier for them to remain open for longer.

Whereas all three countries have favoured the expansion of renewable energy, they differ in their **policies towards nuclear**. On the one hand, Germany has decided to phase out nuclear (the last nuclear reactor will shut down by 2022), and France has decided to gradually reduce the weight of nuclear (by 2025 nuclear will represent 50% of total production in the power sector, down from the current 70%). On the other hand, the UK has decided to construct a new nuclear reactor.

Second, there are important **differences in the market structure and regulatory arrangements** in place in the power sectors in Germany, the UK and France. The French electricity market is dominated by a large company, EDF, which is under public control and close regulatory scrutiny. In contrast, the power sectors in Germany and the UK are more fragmented, and currently less subject to public intervention. Also, all three countries have traditionally followed public policies to protect their industrial sectors, using exemptions to mitigate the effects of increasing electricity prices on energy-intensive consumers.

Third, there are substantial differences in the **electricity prices** paid by households and industrial consumers across the three countries. While Germany has one of the highest electricity prices in Europe, electricity prices in the UK are in the median range, and prices in France are relatively lower. One reason for the low prices in France is that retail prices remain largely regulated, despite the fact that the opening of retail choice dates back to 2007. In 2010, the French government passed the NOME law that eliminates regulated tariffs for industrial consumers but maintains them for households. However, in an attempt to facilitate retail competition, the NOME law makes approximately 25% of EDF's nuclear production available to alternative suppliers at the AREHN tariff, currently set at 42.5€/MWh. This Law might have contributed to keeping retail prices low for French consumers (Creti et al., 2013). Nevertheless, the energy regulator CRE estimates that residential bills could rise by as much as 30% in the next two years, unless this is reversed by political decisions.¹⁰

⁹ Instead, the equivalent of 2.7 GWs of brown coal-fired plants will be taken as reserve power in case of emergency. A summary of the public debate regarding the implementation of the so-called Climate Levy can be found here <https://www.cleanenergywire.org/news/climate-levy-debate-and-proposals-cutting-co2-emissions>

¹⁰ Very recently, in July 2015, the French government has decided to cap price increases at 2.5% from August, below the 3.5%-8% range that the energy regulator CRE had recommended.



Table 2: Electricity prices

| | Germany | UK | France |
|---|---------|--------|--------|
| Electricity prices (Domestic) over EU28 average | 144,7% | 88,3% | 74,5% |
| Electricity prices (Industrial) over EU28 average | 125,3% | 113,6% | 79,1% |

Source: Eurostat

These price differences have given rise to countervailing incentives. On the one hand, the high electricity prices in Germany have provided a stimulus for energy efficiency improvements, which has been absent in the French case. On the other hand, when prices are high, it is less politically feasible to increase bills. In Germany, for instance, the increase in the renewables surcharge led the government to exempt some industrial consumers from paying it, which in turn caused further increases in the surcharge paid by those consumers who were not exempted (typically, households and small businesses). Had these exemptions not taken place, prices to households would not have risen as much as they have. In turn, this would have muted part of the criticisms about the costs of the Energy Transition in Germany.¹¹ Despite this, German society strongly supports the Energy Transition in ways that could probably not be expected elsewhere. In the UK, the increase in electricity prices has led to strong pressure to end renewable support.¹² Indeed, in June 2015, the UK government decided to end support for onshore wind a year earlier than expected.

Fourth, the three countries have important **differences in their institutional and governance structures**. This has had an important impact on the policies adopted as well as on the process of implementation. For instance, unlike other European member states, the UK has a long tradition of independent regulators, which further consult with committees of independent experts. This might explain why, in the UK case, the energy regulator Ofgem has played a decisive role in the Energy Transition. Indeed, in 2009, Ofgem took the initiative of launching *Project Discovery*, a sector inquiry that eventually gave rise to the *Electricity Market Reform*. Furthermore, climate and energy related policies are regularly reviewed by various panels of independent experts, such as the Committee on Climate Change or the Panel of Technical Experts on the Electricity Market Reform, among others.¹³ In contrast, the role of independent regulatory and advisory boards has been more limited in other member states, including Germany and France, as compared to the UK.

¹¹ See for instance the *Spiegel Online International* article “Germany's Energy Poverty: How Electricity Became a Luxury Good”, available at <http://www.spiegel.de/international/germany/high-costs-and-errors-of-german-transition-to-renewable-energy-a-920288.html>

¹² The price increases have also raised concerns about the exercise of market power by the big six electricity companies. Indeed, in June 2014, the UK's big six energy companies have been formally referred to the Competition and Markets Authority for a full investigation.

¹³ See <http://www.theccc.org.uk> and <https://www.gov.uk/government/groups/electricity-market-reform-panel-of-technical-experts>, respectively.



Some of these differences partly explain differences in the policies chosen. Before moving to the lessons that can be drawn from these country experiences, we briefly outline below the evolution of the low carbon policies in each of these countries.¹⁴

1.3.2 Overview: targets and policies

Germany has been a precursor of the Energy Transition in Europe. Even though the name given to it, *Energiewende*, was officially coined in 2011, it has been used since the early 1980s when the energy and climate policy debate first started. Discussions regarding the Energy Transition still occupy a prominent space in the Germany policy agenda nowadays.

The early debates about the role of nuclear power, together with the search for alternatives, shifted the focus towards the need to invest in energy efficiency and renewables. The first target for the reduction in carbon emissions dates back to 1990, when the German government committed to reducing them by 25% by 2005 as compared to 1987 levels. This target was subsequently strengthened on several occasions. The current objective is to reduce greenhouse gas emissions by 40% by 2020, 50% by 2030 and 80-95% by 2050, as compared to 1990 levels.

Probably as importantly, these ambitious emissions reductions targets have been accompanied by a set of policies - notably, the nuclear phase-out decision, the Feed-in Tariff (FiT) system to allow for the renewable energy rollout, and the currently debated Climate Levy that will eventually lead to the gradual phase out of old coal plants. These measures have been coupled with a set of targets for renewables and sector-specific energy efficiency improvements. Germany has decided not to create a capacity system.

In the **UK**, a carbon target was first set explicitly in 1990, with the commitment to reduce carbon emissions to 1990 levels by 2005. The government also imposed a Fossil Fuel Levy on fossil fuel generation to raise funds to pay for nuclear decommissioning. It also placed a Non-Fossil Fuel Obligation (NoFFO) on electricity suppliers, who were required to buy a certain amount of nuclear or renewable electricity at a premium price. Interestingly, some of the NoFFO funds were used to procure renewables through competitive tenders, which resulted in dramatic falls in the cost of renewables.

Since then, energy and climate policy has largely evolved, with targets becoming more stringent, and policy changes facilitating the achievement of those goals. The UK is committed to a series of five-yearly carbon budgets to allow the achievement of its 2050 target,¹⁵ namely to reduce emissions by at least 80% below 1990 levels. The UK is currently in the second carbon budget

¹⁴ Chapters 2 to 4 of this study contain a more detailed description and in-depth analysis of the policies implemented in each country.

¹⁵ <http://www.theccc.org.uk/tackling-climate-change/reducing-carbon-emissions/carbon-budgets-and-targets/>



period (2013-2017), during which emissions have to be reduced by 29%. The fourth carbon budget (2023-2027) requires that emissions be reduced by 50% on 1990 levels by 2025. The 8% emissions reductions achieved during 2014 put the UK 36% below 1990 levels, well on track to achieve its targets.¹⁶ Furthermore, despite some controversies, the government has recently announced that the UK has just met its interim renewable energy target for 2013/14, in compliance with the interim objectives set by the EU Renewable Energies Directive.

Importantly, the UK has accompanied these environmental targets with a deep reform of its power market (known as the *Electricity Market Reform*). Current policy incorporates four main ingredients: a Carbon Price Floor to avoid extremely low carbon prices; Contracts for Differences (CfDs) to incentivise the deployment of low carbon resources (nuclear and renewables); a Capacity Market to address concerns over security of supply; and an Emissions Performance Standard (EPS) that limits emissions from new power stations.

In **France**, a comprehensive debate about the Energy Transition as a whole did not start until 2012, even though previous initiatives existed regarding specific issues, e.g. those triggered by the EU directives (mainly, the 2008 package), the *Grenelle* process launched in 2007, or the 2010 POPE law that included the objective of reducing greenhouse gas emissions by 75% in 2050. One of the reasons for this delay, relative to the German and UK experiences, is probably the fact that the French power sector already has some of the lowest carbon emissions, due to its reliance on nuclear power. However, emission reductions in other sectors of the economy lag behind, and there is ample scope to reduce energy consumption through improvements in energy efficiency. Also, the deployment of renewable energies has been rather slow, and it is unclear whether France will meet its 2020 renewables target (the current weight of renewables is 14.2%, still far from the 23% objective).

In July 2015, the French National Assembly has given the final approval of the *Law on the energy transition for green growth* containing a long-term project to achieve ambitious objectives for emissions reductions, renewables and energy savings for 2020, 2030 and 2050. By 2050, emissions will have to be 75% lower than in 1990, and energy consumption has to decrease by one half with respect to 2012. By 2030, the share of renewables has to reach 32% as a share of final energy consumption, and 40% as a share of total electricity produced. This is coupled with a commitment to gradually reduce the weight of nuclear power in generation, down from the current 75% to 50% by 2025. Interestingly, France has incorporated an explicit target for fossil fuel consumption in 2030, which has to reduce 30% below 2012 levels. Inspired by the example of the UK, France will also implement a national low carbon strategy through binding carbon budgets for different sectors.

¹⁶ However, a recent report by the Committee on Climate Change (CCC) casts doubts as to whether these reductions can be sustained in the long term, and calls the government to strengthen its ongoing efforts to reduce emissions.



In order to achieve these targets, France has put in place support instruments for renewable energies and energy efficiency. There is an FiT system in place for renewable technologies (together with other instruments), and the plan is to move gradually towards a system of competitive tenders. As for energy efficiency, the government has launched a vast program for renovating 400,000 buildings per year between 2013 and 2020, plus the renovation of 800,000 social houses by 2020. In 2006 France also put in place a system of white certificates for energy efficiency. The energy savings achieved during the period 2006-2014 have exceeded the targets. France will put in place a decentralised capacity market.

1.3.3 Policies towards renewables

In **Germany**, the renewable energy roll out was heavily supported by the use of Feed-in-Tariffs (FiTs). The first FiTs, introduced in 1990, were complemented by technology-specific incentive programmes. This initial scheme was reformed in subsequent rounds, with adjustments of the tariffs for different types of technologies. The 2000 reform introduced a system by which the tariff for solar PV was made dependent on the PV capacity expansion during the previous year.

The period 2009-2012 witnessed a large increase in the cost of the FiT system following the boom of solar PV and the rapid decline of wholesale prices (in part driven by the expansion of renewables, but also by the reduction in carbon and fossil fuel prices). This, coupled with the exemption given to industrial consumers, implied rapid increases in the renewable surcharge paid by residential consumers.

The EU Guidelines on State Aid for Environmental Protection and Energy 2014-2020 (EEAG)¹⁷ triggered a change in the regulation of renewables in Germany. Under the current regulation, new renewable installations have to sell their power to the market, and they receive a premium, which is computed as the difference between a technology-specific strike price and the average wholesale market price. Also, roll-out corridors have been set for wind, solar PV, and biomass. If the capacity of these technologies falls outside the corridors, the technology-specific strike prices for the new installations are adjusted upwards or downwards.

France mimicked the German FiT system, but failed to reproduce one of its key characteristics: long term stability. Instead France has quite a history of stop-and-go policies, notably on solar PV and onshore wind tariffs and regulation. Electricity from renewable sources is currently promoted through an FiT system that requires electricity distributors to purchase renewable electricity at administratively set prices for the various technologies.

In contrast to the German and French policies, the **UK** has instead resorted to various alternative instruments: auctions for what were effectively FiTs were first used in 1990; these were replaced by

¹⁷ [http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628\(01\)&from=EN](http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628(01)&from=EN)



a system of Renewable Obligation Certificates (ROCs), which have in turn been replaced by the allocation of Contracts for Differences (CfDs) through auctions. Whereas the auctions that were held in the early 90s proved very effective in pushing down the costs for renewables, they failed in designing the penalties for non-delivery. Indeed, the falling success rate of the contracted renewables led to a rethink of the system, which was subsequently substituted by the system of ROCs. Under this system, energy suppliers had the obligation to source an increasing share of their power from renewables, and they could do so by acquiring certificates. Renewable installations would thus earn the wholesale market price plus the value of the certificates. An initial technology-neutral approach was replaced by a technology-specific approach, as different technologies received different amounts of certificates per MWh. Still, since the ROC system established the same remuneration regardless of location, it gave rise to excessive payments for installations in particularly windy locations. Furthermore, the price of certificates was too volatile and too sensitive to policy intervention.¹⁸

The *Electricity Market Reform* recently implemented in the UK has incorporated long-term 15-year Contracts for Differences for low-carbon investments. The CfD specifies a strike price and pays or receives the value of the strike price *less* a reference market price. Thus, CfDs are essentially like FiTs, with an important difference: unlike in a FiT, the CfD holder is responsible for selling its output to the market, including the responsibility to manage and pay for imbalances. Hence, generators under a CfD are effectively paid less than the strike price as they have to bear the costs associated with balancing renewables, much of which is intermittent.

Auctions are now used to set the strike prices of the CfDs. Renewable technologies are divided in two different pots depending on their degree of maturity.¹⁹ Developers compete by submitting sealed bids to each pot, which are chosen as a function of the strike price regardless of the delivery date or the specific technology within each pot. The allocation of CfDs continues from low to high strike prices until the entire budget allocated to the pot has been used up. Hence, if investors offer lower prices, the total amount of renewable capacity that gets installed goes up.

The total budget for each round of auctions is fixed, with all rounds not exceeding £7.5 billion annually by 2020. The first auction, which was held in December 2014, was very successful in pushing the costs of renewables substantially below the former strike prices. However, and despite

¹⁸ The ROC was due to close on 31 March 2017, with a three-year period of overlap with the Contracts for Difference (CfDs) scheme that started operating in 2014. However, the UK government has recently announced that the ROC system will close to onshore wind farms a year earlier than originally expected. However, ROC support will be continued for projects that have already secured planning permission, a grid connection and land rights.

¹⁹ There is a group of 'established' technologies (onshore wind (>5 MW), solar photovoltaic (>5MW), energy from waste with CHP, hydro (>5MW and <50MW), landfill gas and sewage gas); and a group of 'less established' technologies (offshore wind, wave, tidal stream, advanced conversion technologies, anaerobic digestion (>5MW), dedicated biomass with CHP and geothermal).



the early experience of the NoFFO auctions, penalties for non-delivery have not stopped two solar farms from dropping out after winning a slot at very low strike prices.

1.3.4 Capacity mechanisms

In the **UK**, a Capacity Auction has been introduced following the US experience (Newbery and Grubb, 2014). In the auction, that takes place once a year, both existing assets as well as new installations participate to make their capacities available in exchange for capacity payments. The amount of capacity to be procured, which is set by the government following the advice of the System Operator, enters the auction through a downward sloping schedule.²⁰ If successful, new entrants are granted 15 year contracts for indexed capacity payments, which add up to their energy market revenues. Existing plants act as price-takers. If successful, they receive the clearing price and a one-year contract to guide exit decisions. Demand Side Response can also compete in the auction for one year contracts. The first capacity auction was held in December 2014, and it has delivered a £19.40/kWyr price, well below expectations.

A completely different capacity mechanism will be used in **France**. Rather than opting for a centralised system, the French have favoured a decentralised capacity system much closer to the Renewables Obligation Certificate system that the UK used to incentivise renewables. The French capacity system obliges energy suppliers to contract enough capacity to cover the peaks of their customers' demand. Capacity certificates can be bought from the capacity owners, or from operators aggregating large industrial consumers capable of providing demand response. Certificates will be traded bilaterally, but it is expected that an exchange platform will be created as well. A critical ingredient is the design of penalties for those suppliers who fail to buy enough certificates.

In contrast to these two experiences, **Germany** has opposed the existing and planned reserve mechanisms. In particular, its Energy Minister came out publicly against capacity markets, under the belief that "a functioning electricity market requires real scarcity prices. They send the necessary investment signals."²¹

²⁰ At the cost of new entry, estimated by the regulator at £49/kWyr, the demand schedule hits the exact amount that the government wants to procure.

²¹ <http://www.euractiv.com/sections/energy/gabriel-rejects-senseless-calls-surplus-energy-capacity-311433>



1.4 Lessons from the Energy Transitions in Germany, the UK and France

In this section we summarise the main lessons that can be drawn from the experiences in Germany, the UK and France. These lessons allow us to highlight some policy recommendations aimed at facilitating the achievement of the Energy Transition at least cost.

We have grouped the early lessons from the experiences in Germany, the United Kingdom and France as follows:

1. The Energy Transition is a long process that requires strong political support. The countries that have taken the lead in implementing the reforms have incurred higher costs, but have also enjoyed a first-mover advantage.
2. European climate and energy policy has bolstered national policies, but more progress is needed in certain areas, including carbon pricing and market integration.
3. The Energy Transition has put extra pressure on electricity bills. This reflects the increase in the costs due to the low carbon policies, but also an unbalanced burden share of the costs among the various consumer groups. In turn, concerns over the increase in energy costs have led governments to water-down some climate policies.
4. The ETS has delivered a weak carbon price signal. Countries have had to strengthen it by adding additional mechanisms. Carbon pricing policies at the national level are politically challenging.
5. Renewable energies have played a prominent role in the Energy Transition. Their costs have gone down beyond expectations.
6. The success of the early roll out of renewables rested on technology-specific Feed-in-Tariffs (FiTs). However, the FiT system broadly failed to adjust the tariffs in line with cost reductions, and in controlling total investment.
7. The existing market arrangements have failed to promote efficient investments in generation capacity. Countries have tried to address this issue in an uncoordinated fashion.
8. R&D in low cost technologies has played an important role. Both the climate policies as well as the increase in public expenditure have been important drivers of R&D and cost reductions.
9. Efforts in promoting energy efficiency have been weak. There is mixed evidence concerning the potential of some of these policies to reduce energy consumption.

Below, we provide a more detailed description of the lessons outlined above.



1. The Energy Transition is a long process that requires strong political support. The countries that have taken the lead in implementing the reforms have incurred higher costs, but have also enjoyed a first-mover advantage.

The Energy Transition is a lengthy process. Germany, the UK and France took the lead in implementing national climate policies and still they have a long road ahead towards decarbonisation. Their experiences show that the structural changes needed to trigger changes in consumption and production patterns take time, and that the deployment of infrastructure involves lengthy processes. Furthermore, often conflicting interests further delay the implementation of the reforms.

In light of the long term dimension of the Energy Transition, there is a need for adequate long term policy planning. Policies have to be stable so as to reduce investors' risk *premia*, while at the same time being able to deal with the major uncertainties that are linked to a transition that spreads over several decades.

It is a contentious issue whether early policy implementation provides a competitive advantage or disadvantage. The German experience illustrates the trade-offs. On one hand, it has been costly for Germany to be one of the first movers of the Energy Transition. An important fraction of the low carbon investments were carried out when the technology was not mature. Indeed, the externalities generated by the German renewable energy rollout have allowed other countries to benefit from lower investment costs. For instance, the costs of solar PV modules have dropped 80% in the last 5 years, in part (though not only) due to the strong demand induced by the German renewables policy.

However, Germany has also benefited from a first mover advantage in several other dimensions. In Germany, there have traditionally existed strong links between industrial policy and energy policy, and the *Energiewende* has been no exception. The German green industry is nowadays among the most advanced ones in the world,²² owing significantly to the domestic environmental policies that have contributed to building a robust manufacturing sector. German industry has also benefitted from low energy prices, partly driven by the price-depressing effect triggered by renewables, i.e., the so-called merit-order effect.

²² The performance of the wind industry has been more successful than that of solar PV (as measured by e.g. patent records). The German solar industry has faced strong competition from China in the production of modules but still remains as the leader in solar PV manufacturing equipment and inverters. See Rutten (2014) and IISD (2014) for a discussion of the impact of environmental and energy policies and industrial policy in Germany.



2. European climate and energy policy has bolstered national policies, but more progress is needed in certain areas, including carbon pricing and market integration.

The energy and climate policies of all three countries - Germany, the UK, and France, - have been increasingly embedded in European policy in this area, at least for the 2020 horizon. The 20-20-20 objectives included in the 2008 European energy and climate package have played a key role as they urged countries to put in place or to reinforce policies capable of achieving the legally binding targets for greenhouse gas emissions reductions, renewables and energy efficiency. In some cases, European climate and energy policies have induced countries to have more ambitious objectives. In others, the integration of pre-existing national and European targets has contributed to defining a more consistent set of targets and policies. The monitoring of the interim targets is also contributing to that end.

However, there are some areas where European policy has lagged behind. In particular, the failure of the European Union Emissions Trading System (EU ETS) to deliver a robust carbon price signal has made it more difficult for countries to comply with their decarbonisation commitments. Without disregarding the difficulties, the EU has also failed in promoting a more integrated market, which would have allowed for smoother integration of renewables in the power sector. Arguably, recent initiatives (e.g. the Juncker Investment Plan and the Energy Union package) will help to overcome this, at least partially. The approval of Capacity Allocation and Congestion Management Guidelines should be the basis for a more integrated energy market in Europe.²³

Other European policies beyond climate policies - understood in a narrow sense - have also had major impacts on the low-carbon transition. Particularly important in the German and French cases, the implementation of the EU energy packages led to the unbundling of the transmission and distribution networks. This has proved to be a necessary condition for the successful rollout of renewables. As the German case illustrates, network operators had been very critical of the roll-out of wind energy in the early stage. It was only after vertical unbundling that transmission system operators adopted a neutral role towards the deployment of the full range of generation options.

Competition policy also has a deep impact on climate and energy policies through State Aid control. In particular, in light of State Aid legislation, the EC has assessed (i) the exemptions given to energy-intensive consumers - notably, in Germany and France; (ii) the contract negotiated between the UK government and the French company EDF for the construction of a new nuclear reactor; and it is in the process of evaluating (iii) past renewables policies in several member states. The ex-post evaluation of renewables policies has added regulatory uncertainty among investors. Furthermore, the new 2014 guidelines for state aid on environmental protection and energy narrow down the range of regulatory options for renewable rollout available to the member states. In particular, they

²³ The "Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management" was published in the Official Journal of the EU on 25 July 2015.



limit remuneration schemes to a premium that is added to the market price and make renewable installations responsible for balancing their power. These measures will increase the risk faced by investors, while providing limited benefits.

3. The Energy Transition has put extra pressure on electricity bills. This reflects the increase in the costs due to the low carbon policies, but also an unbalanced burden share of the costs among the various consumer groups. In turn, concerns over the increase in energy costs have led governments to water-down some climate policies.

Electricity prices for households and businesses have been on the rise. Even though there are several confounding factors, it is beyond dispute that climate policies have contributed to this trend. Indeed, the Energy Transition requires important investments in low carbon technologies and infrastructure, and these add pressure to increase energy bills. With the economic crisis in the background, a large fraction of consumers are finding it increasingly difficult to pay their electricity bills, making the 'energy poverty' problem even worse.²⁴

Despite the current price increases, energy costs are expected to go down in the medium-term. A new report from the UK Committee on Climate Change (CCC) has assessed the impact of the UK's low carbon policies on consumer energy bills. Its conclusion is that households would pay more to decarbonise the UK's energy sector in the coming decades, but that energy bills would rise significantly more if the UK failed to implement climate policies.²⁵

Nevertheless, households and firms care about today's prices, and thus they fail to internalise the prospect of future cost reductions. As they become less willing to pay for the current costs of the energy transition, there is a real danger that these policies will be watered-down.

Concerns over affordability not only result from the actual costs of the low-carbon transition, but also from the way certain policies have been implemented. In some cases, climate policies have given rise to windfall profits for firms that have made electricity unduly expensive for consumers. In others, some privileged consumers have obtained exemptions to mitigate the electricity price increases at the expense of the non-privileged ones, who have had to bear a larger share of the costs.

An example illustrates the first of these issues. Carbon pricing is a necessary condition for efficiency; particularly, as it provides incentives for investors to expand low-carbon capacities.

²⁴ In 2012, energy poverty affected more than 54 million people in Europe, i.e., nearly 11% of the EU's population is in a situation where their households are not able to adequately heat their homes at an affordable cost. This problem affects all three countries under study, and it is particularly acute in the UK. See report commissioned by the EC, *Insight_E* (2015).

²⁵ For instance, the Committee concludes that an average household on a dual fuel tariff could be paying about £130 more to support decarbonisation in 2030 than today. The additional cost could be more than offset by the money households save by using less energy as a consequence of the policies.



However, carbon prices are almost fully passed-through to wholesale electricity prices (Fabra and Reguant, 2014; Sijm et al., 2006), leading to increased revenues for the new assets but also for the assets already in existence. Whereas the extra revenues might be needed to incentivise new investors, such revenues are not needed for the existing plants precisely because they already exist. Accordingly, carbon pricing creates windfall profits for the existing low-carbon plants that are ultimately paid for by consumers. These rents are making the energy transition unduly expensive for consumers. And yet, with only a few exceptions, regulators have done nothing to avoid it.²⁶

Free permit allocation is also a source of windfall profits for the pollutants (Fabra and Reguant, 2014; Sijm et al., 2006),²⁷ as the pass-through of carbon prices to electricity prices already compensates them for the extra cost. Regulators have already taken care of these windfall profits earned by pollutants by mandating the use of permit auctions. The revenues obtained through these auctions should be employed to finance the costs of the Energy Transition. However, the windfalls for the non-pollutants remain simply because they have to buy no permits. These have implied a wealth transfer from consumers to operators without delivering environmental benefits.²⁸

Another example illustrates the second issue. In Germany, energy intensive customers have received exemptions for the renewable energy surcharge, which has in turn led to a rapid increase in the surcharges paid by households and small businesses: in 2014, the surcharge paid by non-privileged consumers was more than 100 times the surcharge paid by privileged consumers (5.28 c/KWh versus 0.05 c/KWh).

This asymmetry is even more noticeable if one takes into account the price-depressing effect of renewables. Indeed, wind and solar PV production in Germany have reduced spot market prices by 6€/MWh in 2010 and by 10€/MWh in 2012, with an estimated reduction of 14-16€/MWh by 2016

²⁶ Following the recommendations of the Spanish energy regulator, the government taxed the windfall profits created by the pass-through of carbon prices to electricity prices (from 2006 to 2009, these amounted to approximately 2.800M€). In October 2013, the European Union's Court of Justice ruled that the claw-back did not violate European Law. The regulator's proposal can be found here: http://www.cne.es/cne/doc/publicaciones/cne118_06.pdf and the ECJ's decision can be found here <http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:62011CJ0566>.

²⁷ For instance, Sijm et al. 2016 estimate that at a CO₂ price of 20€/t, ETS-induced windfall profits in the power sector of the Netherlands summed up to €300-600 mln per year, i.e., about €3-5 per MWh.

²⁸ It is important to note that the impact on market prices of increasing input prices is of very different nature as the effect of new regulations. When investors take investment decisions they face, for better or for worse, uncertainty over input costs and their impact on market prices. However, they do not (and should not) face regulatory uncertainty, for better or for worse, e.g. if a nuclear plant is shut down prematurely because of a regulatory decision, investors should be compensated for the windfall loss. For similar reasons, windfalls that arise because of regulatory decisions should not accrue to firms, as if that was the case, consumers would face a windfall loss. Accordingly, the clawback should not apply to installations that have come on line after 2005 when the emissions regulation was first implemented.



(Cludius et al., 2014). Thus, while energy intensive consumers have benefitted relatively more from reduced power prices, they have contributed disproportionately less to financing the costs of the renewables roll out.²⁹ This asymmetry will widen in the future as the increased weight in renewables further reduces spot market prices, thus enlarging the size of the surcharge to be paid by non-privileged consumers. Paradoxically, these measures might have been necessary to avoid opposition to the Energy Transition by energy-intensive consumers. However, by imposing a disproportionately large share of the costs on households and small businesses, it has also given rise to tensions.

Distributional issues have also been contentious in the UK, where cost increases have fallen more heavily on poorer households. This has been partly offset by various programmes (such as Cold Weather and Winter Fuel Payments, and energy efficiency measures). However, these have not always been well-targeted and as a result there has been a transfer from those who do not benefit (many of whom are poor) to those who do benefit (some of whom are rich).

Affordability is certainly a necessary condition to obtain social support for the policy changes. However, consumers' support also depends on other factors. The German case offers a paramount example as, despite the price increases, the *Energiewende* has received broad public support. While this can be partly explained by the intrinsic values of German society, the involvement of new players in the Energy Transition (including households, farmers and small and medium sized firms who have invested in renewable technologies) has certainly played a major role in securing broad support for climate policies. Over time, this broad economic participation has stabilised the policy arena for the Energy Transition and strengthened the robustness of the transition pathway.

4. The ETS has delivered a weak carbon price signal. Countries have had to strengthen the carbon signal by adding additional mechanisms.

With the creation in 2005 of the European Union's Emissions Trading System (EU ETS), Europe showed that it is possible to build up a carbon market that delivers a region-wide carbon price. However, with the economic crisis and the rapid expansion of renewables in the background, the EU ETS has delivered prices that are too low and too volatile to affect investment and production decisions in a meaningful way. Indeed, for the carbon price to have a substantial impact in the power sector, it has to stay above €30-40 per Ton. These figures are well above the ETS prices, which have remained under €10 on average, sometimes as low as €3. It is thus not surprising that, over this period, Europe has failed to reduce coal-fired generation. In fact, from 2011 to 2012, the weight of coal-fired generation has grown by 13%, gas-fired generation has dropped by 23%, and nuclear generation has declined by 2.8% (mainly due to the German nuclear phase-out decision). As

²⁹ Cludius et al. (2014) estimate a zero net effect for privileged consumers, i.e., the renewables roll out policy has not increased nor decreased the energy cost for the privileged consumers; in other words, the non-privileged consumers have fully paid for the cost of the policy.



a consequence, the carbon intensity in the power sector has increased. This suggests that the EU ETS has not been successful in minimising the costs of emissions reductions, failing to induce the exit of high-carbon technologies.

Given the weaknesses of the ETS, the UK introduced in 2011 a Carbon Price Floor to ensure that carbon prices moved on a trajectory that would make low carbon investments profitable. The Carbon Price Floor would start at £16/tonne in 2013, rising to £30/tonne in 2020, and projected to rise to £70/tonne by 2030 (all at 2009 prices). However, because of fears that it might adversely impact British competitiveness, political pressure quickly led the government to freeze the price floor at its early low level. Also, Germany has tried to pass a Climate Levy by which the most polluting installations would effectively face a marginal carbon price twice as high as the ETS price. However, the plan has failed due to political opposition. These two examples show that adopting carbon policies at the member state level can be politically challenging while being more distortive than a common policy at the EU level.

Despite its low prices, the ETS has provided some incentives for investment in R&D. Indeed, a study covering the first five years of operation of the EU ETS, comprising data on over 30 million firms across 23 countries, shows that carbon pricing had a significant impact on technological change. In particular, those firms subject to the emissions regulation increased low-carbon innovation by as much as 10%, while not crowding out patenting for other technologies. As a consequence, the ETS led to a nearly-1% increase in European low-carbon patenting as compared to a counterfactual scenario (Calel and Dechezleprêtre, 2015). Interestingly, permit allocation mechanisms have also had a significant effect on firms' incentives to innovate. Indeed, those sectors that are just below the thresholds required for free allocation are more innovative than those just above those thresholds (Martin et al., 2013).

Despite the overall importance of carbon pricing for innovation incentives, evidence from the power sector suggests that, given the low and volatile carbon prices, policies towards renewables, namely ROCs and FiTs, have been stronger drivers of innovation.³⁰

5. Renewable energies have played a prominent role in the Energy Transition. Their costs have gone down beyond expectations.

Renewables are playing a prominent role in the transition towards a low carbon economy. In Germany, renewables currently represent almost 30% of total electricity generation, and it is estimated that renewables will account for more than 50% by 2030. The current weight of renewables in the power sectors in the UK and France is much lower than in Germany. However, the weight of renewables is expected to increase significantly in the next decade as they both seek

³⁰A survey of this evidence can be found at Martin et al. (2014).



to comply with their EU commitments for 2020.³¹ Under all scenarios, renewables will become the main source of electricity generation in Europe by 2030, reaching up to 80-90% by 2050.

Renewables have also played a key role in addressing the *energy trilemma*. As reported by the European Commission, the EU's 2020 renewables target has resulted in around 388 Mt of avoided CO₂ emissions in 2013, leading to a reduction in the EU's demand for fossil fuels of 116 Mt. Further, this has boosted the EU's security of supply by reducing fossil-fuel import dependency. An on-going study by the European Commission estimates that €30 billion were saved in 2010 by not importing additional non-renewable fuel. This figure is to be compared with the €18.6 billion that were spent in 2010 on renewable support in the EU.

While the environmental benefits of renewable energy are clear, the role that renewable energy can play also depends on its cost effectiveness. Evidence shows that the more mature renewable technologies, such as on-shore wind and solar PV, are becoming increasingly competitive with respect to the fossil fuel alternatives. Indeed, during the last 20 years, these two technologies have achieved major cost reductions: the costs of generating electricity from wind have fallen 50% since 1990; similarly, the costs of solar PV have fallen by 80-90% since then. Forecasts of future costs indicate that the costs of these two technologies will keep on approaching the costs of the conventional energy sources (IRENA, 2014; IEA, 2015).³² The costs of the less mature renewable technologies (off-shore wind; wave power; solar thermal; geothermal energy or biomass) are still much higher. However, their future costs are also expected to fall as they benefit from R&D and learning externalities.

The following quote from a 2014 Ernst & Young report is illustrative of this trend: 'Investment cost estimates made in 2011 by the European Commission and the European Climate Foundation for renewable energy generation equipment, grids and storage, were overestimated...Several renewable energy solutions have accelerated their cost reduction trajectory beyond expectations, thus making the renewable energy pathway more attractive for Europe. This cost reduction has been so significant that the cost level for [photovoltaic] that was expected for 2050 in the ECF Roadmap 2050 has already been reached.'

The current remuneration of the more mature renewable energies is already capturing these cost reductions.³³ The recent capacity auction that was held in February 2015 in the UK cleared at prices

³¹ See the latest progress report published by the European Commission's on the achievement of the 2013/2014 interim renewable energy targets. Available at <http://ec.europa.eu/energy/en/topics/renewable-energy/progress-reports>

³² See also the report, 'In Sight: Unsubsidised UK Solar', which predicts that all three sectors of the UK solar market (ground-mount, commercial and domestic) will be able to compete without subsidy with traditional forms of energy within the next 10 years.

³³ It is important to note that the higher rates paid to the first round of renewable investments do not imply that those investments were inefficient or that they are now been overpaid. To the contrary, it would not



close to £70/MWh for both onshore wind and solar PV, with a 15 year guarantee.³⁴ In Germany, depending on plant size and location, onshore wind farms are remunerated at 70-100 €/MWh and solar PV plants are paid at 120-180€/MWh, with a 20 year guaranteed remuneration. In France, the FiTs for the last quarter of 2014 are at 68€/MWh for ground solar PV with a 20 year guarantee. For wind, the FIT is at 82€/MWh for the first 10 years and between 28€/MWh and 82€/MWh for the remaining 5 years.

6. The success of the early roll out of renewables rested on technology-specific Feed-in-Tariffs. However, the FIT system broadly failed to adjust the tariffs in line with the cost reductions, and in controlling total investment.

The success of the early roll out of renewables in Germany rested on technology-specific Feed-in-Tariffs (FiTs). The technology-specific focus has allowed some technologies, notably solar, to achieve cost reductions that would have been difficult to achieve under a fully technology neutral approach. Indeed, solar PV has experienced one of the fastest reductions in investment costs. Their costs are now close to the costs of wind even though in the early 2000s the costs of wind were much lower than those of solar PV.³⁵

The German approach also offered contracts of differing degrees of generosity to on-shore wind farms based on measured output in the first three years of operation. In contrast to the ROC system used in the UK (that paid the same price regardless of location), this reduced the rents in more profitable locations, thus reducing the cost to consumers of supporting renewables.

The FiT system used in Germany - and subsequently in France - contributed to creating regulatory certainty, as payments per MWh were fixed for sufficiently long periods (typically, 15 or 20 years). Furthermore, other features of the FiTs also contributed to their effectiveness: their simplicity, as they paid investors for metered output, and the fact that they do not make investors responsible for predicting and selling their output. This further contributed to encouraging participation of small investors (farmers, home-owners and small or medium-sized firms), which in turn led to a fragmentation of the market structure and allowed for broad societal support of the renewable rollout.

All this contributed to a rapid deployment of new installations. The early rollout triggered cost reductions, which in turn induced further deployment. However, cost reductions were faster than expected and the FiT system failed to adjust the tariffs for the new installations accordingly. Thus,

have been feasible to achieve the current lower rates without the learning externalities triggered by the first round of investments.

³⁴ Two solar projects were allocated at £50/MWh. However, they have been withdrawn a few days after the auction was held.

³⁵ This is confirmed by the seminal paper by Johnstone et al. (2010), which emphasizes that FiTs have played a major role in promoting innovation the early phases of the renewable energy rollout. Their analysis is conducted using patent data on a panel of 25 countries over the period 1978–2003.



some countries witnessed a boom in installations exceeding the initial objectives, which added financial pressure to the cost of the support schemes. To mitigate this, some countries – Germany and France, among them – introduced mechanisms to facilitate the adjustments of FiTs over time. In particular, they made tariffs dependent on the excess demand for FiTs in previous rounds as compared to the objectives. While this scheme has allowed for some degree of tariff adjustment, there are still some drawbacks: there are lags from one round to another, and it is not easy to choose the correct tariff digression without reliable information on the costs of deployment. Costs change quickly, and only investors know the actual investment costs.

There is an alternative way to allow tariffs to converge to the costs of renewables, namely, through the use of auctions. The experience with the use of auctions for renewables in the UK is very positive. The first auctions that were used in the UK back in the 1990s contributed to significant cost reductions. Similarly, the auction that was held last year for Contracts for Differences for renewables resulted in strike prices well below expectations. However, in both cases, experience shows that more emphasis should be put into the design of penalties for non-delivery.

7. Market arrangements have failed to promote efficient investments in generation capacity. Countries have tried to address this issue in an uncoordinated fashion.

In most member states, overinvestment in gas-fired plants followed by the rollout of renewables and the stagnation of demand, have given rise to an excess of generation capacity.³⁶ Indeed, several fossil fuel plants are operating at low utilisation rates while receiving low and volatile wholesale electricity markets. The UK is probably an exception in Europe as it is the only country in which the reliability index is tight. A distinguishing feature of the UK market was its reliance on a (truly) energy only market, which is probably at the heart of the investment problem. Indeed, the reserve capacity margin in the UK has been steadily going down since 2012, when it first fell below 10%.³⁷ In any event, both pieces of evidence demonstrate that investment decisions have been inefficient - either because there has been too much or too little investment.

As a consequence, several member states have adopted capacity mechanisms. The design of capacity mechanisms differs markedly across countries, despite the EC's attempts to harmonise

³⁶ It is not a contradiction to push for more renewables given the current degree of excess capacity. Depending on the state of the technology, the average costs of new investments in renewables might be lower than the marginal costs of existing assets (particularly so, in a scenario of high carbon prices). For instance, with the variable costs of CCGTs at 60€/MWh, a 50€/ton carbon price would drive the electricity market price up to 75-80€/MWh, a figure which is in line with the strike prices agreed in the last renewable capacity tender in the UK. Hence, even if there is over-capacity in some countries, it might still be efficient to keep on investing in low carbon alternatives.

³⁷ France might also face generation adequacy problems in the (relatively) short run, as a consequence of de-commissioning of conventional plants that do not meet environmental requirements.



these rules.³⁸ DG Competition has also been critical of the use of capacity payments, arguing that they often have more to do with compensating generators in difficult financial conditions rather than with guaranteeing security of supply at least cost. Indeed, DG COMP has launched a sector inquiry into capacity mechanisms to assess whether these are compatible with State Aid regulations.³⁹

Experience with the use of these diverse market designs is too brief to derive relevant lessons. However, it seems clear that the use of different regulatory solutions to address a problem that spreads beyond national borders creates inefficiencies, and leads to tensions among neighbouring countries.

8. R&D has played an important role. Both the climate policies as well as the increase in public expenditure have been important drivers of R&D.

One of the successes of the *Energiewende* regards R&D and innovation. Although it is not straightforward to disentangle the causal impacts of climate policies from the effect of other confounding factors, it is widely recognised that the implementation of climate policies in Germany triggered major technological breakthroughs across several fields (basic technologies, system and sector integration, demand flexibility, storage, smart grids, etc.) as well as cost reductions (particularly so in onshore wind generation, solar photovoltaics and parts of micro CHP).⁴⁰ The research sector has also witnessed the emergence of industrial start-ups as major industrial players, who have in turn contributed to fragmenting the market structure.

Public expenditure on energy related R&D has been very relevant in Germany, where public funding for research on energy efficiency, renewable energies, and energy infrastructure (including storage) rose from €400m in 2006 to more than €800m in 2013. Major R&D efforts have also been undertaken by the industry as a consequence of the incentives provided for the demonstration and early roll-out of renewables. Last, but not least, the public and political support for the *Energiewende* has provided a further stimulus to energy research by creating a supportive social environment.

The UK provides another interesting example on how R&D in low carbon technologies can be promoted, particularly so when it is undertaken by regulated firms subject to price-cap regulation, as has traditionally been the case for energy network operators. If the parameters of the RPI-x regulation are too stringent, e.g. if the price control periods are too short, firms' incentives to innovate are weakened as cost reductions achieved through R&D are taken back shortly after firms achieve them. To mitigate this, the price control periods have been extended from five to eight

³⁸ See the Commission's communication, Delivering the internal electricity market and making the most of public intervention – C(2013).

³⁹ http://ec.europa.eu/competition/sectors/energy/state_aid_to_secure_electricity_supply_en.html.

⁴⁰ See Johnstone et al. (2010) for evidence on the impact of climate policies patent activity.



years, allowing utilities to keep innovation gains for a longer period. Furthermore, the energy regulator Ofgem has created a Low Carbon Network Fund (LCNF) with a £500 million budget to award in annual competitions to projects capable of reducing the carbon intensity of the networks and/or facilitating the connection of low-carbon technologies to the grid.

9. Efforts in promoting energy efficient have been weak. There is mixed evidence concerning the potential of some of these policies to reduce energy consumption.

Investments in energy efficiency can potentially address all three objectives of the *energy trilemma*: energy supplies have to be sustainable, affordable and secure. Indeed, energy savings contribute to security of supply by reducing import dependency: estimates by the European Commission⁴¹ show that a 1% increase in energy savings could diminish gas imports by 2.6%. Energy efficiency also addresses the affordability objective as it allows consumers to save money by reducing the amount of energy they use, even though they often require costly investments. Last, but not least, energy savings help to alleviate environmental concerns through their contribution to cutting greenhouse gas emissions.

Europe has set ambitious objectives in terms of energy efficiency, and some countries have put in place policies to help achieve those targets. The overall EU-wide objective is to improve energy efficiency by 27% by 2030 with respect to 1990 levels. Germany has set the goal of reducing primary energy consumption 20% by 2020, and 50% by 2050, as compared with 2008. France has also an ambitious energy consumption objective as it has committed to reducing it by 50% with respect to 2012 by 2050.

Despite the important achievement towards decarbonisation and renewable energy rollout, the area where Europe lags behind is energy efficiency. The evidence on the potential for energy efficiency investments to deliver significant cost and energy savings is mixed. First, there is the so-called '**rebound effect**': after efficiency upgrades, consumers adjust their behaviours and consume more energy. This is in turn triggered by the combination of two effects: a price effect –efficiency upgrades reduce the per unit cost of energy-intensive goods - and an income effect –energy savings free wealth that can be used to buy other goods that also consume energy. Even though the rebound is likely to significantly reduce the net savings from energy efficiency improvements, the existing evidence points at a low likelihood of backfire. However, the International Energy Agency (IEA, 2014) has recently concluded that the rebound effect could reach as high as 60%.⁴² This does not mean that efforts to improve energy efficiency should be abandoned. Rather, it means that

⁴¹See the EC's Communication on Energy Efficiency and its contribution to energy security and the 2030 Framework for climate and energy policy, July 2014.

⁴² However, there is mixed evidence about the magnitude of the rebound effect. Indeed, it is widely acknowledged that estimating the rebound effect is extraordinarily difficult. See Gillingham et al. 2015.



more efforts should be devoted to mitigate⁴³ and/or compensate for the rebound effect (either through further investments in low carbon assets or through measures to promote demand response and savings).

Second, there is the so-called **energy-efficiency gap**, i.e., consumers and firms seem to fail in undertaking investments in energy efficiency that would increase utility or profits.⁴⁴ There are several potential reasons for this gap, including (i) market failures (innovation externalities, information issues, capital market imperfections, etc.), (ii) behavioural biases and (iii) modelling flaws. For instance, one of the most important factors hindering investments in energy efficient technologies is limited access to capital. This issue is particularly critical given the high upfront costs and the relatively long payback periods of these investments. At the residential level, there is scope for energy efficiency improvements in the form of small and fragmented investments. However, it is also at the residential level where market failures tend to be more acute, and thus, where policy could have stronger impacts.

Having said this, one cannot disregard that, given the current state of the technology, one potential cause for the energy-efficiency gap is a miscalculation: the costs of efficiency upgrades have been underestimated and/or the potential energy savings have been overestimated. According to this, consumers would not be investing in energy efficiency simply because it does not pay back.

A recently conducted randomised controlled trial of more than 30,000 households shows that residential energy efficiency investments may not deliver the expected gains (Fowlie et al., 2015). Participating low-income households were freely provided with about \$5,000 worth of energy efficiency upgrades. These allowed households to reduce their energy consumption by about 10 to 20% each month, translating into \$2,400 in savings over the lifetime of the upgrades. These savings are modest, to the extent that they only cover half of the upgrade costs, and less than half of expected energy savings. While more evidence is still needed, these results show that the net returns on energy efficiency investments might be lower than expected. More research in this area is needed to disentangle whether a true energy efficiency gap exists, and if so, how it can be efficiently addressed. Again, rather than abandoning the efforts to promote investments in energy efficiency, it is paramount to understand why some measures deliver satisfactory results while others don't.

⁴³ For instance, a report by the German Energy Agency (DENA) indicates that after an empirical study on deep retrofitted buildings, the rebound effect reached only 6% on average. This was mainly due to ongoing technical support to improve consumers' awareness. Indeed, consumer awareness through e.g. eco-design and labelling can play a major role in reducing emissions. It has been estimated that the Ecodesign Directive will save 400 million tonnes of carbon dioxide emissions within the EU, comparable to the Emissions Trading System's (ETS) anticipated contribution to carbon dioxide reductions in 2020. See http://ec.europa.eu/enterprise/magazine/articles/sustainable-industry-innovation/article_11045_en.htm

⁴⁴ The seminal paper on this topic is Jaffe and Stavins (1992). For recent evidence, see Allcott and Greenstone (2012).



1.5 Policy recommendations: towards a low carbon power sector

In this section we derive policy recommendations aimed at facilitating the Energy Transition at least cost. Some of them are directly linked to the experience in Germany, the UK and France; others derive more broadly from the economics of energy and climate change:

1. National governments should commit to supporting the Energy Transition without further delay.
2. More emphasis should be put into strengthening cooperation between countries. In this sense, market integration and policy convergence across countries should be promoted.
3. The Energy Transition has to be affordable. Distributional issues (between consumer groups, as well as between firms and consumers) should have a central role when designing and implementing policy.
4. Carbon pricing should be strengthened as it is crucial for the Energy Transition. However, it might not be enough, particularly so in the medium to long run.
5. Renewables must play a prominent role, for environmental as well as for economic reasons.
6. For large renewable installations, there should be a shift towards the use of auctions for long-term contracts. For small installations, the FiT system should be retained. Renewables should not be made responsible for balancing and marketing their electricity.
7. Auctions for long-term contracts should be used to promote investments in back up capacity and plant flexibility.
8. Research and development must be promoted. The impact of regulatory policies on market structure and on the incentives to innovate should be carefully assessed when designing policy.
9. Regulatory stability is crucial for investors' confidence. This is not in contradiction with the need to have rules that evolve during the transition period as long as the course of changes is clearly set and announced in advance.

Below, we provide a more detailed discussion of the recommendations outlined above.

1. National governments should commit to supporting the Energy Transition without further delay

It is urgent to put in place policies aimed at drastically cutting greenhouse gas emissions. Otherwise, atmospheric concentrations of carbon dioxide will keep on rising above 400 ppm, thus leading to an increase in global warming above and beyond 2°C.

The urgent need to implement decarbonisation policies applies to all sectors involved in the Energy Transition, but particularly so to the power sector. Since power plants are long-lived assets, any investment today that does not contribute towards decarbonisation can lock us out of a low-carbon future. The effects would spread across other sectors, as delays in the decarbonisation of the



power sector would further delay the decarbonisation of the rest of the economy. Decarbonisation of the whole economy would simply be unfeasible without a deep decarbonisation of the power sector.

2. More emphasis should be put into strengthening cooperation between countries. In this sense, market integration and policy convergence across countries should be promoted.

The fight against climate change creates a global public good. In the long run, all countries benefit from the reduction in global warming. However, in the short run, there are powerful incentives to leave the burden of reducing greenhouse gas emissions to others. If all countries do the same, climate change action will not take place. Using Game Theory jargon, the fight against climate change leaves countries facing a prisoner's dilemma: they all want to free-ride on the efforts of others, but if they all do so, efforts will not be enough. As is well known, the efficient solution to this dilemma can only be achieved through cooperation. Simply, the Energy Transition cannot be achieved by countries operating on their own.

In Europe, the completion of the internal energy market should be seen as a key instrument to achieve closer coordination among Member States. Indeed, the recently published Energy Union package puts the internal market at the core of its climate and energy policies. The strengthening of the internal energy market through increased interconnection contributes to the environmental agenda. A more closely-linked electricity network facilitates the integration of renewables into the electricity system by reducing the amount of back-up capacity necessary to compensate for their intermittency.

In particular, market integration would allow for a pooling of dispatchable resources across European countries. Since electricity demand net of the production of intermittent resources is not perfectly correlated across European countries, the overall net load is flatter at the EU level than at the level of the individual member states. This has two important implications. First, the peak of net demand in an integrated system is lower than the sum of the peaks at the individual member states. Thus, market integration would reduce the cost of keeping back-up capacity to meet peak load whenever there is not enough wind or sun to meet total demand. Similarly, the minimum load in an integrated system is higher than the sum of the minimum loads at the individual member states. Since overproduction occurs when renewable energy production peaks at times of low demand, market integration also enables a better use of renewable resources.

Market integration will become increasingly important as the weight of renewables increases as these two issues – the need to resort to back-up capacity and the potential for over-production – will become more relevant.

The need to harmonise market rules as a condition for market integration should not be over-emphasised. While some degree of harmonisation is important, it should not come at the cost of imposing solutions which might be suitable for some but not for all countries. Participation and shared values might be more important than full harmonisation, and these cannot be achieved if



certain regulatory solutions are imposed on the countries. Furthermore, countries are at different stages of the decarbonisation process, which implies that policy convergence with some degree of flexibility, rather than full harmonisation, might be preferable.

Despite all of the above, it is essential to acknowledge that market integration might imply some rebalancing across Europe, with consumers in low energy price countries facing higher prices from interconnections which would result in national producers exporting electricity to high price countries. To obtain support for market integration from all Member States, regulatory measures should be put in place to mitigate the negative impacts that market integration might have on some consumers.

3. The Energy Transition has to be affordable. Distributional issues (between consumer groups, as well as between firms and consumers) should have a central role when designing and implementing policy.

There is a clear tension between sustainability and affordability objectives. If the path towards a low carbon economy is not affordable, it will simply not get the necessary public and political support that is needed to address such a fundamental transformation of the energy system. In order to obtain the necessary public support, governments and regulators should stress that today's investments will pay back as they will allow for cheaper energy supplies in the medium to long term. Indeed, countries stand to gain more than they would lose in economic terms from almost all of the actions needed to tackle climate change (Green, 2015).

It is paramount not to make the energy transition unduly expensive for consumers. This is a matter of equity, but it is also a matter of efficiency: if the costs for consumers are too high, they will not support the energy transition policies. Therefore, these policies will not be implemented even if they are efficient overall.

In turn, this suggests three important conclusions:

- Regulators should avoid a misallocation of risks that creates inefficient costs;
- Regulators should avoid rents being created through this long process; and
- Regulators should avoid a scenario where certain consumers bear an unfair share of the costs.

The first two issues point to the importance of devising market arrangements that (i) minimise total costs through an efficient risk allocation, (ii) avoid overpaying certain generation technologies, and (iii) reduce the scope for market power. We turn to these issues at the end of this section. The third issue suggests that the extent of the exemptions given to privileged consumers should be reassessed.



4. Carbon pricing should be strengthened as it is crucial for the Energy Transition. However, it might not be enough, particularly so in the medium to long run.

Without carbon pricing, the negative externality created by carbon emissions remains unpriced. Putting a price on carbon is thus a necessary condition for efficiency as it encourages polluters to take all available steps to reduce emissions that cost less than that carbon price. In this way, emissions reductions are achieved in a least cost way.

The experience so far does not invalidate the importance of carbon pricing, but rather suggests that more should be done in order to strengthen the carbon price signal. For this, it is paramount to remove the excess of allowances from the market, to tighten the cap, and to widen the range of sectors subject to the emissions regulation. The creation of a 'market stability reserve' should allow for more stable carbon prices, as any surplus or deficit of allowances above an upper end or below a lower end will be placed in the reserve or released from it, respectively. However, the efficacy of this reform is yet to be corroborated in practice. In particular, the ETS will have to have enough flexibility to absorb the likely excess of allowances as ambitious levels of renewables and energy efficiency will keep on reducing the overall demand for permits.

In any event, it has to be acknowledged that the efficacy of carbon pricing to induce changes in production and investment patterns in the power sector will be undermined as we move closer to the objective of an almost carbon-free power sector. Indeed, under a high penetration of renewables, the number of hours during which fossil plants will set the market price will go down, and thus the carbon price will no longer be passed-through to the electricity price. Under this scenario, carbon prices will not be enough to generate the flow of revenues that investments in low-carbon assets require. Given that low-carbon assets are long-lived, investors today might already be internalising this future trend, to the detriment of today's investments.

5. Renewables must play a prominent role in the Energy Transition, for environmental as well as for economic reasons.

The Energy Transition cannot be accomplished without a prominent role for renewables. First and foremost, renewable energies have zero emissions and hence are a key ingredient for decarbonisation. And second, they contribute to making the Energy Transition affordable. As argued above, renewables have experienced very significant cost reductions, which are already being passed on to consumers through lower tariffs for the new investments. Forecasts of future costs indicate that even the more mature renewable technologies will keep on reducing their costs further, albeit at a slower pace.

Nevertheless, renewables are not the only low carbon option available. Nuclear and Carbon Capture and Storage (CCS) also provide zero-carbon alternatives. How do renewables compare against these other options? The new CfDs in the UK power sector provide meaningful figures to



shed light on this question. The new nuclear reactor that will be built in the UK (Hinkley Point C) will receive a Contract for Differences with a £92.50/MWh strike price during 20 years.⁴⁵ This is to be compared with the £70/MWh strike prices that on average have been allocated to new wind and solar farms in the last auction in the UK.

However, for the cost comparison to be meaningful, one also has to add the costs of back-up capacity needed to guarantee security of supply in a renewable-based power sector. The German think-tank Agora has conducted this exercise by comparing the current FiTs in Germany with the agreed strike price for new nuclear in the UK and the current cost estimates for CCS, neglecting future technology cost reductions in any of these four technologies. They conclude that the generation costs of new wind and solar is 50% lower than those of new nuclear and CCS, and 20% lower when the renewable option is supplemented with back up capacity of natural gas-fired plants (Agora, 2014).

Having said this, the nuclear industry is working on improvements that target cost reductions in the construction of the new generation nuclear reactors, like the one to be built in Hinkley Point. Similarly, CCS is at the beginning of its learning curve. Therefore, more evidence will be needed to assess the economic performance of these alternatives in the future, as the outcomes of the learning curves are still uncertain.⁴⁶ However, while the reductions in the cost of renewables are generally clear, major technological breakthroughs are still needed to achieve costs reductions in the cases of nuclear and CCS before they can be considered as possible commercially viable options.

6. For large renewable installations, there should be a shift towards the use of auctions of long-term contracts. For small installations, the FiT system should be retained. Renewables should not be made responsible for balancing and marketing their electricity.

Given the key role that renewables play in the Energy Transition, what should be the policy towards their deployment?

Long-term Contracts for Differences:

Electricity spot markets expose renewables to excessive risks. Renewables involve high upfront capital costs, and low and constant variable costs which are uncorrelated with the wholesale market prices (the latter depend on the prices of fossil fuels and carbon prices). Hence, the profit margins of non-fossil generation are too low and volatile, thus leading to inefficient risk *premia*. Furthermore, investors do not take investment decisions based on the current profitability of

⁴⁵ Or £89.50/MWh if the planned new nuclear power plant at Sizewell goes ahead.

⁴⁶ The existing literature acknowledges the difficulties in estimating learning curves, revealing wide ranges in the learning rates of the various technologies. Most of the results reveal larger learning rates are for renewable energy sources (especially for wind and PV), smaller learning rates for fossil fuel plants, and mostly negative rates for existing nuclear plants. See Rubin et al. (2014) for a survey of this literature.



existing assets, but rather about the derivative, i.e., about the effect that new investments will have on the profitability of the old and the new assets. Hence, the price depressing effect of renewables implies an additional barrier to the deployment of renewables when their remuneration is based on spot prices. The higher the weight of renewables in the energy mix, the more important this effect will be, given that renewables will deliver the full load in an increasing number of hours over the year.

In this scenario, long-term Contracts for Differences (CfD) reduce the risk of investments by guaranteeing investors a fixed price, regardless of movements in spot market prices. In turn, this lowers the cost of capital, ultimately benefitting consumers.

Tenders for renewables for large installations:

The challenge with CfDs is to determine the correct strike price. Competition through auctions provides virtually the only means by which strike prices can converge to the investors' actual costs.

Across all EU member states, we will see a shift towards the use of **tenders for renewables**, which the recent state aid guidelines have made compulsory from 2017 onwards. While the use of auctions in the UK offers only a brief experience, their approach seems promising in the light of the cost reductions they have achieved. Unlike the previous failures when setting FiTs, the use of auctions will push down the prices paid by consumers for renewables. Furthermore, they will allow for a tighter control of the amounts to be invested, avoiding excessive investments.

An important issue regarding the design of auctions is whether they can efficiently incorporate locational signals. Concentrating renewable resources in some locations might lead to excess supply to a locally constrained distribution network in sunny or windy hours. As a result, such investments are worth less than investments in unconstrained zones. Hence, renewables should be encouraged to locate where they are most valuable, i.e., where the correlations with other existing renewable installations is lower (i.e. farther away and/or on different networks). Uniform prices over time and space don't induce correct locational signals. Locational grid charges might help towards that end, but they lack credibility as they can be reset during the lifetime of the investment. For this reasons, it is preferable that contracts incorporate such location signals. One way to do it is to adjust the bids of the competing investments according to the costs imposed on the system as reflected by their potential location.

Regulators and competition policy authorities have important roles to play in (i) designing the auction rules and the contracts to be auctioned-off (which duration, which technologies, which requirements) and in (ii) making sure bidders behave competitively. Contentious issues in the design of auctions are the penalties for non-delivery so as to avoid winners walking away from the contract if, ex-post, they find the project unprofitable. The EU should study the possibility of conducting EU-wide auctions in order to achieve more efficient location decisions and induce more competitive pressure, while creating sufficiently large demand-pull to drive down production costs.



Feed-in-Tariffs for small installations:

As we have learnt from the German experience, the participation of small investors in the renewables roll out contributes to fragmenting the market structure and allows for broader societal support for the renewable rollout. For these investors, participation in auctions can be cumbersome. Hence, for **small installations**, standard FiTs should be used.⁴⁷ Tariffs can be made a function of the prices in the auctions for large installations– with some adjustment due to scale differences - and they can also be adjusted according to excess demand in previous rounds. Regulators should also put in place mechanisms for volume control, so as to avoid excessive investments.

Renewables should not be made responsible for marketing and balancing their energy:

Costs to consumers could be further reduced if the authorities re-assessed the use of market solutions for the **marketing and balancing of renewable energy**. It is widely acknowledged that efficiency requires risk to be allocated to less risk-averse agents with the capacity to manage/avoid risk. Different regulatory instruments have different consequences in terms of risk allocation. For instance, under the classic Feed-in-Tariff solution, the investor is paid on metered output at the agreed price, but keeps the production risk as weather conditions are uncertain. Under the current CfDs, there is little price risk, but investors are responsible for balancing the unpredictable wind or solar output. In practice, most independent renewables developers on CfDs shift balancing risk by signing FiTs with aggregators, at a discount of 10-15% of the expected strike price. These *premia* are eventually paid for by consumers, as they are passed on to the strike prices that are auctioned off.

Since there is little investors can do to avoid such risk, it would be more efficient to instruct the System Operator to offer the same risk transfer at a lower cost, as the System Operator is best placed to predict total renewable production and manage system balancing. Hence, the risk allocation embodied in CfDs could substantially raise the support cost of renewables with no clear efficiency benefits. The incentives induced when facing renewable installations with the wholesale market price and balancing risks are unclear, as the production of renewable resources is almost fully exogenous to the investors' decisions. This is the reflection of a standard Principal-Agent trade-off between incentives and risk.

Furthermore, larger companies can manage their whole portfolio and hence they can self-balance better than smaller merchant renewable investors. Thus, making renewables responsible for balancing their energy introduces a barrier of entry for smaller players, which have proved so important in fostering the Energy Transition in Europe. One option that could be explored is

⁴⁷ If this asymmetric regulation is to be implemented, it is important to avoid strategic behaviour by the investors, who might decide to split large projects into smaller pieces. There are easy ways to avoid this, e.g. through the definition of what constitutes an installation.



whether it would make sense to face big players with balancing responsibilities but not the smaller ones. However, here again one would face the trade-off between incentives and risk, though in the case of bigger players this trade-off is less acute.

Technology-specific focus:

A contentious issue is whether all renewable technologies should receive the same strike price (technology-neutral approach) or whether differences in the state of the technology rather suggest the need to treat them differently (technology-specific approach).

Several reasons recommend adopting a technology-specific approach, at least in the short to medium run:

- (i) Under a fully technology neutral approach, investors pick the cheap technology today, but this need not be the most efficient one in the long run.
- (ii) Putting different technologies in competition at the same auction might give rise to excessive rents to the low cost one.
- (iii) Given the uncertainties and challenges associated with the individual technologies, developing a portfolio of renewable technologies serves as a hedge.
- (iv) Some of these technologies serve complimentary roles; e.g. solar production fades down at sunset while the wind blows predominantly at night.

This does not mean that a technology-specific approach should always be adopted. Since the learning curve depicts decreasing returns, mature technologies create much weaker learning effects. Furthermore, as their costs converge, the rents that the low cost technologies would obtain under a technology neutral mechanism would diminish. Hence, arguments (i) and (ii) above in favour of a technology-specific support become weaker as technologies approach maturity- even though arguments (iii) and (iv) remain valid. In the long run, the aim is to create a level playing field where all generators can compete on an equal footing to ensure that decarbonisation objectives are achieved at the lowest cost.

For this purpose, it is important to have the timing right: ceasing technology-specific support prematurely would endanger the learning externalities, which are at the root of the future cost reductions. Even though the EU supports a technology neutral approach, the EEAG leaves ample ambiguity for regulators to decide whether to employ technology specific policies. This flexibility should be used wisely by the member states.

7. Auctions for long-term contracts should also be used to promote investments in back up capacity and plant flexibility.

A large part of the discussion above regarding renewables also applies to the back-up capacity. Theory and practice point to a market failure in the provision of back-up capacity: the public good features of security of supply coupled with the existence of price caps result in a *missing money* problem, which in turn leads to underinvestment (Joskow, 2006). Furthermore, owners of back up plants face excessive risk given that they operate during a small and uncertain number of hours.



Just as in the case of renewables, their production can be broadly considered to be exogenous as they have to operate whenever demand exceeds renewable production, both of which are random.

Since the market fails, the regulator has to step in to determine the amount of back-up capacity that has to be made available, as well as to put in place mechanisms to make sure that firms have incentives to do so. Just as with renewables, the solution could come through competition for long-term contracts referenced to a liquid spot market. In both cases, there should be a shift from competition in the market to competition for the market as the focus moves from short-term production decisions to long-run investment decisions. Clearly, to the extent that the demand side (e.g. through load management and load curtailment by the industry) can offer similar services to balance the system, it should be allowed to compete for such contracts.

If the market is governed by **competition for long-term contracts**, there would be no need to introduce additional capacity markets. Or rather, competition for long-term contracts is a capacity market in itself (though much simpler than decentralised capacity markets, as the one which is about to be introduced in France). The stream of revenues needed to provide investment incentives would already be embodied in those contracts.

The focus on capacity does not mean that energy markets should cease to exist. On the contrary, liquidity of such markets is paramount for productive efficiency. However, the bulk of the revenue stream for investors would be determined at the auctions for long-term contracts. Furthermore, since most generators would be subject to CfDs, their incentives to exercise market power in the energy market will be greatly diminished.

Just as in the case of renewables, the regulator might be concerned not only about the amount of back up capacity, but also about its type. Flexibility is increasingly needed to cope with the intermittency of renewable resources,⁴⁸ and different plants differ in their degrees of flexibility (because they might have different minimum loads and start-up times).⁴⁹ Hence, this might justify the regulator favouring more flexible resources, or only allowing flexible resources to compete in the auctions if the most pressing problem regards flexibility.

Albeit at a smaller scale, the combination of smart meters and real time pricing can add demand flexibility from households. The deployment of automated systems that would, for example, allow the turning on and off of homes appliances as a function of wholesale electricity prices or following

⁴⁸ The production of renewable resources varies greatly due to fluctuations in the availability of sun and wind. Sometimes, there are sudden drops in renewable production that coincide with sharp increases in demand. This occurs at sunset, when solar production drops to zero while electricity demand ramps up.

⁴⁹ Fossil fuel plants such as coal and gas-fired plants, Combined Heat and Power (CHP) and biomass plants are an important source of flexibility, as they can be ramped up and down within few minutes. Hydro production and pumped storage are also an important source of flexibility, but they are not available or they are not sufficiently abundant in all countries.



the instructions of the System Operator, will strengthen the potential response of household demand thus providing a true source of flexibility. The use of the electric vehicle will also strengthen the possibilities for households to provide demand response. Even though the potential for demand response from households is yet to be seen in practice, more resources should be devoted to exploit its full potential.

8. Research and development must keep on playing a key role in the Energy Transition. The impact of regulatory policies on market structure and the incentives to innovate should be carefully assessed when designing policy.

In the power sector, the energy transition implies a shift to innovative and future-proof technologies. This can only be achieved if R&D allows for the discovery of new low-carbon technologies, for the improvement of existing ones, and for the reduction of their costs. Without R&D, the Energy Transition would be technologically unfeasible, or its costs would simply be too high to make it happen.

Regulation has a clear impact on R&D, both directly through the provision of funds and access to capital for innovations, and indirectly through the demand pull effects provided by low carbon policies. Indeed, expectations about future demand for renewable technologies or energy efficient investments increase the incentives to engage in R&D efforts by enlarging the payoff to successful innovators. Carbon pricing also has important effects on R&D efforts: as it makes electricity generation from unabated fossil fuel plants costly, it provides incentives to reduce those plants' emissions rates through retrofitting, through the use of scrubbers, or through improved carbon capture and storage.

All this suggests that those policies that directly or indirectly affect R&D incentives should be assessed and strengthened where needed. In this sense, there is a clear case for strengthening the carbon price signal.

The positive experiences regarding R&D in low carbon technologies should not stop policy from moving forward in this area. While it is true that the initial phase of the energy transition has been conducive to innovation, it is not guaranteed that the future phases will remain so. As the energy transition evolves, the market structure and the business models will change, and so will the regulatory options. Their implications on innovation incentives are still unclear. For instance, if too much focus is put on a technology neutral approach, what will be the impact on innovation efforts in the less mature technologies? Similarly, if auctions are used to allocate new renewable projects, will this create barriers of entry for the small innovative start-ups and thus dampen their innovative potential? In sum, the new regulatory environment might create new challenges with regard to innovation. For the Energy Transition to keep on delivering break-through innovations it is paramount to make sure that resources and incentives are still in place to make innovation possible.



9. Regulatory stability is crucial for the Energy Transition. This is not in contradiction with the need to have rules that evolve during the transition period as long as the course of changes is clearly set and announced in advance.

Low carbon investments are capital intensive and thus require regulatory stability. Otherwise the fear of hold-up will deter investments from taking place, or will at least add risk *premia* to the costs of investments. Some regulatory instruments provide more perceived regulatory stability than others, and so they should be given priority. For instance, FiTs have been shown to be too sensitive to political intervention. In some countries, FiTs for renewables have been decreased in a retroactive manner (e.g. Spain) or ROCs have been stopped earlier than expected (e.g. the UK), undermining investors' confidence. The effects spread across EU borders as investors perceive the EC is compliant with those retroactive measures. In contrast, regulatory uncertainty is much lower if payments to renewables are implemented through CfDs given that these provide stronger contractual rights and obligations to both parties. Indeed, this has been one of the reasons why the UK set up a CfD Counterparty as a Government owned limited-liability company.

It is also crucial to give certainty to investors by defining a clear course well beyond 2020. This can be achieved through interim targets and multiannual plans on the amount of renewable capacity and back-up that is going to be installed. Some degree of flexibility should be left, as the regulator might want to adjust the plans to the evolution of costs and demand.

On the contrary, the use of instruments that add regulatory uncertainty should be avoided. For instance, the EU is currently investigating whether the support schemes for renewables in some EU member states constitute incompatible State Aid. It makes sense that the EC reviews payment schemes ex-ante, before they are put in place. However, ex-post assessments create regulatory uncertainty thus adding further costs to the Energy Transition.

1.6 Concluding Remarks

The regulatory experiences in Germany, the UK and France provide relevant lessons for the Energy Transition in Europe, and elsewhere. The goal is challenging, but the rewards can be large. First and foremost, the transition to a low carbon economy is a necessary condition to avoid dangerous climate change. But the benefits will also go beyond those that are purely environmental, as the deep transformations embodied in the Energy Transition offer opportunities for growth in innovation-intensive and high value-added activities.

The power sector is a cornerstone of the Energy Transition given its unique potential to incorporate low carbon energy resources into the whole economy. However, to facilitate the Energy Transition in the power sector, the current electricity market arrangements have to be redesigned. Which revenue streams would the current market arrangements deliver when low carbon assets – with very low marginal costs – cover demand during an increasing number of hours? How will environmental externalities be addressed in the power market when carbon prices will no longer



be passed through to electricity prices? What kind of competition is probable in these circumstances? If prices in wholesale markets remain low, what would be the impact on energy efficiency and how could it be enhanced? And will be the incentives to invest in back-up capacity that will rarely be used, be preserved?

Back in 2010, the diagnosis underlying the UK Electricity Market Reform was clear: “the unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency and the closure of ageing power stations has combined to cast reasonable doubt over whether the current energy arrangements will deliver secure and sustainable energy supplies.” Despite differences across countries, this statement applies broadly beyond the UK.

Some of the reforms implemented in Germany, the UK and France pave the way towards sustainable, secure and affordable energy supplies. Their experience makes us believe that a future-proof electricity market will have to rest on three pillars:

- Competition *in* the market should be progressively replaced by competition *for* the market, i.e., through capacity tenders run by (or on behalf) of regulators;
- Long-term Contracts for Differences for renewables and for back-up capacity, referenced to the spot energy market price, should be used to de-risk investments, and
- A liquid wholesale energy market should be preserved.

The road ahead is not straight. Ongoing efforts will have to be devoted to identifying the least cost means of avoiding climate change, and the contribution of the power sector towards this end.



3. Case Study 1: The Energy Transition in Germany, by Felix Christian Matthes

3.1 History, objectives and targets of the energy transition in Germany

The energy and the electricity systems have been subject to a wide variety of changes during the last hundred years. In contrast to this more or less steady change, the energy transition can be understood as a politically driven process of structural changes in the energy system. The special quality of the energy transition results from the combination of political drivers and structural change. In the history of the (German) energy system there have been strong political interventions (e.g. the support of the coal industry, phase-in of nuclear power) and essentially market-driven structural changes (e.g. the phase-in of long-distance electricity transmission and its implication for the patterns of power generation) but they have rarely occurred in combination.

In this sense energy transition has been a part of the German energy debate since 1980 when Öko-Institut published its book 'Energiewende: Growth and Prosperity without Oil and Uranium' (Krause et al. 1980). It constituted a minority position in the energy policy discourse of the time but quickly emerged as an essential element of the debate. This was especially true after the policy-driven shift from an oil and nuclear-based system towards a system characterised by energy efficiency, renewable energy and domestic coal (at this time) found its way into the energy policy pathways drafted by two study commissions of the German Bundestag (BT 1980, 1983) on nuclear policy. The aim of these two studies was to determine policy alternatives and to break through the extremely polarised nuclear debate in Germany at the time.

The concept of the *Energiewende* was adjusted in the late 1980s after climate change emerged as a new topic on the German energy and environmental policy agenda, again catalysed by two study commissions of the German Bundestag (BT 1990a, 1994). The new paradigm of energy transition as a structural change of the energy system to decrease greenhouse gas emissions and phase out nuclear power, by shifting the basis of the system towards one of energy efficiency and a major roll-out of renewable energies partly found its way into German energy and climate policy. The German government set a target for the reduction of carbon dioxide emissions (25% by 2005 compared to 1987 levels) for the first time on 13th June 1990. It adjusted this target to a range from 25% to 30% after the reunification of Germany (reflecting the large emission abatement potentials in the former East Germany) with a new decision on 7th November 1990 (BReg 1992). It then fixed the upper bound of this range by shifting the base year in 1995 to 1990 (BReg 1997).

These medium-term emission reduction targets were complemented by slight changes in nuclear policy. The nuclear reactors in Eastern Germany were shut down immediately after German reunification in 1990. In addition, a major revision of the German Atomic Energy Act was introduced in 1994, which effectively banned the commissioning of new nuclear power plants (Matthes 2000).



During the 1990s, German policy and society reached, relatively quickly, a consensus on medium-term greenhouse gas emission reduction targets⁵⁰ and climate policies on energy efficiency and renewable energies (BReg 1994, 1997, 2000a). However, nuclear policy has remained a key controversy in energy and climate policy. Several attempts to find a cross-party compromise on the future of the nuclear power plant fleet in Germany failed in 1993 and 1995 (Matthes 2000, Barthe 2001).

A new period of energy transition policies began when the coalition of Social Democrats (*Sozialdemokratische Partei Deutschlands* – SPD) and the Greens (*Bündnis 90/Die Grünen*) took office in 1998 and ended a phase of 16 years in which the federal government was run by a coalition of Conservatives (*Christlich Demokratische Union Deutschlands/Christlich-Soziale Union Deutschlands* – CDU/CSU) and Liberals (*Freie Demokratische Partei Deutschlands* – FDP). For the first time the climate policy program of the German federal government indicated partial targets (renewable energy, energy and resource efficiency) for the period up to 2020 (BReg 2005). In parallel, a study commission of the German Bundestag explored ambitious, longer term greenhouse gas emissions reduction targets of up to 80% by 2050 (BT 2002). The Social Democrat-Green government negotiated an agreement with the electric utilities which run nuclear power stations in 2000 (BReg 2000b), which was translated into law during 2001 and entered into force in the beginning of 2002. According to this new nuclear power legislation, the lifetime of nuclear power plants was limited to 32 years of operation, including some flexibility to transfer production quotas from older to more modern plants. The legally binding phase-out of nuclear power generation for the German power system was planned to be completed by the year 2025.

The Social Democrat-Green coalition lost its majority in the elections of 2005. The new government, formed by conservatives and social democrats (Grand Coalition), initiated a comprehensive energy and climate policy package – the Integrated Energy and Climate Programme (*Integriertes Energie- und Klimaprogramm* – IEKP) in 2007 (BReg 2007, BMWi/BMU 2007). This programme included for the first time – alongside a list of 14 key energy and climate policy instruments – a firm commitment to a greenhouse gas emission reduction target of 40% below 1990 levels, if the European Union set a greenhouse gas emission reduction target of 30% by 2020 and other countries agreed to ambitious emission reduction targets (BReg 2007, BMWi/BMU 2007). The nuclear issues remained controversial in the Grand Coalition and the status quo of the nuclear phase-out trajectory set in 2000/2002 was maintained during the legislative term from 2005 to 2009.

After the end of the Grand Coalition in 2009, the new coalition of conservatives and liberals focused energy policy on the revision of the nuclear phase-out legislation from 2000/2002. Given the strong

⁵⁰ The German national greenhouse gas emission reduction target was adjusted to 21% below 1990 levels after the Kyoto Protocol of the United Nations Framework Convention on Climate Change (UNFCCC) was signed in 1997.



controversies, even within the ruling parties, the lifetime extension of the German nuclear power fleet was embedded in a broader energy and climate policy package – the Energy Concept 2010 (BMWi/BMU 2010):

- The nuclear phase-out trajectory of 2000/2002 was extended by 8 years for the older reactors and by 12 years for the newer reactors.
- Greenhouse gas emission targets were set for 2020 (40%, now unconditional), 2030 (55%) and 2050 (80% to 95% below 1990 levels).
- Ambitious targets for energy efficiency and the roll-out of renewable energy sources were defined for different energy sectors, including the power sector.

The shift towards long-term greenhouse gas emission reduction targets, which essentially embody the more or less full decarbonisation of the energy system, was not a stand-alone process in Germany. At the same time, other member states of the European Union, as well as the European Commission, worked, at different levels of intensity, on long-term decarbonisation targets and trajectories (e.g. EC 2011a+b).

Table 1: General and sectoral targets for the German energy sector according to the Energy Concept 2010 and the Energiewende decision in 2011

| | Targets: Energy Concept 2010 and ... | | | | | | | ... 2011 |
|-----------|--------------------------------------|-------------------------|------------------|-------------------|---------------|--------------|-------------------|---------------|
| | GHG emissions | Renewable Energies | | Energy efficiency | | | | Nuclear power |
| | | Gross final consumption | Power generation | Primary energy | Space heating | Final Energy | Power consumption | |
| 2011 | | | | | | | | -41% |
| 2015 | | | | | | | | -47% |
| 2017 | | | | | | | | -54% |
| 2019 | | | | | | | | -60% |
| 2020 | -40% | 18% | 35% | -20% | -20% | -10% | -10% | |
| 2021 | | | | | | | | -80% |
| 2022 | | | | | | | | -100% |
| 2030 | -55% | 30% | 50% | | | | | |
| 2040 | -70% | 45% | 65% | | | | | |
| 2050 | -80 to -95% | 60% | 80% | -50% | -80% | -40% | -25% | |
| Base year | 1990 | - | - | 2008 | 2008 | 2005 | 2008 | 2010 |

Source: German Federal Ministry for the Environment, Nature Conservation and Reactor Safety

After the Fukushima disaster in March 2011, the German government issued a moratorium for the operation of the older reactors and commissioned analysis from the Reactor Safety Commission and a newly established Ethics Commission. After both bodies presented their results on the nuclear phase-out (RSK 2011, Ethics Commission 2011), the government elaborated a revision of the Atomic Energy Act which entered into force in August 2011. This act reverses the nuclear plant



lifetime extension of 2010 and slightly accelerates the original phase-out trajectory set up in 2000/2002. The legally binding shutdown of the last German nuclear reactors was now scheduled for the end of 2022 (BMU 2011) and was supported by a vast majority in the final voting of the German Bundestag on the respective revision of the Atomic Energy Act on 30th June 2011.

All other elements of the 2010 Energy and Climate Policy Package remained unchanged after the U-turn on German nuclear policy. Consequently, the new framework of energy and climate policy in Germany was based on ambitious greenhouse gas emission reduction targets equivalent to a full decarbonisation of the economy by 2050 and the transition to an energy system in which energy supply is almost fully based on renewable energies (Table 1).

The term '*Energiewende*', which first arose in 1980 within the scope of a minority position in the German energy policy debate, was adopted as the official headline of the new German energy paradigm in 2011. The German approach to the political decisions on a long-term energy transition to a decarbonised energy system has a number of specifics. Among these is the strong political link between ambitious emissions reduction and renewable energy rollout on the one hand and the phase-out of nuclear power on the other hand.

Although the *Energiewende* framework was set as an economy-wide programme with a broad range of targets, sub-targets and policies for at least all sectors, the power sector has always been at the centre of the debates and political action. This is partly because the heavily coal-based German power sector contributes the major share of German greenhouse gas emissions. However, it is also because this sector is primarily linked to the nuclear controversies and is, at the same time, where the potential of renewables as alternatives to nuclear and carbon-intensive power generation became first and most strongly visible for the political process.

On the long political road to the *Energiewende* decisions of 2010 (long-term decarbonisation targets) and 2011 (ultimate phase-out of nuclear energy), a huge body of analysis and modelling built up on the different policy goals as well as on the wide range of implemented and new policy instruments. All key decisions of the German government in 1990, 1994, 1997, 2000, 2007, 2010 and 2011 were complemented by a wide range of analytical work commissioned by the government and the parliament, in addition to other analysis provided or commissioned by different stakeholders of the process.⁵¹ Irrespective of the differences in the analysis and views presented in these studies, the vast majority of analysis stated that the most significant challenges of the energy transition and its targets would result not from technical feasibilities, macroeconomic

⁵¹ Altner et al. (1995), BET et al. (2011), BT (1990a+b, 1994, 2002), Consentec/IWES (2013), DEWI et al. (2005), DIW et al. (1997, 1999), dena (2012), DLR et al. (2004, 2009, 2010, 2012), Enervis (2014), EWI et al. (2010), FENES et al. (2014), FhG-ISI et al. (1997, 2008), IWES (2009), Nitsch et al. (2007), Öko-Institut (1990, 1991, 1996, 2000), Öko-Institut et al. (2008a+b, 2010, 2013, 2014), Prognos et al (1995, 1999, 2001, 2005, 2006, 2007, 2009, 2010, 2011, 2014), Prognos/IAEW (2014), r2b/EEFA (2010), r2b (2011), SRU (2011), UBA (2010).



costs, affordability in general or security of supply issues, but from the appropriate regulatory and market arrangements as well as distributional issues between different segments of society.

Explicit climate policy and energy policy with major impacts on greenhouse gas emissions or on the transition of the energy sector in Germany have a comparatively long history, covering a quarter of a century. A broad range of achievements and progress have resulted from comparatively long-lasting policies but also the settlement of certain policy traditions. The wide coverage of policies and the increasing wealth of significant analyses, as well as the broad involvement of stakeholders over a comparatively long time of policy formulation and policy implementation, also have major, and very different implications, for the capabilities of climate and energy policies and are probably among the particularities of the German *Energiewende*. On the one hand, climate and *Energiewende* policy receives continuously broad public support in German society (BDEW 2014). On the other hand, public policy is confronted not only with 'old vested interests' (the losers of the energy transition, essentially the fossil fuel industry and a part of the energy utilities), but also with 'new vested interests' (the winners of the first phase of energy transition, e.g. farmers, new energy industries and developers, as well as a share of the energy utilities).

It also needs to be highlighted that the target-driven energy and climate policy of Germany was increasingly embedded in, or interacted with, the respective European activities, at least for the time horizon towards 2020. The European energy and climate package of 2008 played a key role in this respect. It sets legally binding targets for greenhouse gas emissions and the use of renewable energy sources as well as indicative targets for energy efficiency. Even if the German national targets were more ambitious, the setting of legally binding targets at EU level has stabilised the German target-driven policy approach, especially if the special circumstances of German reunification are taken into account.

It should, however, also be considered that German climate and energy policy has been significantly influenced by, and interacted with, the rules of the European Union beyond climate policy in its narrow sense:

- The liberalisation of the electricity and gas market with the three internal market packages of the European Union (EU 1996, 2003, 2009) constantly faced strong resistance from different German governments at the time, which enabled at least a slowdown of the structural changes but did not ultimately succeed in blocking them (unbundling of generation, transmission and distribution networks, set-up of energy market regulators);
- The European rules on state aid have long been a topic of controversy between Germany and different EU institutions but only emerged as a key issue of German policy making after the European Commission strongly criticised the privileges of the industrial sectors under the German Renewable Energy Sources Act in 2014 and forced Germany to undertake a fundamental revision of its remuneration scheme for renewables which complies with the new guidelines on state aid (EC 2014).



The integration of German climate and energy policy is also relevant for major failures of European policies. In particular the deep crises of the European Union Emissions Trading System (EU ETS), after huge surpluses arose in the system from 2009 onwards, significantly interfered with German energy and climate policies and compliance with the respective national targets. This crisis of the EU ETS led to a situation in which the significant roll-out of renewable energies in the German power sector was not complemented by comparable emission reductions. This was because carbon-intensive power generators were not given, in the framework of extremely low CO₂ prices, an incentive to reduce emissions, and increased exports to neighbouring countries led to a stagnation of emission reductions in the German power sector.

The German policy on energy transition in its different dimensions (emission abatement, nuclear phase-out, roll-out of renewables) goes back further than the decisions of 2010 and 2011. A thought experiment may, however, illustrate the real essence of these decisions. If the years 2010 and 2011 were excluded from history, this experiment shows that the effects of the *Energiewende* decision in 2010 and 2011 will primarily materialise beyond 2020. The nuclear phase-out has been legally binding since 2002 onwards and the roll-out of renewables up to 2020 is based on legal obligations to comply with the legal framework of the 2008 Energy and Climate Package of the European Union (EC 2008, CEU 2009). Based on a longer history and tradition of climate and energy policy, the key difference made by the *Energiewende* decisions in 2010 and 2011 is that these policies shifted the perspective from the short- and medium-term (2020) to the clear long-term with strategic goals and objectives (2050). This new framework helps to ensure consistency of goals and policies. It also triggers the need for approaches that can address uncertainties and innovation needs, as well as substitution, modernisation and policy cycles.

3.2 Main policies and regulatory instruments in the power sector

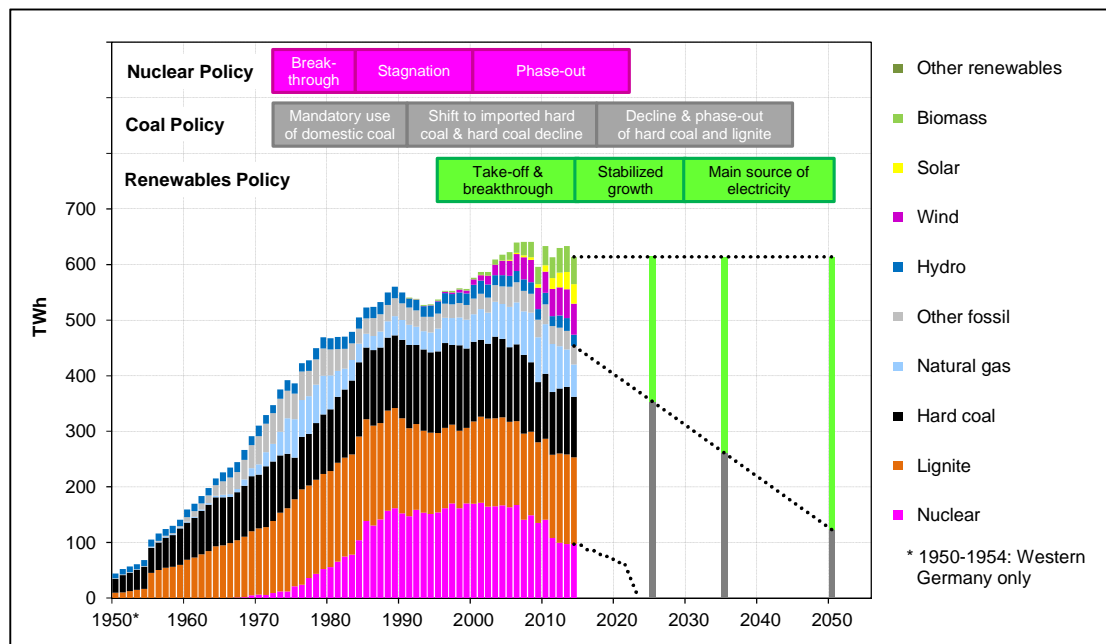
3.2.1 Introduction

The power sector made up approximately 38% of the total carbon dioxide (CO₂) emissions and approximately 44% of all greenhouse gas emissions (CO₂, methane – CH₄, nitrous oxide N₂O, HFs, PFCs and sulphur hexafluoride – SF₆) in 2014. It is the largest single source of greenhouse gas emissions and as a result a key area of climate action. Given the fact that the existing emission reduction targets effectively lead to a nearly full decarbonisation of electricity, and nuclear and CO₂ capture and storage (CCS) have been rejected as acceptable decarbonisation options⁵², the transition of the power sector needs to be based on an highly efficient use of electricity, the shift to

⁵² In the case of CCS, this applies at least for the power sector. It is still questionable whether the ambitious long-term emission reduction targets (80% to 95% by 2050 compared to 1990 levels) can be met without using CCS for industrial sectors like iron and steel or cement (Prognos et al. 2009, Öko-Institut et al. 2014).

high shares of renewable energies and a larger role for less carbon-intensive generation options for the transitional period.

Figure 1: Historical and projected structure of power generation and phases of electricity policy in Germany, 1950-2050



Source: Statistical Office of the German Coal Industries, Öko-Institut

Figure 1 shows the policy targets for the electricity sector and respective projections in a historical context:

- Following a 30-year period of rise and stagnation, nuclear power has clearly been in a period of decline since 2000, driven by political decisions which will not, with a very high probability, be reversed in the upcoming seven years.
- Power generation from renewable energy sources have shown steep, policy-driven growth since the early 1990s, which led to low production costs at least for solar PV and onshore wind from 2012. The major revision of the Renewable Energy Sources Act of 2014 marks the transition to a stabilised growth phase. After 2030 renewables are estimated to account for more than half of electricity generation.
- Electricity generation from coal power has been subject to regulatory interventions for many years. In the case of hard coal the use of domestic coal has been mandatory since 1973 or was heavily subsidised. After the phase-out of subsidies for domestic hard coal in 2018, the power generation from hard coal will be based on imported coal but continue to shrink due to the roll-out of power generation from renewables. The lignite-based power generation, with very low short-term marginal costs (in the absence of a significant

carbon price), has recently been kept at comparatively high levels. However, it will face the challenge of carbon pricing in the framework of the EU ETS and/or national measures for the decarbonisation of the power sector, given the dominant share of emissions from lignite in the total power sector emissions of Germany.

- Natural gas has never been subject to explicit power sector policies in Germany, apart from specific support for combined heat and power (CHP) production, which makes up the major share of natural gas-based power generation. Given the challenging economic framework in the continental European power markets for the foreseeable future (relatively high spread between natural gas and coal prices, low CO₂ prices and an incumbent fleet of coal-fired plants with low short-term marginal costs), the role of gas-fired power generation will depend on the policy framework for CHP, at least for the next one or two decades.

Most of the recent analysis assumes decreasing electricity consumption from traditional appliances (Prognos et al. 2014, Öko-Institut et al. 2014), mainly as a result of a shrinking population and the increasing penetration of highly efficient electric appliances if no major rebound effects are assumed. If effective decarbonisation policies for the transport and the heat sectors are put in place, a net growth of electricity consumption could result for the period beyond 2030 (Öko-Institut et al. 2014).

Against this background, the regulatory framework and/or the market arrangements for renewable energies, CHP and the efficient use of electricity, the phase-out of nuclear power, the decarbonisation of the remaining fossil fleet as well as the overarching design of the future electricity market need to be seen as the key pillars of the energy transition for the German electricity sector.

3.2.2 The remuneration scheme for power generation from renewable energy sources

The introduction of a comprehensive remuneration scheme for electricity generation from renewable energy sources was one of the early and far-reaching climate policy activities in Germany which had a strong, technology-specific focus. The general approach has not been changed in the last 25 years but the instrument has nevertheless been subject to many changes, including significant structural ones from 2012 onwards.

The first version of the remuneration scheme for renewable electricity generators was introduced with the German Electricity Feed-in Act (*Stromeinspeisungsgesetz – StrEG*) in December 1990. Electricity suppliers were obliged to purchase electricity from renewable energy sources at a fixed tariff and were allowed to bill the costs from the feed-in tariff to their customers. Electric utilities were not allowed to benefit from this scheme; the tariff was differentiated by three groups which received at least 75% (hydro power electricity from landfill and sewage gases), at least 90% (wind



and solar power) or at least 65% (other renewables) of the average price for deliveries to end consumers. The Electricity Feed-in Act was complemented by a series of technology-specific incentive programmes.

A comprehensive reform of the feed-in tariff scheme was enacted by the German Renewable Energy Sources Act in April 2000 (*Erneuerbare-Energien-Gesetz* – EEG 2000). The feed-in tariffs were determined in a much more technology-specific way and the tariffs for solar PV in particular were increased significantly. Electric utilities were now allowed to produce electricity under the feed-in tariff scheme.

Subsequent to a more technical revision in 2004 (EEG 2004), another revision in 2009 (EEG 2009) introduced – besides a series of adjustments of specific tariffs and legal clarifications – two structural changes. On the one hand, the transmission system operators were obliged to sell the electricity from renewables at the electricity exchange to obtain more transparency in the value of the electricity and the costs of the scheme.⁵³ On the other hand, the tariff for solar PV was shifted to a dynamic approach where the degression of the tariff was made dependent on the PV capacity expansion during the last 12 months.

The period from 2009 to 2012 proved a main failure of the German Renewable Energy Sources Act. The costs for solar PV decreased significantly faster than foreseen by the tariff degression and its dynamisation mechanism and as a result an enormous boom of solar PV installations occurred. In combination with a collapse of wholesale market prices (mainly due to significant price drops in the CO₂ and fuel markets and, to some extent, as a result of the increasing power generation from renewables⁵⁴), the costs of the scheme for non-privileged customers increased significantly.⁵⁵ In 2003, the renewables surcharge amounted to 0.42 cent per kilowatt hour (ct/kWh), increasing to 0.88 ct/kWh in 2008, to 1.31 ct/kWh in 2009, 2.05 ct/kWh in 2011 and 3.53 ct/kWh in 2012. This caused hectic revisions of the Renewable Energy Sources Act in June 2011 (EEG 2012a) and June 2012 (EEG 2012b), without being able to break the dynamics of the surcharge.

⁵³ The marketing of renewable electricity and the calculation of difference costs between the payments to the operators and the market value had previously been left to the network operators who added system service charges and other adders to the costs of the scheme, which led to a wide range of complaints against these practices.

⁵⁴ Whereas the price of emission allowances in the EU ETS clearly dominates the wholesale price trends, the impact of fuel prices and the increasing generation from renewable energy sources on the wholesale power prices differs for the spot market and the different futures markets for base and peak products (Cludius et al. 2014, Kallabis et al. 2015, Matthes 2015).

⁵⁵ A broad range of industrial consumers was and is exempted from the renewables surcharge. These exemptions depend on the hypothetical costs that these industrial consumers would have to bear without these exemptions. This mechanism leads to significant repercussions: The industrial privileges decrease the basis for the surcharges and increase the surcharges. This led to higher hypothetical costs and more industrial consumers were exempted, which resulted in a further shrinking of the base for the surcharge payments, leading again to higher surcharges, etc.



This increasing level of the renewables surcharge and the dynamics caused by the growing privileges for industrial customers⁵⁶ led to a highly controversial debate on the reform of the remuneration scheme. This debate escalated after the European Commission intervened and declared that the industrial privileges were not consistent with the state aid provisions of the EU. Although the German government took the legal position that the scheme was not subject to state aid supervision, it faced the challenge that they could no longer guarantee the industrial privileges under the emerging legal uncertainties. Against this background, the German government negotiated with the European Commission on the guidelines for state aid on environmental protection and energy for 2014 to 2020 (EC 2014). It elaborated and gave notification of a major revision of the German Renewable Energy Sources Act (EEG 2014) that is in line with the state aid guidelines. This revision introduced a series of structural changes:

- Firstly, almost all new installations have to market their electricity directly and receive a dynamic premium, which is calculated as the difference between a technology-specific strike price and the average wholesale market price.
- Secondly, roll-out corridors were set for electricity from wind (2,400-2,600 MW annually), solar PV (2,400-2,600 MW annually) and biomass (100 MW annually). The technology-specific strike prices are subject to adjustment if the capacity additions fall outside these corridors.
- Thirdly, the corridor for power generation from biomass was set very restrictively, essentially almost ending the expansion of biomass-based power generation.
- Fourthly, tenders for the strike prices of the variable premium model were to be introduced in stages by 2017.
- Fifthly, the whole model of industrial privileges regarding the obligation to contribute to the renewable surcharge was re-organised to make it structurally compliant with the new state aid guidelines, which did not however lead to significantly lower levels of exemptions for the industry under the EEG 2014.
- Sixthly, the incentives for the grid parity-driven rush to self-generation and indirect transfers were significantly decreased by introducing an obligation to carry a share of the renewable surcharge also for self-consumption of electricity.⁵⁷

⁵⁶ Industrial electricity consumers were allowed to apply for exemptions if the total costs of the renewables surcharge at the standard rate exceed certain thresholds. The increasing level of the surcharge expanded the range of exemptions, which increased the surcharge due to the shrinking base for the surcharge.

⁵⁷ The relatively high retail prices for electricity and the significant shares of network access fees and surcharges in the prices attracted a lot self-generation from 2010 onwards when many decentralised generation options reached grid parity in Germany and an erosion of the financial basis for networks and the different schemes (renewables, CHP, electricity tax, concession fees, etc.) and the respective indirect transfers became significant. According to EEG 2014 self-generators with renewable or CHP installations



Although on several occasions fundamental alternatives to the Renewable Energy Sources Act (e.g. quota models) were heavily promoted by certain stakeholders (RWI 2012, Acatech 2012), these attempts were never able to reach beyond a (weak) minority position in the debate. The promises of these alternative models with regard to efficiency gains and lowering costs for consumers were too vague or were questioned for good reason. In addition, the loss of investment certainty was perceived as far too risky from the perspective of a broad range of players in the field of renewable power generation as well as the broader public and the policy arena.

As a result, fixed tariffs for electricity generation from renewable energy sources were maintained over a phase of about 25 years of successful roll-out of renewable power in the German energy system.

However, the changes introduced by EEG 2014 as well as the emerging levels of renewable power generation (Figure 2 and Figure 3) provide a strong indication that further adjustments of the remuneration scheme for renewables will be needed soon:

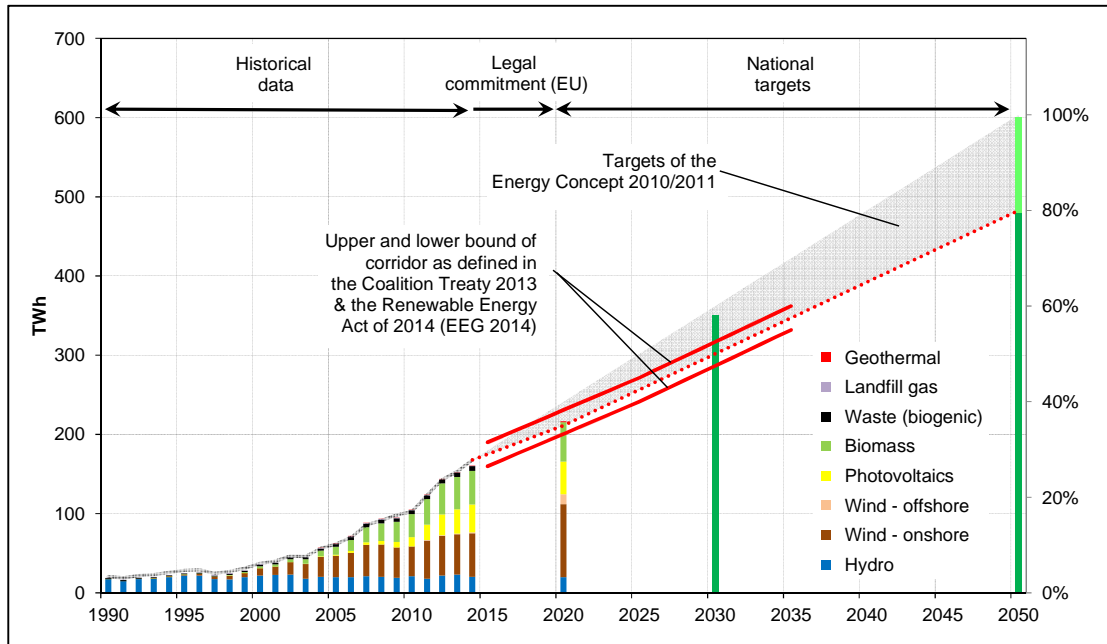
- The legal framework of the recent state aid guidelines requires the shift to tendering procedures from 2017 onwards. This will end the phase of administratively fixed tariffs (or the equivalent strike prices within the model of variable premiums).⁵⁸ Even if these state aid guidelines did not apply, administratively fixed tariffs for significant shares in the total electricity generation (soon more than a third in Germany) would no longer fit in the framework of the liberalised market model of the electricity sector in Europe.
- Beyond a share of 30% of renewable power generation, mainly from variable sources like solar PV and wind, renewables will deliver the full load in an increasing number of hours of the year. If the remuneration scheme for renewables continues to be based on premiums for electricity generation this will cause increasingly negative prices in the wholesale market, which will not result from technical inflexibilities of conventional power plants but from the regulatory framework for renewables.⁵⁹ This topic will have a major impact on investment certainty, which has been one of the most significant benefits of the existing model, given the fact that the state aid guidelines exclude the payment of premiums if the periods of negative prices in the wholesale markets reach durations of 6 or more hours.

larger than 10 kW must pay a 40% share of the renewables surcharge for self-consumed electricity from 2017 onwards, all other self-generators are obliged to pay the full surcharge.

⁵⁸ The German government continues to take legal action against the position of the European Commission that the German feed-in legislation is subject to state aid control. However, the duration of these legal processes of clarification will lead to a situation in which the design of the German remuneration scheme for renewables needs to comply with the state aid guidelines at least for the next few years.

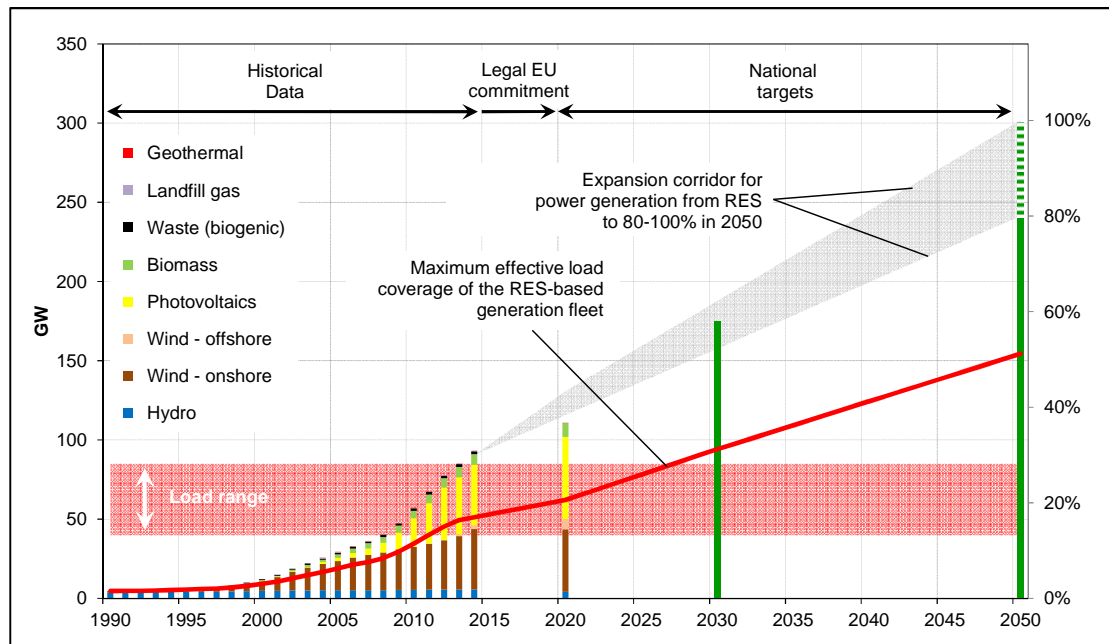
⁵⁹ If negative prices occur in the wholesale market, renewable generators will only start to shut down production if the level of negative prices is higher than the premium on electricity generation which the generators are to lose if they stop producing.

Figure 2: Historical and projected power generation from renewable power sources according to the German Energy Concept 2010/2011, 1990-2050



Source: German Federal Ministry for Economic Affairs and Energy, Öko-Institut

Figure 3: Historical and projected power generation capacities of renewable power sources according to the German Energy Concept 2010/2011, 1990-2050



Source: German Federal Ministry for Economic Affairs and Energy, Öko-Institut

In contrast to the last few years, the cost of the remuneration scheme for renewables will probably be of less importance in the near future. The recent level of the renewables surcharge is projected to be stable for the next few years and only grow slowly afterwards. The probability of steep increases of the surcharge in the future and the related political turmoil is relatively low (Öko-Institut 2014a) and so the structural aspects of the remuneration schemes and the overall consistency of the regulatory framework of a liberalised electricity market will acquire major importance. This will trigger new debates on the appropriate remuneration mechanisms for renewable energies. These will need to find a new balance between the integration into the coordination mechanisms of the electricity markets and the need for a sufficient level of investment certainty for renewable energy projects and the relevant groups of investors (Öko-Institut 2014c).

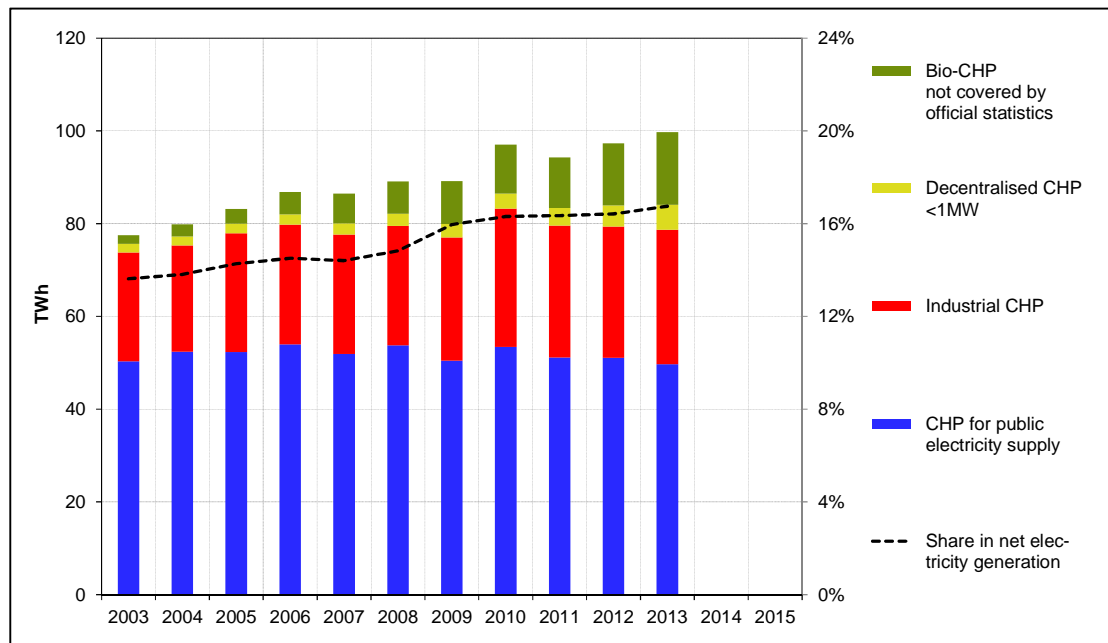
3.2.3 The remuneration scheme for combined heat and power production

Historically, combined heat and power production (CHP) has played a special role in the German electricity system. This is firstly a result of the strong role of municipal utilities in the German power industry, which often combine the production of district heat for residential, commercial and industrial customers with power generation in CHP installations. Secondly, many industrial

enterprises in Germany use CHP for their self-generation of power and heat for thermic production process.

Significant parts of the energy production in CHP plants in Germany are based on natural gas. Coal-based CHP also contributes to energy production, but less significantly. Due to this, CHP is not only widely perceived as an option for the efficient use of energy resources, but also as a significant contribution to the reduction of greenhouse gas emissions, at least in the medium-term. Furthermore, increasing investments in decentralised CHP installations have made CHP a widespread technology that receives a lot of public attention.

Figure 4: Historical power generation from CHP installations by operator group and share in total net electricity generation in Germany, 2003-2013



Source: German Federal Ministry for Economic Affairs and Energy, Öko-Institut

Combined heat and power production has been the subject of intense energy policy debate, which has led to regulatory interventions since 2000:

- The decline of electricity prices in the wholesale markets immediately after the electricity market liberalisation became effective for Germany led to major economic problems for CHP installations, especially those owned by municipal utilities. Emergency legislation on CHP was issued in May 2000 (*Gesetz zum Schutz der Stromerzeugung aus Kraft-Wärme-Kopplung*) and followed by a broader support scheme in March 2002 (*Gesetz für die Erhaltung, die Modernisierung und den Ausbau der Kraft-Wärme-Kopplung – KWKG 2002*). The schemes are based on administratively fixed premiums.

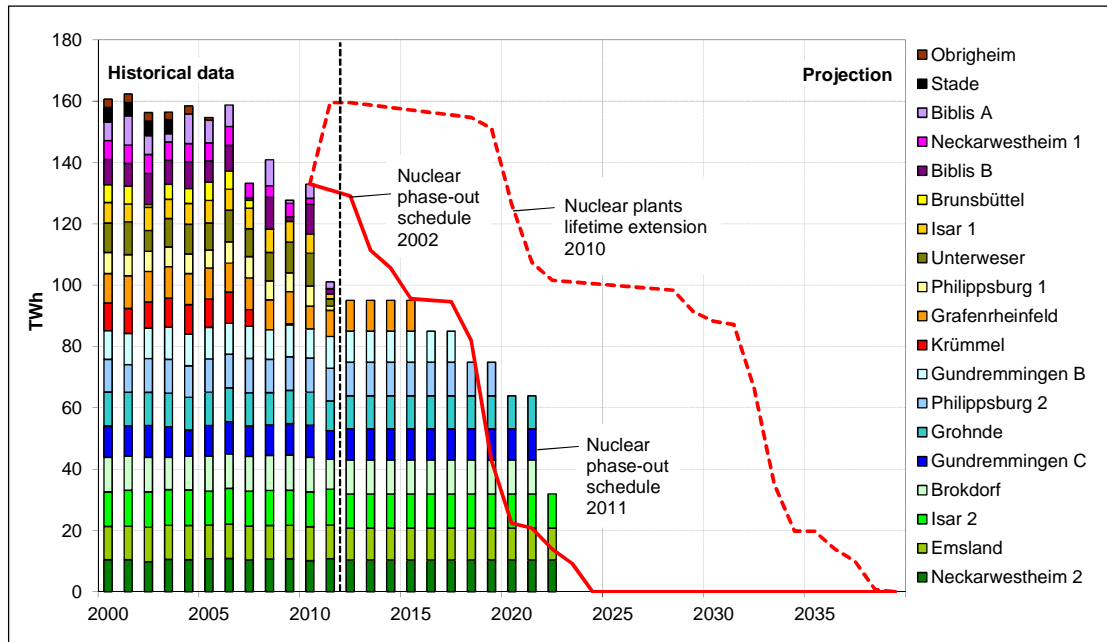
- In the framework of the German Integrated Energy and Climate Programme of 2007 a national target was defined for the expansion of power generation from CHP, which was set at the level of 25% by 2020 (BMW/BMU 2007).
- In reference to this target, and to comply with the European Union's legislation on the support for CHP, major revisions of the German CHP support scheme were undertaken in 2008 and 2012 (KWKG 2008 and KWKG 2012). This broadened the coverage of the scheme to industrial CHP installations and CHP self-generators, and focused the support on highly efficient new installations and phased out the payments for existing plants. These support measures helped to increase the share of electricity from CHP from 14% in 2003 to almost 17% in 2013, driven essentially by industrial and biomass-based CHP installations.
- This is, however, far off the trajectory towards the 25% target for 2020. The foreseeable failure to comply with the target as well as the increasingly complicated position of CHP in the power market (due to declining electricity prices in the wholesale markets and the increasing spread between the prices for natural gas and hard coal) led to new proposals to adjust the scheme. These plans include a re-definition of the target (as the share in thermal power generation to reflect the increasing role of variable renewables in the system) as well as the return to a support of existing, high-efficient and gas-fired CHP plants (BMW 2015c).

Alongside the broad support for renewable energies in the power sector, the targeted support of CHP is one of the key elements of energy transition-motivated regulatory interventions in the German power system. In terms of monetary volumes the support for CHP is relatively low compared to the remuneration scheme for renewables. The surcharge for the refinancing of the CHP support scheme ranged from 0 to 0.34 ct/kWh in the period from 2003 to 2012 but increased significantly in 2013 (0.13 ct/kWh), 2014 (0.18 ct/kWh) and 2015 (0.25 ct/kWh) for the non-privileged residential and commercial customers and it was almost negligible for more energy-intensive electricity consumers. The new plans, especially for the support of existing CHP installations, will lead to significant increases of the CHP surcharge for non-privileged customers in the upcoming years (BMW 2015c).

3.2.4 The nuclear phase-out

The controversy about nuclear power has been a major driver of the political debate on energy transition since the late 1970s. After some precursors of an explicit phase-out scheme (shutdown of the East German reactors in 1990, effective ban on new nuclear plants with the revised German Atomic Energy Act in 1994) the agreement with the nuclear operators in 2000 and the subsequent legal implementation (which became effective in January 2002) mark the turning point in German nuclear policy.

Figure 5: Historical and projected nuclear power generation in the framework of the different decisions on plant lifetime in Germany, 2000-2040



Source: Öko-Institut

The lead time of more than a decade is one of the key reasons why the decision on the quick shutdown of the older reactors after the plant lifetime extensions in September 2010 and the Fukushima disaster in March 2011 was manageable without major challenges. The respective reactors would have been subject to shutdown in the period of 2010 to 2015 under the legislation from 2002 anyway (Figure 5).

Besides the related political turmoil and the ongoing broad consensus on the nuclear phase-out in German politics and society, another argument supports the assumption that the phase-out decision in Germany will not be reversed again. The owners agreed to the gradual nuclear phase-out in 2000, with a view to the low wholesale market prices at the time. Accordingly, the fight for lifetime extensions was significantly motivated by the high price levels in 2008 and the subsequent years. Against the background of foreseeable low prices and the decrease of contribution margins caused by the nuclear fuel tax (introduced in 2010), the motivation of the nuclear operators to engage in another round of conflicts on the topic of lifetime extensions seems to be very low. The nuclear operators nevertheless undertook legal action against the German government to receive financial compensation for the shutdown of nuclear plants, at least for the moratorium period from March to September 2011.

Against the background of the economic performance and the changing strategic orientation (split-up of E.ON, withdrawal of Vattenfall from the German market) of the utilities which own nuclear



installations, the issue of decommissioning funds is increasingly attracting political attention. The political debates and potential regulatory action primarily concern securing the nuclear liabilities, as well as the mid- and long-term availability of decommissioning funds (approximately € 38 billion) which are currently held in the balance sheets of the companies but potentially or partly need to be secured by a transfer into a public fund (Merkel et al. 2015).

3.2.5 Policies to enhance the efficient use of electricity

Although declared as a political priority on a regular basis and in many energy and climate policy programmes, energy efficiency is still one of the remaining challenges to having an effective approach to energy transition.

The German approach to a more efficient use of electricity is based on three different pillars:

- standards set by European legislation (e.g. in the framework of the Eco-design directive);
- a new tax on electricity was introduced within the framework of the ecological tax reform from 1999 to 2003. The initial rate was set at 1.02 ct/kWh in 1999 and increased by 0.26 ct/kWh in the beginning of 2000, 2001, 2002 and 2003, resulting in a tax rate of 2.05 ct/kWh, which has been unchanged since then. The effects on electricity consumption have been modest (Bach 2009).
- targeted incentive programmes:
 - a range of specific information programmes and incentive programmes was set up by the German government, *Länder* (i.e. state-level) governments and a broad range of utilities. This is maintained for selected activities (e.g. industrial efficiency networks) or technologies (e.g. motor drives, commercial cooling appliances);
 - a new approach is based on the National Action Plan on Energy Efficiency (*Nationaler Aktionsplan Energieeffizienz – NAPE*), which foresees the introduction of energy efficiency tenders for electric appliances from 2015 to 2018 (BMW 2014c)⁶⁰.

The efficiency gains from these policy efforts will – alongside other factors like the ongoing structural change of the economy (Ziesing 2015) – certainly play a significant role for the trajectory of electricity consumption in Germany for the next decade. In the longer term, other policy-driven trends will compensate or over-compensate this trend:

- The German government has set ambitious goals for electric mobility. Even if the recent target to put 1 million electric vehicles on the road by 2020 seems to be overambitious at

⁶⁰ The planned budgets for these tenders amount to €m 15 for 2015, €m 50 for 2016, €m 100 for 2017 and €m 150 for 2018.



the moment, electric mobility will need to play a significant role for the decarbonisation of the energy system beyond the power sector.

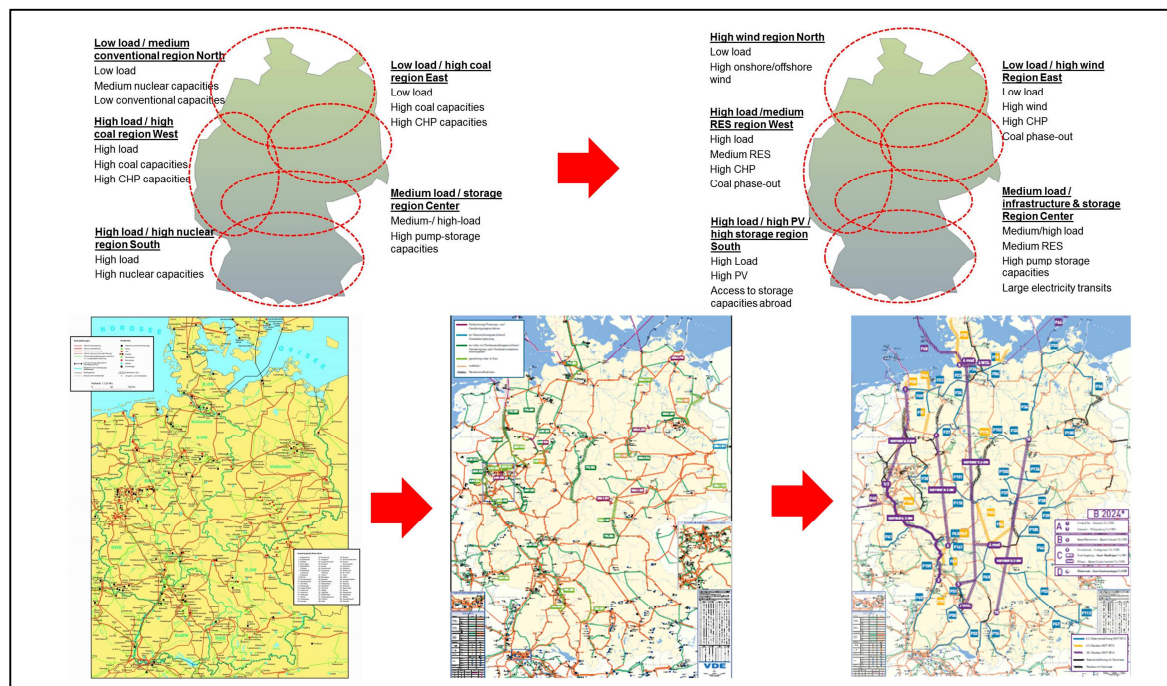
- Electricity will also play a role in the decarbonisation of the heat market, and the heat market will deliver some of the flexibilities needed for a system mainly based on solar and wind power generation (Power-to-X). However, this will also increase the net demand for electricity.

Especially against this background, the efforts to increase the efficient use of electricity for traditional appliances need to go significantly beyond the recent levels.

3.2.6 Transmission and distribution network development

The plans and efforts to restructure the German energy system have far-reaching geographical and regional implications. The transition to renewable energy sources implies, on the one hand, a major relocation of generation to the Northern regions of Germany where the conditions for wind power are favourable and the low population density allows a significant expansion of wind power generation. On the other hand, the phase-out of nuclear power removes generation capacities from the regions with high load demands in Southern Germany. In the longer term, the situation will be even more complex when coal-fired power generation in the Western part of the country will gradually lose importance and the high load centres of the West will need supplies from the wind- and solar-rich regions of Germany (figure 6).

Figure 6: Changing regional pattern of the German electricity system and the necessary upgrades of transmission grid infrastructure



Source: German Transmission System Operators, Öko-Institut

Based on the relevant European legislation, the German electricity market regulator and the transmission system operators have set up a comprehensive network development process to identify and implement the necessary upgrade of the transmission grid:

- Each year the transmission system operators run an analysis to identify and test the need for network upgrades and expansions.⁶¹ The full process (from the scenario framework to the draft plans) is subject to extensive consultations and approval by the electricity market regulator. For the 2015 analysis, trajectories of the power sectors were considered for the first time, which not only consider the nuclear phase-out and the roll-out of renewable power generation, but also reflect the climate policy-driven reduction of coal-based power generation in Germany (BNetzA 2014).
- Every three years the need for network upgrades are compiled in specific legislation (*Bundesbedarfsplangesetz – BBPlG*), which creates the legal basis for licensing procedures etc.

⁶¹ www.netzentwicklungsplan.de



Centre on Regulation in Europe

Improving network industries regulation

After a few years of slow progress, the transmission network roll-out has gained significant momentum. Approximately 40% of the projects (in terms of system kilometres) which have already been approved in a first legislative round in 2009 (*Energieleitungsausbaugesetz* – EnLAG) are projected to be put into operation by 2016 (BMW 2014e, BNetzA 2015). A series of EnLAG-regulated projects, however, is still suffering from significant delays amounting to 5 years on average (BNetzA 2015). The main reasons for these delays are complex planning and licensing issues under the auspices of the German states (*Länder*).

However, the need for transmission system upgrades goes significantly beyond the approximately 1,800 km system length approved by EnLAG. For the next phase, four high capacity direct current (DC) systems are planned to eliminate the congestion between Northern and Southern Germany and to limit unplanned loop flows over the transmission systems of Poland and the Czech Republic caused especially by wind power generation in Northern Germany (CEPS et al. 2013).

These projects have been the subject of intensive and, to some degree, heated debates in some regions and will remain on the political agenda for a time. Although the state government of Bavaria questioned the need for an additional infrastructure roll-out (Aigner 2015), there is still a broad consensus between the German government and most of the state governments. They broadly agree on the need to drive forward the upgrade of transmission systems as a strategy to maintain a high level of security of supply, create the infrastructure for major electricity transmission from Northern to Southern Germany and explore the capability of long-distance transmission of electricity as a flexibility option which can complement the increasingly variable power generation from renewables.

The urgent need for upgrades of the transmission system infrastructures was eventually reflected in a political agreement between the ruling parties (and the government of Bavaria) on 1 July 2015 (Merkel et al. 2015) to end the political blockade and create new momentum for the necessary planning and licensing processes. New projects beyond the first package under the EnLAG are partly subject to streamlined planning and licensing procedures under the auspices of the German government and regulated by specific legislation (*Netzausbaubeschleunigungsgesetz Übertragungsnetz* – NABEG). Regardless of whether or not the new transmission projects will be implemented according to the original plans and schedules, or what delays might occur, a significant portion of the stagnation in transmission infrastructure planning, licensing and implementation was overcome by the agreement of 1 July 2015.

The debates over, and the resistance against, new transmission lines have triggered significant efforts to find new and innovative solutions. This includes opting for cables instead of overhead lines in certain regions, using existing routes of electricity or transport infrastructures for upgraded transmission capacities or even combining alternating current (AC) and direct current (DC) lines on certain routes (the ULTRANET project).



The long-distance transmission of electricity is, however, not the only infrastructural challenge for the energy transition. Against the background of a significantly increasing share of decentralised power generation from renewables, and the need to employ demand-side flexibilities on a much broader scale than in the past, the upgrade and the related regulatory framework for distribution networks is increasingly gaining importance and has become the subject of heated debates. The question of whether the existing regulatory approach of incentive regulation is consistent with the need to develop smart grids on a large scale is still a highly controversial one in the German electricity policy arena.

The infrastructure needs of the energy transition will remain a highly sensitive issue in the whole restructuring project and will require significant and continuous political efforts as well as new ways of participation and project designs.

Last but not least, it should be mentioned that the restructuring of ownership and control of the grids has been a key success factor for the roll-out of renewables in Germany. Whereas network operators were very critical of the roll-out of wind energy in the early stages (EON Netz 2004), there was a complete reversal of this attitude after the ownership unbundling of transmission and generation was implemented and the transmission system operators found a new role as much more neutral infrastructure providers for the full range of generation options (TenneT 2010).

3.2.7 The acceleration of decarbonisation in conventional power generation

In the framework of the German *Energiewende* the nuclear phase-out and the roll-out of renewable power generation is moving on robust tracks and the activities on energy efficiency, CHP and creating the necessary network infrastructure adjustments are at least identified and need some improvement. But the blind spot of *Energiewende* policies is still how to deal with the existing fleet of fossil-fuel power plants. The related challenges are multifaceted:

- Renewable power generation has mainly substituted gas-fired power generation, given their position in the merit order as the option with high short-term marginal costs. The key reason for this is the significant spread between natural gas and coal prices, as well as the failure of the EU ETS to provide scarcity-based CO₂ prices.
- The large and, more significantly, outdated fleet of German coal-fired generation capacities, with very low short-term marginal costs, has led to significantly increasing electricity exports to neighbouring countries and electricity markets.
- Although the share of renewables grew significantly in the last decade, the greenhouse gas emissions from the German power sector more or less stagnated in this period, mainly because of the massively increasing net exports from Germany (Figure 7).

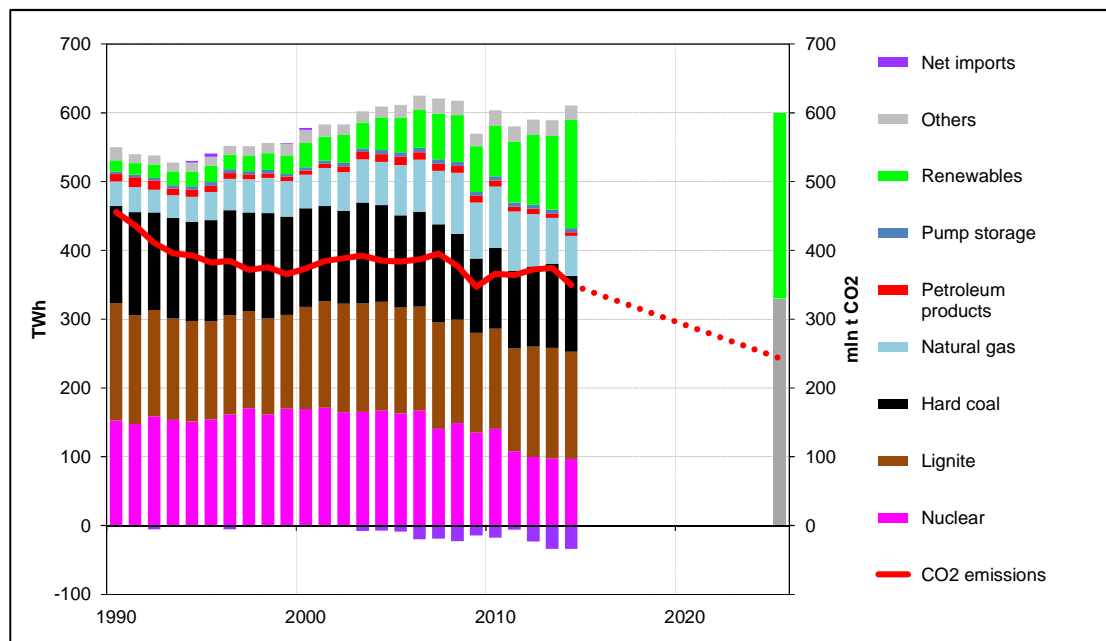
This situation raised political awareness that an exclusive focus on the roll-out of renewables, maintaining the existing levels of CHP production and some efforts on energy efficiency might not be sufficient to meet the national targets on greenhouse gas emissions, at least for the time



horizon of 2020, when the efforts to reanimate the EU ETS might not have been effective. As a consequence, the German government announced in its Climate Policy Action Programme in December 2014 (BMUB 2014) that it will take action to achieve additional emission reductions of 22 million tonnes of CO₂ from the power sector by 2020.

In a market situation in which gas-based power generation is not competitive beyond CHP with hard coal- or lignite-fired generation, and large outdated lignite-fired capacities with very low variable costs compete against relatively modern hard coal-fired power plants, the only way to achieve additional emission reductions at low costs is to shift production from old lignite to modern hard coal-fired plants. In March 2015 the German Ministry for Economic Affairs and Energy put forward a proposal on a selective CO₂ floor price that only applies to outdated power plants' generation. It quickly became the subject of heated political debates in the energy policy arena and was cancelled by the political agreement of 1 July 2015 (Merkel et al. 2015). It is unclear whether or not the alternative proposal of a capacity reserve, which should absorb 2.7 gigawatts of carbon-intensive lignite power plants, will prove to be realistic in practical and legal terms. However, regardless of this, the fact that additional activities are needed to lower the CO₂ intensity of the fleet of fossil-fuel power plants will not disappear from the German energy policy agenda, at least as long as the EU ETS is not able to deliver scarcity-based CO₂ prices.

Figure 7: Gross power generation in Germany and CO₂ emissions from the power sector, 1990-2025



Source: German Working Group on Energy Balances, Öko-Institut

The only option to achieve these emission reductions for Germany in the market arrangements of Central Europe is to trigger a switch from higher to lower carbon intensive conventional power



plants. The option to employ power plants with Carbon Dioxide Capture and Storage (CCS) essentially no longer applies in Germany after the CCS legislation effectively banned the application of this technology because of the strong public resistance in many regions of Germany and the dominant public notion that CCS is solely an option to maintain high levels of coal use in Germany. All pilot or demonstration projects in Germany were cancelled or terminated by the utilities.

3.2.8 An energy market reform?

As in other European countries, the declining prices in wholesale electricity markets, the perspective of policy-driven decommissioning of significant generation capacities and the impact of growing renewable generation capacities put the issue of the future power market design on the political agenda in Germany from 2011.

Although concerns about the future security of supply have been the key starting point of all debates on market design, a broad mixture of tactical, strategic and opportunistic motivations have made the debate on market design and energy market reform in Germany extremely complicated:

- the different economic and political core beliefs on the nature of security of supply, seen either as a private or common or merit good,
- the different economic core beliefs on the capability of the energy-only market to deliver the sufficient investments and to maintain operations,
- the hope for compensation for collapsing business models in conventional power generation,
- the resistance to new and potentially complex legislation,
- the opposition to any new revenue stream for conventional power generation,
- the hope for robust revenue streams for new businesses in demand flexibility etc.,
- the prevention of any new regulation that could create power price effects which are attributable to political action,
- the longer-term search for a sustainable economic basis for the future power system.
- different notions on the urgency of action,
- different notions on the needs and opportunities to find cross-border solutions to the capacity challenge,

After intensive debate among German analysts⁶², and political discussions in different fora and formations⁶³ over more than three years, the German Federal Ministry for Economic Affairs and

⁶² Müsgens/Peek (2011), Frontier (2011), Formaet (2011), Consentec (2012a+b), r2b (2012, 2014), EWI (2012), Öko-Institut et al. (2012), IZES (2012), Cremer (2013), Enervis/BET (2013), Growitsch et al. (2013), Consentec/Frontier (2013), Frontier/Formaet (2014), Frontier/Consentec (2014), A.T. Kearney (2014), Öko-Institut/LBD (2015).



Energy published a Green Paper in October 2014. This clearly indicated that the way forward will not include the shift to capacity mechanisms (BMW 2014b). In the summer of 2015, a clear decision was announced to improve the regulatory framework for the energy-only market, to set up a capacity reserve and to avoid regulatory electricity market interventions in case of price spikes or brownouts etc. (BMW 2015a, Merkel et al. 2015).

The German debate showed, however, some remarkable characteristics and inconsistencies:

- the debate was dominated by the perspective on the existing excess capacity in Central Europe and the incumbent fleet of carbon-intensive plants, and widely ignored the policy-driven decommissioning in Germany and neighbouring countries beyond 2020,
- the need for a wide range of flexibility options as complementary options to variable power generation from renewables was not set in the context of the capacity market debate,
- the implicit capacity mechanisms (CHP support in Germany, continued free allocation to power generators in Central and Eastern Europe, etc.) have rarely been considered as capacity mechanisms with major impacts on the electricity market,
- the criteria dominating large parts of the debate on the modernisation of the renewable remuneration scheme in Germany (investment certainty as the highest priority, urgent need for long-term contracts etc.) have not been applied or have been rejected for the non-renewable segments (conventional power plants, demand-side flexibility, storage) of the system (price volatility is not a challenge for investments, the absence of longer term contracts is rather beneficial, etc.).

As a result, the approach to energy market design and energy market reform continues to be strictly segmented and separated (renewable/non-renewable segment of the system). In contrast to the long-term and far-reaching technical visions and orientation of the energy transition for Germany, the strategy regarding the economic and market arrangements for this transition lacks a longer perspective and is still designed as a very incremental reform process, if at all.

3.3 Evaluation and prospects

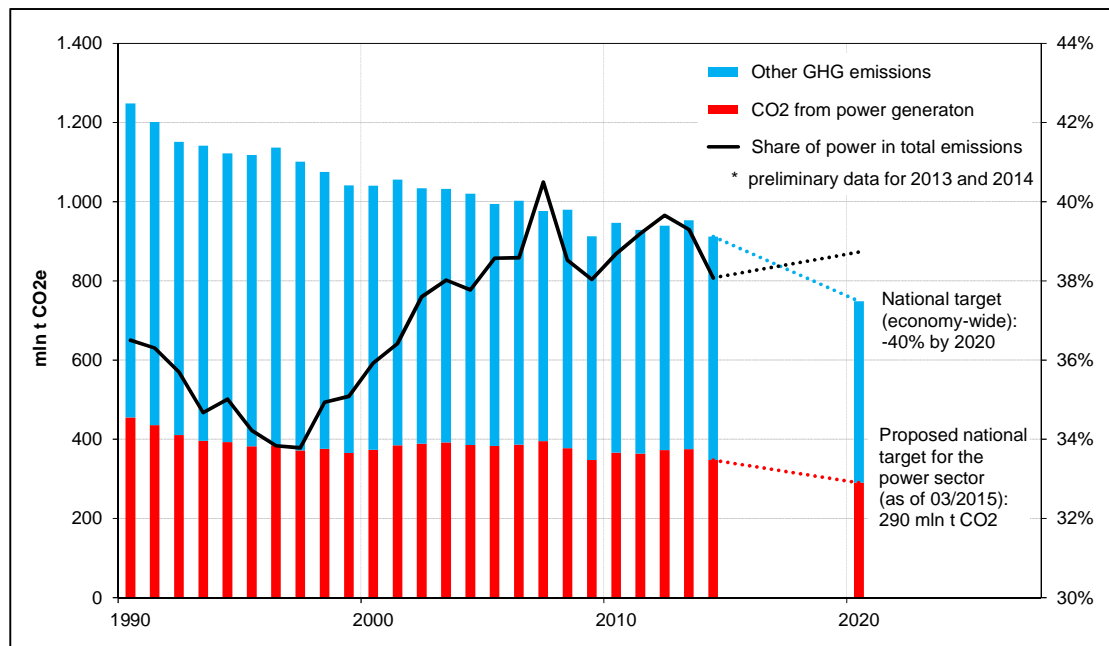
3.3.1 Greenhouse gas emissions

Ambitious national targets for the reduction of greenhouse gas emissions constitute a key element of climate and energy policy in Germany. The German Energy Concept 2010/2011 provides a

⁶³ Electric utilities, some states (*Länder*) from Southern Germany and some environmental NGOs were in favour of (different) capacity market models in this process; the renewable energy industry, consumer organisations, the energy-intensive industries, other states and the other share of environmental NGOs positioned themselves in strict opposition to capacity markets.

framework for a long-term decarbonisation of the economy, which enjoys broad political support and is extremely useful to ensure consistency of short- and medium-term policies.

Figure 8: Total greenhouse gas emissions and CO₂ emissions from the power sector in Germany, 1990-2020



Source: German Federal Environment Agency, Öko-Institut

However, the progress towards the interim targets for 2020 (-40% compared to 1990) and 2030 (-55%) shows mixed results, especially with regard to the emissions from the power sector (Figure 8):

- The emission reductions achieved in the power sector (-25% in 2014) lag behind the economy-wide emission reductions (-29%). The key emission reductions in the power sector occurred in the first half of the 1990s whereas the total emission reductions show a much steadier trend. As a result, power sector emissions as a percentage of total emissions increased from 34%-36% in the 1990s to 38%-40% after the turn of the century.
- The stagnation of power sector emissions can partly be attributed to major emission imports via the increasing electricity exports from carbon-intensive German power plants with very low variable costs. From a German perspective, this is reversed carbon leakage and raises the question of the robustness of national emission reduction targets in a highly integrated and interconnected electricity market.
- The decline of greenhouse gas emissions in 2014 is partly a result of weather conditions. 2014 was a comparatively warm year for an energy system which is driven to a large extent by heat demand. However, it is also an indication that the export potentials for carbon-intensive German power generation may be reaching a saturation phase.



Figure 8 also indicates the recent policy targets for the power sector's contribution to the national target of a 40% emission reduction in 2020. This highlights that other sectors need to deliver extensive additional emissions reduction, and that the power sector's share of total emissions will probably increase in the years ahead.

This situation underlines the fact that the transition to a low/zero-carbon energy system needs to address the phase-in of carbon-free alternatives (in the German case: renewable energies) but also needs to manage an accountable framework for the exit of high-risk or high-carbon assets. The regulatory framework for the nuclear phase-out in Germany provides such a framework. There is still a need for action, preferably at the European level, for outdated and high-carbon assets (e.g. by reanimating the EU ETS as quickly as possible), or a coordinated approach among the countries of the interconnected electricity markets. Effective and timely climate policy will require both supply-side and demand-side decarbonisation.

3.3.2 Electricity costs

The effect of the *Energiewende* on electricity prices has been a major issue in many policy debates and political processes in Germany and abroad. The analysis of price effects, however, requires differentiation:

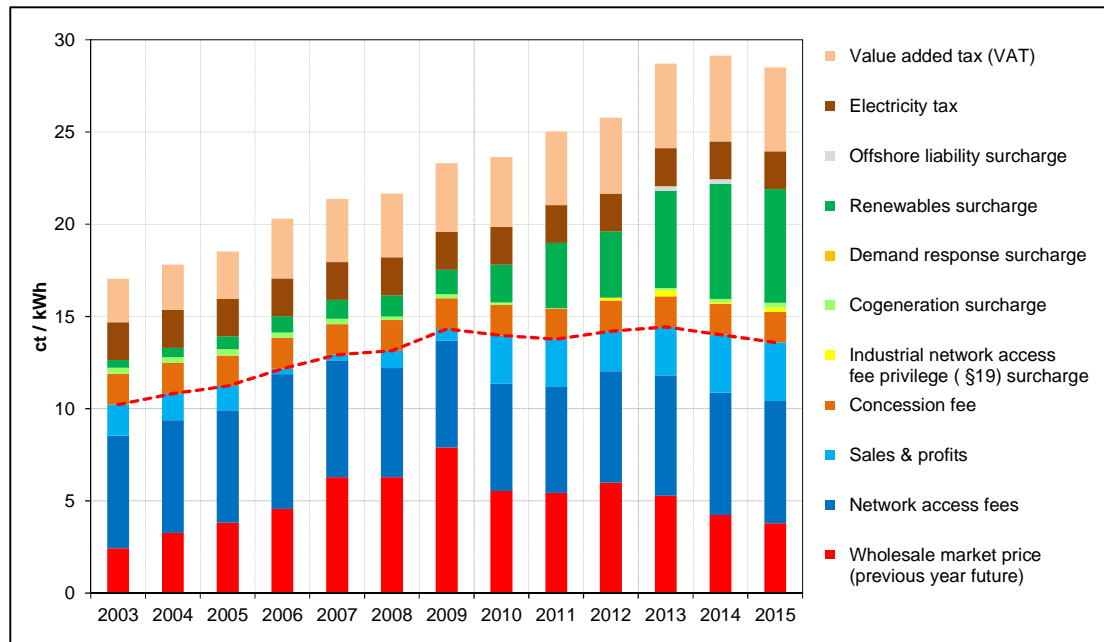
- The evidence for the nuclear phase-out within the scope of the energy transition is comparatively clear. The price effects have been very small and have only been visible for a very short time (Thoenes 2011, Matthes 2012).
- The price effects triggered by the shift to new energy sources are very different for residential and commercial consumers on the one hand and energy-intensive industrial consumers on the other (Matthes 2015).

Figure 9 shows the development of retail prices for residential electricity consumers. The prices rose from 17 ct/kWh in 2003 to 28.5 ct/kWh in 2015. There are two main drivers for this trajectory. On the one hand, the renewable surcharge increased from 0.4 ct/kWh in 2003 to 6.2 ct/kWh in 2015. On the other hand, the utilities have obviously been able to increase their margins after the decline of wholesale market prices in the aftermath of the energy price boom in 2008 by not passing the decreased prices to the final customers.

The development of the renewables surcharge over time deserves, however, a closer analysis:

- a share of approximately 1.8 ct/kWh of the total surcharge of approximately 6 ct/kWh results from a redistribution towards the privileged industrial consumers and self-generators of electricity (Öko-Institut 2014b);
- a share of approximately 1.7 ct/kWh of the total surcharge can be attributed to the technology support for solar PV, which contributed significantly to the cost degeneration of this technology (Öko-Institut 2014a).

Figure 9: Retail prices for residential customers in Germany, 2003-2015



Source: German Association of Energy and Water Industries, Eurostat, EEX, German Federal Network Agency, Öko-Institut

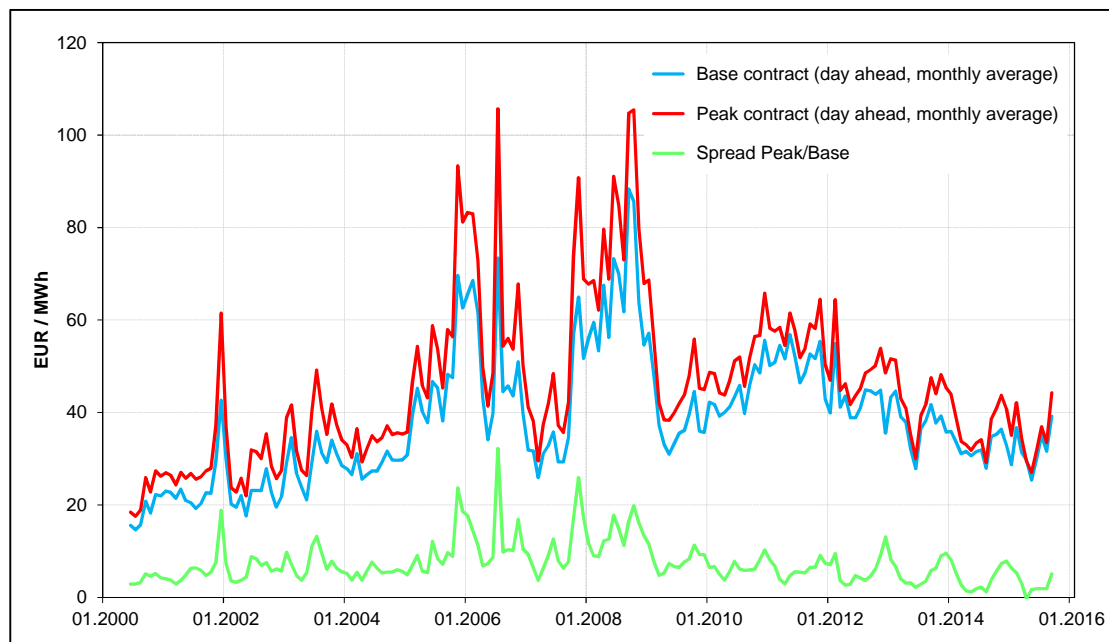
As a result, 40% of the recent renewables surcharge (or 25% of the total price increase from 2003 to 2015) may be attributed to industrial policy (protecting energy-intensive industry) or innovation policy with a global focus (contributing to the cost-buy down for PV). This seems to be acceptable for a country where the electricity bill for residential customers represents a share of total private expenditure for consumption ranging from 1.5% to 2.5% during the last 25 years. This low share of expenditure for residential consumers might be a justification for the fact that these consumers were forced to help significantly to create demand in one of the lead markets for solar PV and onshore wind (and potentially for offshore wind in future), which had the size and the robustness to trigger major cost reductions for key renewable technologies.

This is not to say that the remuneration scheme for renewables in Germany would not have offered opportunities for lowering the costs of the scheme. The failure to adjust feed-in tariffs after the massive cost decline for solar PV from 2008 to 2013 and the continuation of comparatively high feed-in tariffs for power generation from biomass, even in a setting in which all assumptions on cost reductions for these options proved to be wrong, are key lessons to be learned from the German scheme.

For industrial consumers, the situation differs at least partly from that of residential and commercial electricity customers:

- Energy-intensive industrial consumers are almost fully exempted from surcharges for renewable energies, CHP and other schemes as well from the electricity tax and concession fees. In addition, these consumers can benefit from a deduction of network access fees (which then will be paid by non-privileged residential and commercial consumers), and from a scheme that rewards load flexibility of specific energy-intensive industries (that is also refinanced by residential and commercial customers). They can also benefit from monetary compensation for the part of the electricity prices that can be attributed to the pass-through of CO₂ costs from the EU ETS and from the price decrease in the wholesale markets due to the increasing levels of power generation from renewables.
- Non energy-intensive consumers are not exempt from the renewable surcharge but rather are only subject to reduced surcharges for CHP etc. and pay only a fraction (approximately 25%) of the electricity tax.
- All consumers benefit from the price reductions in the wholesale market caused by the production of renewable power generators. The mainstream estimate for this merit order effect is approximately 1 ct/kWh (Öko-Institut 2014b, Cludius et al. 2014).

Figure 10: Wholesale prices on the German electricity exchange, 2000-2015



Source: LPX, EEX, EPEX, Öko-Institut

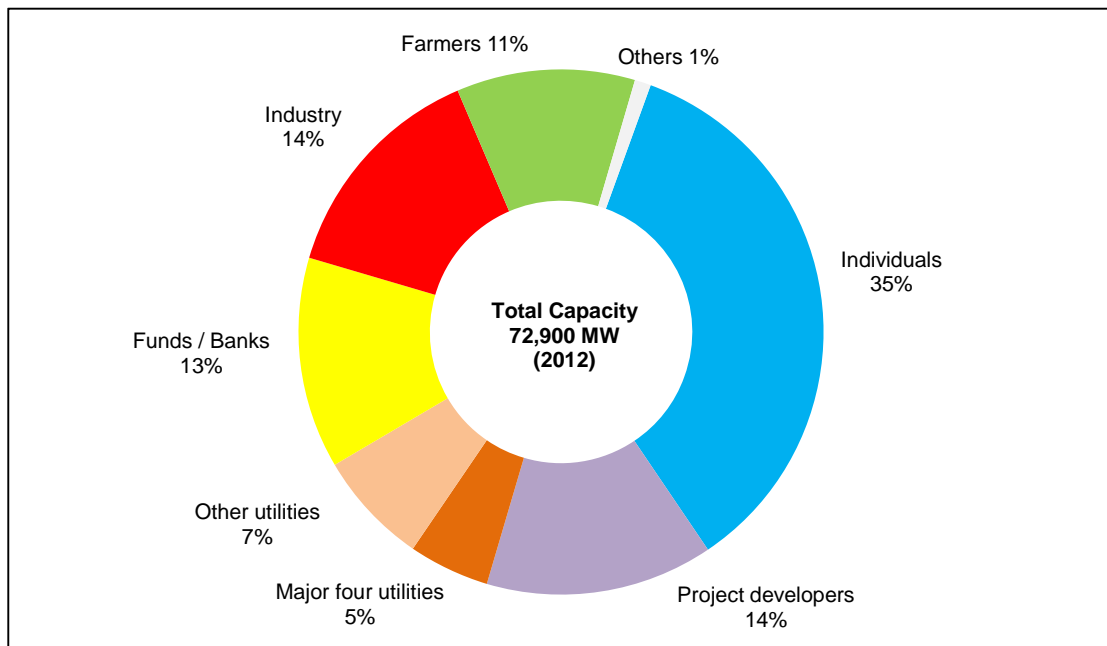
Figure 10 shows the price trends in the wholesale market for base and peak contracts during the last 15 years. Due to low fuel prices, a collapsed CO₂ market and the impact of renewable energies, the prices remain at extremely low levels and the spread between peak and base prices is

decreasing. This underlines the fact that the major concern with regard to the recent price trends is most likely not the price levels for large and energy-intensive electricity consumers. Rather, concern centres on the lack of an economic basis for the emerging investments for the different segments of the electricity system in the framework of an energy-only market with extremely low prices levels in general.

3.3.3 Participation

One of the interesting experiences from the roll-out of renewables is the increasing diversity of the power system in terms of ownership structures. The regulatory framework for investments in renewable power generation has attracted a wide range of new players to invest in renewable energies.

Figure 11: Breakdown of ownership patterns for renewable generation capacities, 2012



Source: trend:research, Öko-Institut

Figure 11 provides an overview of the respective ownership structures in 2012. Only 12% of the renewable generation capacity was owned by utilities at this point in time, which represent nearly 100% of the conventional generation capacities. This share might increase to some extent if capital-intensive investments like offshore wind projects will gain a bigger role, or if a more in-depth understanding of the energy markets or competitive processes becomes increasingly important for the further roll-out of renewables. Experience, however, also shows that a broad range of new players has been able to manage complex projects like wind farms and to develop or acquire the necessary know-how.



Over time the diversity of investments and the broader economic participation has emerged as an own goal of renewable energy policy in Germany. Even if the question can be asked as to whether this approach might have led to losses in terms of economic efficiency, the fact must be considered that this broader participation has significantly stabilised the policy arena for the energy transition and strengthened the robustness of the transition pathway. The broader foundation of the transition process nevertheless also has its downsides. The broad economic participation can significantly complicate adjustment processes which will become necessary if the transition process advances. The failure to adjust the feed-in tariffs for solar PV and biomass in a timely manner can be attributed at least partly to the 'new vested interests', which have been created by widespread investment opportunities in renewable energies.

The transformation of the remuneration scheme for renewables will, however, face the challenge of introducing new mechanisms, such as tenders, in a way that allows broad economic participation to be maintained. This will require gradual phase-in and careful preparation, making use of non-competitive auction segments for small players, incentivising the kick-start of support services, as well as other measures.

However, economic participation is not the only innovation in terms of participation. Starting with the processes to design the network development plans, the style of decision-making shifted step-by-step to an approach with much more consultation, monitoring and assessments. The implementation of the *Energiewende* decisions of 2010/2011 are subject to regular monitoring and progress reports (BMW 2014d+e), which are assessed by an independent, expert scientific panel (ExpK 2014a+b). The controversial debate on a new market design was also based on an extensive consultation approach at a relatively early stage in decision-making (BMW 2014b, 2015a), which is not the traditional method of decision-making in German policy. It remains to be seen whether these changes towards broader and increased consultation- and participation-based policy-making will be maintained in the future. However, recently it constitutes a significant policy innovation.

3.3.4 Innovation

In the recent stage of energy transition, the political and public notion of energy transition is clearly dominated by the perspective of modernising the power system and shifting it to innovative and future-proof technologies and structures. This was not always the case during the first phase of *Energiewende* discussions, when nuclear power was widely seen as a modernising energy source while renewables and energy efficiency were regarded more as a kind of eco-romanticism. Energy transition as an innovation-based modernisation approach developed not least as a side effect of other developments. These were the significant growth of power generation from renewable energy sources and a larger-scale penetration of highly efficient low-carbon power generation technologies after the turn of the century, both with rapidly improving technologies (from wind and



solar energy to micro-CHP) and an increasingly visible value chain in Germany.⁶⁴ This trend clearly sparked the reflections on a broader strategic framework. The concept of an innovation-based ecological industrial policy (BMU 2006, Machnig 2011) emerged and constitutes one of the key foundations of political and public perception for large parts of the political spectrum.

Although there are conceptual and practical challenges in appropriately measuring the level and trends of innovation (which is understood here as the combination of invention and commercialisation), some partially and broader anecdotal evidence might help to highlight the role of innovation in the German approach to energy transition.

A first and important indicator for the increasing role of innovation is the trend in German government expenditure on energy research. This rose from €400m in 2006 to more than €800m in 2013, with an almost exclusive allocation of the additional funding to energy efficiency, renewable energies, energy infrastructure (including storage) and systems research (BMW 2013, 2014a, 2015b). In terms of government spending levels and growth for non-fossil and non-nuclear research and development, Germany is ranked among the top group of OECD countries. It should, however, be considered that these data do not reflect spending for research and development by industry, which is traditionally strong in Germany – especially for the fast growing renewable energy and energy efficiency industries – but for which more systematic data collection is lacking.

In the German innovation approach within the framework of *Energiewende*, demonstration and early deployment (i.e. setting incentives for early roll-out) in the innovation chain play a strong role. The result of this approach for the power sector is mixed:

- Onshore wind generation, solar photovoltaics and parts of micro CHP (partly also as an innovation investment on the global scale) have proved successful and will probably lead to significant results for offshore wind generation in deep water locations.
- The machinery industry of Germany, with its strong tradition of innovation, has provided major innovations in decentralised power generation, system integration, grid solutions and machinery for the production of key products for the energy transition.
- The innovation gains for the majority of power generation from biomass have been extremely limited, making it one of the fields without innovation breakthroughs.
- The expectations of breakthroughs with carbon dioxide capture and storage (CCS) were not met, although major efforts were made in research and development before the public and political acceptance essentially disappeared for other reasons after 2010.

⁶⁴ It should be highlighted that a significant part of production facilities for renewable energy technologies settled in regions which face major challenges of structural change. This applies especially for Eastern Germany after the crash of the old industries (e.g. production of wind power plants and solar PV equipment, although a part of PV industry declined due to competition from the Far East, at least for some parts of the PV value chain) as well as the Northern regions of Germany where maritime industry (production of wind power plants, offshore wind logistics etc.) is in ongoing crisis.



Centre on Regulation in Europe

Improving network industries regulation

Although not all hopes for future products (e.g. biomass) and future industries (e.g. for the solar industry) have ultimately been realised, the German experiences regarding technological innovations for the future energy system have exceeded many expectations. A lively, extremely creative and fast-growing research sector in many fields (basic technologies, system and sector integration, demand flexibility, storage, smart grids, etc.) and a wide range of industrial start-ups – some of which have emerged as major industrial players – have become key characteristics of the energy transition in the meantime.

An interesting aspect of the German experience with innovation is the matter of the drivers of innovation. The extremely innovation-friendly environment for many parts of the energy transition in Germany was triggered by at least five key mechanisms:

- The major, and increasing, government expenditure in different programmes.
- The strong industrial innovation efforts and expenditures motivated by the highly visible and robust market opportunities provided by the highly visible and robust approach of early deployment (e.g. for renewable energies and system integration technologies).
- The need for a wide range of innovation arising from practical challenges of large-scale practical implementations (e.g. space-saving combinations of AC and DC transmission lines).
- The largely decentralised structure of German society and the economy (strong role of municipalities and municipal utilities, strong political impact of the German states, the traditionally strong role of innovation-based medium-sized companies, the significant role of new market players after liberalisation of the power market) which offers a wide range of interfaces and opportunities to start innovative activities.
- The public and political consensus – which has become strong in the meantime – on the general pathway decisions in favour of the *Energiewende*.

Not all efforts to trigger innovations for the *Energiewende* have proved to be successful (e.g. biomass, CCS) and some parts of the respective approaches may not necessarily be assessed as cost-effective from today's perspective (e.g. early roll-out of storage technologies). Nevertheless, a highly innovative environment for the technological dimension of energy transition has been created.

The strong focus on technological and system innovation is not surprising in the framework of German industrial culture and tradition, but also indicates the important gaps which still exist with regard to innovation. Major gaps in the necessary innovations remain with regard to the economic and regulatory foundations, future business models of a structurally and fundamentally changed electricity system, as well as the social integration of the future system in its different segments. For the next stage of the *Energiewende* these challenges will emerge as significant, and will trigger the need to create an innovation-enabling environment for areas which are much less deeply rooted in German society, policies and tradition.



3.3.5 European cooperation

The course of the German *Energiewende* interacted heavily with policies of the European Union. At least for the decade from 2000 to 2010, European decisions played a major driving role for a wide range of processes which are important for many dimensions of the transition process in Germany. These implications range from the overarching European targets for the reduction of greenhouse gas emissions, renewable energies and energy efficiency, to framework legislation which made implementation measures mandatory. The latter includes the EU's Emissions Trading System (EU ETS), the EU Renewables Directive and the EU requirements for electricity market liberalisation, unbundling and set-up of electricity market regulators. Germany has been supportive of some of this legislative action (e.g. setting of ambitious targets, legislation on renewable energy), has played a non-constructive role on some issues (e.g. on electricity market liberalisation) or changed its position over time from being non-constructive to being supportive of European action (e.g. on the EU ETS).

However, the European dimension of the German *Energiewende* policies for cooperation within the European Union and with neighbouring countries remains challenging. This results, on the one hand, from the broad scepticism and resistance to the German *Energiewende* targets and efforts, especially in the early phase of the project, from both governments of neighbouring countries and European institutions. On the other hand, many policy makers largely ignored the increasing importance of the European integration of the energy transition. This covers a range of issues including concerns of neighbouring countries about how Germany's decisions could impact security of supply abroad and vice versa, the integration benefits of a cross-border electricity market, the role of EU-wide instruments like the EU ETS and EU-wide targets, and the adoption of *Energiewende* elements in other EU countries.

It remains to be seen whether the recent steps to establish regional coordination structures, e.g. in the Pentalateral Energy Forum, and to intensify the approach of gradual integration of cross-border mechanisms for the different activities, without losing the dynamics of an innovating and front running country, will be successful.

The European integration of Germany's *Energiewende* is, however, certainly one of the test cases for the adaptability of the project for other jurisdictions in Europe and on a more global scale.

3.3.6 Institutional arrangements and specifics

A range of institutional arrangements have been of significant importance in the course of the *Energiewende* process up to now.

A widely ignored aspect has been the changing allocation of responsibilities in the German government:

- Historically the full responsibility for all energy issues was allocated to the Ministry of Economic Affairs (*Bundesministerium für Wirtschaft* – BMWi);
- After the Social Democrat-Green government took office in 1998, the responsibility for renewable energies was shifted to the Ministry for the Environment, Nature Conservation and Nuclear Safety (*Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit* – BMU) while all other energy-related responsibilities remained at BMWi;
- The government coalition formed in 2013 shifted the responsibility for renewable energies back to the re-named Ministry for Economic Affairs and Energy (BMWi).

For a key period in the configuration of important parts of the *Energiewende* project, the preparation of nearly all strategies and decisions was subject to the in-depth involvement of BMU, which had always taken a very strong stance on ambitious climate policies. BMU was now able to successfully claim a co-decision competence because of its responsibilities for renewables, with their increasing shares in the energy supply. As a result, many decisions, and a significant part of the whole legislation on energy issues, were significantly impacted by an institution which was deeply committed to the need for major changes in the energy system. There was, however, a downside to this shared competence. Many processes took quite a long time; in some cases the German government was not able to present a well-coordinated position in EU processes and negotiations and day-to-day politics impacted policy-making in the energy field more than usual.

A number of factors contributed to a decline in political interest in avoiding administrative monopolies for energy policy preparation. This decline resulted in the re-bundling of all competences on energy policy at BMWi. The factors for the decline in political interest included the conclusion of decisions on the nuclear phase-out. In addition, the role of conflicts on energy issues became less dependent on the political core beliefs on nuclear energy or reached a level of differentiation which started to split even the different political parties (on CCS, transmission infrastructure, electricity market design etc.). How successful the institutional separation of energy policy (BMWi) and climate policy (BMU) will prove to be remains an open question.

Beyond the competence sharing at the federal governmental level, which has the key competence on the general framework for energy policy, the power sharing within the federal governmental system has played a major role in German energy policy of the last three decades:

- The German states have limited responsibilities in designing general policies but have a strong role in approving a wide range of policies, and in many policy implementation procedures. As a result it is very difficult to design policies which raise major objections from non-minor parts of the 16 states. Given the fact that there is a large variety of ruling coalitions in the states⁶⁵, the regional interests in certain parts of the energy transition

⁶⁵ In April 2015 the German government was ruled by Social Democrats and Conservatives but in 8 of the 16 states the ministers responsible for energy are from the Green Party.

have become significant in the meantime⁶⁶. Even the limited competences have offered scope for energy policy activities, experiments or policy innovations. As a result, the states play an important role in the energy transition and have widely made use of their different role in the German energy policy system.

- Municipal utilities have a specific role in the German electricity system. More than 700 municipal utilities (VKU 2014) are active in electricity. They have little or no interest in the generation options which are challenged by the energy transition (nuclear, lignite- or coal based power generation) and have significantly more interests in businesses which are technically, economically or even politically, the citizens of the municipalities. Over time municipal utilities have also served as significant experimenters and innovators in energy policy⁶⁷ and played a significant role in key energy policy decisions (e.g. the nuclear phase-out decisions in 2011).

The liberalisation of the electricity market has triggered some structural changes for the electricity enterprises, as well as the institutional consequences of the changing regulatory framework for the power sector:

- The freedom of choice for the electricity consumers made incumbent suppliers vulnerable to public acceptance when it came to very controversial activities of the power industry (plant lifetime extension for nuclear power, investment plans for coal-fired power generation, expansion of lignite mining for power generation, etc.). In all these controversies, the respective suppliers lost significant market shares in their retail businesses.
- A wide range of new electricity suppliers entered the market after the opening of the electricity market in 1998 and after key barriers for competition were removed after the turn of the century. Many of these players emerged as outspoken supporters of the *Energiewende* in the subsequent years and settled as influential players in the energy policy arena. A range of new business models (e.g. direct marketing of power from renewables) was developed mainly by new players in the market. This also broadened the innovation capacity for market and system integration of renewables as well as the respective flexibility options (demand response, power-to-heat, storage, etc.).
- The unbundling of generation and transmission and a large part of the distribution businesses, in the course of EU-driven market opening, changed the attitude towards

⁶⁶ Wind energy and the wind energy industry play an important economic role in the Northern states, solar energy and the solar industry in the Eastern and Southern states, biomass in all rural states, coal in the states of Brandenburg, Saxony, Saxony-Anhalt and North Rhine-Westphalia.

⁶⁷ The instrument of guaranteed fixed tariffs for power generation from renewable energy sources were first introduced by municipal utilities; a wide range of efforts to integrate variable renewables into the electricity system has taken and is taking place at the level of municipal utilities and these enterprises represent the major share of gas-based power generation from CHP plants.

renewables. The transmission network operators in particular took a more sceptical stance when the share of wind power generation reached significant levels after the turn of the century (E.ON Netz 2004) and the transmission companies were a part of integrated companies with a strong interest in nuclear- and/or coal-based generation subsidiaries. After far-reaching ownership unbundling, the transmission system operators emerged as supporters of the roll-out of renewables, which create the business case for the related infrastructure roll-out (TenneT 2010).

- Finally, the establishment of an independent electricity market regulator, the German Federal Network Agency (*Bundesnetzagentur* – BNetzA), in 2005, was significant. BNetzA monitors competition but also serves to monitor and ensure security of supply. It is the main body for infrastructure planning and plays a role in the implementation of the remuneration scheme for renewables. The regulatory tradition of this institution and its strong focus on transparency and broad consultation processes brought significant innovation to the traditional command-and-control and corporatist German policy style. Not all decisions and processes made or hosted by BNetzA have been without controversy (e.g. with regards to the roll-out of transmission infrastructure) but in general BNetzA has emerged as an accountable and fair player in the overall institutional arrangements of the German *Energiewende*.

The institutional arrangements for the transition of the power sector will continue to be dynamic for the foreseeable future. A closer institutional integration of energy and climate policy is clearly on the agenda as well as the establishment of a Federal Energy Agency, which bundles competences from the Federal Network Agency (BNetzA), the Federal Office for Economic Affairs and Export Control (*Bundesamt für Wirtschaft und Ausfuhrkontrolle* – BAFA) and the Federal Environment Agency (*Bundesumweltamt* – UBA) and would enable a stricter separation of regulatory and implementation tasks of BNetzA.

3.4 Lessons and challenges ahead

The gradual transition towards a decarbonised energy system has been, and will be, a steady discovery process for which many issues have not been, and cannot be, identified in advance. The transition process can, however, be regarded as having five robust key characteristics:

- The system and many of its elements will be coordination-intensive and appropriate coordination mechanisms need to be identified, implemented and improved over time.
- The system and many of its elements will be capital-intensive and will probably require new economic and market arrangements.
- The system and many of its elements will be infrastructure-intensive, which will require new regulatory arrangements for infrastructure and careful consideration of public acceptance in its different dimensions.

- The interfaces between the electricity system and the citizens will broaden, which could strengthen the political support for the *Energiewende* project but will also create new challenges for the implementation of a much more distributed, and not always decentralised, system.
- The system and many of its elements will be innovation-intensive in terms of technologies but also with regard to business models, regulatory and market arrangements as well as the different dimensions of participation.

Against this background, the lessons to be learned from a period of at least 25 years of efforts to set up a fundamental transition process for the German energy sector with the target of a decarbonised energy system are mixed:

- There are huge achievements in rolling out renewables at a scale that was thought to be illusionary one or two decades ago. Power generation from renewables is going to leave the niche area and start to dominate the whole system. This has been essentially triggered by a robust investment framework, which has been accessible for a broad range of players.
- Whereas the phase-out of nuclear power is on a robust track after repeated (political) turmoil, the right approach to designing the 'exit game' for outdated and carbon intensive power generation assets still needs to be found and will be complicated in a country in which the role of coal is a highly sensitive issue politically. Significantly increased and specific attention, however, needs to be paid to the back-end costs and other challenges of an accelerated phasing-out of supply options on a large scale in a fundamentally and structurally changing energy system and new market structures.
- Progress is lacking in the efficient use of electricity, the roll-out of necessary grid infrastructures, and an intensified cooperation with neighbouring countries and within the EU. This requires significantly more effort and acceleration.
- A significant challenge arises from the much bigger role of decentralised options in the electricity system. On the one hand, this creates significant opportunities for broader participation and robustness of the transition process. However, on the other hand, a broad shift to indirect transfer mechanisms (self-supply triggered by grid parity) can jeopardise the economic basis of the system.
- A more decentralised and more infrastructure-intensive electricity system increases the number and the permanence of interactions with the citizens of the country. This requires a new quality of participation and new procedures at many points to address the extremely sensitive issue of public acceptance.
- Many questions on the appropriate transition strategies towards a sustainable economic basis of the future electricity system are still open and the German debate has been called off at too early a stage. The discourse on a future-proof electricity market design needs more attention, less tactical considerations and a clear strategic perspective.

- The European dimension of the *Energiewende* still needs to be addressed more strictly and the cooperation with neighbouring countries and within the European Union calls for much broader approaches.
- The German experience shows that a mix of clear political targets for the long-term and accountable implementation strategies and policies can help to raise public acceptance and trigger innovations on an enormous scale.
- The energy transition in Germany has been the subject of a wide range of analytical efforts for almost 25 years. The research community is broad and has gone through many stages of findings and controversies, part of which has been very fundamental and part of which has been of a more technical nature. Public policy started reflecting the challenge of massively increasing analytical capacity by setting up more accountable monitoring and assessment processes and broadening the consultation-based approaches to decision-making.

The long and, at certain points, very controversial debates and political processes on the first transition phases towards a decarbonised electricity system allow some preliminary lessons to be drawn:

- Some of the challenges which occurred during recent years in Germany will not occur again in other settings, especially with regards to the costs of basic innovations, etc.
- The neutralisation of networks, i.e. the unbundling of generation, transmission and distribution, is a key success factor for the effective and cost-efficient roll-out of new generation options.
- The appropriate policy and regulatory approaches strongly depend on the stage of transition. A phase model for the stages of 0-25% / 25-50% / 50-75+% market penetration of new renewables can provide a useful framework to identify the priorities for each stage.
- Key challenges for the design of the transition process arise from the need to balance conflicting issues:
 - to balance investment certainty (which is of special importance in the early stages of transformation) and the need for market-based coordination (which is of outstanding importance beyond the niche area);
 - to balance broad economic participation (which is important for the robustness of the policy arena) and the ability to adjust the regulatory framework over time (which will lead to problems with the 'new vested interests' at some points);
 - to balance policy innovation by front-running (which is essential for initial phases) and the need for European integration, convergence and harmonisation (which needs to reflect different development stages and differing core beliefs on carbon-free energy options);

- to balance the role of ambitious European policies and measures (which are always preferable) and complementary national policies and measures of an interim nature (especially if European instruments take more time or need major structural reforms like the EU ETS); and
- to balance economic efficiency (which is an important precondition to make the energy transition a role model in the global framework), distributional aspects (which is of key importance for most policy processes) and strategic robustness and accountability (which might sometimes require a stronger focus on second- or third-best approaches).
- Significant efforts to create an accountable and broad basis for comprehensive innovation processes are key enabling factors for new technologies, businesses and regulatory arrangements.
- A new electricity system will require new institutional, regulatory and market arrangements. The need for such arrangements will be different in different stages of the transition, and also depends on political cultures and traditions. Nevertheless, it needs to be addressed as an essential part of the necessary innovation process.
- A successful energy transition goes beyond the enabling framework for new and clean energy options and infrastructures. Specific attention needs to be paid to the carefully and robustly designed regulatory framework for the phase-out part of the transition and its implications on the environmental and economic integrity of energy transition.
- A clear definition of strategic orientations and target models and a strong focus on structured and steady improvement of implementation policies (based on permanent, well-organised and transparent evaluations) is likely to be of key importance to enable progress, innovation and the necessary adjustments, and to avoid major technical, economic or political lock-ins.
- Finally, the development of a wealth of strong analyses and analytical capacities is one of the fundamentals of an energy transition, especially if the design and implementation processes require comprehensive and fast-learning processes as well as strong evaluation and adjustment mechanisms, which are strongly needed in an increasingly dynamic political and economic environment.

The case of the German *Energiewende* provides a broad range of favourable and some unfavourable experiences. Not all of these experiences might be relevant for other jurisdictions or settings. The German case, however, underlines the fact that energy transition can be an interesting and explicit modernisation strategy for a highly industrialised country in a carbon-constrained world.



4. Case Study 2: The Energy Transition in the UK, by David Newbery

4.1 Objectives and targets of the UK energy transition

Energy policy when the electricity supply industry was under state ownership was primarily about fuel mix, but with the arrival of the privatising Conservative government under Margaret Thatcher in 1979 the emphasis shifted to market led guidance. As the Secretary of State for Energy, Nigel Lawson, said in a speech to the IAEE in 1982: “I do *not* see the government’s task as being to plan the future shape of energy production and consumption. It is not even primarily to try to balance UK demand and supply of energy. Our task is rather to set a framework which will ensure that the market operates in the energy sector with a minimum of distortion.” This reflected the government’s aim to roll back the boundaries of the state, culminating in the restructuring and privatisation of the electricity supply industry in England and Wales in 1989.

The UK took the first tentative steps to decarbonise the electricity sector in the process of developing the privatisation legislation. This was a period of growing concern over climate change, with the 1990 publication by the Thatcher Conservative government of *This Common Inheritance: Britain's Environmental Strategy* (HMSO, 1990), which set as a target to reduce CO₂ to 1990 levels by 2005. In order to support nuclear power and make it suitable for privatisation, the government imposed a Fossil Fuel Levy on fossil fuel generation to raise funds to pay for nuclear decommissioning. DG Comp insisted that this subsidy be made available to all zero-carbon generation, which also included renewables. A Non-Fossil Fuel Obligation (NoFFO) was placed on electricity supply companies in the 1989 *Electricity Act*, who were required to buy a certain amount of nuclear or renewable electricity at a premium price. Some of the NoFFO funds were used to procure renewables in a series of five orders, starting in 1990. As Mitchell (2000) noted “The awarding of the NoFFO contracts and the price paid for the renewable generation is decided as a result of competitive bidding within a technology band on a prearranged date.” Competitive bidding resulted in dramatic falls in the cost of renewables, but later rounds suffered from a high drop-out rate as contract terms were too inflexible to accommodate sitting changes, as well as the “winner’s curse”, although this was a low risk given that failure to deliver was not penalised.

Three years after the electricity privatisation, as the vesting contracts to supply British coal to the power sector ran out, the Government held an inquiry into future of the coal industry, and the resulting document (DTI, 1993) affirmed that “Competitive markets provide the best means of ensuring that the nation has access to secure, diverse and sustainable supplies of energy in the forms that people and businesses want, and at competitive prices.”



Centre on Regulation in Europe

Improving network industries regulation

The Conservative government lost the 1997 election and the incoming Labour government had a complex set of objectives reflecting the special interests of its major union supporters, notably coal miners, but also a strong environmental commitment to Kyoto and reforming the support of renewables, discussed in section 2. Their manifesto stated: “We will put concern for the environment at the heart of policy making so that it is not an add-on extra, but informs the whole of government from housing and energy policy through to global warming and integrated agreements.” They introduced a fuel price escalator which raised the real price of road fuels by 5% p.a. as part of their Kyoto commitment, but decided against a carbon tax and instead introduced a cumbersome Climate Change Levy (CCL). They imposed a moratorium on gas-fired generation to protect coal, although almost all the UK’s fall in CO₂ emissions had come from the rapid switch from coal to gas-fired generation after privatisation, shown in Figure 1 below. The government published the *Utilities Act 2000* which replaced the NoFFO and instead transferred the obligation to secure the nuclear and renewable power from the Non-Fossil Purchasing Agency to an obligation on electricity suppliers to procure a specified fraction of their sales from just renewable sources. It also set up the Stern review on climate change which published its major report in 2006.

Labour’s objectives were reasonably clear and set out by Prime Minister Tony Blair in 2002 as “securing *cheap*, reliable, and sustainable sources of energy supply has long been a major concern for governments’ (PIU, 2002, emphasis added), although critics responded: choose any two of these three, as if it is reliable and sustainable it will not be cheap, and if cheap and sustainable it will not be reliable. Eventually what has become known as the energy Trilemma was more sensibly reformulated under the next Labour Prime Minister Gordon Brown when he set up the Department of Energy and Climate Change (DECC) in October 2008. DECC’s website by 2009 set out the government’s energy and climate change objectives as to “ensure our energy is secure, *affordable* and efficient’ and ‘bring about a transition to a low-carbon Britain’ (emphasis added).

If the incoming Labour government was reasonably clear about its objectives, the means to that end were anything but, with a whole series of White Papers gradually moving from hostility to nuclear power to somewhat grudging acceptance. The government published *The Energy Challenge* (DTI, 2006) and its response in the subsequent White Paper *Meeting the Energy Challenge* (DTI, 2007). This set out the government’s goals of reducing CO₂ emissions by 60% (all reductions are relative to 1990 levels) by 2050 while retaining security of supply, ensuring every home is affordably and adequately heated, and promoting competitive but sustainable markets. It started the legislative process for a *Climate Change Bill* which became the *Climate Change Act 2008*. It set a target for renewable electricity of a share of 10% by 2010 and 20% by 2020. After a lengthy period during which the Labour party was unable to commit to nuclear power the White Paper announced that it would allow private sector investment in nuclear power.

The *Climate Change Act* received Royal Assent in November 2008, and provides a legal framework for ensuring that Government meets its commitments to tackle climate change. It also set up the Committee on Climate Change (CCC) as an independent body to advise and monitor the



Government's carbon commitment. The Act set tougher targets for decarbonisation and renewables than the 2007 White Paper. The Act requires that emissions are reduced by at least 80% by 2050 compared to 1990 levels, and that the Government commit to a series of 5-year carbon budgets.⁶⁸

The government then published the White Paper *The UK Low Carbon Transition Plan* (DECC, 2009) describing it as "the UK's first ever comprehensive low carbon transition plan to 2020. This plan will deliver **emission cuts of 18% on 2008 levels by 2020** (and over a one third reduction on 1990 levels). ... **Getting 40% of our electricity from low carbon sources by 2020 with policies to:**

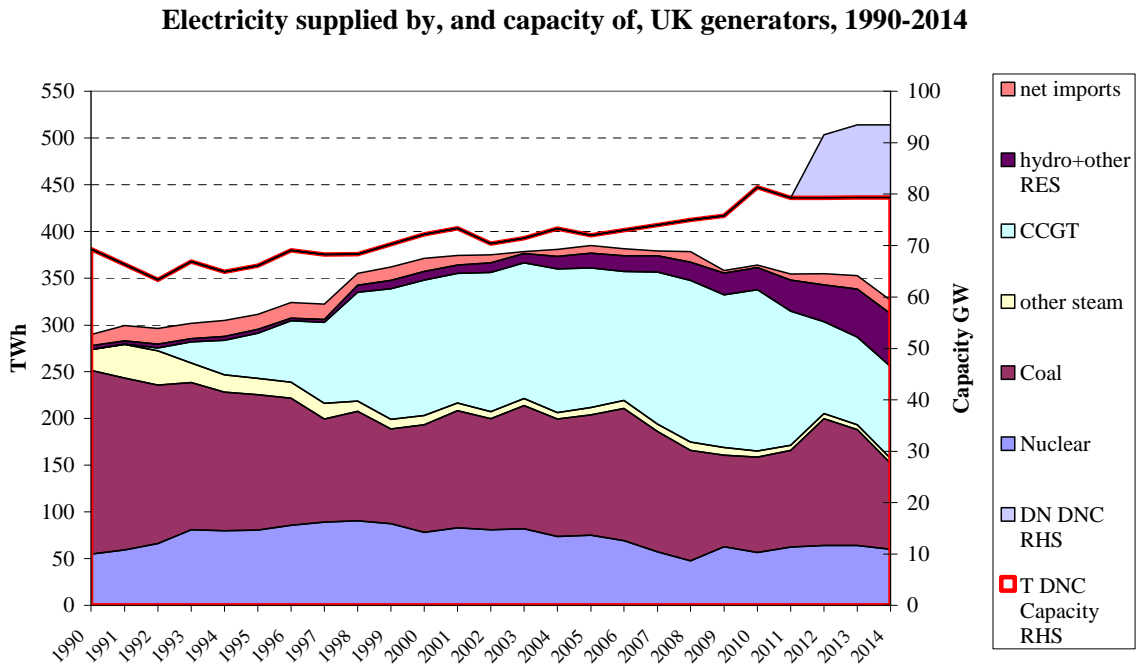
- **Produce around 30% of our electricity from renewables** by 2020 by substantially increasing the requirement for electricity suppliers to sell renewable electricity;
- **Fund up to four demonstrations of capturing and storing emissions from coal power stations;**
- Facilitate the building of new nuclear power stations." (Emphasis in original.)

4.2 Main policies and regulatory instruments in the power sector

The United Kingdom had a population of 62.3 million in 2011 (GB had a population of 60.4 million), and in that year its peak electricity demand was just under 60GW, suggesting a peak demand of about 1 kW/head. Figure 1 shows the evolution of electricity supply and capacity (T DNC is declared net capacity connected to the high tension grid, DN DNC is that connected to the Distribution Network for which data are only available after 2012). Note the fall in demand, and the more rapid fall in coal generation as plant is closed or converts to biomass and the growth in renewables displacing fossil generation.

⁶⁸ <http://www.theccc.org.uk/about-the-ccc/climate-change-act>

Figure 1: Electricity supplied by, and capacity of, UK generators, 1990-2014



Source: DECC, DUKES various years.

Note: 2014 is based on the Q1-3, DNC for 2014 is not available and is set at 2013 levels

4.2.1 The role of the power sector in the energy transition

It is widely appreciated that the electricity sector is the easiest sector to decarbonise, as the end product, electricity, is unchanged and there are a variety of ways of producing zero or low-carbon power from nuclear power to various renewables technologies, each with its advantages and limitations (MacKay, 2009). In contrast most other sectors, such as domestic heating and transport, would require major behavioural changes to reduce their carbon intensity. The process of consciously aiming to decarbonise electricity dates from before privatisation, when the then prime minister Thatcher was enamoured by a major push to nuclear power, a process that was derailed by the lack of its commercial viability demonstrated in initial attempts to include nuclear power in the original privatisation. This was despite the Fossil Fuel Levy and the Non Fossil Fuel Obligation which required suppliers to buy a certain amount of nuclear or renewable electricity at a premium price. While the nuclear power stations were already producing, the Government had to arrange the delivery of renewable power. Initially contracts were allocated on the basis of ‘cost justification’ (Mitchell, 1995) but after the first round, contracts for effectively Feed-in Tariffs (FiTs) were awarded by competitive auctions, resulting in a dramatic fall in cost per MWh, but also an



increasing failure to meet the delivery targets as winners could walk away from the contract if they found costs or planning obstacles rendered their projects unprofitable.

Dissatisfaction with the falling success rate of contracted renewables led to a rethink and the *Utilities Act 2000* placed an obligation on electricity suppliers to secure a specified proportion of their sales from renewable sources, which would be given Premium FITs, called Renewables Obligation Certificates (ROCs). The amount is set out each year in the Renewables Obligation Order, which also sets the buy-out price for failure to buy a sufficient number of ROCs. Demand and supply for ROCs sets their price which is added to the wholesale price, and the revenue from the buyout fund is distributed to those issuing the ROCs in proportion to their sales, thus enhancing their value. When first introduced in 2002 all renewable energy sources received 1 ROC/MWh of electricity generated.

In 2008 the EU proposed the 20-20-20 *Renewables Directive* (introduced in 2009 as 2009/28/EC) that increased the share of EU energy (not electricity) that must be generated from renewables by 2020 from 12.5% to 20%.⁶⁹ Each Member State was given an individual target that reflected a balance between efficiency (least total EU-wide cost) and equity (with richer countries shouldering more of the burden). The UK accepted one of the most challenging targets (relative to its initial position) of 15%.⁷⁰ The ROC system was reviewed and from 2009 each renewable technology was placed in a band and received a different number of ROCs per MWh generated, with on-shore wind receiving 1 ROC/MWh and off-shore wind 2 ROCs/MWh. The bands were reviewed and changed in 2012 for the period 2013-17, with on-shore wind lowered to 0.9 ROCs/MWh but some less mature technologies receiving up to 5 ROCs/MWh.⁷¹

Newbery (2011, 2013) criticised the design of ROCs for paying the same price regardless of location (although at least the renewable generators were required to pay a (moderately) cost-reflective location Transmission Network use of System charge). A ROC price sufficient to induce the least favoured wind farm would over-reward those in more profitable locations. The German approach of offering contracts of differing degrees of generosity to on-shore wind farms based on measured output in the first three years of operation would reduce this unnecessary rent and thus reduce the cost to consumers of supporting renewables.

The impact of these policies on electricity generation can be seen in figure 1, while the most recent issue of *Energy Trends* (Feb 2015) gives the following highlights:⁷² "Electricity generated in the third

⁶⁹ This section draws heavily on Newbery (2012a).

⁷⁰ Apparently the Prime Minister thought he was agreeing the share of renewable *electricity*, not *energy*, and against the advice of ministers (Henney, 2011).

⁷¹ Details at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66516/7328-renewables-obligation-banding-review-for-the-perio.pdf

⁷² At https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/386836/5_Electricity.pdf



quarter of 2014 fell by 5.1%, the lowest level of generation since 1998. Renewables' share of electricity generation was 17% in 2014 Q3. ... Coal's share decreased from 33.6% to 20.1%, whilst gas' share of generation increased from 26.6% in the third quarter of 2013 to 38% in the third quarter of 2014, due to a large decrease in coal generation and lower wholesale gas prices. Low carbon electricity's share of generation increased from 37.1% in the third quarter of 2013 to 38.6% in the third quarter of 2014, with the fall in nuclear generation offset by an increase in generation by renewables." For the first three quarters of 2014, nuclear power accounted for 19.3% and renewables 18.5%, with on-shore wind 6.7% and off-shore wind 3.7% of total output.

Over the five years from 2009-13 the average annual rate of growth of total renewable capacity has been 19.7% p.a. and of renewable generation has been 16.3% (the lower figure reflecting the growing share of PV with its low capacity factor). If these rates of growth of capacity are sustained until 2020 there would be 22 GW of on-shore wind and 24 GW of off-shore wind (whose output over the period 2009-13 grew at 45.5%). This projection at a constant rate of growth gives 46 GW wind compared to the 2020 government target of 27-35 GW. If the volumes are projected to grow at the same annual average increment of 1.4 GW then the projected volume would fall to 20.7 GW, averaging only 9.2% p.a. The mid-point target of 31 GW would require a growth rate for total wind of 15.6% p.a. compared to the 2009-13 average for all wind of 20.5% p.a. Solar PV grew 50% from 2012-13 but this is an unsustainable (or more accurately unaffordable) rate of growth. For reference, DECC (2013a) was projecting a 2030 (not 2020) installed capacity of 14 GW of on-shore wind and 18 GW of off-shore wind or 32 GW in total. Thus recent experience suggests that the UK is on track for renewable electricity, albeit with growing doubts about its affordability (Henney, 2011).

4.2.2 Electricity Market Reform

The Labour government's White Paper *The UK Low Carbon Transition Plan* (DECC, 2009) set out ambitious targets for the electricity sector, described above. One might have expected DECC to take the lead in examining the ability of the energy market to deliver these targets, but it was the regulator, Ofgem, that launched *Project Discovery* in June 2009 in its scrutiny of security of GB energy supply.⁷³ Ofgem reported on 3rd Feb 2010 recommending "far reaching energy market reforms to consumers, industry and government" and concluded that "The unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency and the closure of ageing power stations has combined to cast reasonable doubt over whether the current energy arrangements will deliver secure and sustainable energy supplies."

After a pause and a change of government to the Conservative and Liberal Democrat coalition on 6 May 2010, DECC launched its consultation on *Electricity Market Reform* (EMR) in December 2010 (DECC, 2010). Its diagnosis was similar to that of *Project Discovery* (and the CCC) - the carbon price

⁷³ <http://www.ofgem.gov.uk/markets/whlmkts/discovery/Pages/ProjectDiscovery.aspx>



was now too low to support unsubsidised nuclear power while the wholesale electricity price was set by fossil fuel prices (and the ETS). Fossil generators thus had a natural hedge as the difference between the electricity sales price and the cost of fuel is reasonably stable, while that for non-fossil generation is very volatile as their variable costs are low and constant. Looking forward, non-fossil generation faces volatile carbon prices that are too low and sensitive to political intervention, thus undermining their future credibility.

The 2010 DECC consultation noted that security of supply was becoming an issue with rapidly approaching generation plant decommissioning, and that the market did not seem to be delivering the required volume of renewables, all suggesting that the electricity market was not well suited to delivering secure, sustainable and affordable electricity – the three key Government objectives.

The 2010 estimated cost of meeting the Government's carbon and renewables targets by 2020 in electricity alone amounted to £120 billion, or over £12 billion per year compared with less than £5 billion in 2008 (itself nearly 80% above the previous decade average).⁷⁴ This was considerably above financial analysts' estimates of the capacity of the Big Six⁷⁵ electricity utilities to finance on its own, indicating the need to access new sources of finance. Given the high capital cost of most low-carbon options, anything to de-risk investments and lower the Weighted Average Cost of Capital (WACC) would have significant benefits in terms of lower costs and prices. A reduction in the equity risk premium and an increase in the debt share might reduce the WACC by 1% (or even more for smaller entrants), which would reduce the capital cost by £1.2 billion each year by 2020, or nearly £45/year per household, compared with current electricity bills of £450/yr (although domestic consumers consume about 40% of the total, electricity prices feed through into other goods ultimately consumed).

The consultation proposed a Carbon Price Floor (CPF) to ensure that the carbon price moved on a trajectory that would ensure the commercial viability of nuclear power without further support, and this was the subject of a separate and rather hasty consultation by HM Treasury, with draft legislation published on 11 Jan 2011. The levels announced in the Budget in March 2011 would support the price of CO₂ starting at £16/tonne in 2013, rising to £30/tonne (€35/tonne) in 2020, and projected to rise to £70/tonne by 2030 (all at 2009 prices).⁷⁶ By itself, any tax, and particularly a carbon tax that might adversely impact British competitiveness, would not be credible, as it could be reversed in any Budget. Indeed, the Budget of 2014 would demonstrate this by freezing the price at its early low level.

The central element in the consultation, endorsed in the resulting *White Paper* published in July 2011, was therefore to offer long-term 15-year contracts for low-carbon generation (so-called

⁷⁴ £4.3 billion at 2005 prices (Office of National Statistics)

⁷⁵ British Gas, npower, Scottish and Southern, Scottish Power, EDF and E.ON

⁷⁶ HM Treasury, *Budget 2011*, HC 836, March 2011



Contracts-for-Differences, CfDs with FiTs). The CfD would specify a strike price (in constant £/MWh) and would pay or receive the value of the strike price *less* the market price (i.e. if the market price were above the strike price the CfD holder would pay back the excess, but otherwise receive the shortfall). As such it had similarities, but also important differences, from the standard FiT contract. In particular, the CfD holder is still responsible for predicting and selling output and being responsible for imbalances, in contrast to the standard FiT which just pays on metered output. Newbery (2012b) criticised the way in which CfDs would place the onus of marketing and balancing the unpredictable output from on-shore wind farms on the operators, rather than in the classic FiT contract in which the operator would be paid on metered output at an agreed price. The UK solution seemed to attach unreasonable weight to the desirability of using market solutions despite an allocation of risk that could substantially raise the support cost. In practice most independent renewables developers shift this risk by signing FiTs with one of the Big Six utilities, at a discount of 10-15% of the expected strike price. Arguably it would have been cheaper to instruct the System Operator to offer the same risk transfer, as the SO is best placed to manage system balancing.

The CfDs would be further bolstered by an Emissions Performance Standard (EPS) that would limit emissions from any new power station to 450gm/kWh “at base load”, intended to rule out any unabated coal-fired station (with exemptions for the demonstration Carbon Capture and Storage, CCS, stations which would only require a third or less of output to be subject to carbon capture).

The final component of the EMR was a proposal to introduce a Capacity Mechanism to encourage an adequate supply of flexible peaking plant to ensure security of supply for GB.⁷⁷ As the volume of intermittent wind connected to the system increases (and the 2020 targets are for 27-35 GW of on- and off-shore wind) so the risk of sudden drops in wind power increase. If we take as an example wind power simulated over Britain from 9-11 October 2003 (using data from Green and Vasilakos, 2010) the wind output fell from a capacity factor of over 85% to less than 5% over a period of 24 hours, and by 65% in the first 10 hours. If the UK succeeds in building 27 GW of wind, this would require the rapid start up and/or import of nearly 18 GW of capacity over 10 hours (assuming that the system had been able to accommodate the previous peak wind output of 23 GW compared to demand then of 34 GW). In the past, peaking capacity was supplied by older power stations with high variable costs, but the LCPD and the EU Industrial Emissions Directive will force most such plant off the system (except perhaps for some older CCGTs). This requires new peaking plant to be built to run a modest and rather variable number of hours per year, for prices that would be hard to predict.

⁷⁷ Northern Ireland is part of the all island Single Electricity Market, which already has a capacity remuneration mechanism, hence the restriction to GB which is the UK less NI.



4.2.3 Delivery of the Electricity Market Reform⁷⁸

After much consultation and debate, the EMR described above was enshrined in the *Energy Act 2013* and received Royal Assent on 18 December 2013. The carbon price floor was the responsibility of the Treasury and had been set in the Budget of March 2011, but almost immediately after the enactment of the *Energy Act*, the 2014 Budget froze the price floor from its then rather low level until later this decade – clearly any instrument subject to the passing whim of chancellors setting budgets creates additional uncertainty for those making investment decisions and underlines the need for credible contracts.

Designing the Renewable Contracts for Differences

DECC was charged with delivering the EMR, and delegated the task of advising the setting of strike prices for the CfDs and the amount of capacity to procure in the capacity auction to National Grid as System Operator. DECC appointed an independent Panel of Technical Experts (PTE) in February 2013 to advise on the methodology and evidence used by National Grid (but not on any policy issues nor on its affordability). DECC published its consultation on the draft strike prices for the CfDs for renewable technologies together with supporting documents in July (DECC, 2013a), including the PTE's first report (DECC, 2013b). The strike prices⁷⁹ differed by technology, and in £2012 prices for 2014/15 ranged from £55/MWh for landfill gas to £95/MWh for on-shore wind, £120/MWh for large solar PV, £155/MWh for off-shore wind, up to £305/MWh for wave and tidal stream.

The PTE were critical of the methods for setting these strike prices for a number of reasons. They considered that the hurdle rate (the Weighted Average Cost of Capital, WACC) used to determine the strike price was probably too high, given the extent to which these contracts (of 15 years duration, indexed to the price level) had de-risked investments, and they argued that it would be better to use auctions to determine the strike prices (DECC, 2013b, para 79). A further criticism of the new support system is that although it was pre-figured before the ROC re-banding of 2012, the RO system was scheduled to continue in parallel with the CfDs until 2017. The immediate effect of this was that in order to make the new scheme appear successful it had to be at least as generous as the already over-generous RO scheme, and offer the same uniform country-wide prices.

DG COMP were similarly critical of the failure to market test the state aids offered through the CfDs, and in response the government announced in September 2014 the possibility of auctioning CfDs if the volume of applications exceeded the amounts available (DECC, 2014b), and as this

⁷⁸ The author is a member of the Panel of Technical Experts advising DECC on EMR delivery, but the views expressed here are his alone and the evidence presented is confined to that available in the public domain.

⁷⁹ Published at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/263937/Final_Document_-_Investing_in_renewable_technologies_-_Cfd_contract_terms_and_strike_prices_UPDATED_6_DEC.pdf



condition was met, the Low carbon Contracts Company (2015) issued its implementation plan. The plan divides the budget into three separate pots for technologies of varying degrees of maturity. Each budget is announced shortly before the allocation (and as at March 2015, the autumn 2015 budget had not yet been announced) and its cumulative total is limited by the Levy Control Framework (to £7.6 billion annually by 2020). Developers submit sealed bids, which are chosen in order of increasing strike price regardless of the delivery date. If there are inadequate bids for any pot then the developers receive the administratively set and published strike prices.

The first CfD auction was held in February 2015, and results are presented in Table 1.

Table 1: CfD Auction Allocation: Round 1

| Technology | | admin price | lowest clearing price | 2015/16 | 2016/17 | 2017/18 | 2018/19 | Total Capacity (MW) |
|--|-------------|-------------|-----------------------|-----------------|-----------------|----------------|------------------|---------------------|
| Advanced Conversion Technologies | £/MWh MW | £140 | £114.39 | | | £119.89 36 | £114.39 26 | 62 |
| Energy from Waste with Combined Heat and Power | £/MWh MW | £80 | £80 | | | | £80.00 94.75 | 94.75 |
| Offshore wind | £/MWh MW | £140 | £114.39 | | | £119.89 714 | £114.39 448 | 1162 |
| Onshore wind | £/MWh MW | £95 | £79.23 | | £79.23 45 | £79.99 77.5 | £82.50 626.05 | 748.55 |
| Solar PV | £/MWh MW | £120 | £50.00 | £50.00 32.88 | £79.23 36.67 | | | 69.55 |

Source: DECC (2015)

The 27 successful projects will receive subsidies of £315 million per year by 2020/21. Table 1 shows that the offered strike prices for many technologies were substantially below the published strike prices (which will be henceforth interpreted as price caps), supporting the view that the WACC had been set too high. The solar bid of £50 for 2015/16 was, however, implausible, and has not been registered, so it fails to receive a CfD.⁸⁰ This may not be surprising given that the penalty for withdrawing (set out in DECC, 2015b) and is hardly penal: “no new application may be made for a CfD where the site of the generating station described under the new application overlaps with the excluded site.” Thus the end of 25 years of designing supports for renewables brought us back to the original tender auctions of the NoFFO described above, but this time paying (slightly) more attention to penalties for non-delivery.

⁸⁰ See the list of registered projects at <http://cfd.lowcarboncontracts.uk/>



The Capacity Mechanism and the Capacity Auction

The efficient price of electricity is the sum of the System Marginal Cost (SMC) plus a Capacity Payment, CP, where

$$CP = LoLP*(VoLL-SMC). \quad (1)$$

LoLP is the “Loss of Load Probability” and VoLL is the Value of Lost Load, a measure of value that should reflect the willingness to pay to avoid a loss of load. The original English Electricity Pool set up in 1989 but replaced by an energy-only market in 2001 added this CP to the System Marginal Price (which might and often was above the SMC). At that time VoLL was set at £(2014) 5,000/MWh but this time DECC has accepted a value of £17,000/MWh, arguably on the high side (Newbery and Grubb, 2015).

The EU Third Package⁸¹ (of energy market reforms) sets out the Target Electricity Model (TEM) to come into effect by 2014. Its core is an energy-only market with a single auction platform, Euphemia, for day-ahead, intra-day and balancing trades, which simultaneously clears bids and offers and the use of all interconnectors across the EU, fragmenting the market into different price zones only after interconnectors are fully used. By the end of 2014 Euphemia had coupled markets from Finland to Portugal, including GB, but not the Single Electricity Market (SEM) of the island of Ireland, which has a derogation until 2017. As the efficient electricity price includes the capacity payment in (1), the TEM raises the question whether, and if so how, energy-only markets will deliver reliability. The model for the TEM was Nord Pool, which has operated a successful energy-only trading system for many years, as have the major power exchanges such as EEX and APX, but not all EU countries have (or once) followed this model. Many markets have made or continue to make capacity payments. DG COMP has been very critical of this practice, arguing that they often have more to do with compensating generators for stranded assets than delivering reliability at least cost.

There is a legitimate case for a capacity payment where generators are required to bid their Short Run Marginal Cost (SRMC, mostly fuel costs), as under the Bidding Code of Practice of the SEM (SEM, 2007), for they will fail to recover their fixed costs without such an addition. The Electricity Pool of England and Wales also added a CP of exactly the form of (1), but allowed generators to offer a supply function that was not necessarily their SRMC (and indeed, given the market power of the generators, was often above that level) (Green and Newbery, 1992, Newbery, 1995, Sweeting, 2007). If generators are aware of growing tightness in the market and are free to offer at prices above their SRMC, they will price in scarcity up to any price cap (logically set at VoLL) and

⁸¹ See e.g. <http://www2.nationalgrid.com/UK/Industry-information/Europe/Third-energy-package/>



effectively charge the CP in (1). There is some evidence that spot prices reflect such scarcity payments (Newbery, 2015).

On the face of it one might conclude that energy-only markets can deliver sufficiently sharp scarcity prices that should signal the profitability of new investment that, if delivered, would ensure an adequate reserve margin and hence satisfactory reliability. This might be plausible if all investment decisions were taken on commercial grounds, that prices were not capped well below the VoLL, that the policy environment were predictable and stable, and that either liquid forward markets existed for a reasonably fraction of the proposed plant life (i.e. 20+ years ahead of the final investment decision) or credible long-term power purchase agreements could be signed with credit-worthy counterparties. Unfortunately, hardly any of these conditions hold in GB (nor in many of the liberalised electricity markets in the EU) during the period of delivery of the TEM. The US has long argued that there is a “missing money” problem caused by low price caps that prevent prices reaching levels that would cover fixed costs of peaking plant that is only required a few hours per year (Joskow, 2013) and now GB is advancing the same argument.

The chosen design for the Capacity Auction was best practice, drawing on extensive US experience (Newbery and Grubb, 2015). It would be a descending clock auction with a downward sloping demand schedule that would hit the target amount to procure at the net Cost of New Entry. That was estimated by National Grid (2014a), the TSO advising on the auction design and parameters, at £49/kWyear. New entrants would be granted 15 year contracts for indexed capacity payments, but would expect to earn the bulk of their revenue from the energy markets (forward, spot, balancing and ancillary services), as the capacity payments were intended to provide the missing money that energy-only markets were thought to experience. Existing plant would be price-takers, capped at £25/kWyr, but if successful would receive the clearing price and a one-year contract to guide exit decisions (and they could repeatedly bid for successive one-year contracts).

National Grid’s advice was scrutinised by the independent Panel of Technical Experts (PTE) as part of their duties to examine EMR delivery. The PTE made a number of criticisms in their June report (DECC, 2014a), the main thrust of which was that as the decision on the amount to procure was made by the minister, advised by the TSO (each of whom would be blamed for press concerns about “the lights going out” and neither of whom had to bear the cost of procurement), there was a bias towards over-procurement and an unwillingness to rely on imports. Ironically, while the argument for the auction was one of missing money, excessive procurement would drive down future energy prices, and make the missing money problem worse.

The auction cleared at £(2012) 19.40/kWyr on 18th December, 2014 (National Grid, 2014b), 40% below the estimated clearing price, dramatically demonstrating the power of competitive auctions compared to administrative decision-making. Just under 65 GW bid and 49.3 GW received Capacity Agreements for delivery in 2018/19 at a cost of £(2012) 956 million. 77 (out of a total of 306) new units, average size 34 MW, were successful totalling 2.4 GW, and received 15-year contracts. Most



surprising was that the largest share of entrants was by two Combined Cycle Gas Turbines, which the TSO had used in predicting the £49/kWyr entry price. 166 MW of Demand Side Response was successful and were granted one-year contracts. 43.7 GW of existing plant received 1 year contracts, while 6.3% received 3-year contracts (for refurbishing, mostly nuclear stations). 8.5 GW of existing plant failed to secure an agreement.

Financing of low-carbon projects

The financing of all renewable electricity falls on electricity consumers, either directly as a cost borne by electricity suppliers under the Renewables Obligation, or as a compulsory levy on all licensed suppliers in the UK. The move from a market-determined ROC to a strike price set by DECC (or as a contract secured in the CfD auction) raised concerns about the credit-worthiness of the counterparties (initially the supply companies), given that the contracts were for 15 years but consumers can switch supplier at very short notice, potentially stranding such contracts. The solution was for the government to set up a CfD Counterparty as a Government owned limited liability company.⁸²

In response to growing complaints about the rising cost of environmental obligations passed on to electricity consumers, DECC has updated its policy in November 2014⁸³ as follows:

- “Inclusion of the December 2013 package to reduce bills for households by £50 on average in 2014: this covers changes to the ECO, a £12 Government-funded electricity rebate, and voluntary deferrals to charges by distribution network operators;
- Updated electricity market modelling: reflecting the impact of the cap in the Carbon Price Support rate announced at Budget 2014⁸⁴ and final proposals on Electricity Market Reform;
- Inclusion of measures to help energy intensive industries: this covers compensation for the indirect costs of the EU ETS and CPF, RO and FITs, exemptions from the future costs of CfDs, and discounts on the CCL; ... ”⁸⁵

Nevertheless, this system of financing is fiscally illiterate, as the financing of renewables is a public good essentially defended for the spill-over of learning-by-doing through the EU burden-sharing obligation under the *Renewables Directive*, and as such should be supported from general tax revenue. This could almost painlessly be delivered by removing all such levies from electricity and

⁸² See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65635/7077-electricity-market-reform-annex-a.pdf

⁸³ See <https://www.gov.uk/government/publications/estimated-impacts-of-energy-and-climate-change-policies-on-energy-prices-and-bills-2014>

⁸⁴ i.e. renegeing on the earlier Carbon Price Support announced in 2011 to make nuclear power “commercial”.

⁸⁵ ECO is the Energy Company Obligation, CPF is the Carbon Price Floor (the CP Support is the tax difference between this and the EUA price), CCL is the Climate Change Levy. This alphabet soup is indicative of the growing complexity of supporting renewables and energy efficiency, (Chawla and Pollitt, 2013).



gas and moving the VAT rate from its artificially subsidised level of 5% to the standard rate of 20%. This would exempt the production sector (thus avoiding the need for discriminatory selective exemption for energy-intensive industries), remove the differential distortion between electricity and gas (as the electricity levies are substantially higher than on gas), and the distortion between energy consumption and energy efficiency measures which are subject to standard rate VAT.

Governance issues and the role of public institutions

DECC and Ofgem worry about conflicts of interest in having the System Operator as the main EMR delivery agent, and as noted, DECC appointed an independent Panel of Technical Experts to assess the delivery process. Parliament scrutinises the delivery of EMR (and all policies) through its Select Committee process. Thus the *Draft Energy Bill* was criticised cogently by witnesses who gave evidence to the Parliamentary Energy and Climate Change Committee (HC, 2011; 2012).

A good example of a potential conflict of interest is the setting of the amount of capacity to procure in the December 2014 capacity auction. Newbery and Grubb (2015) argued that the amount procured was likely to be excessive for a number of reasons, one of which was a potentially misleading terminology used in setting the security standard as 3 hours per year Loss of Load Expectation. “Loss of Load” suggests blackouts to be avoided, when in fact all it means is that the System Operator (SO) has to step in as offered supply falls short of expected demand. The SO has a range of tools available to address this potential problem, and after these have been exhausted, if these measures are not enough, reducing voltage (“brown outs”) and in the final step, making controlled disconnections (which fall far short of a general black out).

The SO recommended the amount to procure to the Secretary of State for his final decision. As there is no cost to the SO of over-procuring, and some benefit in that the SO is likely to be blamed if he fails to balance the system and “keep the lights on”, the SO is likely to err on the cautious (and expensive) side. Similarly the Secretary of State fears the tabloid headlines of “Britain is heading for power cuts” and is also cautious. As an authority has to set the required level for capacity to procure in a capacity auction, this naturally attracts criticism about the politics of public decision-making on what are technically highly complex issues, in which the current arrangement seems likely to lead to overly cautious (and costly) choices. That suggests the need for a technically competent but independent institution (perhaps an Independent System Operator working with Ofgem) in setting the volumes to procure in the Capacity Auctions.

Policies to support R&D and innovation in low carbon technologies

Perhaps the most innovative policy pioneered by the UK has been Ofgem’s Low Carbon Network Fund (LCNF) for electricity distribution network operators, and its expansion to Network Innovation Competitions for electricity (high tension grids on and off-shore) and gas (transmission and



distribution networks).⁸⁶ The LCNF had a budget of £500 million to award in annual competitions to projects to demonstrate near-commercial methods for reducing the carbon intensity of the networks and/or facilitating the connection of low-carbon technologies such as wind farms. The case for such a fund was that regulated network utilities are discouraged from innovating, for if they are unsuccessful their shareholders bear the cost but if they are successful the gains will be taken back at the next price control. In concert with this, the system of price-cap regulation known as RPI – X, in operation since the privatisation of British Telecom in 1984, has been replaced by RIIO (Revenue = Incentives + Innovation + Outputs),⁸⁷ which extends the price control period from five to eight years, allowing utilities to keep innovation gains for a longer period.

4.3 Evolution and prospects

UK energy and environment policy has been a complex work on progress for at least 25 years since the electricity supply industry was privatised. There has been no shortage of critics (most notably Henney, 2011) including this author. Much of the complexity has arisen as the government feels strongly that it should only change past policies that have guided investment decisions in ways that do not undermine the implicit compact under which those investments were made, resulting in additions to rather than reforms of past unsatisfactory interventions. While there is a good case for guaranteeing the existing contracts will be honoured, there seems to be sometimes too great concern about not disturbing near and mid-term investment plans, although the sudden changes in PV FiTs are an exception. EMR was intended as a more thorough rethinking of the support package, but as noted it has also been constrained by past decisions, while the one set of policies that do change at political whim, namely the tax system, remains inconsistent with the stated objectives of the government's policy and sound public finance principles. On several occasions DG Comp's interventions have introduced a greater reliance of market testing to the benefit of policy, although their requirement that existing interconnectors should be included in future capacity auctions effectively gives them extra money for no extra effort. Similarly DG COMP's insistence on premium FiTs risks raising costs as it exposes renewables to both energy price and balancing risks. One could argue that the intention behind DG COMP's requirement was that the SO should allocate the full costs that renewables impose on the electricity system to those responsible, and this could be achieved in less costly ways. It would seem likely to be cheaper if the SO (or another delivery body) were empowered to offer fixed price contracts (classic FiTs or CfDs) to renewables for their metered energy together with a second fixed price contract for all the associated balancing and ancillary services required. There is no doubt that these might be substantial, as the consultation

⁸⁶ See <https://www.ofgem.gov.uk/electricity/distribution-networks/network-innovation/low-carbon-networks-fund>

⁸⁷ See <https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model>



for these services in the Single Electricity Market (SEM) of the island of Ireland demonstrates (SEM 2014).

EMR has only just held its first capacity auction and the CfD support system for renewables is only just starting and so it is premature to judge EMR's success. The longer-term CfD for the proposed Hinkley Point nuclear power station⁸⁸ (3.2 GW and one of the most expensive generation projects in the world) is still being scrutinised by DG COMP under its state aids framework, and appears to be an unnecessarily expensive way of financing the project. The government's aim of supporting CCS demo plants was set out in the 2007 White Paper (DTI, 2007) but has been much delayed,⁸⁹ and a competition was finally launched in 2012 with two projects short-listed in Jan 2013 and at March 2014 still awaiting award.⁹⁰ As noted above, renewable electricity has been growing rapidly and at its recent geometric rate of growth would easily meet the 2020 targets. However, funding for renewables is capped by the Levy Control Framework, which limits annual support to amounts rising to £7.6 billion by 2020 and is already imposing a limit on support levels. Ironically, the cost of support increases as the price of fossil fuels (especially gas) falls, so even though consumers would be better able to support the programme the existing funding mechanism could impede that.

4.3.1 Evolution of prices

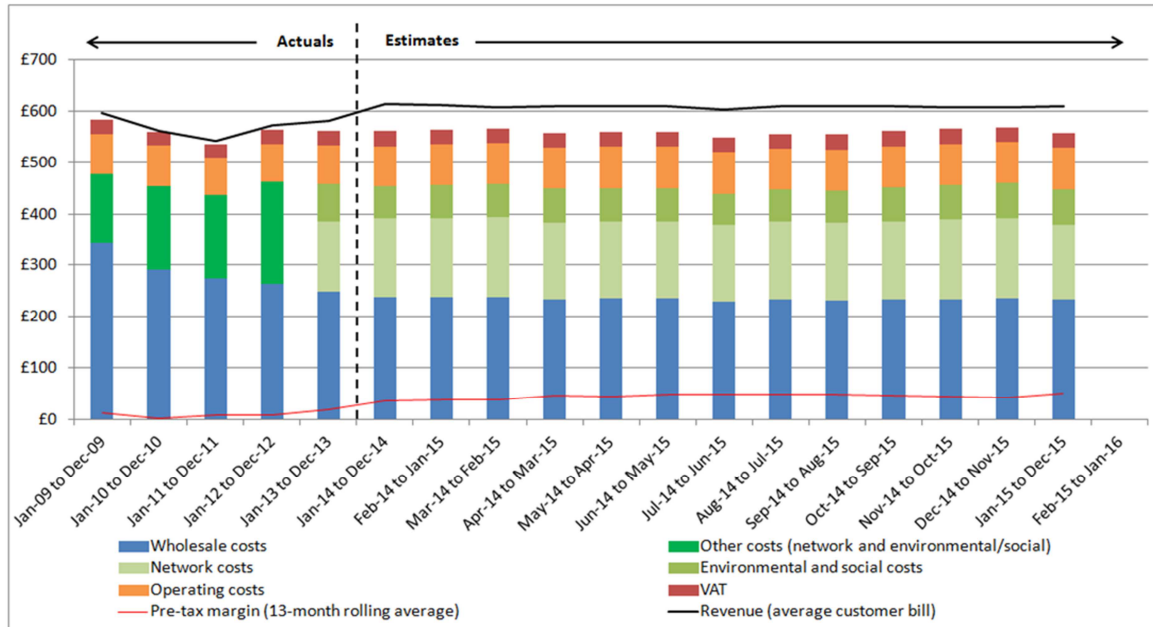
Wholesale electricity prices have been primarily driven by fossil fuel prices, but final prices include network costs, which have been rapidly increasing to accommodate increased wind penetration in Scotland and off-shore, and the various levies to finance renewables, energy efficiency, warm homes and all the other aspects of UK energy policy. Chawla and Pollitt (2011) note that over the period 2000-2011 typical electricity bills have risen by one-third in real terms, and that policy costs have risen from zero to 14% of the total bill over that period. Figure 2 is taken from Ofgem's periodic update of the build-up of consumer bills, which can be supplemented by similar graphs for earlier periods in Chawla and Pollitt (2011).

⁸⁸ See <http://www.edfenergy.com/energy/nuclear-new-build-projects/hinkley-point-c>

⁸⁹ See e.g. <http://www.green-alliance.org.uk/resources/The%20CCS%20challenge%20-%20securing%20a%202nd%20chance%20for%20UK%20CCS.pdf>

⁹⁰ See <https://www.gov.uk/uk-carbon-capture-and-storage-government-funding-and-support>

Figure 2: Build-up of domestic electricity bills



Source: Ofgem Supply Market Indicator (2015) at <https://www.ofgem.gov.uk/publications-and-updates/charts-outlook-costs-make-energy-bills> but see also <http://www.energy-uk.org.uk/publication.html?task=file.download&id=5008>

Complaints about the high cost of domestic electricity have resulted in a Competition and Market Authority Inquiry into the electricity market, despite GB lying in the bottom third of EU-15 electricity prices and having probably one of the most competitive wholesale electricity market in the EU.

4.3.2 Impact on investment

As noted above, the rate of delivery of renewables has been impressive and successfully financed, while the massive increase in transmission investment on and off-shore has been financed at a low WACC. There is clearly an international appetite for low risk infrastructure projects in this era of remarkably low real rates of return, provided they are supported by credible long-term contracts.

4.3.3 Distributional impacts

Fuel poverty (defined rather imperfectly as spending more than 10% of income on fuel) has long been a matter of political concern, and after falling with falling energy prices in the 1990s is now rising again, as highlighted in the *Poverty Review Hills* (2012). Chawla and Pollitt (2011) show that the costs of policies falling on domestic electricity bills has risen from zero in 2000 to over 14% in 2011. As electricity is income inelastic, the impact fell more heavily on poorer households, they



show that households in the lowest income bracket paid around 1% of their disposable income on policy costs while those in the highest bracket only paid 0.1 of 1% of their disposable income. This has been partly offset by various programmes such as Cold Weather and Winter Fuel Payments, and energy efficiency measures (CERT, CESP, Green Deal, ECO, etc.) discussed in Chawla and Pollitt (2011). These have not always been well-targeted and as a result there is a transfer from those who do not benefit (many of whom are poor) to those who do benefit (some of whom are rich). Possibly the most regressive transfer is to those with large houses that have installed incredibly generous FiTs for solar PV panels, paid for by the poor in higher and rising policy costs.

4.3.4 Cooperation with neighbouring countries

Interconnectors have finally been accepted as contributing to security of supply, despite their absence in the first capacity auction (Newbery and Grubb, 2014), primarily because of DG COMP pressure. As such it is important to cooperate with countries to which we are interconnected, and to some extent this is ensured through the TEM and the single Euphemia auction platform. A more worrying failure to cooperate is the frustration with the failure of the EU ETS and the perceived need for GB (not Northern Ireland) to introduce a Carbon Price Floor. Failure to cooperate and ensure similar efficient pricing of carbon across interconnectors means that flows will not necessarily reflect efficient costs.

An apparently more serious failure lies in the difficulty of trading renewable power across borders, resulting in an inefficient allocation of investment, but arguably this does at least deliver the necessary volumes of investment to create sufficiently large demand pull to drive down production costs. The main problem in making renewables tradable is that different technologies are at different stages of maturity, and can justify differing amounts of development support (defined as the excess of the subsidy over that required to cover the value of the carbon saved). One can imagine various solutions, for example trying to agree how many green certificates should be allocated per MWh of each technology, and allowing trade in these green certificates. Perhaps better would be to determine the number of certificates per MWh by an EU-wide auction process. Alternatively one might prefer that the renewables targets be translated into cash amounts for each country, leaving them free to commission renewables in any location. They would be credited with the least amount of subsidy that such a technology would need compared with a reference form of generation (e.g. a combined cycle gas turbine). This would have the advantage that the total budget could either be allocated to renewables or to R&D or demonstration plants (e.g. for CCS), provided such funds were available for competitive EU wide bids.



4.4 Challenges and lessons

The main challenges remain to deliver a reliable low-carbon electricity industry at least cost, and to finance that efficiently. As wind penetration rises, so does the need for managing the reduction in synchronous power, a problem that the SEM on the island of Ireland faces more immediately, and which she is addressing through the DS3 programme.⁹¹ Increased renewable generation requires more and smarter transmission and distribution network delivery, both investment and management, on-shore, off-shore and via more interconnection. Ofgem has been consulting on how best to do this through its Integrated Transmission Planning and Regulation project (Strbac et al, 2015).⁹²

One of the main and remaining challenges has been to secure planning permission for renewables, particularly on-shore wind, and transmission lines. This is not peculiar to the UK, but perhaps the UK has been less effective at mobilising community support and shared ownership for wind farms.

4.4.1 Reconciling the energy trilemma

The main tension has always been between affordability and sustainability, as security of supply is taken as an over-riding objective, arguably to an excessive degree. This tension has not been helped by periodic political commitments to reduced rates of VAT on energy combined with a perverse willingness to load all policies on to customer bills, with the resulting adverse distributional impact noted above. When the political pressure becomes overwhelming the standard approach has been to drop or freeze various policies, as in the case of the Carbon Price Floor.

4.4.2 Success stories and lessons

Ofgem's Low Carbon Network Fund and its successor NICs have been an impressive success and are surely a good regulatory initiative to follow.⁹³ The main lesson I would draw is that while underlying risks may not be avoidable, their cost can be greatly reduced by allocating them efficiently, trading off the desire to provide incentives for their mitigation against the insurance benefits of allocating them eventually to final consumers, for whom the cost of energy is a small part of expenditure. Thus System Operators are best placed to forecast and manage wind risk, pension funds may be appropriate sources of finance once the uncertainties of building new nuclear power stations has been resolved and they have been commissioned, and auctions are the best form of price discovery if there is adequate potential competition.

⁹¹ See <http://www.soni.ltd.uk/Operations/DS3/>

⁹² See <https://www.ofgem.gov.uk/electricity/transmission-networks/integrated-transmission-planning-and-regulation>

⁹³ The author should declare an interest as a panel member of all three competitions.



5. Case Study 3: The Energy Transition in France, by Michel Colombier, Mathilde Mathieu & Andreas Rüdinger

5.1 Introduction

Like many other industrialised economies, France has identified the energy transition as one of the major challenges ahead, considering its environmental, economic and social dimensions. From November 2012 to July 2013, the then newly elected president François Hollande initiated a national energy transition debate, regrouping all major stakeholders (industry, unions, civil society, political representatives and experts) to pave the way for a new vision of the French energy model towards a low-carbon economy, which was later translated into the currently debated *law on the energy transition for green growth*.⁹⁴ This law aims to define the blueprint of this long-term project around ambitious objectives covering the energy system as a whole: a strong push for energy efficiency across the economy; the diversification of energy supply in all sectors; and a reduction by a factor of 4 of greenhouse gas emissions by 2050. Furthermore it also includes several important policy measures regarding support instruments for energy efficiency and renewable energies, as well as strategic planning tools.

Beyond the national scope, this new policy dynamic is representative of the wider international commitment France is willing to demonstrate, considering not only the cooperation with its European partners within the 2030 climate and energy framework, but also the international conference on climate change to be hosted by France at the end of 2015. In this context, the national strategy also represents a means to show off the 'exemplarity' of French energy and climate policy as a frontrunner with regards to the low-carbon transition.

Much like in other European Member States, the power sector plays a key role in triggering this transition process. This is true from a technological perspective, regarding the potential of electrification and cost-effective abatement options. But it is even more so from a political perspective: the institutional structures of the French power system are very much constitutive of its energy policy model and they are, to a large extent, at the core of the political tensions around the shift between an old and a new energy model. Thus, the current project of transformation reaches beyond the nuclear vs. renewables debate, and might lead to a broader overhaul of the power market, including governance issues (centralised vs. decentralised) and the regulatory paradigm (public service approach vs. competition and liberalised markets).

⁹⁴ The law undergoes its second reading at the National Assembly in May 2015; the final adoption is expected for July 2015.



The political challenges of the transformation of the power sector are all the more visible when considering the issue of political narratives. Unlike other major European economies such as Germany or the UK, the political narrative for the transition towards a low-carbon power sector remains on a rather fragile basis in the French context. Indeed, through its strong reliance on nuclear power, the French electricity mix has already one of the lowest carbon intensities across Europe, justifying, at least for the short-term, the reliance on the *status quo* and requiring a more elaborate vision on the need for a diversification of energy sources and the timing and pace of such a transformation.

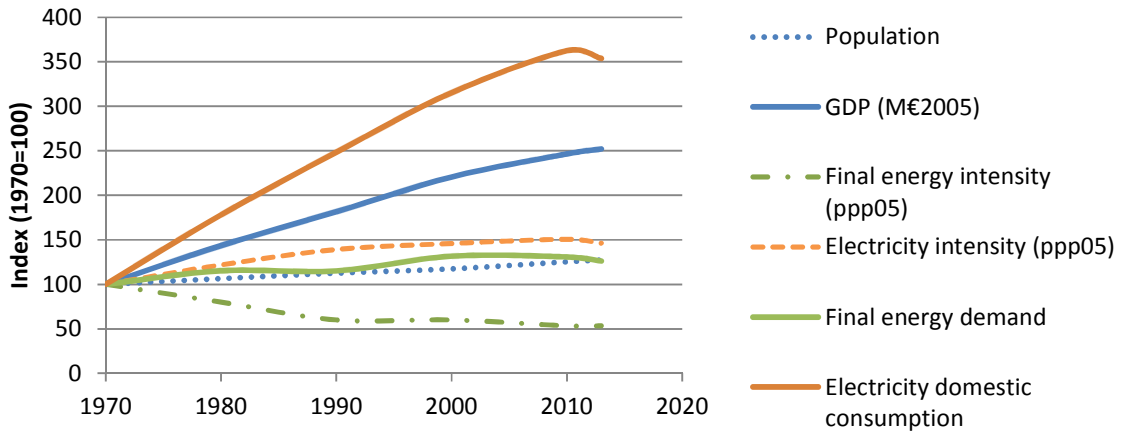
Considering this context, this chapter provides an assessment of the main challenges for the transition of the French electricity system in the short and long-term, taking into account its technical, economic and political dimensions. The first section will provide a brief overview of the main characteristics and evolutions of the French energy and power systems to provide valuable background information. The second section will present the overall strategy for the energy transition in France, retracing the main political debates and orientations to highlight some of its specificities, including the structural question of the future role of electricity in the energy system. The third chapter provides a deeper look into the main policy changes and regulatory challenges within the power sector, considering the national transition and interactions with the larger European agenda of market integration. The last section will put the identified aspects into perspective, regarding future evolutions and challenges as well as the lessons that could be drawn from the French experience.

5.2 A glance at the French energy model: main characteristics and long-term objectives

5.2.1 Historic evolution of energy demand

Between 1970 and 2013, French GDP more than doubled, the population increased by 27%, and despite the efforts made to reduce its final energy intensity (-50%), final energy consumption increased by 25%.

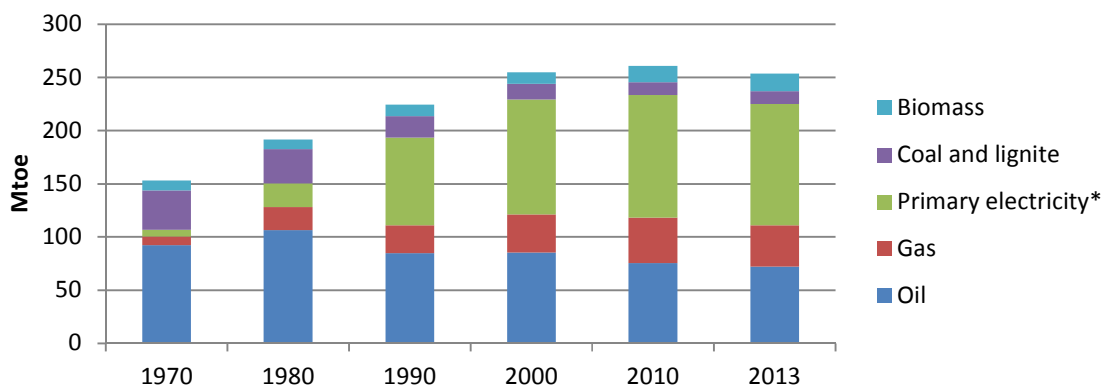
Figure 1: Economic, demographic and main energy indicators for France (1970=100)



Source: IDDRI, Enerdata

In the same period, France has experienced significant electrification with a multiplication of demand by 3.5, while the share of oil products has decreased in relative and absolute terms (figure 2). Indeed, after the oil crisis of 1973 the energy mix changed completely. In 1974, in order to reduce the dependence from imported fossil fuels, the French Government led by Prime Minister Pierre Messmer, launched a substantial nuclear program and ordered the construction of 13 nuclear power stations. The bulk of the French nuclear power fleet (40 GW out of 63 GW in total) was built during the 10 subsequent years.

Figure 2: Primary energy consumption in France since 1970



*: Primary electricity regroups nuclear heat (including losses) and renewable electricity generation.

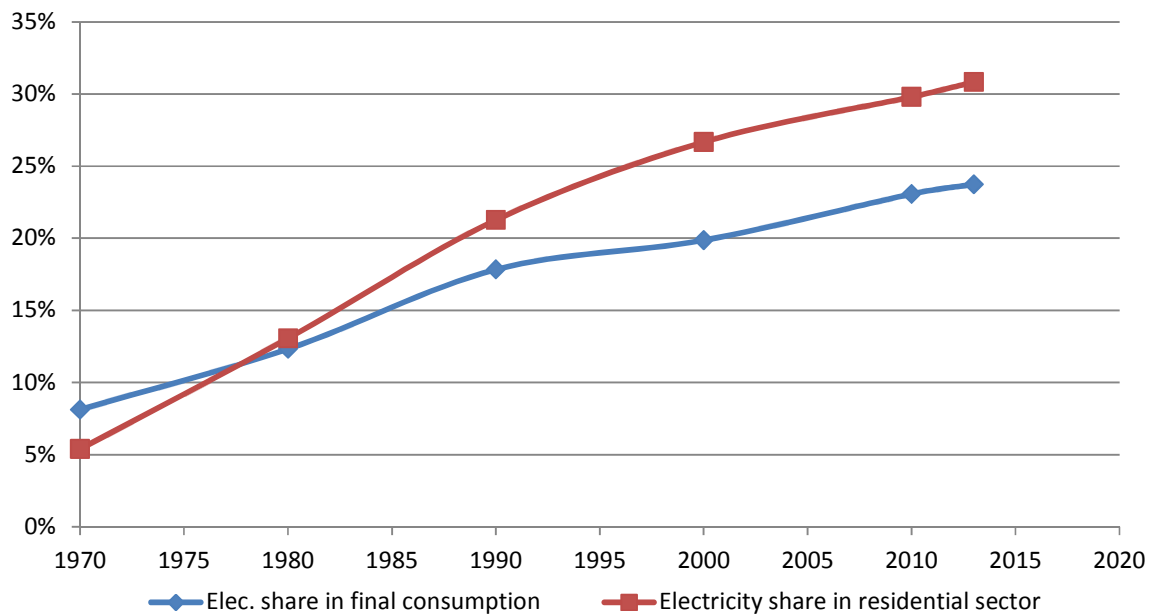
Source: IDDRI, Enerdata

Compared to other countries, the expansion of the power sector has had an important influence on the evolution of energy consumption in the building sector, with significant electrification of heating and hot water appliances. **Currently, about one third of French buildings are heated through direct electrical heating and electric hot water boilers have an important share of the**



market. This leads to a cumulated consumption of over 85 TWh per year (about 20% of final electricity consumption). Beyond the increase in overall demand, this electrification has raised a new challenge in terms of peak demand in winters. Due to the high share of electric heating, the French power system is extremely temperature-sensitive: according to the transmission grid operator *Réseau de transport d'électricité (RTE)*, each degree C° below average temperatures in winter increases peak demand by 2300 MW, representing more than half of the temperature-sensitivity of the entire European power system (RTE 2012). During February 2012, France's peaking demand reached an historical record of 102.1 GW, a 28% (+ 22 GW) increase compared to the peak registered 10 years before (Figure 4).⁹⁵ Considering the challenge for security of supply and the fact that extreme peaking plants cannot be refinanced through the energy-only market, France recently initiated a capacity mechanism to address this issue in the near future (see section 3.3).

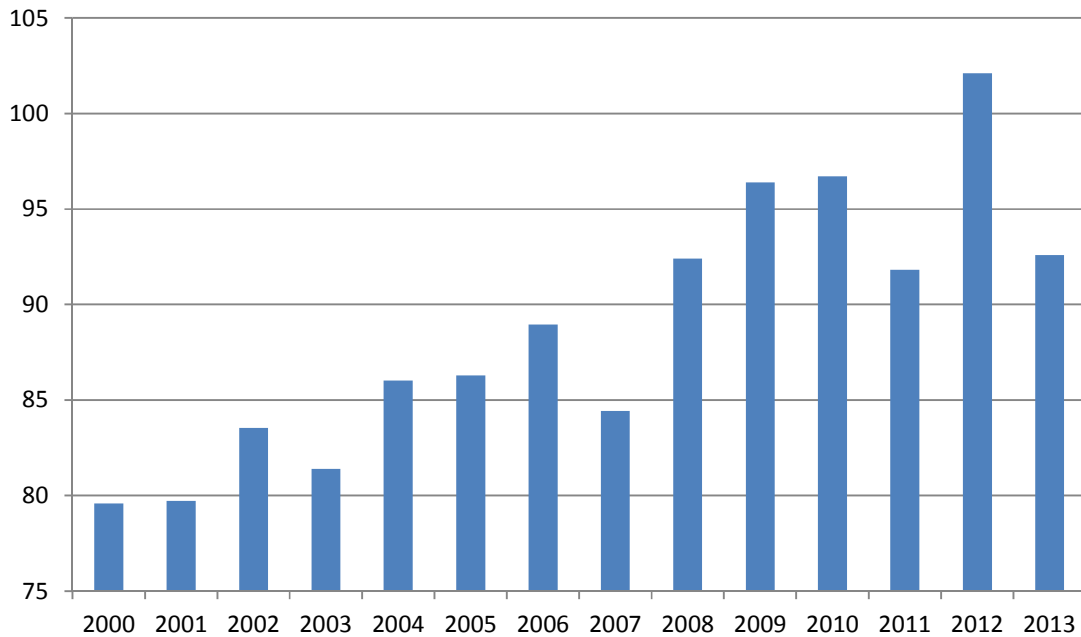
Figure 3: Electricity share in total final energy demand and in the residential sector



Source: IDDRI, Enerdata, RTE 2013

⁹⁵ By comparison, despite a 30% higher population, peaking demand reached a maximum of 85 GW in Germany. In the UK, with a roughly similar population as in France, peak demand was 60 GW.

Figure 4: Peak demand since 2000 (in GW)

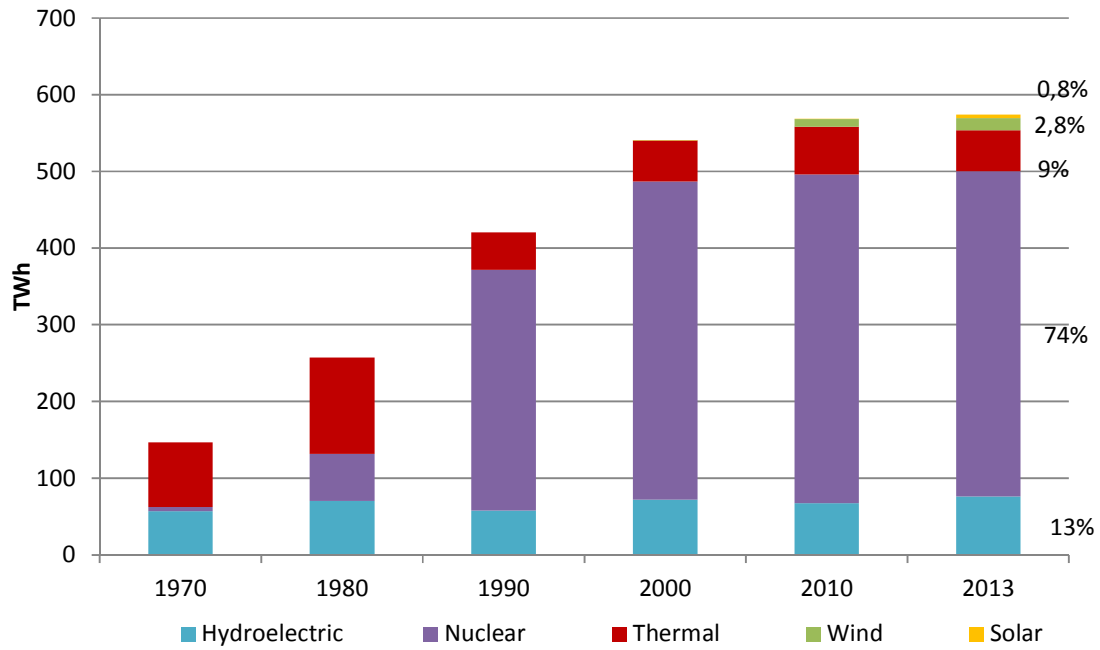


Source: IDDRI, Enerdata, RTE 2013

5.2.2 Energy supply and electrification

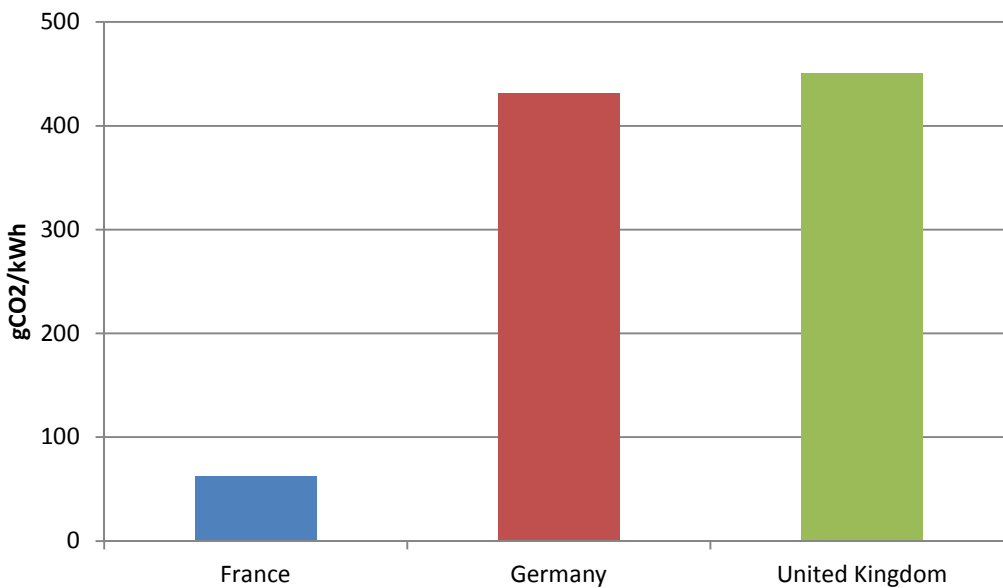
The French electricity mix is characterised by a very high share of nuclear power (74% of total generation), and a comparatively high share of hydro power, resulting in one of the lowest carbon intensities of electricity generation in Europe (and the world for what matter), almost ten times lower than in the UK or Germany.

Figure 5: Evolution of the electricity production mix



Source: IDDRI, Enerdata

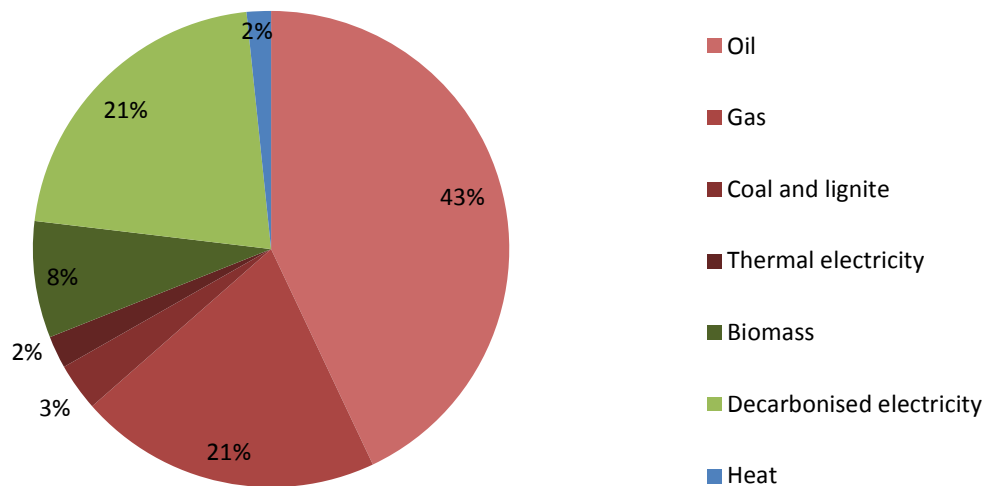
Figure 6: Carbon intensity of electricity in 2013



Source: IDDRI, Enerdata

However, considering the overall final consumption, France still relies on fossil fuels for about 70% of its energy uses, with oil representing by far the largest share (Figure 7).

Figure 7: Final energy consumption of France by source (2013)

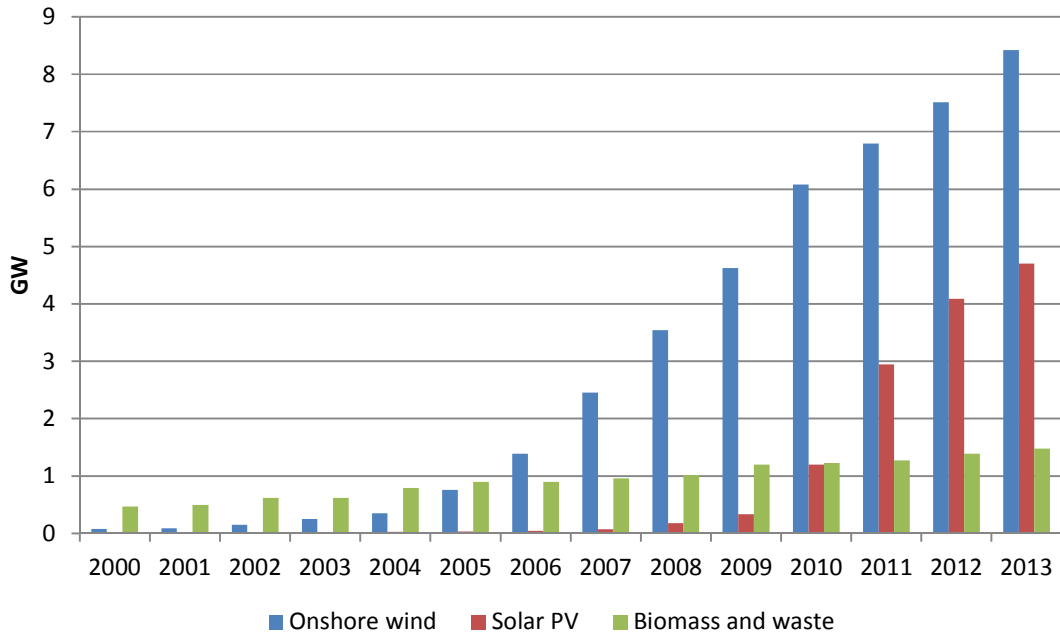


Source: IDDRI, Enerdata

While renewable energies already represent a total share of 18% of power generation (2013), the deployment of new renewable capacities (excluding existing hydro plants) has been rather slow compared to the 2020 objectives⁹⁶. This has in part been due to delays in onshore and offshore wind deployment. Indeed, according to the *Syndicat des Energies Renouvelables, SER*, (French industrial federation for Renewable Energy Systems, RES), under current trends, the total share of RES in gross final consumption would only reach 17% by 2020, while the national objective stands at 23% (27% for the electricity sector). This slowdown is all the more alarming in the current context of the energy transition law, which defines an even more ambitious objective of a total RES share of 32% by 2030 (40% for the share of RES in the power sector, see section 2).

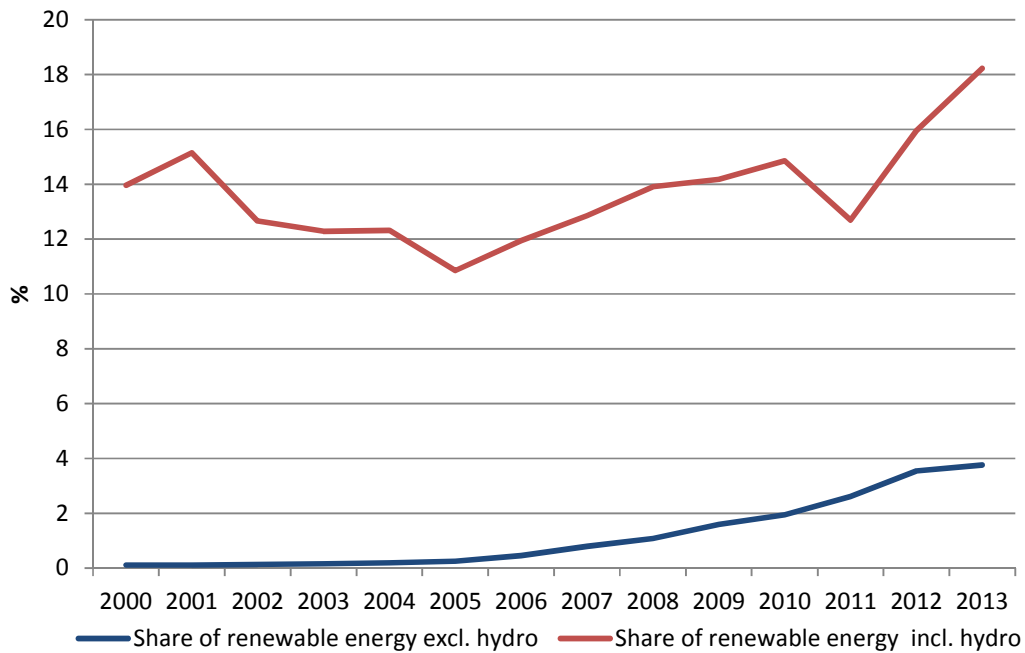
⁹⁶ Under the 2008 Renewable Energy Directive, France committed to increasing the share of renewables in gross final consumption to 23%. The National Action Plan for Renewable Energies indicates that this should result in a 27% RES share for electricity, including the development of 25 GW of wind (of which 19 GW onshore), 5,4 GW of Solar PV and 2,3 GW of biomass plants.

Figure 8: RES capacities excluding hydro



Source: IDDRI, Enerdata

Figure 9: Share of RES in electricity production



Source: IDDRI, Enerdata



5.2.3 General objectives and targets for the energy transition

The national debate on the energy transition (DNTE), which took place between November 2012 and July 2013, constituted a first-of-a-kind initiative in the French context. There had been prior stakeholder conferences (such as the *Grenelle* summit on the environment in 2007) to define some of the major mid- and long-term targets. However, in comparison to these, the DNTE stood out for its ambition to provide a comprehensive and coherent strategy for the energy transition, tackling all sectors and issues rather than dividing them up into smaller parts. While the recommendations of the stakeholder debate were purely indicative by nature, most of them have been taken up in the currently debated law on the energy transition. Integrating pre-existing national and European targets, this policy process has contributed to defining a more consistent set of targets for the period between 2020 and 2050.

Main objectives and instruments for the energy transition in France

In addition to the definition of mid- and long-term objectives outlined in the table below, the energy transition law also aims to introduce new policy planning tools to implement the transition. Inspired by the UK, the national *low carbon strategy* should define binding carbon budgets for the different economic sectors for three successive 5-year periods, to be revised and adopted by the parliament every 5 years. On the same timeline, the *Planification pluriannuelle de l'énergie* (multiannual planning framework for energy) aims to provide a more detailed plan for future investments in all relevant sectors (including energy sources, energy efficiency in buildings and mobility, etc.) with the corresponding policy and financial instruments (see section 3.1).

Several particularities can be highlighted, considering the targets currently defined in the draft bill. While most objectives until 2030 are in line with the strategies of other countries, the specific objective regarding the reduction of fossil fuel consumption represents an interesting point. Introduced first by president François Hollande at his opening speech for the 2013 environmental conference, it explicitly aims to provide a more stringent focus for energy efficiency policies, i.e. targeting the heating and transport sectors primarily (given that the power sector is already decarbonised). The highly ambitious objective of a 50% reduction in final energy consumption by 2050 represents another strong commitment, clearly indicating the idea that efficiency should be the first pillar of the French transition (see section 2.2.).

Eventually, the fact that no objective has been set regarding the share of renewables by 2050 (in both final energy consumption and electricity consumption) reflects the high level of ambiguity over the long-term future of nuclear power. Indeed, so far there are no clear indications on how the power sector should evolve after 2030.⁹⁷

⁹⁷ The French Energy Agency planned to publish an extensive study on a “100% renewable electricity scenario by 2050” in April 2015. However, because of its very political nature, this study has been censored so far,



Table 1: Main objectives for the energy transition in France⁹⁸

| 2020 | |
|--|------|
| GHG emission reductions (base 1990) | -20% |
| Share of RES in gross final consumption | 23% |
| Reduction in primary energy consumption (vs. Baseline) | -20% |
| 2030 | |
| GHG emission reductions (base 1990) | -40% |
| Share of RES in gross final consumption | 32% |
| Share of RES in electricity generation | 40% |
| Reduction in fossil fuel consumption (base 2012) | -30% |
| 2050 | |
| GHG emission reductions (base 1990) | -75% |
| Reduction in primary energy consumption (base 2012) | -50% |

Source: IDDRI

Energy efficiency and the role of electricity at the core of the debate

While it would easily exceed the scope of this paper to reiterate the richness of the debate in general, some of the main aspects and political tension lines can briefly be summarised here. Two factors can be highlighted in particular: the overall importance accorded to energy efficiency measures and the remaining uncertainty over the future role of electricity in the decarbonisation of the energy system.⁹⁹

The major role of energy savings in the long-term transition...

Energy efficiency and conservation (*sobriété*)¹⁰⁰ have been defined as the major drivers of the transition across all sectors. This priority has been defined in relation to the potential economic benefits (savings on external energy bill vs. additional investments) and the recognition that, among the four long-term trajectories considered, only those scenarios aimed at reducing energy

which gives a very clear illustration on the political sensitivity surrounding the long term future of nuclear power in France. See for example the article by *Le Monde*

⁹⁸ As defined in the draft law adopted by the National Assembly in February 2015. Objectives are still subject to changes due to the ongoing parliamentary debate.

⁹⁹ See (Ribera & Rüdinger, 2014) for longer analysis of the French energy transition debate and upcoming policy challenges.

¹⁰⁰ Commonly in France, the concept of « efficiency » refers to the idea of using less energy input for a same energy service (e.g. heating a building), while conservation or “*sobriété*” invokes the ability to reduce the need for energy services in the first place (e.g. reducing mobility needs through smarter urban planning).



consumption by at least 50% (between 2012 and 2050) achieved the objective of a factor of 4 (75%) reduction of greenhouse gas emissions by 2050. While there seemed to be a large consensus on the relevance of energy efficiency measures, this was much less the case for energy sobriety (i.e. reducing energy needs). Furthermore, many experts remain sceptical about the observed gap between the very ambitious objectives on energy efficiency and the lack of equally ambitious policy measures to drive the rapid deployment of investments at the local level. Furthermore, under current circumstances (energy prices, efficiency and amount of public aids, maturation of the market for efficient goods and deep retrofits), the economic feasibility of ambitious energy efficiency measures remains questionable. In the French context, stakeholders of the power industry have also repeatedly challenged the relevancy of electricity savings for decarbonisation in relation to the very low carbon intensity of the French power generation.¹⁰¹

...does not provide any clear indications on the future role of electricity

The priority given to energy efficiency measures could obviously have major implications for the future level of electricity demand, taking into account the potential for efficiency improvements in buildings and electrical appliances. **Indeed, among the 15 long-term scenarios evaluated during the debate, the assumed levels of electricity demand by 2050 range from a minimum of 280TWh to up to 840 TWh (compared to a current final consumption of 440 TWh).** While the lower limit belongs to one of the most ambitious transition scenarios with a strong focus on overall demand reductions and a nuclear phase-out by 2030,¹⁰² the upper limit has been set by a scenario that approaches decarbonisation primarily through electrification and a doubling of the current nuclear power fleet.¹⁰³

Considering the current political process, unlike other countries¹⁰⁴, France has set no specific targets for electricity savings, nor does the law give any orientation on what could be considered as a targeted level of power demand. This in turn leads to a growing uncertainty on the type of policy measures that would actually be required to achieve the objective of reducing the share of nuclear power to 50% of generation. If consumption were to increase sharply due to electrification, this target could be achieved without closing one single plant¹⁰⁵, whereas up to 30 reactors or more

¹⁰¹ Union Française de l'Electricité (2014): *Réussir la démarche d'efficacité énergétique en France*.

¹⁰² Scenario Négawatt 2011: http://www.negawatt.org/telechargement/SnW11//Scenario_negaWatt_2011-Presentation_anglais.pdf

¹⁰³ The report on the comparison of scenarios is available here: http://www.carbone4.com/download/Etude_Trajectoires_DNTE_C4.pdf

¹⁰⁴ For example, the German *Energiekonzept* defines an explicit objective of reducing electricity consumption by 10% until 2020 (against 2008) and by 20% until 2050 and aims at eradicating conventional electric heating through the thermal regulation on buildings. Similarly, Switzerland and Sweden have adopted policy objectives to phase-out electric heating by 2020.

¹⁰⁵ During the national debate, this was the position defended by the former CEO of EDF.



should be closed under a scenario relying on high efficiency and a shift away from direct electric heating.

Inversely, policy measures to facilitate the deployment of electric vehicles (direct subsidies and deployment of charging stations) could lead to higher electricity uses, although the impact would be much more visible in terms of load management than overall consumption volume.

The ongoing uncertainty over the future role of nuclear power

With 63 GW of nuclear generation capacity (and an additional 1600 MW under construction), France has by far the largest nuclear power fleet in Europe. This has allowed France to have one of the lowest carbon intensities of electricity generation in Europe, and relatively cheap power for end-users, considering that regulated tariffs are calculated on a cost-coverage basis, avoiding windfall profits. The objective (and prior electoral commitment of François Hollande) of reducing the share of nuclear power from 75% to 50% by 2025 was considered a fixed input at the beginning of the debate, based on the need to diversify generation sources from a technical and industrial point of view. Indeed, from a technical perspective, the French Nuclear Safety Authority raised the argument that, because of the homogeneity of the nuclear power plants (up to 20 reactors built on the same model), and the advanced age of the plants, the occurrence of a technical failure in one reactor could likely transform into a “systemic failure” (i.e. affecting most or all reactors of the same design), thus requiring a shut-down of a large part of the existing capacity. This risk could not be assumed without viable alternative power plants. The objective of industrial diversification (creating a real industry for renewable technologies in parallel to the nuclear branch) constituted a second political objective justifying such a decision. However, unlike the debate on the nuclear phase-out in Germany, the risk of nuclear accidents never played a major role in the French policy debate.

However, this orientation continues to be challenged by many stakeholders (business federations and unions) and policy makers (right-wing opposition) who refer to the potential costs and economic risks of substituting the cheap power generated by the existing and amortised nuclear power plants by alternative energy sources. The fact that the inter-parliamentary mixed commission¹⁰⁶ was dissolved after only ninety minutes of debate, illustrates the significant and ongoing political tension surrounding this issue. More importantly, even though it remains likely that the objective of reducing the share of nuclear (including a specific date, possibly 2030 rather than 2025) will be included in the final version of the law, it lacks a clear political strategy on how to implement this decision. In the absence of clear and binding mechanisms for the operator EDF, the

¹⁰⁶ The *Commission mixte paritaire* is a parliamentary body regrouping 14 members from the Senate and National Assembly. It intervenes in case both chambers are not able to agree on a single law in order to identify a compromise.



government will be at risk of triggering a battle with high political costs over each individual shut down decision.

Clarifying the governance of the energy system

Along with the technical-economic transformation of the energy system, the debate opened up a new chapter on governance issues, referring both to the possible decentralisation of energy policy (between the State and local authorities) and the organisation of the energy market itself. On the first aspect, the law on the energy transition indicates a slight shift towards more competences for the regions and municipalities. In particular, this regards the implementation of energy efficiency measures and the establishment of regional energy plans. However, the main political competences and financial capabilities remain at the national level. Similarly, the request formulated by many stakeholders to re-establish the right to create municipal energy companies (forbidden since the adoption of the energy law in 1946 which created the national monopolies in the electricity, gas and coal markets) was not satisfied.

Regarding the issue of market organisation, the debate was not able to draw a clear vision for the progressive liberalisation of the French energy market (see section 5.3.4). Even though regulated tariffs have already been phased out for larger consumers and specific rules have been laid out to make regulated tariffs for domestic consumers challengeable by alternative suppliers, market concentration remains high.¹⁰⁷ More generally, the debate did not solve the more structural dialectic between the historical French conception of a public service for energy (thus controlled through public policies and state-controlled companies) and the European dynamic of market liberalisation and increased power for independent regulators.

5.3 Main policies and regulatory instruments in the power sector

As highlighted in the previous section, the power sector remains at the top of the political agenda for the energy transition, considering in particular the future balance between existing nuclear power plants and new RES capacities, as well as the associated policy instruments. In the following, four major aspects of current reforms affecting the French electricity market will be assessed. The first section refers to the implementation of new planning instruments that are supposed to govern the transformation of the power sector, including those aimed at reducing the share of nuclear power and allowing for the deployment of RES. A second section will assess the current state of market liberalisation in the French context, along with the particular position of the French regulator. The two final sections will address two of the major reforms ahead, concerning the

¹⁰⁷ According to the French regulator CRE, at the end of 2014, only 10% of all customers (16% of total consumption of electricity) had switched to alternative suppliers, despite the fact that at least 3 suppliers offered a lower price (for residential customers) than the regulated tariff provided by EDF.



evolution of support mechanisms and deployment of RES as well as the recently implemented capacity mechanism.

5.3.1 Long-term planning in the electricity market

The energy transition law introduces two major planning tools at the national level to improve visibility on the planned transition pathway and ensure the coordination among the various policy tools. Inspired by the example of the UK, France will implement a **national low carbon strategy**, which should fix binding carbon budgets for different sectors for two following five-year periods. Furthermore, this strategy should include an evaluation of the individual contribution of existing policy instruments to meeting this target, as well as recommendations on additional instruments, if needed. The due date for the first strategy has been set in the law for the 15th of October 2015.

The **multiannual planning framework for energy** (*planification pluriannuelle de l'énergie, PPE*) represents the second instrument and will also be based on five-year periods.¹⁰⁸ This tool is based on the former multiannual investment plan, with the main difference being that the PPE will have a broadened scope: while the focus of the former was only on future investments in the energy supply sector (mainly power and gas), the latter should also take into account an investment trajectory for energy efficiency measures and include security of supply assessments (integrating flexibility issues in the case of the power sector).

Both the low-carbon strategy and the PPE should be complementary, with the first providing strategic guidelines and the second delivering a more detailed and operational assessment of investment needs detailed by energy sources, with a specific focus on supporting policies and associated public costs.¹⁰⁹

Although the working process on both documents has recently been launched within the administration in association with stakeholder groups, the potential operational value of these strategic planning instruments cannot be assessed so far. This is particularly true regarding future orientations on nuclear power. Given the political conflict potential, it is likely that the documents will remain vague on this issue without providing a clear assessment of the mechanism that should govern the choice (e.g. defining the criteria used to determine which nuclear power plants should be closed first) and pace of potential nuclear power plant shut-downs. More importantly, if the law and the strategic plans do not provide a viable mechanism that attributes clear responsibilities for the shut-down decisions (among the state, EDF, the regulator and the Nuclear Safety Agency), it is very likely that the government will get stuck in very costly and complicated political battles over each single shut-down decision. This has already been seen in the attempt to close down the oldest

¹⁰⁸ The first period of the PPE will however only extend over 3 years, in order to align the periods with the duration of political mandates.

¹⁰⁹ See: <http://www.developpement-durable.gouv.fr/Programmation-pluriannuelle-de-l.html>



nuclear power plant in Fessenheim. The limited timescale of the PPE (covering 2016-2018 and 2019-2023 for the first two periods) also generates a potential limitation insofar as it will not provide any indication on the expected (or targeted) level of electricity demand by 2030, despite its key importance in defining a trajectory to reduce the share of nuclear to 50% of total electricity generation.

The decisions on nuclear are not just of a political nature. This fact further complicates this issue. Indeed, the Nuclear Safety Agency should soon publish a new referential, updating the safety standards for existing reactors. Depending on how stringent these criteria will be (e.g. taking into account the experience gained through Fukushima and current state of the art technologies, such as the European Pressurised Reactor, EPR), it could be possible that a number of reactors will have to shut down earlier, due to the fact that retrofitting measures are either technically impossible or not economically viable. Indeed, recent estimates regarding the potential cost of retrofitting the nuclear power fleet range from 110 to 250 billion euros up to 2030. This comes with potentially high impacts on future generation costs, depending on the investment cost and lifetime extension (10 or 20 years) taken into account (Brottes & Baupin, 2014; Cour des Comptes, 2014; Marignac, 2014).¹¹⁰

5.3.2 The evolution of support mechanisms for renewable electricity generation

Last year, the European Commission released the Guidelines on State aid for environmental protection and energy 2014-2020 (European Commission, 2014). This included important markers for the future evolution of RES support mechanisms, towards market-based instruments (i.e. market premium schemes and technology neutral tenders) and an eventual phase-out of support after 2020. In order to meet these recommendations and limit the costs borne by consumers, the French government announced that current feed-in tariffs (FIT) will be replaced by a feed-in premium (FiP) with direct marketing by 2016, whereas the amount of support should be set and allocated through tendering procedures by 2017.

While the French administration recently started a stakeholder consultation process to calibrate the specific design of the Market Premium scheme, its future implementation (at the beginning of 2016) is still surrounded by important uncertainties on the specific design parameters. In particular, this regards:

- the calculation of the reference market value according to which the ex-post premium will be calculated. Alternatives under discussion include a yearly (vs. monthly) average spot market price, but also the question of whether the reference market value should be

¹¹⁰ The mentioned reports indicate that depending on cost assumptions and the extension of the lifetime of existing plants (10 or 20 years), the cost of nuclear power could reach between 60 and up to 140 €/MWh.

differentiated by technology (considering for example that wind might produce more electricity at hours with prices above the average);

- the treatment of negative prices. The debate refers to the question of whether producers should receive any remuneration for reducing their production or if there should just be a general rule, indicating that no premium would be paid in the occurrence of negative prices;
- the nature of the premium itself: France initially headed for a volume-based premium, but there are still some thoughts on the possibility to link the premium to capacity rather than production. Another linked issue was the question of whether the premium scheme will be able to incentivise the development of system-relevant installations, as for example second generation wind power plants with lower total production and lower variability, or East-West oriented solar plants (instead of plants directed to the south, increasing overall production but with more intermittency and higher peak capacity);
- the possibility of progressively decreasing the premium over the lifetime of the installation. However, the integration of a specific discount rate might be overly complex and increase existing difficulties related to the access and cost of finance.

Furthermore, while the evolution towards more market-based schemes has been associated with the promise of cost reductions, several factors might actually induce an increase in costs, compared to a situation where an FIT were to be maintained (Tisdale, Grau, & Neuhoff, 2014). This argument can be upheld based on three issues: the first concerns the additional risk premium resulting in higher financing costs for these very capital-intensive plants. The second is related to the fact that the obligation for direct commercialisation will render explicit some of the transaction costs that were formerly hidden or mutualised.¹¹¹ In particular this regards marketing costs of commercialisation and costs for forecasts and intraday balancing. Thirdly, the capacity of the French short-term market to efficiently integrate the direct commercialisation of RES generation remains uncertain (Adigbli, 2015). Indeed, given the high concentration of the market for both generation and supply, the liquidity of the short-term market (and in particular intraday trading) remains quite small, compared to Germany for example. This means that in the absence of increased liquidity, the cost of balancing forecast errors through the intraday market might actually be higher than that observed in other countries. Furthermore, to date there are no aggregators on the French market, which could reduce the transaction costs of individual plants through

¹¹¹ These costs are so far internalized by EdF as the obliged buyer of RES electricity. Given that EdF can easily integrate the additional amount of electricity in its own generation portfolio, it can easily compensate forecast errors and its incremental marketing costs are reduced, given that EdF already is very active on the wholesale market. Recently, EDF indicated a total balancing cost for variable generation of about 0,4 €/MWh, which is already much lower than the values observed in Germany (2-5€/MWh). Thus the margin for further optimization through direct marketing is very small, and many actors argue that this might actually lead to an increase in balancing costs for the system as a whole.



economies of scale and portfolio management. Given the current state of market concentration, it remains to be seen if these new market players will spontaneously emerge in the French context.

Similar questions are linked to the potential evolution towards technology-neutral tenders by 2017 (Fraunhofer ISI, 2014). While tenders might theoretically reduce costs through increased competition, this does not always apply in practice and depends both on the efficient design of tenders (reducing administrative costs) and the state of the market (size and number of competitors). In this sense, a generalisation of tenders could result in increasing stranded costs for RES developers and thus raise a significant challenge, in particular for smaller developers. Similarly, considering its limited size, the French regulator would most likely need additional resources in case tendering schemes were to be generalised.

In sum, there is a high level of uncertainty surrounding the initial promises associated with the evolution of RES support schemes, regarding both the improvement of technical and economic market integration and the ability to achieve the policy objectives. Indeed, this focus has eclipsed some of the more fundamental issues for RES deployment in France:

- Regardless of the considered support scheme, the main issue for RES deployment in France is the lack of stability, as can be illustrated through the moratorium on FIT for solar in 2010/11 and the uncertainty over the legality of FIT for wind power during most of 2014.¹¹²
- Considering the high level of development risks (related to the lack of stability of policies and administrative procedures), risk premia and financing costs are comparatively high in France. In this sense, the implementation of a preferential financing mechanism (such as the soft loans provided by the Kreditanstalt für Wiederaufbau, KfW, for RES projects in Germany) could lead to considerable reductions in RES support costs with very limited public funding.
- Thirdly, administrative procedures linked to the development of RES projects are very complex in France, resulting in increasing delays, slow development and high financing costs. For example, the lead-time for wind power projects reached 7 to 8 years in France, compared with 2 to 3 years in Germany.

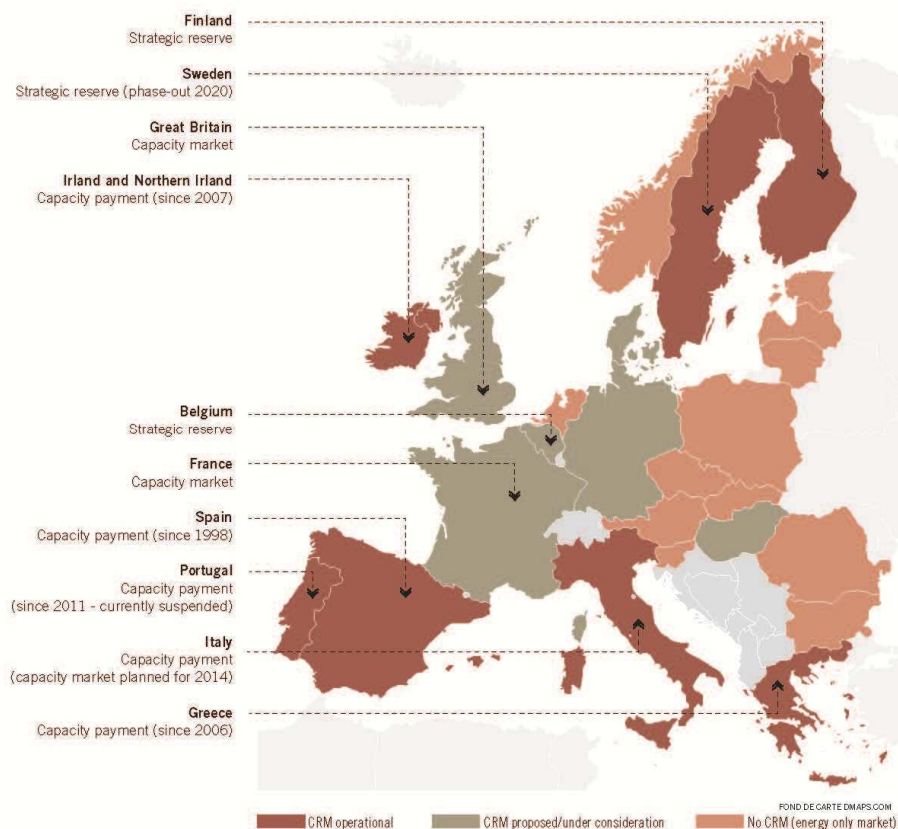
While the current level of RES deployment is already insufficient to achieve the 2020 targets, the planned evolution of support mechanisms risks bringing the industry to a standstill, especially if the more fundamental factors outlined above are not addressed in the meantime.

¹¹² In its initial proposal for projects to be financed under the Juncker Plan, France included the idea of a national guarantee fund for RES projects to “cover the risks of future evolutions of regulation”, to be paid for by the Commission. In a very cynical way, this illustrates quite well the lack of confidence and stability of the French support policies.

5.3.3 The French capacity mechanism

Because of decreasing price levels, most wholesale markets in Europe currently do not deliver a sufficient signal to incentivise investments in new plants, resulting in new debates and policy initiatives to ensure generation adequacy and security of supply in the long-term (Figure 11). Additionally, the rapidly increasing share of variable renewables requires new solutions for flexibility, including flexible back-up plants. While both challenges are obviously related¹¹³, there seems to be a great level of confusion on what they recover and how new capacity mechanisms could or should address them.

Figure 10: National measures to preserve capacity adequacy



Source: ACER, 2013

¹¹³ In theory, new power capacities can be perfectly suited to address both the adequacy (i.e. having sufficient capacity reserves in the system to satisfy peak load) and the flexibility challenges (e.g. very flexible gas power plants with quick ramping). However, this is not always the case: an old coal power plant can ensure security of supply but will not be flexible enough to compensate the variability of RES generation.



Similar to other Member States, France designed its own capacity mechanism, albeit for a very specific reason. While flexibility requirements related to RES remain low so far¹¹⁴, the pending issue of a fast-growing peak load demand in winter had to be addressed through a dedicated mechanism, which was first introduced in the 2010 law on the energy market.

The French capacity market transfers the adequacy requirement to the electricity providers, who have to obtain the amount of capacity certificates necessary to cover up to an extreme peak load in a given year. They can either certify their own generation capacities or purchase certificates (both generation and demand-side management) from other actors. The obligations will be assigned to suppliers four years before the target delivery year. Capacity certificates will be delivered by RTE to operators based on the projected contribution of their capacities to reduce the shortfall risk during peak periods (RTE, 2014a). The Ministerial Decree was signed on January 22nd, 2015 and the first capacity certificates (to cover the 2017 peak load) will be delivered in April 2015. According to simulations by RTE, the price of certificates should stay in a band between 0 and 30,000 € / MW per year. In case of severe shortages it could theoretically rise to 60,000 €/MW per year, representing the capital cost of a new peaking plant.

The French capacity mechanism is often considered as being well-designed, since it is market-based and market-wide (all assets, including renewables and demand-side solutions can be certified). However, it also faces important limits and criticism. At the European level, many neighbouring countries are concerned with possible market distortions and spillover effects that might be related to the French mechanism. Similarly, the European Commission pressured France to allow the participation of foreign capacity providers. Eventually, on the domestic level, the adequacy of the solution itself has been questioned. Indeed, given that the issue of winter peak demand is largely linked to the importance of electric heating in France, the country could have tried as well to resolve it (at least partly) through offensive demand-side policies, including a more focused building retrofitting program and possibly policies aimed at phasing-out direct electric heating (such as those implemented in Sweden and Germany for example).

5.3.4 Power market liberalisation and European integration: the French case

The French system remains a very unique model in the European landscape of increasingly liberalised electricity markets. The degree of concentration remains at very high levels, and so far the hesitant attempts to improve competition have not produced much effect. This is true for the progressive phase-out of regulated tariffs, which did not produce a higher switching rate among

¹¹⁴ Variable RES currently represent a share of only 3.2% of total generation. Furthermore, France already has an important source of flexibility provided by the existing hydro power capacities.



consumers so far,¹¹⁵ but also for the attempt to reinforce competition among suppliers through the implementation of the regulated access to the historical nuclear electricity (ARENH). Since 2010, the ARENH scheme obliges EDF to sell 25% of its nuclear generation to other competitors in the retail market at a price fixed by the regulator (currently at 42€/MWh) in order to enable them to propose competitive tariffs (Cour des Comptes, 2015).

French reluctance towards market liberalisation can also be seen in the on-going debate over the renewal of concessions for hydro power plants. While France initially wanted to organise tenders to allocate the concessions, a majority of policy makers advocated in favour of a more regulated approach to maintain local ownership as much as possible. However, this might go against European market rules and create new conflicts, considering that many foreign utilities also expressed their interest in taking over some of the concessions.

While the supremacy of liberalised markets can be challenged both theoretically and empirically, the complexity of the French case emerges from the constant mixture of both approaches, which often creates a barrier to efficiency. This can be illustrated with the case of RES support schemes described above. While the move towards more market-based mechanisms can produce benefits in terms of economic and technical integration, it also requires specific conditions for success. However, in the context of a highly concentrated market, it is not certain that the move towards direct marketing of renewable electricity will improve efficiency, given that the market itself is not ready (in terms of liquidity and number of actors) to adjust to this evolution.

In more general terms, this raises a fundamental question about the role and competences of the regulator itself in a context where the numerous interactions between energy and climate policy create a new need for efficient regulation. In the case of France, although the newly created Commission for Energy Regulation (CRE) was awarded increasing responsibilities, its effective competence is being questioned and its resources have regularly been reduced: according to its director Philippe de Ladoucette, the French CRE remains much smaller than its counterparts in the other main European member states and its budget has declined by 11% since 2012.¹¹⁶ Beyond the lack of financial and human resources, the independence of the regulator remains a challenge given that the government has the power to overrule the regulator's decisions. This has been illustrated by the past through the (regular) refusal of the government to accept the CRE's proposition to raise both the regulated tariffs and the contribution to the public service of electricity (CSPE) in line with

¹¹⁵ EDF still maintains a 93% market share for small consumers, despite the existence of up to 20 competing suppliers. Recent surveys indicated that the public still identifies EdF with the former public service for energy and is not aware that EdF, RTE (the TSO) and ErDF (the DSO) are actually separated companies.

¹¹⁶ Hearing of P. la Doucette by the parliamentary Commission for Economic Affairs, September 11th 2014: while the UK regulator Ofgem employs up to 700 people, the German Bundesnetzagentur 300, the French CRE remains much smaller, with only 125 employees, with a downward trend.



the observed costs.¹¹⁷ The fact that the Energy Transition law also proposed to implement a political committee to manage the costs of the CSPE (considered a core competency of the regulator) further undermines the credibility and legitimacy of the regulator, precisely when it is paramount to have an independent regulator as a necessary condition to improve market performance.

5.4 Evolution and prospects

The French energy model is currently in the midst of a structural transformation that encompasses not only the transition between technologies, but, more importantly, also between different governance models. In that sense, the ability to drive the transformation of the power sector will depend to a large extent on the political will that is created to push decisions that break with the conventional approach. The new energy transition law clearly opens up the political opportunity for transformation by proposing very ambitious and far reaching objectives, but it remains to be seen if this will actually result in the corresponding policy measures being implemented in the short-term to trigger this process.

5.4.1 Compliance with targets

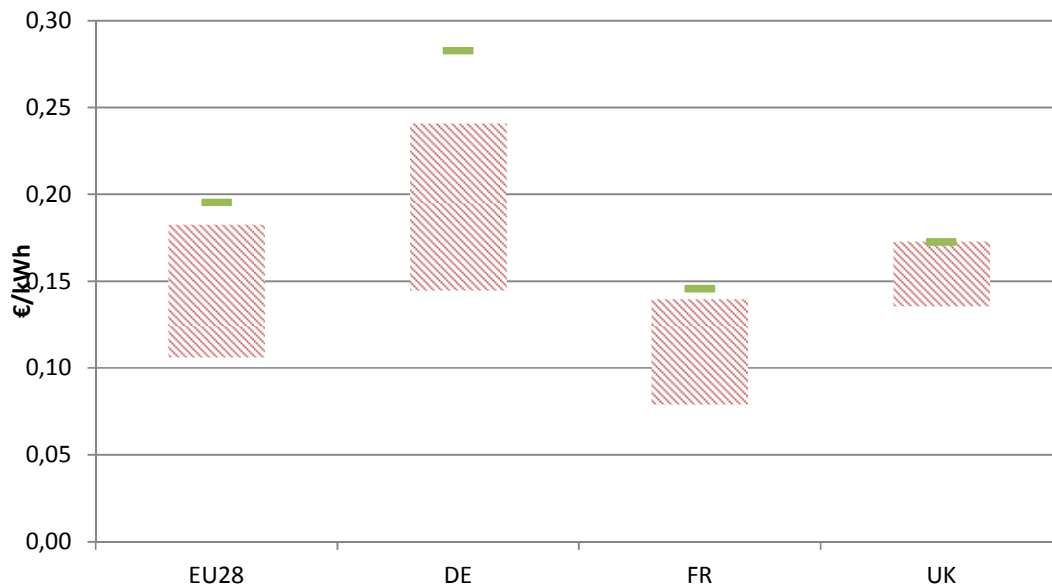
While it is much too early to assess the feasibility of the different objectives, the preceding analysis helps to define a series of conditions that will be required for success. This refers in particular to the ability to define a credible and operational long-term strategy for the power sector itself, which is the one single driver that could help clarify further steps regarding both the management of historical nuclear assets and the deployment of renewables. So far, policy makers have not directly addressed the great discrepancy that currently exists between very specific and ambitious long-term targets (on the share of nuclear, the level of energy efficiency, etc.) and a strongly elusive approach on tangible measures of implementation. In this sense, many decisions will depend on the ability to provide a target scenario regarding the future level of electricity demand (including specific measures for electricity savings) and the elaboration of a clear timetable and action plan to manage the existing nuclear fleet accordingly. As long as these decisions are not taken, France might be at risk of pursuing a 'doing it all' strategy (more renewables, more nuclear, more efficiency), which is eventually doomed to fail in a market that already suffers from overcapacity.

¹¹⁷ Paid by all final consumers, the CSPE covers the costs related to renewable generation, social tariffs and tariff equalization among all French territories (including overseas). On several occasions, the CRE alerted the government on the need to substantially raise the contribution to cover the increasing costs, but the government only authorized a smaller increment. Eventually, the debt accumulated under this mechanism reached 7 billion euros in 2013.

5.4.2 Evolution of prices and distributional issues

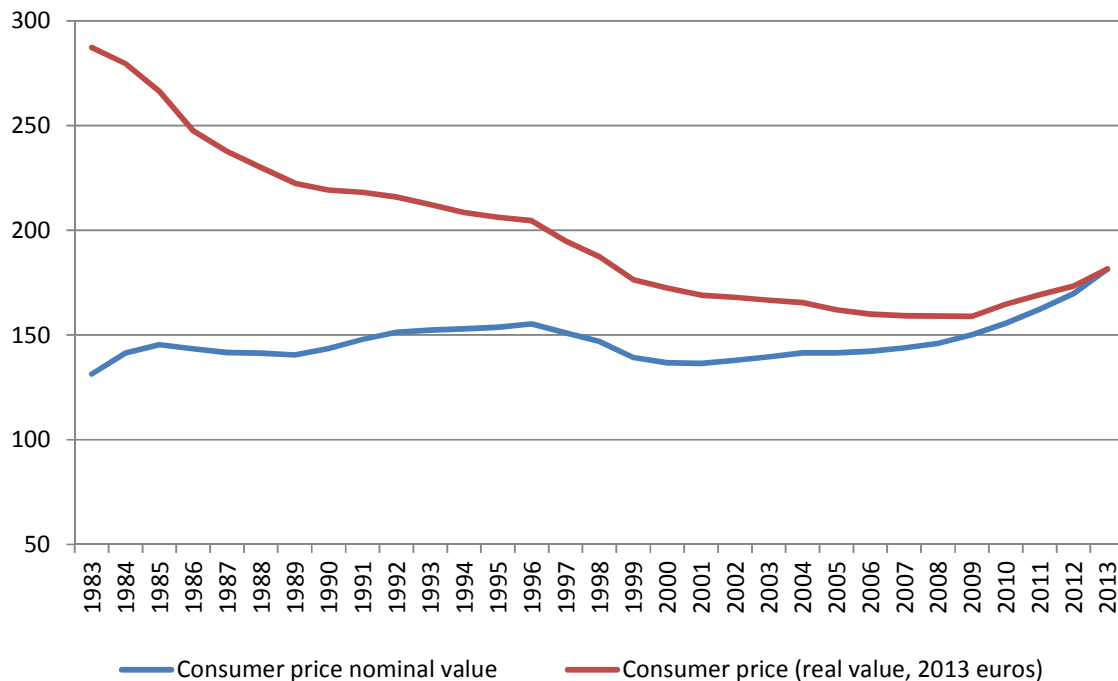
France displays one of the lowest costs of electricity among the major EU economies. Prices remained stable in nominal terms for almost 20 years (i.e. decreasing in real terms) before regaining an upward tendency since 2010 (Poniatowski & Desessard, 2012). However, several factors might lead to a stark and continuous increase of prices in the next years. The French regulator assessed that regulated tariffs must keep the pace with the observed and future increase in generation costs, inducing an increase for regulated tariffs of up to 30% between 2012 and 2017 (CRE, 2013b). This does not yet include the potential future costs of retrofitting the aging nuclear power plants, which remain largely uncertain and could induce substantial increases as well.

Figure 11: Electricity prices for industrial and domestic consumers



Source: IDDRI, data from Eurostat, INSEE

Figure 12: Household electricity prices in nominal and real values for France



Source: IDDRI, data from Eurostat, INSEE

Albeit remaining rather low, compared for example to Germany, the surcharge related to the cost of RES deployment represents a growing share of electricity prices.¹¹⁸ Recent scenarios suggest that the incremental cost of RES support could double by 2020 and reach €8 billion by 2025, compared to €3.6 billion in 2013 (CRE, 2014).

Similar to Germany, large industrial consumers are entitled to preferential tariffs, including a partial exemption from the *charge de service public de l'électricité* (CSPE).¹¹⁹ On average, large consumers pay a surcharge equivalent to approximately 15% of the charge per kWh (1.95 Euro cents) paid by small consumers. Since 2010, a consortium of 27 major electro-intensive industries in France also signed a long-term contract with EDF to secure a guaranteed tariff until 2034, in exchange for an

¹¹⁸ The current surcharge for renewables applied in France is 1,95 cents/kWh, representing about 10% of electricity prices (compared to 6,3 cents/kWh in Germany). In France, the charge on renewables is not indicated separately but part of the so-called “charge for the public service of energy” (CSPE) which also includes compensations for social tariffs, cogeneration, tariff equalization and the budget for the mediator of energy (CRE 2014).

¹¹⁹ Three complementary exemptions can apply to large industrial consumers: the overall yearly amount paid by a single consumer is capped at 570.000 €; for industries consuming more than 7 GWh per year, the payable amount cannot exceed 0,5% of their added value; and on-site power production is entirely exempted to a maximum of 240 GWh.



upfront payment, which was initially supposed to contribute to the funding of the EPR reactor in Flamanville. Since the long-term price exceeded wholesale market prices in recent years (due to the economic crisis and decreasing demand in Europe) the financial conditions of this contract have been renegotiated in 2014 in order to make it competitive again.

The issue of industrial competitiveness has been at the core of recent debates on the cost of the energy transition. In particular, many industrial actors argued that Germany is distorting the market through excessive exemptions for its own industry. However, a recent report by the regulator examining cost and pricing conditions for large consumers in both countries came to the conclusion that actual prices paid are very similar in both countries and that French prices are more competitive if the wholesale market price exceeds €43/MWh.¹²⁰

The rapidly emerging issue of energy poverty has become a key topic in the French energy debate. According to statistics, up to 15% (4 million households) of the population are affected, resulting in an even higher political reluctance to implement an increase in power prices, even though this might be necessary to create a visible price signal and recover existing costs, particularly for electricity. Recent studies showed that the specific electricity consumption (i.e. excluding heating and hot water) of a French household is on average 30% higher than that of its German counterpart, a difference that can at least partly be attributed to the diverging price signals and induced penetration rate for very efficient appliances (Sowatt / Enerdata, 2012).

Similarly, this triggered a broader debate on the relevance of different measures (e.g. social tariffs and targeted investment subsidies for low-income households) to address this issue, without, however, producing any fundamental transformations so far.

More generally, in the French context, the social impact of policy decisions represents a key driver (or obstacle) for climate policy: the attempt at introducing a carbon tax has been blocked, based on concerns over equity. And even though there seems to be an increasing consensus on the long-term economic benefits of the transition, the issue of rising costs (and their distribution) in the short-term remains very complex.

Recently a new aspect was added up to the debate over distributional impacts. Inspired by the German experience,¹²¹ French policy makers defined several measures to facilitate the financial participation of citizens in community-led RES projects. While these measures primarily aim to improve local acceptance of projects, they might also emerge as a key condition to maintain support for bearing the mutualised costs of the transition in the long-term. Indeed, they tend to

¹²⁰ CRE 2013: *Analyse de la compétitivité des entreprises intensives en énergie : comparaison France-Allemagne, Juin 2013.*

¹²¹ Based on a favourable regulatory framework, citizen-led projects have dominated the energy landscape over the last years : almost 50% of all RES capacities installed are owned by private persons and farmers, while the four major utilities only own 6% (Holstenkamp, 2013).



transform the perception of the citizens within the transition, away from a “customer and taxpayer” towards a “prosumer”, actively participating in the implementation of the local transition (Poize & Rüdinger, 2014).

5.4.3 Potential for regional cooperation

Due to its key geographical position as a central hub in the European power system, connecting the Iberian peninsula to the Central Western market, France is already strongly integrated into the regional (Central Western) and wider European market, with a total of 37 interconnections (14 GW export, 11 GW import) (RTE, 2014b). Several aspects illustrate the high degree of integration. Firstly, France is by far the largest net exporter in Europe, with an average net balance of 40 to 60 TWh per year. However, taking into account the current surplus of capacities on the European market, there are some concerns over the future demand and value of these exports.¹²² Secondly, France relies to a large extent on its interconnections to cover peaking demand in winter. In February 2012, France imported up to 8 GW from its neighbours, resulting in an inversion of usual power flows for many interconnectors (CRE, 2013a). Thirdly, power flows are increasingly correlated with variable renewable output in neighbouring countries, especially on the borders with Spain and Germany, demonstrating the flexibility value of the European market (ibid). Eventually, the market coupling process within the Central Western market area, and in particular increased coupling of short-term markets between France and Germany has increased exchanges and the frequency of saturations of cross-border interconnections. This highlights the potential for additional exchanges, if the grid infrastructure develops accordingly (RTE, 2015). However, there remains a general reluctance towards increased market interconnections due to the apprehension of possible price increases for French customers, even though this has not been confirmed through practice so far.

While there is still a general reluctance among policy makers to consider the potential domestic benefits of the European market integration process, the openness towards new cooperation opportunities might be reinforced by the current energy transition agenda. Indeed, if France seriously wants to implement its mid-term targets regarding nuclear power and renewables, regional cooperation will be a key dimension to limit the cost and need for additional flexibility resources.

Another new opportunity for strengthened cooperation on both political and technical levels emerged in the Franco-German context. Indeed, even though the French and German energy models tend to be perceived as antagonistic (referring to nuclear policy in particular), the

¹²² The average price on the spot market decreased by 20% between 2013 and 2014 for France, 12% for the UK, 13% for Germany (RTE, 2015). Due to the temperature-sensitivity, the French export potential is at its maximum in summers. However, it is increasingly overlapping and competing with the growing solar PV output of neighbouring countries, which enters the market at a near zero marginal cost.



fundamental convergence on the main mid- and long-term objectives of both national strategies remains striking. This applies not only to the general objective of reducing greenhouse gas emissions, but also to the priority given to energy efficiency in the long-term (-50% in energy consumption by 2050) and the development of renewable energies until 2030. Interestingly, the challenge both countries will face regarding the substitution of nuclear power until the mid-2020s is also strikingly similar. While Germany has to replace 140 TWh of nuclear generation until 2022 to complete the phase-out, France would need to compensate for a similar amount (approximately 135 TWh, equivalent to the production of 22 nuclear reactors) to reduce the nuclear share towards 50% by 2025, if total generation remains stable at the current level. This also implies that there is a much clearer agenda for potential cooperation on energy policies now than in the recent past, which could create a push towards improved regional market integration and potentially also a larger political stimulus on the European level, provided both countries advance with a more coordinated approach.

5.5 Challenges and lessons

The French power sector might be considered an example of what is often referred to as the '*exception française*'. This 'exception' rests on its peculiar historic structure built around the symbolic attachment to a public service of energy, vertically integrated national champion and strong reliance on nuclear power. All this tends to put the political debate on the transformation of the power sector in a different framing as compared to neighbouring countries. In this sense, the transformation of the French power sector is not only about the 'decarbonisation narrative' itself. It also oscillates between the pride over the historic achievements and the will to maintain the *status quo*, and an increasing awareness over the fact that this system cannot hold indefinitely and needs a viable long-term plan for diversification.

This tension line applies to the various dimensions of the power sector's transition. The dilemma over technology choices is certainly the most visible one: willingness to become a champion in the field of renewables on one side; high uncertainty over the future management of the aging nuclear power fleet (considered both an asset and a liability) on the other. By introducing an explicit target on nuclear power, the energy transition law potentially provides a landmark decision to implement this progressive diversification but lacks any operational value in the absence of a clear and consensual strategy on the future of the power sector, addressing the main questions that have not been answered so far:

- What should be the role of electricity within the transition?
- What level of power demand are we aiming for, and under what conditions?
- How is the very ambitious long-term target for energy efficiency reflected in the power sector and would it be relevant to elaborate a specific strategy to support electricity savings and demand-side management?



In this sense, the French case highlights the strong interaction between long-term orientations and short-term actions: without a clear vision that provides a need for specific action, there is no legitimacy for any single short-term measure.

A similar analysis can be made regarding the implementation of the European market liberalisation agenda, which is potentially at odds with the French vision of public service for energy. So far, rather than embracing the idea of liberalisation as a whole, France has mostly taken up small bits of it (mostly when pressured to do so by Brussels), avoiding any radical transformation. This can lead to a situation where the combination of both logics (public regulation and liberalised markets) eventually produces new complexities without providing the benefits associated with fully implementing one of them. The very particular market arrangements made to artificially support competition in the retail sector provides a good illustration. While most experts concede that they are largely insufficient to instil real competition, they nevertheless add a new layer of complexity while avoiding a debate over more structural solutions. The public control over prices is another striking example: it would actually be beneficial for the government to leave this responsibility with the regulator alone, in order to align tariffs with real costs and avoid being held responsible for future increases.

A somehow similar assessment applies to the diversification towards renewables. The move towards market-based support schemes has been adopted surprisingly quickly in France. However, it seems to be associated with a lot of overly optimistic promises regarding potential cost reductions and benefits for market integration, while impeding the examination of more fundamental drivers needed to achieve the 2020 and 2030 targets: stability of policy decisions, a simplification of administrative burdens to reduce delays and project risks, the implementation of preferential financing mechanisms to decrease the cost of capital, and a more comprehensive approach to adjust the functions and design of the wholesale market towards the objective of integration of renewable sources. While the policy debate seems to be exclusively focused on the support scheme issue, addressing these issues would certainly have a much greater impact on both cost reduction and future deployment.

Eventually, although the policy process has been focused mostly on national issues so far, the reinforcement of regional cooperation initiatives might become a major driver for the transition agenda in France. Indeed, almost all recent changes in the regulation of the French power sector can be traced back to the European policy agenda and, thanks to the market coupling, the French wholesale market benefits from a number of design features which were initially developed to address the challenges of RES integration in Germany.

If France takes up the challenge of massively deploying variable RES, it might actually turn into a leader of the regional integration process to mutualise flexibility resources, especially if the converging Franco-German agenda on the energy transition stimulates a renewed cooperation between both countries.



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