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On the impact of energy policy on electricity markets

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Abstract

Decarbonising the power sector has a crucial role in the fight against global warming. In this respect, governments employ a range of policies and regulations. As such, energy policy is usually driven by the energy policy objective triangle of affordability, security of supply and sustainability, whereby the latter has become ever more pressing in the last decades.

This thesis researches the impact of actual and potential energy policies on the market in five studies. The first study analyses the drivers of wholesale power prices finding *inter alia* that power prices are driven by a combination of policies and markets. A drop in German wholesale power prices between 2008 and 2014 can be attributed to policies furthering the deployment of low marginal cost renewable energies and economic market factors such as lower prices for fossil fuels used for power generation. For their part, carbon prices are a combination of a political and a market driver, and proved to be an influential driving force of power prices, and with it, of power markets.

The second study dives deeper into the price setting on European wholesale markets, researching how different national policies influence the market and establishing which power generation technologies set prices. It finds a high level of interconnection between European power markets and that price setting in smaller countries is often dominated by larger neighbouring countries. The energy policy of one state can thus significantly influence power markets in other countries, a matter that is further explored in the third study. Conventional wisdom holds that gas- and coal-fired generation capacities are the major price-setting technologies on most European markets. The study result confirms this, yet also finds a more nuanced picture of price-setting technologies than the conventional wisdom suggests.

Whilst studying the influence of national policies on power markets, the German regulator announced a discontinuation of the common German-Austrian bidding zone. This provided a real-world example to study the influence of energy policy on the market. Following the announcement of the German regulator, market participants faced some uncertainty regarding outcomes and effects of this coming price zone split. As a consequence, it was decided to research this price zone split in a third study – to add new insights to the public debate surrounding it. Using the energy policy objective triangle as an evaluation tool, the study finds that German energy policy objectives of affordability and sustainability can be expected to be influenced positively by a breakup of the common bidding zone, whilst the same objectives are impacted negatively for Austria. Altogether, the results indicate that the price zone split leads to overall cost savings and lower CO_2 emissions.

With climate change becoming an ever more pressing issue, the energy policy objective of sustainability gains an increased focus. With this come more frequent calls for carbon price floors on a national level. The fourth study therefore explores the practical issues of pricing carbon unilaterally. In a nutshell, pricing power generation-related carbon emissions unilaterally in addition to the European Union Emission Trading Scheme (EU ETS) comes either with competitive disadvantages for national producers (as imports cannot be charged) or with issues regarding the non-discriminatory principles of the World Trade Organisation (WTO).

The fourth study therefore suggests a market design model using guarantees of origin (GoO) as a workaround to price carbon emissions unilaterally. This is done by offering exemptions from a CO_2 levy for GoO from carbon neutral generation.

The fifth and final study researches the changing competitiveness of renewable energies, namely wind and photovoltaics (PV). Wind and PV generation are increasingly looking to compete with conventional power generation sources outside of traditional support schemes. A reoccurring theme in this context is the so-called 'cannibalisation' of wind and PV, which describes declining value factors of wind and PV generation at higher penetration rates. Here, the impact of market and policy-based drivers on wind and PV value factors and capture prices is explored. *Inter alia* it is found that natural gas and carbon price changes have a significant impact on wind and PV value factors and capture prices. The study finds no significant cross-cannibalisation between the two technologies in terms of relative value factors.

Kurzfassung

Die Dekarbonisierung der Energiewirtschaft nimmt in den Anstrengungen gegen den Klimawandel eine zentrale Rolle ein. Um diesem Ziel nachzukommen, verwenden Regierungen eine Reihe von politischen Maßnahmen und Regulierungen. In diesem Zusammenhang wird Energiepolitik von dem energiepolitischen Zieldreieck aus Wirtschaftlichkeit, Versorgungssicherheit und Nachhaltigkeit getrieben, wobei letzteres in den vergangen Jahrzehnten zunehmend dringlicher wurde.

Diese Dissertation untersucht den Einfluss von unterschiedlichen energiepolitischen Maßnahmen auf den Markt mit dem Ziel das Verständnis des Zusammenspiels von tatsächlichen und potenziellen Maßnahmen und dem Markt zu erhöhen. Die erste von fünf Studien, die im weiteren Verlauf unterschiedliche Kapitel bilden, analysiert die Treiber der Strom-Großhandelspreise und kommt unter anderem zu der Erkenntnis, dass Strompreise durch eine Kombination von energiepolitischen Maßnahmen und Markteffekten getrieben werden. Ein Verfall der deutschen Großhandelspreise kann auf Fördermaßnahmen für erneuerbaren Energien mit niedrigen Grenzkosten und ökonomischen Markteffekten wie niedrigere Primärenergiepreise für die Stromerzeugung zurückgeführt werden. Auch CO_2 Preise, die sowohl als politischer Treiber als auch als marktbasierter Treiber oder als Kombination beider angesehen werden können, erweisen sich als einflussreicher Faktor von Strompreisen und dem Strommarkt.

Die zweite Studie setzt sich genauer mit der Preissetzung auf europäischen Großhandelsmärkten auseinander und untersucht, wie unterschiedliche nationale Politiken die Märkte beeinflussen und welche Erzeugungstechnologien die Preise bestimmen. Sie stellt fest, dass die europäischen Strommärkte in hohem Maße miteinander verbunden sind und dass die Preissetzung in kleineren Ländern häufig von größeren Nachbarländern dominiert wird. Die Energiepolitik eines Staates kann daher die Strommärkte in anderen Ländern erheblich beeinflussen, eine Frage, die in der dritten Studie weiter untersucht wird. Nach herkömmlicher Auffassung sind gas- und kohlebefeuerte Erzeugungskapazitäten auf den meisten europäischen Märkten die wichtigsten preissetzenden Technologien. Das Ergebnis der Studie bestätigt dies, zeigt aber auch ein differenzierteres Bild der preissetzenden Technologien als häufig vermutet.

Während der Untersuchungen des Einflusses von politischen Maßnahmen auf den Strommarkt, kündigte der deutsche Regulator die Auflösung der gemeinsamen deutsch-österreichischen Strompreiszone an. Diese Situation bot ein reelles Beispiel zur Untersuchung des Einflusses von Energiepolitik auf den Markt. Nach der Ankündigung der Bundesnetzagentur waren Marktteilnehmer mit Unsicherheiten hinsichtlich der Auswirkungen einer Preiszonentrennung konfrontiert. Es wurde daher beschlossen diese Preiszonentrennung in einer dritten Studie zu untersuchen und so einen Beitrag zur öffentlichen Diskussion zu leisten. Unter Verwendung des energiepolitischen Zieldreiecks zur Evaluation, kommt die Studie zu dem Ergebnis, dass in Deutschland energiepolitische Ziele der Wirtschaftlichkeit und Nachhaltigkeit durch eine Aufspaltung der gemeinsamen Preiszone voraussichtlich positiv beeinflusst werden, während die gleichen Ziele in Österreich negativ

beeinflusst werden. Insgesamt deuten die Ergebnisse darauf hin, dass die Preiszonenteilung zu Kosteneinsparungen und geringeren CO_2-Emissionen führt.

Durch die zunehmende Rolle des Klimawandels in der öffentlichen und politischen Wahrnehmung, rückt auch das energiepolitische Ziel der Nachhaltigkeit stärker in den Mittelpunkt. Dabei werden immer häufiger CO_2-Mindestpreise auch auf nationaler Ebene gefordert. Die vierte Studie setzt sich mit praktischen Fragen und Herausforderungen einer solchen Bepreisung auseinander. Zusammenfassend lässt sich sagen, dass eine unilaterale Bepreisung der mit der Stromerzeugung verbundenen Kohlenstoffemissionen zusätzlich zu oder neben dem Emissionshandelssystem der Europäischen Union (EU-ETS) entweder mit Wettbewerbsnachteilen für die nationalen Produzenten (da Importe nicht angerechnet werden können) oder mit Problemen bezüglich der Grundsätze der Nichtdiskriminierung der Welthandelsorganisation (WTO) verbunden ist. Zur Lösung wird ein Modell vorgeschlagen, in dem CO_2 indirekt über Herkunftsnachweise bepreist wird.

Die fünfte und letzte Studie untersucht die sich verändernde Wettbewerbsfähigkeit von Wind- und Photovoltaikanlagen (PV). Am Markt lässt sich eine zunehmende Wettbewerbsfähigkeit der Erzeugung aus Wind und PV außerhalb von traditionellen Förderregimen beobachten. Ein wiederkehrendes Thema in diesem Zusammenhang ist die sogenannte Kannibalisierung von Wind und PV, die abnehmende Wertigkeiten der Wind- und PV-Erzeugung bei höheren Marktanteilen beschreibt. In der Studie werden die Auswirkungen von unterschiedlichen Treibern auf die relativen Wertigkeiten und absoluten Markterlöse von Wind und PV untersucht. Unter anderem wird festgestellt, dass CO_2- und Erdgaspreisänderungen einen signifikanten Einfluss auf die Wertigkeit und Markterlöse von Wind- und PV-Anlagen haben. Zudem zeigt die Untersuchung, dass es im Hinblick auf die relativen Wertigkeiten keine Quer-Kannibalisierung zwischen Wind und PV gibt.

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Executive Summary

Energy policies are commonly driven by the energy policy objective triangle of affordability, security of supply and sustainability. In efforts to fight climate change and decarbonise global economies, the objective of sustainability has been the subject of increased focus in recent decades. Given the limited remaining carbon budget to prevent a temperature rise of more than 1.5 degrees that would significantly increase risks of irreversible effects, it is critical to carry out rapid transformations of entire energy systems. This transition towards decarbonised energy systems is threatened by public backlashes. In order to provide social and economic acceptability governments have to ensure that energy policies coincide with all three objectives.

This thesis is intended to contribute to the discussion by researching the interplay between energy policies and power markets and evaluating energy policies with respect to the energy policy objective triangle. More precisely, this thesis assesses questions of how energy policy affects and shapes the market. It examines the outcomes of political and regulatory decisions and potential policies. Those questions are explored in the form of different peer-reviewed studies, all answering slightly different questions regarding the outcomes of energy policies on power markets. These studies form different chapters of the thesis and are summarised below.

Ex-post analysis of wholesale power price drivers

This chapter analyses the drop in German wholesale power prices in the period between 2008 and 2014. A model-based assessment quantifies the impact of energy policy and more precisely single-price drivers on power prices. The analysis shows, *inter alia*, that the common hypothesis arguing that the expansions of German renewable capacity caused prices to plummet is insufficient to explain the full price decline. Indeed, whilst the expansions of renewables contributed to the price drop, other price drivers such as the CO_2 allowance price decline and lower primary energy prices had more substantial effects.

These findings have since been backed by Hirth (2017), Bublitz (2017) and Kallabis (2016), who also researched the aforementioned phenomenon. A shared finding of the papers is the significant influence of CO_2 allowance prices on wholesale power prices and the derived political power of EU ETS prices. Carbon pricing can thus be seen as a key policy tool not only for decarbonisation purposes but also to influence electricity markets.

In addition to the mentioned findings, the chapter discusses an energy policy of multiple steering, drawing the conclusion that the policy of introducing an emission trading system and support schemes for renewables simultaneously failed to deliver the expected results. The energy policy aimed to force highly polluting coal-fired power plants out of the market, thereby contributing towards climate targets. However, the additional policy objective of a nuclear phase-out as well as low coal and CO_2 prices eventually caused natural gas-fired units to become unprofitable while coal remained the largest source of electricity in Germany. Altogether, using the energy policy objective triangle as tool, the analysis demonstrates that the policy failure is primarily a result of the economic crisis that changed the economic framework.

Price setting on European electricity markets

This study looks into the price setting on European wholesale markets and the extent to which coal- and natural gas-fired power plants are indeed the marginal units that set the price as it is often stated. From the hourly calculations of a fundamental model replicating the European power markets, one can derive the marginal price-setting technology for any given hour. Taking a whole year as a timeframe, it is possible to analyse how the hours of a year are structured and what share different generation technologies take in providing the marginal price-setting units. The core objective is to broaden the knowledge of price setting on European power markets and obtain a more nuanced picture of what technologies set market prices.

In view of ongoing public debates on CO_2 price floors and the announcement of the Dutch government that one be introduced, this study analyses how different CO_2 price floors affect the price setting. This sheds light on the question of how carbon price floors influence marginal price setting and if a given price floor will result in a shift from coal to natural gas as a dominant price-setting technology. The policy measure of a carbon price floor is evaluated using the policy objective triangle as a tool to measure how the three objectives (affordability, security of supply and sustainability) are affected. It is shown that whilst carbon price floors have little effects in terms of switching the price-setting technology, they can – if executed on a multilateral basis – trigger substantial emission reductions at a wider European level.

A key observation is that, with respect to the marginal price-setting units, the modelling results indicate a higher level of interconnectivity than one might assume. Electricity markets and wholesale power prices of comparably small countries are significantly influenced by the energy policies of their larger neighbours.

In terms of technology one notes that natural gas-fired power plants provide the price-setting units for one third of the total hours and coal- and lignite-fired power plants together for about a quarter of the hours. On an individual country basis, the picture of price-setting technologies can look very different depending on countries' – and surrounding, connected countries' – generation portfolios.

Altogether, the research shows that large countries tend to have a strong influence on price setting in smaller neighbouring countries, as long as there are sizeable interconnector capacities. National policy measures such as coal phase-outs or carbon price floors thus have substantial effects across national borders. Generally, we find a price-setting pattern that is more complex and nuanced than the conventional wisdom suggests, and that power generation technologies other than coal- and natural gas-fired power plants provide the marginal price-setting units more often than one may assume. This should be taken into account upon discussions on the price setting on electricity wholesale markets.

Case Study: Impact of the German-Austrian bidding zone split on European Energy objectives

This chapter discusses the potential effects of a breakup of the German-Austrian bidding zone. Following the announcement of the German regulator Bundesnetzagentur in Fall 2016, where it officially asked the TSOs in Germany to prepare the introduction of congestion management on the German-Austrian border, market participants faced some uncertainty.

The study investigates the market effects brought about by a breakup. It analyses the market outcomes with respect to the energy policy objective triangle of affordability, security of supply, and sustainability. It clarifies what price development one can expect in the affected countries (affordability), if there will be supply shortages (security of supply), and which how the new bidding zone configuration affects the power plant dispatch with respective carbon emissions (sustainability).

The analysis shows that the German energy policy objectives of affordability and sustainability can be expected to be influenced positively by a breakup of the common bidding zone, whilst the same objectives are impacted negatively for Austria. Some of the neighbouring countries could expect slightly positive effects on affordability and others slightly negative effects. However, the largest neighbouring markets stay virtually unaffected by a breakup of the German-Austrian bidding zone. Altogether, the results indicate that a price zone split would result in overall cost savings and lower CO_2 emissions.

A unilateral climate and supply market model

In light of continuous low EU ETS allowance prices, national carbon pricing schemes and unilateral CO_2 taxation models are often discussed by politicians, academics, regulators, associations and the public alike. Fewer thoughts are, however, centred on concepts of how national carbon pricing policies could be implemented. Legal or economic constraints are thereby often neglected.

The chapter "A unilateral climate and supply market model" discusses those challenges and suggests a carbon taxation model in line with all relevant international and EU laws. Unilateral carbon taxes easily violate the so called 'most-favoured nation treatment' of the GATT, which requires equal treatment of 'like products' imported/exported from/to WTO members.

It has become apparent that carbon taxation models have a vital legal component. Thoroughly analysing carbon pricing models requires a legal perspective and pricing carbon on a unilateral basis can be more complex that one may initially assume.

Economic principles prevent straightforward taxation models such as the British one. The British carbon price support mechanisms, which works as top-up of the EU ETS does not apply to electricity imports. This consequently creates competitive economic disadvantages for British power producers. Yet due to the relative low interconnector capacity of Britain with mainland Europe these competitive disadvantages are rather limited. Nevertheless, the model does not represent a suitable solution for countries with a more interconnected electricity market.

Further findings include that taxing imports from different generation technologies depending on their CO_2 emissions per produced unit of electricity is likely to violate WTO rules. Given that Guarantees of Origin are not classified as 'goods' under international law, they can be used as a workaround to implement a national carbon price.

Drivers of wind and PV value factors and capture prices

With growing penetration of renewable electricity sources in a given system, the question arises as to what extent wind and PV cannibalise their own market revenues. Most existing studies analyse the market value of renewables at different penetration levels, looking at the extent to which PV panels and wind turbines cannibalise their own market revenues. This study explores how other market and policy drivers affect wind and PV value factors and capture prices in real world settings over the next three decades. To this end we model and analyse a number of scenarios with altered natural gas, coal and carbon prices as well as varied availabilities of wind and PV in Europe.

The results demonstrate that wind and PV value factors and capture prices are driven by different factors. Changes of natural gas prices substantially influence value factors and capture prices. Generally, wind and PV operators profit less from higher natural gas or carbon prices than pure baseload producers, as capture prices rise less than the base price. Vice versa, in the case of lower natural gas or carbon prices, value factors of wind and PV rise, i.e. wind and PV capture prices fall less than the base price. In contrast to natural gas, coal price alterations represent another market-based driver; they have only very limited influence on wind and PV value factors.

In terms of political drivers, changes of production profiles by 10 per cent reflecting higher or lower PV and wind deployments have significant impacts on wind and PV value factors and capture prices and thus on incomes of wind and PV operators. We find no significant cross cannibalisation of wind and PV in terms of relative factors.

In absolute terms – i.e. capture prices – the merit-order effect of both PV and wind profile changes is substantial. Increasing or decreasing PV and/or wind production profiles by 10 per cent has a measurable merit-order or reverse merit-order effect. Even though altered PV production profiles have no effect on wind value factors, the subsequent merit-order effect or reverse merit-order effect influences wind capture prices. Given that wind value factors are not affected, the capture price changes are of the same magnitude as base price changes due to the merit-order effect. For PV producers in countries with a sizeable wind portfolio, the merit-order effect of additional wind production can be greater (in terms of absolute capture prices) than the merit-order effect and cannibalisation effect of additional PV production combined. Hence, PV operators in those markets should follow wind deployment paths even though we find no significant cross-cannibalisation of wind and PV.

1 Introduction

1.1 Motivation

We live on a planet whose temperature increased by more than 1°C since 1880, whereby two-thirds of that temperature increase occurred since 1975 (NASA, 2020). There is a strong scientific consensus that this warming is caused by human activities, which is why it is also referred to as anthropogenic global warming (Cook et al., 2013). A global warming of 1.5°C or more significantly increases risks of irreversible effects such as the loss of ecosystems (IPCC, 2018). It would also further intensify devastating outcomes associated with temperature increases such as sea levels rises and extreme weather events (UNEP, 2019).

In April 2016, the Paris Agreement opened for signatures to keep the global average temperature increase well below 2°C above pre-industrial levels and to pursue efforts to limit the increases to 1.5°C. As of today, all United Nations Framework Convention on Climate Change members have signed the agreement[1] (United Nations, 2020). Nonetheless, even if all Nationally Determined Contributions (NDCs) of the Paris Agreement are implemented, global temperatures are still expected to rise 3.2°C above pre-industrial levels (UNEP, 2019).

If governments want to deliver on the commitments made in the Paris Agreement and keep the global average temperature increase well below 2°C above pre-industrial levels, certain actions need to be taken. Following the latest (2018) special report on Global Warming of 1.5°C by the Intergovernmental Penal on Climate Change (IPCC) and the 2019 Emission Gap Report by the United Nations Environment Programme (UNEP), the remaining carbon budget for limiting temperature increases to 1.5°C with a probability of 66% is approximately 420 $GtCO_2$ or eight years of current emission at the time of writing (early 2020) (IPCC, 2018; UNEP, 2019). This illustrates the urgency for decarbonisation efforts.

Today, the power market is at the heart of these decarbonisation efforts. Firstly, because it has traditionally been a sector that is responsible for a large share of carbon emissions and secondly, because low-carbon or carbon-free technologies are readily available. In recent years, policymakers have also increased efforts to replace fossil fuels in other sectors with electricity, first and foremost in the mobility and heating sectors.

The power sector is an economic field that is – more so than others - government-steered and shaped by regulations and changing political positions. Interestingly enough, this political influence is not limited to national governments as electricity markets are interconnected and, in Europe, embedded in a European context and thus affected by decision making and policies of multiple nation states. The objective of this work is to get a clearer image of how political decisions – or lack thereof – influence and alter the power market. Energy policies strive to provide an affordable, secure and sustainable supply of electricity. This thesis evaluates the performance of a number of policies in this respect and explores challenges and market design questions on the way.

[1] In November 2019, the Trump administration of the United States of America notified the Secretary General of the United Nations of its decision to withdraw from the Agreement.

1.2 Objectives of this thesis

The core objective of this PhD thesis is to study the interaction of energy policy and power markets. Questions that are considered include how energy policy affects and shapes the market. Energy policies are often implemented under the overarching policy objectives of decarbonisation, cost optimisation and supply security. One can refer here to the energy policy objective triangle of affordability, security of supply and sustainability. In a methodological sense, this energy policy objective triangle is used as a framework for evaluating energy policies.

The dissertation contributes to and furthers the research by examining the consequences of political and regulatory decisions or potential policies and market designs. The work adds new insights to public debates that accompany or precede political decisions. The focus is not to give policy recommendation but rather to objectively analyse potential market effects and evaluate alternative options.

Whenever possible, quantifying results is seen as beneficial to lay adequate groundwork for further analysis. Ultimately, this work contributes to the field of energy policy by providing further evaluation of market effects of different energy policies. This objective is explored in the form of different studies, all answering slightly different questions regarding the outcomes of energy policies on power markets.

Specifically, chapter *3 Ex-post analysis of wholesale power price drivers* asks how policy decisions in Germany influenced an observed decline in wholesale power prices and how their influence compares with market effects. It aims to address just what caused prices to plummet and quantifies the price effects of policies such as the nuclear phase-out and subsidy schemes for renewable energy sources. The policies are then evaluated with reference to the energy policy objective triangle. This *ex-post* analysis therefore advances the objective of an increased understanding of the interplay of energy policies and the market.

This theme is continued in chapter *4 Price setting on European electricity markets*. This chapter aims to increase the knowledge of price-setting principles. Given that on energy-only markets the last activated unit in the merit order sets the price for all generating units during a given hour, furthering the understanding of the price setting is instrumental to analysing how policies might affect this. Specifically, this chapter aims to analyse how different carbon price floors influence the price-setting principles and energy policy objectives. It is a related objective of the study to investigate the price-setting across borders and determine how power markets in countries are affected by neighbouring countries and their energy policies.

Chapter *5 Case study: Impact of the German-Austrian bidding zone split on European energy objectives* is a case study on the breakup of the common German-Austrian bidding zone, in order to quantify the impact of this policy (or regulatory) decision. Using the energy policy objective triangle as a tool, this chapter evaluates the potential outcomes of the bidding zone split. It aims to determine what consequences the breakup of the common price zone has on the policy objectives of affordability, security of supply and sustainability for Germany, Austria and surrounding countries. By doing so, this chapter contributes to the debate that accompanies the decision to break up the common bidding zone. In terms of the overall objective of the dissertation, this case study analyses market effects of an actual real-world policy decision.

Chapter *6 A unilateral climate and supply market model* takes a slightly different approach. Having touched upon the significant influence of carbon pricing in preceding chapters and observing comparably low EU ETS allowances prices, this chapter explores the challenges of pricing carbon unilaterally. It aims to examine the roadblocks of carbon pricing in addition to the EU ETS, and it presents a market design to legally price carbon unilaterally. It is the objective of the study to add new insights to the public debate on carbon pricing and put forth a possible market design.

Last but not least, chapter *7 Drivers of wind and PV value factors and capture prices* concentrates on renewable energies – namely wind and PV and their future roles in the market. With wind and PV increasingly looking to compete on the market outside of traditional support schemes, questions regarding future values and revenues of wind and PV production arise. The objective of this chapter is to research how different policy factors and market effects affect the values of wind and PV generation. The study aims to answer these questions in different scenarios that simulate different developments.

Taken together, these studies shed light on the interplay of energy policy and power markets. It is the objective to contribute to public debates and the field of study by researching how policies and market effects impact and shape power markets.

1.3 Major literature

Considering the aforementioned objectives, a subsequent question is what exactly constitutes energy policy? Defining energy policy comes with more general issues of defining 'policy' in the first place. McGowan notes that "energy policy is concerned with the coal, electricity, gas and oil industries, as well as […] nuclear power, renewable energy and activities to enhance the efficiency of energy supply and consumption" (McGowan, 1996). Further, he differentiates between official and unofficial policies whereby the former describe explicit government-formulated strategies to manage energy balances, and the latter are adopted for a variety of reasons and affect the energy industry intentionally or incidentally (McGowan, 1996).

This dissertation focuses on what McGowan refers to as official energy policy, even though the term 'official' can be misleading in this context since many policies that are examined are proposed are potential policies, subject to public debate and as such not (or not yet) official. For the purpose of this research, energy policies or energy industry managing political measures also includes regulatory aspects. Examples of energy policies evaluated in this dissertation are carbon price floors, bidding zone configuration, deployment of renewable energy sources and market design options.

These energy policies have different kinds of effects that are evaluated with the framework of the aforementioned energy policy objective triangle. One analysis is therefore, for example: how a bidding zone split affects the affordability, security of supply and sustainability of power systems.

Besides energy policy, there are other developments that can impact the market and the three objectives of affordability, security of supply and sustainability. For some primary energy sources, rising prices may affect the market as government set carbon price floors, yet do not fall within McGowan's definition of official energy policy.

Carbon prices in particular, or more precisely, prices for allowances, are driven by a combination of political measures and market effects. Arguably, carbon price developments can be seen either as a market or a political factor. In this context, one can note that as long as there is not a minimum price or price corridor set by the government, rising or falling allowance prices would - for the purpose of this research - not constitute an energy policy. Similarly, falling or rising prices for primary energy sources such as coal or natural gas do not comprise an energy policy in this context (even though they may have underlying political causes).

In contrast, political or regulatory decisions such as bidding zone configurations and coal or nuclear phase-outs clearly fall within what McGowan describes as 'official energy policy'. And so do capacity additions of renewables, as long as they receive some form of subsidies, i.e. through government-steered renewable support schemes, or those that have allocated predetermined spaces (as is the case for many offshore wind parks).

For the purpose of this research, the classification of what constitutes an energy policy therefore follows McGowan's idea of 'official energy policy'. Other policies that may affect the energy policy objectives indirectly will not be regarded as energy policy here.

Given that the following chapters and studies shed light on different aspects of energy policy and market dynamics, the chapters discuss relevant literature separately. This is due to the fact that many market effects and policies have their own state of the art and specific, respective literature. Nevertheless, there are some overarching relevant works.

One of those is without doubt *"The Merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany"* by Frank Sensfuß, Mario Ragwitz and Massimo Genoese (2008). The authors not only coined the term 'merit-order effect' but also researched the effects of increased renewable electricity supply on market prices. In parallel, in a sensitivity analysis they evaluated the impact of price drivers such as CO_2 and fuel prices, concluding that a variation of gas prices has – aside from growing renewable electricity generation – the highest impact on the magnitude of the merit-order effect. Their quantification of the merit-order effect was widely acknowledged and many scholars took the Sensfuß, Ragwitz and Genoese research further.

Some such as Clò et al., 2015; McConnell et al., 2013; Woo et al., 2011 researched the merit-order effects for other countries or regions. Others looked further into how the merit-order effect impacts on investment incentives in new generation capacity. On this aspect Sensfuß et al. (2008) noted that thus far (up until 2006), "the development of renewable electricity generation has had no major impact on investments into new generation capacity" (Sensfuß et al., 2008). With newer data and further deployment of renewable capacity, other scholars such as Traber and Kemfert (2011) challenge this statement and find that investment incentives in new generation capacity (in particular in flexible gas-fired units) are largely reduced.

Another finding by Sensfuß et al. (2008) that can be questioned is their conclusion that the merit-order effect is a distributional effect that shifts profits from generation companies to consumers. From today's perspective, this statement can be challenged for two reasons. First, lower wholesale power prices have not been passed on to final consumers and second, the increased amounts of the EEG surcharge have led to higher costs for a group of non-privileged consumers[2]. The redesign of the German renewable support scheme with its shift from a classic feed-in tariff towards the more market-based feed-in premium reinforces this effect. With the shift to the market premium, the EEG surcharge is used to finance the gap between the wholesale power price and set renewable remuneration level. Lower wholesale power prices thus increase this gap and subsequently trigger a rising EEG surcharge. In this light, Cludius et al. (2014) find a different distributional effect than Sensfuß et al. (2008). Rather than a shift of profits from generation companies to consumers, they find a significant redistribution effect from the group of non-privileged consumers to the group of privileged consumers (consisting mainly of the energy intensive industry and large industrial electricity consumers).

Nevertheless, the research of Sensfuß et al. (2008) on the merit-order effect should be seen as one of the most important pieces of literature on the effects of energy policy on the market.

A central work that looks at energy policy from a security of supply, sustainability and competition perspective is a viewpoint from British economist Dieter Helm. In his paper *"Energy Policy: security of supply, sustainability and competition"*, Helm (2002) writes about the issues of power market liberalisation and the inevitability of tight regulation. He identifies the energy sector as one that inherently has to be steered by energy policy.

According to his analysis, it is a market that suffers from multiple market failures and will always be subject to government interventions for social, regional, industrial or environmental objectives. In this sense, governments control – willingly or not – the framework within which the market operates. In the aftermaths of the California energy crisis, he underlines the importance of good energy policy and analyses the energy policy of the UK in terms of security of supply, sustainability and competition.

His harsh judgement of the energy policy ("designed to solve yesterday's problems") might be correct yet his solution approach is rather vague (Helm, 2002). He merely calls for the creation of an energy agency between the ministry and the regulator, without defining the role specifically.

1.4 Structure

In order to answer the aforementioned research questions in detail, this thesis is structured into five main chapters followed by an overarching conclusion. Preceding the following chapters is description of the methodological approach.

1.4.1 Ex-post analysis of wholesale power price drivers

This chapter analyses different drivers of wholesale power prices that caused a plummeting of German power prices and is based on the published journal paper "Politics vs markets: How German power prices hit the floor" (Everts, Blume-Werry and Huber, 2016). The chapter introduces the reader to the energy policy objective triangle of security of supply, affordability and sustainability before presenting different theoretical models of energy policy

[2] Given the development of the EEG Umlage and its burden sharing, one should differentiate here between two types of consumers. Those who are largely exempted from the EEG surcharge and those who are not. Cludius et al. (2014)divide the consumers in this manner into a 'privileged' and a 'non- privileged' group.

governance. It then explores German energy policy following the Fukushima nuclear power plant accident and compares the political and market-based drivers of German wholesale power prices.

1.4.2 Price setting on European electricity markets

This chapter delves into the price-setting mechanisms on European power markets and is based on the working paper “Eyes on the price: Which power generation technologies set the market price?” (Blume-Werry et al., 2018) – currently under review at Economics of Energy and Environmental Policy (submitted in April 2019). It first provides some background on the general principles of price setting on liberalized European power markets before laying out the research approach. The results are analysed firstly with regard to price setting across borders and secondly with a close look on different generation technologies. Afterwards, low-priced hours are compared with high-priced hours and the conventional wisdom that hard coal and natural gas-fired power plants are the dominating price-setting technologies is challenged. Last but not least, two potential carbon price floor policies with different participants are examined with respect to the effects on price setting mechanisms and in light of the policy objective of sustainability.

1.4.3 Case study: Impact of the German-Austrian bidding zone split on energy policy objectives

This case study forms explores the effects of the breakup of the common German-Austrian price zone. It is based on the published journal article “Splitting price zones: The impact of the German-Austrian breakup on European energy objectives” (Blume-Werry et al., 2017). After providing some background and presenting the methodological approach, it analyses the potential effects of the breakup with respect to the energy policy objectives of affordability, security of supply and sustainability. In that order, the impact on each of the policy objectives is evaluated for Germany, Austria and affected surrounding countries.

1.4.4 Pricing carbon unilaterally: a market design study

This chapter presents a new market design suggestion. It is based on the published book chapter “A unilateral climate and supply market model” (Blume-Werry et al., 2019). The study fist explores different energy policy concepts and current issues of carbon pricing in the European Union. After illustrating three existing carbon taxation models, the study presents its own market design suggestion to price carbon unilaterally. Subsequently, some legal considerations are explored as well as an example demonstrating how the climate and supply market model could function in practice. The study shows potential variations of the model and discusses the adaption potential.

1.4.5 Drivers of wind and PV value factors and capture prices

The final chapter looks at how different drivers affect wind and PV value factors as well as capture prices, and is based on the working paper “Politics vs markets: what drives value factors and capture prices of renewables?” (Blume-Werry et al., 2020) – currently under review at Energy Strategy Reviews (submitted in February 2020). Following some background on the matter and an extensive literature review, the chapter discusses the methodological approach. The results of the research are then examined for each driver of value factors and capture prices. Finally, the study discusses the results and concludes.

These five main chapters are followed by an overarching conclusion, referring back to the research questions formulated in 1.2.

2 Method of approach

In order to answer the aforementioned research questions, a variety of different methods and approaches has been applied. Those include *inter alia*, *ex-post* analyses of historic data and development of scenarios to assess future developments.

Most important and repeatedly used is the techno-economic model Green-X of the European power market. The Green-X model can be described as a numerical dispatch and investment optimisation model of twenty interconnected European countries and power systems[3]. In economic terms it is a partial equilibrium model of wholesale electricity markets, focussing on the supply side. Amongst other things it is used to answer several 'what if' questions that are covered in the different studies. The methodological sections 4.3.1, 5.2 and 7.3 describe the model, employed parameters and specific use case in detail. The chapters also outline scenarios created in order to answer the specific research questions and *ceteris paribus* assumptions if used. Below, in section 2.1, those are complemented with a general characterisation of the model and its database. This is followed by a brief description of the energy policy objective triangle in section 2.2. The three objectives of the triangle, i.e. security of supply, affordability and sustainability are used as an evaluation tool for energy policies discussed here.

2.1 Green-X model

The partial equilibrium approach relates to economics theory of a supply-demand equilibrium which is reached when the sum of the producers' and consumers' surpluses is maximised. The consumer surplus can be defined as the difference between the price a consumer pays and the price he or she would be willing to pay. The higher the willingness to pay and the lower the price, the greater is the consumer surplus. In turn, the producer surplus describes the difference between the price a producer is willing to sell his or her good for and the actual price the good is sold for. The equilibrium describes the intersection of the demand and supply curves and represents the point at which the sum of consumer and producer surpluses is maximised (see Figure 1). One can refer to this sum of producer and consumer surplus as economic surplus or total welfare.

$$W = CS + PS \tag{1}$$

Whereby
W...total welfare
CS… consumer surplus
PS… producer surplus

[3] The twenty European countries covered by Green-X model are in alphabetical order: Austria (AT), Belgium (BE), Czech Republic (CZ), Denmark (DK), Finland (FI), France (FR), Germany (DE), Hungary (HU), Italy (IT), Luxembourg (LU), Netherlands (NL), Norway (NO), Poland (PL), Portugal (PT), Slovakia (SK), Slovenia (SI), Spain (ES), Sweden (SE), Switzerland (CH) and the United Kingdom (UK).

The general idea of the consumer surplus is the estimation of the savings of a consumer at a given market price p*. The consumer surplus is arithmetically represented as the integral of the inverse demand function over [0.x] less than sales:

$$CS = \int_{0}^{X^*} WTP(x)dx - x^* p^* \tag{2}$$

Whereby
WTP...willingness to pay
d......... demand
x......... quantity
p......... price

In turn the producer surplus is a result from the incomes of a producer minus the costs (c) and practically represents the profit of a producer at a market price p*

$$PS = p^* x^* - c(x^*) \tag{3}$$

Taken together one can note for the total welfare

$$W = CS + PS = \int_0^{X^*} WTP(x)dx - x^* p^* + p^* x^* - c(x^*) \tag{4}$$

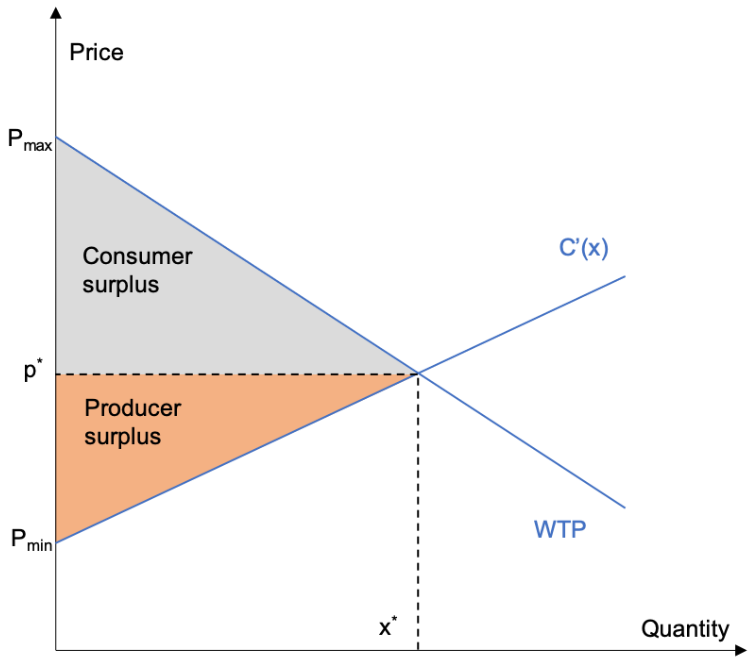

Figure 1: Consumer and producer surplus illustration

$$CS = \frac{1}{2} * x^* * (P_{max} - p^*) \tag{5}$$

$$PS = \frac{1}{2} * x^* * (p^* - P_{min}) \tag{6}$$

The Green-X model assumes perfect markets in which the social planner solutions determine the market equilibrium. In principle, that means that optimal deployment is the competitive deployment. The modelling process incorporates the dispatch and investment in power plants, minimisation of total investment costs as well as production and trade decisions with a range of technical constraints. The total system costs are put together by the sum of capital costs, fuel and carbon costs and fixed and variable costs of generation, storage and transmission.

The actual modelling can be described as a three-level process (see *Figure 2*). In a first step, endogenous and exogenous capacity additions and deductions are determined. To this end, the model includes an up-to-date power plants database of all major (>10MW capacity) power plants in the geographical scope of the model. This includes plants under construction, planned constructions and decommissioning plants. The economics of power plants such as the efficiency are either based on available data or estimated based on the specific generation technology, construction date and other available data. Smaller plants and non-hydro renewables are included in the form of clusters. Endogenous capacity additions are based on economic criteria with support schemes and political frameworks taken into account. The latter is especially important for renewable technologies, first and foremost wind and photovoltaics. For endogenous capacity additions and the assessment of economic viability and incomes of power plants in this step, the long-term marginal costs are key whereas the short-term marginal costs are decisive for the dispatch (second step). For the assessment of economic viability, the model takes -next to incomes from the sport market- also incomes from support schemes, capacity remuneration mechanisms or balancing services into account.

The second step computes the hourly power plant dispatch based on the determined power plant portfolio under given constrains. Those include interconnector capacities, power plant availability and power demand. A marginal cost based merit order curve determines marginal power plants for every hour and country-specific power prices.

The third and final step calculates final market prices and considers the economic viability of new power plants. To this end, the model also estimates incomes from ancillary services based on information on historic ancillary services payments and expenditure published by TSOs.

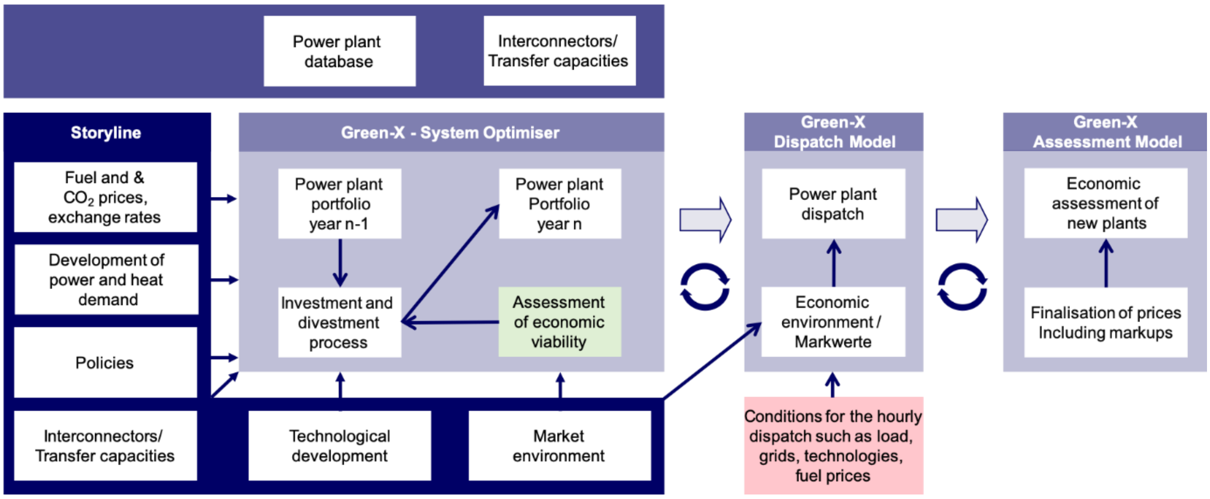

Figure 2: Three step modelling process in the Green-X model

Power generation is modelled with a high level of detail of power generation technologies. Those include hard coal fired power plants, lignite fired power plants, nuclear power plants, open cycle gas turbines, combined cycle gas turbines, oil fired power plants, mixed-fuel power plants, waste incarnation plants, different biomass plants, biogas plants, geothermal power plants run-of-river hydro power plants, hydro storage plants, pumped-hydro plants, battery storage, photovoltaics, concentrated solar power, tidal energy as well as wind onshore and wind offshore. For further differentiation there are a number of sub-categories (bands). In the aforementioned power plant database every power plant is listed with the technical and financial input parameter shown in Table 1:

Technical input parameter	Financial input parameter
Construction year	Investment/repower costs
Expected decommissioning date	Fixed operation and maintenance costs
Full load hours electric	Variable operation and maintenance costs
Full load hours heat	Eligibility for support schemes
Efficiency electricity generation	
Efficiency heat generation	
Capacity electric	
Capacity heat	

Table 1: Technical and financial input parameter

Dispatchable plants generate electricity whenever prices are greater than their variable costs. Existing plants are regarded as sunk investments and decommissioned when they cannot cover their costs. The model regards some combined heat and power generation as must-run generation. That means a share of co-generation power plants are operational even if prices are below their marginal costs. The total amount of heat output from combined heat and power plants is exogenous given and fixed but investments and divestment is possible.

Given the total cost minimisation approach, the model calculates cross-border trade endogenously. It is limited by net transfer capacities (NTCs) which are given exogenously. Currently, the capacities are determined based on the Ten Year Network Development Plan (TYNDP) by ENTSO-E. Within countries it is assumed that there are no network constrains (copperplate).

The Green-X model is deterministic and thus does not model uncertainty regarding future price or demand developments. Demand is given exogenously and is assumed to be price inelastic. Technological change is not modelled, yet expected cost reductions are given exogenously based on current cost projections by leading research institutes. Given that the majority of new capacities are nowadays installed outside of the geographical scope of the model an endogenous learning curve approach is deemed unsound.

One aspect many power market models struggle picturing accurately is hydro reservoir modelling. The dispatch of hydro storage is -unlike other generation technologies- not marginal cost based. Hydro reservoirs have effectively very low marginal costs, yet only a limited amount of water that can be discharged every year. One can note that the opportunity costs of releasing water are equal to the expected future value of electricity produced (see section 4.2). The Green-X model uses shadow prices reflecting the marginal costs of additional (thermal) power plants to model the dispatch. In a final step, the shadow prices are adjusted manually within a slope until the dispatch reflects historic monthly water levels of hydro reservoirs.

The Green-X model is back-tested regularly to compare the model output to historic market data. This is done for calibration purposes in order to replicate the power market accurately in modelling. Features of the power market such as hourly to yearly average prices, price spreads, peak and off-peak spreads, capacities, generation mixes, carbon emissions and interconnector flows can be replicated adequately. It should, however, be noted that no model can give an absolute accurate replication of power markets due to the complex nature of interconnected power markets with dynamic developments and market actors behaviour.

The model requires a range of inputs in order to model power markets (see Table 2). For some inputs actual market data can be used as far as it is available. For most fuel prices for instance future market prices are available for coming years yet assumptions have to made for the more long-term time horizon. Other inputs have to be estimated based on available studies and literature.

The model allows the selection of range of support schemes (policies). To reflect current and expected policies most accurately, policies for all modelled countries are updated annually. It is also possible to change or combine policies and parameter settings within a simulation run.

Inputs	Outputs
Fuel prices	Power prices (yearly and hourly resolution)
EUA allowance prices (carbon prices)	Price spreads
Fuel transport prices	Generation mixes
Power plant database (including plant efficiencies)	Generation mixes
Currency exchange rates	Carbon emissions

Generation technology cost developments	Technology-specific value factors
Net transfer capacities	Technology-specific capture prices
Power demand	Marginal power plants
Policies (including support schemes, capacity remuneration mechanisms, technological phase-outs)	Import/export balances
Renewable potentials	Hydropower dispatch
Historic availability of intermittent energy sources and hydropower water levels	Marginal costs of power generation technologies

Table 2: Green-X model inputs and outputs

The following section describes how power prices for different countries are determined in the Green-X model. The general modelling approach derives the balance between supply and demand on an hourly basis. Depending on the generation technology, power plants are depicted individually or grouped into clusters or so-called bands. The plants within a cluster have very similar characteristics in terms of both marginal costs and hourly availability (e.g. wind turbines in Northern Germany). The power plants or clusters within the market available at that hour are sorted according to their short-term marginal costs (merit order supply curve). The equilibrium point varies between countries depending on the demand to be met and the available transmission capacities.

To solve this linear problem of the electricity market, an external linear solver is used, which minimises the total cost of electricity supply taking transmission capacities between countries into account.

The optimisation is result of the national costs and import costs. First, consider the costs of national or domestic generation:

$$C_{nat} = \sum C_b E_b \tag{7}$$

Whereby
C_{nat}… cost of national (or domestic) generation
b………band/cluster of electricity generation (e.g. coal or run-of-river hydro)
C_b …….marginal costs of the power plant or band/cluster b
E_b…….produced power of plant or band/cluster b

Second, regarding the costs of electricity imports we note

$$C_{imp} = \sum_{u \in V} (f_{vu} + C_v)\, E_{vu} \tag{8}$$

Whereby
C_{imp}… cost of electricity imports
u…….. destination or importing country

v…….. exporting country
f_{vu} ..... transmission costs for the transfer from v to u
C_v ……marginal costs of electricity generation in country v
V ...... considered countries
E_{vu} .... transferred quantity of power from country v to country u

Taking this together, the optimisation can be described as:

$$min \sum_{v \in V} \left(\sum_{b \in B_v} C_b E_b + \sum_{u \in V} (f_{vu} + C_v)\, E_{vu} \right) \tag{9}$$

Whereby
B_v....... sum of cluster in country v

This means that the sum of the nationally available generation technologies[4] and the available energy quantities for import[5] must be minimised across all countries considered. This means that, in sum, the most cost-effective overall system is depicted. The following three secondary conditions apply:

Secondary condition 1
The law of conservation of energy for each country ensures that the amount of energy produced (E_b) plus the amount of energy imported (E_{vu}) minus the amount of energy exported (E_{vw}) corresponds exactly to the energy demand of the respective country. National demand must therefore be covered at all times:

$$\sum_{b \in B_v} E_{bm} + \sum_{u,v} E_{vu} - \sum_{v,w} E_{vw} = d_v \tag{10}$$

Whereby
E_{bm} .... maximum producible amount of energy of each band b
d_v .... national demand
u, v, w... are exemplary for connected countries u,v and w

Secondary condition 2
The capacities of interconnectors cannot be exceeded. The hourly import is restricted by the interconnector capacity:

$$0 \leq x_{uv} \leq C_{uv} \tag{11}$$

[4] Corresponds to the marginal costs multiplied by the quantity per band

[5] Correspond to the transmission costs multiplied by the amount of energy available

Whereby
C_{uv} .....maximum transfer capacity from country u to country v

Secondary condition 3
The maximum production quantity of a band must not be exceeded:

$$0 \leq E_b \leq E_{bm} \tag{12}$$

After determining the power plants used in the individual countries, the next step is to determine national electricity prices p_v (c_v). For this purpose, the band used with the highest marginal costs is determined for each country. These could be the price-setting plant for the country in question.

$$b_v^{max} = \underset{b \in B_v}{arg\,max} \{ C_b \,|\, E_b > 0 \} \tag{13}$$

Whether it is actually price-setting depends on the utilisation of interconnector capacity to neighbouring countries, i.e. the price-setting band could also come from abroad. If capacities to other countries are available, the electricity price of a country is defined by the maximum b_v^{max} v of all interconnected countries[6]. If the transfer capacity to all neighbouring countries is fully utilised, the national marginal power plant b_v^{max} determines the national electricity price.

2.2 Energy policy objective triangle

Energy policy is commonly driven by three objectives: Security of supply, affordability and sustainability. Given that an ideal energy policy delivers sustainable electricity at affordable prices with a high level of security of supply, these objectives are used here an evaluation tool for energy policies.

The policy objectives may compete with one another and to a certain degree they appear to be mutually exclusive. The energy policy objectives are often grouped together and referred to as the energy policy objective triangle

[6] If the highest marginal cost price in country v is lower than in country u and interconnector capacity is still available, then country v would export energy quantities to country u until the marginal costs in country v, including transport costs to country u, are equal to the marginal costs in country u (condition of freedom of arbitrage).

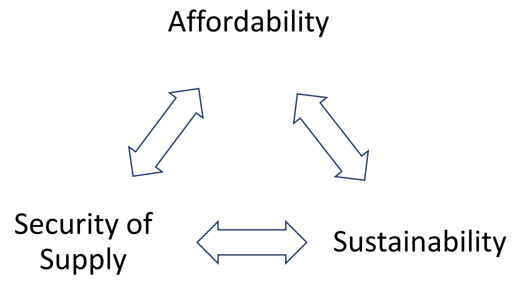

Figure 3: The energy policy objective triangle of security of supply, affordability and sustainability

2.2.1 Security of supply

The energy policy objective of security of supply refers to the reliability and stability of a system. For the electricity sector this basically means that there is a constant and secure supply of electric power. Often governments or the regulator in charge of the security of supply quantify this objective and sets a target defining an outage time period that ought not to be exceeded. In other words, consumers ought to have access to electricity all the time and given that outages can occur, these outages should be limited to an acceptable time period. One can refer in this context to the so-called System Average Interruption Duration Index (SAIDI) which is an index to measure and compare time periods consumers are without access electricity. Whilst there are slightly different methodologies, the security of supply is generally regarded as high in Europe with SAIDI ranging between 9 and 371 minutes in 2016 (CEER, 2018). Nevertheless, there are concerns regarding the long-term security of supply. To evaluate the long-term security of supply, many European Member States have conducted generation adequacy assessments and introduced so-called capacity remuneration mechanisms as a result with the intention of guaranteeing the long-term security of supply. The European Union plans to conduct EU-wide European Resource Adequacy Assessments (ERAA) as part of the Clean Energy for All Europeans Package (CEP).

2.2.2 Affordability

Given the pivotal role of electricity for the functioning of modern lives and society, it is an imperative for governments to ensure that its energy policy delivers reasonable and affordable electricity prices for citizens and businesses. Businesses need affordable electricity prices to be competitive and high prices for private consumers can hinder developments or lead to so-called fuel poverty (i.e. when people cannot afford to keep their homes adequately heated or supplied with electricity to meet their corresponding needs). Affordability is also an important aspect in regards to voting behaviour among the electorate and public support for envisaged energy transitions.

Economic growth is often still accompanied with growing electricity demand and it is a significant policy objective for governments to ensure affordable prices. Final prices for consumers can vary significantly depending on the location and type of consumer. Affordability is also crucial with respect to the envisaged electrification of the heating and mobility sector in the context of sector coupling driven by decarbonisation efforts.

2.2.3 Sustainability

Current energy transitions in Europe are predominately driven by the objective to decarbonise the power sector. Many energy policies such as renewable support schemes or pricing carbon emissions work towards a more sustainable electricity supply. In recent decades the policy objective of sustainability has gained increased focus. The reasons for this are twofold. On the one hand, one can note that the power sector has traditionally been a sector responsible for a large share of carbon emissions and, on the other hand, it is a sector where low-carbon or carbon free alternatives (such as renewable energy sources) are readily available.

Energy policies with sustainability as the primary objective aim to reduce the negative externalities associated with conventional fossil-fuel based power generation. Negative externalities encompass local effects, such as air pollution caused by NO_x from coal combustion, and global effects caused by greenhouse gas emissions. For simplification purposes, the sustainability of a given policy or system is often analysed using CO_2 or CO_2 equivalents (CO_{2e}) emissions rather than a set of different greenhouse gases. When speaking about carbon emission from power generation one can point to the carbon intensity of electricity, i.e. the ratio of CO_2 emissions and gross power generation measured in gram of CO_2 per unit of electricity, e.g. g/kWh. Widely used is also the approach of comparing annual emissions with those of a historic reference year, e.g. 1990, in line with related policy targets.

2.2.4 Application

The energy policy objective triangle is used here as tool to evaluate (potential) energy policies when sensible and applicable. This is carried out in the chapter analysing policies that contributed to the drop of German wholesale power prices and in the case study researching the effects of the breakup of the common German-Austrian bidding zone.

The former chapter combines historical data with the Green-X model for the *ex-post* analyses of drivers of German wholesale power prices to replicating hourly spot market prices. Changing certain input parameters enables assessing the impact of different drivers on the observed price decline. The quantitative data obtained then supports the policy evaluation with the policy objective triangle.

The study researching the price setting on European power markets uses Green-X power market model data to determine price-setting technologies and countries across different power systems. For the analysis of different carbon price floors in this context, carbon prices were altered *ceteris paribus*. Chapter 4.3 outlines this methodology in greater detail.

In a similar methodological approach the case study of the German-Austrian bidding zone split is researched. Using the Green-X power market model, different transfer capacities between Germany and Austria in different reference years are set *ceteris paribus* to analyse the effects a bidding zone split might have. See chapter 5.2 for a closer description of the methodology. The model proves a powerful and valuable tool and enables to support the policy evaluation with quantitative data.

The market design study takes a different methodological approach. It analyses advantages and disadvantages of existing carbon taxation models in Europe. Following, it suggests an own carbon taxation model that addresses aforementioned weaknesses of existing designs.

Given that a reoccurring theme for carbon taxation models are legal considerations, the analysis of legal aspects in this context take an important role.

Last but not least, the final study uses the model Green-X again to research capture prices and market values of wind and PV. In order to analyse the influence of different factors on capture prices and value factors, capture prices and value factors are determined in different scenarios over a time horizon of 30 years. In order to do so, the different input parameter were varied *ceteris paribus*. Chapter 7.3 illustrates this methodological approach in greater detail.

3 Ex-post analysis of wholesale power price drivers

3.1 Three policy objectives

A reliable and constant supply of electricity is commonly seen as essential for the functioning of the modern state. Selecting an appropriate electricity mix and using a variety of instruments to shape the energy policy is thus of great importance for governments. Commonly, one speaks in this context of three different policy objectives: (a) security of supply, (b) affordability, (c) sustainability. An ideal energy policy therefore delivers sustainable electricity at affordable prices with a high level of security of supply.

These policy objectives are however competing with one another and to a certain degree they appear to be mutually exclusive. Usually, a government can promote two of the three objectives at the most, at the expense of the other objective(s). This phenomenon is sometimes referred to as "energy trilemma" (World Energy Council, 2013).

3.1.1 Security of Supply

One factor for governments to consider with regard to their energy policy is the availability of resources. Traditionally, countries developed an electricity mix based primarily on the availability of local resources and secondarily on the availability of resources on the international markets. Using locally available energy resources to generate electricity has three crucial advantages: it supports the local industries, makes the most of a country's assets and from the security of supply perspective most importantly, it provides a great level of independence from outside forces.

Due to the fundamental role of electricity in our modern society, it is vital for the state to ensure a stable supply of energy resources for electricity generation purposes. This is also a reason why some countries subsidise the economically non-viable production of local energy resources (Pedraza, 2015).

However, security of supply has another dimension, which one could describe as reliability. Even though renewable electricity sources such as wind or solar do not require any fuel as such, their production heavily depends on the weather and is intermittent. Next to the above-described political aspect of the security of supply policy objective, governments have to take characteristics of different technologies into account when designing and amending their energy policy.

In order to ensure a reliable supply of electricity, it is the task of energy policy to give the market adequate incentives to provide sufficient and flexible generation capacity. This is an imperative to guarantee a high level of security of supply because fluctuating output of renewable energy sources, sudden power plant outages or unexpected high demand can otherwise cause power shortages.

3.1.2 Affordability

Regardless of whether a country imports fuels for electricity generation, subsidises local production, provides financial incentives for the deployment of renewables, or all of the above, the competitiveness or affordability of the system takes a key position. Effectively, most countries tend to seek a middle way between what is affordable and compatible with other factors such as security of supply and sustainability. Prices of fuels can be volatile and consequently most governments aim to have a somewhat diverse electricity mix in order to reduce vulnerability to price spikes. For obvious economic and social reasons, it is important that the energy policy of any government delivers reasonable and affordable power prices for citizens and businesses. Businesses need affordable power prices to be competitive and high prices for private consumers might even lead to so-called 'fuel poverty'[7]. Affordability is also an important aspect in regards to voting behaviour and party support among the electorate.

Economic growth is commonly accompanied with growing electricity demand and it is a significant policy objective for governments to ensure affordable prices. Many policy instruments such as carbon emission pricing or support schemes influence the competitiveness of certain technologies directly or indirectly. In this context, competiveness and affordability have also been used interchangeably as reasonable (or affordable) power prices are necessary for many businesses to stay competitive. Competitiveness has thus also been referred to as 'affordability' or simply 'costs' in the energy trilemma.

3.1.3 Sustainability

The sustainability of the electricity sector has become an ever more important factor in recent decades. Through their energy policies, governments strive to decarbonise the electricity sector and minimise negative externalities. Negative externalities encompass local effects, such as pollution caused by NOx emissions, as well as global effects caused by greenhouse gas emissions.

Renewable electricity sources have grown significantly and many governments subscribed to implement a certain share of renewables in their electricity sector. Next to the objectives of reducing greenhouse gas emissions and implementing more renewables, the aspect of sustainability also includes energy efficiency measures. Energy policy measures aiming to promote and boost energy efficiency have few if any downsides, and are thus an important energy policy instrument.

3.2 Theoretic models of energy policy governance

There are different means of balancing the three objectives of (a) security of supply, (b) affordability and (c) sustainability. In the following, two major theoretical approaches of (i) direct steering and (ii) multiple steering are presented and discussed.

3.2.1 Direct Steering

One approach to reach given climate targets is the so-called 'direct steering' model. The fundamental idea is to price and internalise greenhouse gas emission costs. Practically, this can be implemented by the introduction of a CO_2 tax and an emission trading system such as the European Union Emissions Trading Scheme (EU ETS).

The subsequent economic implication is a rise of wholesale power prices as a result of the CO_2 price component, presuming that the CO_2 price is sufficiently high. These high prices

[7] Fuel poverty describes a condition in which people cannot afford to keep their homes adequately heated.

indirectly contribute to a higher attractiveness of low CO_2 emission technologies such as renewable electricity sources. However, high power prices also have negative effects on the competitiveness of the economy especially for energy-intensive industries operating in an international environment.

Using Germany as an example, we have calculated the effect of the CO_2 tax and emission trading system on the electricity wholesale market prices with the fundamental model Green-X[8]. In a first step we have chosen all input data (power plant park, grid availability, subsidies, coal and natural gas prices, etc.) according to 2014 values and calibrated the fundamental model to match the actual electricity wholesale market prices. In a second step we switched the CO_2 pricing and emission trading system in the fundamental model off and analysed the delta between the two calculations.

It can be shown that a CO_2 price of 6 EUR_{2014}/t has a price increasing effect on German wholesale power prices of approximately 4 EUR_{2014}/MWh. In other words, power prices in 2014 would have been 4 EUR_{2014}/MWh lower if there had not been a price for CO_2 emissions (see Figure 4) .

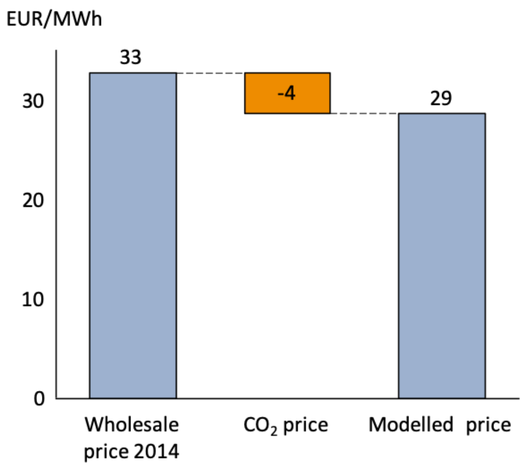

Figure 4: The carbon pricing and emission trading scheme increased wholesale power prices.

The resulting effect on the merit order and therefore on the electricity mix is that coal fired power plants are forced out of the market as they cease to be economically viable due to the CO_2 pricing system. It is assumed that natural gas-fired power plants remain in the system, ensuring security of supply and setting the price as units with the highest marginal costs.

In terms of the three policy objectives one can note that the aspect of sustainability is covered as well as preserving an appropriate level of security of supply. The resulting high power prices jeopardise the competitiveness of energy intensive businesses (unless a CO_2 tax and

[8]Green-X is a fundamental power model covering the EU-28 and selected other EU neighbours. It allows the investigation of the future deployments in the power and renewable sector including accompanying costs and benefits. It enables the derivation of a detailed quantitative assessment of the renewable electricity sources deployment in a real-world policy context on a national and European level for the power, heat and transport sector. It has been successfully applied for the European Commission within several tenders and research projects to assess the feasibility of '20% renewable electricity sources by 2020' and for assessments of its developments beyond that time horizon. In addition, Green-X can be used for a detailed quantitative assessment of the hourly market prices of European power markets (Huber et al., 2004).

emission trading system is applied globally) and will also lead to higher prices for private consumers, which is why this direct steering approach fails to meet the policy objective of affordability.

3.2.2 Multiple Steering

Another approach is the 'multiple steering' model. In addition to the measures introduced by the direct steering model this approach also includes active support schemes for renewable electricity sources.

The economic effect of the additional support schemes for renewables is that electricity wholesale prices do not rise as much as they do in the direct steering model. Due to their low marginal costs, wind and solar electricity enter the merit order near the bottom of the supply curve and cause the supply curve to shift to the right, resulting in lower average power prices as higher marginal cost technologies (in this case coal-fired power plants) are no longer necessary to satisfy demand and thus forced out. This effect of renewable technologies triggering lower electricity wholesale prices has often been labelled 'merit-order effect' (Sensfuß et al., 2008)

A multiple steering approach can produce price neutrality as the negative consequences on affordability caused by the introduction of a CO_2 pricing and an emission trading system are balanced with the positive effects of support schemes for renewables. Put differently, a multiple steering policy can offset the power price increase of the CO_2 pricing with the power price decrease of low marginal costs renewables. Maintaining price neutrality is essential in order to avoid market distortion and is thus a crucial aspect for policy makers to consider, also to ensure compliance with EU state aid and competition legislation.

The fundamental model Green-X allows us to model and calculate the effect of the current support schemes for renewables on the electricity wholesale market prices. First, the model is used to compute power prices with input data from 2014 (such as the power plant park). In a second modelling run we have adjusted the power plant park for wind and solar power plants to the level of 2008 – before the major German Renewable Energy Act (EEG) reform in 2009. It is thereby assumed that approximately 14 GW of wind capacity and approximately 31 GW of solar capacity were built as a result of the support schemes.

The fundamental modelling shows that power prices in Germany decreased by approximately 11 EUR_{2014}/MWh as a result of the expansion of renewables. In other words, one can say that German power prices would be approximately 11 EUR_{2014}/MWh higher, without the renewable capacity increase of approximately 45 GW (see Figure 5).

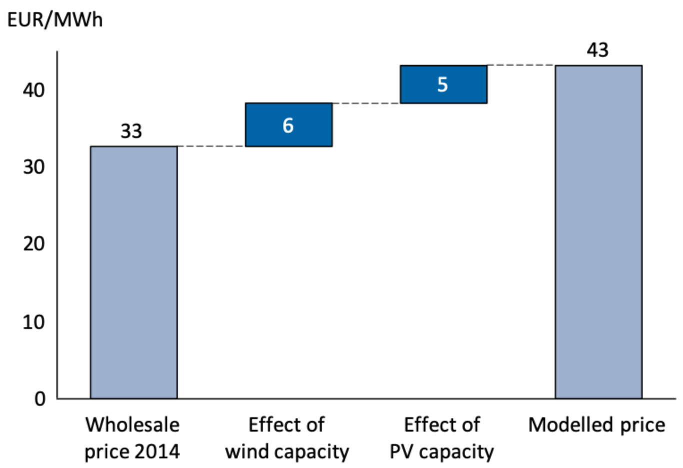

Figure 5: Deployment of low marginal cost wind and PV capacities reduced wholesale power prices.

In theory, the emission levy and the subsidies for renewables should force coal-fired power plants out of the market as CO_2 prices and fewer operating hours cause their production to be economically non-viable. Natural gas-fired power plants on the other hand should remain in the system. Their marginal costs are less affected by CO_2 prices and they are more suited to provide the flexible generation necessary for balancing intermittent renewable power generation.

It follows that theoretically all three policy objectives can be achieved by the multiple steering model. The parallel introduction of a carbon pricing and trading system as well as support schemes for renewable electricity sources and energy efficiency measures delivers (c) sustainable electricity without (b) climbing prices and threatening (a) security of supply.

It comes as no surprise that policymakers favoured the multiple steering model and introduced the European Emission Trading Scheme (EU ETS) and support mechanisms such as feed-in tariffs for renewable electricity sources. However, two events, namely the Fukushima nuclear accident and the economic crisis, drastically changed the political and economic environment.

3.2.3 Price neutrality

In theory, the price effect of a multiple steering energy policy should be zero – or as little as possible. An increase in power prices would lead to a loss of competitiveness of the energy intensive industry. A decrease of power prices on the other hand would lead to distortions and wrong incentives for investments. If the price decreasing effect is too large, new investments in flexibility become unprofitable, threatening the security of supply.

The figures of the analysis suggest that the price neutrality is not given. The current energy policy has a price decreasing effect of approximately 6 EUR_{2014}/MWh. One can conclude from this data that either the support schemes for renewables have led to an excessive deployment of renewables with a subsequent too large price decreasing effect or that the levies on emissions and the accompanying price increasing effects of the CO_2 pricing are too low. As a matter of consequence, the intended price balancing effect of the multiple steering model did not occur.

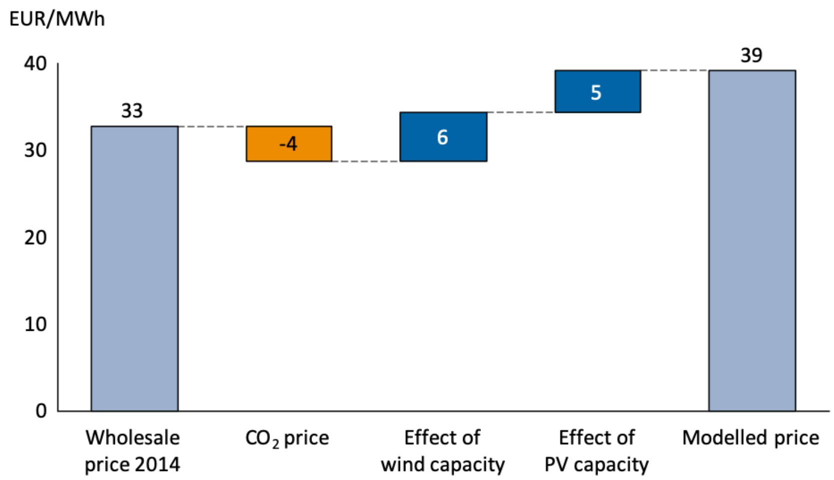

Figure 6: Effects of the carbon emission trading scheme and renewable deployment on wholesale power prices.

The current distortions of the electricity industry confirm the theoretical analysis. Currently, power prices are too low to foster new investments in flexibility. However, intermittent renewables such as wind and solar need to be backed up by flexible generation units in order to ensure the targeted level of security of supply.

3.3 Energy policy after Fukushima

Following the nuclear accident in Fukushima in March 2011, Germany chose to shut down eight of its nuclear power plants immediately and retire all of the remaining by 2022. Similarly, other governments, such as the Swiss decided to phase out its nuclear power plants.

Abandoning base-load nuclear power has considerable effects on the energy market. Coal-fired power plants which in the initial multiple steering model are forced out of the market, are now necessary to make up for shut down nuclear power plants. This impedes the climate targets as CO_2 emission-low nuclear power production is replaced by highly polluting coal. With coal-fired power plants back among the producing units, the political objective of sustainability falls short.

We have modelled the effect of the shutting down of the eight German nuclear power plants with the fundamental model Green-X by re-introducing them in the theoretic fundamental model and analysing the price differences between the power prices with and without the power plants.

Our analysis shows that the discontinuation of the German nuclear power plants led to a price increase of 6 EUR_{2014}/MWh (see Figure 7). Put differently, power prices in Germany would be approximately 6 EUR_{2014}/MWh lower if the eight nuclear power plants with a capacity of roughly 9 GW were still running.

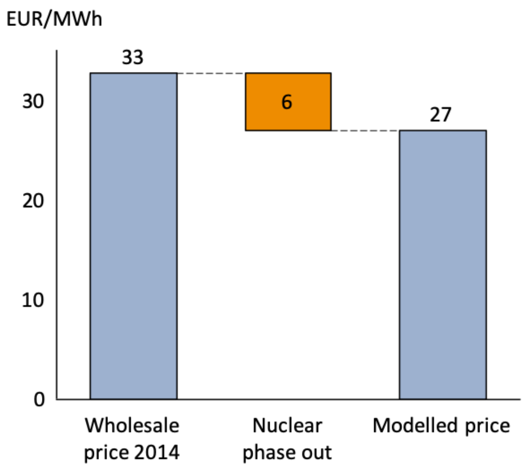

Figure 7: Shutting down nuclear capacities led to a price increase of 6 EUR$_{2014}$/MWh.

Hence, the nuclear phase-out has a negative effect not only on CO_2 emissions but also on competitiveness and as a policy objective on its own it would be incompatible with the goals of (b) affordability and (c) sustainability.

In fact, in terms of the three policy objectives of (a) security of supply, (b) affordability and (c) sustainability, it would be very difficult to integrating the nuclear phase-out into the multiple steering model. One could argue that the objective of affordability could be achieved by combining CO2 levies and a nuclear phase-out with support schemes for renewables. However, as mentioned the sustainability target cannot be achieved in this context due to the re-introduction of coal-fired power plants.

3.4 Comparing policy and market effects

The following chapter puts the effects that followed the 2008-2009 financial crisis in relation to the mentioned energy policy instruments of a CO_2 emissions trading system, support schemes renewables and the nuclear phase-out. 2008 is thus picked as a reference year, not just because it reflects the pre financial crisis situation but also because in precedes the German Renewable Energy Act reform (EEG 2009), which initiated a new growth in renewable capacity (especially solar). Additionally, it is important to note that the EU ETS went into the second phase in 2008 after the first phase ended with prices close to zero in 2007. This second phase initially delivered significant CO_2 prices, reaching 30 EUR/t in summer 2008 (Feess and Seeliger, 2013). The subsequent financial crisis and the serious economic downturn that came with it had unprecedented effects on the power market.

In order to analyse the market effects, the fundamental model Green-X is run several times with different input parameters. We calibrate the fundamental model and use 2014 coal and natural gas prices, power plant parks, network transmission capacities, fuel prices, etc. in order to calculate 2014 power prices. We then change each input variable of the fundamental model in order to evaluate its influence on power prices. To assess the effect of the economic downturn on power prices, we have chosen to set all important input variables (one by one) back to their 2008 values. This means that we are running the fundamental model Green-X first with 2014 prices (e.g. 2014 coal prices) in order to calculate 2014 power prices and secondly with 2008 coal prices to analyse effect of the coal price change on power prices.

The analysis is based upon the following assumption: Coal prices were approximately 7 EUR2014/MWh and natural gas prices approximately 10 EUR2014/MWh higher in 2008 then they were in 2014. Electricity demand was approximately 42 TWh higher and CO_2 prices approximately 19 EUR2014/t higher in 2008 then they were in 2014. Moreover, it is assumed that the support scheme for renewables fostered 14 GW wind capacity and 31 GW solar capacity and that the nuclear phase-out decreased the nuclear capacity by approximately 9 GW.

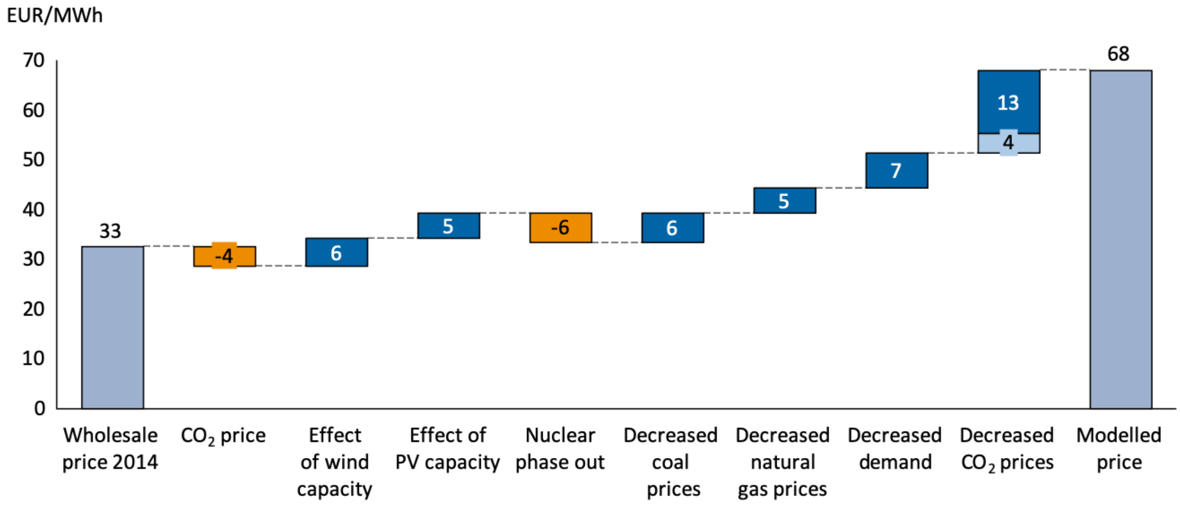

Figure 8: Overview of different researched drivers' influence on wholesale power prices in Germany.

After having modelled the most relevant drivers with their 2008 values, the modelled power prices were close to the actual 2008 power prices (even though the model was calibrated for 2014). Our modelling approach shows that a coal price decrease of approximately 7 EUR2014/MWh leads to a power price decrease of approximately 6 EUR2014/MWh and a natural gas price decrease of approximately 10 EUR2014/MWh results in a power price decrease of approximately 5 EUR2014/MWh. The decreased demand of approximately 42 TWh does have an astonishingly large impact on power prices of 7 EUR2014/MWh. Hence, one can argue that approximately 50% of the decrease in wholesale power prices since 2008 can be attributed to the economic downturn and its wider consequences, including the price decline of coal and natural gas.

Regarding carbon prices, we have shown that if there were no price for carbon, power prices would be 4 EUR2014/MWh lower. In order to evaluate how the decrease of CO_2 prices from 2008 to 2014 affected power prices, we have to reintroduce CO_2 prices (and hence add 4 EUR2014/MWh) and in a second step increased the CO2 prices by 19 EUR2014/t back to their 2008 value, resulting overall in an increase of power prices by 13 EUR2014/MWh or nearly 40%.

The economic rationale behind the current low wholesale market prices is as follows: With low coal prices, hard coal and lignite power plants became economically more viable than natural gas-fired plants. Natural gas-fired power plants are thus forced out of the market and hard coal power plants became the price setting units in the merit order. The weakened electricity demand and the economic competitiveness of coal-fired power plants led to a fall of electricity wholesale prices that had positive effects on the objective of (b) affordability.

The policy objectives of (c) sustainability and sound (a) security of supply, however, are missed. Regarding the aspect of sustainability, one can note that the coal and lignite-fired power plants jeopardise climate targets. In respect to security of supply it is important to mention that flexible natural gas-fired plants which are considered necessary to balance intermittent generation from renewable sources thereby guaranteeing security of supply, are forced out of the market since their continuation is no longer economically feasible.

3.5 Conclusions

The energy policy of multiple steering - which introduced a carbon tax, an emission trading system and support schemes for renewables - failed to deliver the expected results. The energy policy aimed to force highly polluting coal-fired power plants out of the market, thereby contributing towards climate targets. However, the additional policy objective of a nuclear phase-out as well as low coal and carbon prices eventually caused natural gas-fired units to become unprofitable whilst coal remains the largest source of electricity in Germany. Altogether, it has been shown that the policy failure is primarily a result of the economic crisis that changed the economic framework.

The idea was to keep wholesale power prices on a reasonable level through the expansion of renewables, yet the weak demand and the somewhat unexpected strong growth of renewables caused – together with low coal and natural gas prices due to the economic crisis - prices to plummet which threatens investments in new capacities. This impact, in combination with the shut-down of natural gas-fired generation capacities, puts also the long-term security of supply at risk.

As a response Germany (as well as other European countries) has recently introduced capacity remuneration mechanisms[9] to provide market participants with more incentives for building or maintaining generation capacities in order to guarantee security of supply. Looking at these developments one can note that capacity remuneration mechanisms are an unintended product of a failed energy policy.

This is however not to say that the multiple steering energy policy was poorly designed. The economic crisis and to a lesser extent the added policy objective of a nuclear phase-out drastically changed the framework in which the energy policy operates. The result was a multiple steering energy policy in an economic environment that no longer fitted its design.

[9] Whilst capacity remuneration mechanisms can take different forms, they generally provide monetary payments towards generators for available generation capacity.

4 Price setting on European electricity markets

4.1 Background

Wholesale power markets follow the principle of short-run electricity markets where the market clearing price is determined by the intersection of supply and demand at any given hour. In theory, the resulting hourly day-ahead market price is equal to the marginal costs of the last (marginal) unit in the merit order necessary to satisfy the demand. Given that this marginal unit sets the price for all power generation units operating during that particular hour, one can refer to this as 'price setting'.

It is frequently stated that in most central European markets, natural gas- and/or coal-fired power plants are usually the marginal price-setting units (Finon, 2013; Geiger, 2011; Genoese et al., 2015; Pietroni, 2017). Geiger, for instance, notes with respect to the German power market that “the price setting unit is often either a gas or a coal plant” (Geiger, 2011). Also concerning the German market, Genoese and Egenhofer conclude that “it is safe to assume that gas was the price-setting technology in most hours” when analysing the comparably high prices of 2008 (Genoese et al., 2015). Researching the British market, Roques et. al. state that “gas-fired plants were often the marginal price-setting plants in the British electricity market” (Roques et al., 2008). But is it safe to assume this? Is it still valid at present? And on what basis is this conventional wisdom accepted?

There are well founded reasons for this general idea. First, one can point towards the nature of European power plant portfolios with significant coal- and natural gas-fired generation capacities and their marginal pricing. Second, it should be noted that causal relationships between coal and/or natural gas prices and wholesale power prices have indeed been observed and documented (Emery and Liu, 2002; Ferkingstad et al., 2011; Mohammadi, 2009; Moutinho et al., 2011; Roques et al., 2008). Beyond this research on the relationship between fuel and power prices, there is to our knowledge no academic literature that looks in detail into the actual price setting on European markets and the extent to which coal- and natural gas-fired power plants are indeed commonly price-setting.

This study aims to fill this gap and investigate price setting on European power wholesale markets using a fundamental electricity market model. From the hourly calculations of European power markets, one can derive the marginal price-setting technology for any given hour. Taking a whole year as a timeframe, it is possible to analyse how the hours of a year are structured and what share different generation technologies take in providing the marginal price-setting units. The core objective is to broaden knowledge of price setting on European power markets, and obtain a more nuanced picture of what technologies set market prices. Given that the European power market is integrated and significant cross-border flows are occurring, the analysis is not limited to one country but looks at 20 integrated central

European power markets[10]. This will help to understand interdependencies and in what ways larger markets dominate price setting elsewhere.

This framework can then be used to research a whole range of developments to see how certain changes in the market affect the price setting. There are many possible 'sensitivities' one can employ here; such as fuel price changes, interconnector capacity changes, power plant portfolio changes, etc. In view of ongoing public debates on CO_2 price floors and the announcement of the Dutch government that one be introduced, the authors have chosen to analyse how different CO_2 price floors affect the price setting on those markets. This will shed light on the question of how carbon price floors influence marginal price setting and if a given price floor will result in a shift from coal to natural gas as a dominant price-setting technology.

To this end, the study first discusses the general approach to price setting on European power markets and the existing literature and research. This is followed by a description of the applied methodology with regards to the employed model and carbon price floors. Afterwards, the results are presented, analysed and discussed. First in the light of price setting across borders, second with respect to the different price-setting technologies and sorted into three price level. Last but not least, the study looks at the employed carbon price floors before concluding.

4.2 General Price setting approach

As aforementioned, conventional wisdom holds that natural gas- and/or coal-fired power plants are the price-setting marginal units in different central European countries for most hours of the year. This seems reasonable given the substantial capacities of natural gas- and/or coal-fired generation capacities in many countries and their marginal pricing. The marginal costs of coal- and natural gas-fired power plants fall within the commonly observed range of wholesale power prices. Other generation technologies such as nuclear power or renewable energy sources are characterised either by very low marginal costs or, in the case of peak generation units like oil or diesel generators, by very high marginal costs. Therefore, unless power prices are at any given moment extraordinary high or low, one can assume that these technologies do not provide the marginal price-setting units.

It should be noted at this point that European wholesale power prices have experienced a significant drop within the last several years, and that the number of hours in a year with very low prices increased significantly (Everts et al., 2016; Hirth, 2018)[11]. It therefore seems plausible that during those low-priced hours, inflexible low-marginal cost generation technologies such as lignite, nuclear power or must-run technologies are indeed providing the last marginal unit on the merit order to meet the load – and are thus price-setting.

A look at the merit order can help to take further the idea of substantial coal- and natural gas-fired power plant capacities and their marginal pricing. Figure 9 displays an approximated example of a merit order in Germany. The line shows the German residual load of the year 2017 in 1,000 Megawatt (MW) brackets. The residual load is commonly defined as the

[10] The twenty modelled countries are: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

[11] For a discussion on the causes of the price drop see Everts et al. (2016) and Hirth (2018).

difference between actual power demand and the non-dispatchable stochastic power generation of photovoltaics and wind turbines (Schill, 2014). Other generation technologies (in this case predominantly thermal ones) are therefore those covering the residual load. The distribution of the residual load over the merit order curve shows which generation technology should, in theory, set the price at a given residual load. Following this principle, lignite and hard coal power plants should be the price-setting units during most hours of the year, whilst natural gas-fired power plants alongside biomass and nuclear power plants take a smaller share.

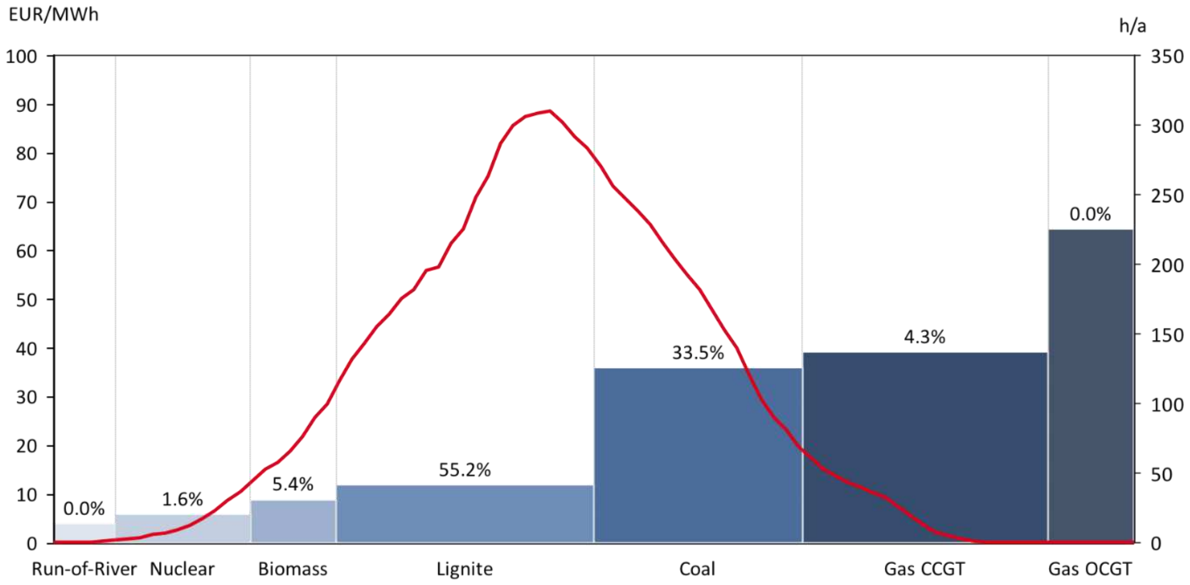

Figure 9: Approximated 2017 German merit order and residual load (as probability density function) [12]. At 100 per cent power plant availability, lignite- and coal-fired power plants seem to set the price for the majority of hours.

One should note at this point that the unavailability of power plants – for instance due to revisions, maintenance and naturally occurring lower capacity factors of run-of-river and biomass power plants – are disregarded in this visualisation. Taking these factors into account would shift the merit order curve to the left and increase the hours in a year during which natural gas-fired power plants should provide the marginal units. In addition to the unavailability of power plants, this merit order and residual load-based view of the price setting concept also disregards cross-border flows, i.e. electricity imports and exports. These drawbacks demonstrate why this approach is not the most accurate way of looking at the concept of marginal units and price-setting technologies, but it *can* help to understand where the conventional wisdom or usual narrative might originate from.

Numerous scholars have researched price dynamics between natural gas or coal prices and power prices in different countries. Emery and Liu analyse the relationship between electricity futures prices and natural gas futures prices and find that they are co-integrated (Emery and Liu, 2002). Mohammadi finds a stable long-run relation between real prices for power and coal and insignificant long-run relations between power and natural gas prices (Mohammadi, 2009). Ferkingstad et al. research the interplay of different fuel and electricity prices in the Nordic and German markets and find a strong connection between natural gas and electricity

[12] Marginal costs are based on authors' estimations. Residual load and capacity data from Bundesnetzagentur | SMARD.de (Bundesnetzagentur, 2018).

prices yet no significant connection between electricity and coal prices (Ferkingstad et al., 2011). Moutinho et al. observe *inter alia* a positive correlation between natural gas and electricity prices on the Spanish market (Moutinho et al., 2011). Roques et al. analyse the correlation between electricity and natural gas prices in Britain with respect to portfolio optimisation for generators and calls for further research in the area, especially in regard to effects of carbon emission allowances on the marginal technology in the market (Roques et al., 2008).

Even though the findings of scholars differ with different methodologies and research focuses, it can be noted that causal relationships between natural gas and/or coal prices and power prices exist, depending on the researched countries, time frames, applied methodologies and so forth.

In terms of price setting, reservoirs or storage plants, as well as pumped-hydro storage plants, serve a special role. Reservoirs and hydro-storage plants have effectively very low marginal costs and are, however, often the marginal unit to satisfy demand. Given that those plants have only a limited amount of water that can be discharged within a year, the usage hours are optimised to serve the highest priced hours. Economists mention that the opportunity costs of releasing water are equal to the expected future value of electricity produced when referring to this non-marginal costs-based dispatch (Faria and Fleten, 2011; Pikk and Viiding, 2013). With regards to hydro-storage plants or pumped-hydro storage plants, the term 'price setting' can thus be misleading since *shadow prices* – reflecting the marginal costs of additional alternative (thermal) power plants – are used for the dispatch. The shadow prices thereby relate to the costs of a thermal reference power plant, and the historic monthly water levels of reservoirs are used for modelling the dispatch of reservoirs and pumped-hydro power plants.

4.3 Methodology

4.3.1 Model

The techno-economic model Green-X[13] is used to model the European power market. The modelling process incorporates the dispatch and investment in power plants, minimisation of total investment costs as well as production and trade decisions, all with a range of technical constraints. In economic terms, the model is a partial equilibrium model of wholesale electricity markets, focussing on the supply side. It includes an up-to-date power plant database[14] of all twenty countries including plants that are planned or set to be

[13] Green-X is a fundamental power model covering the 28 Member States of the European Union (EU) and selected EU neighbouring countries. It allows for the investigation of future deployments in the power and renewable sector including accompanying costs and benefits. It enables the derivation of a detailed quantitative assessment of renewable electricity sources deployed in a real-world policy context on a national and European level for the power, heat and transport sectors. It has been successfully applied for the European Commission within several tenders and research projects to assess the feasibility of '20% renewable electricity sources by 2020' and for assessments of its developments beyond that time horizon. In addition, Green-X can be used for a detailed quantitative assessment of the hourly market prices of the European power markets (Everts et al., 2016; Huber, 2004).

[14] Small-scale plants and non-hydro renewables are grouped into clusters.

decommissioned, as well as an up-to-date database of all interconnectors among those countries.

Aside from the Green-X model power plant database – including planned plants and those under construction – the model also adds further capacities endogenously. Although endogenous conventional capacity additions are limited given the relatively short time horizon of this research, they take an important role in longer-term modelling. The endogenous capacity additions are based on economic criteria with support schemes and political frameworks taken into account, which is especially important for renewable technologies, and first and foremost wind and photovoltaics.

The actual modelling can be described as a three-level process. In a first step, the endogenous and exogenous capacity additions/deductions (the latter from the aforementioned power plant database) are determined. The second step consists of computing the hourly power plant dispatch based on the determined power plant portfolio (taking into consideration interconnector capacities, power plant availability and power demand). A marginal cost-based merit order curve determines the marginal power plants for every hour in addition to country-specific power prices. The third step examines the economic viability of new power plants and calculates final market prices. For the latter, the model also estimates incomes from ancillary services based on information provided by TSOs regarding historic ancillary services.

4.3.2 Price-setting technologies

The model was calibrated in a way to most accurately represent the current European power market and replicate hourly day ahead prices on the power exchanges. The year 2020 was chosen as a reference year as it is the year the Dutch carbon price is supposed to come into effect. This comparable near future horizon allows for using actual future market prices for most primary energy sources that were taken from the Intercontinental Exchange (ICE) at the time of the modelling (Spring 2018).

For transfer capacities between countries, the model uses current data and planned additions from the European network of transmission system operators for electricity (ENTSO-E). Within countries the model assumes that no congestions exist. To model yearly power demand, historic GDP and power consumption data of different providers are used for an accurate calibration. The influence of energy policies on power consumption such as increases and reductions in demand through the deployment of electric vehicles or energy saving measures is taken into account, yet due to the short time horizon in question this influence is rather limited. For the modelling of the hourly demand, the model uses historic load profiles, whereby changes in consumption behaviour are considered.

4.3.3 Carbon price floors

Ceteris paribus, carbon prices were changed once to 18 EUR/tCO_2 for the Netherlands to simulate the announced carbon price floor, and once to 30 EUR/tCO_2 for Austria, the Benelux countries, France, Germany and Switzerland to simulate the concept of a common carbon price floor. The floor price of 18 or 30 EUR/tCO_2 thereby includes the EU ETS allowance price and is not to be understood as a top-up or premium.

The corresponding CO_2 emissions of the different scenarios are derived from the calculated hourly power plant dispatch. The emissions of the different power plants are hereby limited to CO_2 emissions. Other greenhouse gas emissions such as methane (CH_4) or nitrous oxide (N_2O) are not taken into account.

4.4 Modelling results

4.4.1 Price setting across borders

It is the key question of how the modelling results compare with the conventional wisdom. A first observation is that, with respect to the marginal price-setting units, the modelling results indicate a higher level of interconnectivity than one might assume. Large countries tend to dominate the price setting – presumably simply due to the large number of power plants and their differentiated marginal costs. Small countries such as Luxembourg only provide the price-setting marginal units for few hours a year and are to a great extent influenced by their neighbouring countries. Relative size, i.e. the size in relation to neighbours, also matters in this context. Hence, electricity markets and wholesale power prices of comparably small countries are significantly influenced by the energy policies of their larger neighbours. Indeed, modelling results show that in terms of price setting, foreign energy policies can have a larger influence on a given state's electricity market than domestic policies.

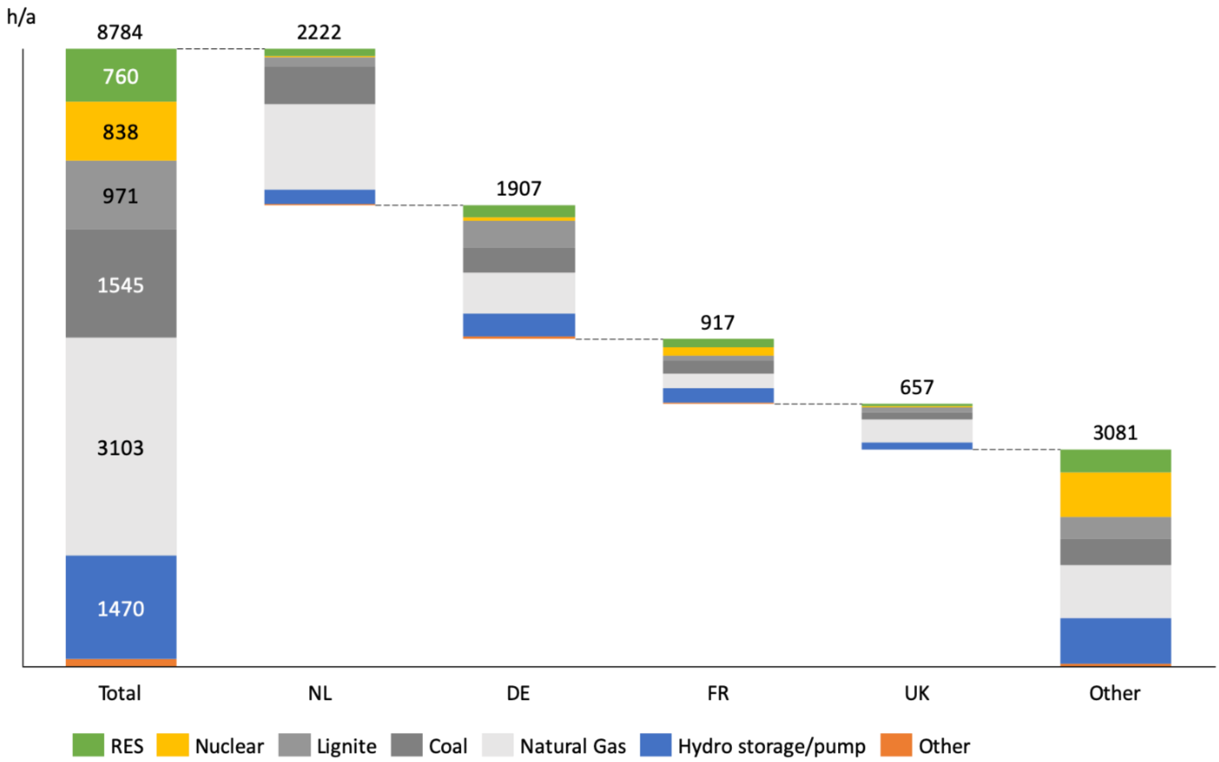

Figure 10: Price-setting technologies Netherlands 2020 in hours per year. Price setting in the Netherlands shows a substantial foreign influence.

Figure 10 shows the structure of the price-setting units in the Netherlands for the year 2020. The bar on the left illustrates the amount of hours different technologies provide the price-setting units. The other bars show the countries where those price-setting units are located (Netherlands, Germany, France, Great Britain and other countries combined). Gas-fired power plants represent the most dominant price-setting technology and for most hours of the year, foreign power plants set the price in the Netherlands. One can therefore surmise that foreign markets and thus foreign energy policies influence the Dutch power market considerably.

A closer look at the German price setting (Figure 11) reveals that this is not merely a Dutch or small-state phenomenon given that the German market represents the largest European market.

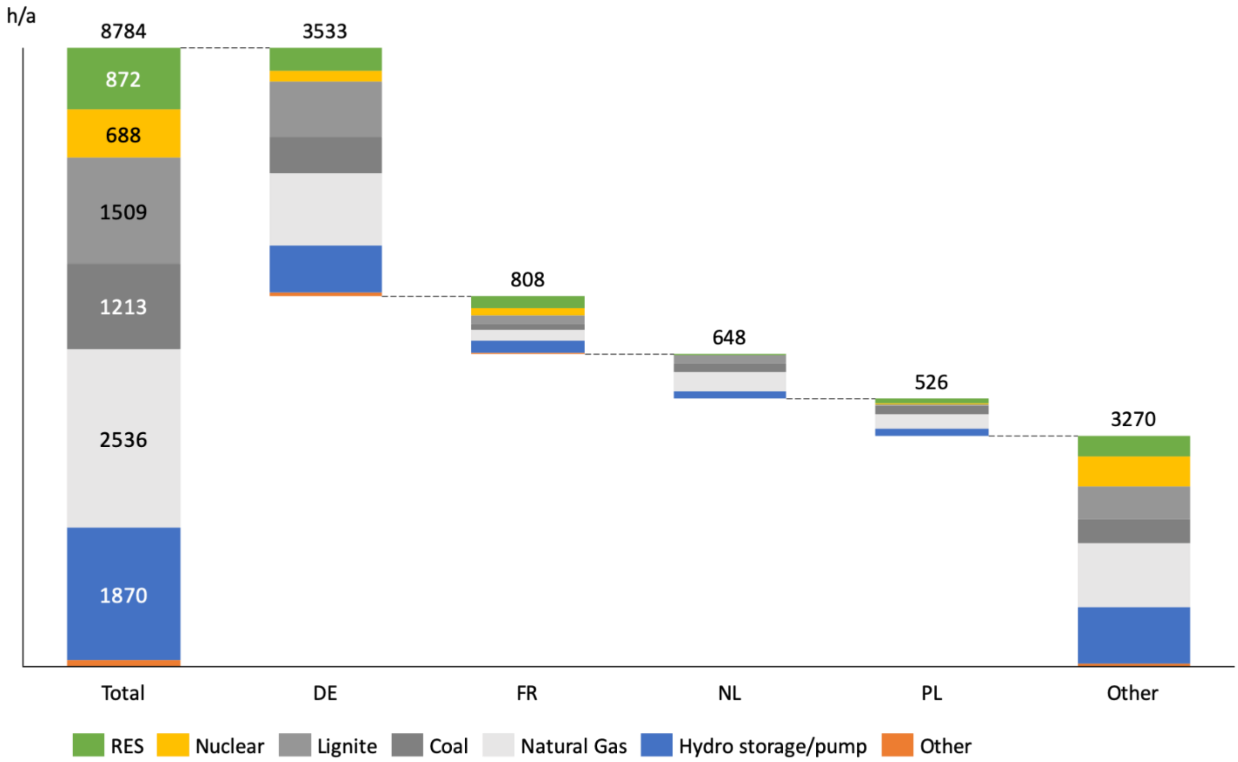

Figure 11: Price-setting technologies Germany 2020 in hours per year. Price setting in Germany is heavily linked with foreign markets despite the considerable size of the domestic market.

Other more isolated markets such as Great Britain are only marginally influenced by cross-border flows due to rather limited net transfer capacities. The Spanish and Portuguese markets on the Iberian Peninsula are also barely affected by outside markets in terms of price setting (see Figure 12).

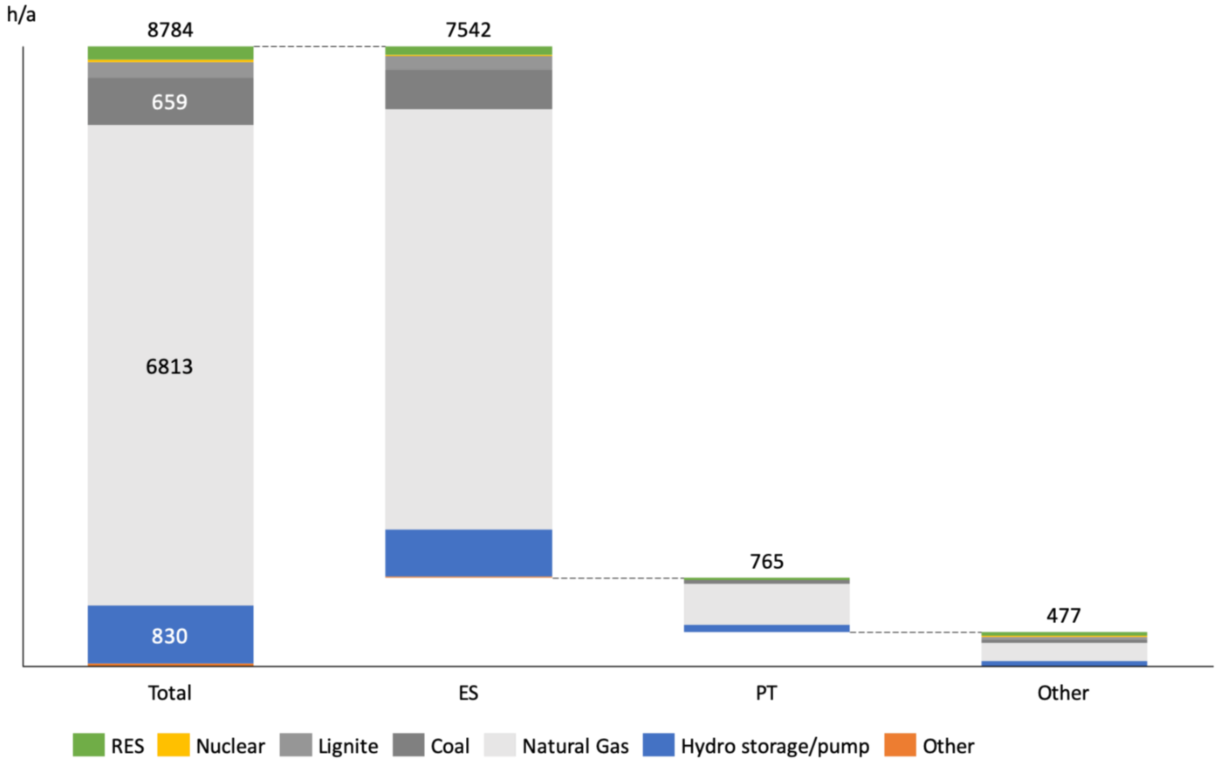

Figure 12: Price-setting technologies Spain 2020 in hours per year. Price setting in Spain shows little foreign influence.

As a general observation, the number of total hours power plants from a given country are price setting is highest in that given country, i.e. plants from country X do not provide as many price-setting hours in any other country as they do in country X.

4.4.2 Price-setting technologies

Looking at the technologies that provide the marginal price-setting units, one can confirm aforementioned presumptions. For the large majority (>90%) of total hours in all countries, reservoirs, pumped-hydro, nuclear, gas-, coal- and lignite-fired power plants provide the marginal price-setting units. Other technologies such as stochastic renewables or other fossil plants play an almost negligible role in terms of price setting. This seems plausible given the very low marginal cost of renewable energies and their subsequent position at the starting point of the merit order. During most hours, further power plants are necessary to satisfy the demand.

Altogether, the modelling results show that natural gas-fired power plants provide the price-setting units for almost a third of the total hours and thus for more hours than any other generation technology. Coal- and lignite-fired power plants follow, and together provide the price-setting units for over a quarter of the total hours (whereby lignite-fired power plants take a larger share than coal-fired ones). A notable point is that reservoirs and pumped-hydro power plants are also price setting for another quarter of the total hours. Nuclear power plants set the price for just below 10 percent of the hours, a share similar to that of renewables, including run-of-river power plants (see Figure 13).

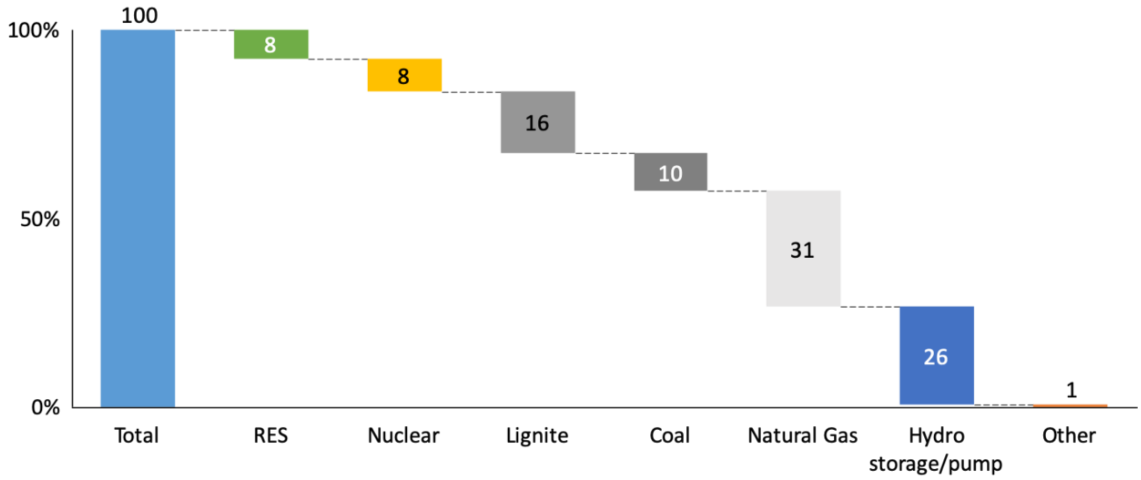

Figure 13: Price-setting technologies of all researched countries 2020 in per cent.

On an individual country basis, the picture of price-setting technologies can look very different depending on countries' – and surrounding, connected countries' – generation portfolios. Here one can observe some expected outcomes. The price setting in Poland, for instance, is dominated by lignite- and coal-fired power plants whereas in Great Britain, Italy and on the Iberian Peninsula, natural gas-fired power plants provide the price-setting units for the most hours. Similarly, Norwegian reservoirs as well as Finnish and Swedish nuclear power plants share the price-setting hours in the three states, which generally have a similar picture in terms of the price-setting units. This can be seen as an indicator of similar production parks, a high level of interconnectivity, or indeed a combination of both.

4.4.3 High vs low priced hours

In order to evaluate the modelling results further, one can divide the hours in a year into different groups. Therefore, the 8,784 hours of the year 2020 were divided into the highest, medium and lowest priced hours per country.

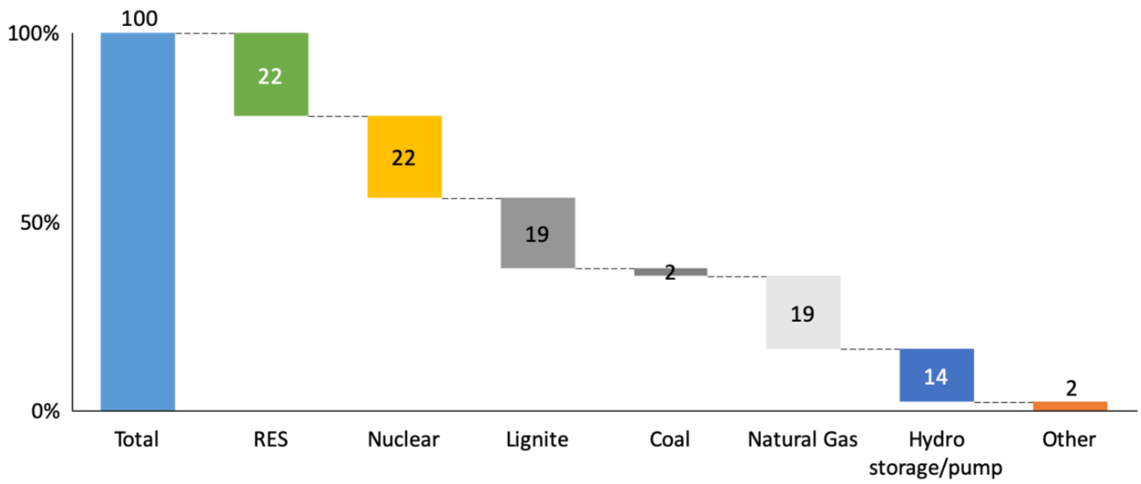

Figure 14: Price-setting technologies of the lowest priced tercile in per cent

The price setting of the lowest priced tercile is as one might expect; characterised by low marginal cost technologies. Hence, nuclear is the technology that sets the price for most hours in the lowest priced tercile with almost a quarter of the total hours. Indeed, the hours during which very low marginal cost technologies such as nuclear, stochastic renewables and run-of-river power plants set the price are almost exclusively found in the lowest priced third of the total hours. Of interest here is the observation that coal-fired power plants provide almost no price-setting units in this low-price segment. In contrast, lignite-fired power plants set the price for a fifth of the hours in this segment. It may come as a surprise that, according to the results of the model, natural gas-fired power plants also provide the price-setting units for a fifth of the hours in the lowest priced third. In fact, natural gas-fired power plants are price-setting in lowest priced tercile throughout all modelled countries[15]. For most countries, this share only comprises a small percentage of the hours, but they dominate the price setting in this price segment on the British, Spanish, Portuguese and, to a lesser extent, the Italian market. It should be noted at this point that those four markets also comprise the markets with the highest overall price-level by quite a margin. This is the consequence of price-setting gas-fired power plants.

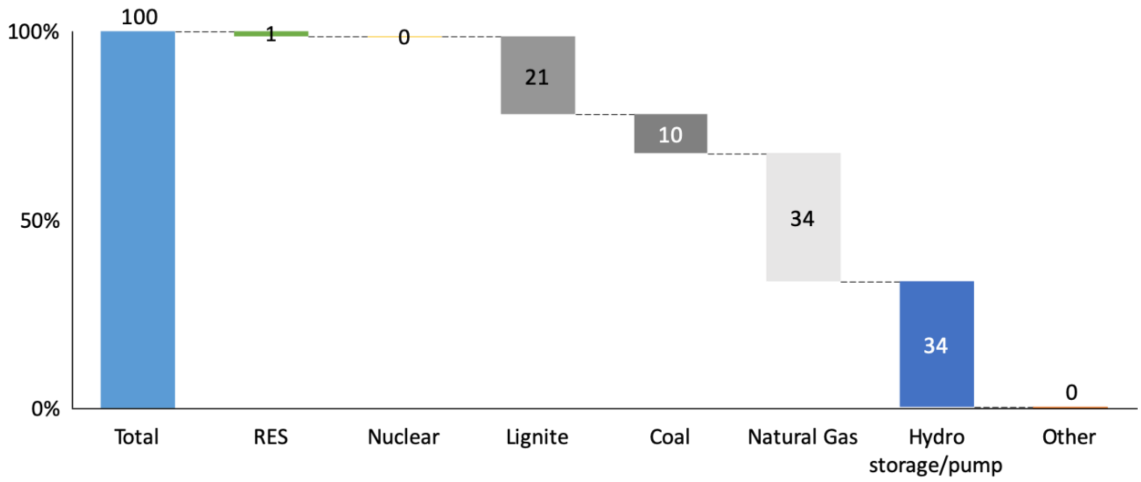

Figure 15: Price-setting technologies of the medium priced tercile in per cent

The picture of price-setting technologies changes significantly in the medium-priced segment (Figure 15). Renewable energies and nuclear power plants are no longer a relevant factor in terms of providing price-setting units. Natural gas-fired power plants, reservoirs & pumped-hydro plants as well as lignite- and coal-fired power plants each provide the price-setting units for about third of the hours. Again, the share of lignite-fired power plants is higher than that of coal-fired plants, and gas-fired units dominate the price setting on the British, Spanish, Portuguese and Italian market. Among Sweden, Finland and Norway it is Norwegian reservoirs that are setting the price for the great majority of hours.

[15] In countries with little or no natural gas-fired generation capacity, foreign natural gas-fired power plants provide the price setting units during those hours.

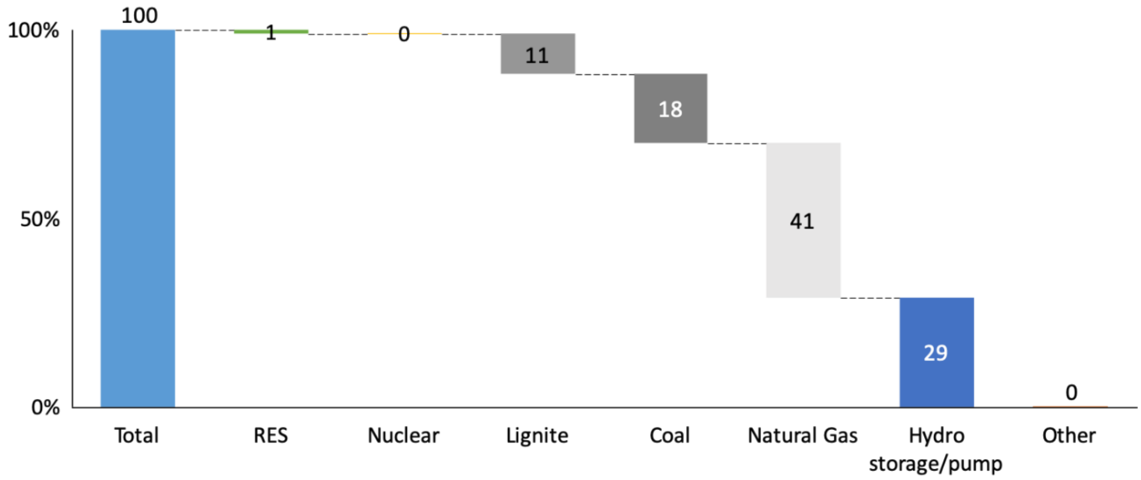

Figure 16: Price-setting technologies of the highest priced tercile in per cent

In the highest priced tercile, the share of natural gas-fired power plants as price-setting units increases further to two fifths of the hours, whilst the share of lignite-fired power plants is lower than in the other price segments (Figure 16). Only in Eastern Europe does the latter technology remain a relevant price-setting technology. Coal-fired power plants provide the price-setting units for one fifth of the hours. As a further point of interest, the share of reservoirs as price-setting units is slightly lower compared with the medium-priced segment. It seems striking that their share as price-setting units in Sweden, Finland and Norway is lower than in the medium priced tercile. Furthermore, for some hours in the highest price segment – albeit very few – there are lignite- and coal-fired power plants providing the price-setting units in the three countries, despite those technologies not playing a role there in the price setting in the medium and lowest priced thirds.

A look into prices reveals that Norway, Sweden and Finland represent the three countries with the lowest general price level and that prices during most hours, even in the highest priced segment, are not significantly above the marginal cost level of coal-fired power plants.

With respect to the price setting in the Nordic countries, analysts mention the relevance of German off-peak pricing for Nordic power prices (Loreck et al., 2013; Mollestad, 2016). The modelling results do not convey a *significant* relevance of German off-peak generation units as price-setting power plants in the Nordics. However, German off-peak generation may still be relevant in this context, even if it is not providing the price-setting units directly. During most hours in the Nordics, Norwegian reservoirs set the price as per the modelling results. However, the marginal costs of these reservoirs are not the decisive factor. Shadow prices used for the optimisation reflect the marginal costs of the next dispatchable power plant in the merit order, which in this case can be German coal- or lignite-fired power plants, once those in Finland and Denmark are exhausted. Hence, German off-peak generation may still have an influence on the price setting in the Nordic countries, without providing the actual price-setting units for a significant number of hours.

4.5 Conventional wisdom vs modelling results

Subsequently, there is the question of how the modelling results compare with the aforementioned conventional wisdom.

First, the modelling results indicate that natural gas-, lignite- and hard coal-fired power plants are indeed setting the price during most hours of year. This dominance is, however, not as clear cut as conventional wisdom might suggest. Whilst natural gas-, lignite- and hard coal-fired power plants provide the marginal price-setting units for most hours, their share lies below two thirds (Figure 13). Reservoirs and pumped-hydro power plants provide the marginal unit for approximately a quarter of the hours of a year, predominantly in the medium- and high-priced segments. Nuclear power plants and renewable electricity sources – first and foremost run-of-river hydro power plants – also provide price-setting units, primarily during low-priced hours. Generally, the results reflect the merit order of a given country, but according to the results of the model, the level of interconnectivity in terms of price setting can be high (see Figure 10).

Altogether, the modelling results indicate that the price setting in Europe can be more complex than conventional wisdom might suggest. It is not incorrect to argue that coal-fired power plants set the price in times of low demand and natural gas-fired power plants when demand is high, but this can potentially disregard the heterogeneity of European power systems and the interconnectivity of markets.

4.6 Application to carbon price floors

Carbon price floors are currently subject to an ongoing debate in academia and the public sphere. The European Union Emissions Trading Scheme (EU ETS) is characterised by a comparably low allowances price level; a level scholars generally regard as too low to fulfil the intended functions of the scheme (Abrell et al., 2016; European Commission, 2014; Rogge et al., 2011). There is an extensive body of literature on the weak performance of the EU ETS and possible paths to reform, yet policy makers have increasingly looked towards setting a carbon floor price.

In this vein, the recently formed Dutch government under Mark Rutte (the third Rutte cabinet) announced its plans to introduce a national carbon price floor for the power sector starting at 18 EUR/tCO_2 in 2020 (Van Veldhoven in Franke, 2017)[16]. And since becoming French president, Emmanuel Macron has reiterated his campaign call for a pan-European carbon price floor (Macron, 2017a). When presenting his oft-reported 'Initiative for Europe', President Macron stated than any price floor below 25-30 Euros per ton of CO_2 would not be effective (Macron, 2017b).

The German approach is far more cautious. The coalition agreement of the new government (the fourth Merkel cabinet) did call for a CO_2 pricing system that was globally oriented; to at least include the G20 states (Christlich Demokratische Union et al., 2018). This call –deemed unrealistic – was followed by a statement advocating to follow the momentum of the recent common Franco-German resolution marking the 55th anniversary of the Élysée treaty, and co-operate in the framework of Franco-German partnership for the implementation of the Paris climate agreement and the commitments of the “One Planet Summit” (Christlich Demokratische Union et al., 2018).

[16] Final details are yet to be disclosed, but Member of Parliament van Veldhoven from the liberal D66 party announced a starting price of 18 EUR/tCO_2 which will rise to 43 EUR/tCO_2 in 2030 (in Franke, 2017).

The common resolution of the German and French parliaments includes a proposal to suggest common initiatives regarding a CO_2 price (Assemblée Nationale and Deutscher Bundestag, 2018). Nevertheless, the fact that the German coalition agreement fails to mention the prospect of a national, European or Franco-German CO_2 pricing initiative is telling. Optimists may point towards the subsequent mentioning of the common resolution and argue that it could be construed as a signal to France that the door might not be fully shut.

Regardless, and despite its comparably slim chances of coming into fruition, this study will entertain the idea of a common Pentalateral Energy Forum[17] CO_2 price floor, next to a sober analysis of the announced Dutch price floor. Even though the Pentalateral Forum has been primarily a platform for regional integration towards electricity market integration (i.e. market coupling) and security of supply, it is assumed in this scenario that the energy ministers in question would follow Macron's proposal and take the step for a common CO_2 price floor for the power sector.

The market outcomes of the two policies (Dutch and Pentalateral Energy Forum carbon price floor) will evaluated with respect to the energy policy objective triangle of (i) affordability, (ii) security of supply, and (iii) sustainability.

Aside from the potential aforementioned initiatives, there is currently only one active carbon price floor scheme in the EU that applies to the power sector, which is the British Carbon Price Floor established in 2013. An issue common to carbon price initiatives is the question of how to handle electricity imports and exports. In legal terms, any scheme ought to be compatible with relevant legislation and in particular with WTO law, EU Law and other trade agreements. Thus far, the only established system (i.e. the British system) disregards electricity imports, which means power imports from abroad are not charged the carbon price support[18]. Whilst subsequent competitive disadvantages for domestic power producers are somewhat limited in Great Britain due to the comparably low interconnection capacity, the picture might look different on the continent. Details on the forthcoming Dutch carbon price floor are yet to be published, yet analysts expect it to follow the British model (Carbon Pulse, 2017; Tijs, 2017). In this analysis it is therefore assumed that the Dutch carbon price floor as well as the theoretical Austrian-Benelux-Franco-German-Swiss (Pentalateral Forum) price floor would function in this manner.

4.6.1 Dutch CO_2 floor price of 18 EUR/tCO_2

Market analysts and traders expect the Dutch CO_2 price floor to cause production shifts from the Netherlands to the neighbouring countries. Following the introduction of the price floor in 2020, Dutch fossil fuel generators will face higher marginal costs and thus have a competitive disadvantage over their Belgian and German counterparts. This rests of course upon the assumption that the Dutch price floor will indeed follow the British model in

[17] The Pentalateral Energy Forum is an intergovernmental initiative and a framework for regional co-operation in central Western Europe towards improved electricity market integration and security of supply. It was created in 2005 by energy ministers from Austria, the Benelux, France, Germany, and Switzerland as permanent observer (European Commission, 2015; Umpfenbach et al., 2015)

[18] Carbon taxation models looking to charge electricity imports a minimum carbon price are subject to an extensive legal debate. It is questionable whether border tax adjustments or other measures could be successfully and legally employed for this purpose (Blume-Werry et al., 2019; Holzer et al., 2017; Kreiser et al., 2015).

handling imports (see above). Consequently, analysts expect rising prices in the Netherlands and increased imports from Germany, Belgium and Great Britain depending on British carbon policy post Brexit[19] (Franke, 2017; Tijs, 2017; Witkop, 2018).

The modelling results confirms this view. Even though the Dutch CO_2 price floor of 18 Euros$_{2017}$ per ton of CO_2 is only a couple of euros higher than the EU ETS future prices at the time of the modelling, the results show noteworthy developments. Dutch net power imports rise by almost a quarter. As a result, one notes rising exports from Germany and reduced British imports from the Netherlands. Average wholesale baseload power prices in the Netherlands and its neighbours rise marginally; about 30 cents$_{2017}$ per megawatt hour (MWh) in the Netherlands, 20 cents$_{2017}$ in Belgium and 10 cents$_{2017}$ in France and Germany.

A higher price mark-up than the proposed price floor shows amplified effects. Whilst Dutch coal- and gas-fired generation decreases by approximately ten and five per cent respectively at a Dutch carbon floor price of 18 Euros per ton of CO_2 compared with the reference scenario, these numbers do rise to approximately 45 and 15 per cent respectively when a higher carbon price floor of 30 Euros per ton of CO_2 is applied in the Netherlands. In a similar fashion, such a higher carbon price floor would also result in higher wholesale baseload prices in the Netherlands and neighbouring countries, as well as considerably larger changes in the import and export balances. In this case, Dutch power imports would approximately double as Dutch coal- and gas-fired generation is replaced: primarily by German, British, Belgian and even Italian natural gas-fired generation.

In terms of the price-setting technologies, the effects are negligible. On a country-to-country basis, the number of hours during which Dutch power plants are price-setting rise due to the carbon price floor and the subsequently, slightly higher price level. In turn, German and Belgian plants have slightly less hours during which they provide price-setting units. Of more significance are the effects of the price floor on carbon emissions. The CO_2 emissions of the conventional Dutch power plant fleet shrink by approximately five per cent as Dutch coal and gas-fired power plants produce less electricity than in the reference scenario. On a European level, this reduction is, however, offset by increased emissions elsewhere – in particular in Belgium, Germany and Poland.

Altogether, the modelling results back the prevailing view. The Dutch carbon price floor would lead to rising Dutch imports and ergo reduced Dutch emissions, but with little to no emission reductions on a wider European level (as in most cases Dutch power plants are substituted with power plants of the same technology elsewhere). With respect to the price-setting technologies, the general price setting picture stays virtually unaffected by the Dutch carbon price floor and there are no major shifts taking place. In terms of the energy policy objective triangle one can conclude that the objective of affordability is affected negatively as prices rise slightly. The policy objective of sustainability is affected positively as Dutch emissions decrease slightly as a result of the price floor. Given that Dutch power imports rise in this scenario due to the aforementioned production shifts one could argue that policy objective of security of supply is affected negatively if the lower running hours of Dutch fossil power plants trigger plant closures.

[19] In the computations it was assumed that Great Britain will continue to participate in EU ETS.

4.6.2 Pentalateral Energy Forum CO_2 price floor of 30 EUR/tCO_2

In a second scenario it is assumed that the countries of the Pentalateral Energy Forum (Austria, Benelux, France, Germany and Switzerland) introduce a common carbon price floor of 30 Euros per ton of CO_2. The research year remains the same (2020) as in the reference and Dutch price floor scenario. Given the significantly higher carbon price and the larger pool of countries introducing the price floor, one would expect considerably more substantial effects.

The modelling results show that such an initiative would cause wholesale power prices to rise. Prices in the Benelux and Germany are approximately 2.5 EUR_{2017}/MWh higher in this scenario compared with the reference scenario. In the less carbon-intensive power markets of Austria, France and Switzerland, prices rise by approximately 1.7 EUR_{2017}/MWh. With regards to the import/export balance, one can observe notable shifts with Dutch power imports nearly doubling and Germany turning from a net exporter into a net importer.

Carbon price floors serve the declared target of emission reductions and the modelling results confirm that the carbon price floor analysed leads to lower emissions in the countries introducing it and, in this case, also overall at a wider European level. In absolute terms, emission reductions are most significant in Germany and the Netherlands whilst British, Polish and Czech power plants increase their output and subsequently their CO_2 emissions. Altogether, the clear emission reductions in the countries of the Pentalateral Energy Forum - of whom Belgium, Germany and the Netherlands experience emission reductions of 15-20 per cent – are, unlike in the scenario of the Dutch carbon price floor of 18 EUR/tCO_2, not fully offset by rising emissions elsewhere even though emissions in Eastern Europe and in Great Britain rise significantly.

It is important to note at this point that the modelling computations disregard EU ETS price developments originating from the introduction of the carbon price floor. It has been argued that emission reduction measures in one area or facility will depress demand which in turn puts downwards pressure on prices and results in subsequent emission increases in another area or facility (Burtraw et al., 2017). One can refer to this as the so-called 'waterbed effect'[20].

Be that as it may, the carbon price floor leads to a fuel switch in Germany, with running hours of natural gas-fired power plants increasing and those of coal- and lignite-fired power plants decreasing. The modelling results further indicate reduced production volumes of all fossil

[20] Emission reduction measures outside or independent of the EU ETS often face critique related to the 'waterbed effect'. The coining of the term 'waterbed effect' is commonly credited to British economist Paul Geroski, who described that if prices are pushed up or down on one side of a two-sided market, it can result in a rebalancing at the other side – just like a waterbed (Genakos and Valletti, 2008). As regards the EU ETS, it has been argued that emission reduction measures in one area or country do not reduce total emissions as they are set by a fixed cap. To what extent the waterbed effect is actually applicable to the EU ETS and potential carbon price floors within it is disputed; as is the question of whether total long-term supply of allowances is fixed and capped or set by future policy decisions (Burtraw et al., 2017; Edenhofer et al., 2017; Perino and Willner, 2016; Whitmore, 2016). The most recent EU ETS reform enables EU Member States to voluntarily cancel allowance units following national energy policies that lead to a reduction of their electricity generation capacity (European Parliament and European Council, 2018). In theory, this paves the way for national or regional carbon price floors and coal-fired power plant phase-outs as envisaged by some Member States without risk of the waterbed effect. However, experts remain very sceptical of the (large-scale) use of this new measure that enables Member States to cancel allowances to counteract the impact of capacity closures (Edenhofer et al., 2017; Ferdinand in Evans, 2017).

generation technologies in the Netherlands and increased outputs of British natural gas-fired power plants following the introduction of the carbon price floor in the countries of the Pentalateral Energy Forum.

With respect to the price-setting technologies, the effects of the carbon price floor are again small scale or indeed negligible. The results of the model show minimal changes compared with the reference scenario. It is thus a key finding that even though the marginal costs of fossil plants, general price level and import and export balances change, the structure of the price-setting technologies remains very similar. Even though coal-fired power plants, for instance, provide the price-setting units for slightly less hours in this carbon price floor scenario than in the reference scenario, the scale of change is too insufficient to observe important changes.

In terms of the energy policy objective triangle one notes that the policy objective of affordability is affected negatively in the countries introducing the price floor due to higher wholesale power prices, whilst the objective of sustainability is affected positively. With production shifts towards countries outside of the Pentalateral Energy Forum and possible plants closure one could argue that the policy objective of security of supply might be affected negatively.

4.7 Conclusion

The conventional wisdom holds that in many central European countries, coal- and/or gas-fired power plants provide the marginal price-setting units for most hours of the year. The modelling results confirm that in the countries researched, coal-, lignite- and gas-fired power plants are indeed price-setting for most hours of the year. Their dominance is, however, not as clear cut as the conventional wisdom might suggest. The analysis with a electricity market model has shown that during hours of low demand, nuclear power plants and renewables are providing price-setting units for a considerable number of hours alongside lignite- and natural gas-fired power plants. Throughout all price segments yet especially during mid- to high-priced hours, reservoirs and pumped-hydro power stations play a substantial role in the price setting process. However, one should keep in mind that their marginal pricing does not reflect the marginal costs, as shadow prices or water values – reflecting the marginal costs of an additional alternative (thermal) power plants – are used for the dispatch (see above). In the highest priced segment, natural gas-fired power plants provide the price-setting units for the largest share of hours.

Large countries tend to have a strong influence on the price setting in smaller neighbouring countries, as long as there are sizeable interconnector capacities. More generally, one can observe a high level of interconnectivity between the countries researched. The price-setting technologies per country vary significantly depending on the generation portfolio of a given country and the connected surrounding countries. In Southern Europe (Italy, Portugal and Spain) and Great Britain, gas-fired power plants dominate the price setting, whilst lignite- and coal-fired power plants tend to do so in Eastern Europe. Hydro-storage and pumped-hydro plants provide the price-setting units during most hours in Northern Europe. The most balanced picture with respect to the price-setting technologies is to be found in central Europe and the price setting ergo reflects the general generation portfolio.

Two scenarios with different carbon price floors have shown that the general structure of the price setting remains largely unaffected by the researched carbon price changes. A Dutch carbon price of 18 EUR/tCO_2 would lead to reduced Dutch coal- and gas-fired generation and CO_2 output, and subsequently higher electricity imports. Despite these observations, the changes in the price-setting technologies as a result of the Dutch carbon price are found to be limited.

One can draw conclusions regarding the scenario of a wider European carbon price floor encompassing the countries of the Pentalateral Energy Forum in a similar fashion. The carbon price floor would have a substantial impact on wholesale power prices, fuel switching, CO_2 emissions and import/export balances, whilst the general structure of price-setting technology remains largely the same as in the reference scenario. For Austria, the Benelux, France, Germany and Switzerland the results show rising power prices, production shifts to surrounding countries with lower carbon prices and subsequently lower emissions.

Altogether, the analysis contributes to fill the identified gap in the literature. It shows that price-setting patterns are more complex and nuanced than the conventional wisdom suggests, and that power generation technologies other than coal- and gas-fired power plants provide the marginal price-setting units more often than one may assume. In this light, further research can help to establish a more detailed view on the price setting on European power markets and how this may change as the decarbonisation of the power sector progresses.

5 Case study: Impact of the German-Austrian bidding zone split on European energy objectives

5.1 Background

Whilst the deployment of renewables in Germany is progressing rapidly, grid expansion is behind schedule. Northern Germany offers worthy conditions for onshore and offshore wind. However, on windy days it is increasingly difficult to transport generated electricity to southern demand centres. The existing German transmission network capacities are often insufficient to handle these flows, which is why cross border flows into neighbouring countries (called loop-flows) and congestions are becoming more frequent. These congestions are not supposed to exist within bidding zones and it is a subsequent matter of dispute whether the congestions amount to what is perceived as structural (rather than intermittent) congestions.

A result of these insufficient network capacities is that significant electricity flows through the networks of some neighbouring countries are being registered (ČEPS et al., 2013). The Transmission System Operators (TSOs) of the Czech Republic, Hungary, Poland and Slovakia publicly express their discontent with these flows. They argue that these endanger the network security of their systems, limit their cross-border trade capacity and cause their systems to be excessively loaded by large scale unplanned flows, which are not controlled by any market mechanism (ČEPS et al., 2012).

Following a request by the Polish regulator Urząd Regulacji Energetyki (URE), the Agency for the Cooperation of Energy Regulators (ACER) published a recommendation in September 2015, which concluded that the mentioned congestions were indeed structural and recommended a splitting of the price zone (ACER, 2015). This (legally non-binding) statement fuelled the debate and resulted *inter alia* in E-Control taking legal action against ACER at the European General Court (EGC)[21] (E-Control, 2015).

In October 2016, the German regulator Bundesnetzagentur asked the TSOs in Germany to prepare the introduction of congestion management on the German-Austrian border, targeting 3 July 2018 as the implementation date (Bundesnetzagentur, 2016a). Even though this has not been officially described as a split-up of the price zone, it effectively lays the groundwork for an end to the common zone in 2018 and has been described by analysts as such (Falker, 2016).

According to those in favour of a continuation of the common bidding zone such as E-Control, congestions within Germany are the core problem and an inner German price zone split, rather than a split at the German-Austrian border, ought to be discussed (Graf and Irschik, 2016). However, dividing Germany into two or more price zones has been described as "political dynamite" and appears barely feasible in political terms (Schlandt, 2015). It has been argued that this constitutes an acknowledgement of a failed energy policy and threaten the

[21] The European General Court eventually rejected the legal action by E-Control to annul the ACER statement as inadmissible given the legally non-binding nature of opinion statements (EGC, 2016, 2015).

public acceptance of the energy transition (Graf and Irschik, 2016). In contrast, a split along the German-Austrian border should be feasible and communicable (Wetzel, 2015).

To be published in the fourth quarter of 2017, the bidding zone review by the European Network of Transmission System Operators for Electricity (ENTSO-E) may give the debate a new direction, as could potential legal action by E-Control or the Austrian TSO APG. Legally, the Bundesnetzagentur sees itself in line with the requirements of the European law and the intended measures as necessary since the excessive trade between Germany and Austria threatens system security and stability in other countries (Bundesnetzagentur, 2016a). Nonetheless, if current European processes on the bidding zones such as the ENTSO-E bidding zone review come to the conclusion that the planned measures will have no positive effect in this respect, then the transmission system operators will cease the preparatory work on congestion management (Bundesnetzagentur, 2016a).

Altogether, a likely outcome remains a splitting of the bidding zone along the German-Austrian border in 2018 and it is therefore relevant to analyse the expected market outcome of this transformation.

5.2 Methodology

The Bundesnetzagentur is yet to officially quantify the net transfer capacity (NTC) it would set for the German-Austrian border following the breakup of the common bidding zone.[22] However, in a recently published study it determined the threshold underneath which the trade can be safely managed without the need to perform countermeasures such as redispatching. This can therefore be seen as a first indication, the (n-1) secure value set for the transfer capacity in the study is 2500MW for 2019/2020 and 5500MW for 2024[23] (Adamek and Ahlhaus, 2016).

Consequently, these values and the years 2020 and 2024 are used as the basis for the calculations in this study. In order to assess the outcomes of a price zone split along the German-Austrian border, the split is simulated in the fundamental model Green-X, using the NTC values in the respective years provided by Adamek and Ahlhaus (2016). The calculations of the fundamental model for the years 2020 and 2024 provide (i) yearly average wholesale power prices, (ii) hourly prices, and (iii) hourly expected power plant dispatch.

These results enable an in-depth examination of the compatibility of a price zone split with the energy policy objective triangle: the average yearly power prices indicate the (i) affordability of a system, the hourly prices reveal price spikes which represent a degree of (ii)

[22] This holds true for the time of conducting this case study (early 2017). Later, the regulators agreed on a value of 4900MW to be reserved for long-term capacity allocation.

[23] Following the discussions and call of the Bundesnetzagentur on the TSOs to prepare the introduction of congestion management on the German-Austrian border, there have been several studies researching the expected developments with different methodologies and a range of distinct NTC values. The NTC value chosen for this study rests upon the work of Adamek and Ahlhaus from the Bundesnetzagentur. The last indicative NTC value set by ENTSO-E for the border in 2011 was 2200MW and thus close the value of 2500MW chosen here for 2020 (ENTSO-E, 2011). In comparison with other studies, the NTC values used here are rather on the conservative, i.e. lower end (see Aurora Energy Research, 2016a; Bloomberg New Energy Finance, 2016; Energy Brainpool, 2016)

security of supply, and the expected power plant dispatch shows the utilisation of the different generation technologies and consequently sets the (iii) sustainability of the system.

Aside from Germany and Austria, the subject of research includes all neighbouring countries, i.e. Belgium, the Czech Republic, Denmark, France, Hungary, Italy, Luxembourg, the Netherlands, Poland, Slovakia, Slovenia and Switzerland as well as Sweden and Norway which are directly connected to the German grid. Given the significant size of the German-Austrian bidding zone and the interconnectivity of the networks in central Europe, all of these markets are potentially affected by a breakup. The focus of the analysis is, however, set on Germany and Austria and the calculations also show the most significant effects there.

5.3 Results and analysis

The fundamental model Green-X was used to calculate (i) yearly average wholesale power prices, (iii) hourly prices, and (iii) expected power plant dispatch. In order to obtain comparable results, the calculations were taken once with the NTC values set as proposed by Adamek and Ahlhaus from the Bundesnetzagentur (2500MW for 2020; 5500MW for 2024) and once without a NTC limitation (Adamek and Ahlhaus, 2016).

5.3.1 Affordability

Within the context of the energy policy objective triangle, the objective of affordability is also referred to as competitiveness or, simply, costs. Generally speaking, the objective relates to the expenses consumers and the industry have to cover for their energy consumption. An ideal energy policy delivers energy to consumers and businesses at affordable or reasonable costs.

From a policy perspective, affordability is key for multiple reasons. First of all, businesses and especially energy intensive industries need affordable electricity in order to be competitive in a globalised world. In terms of private consumers, it is important to underline that electricity is a vital good and needs to be affordable for everyone within society. For policy makers, it is therefore also relevant with regards to voting behaviour and party support among the electorate. This was illustrated with the proposed price freeze by the British Labour party during the last United Kingdom general election campaign (Wintour and Perraudin, 2015).

It has to be noted at this point that the results from the model presented above portray wholesale power prices, whereas the policy objective of affordability refers to prices for consumers and businesses. The retail prices or tariffs consumers and business pay for their electricity differ substantially from the prices on the wholesale markets. Wholesale power prices are very volatile and fluctuate every hour depending on supply and demand. In contrast, the electricity tariffs that consumers pay are independent from daily market developments. Consumers usually pay a fixed and somewhat regulated rate per consumed unit of electricity, independent of the current wholesale market price. These tariffs or retail prices for consumers vary depending on country, region, consumption volume and electricity supplier. Next to the actual electricity procurement costs, it contains different taxes and fees as well as grid costs and, nowadays, also often includes a charge to finance the deployment of renewables.

In Germany for example, energy procurement and supply costs account for the largest share that amounts to 26 per cent. The EEG surcharge used to finance feed-in and feed-in premium tariffs for renewables takes the second largest share with 21 per cent, closely followed by network charges with another 20 per cent. Different forms of taxes as well as charges for metering and other surcharges complete the picture (Bundesnetzagentur, 2016b).

In Austria, energy procurement costs take the largest share with 31.5 per cent, followed by a composition of different taxes and fees (27.5 per cent). Grid costs make up 27.3 per cent and the surcharge for renewables accounts for 13.6 per cent – according to E-Control (E-Control, 2016).

Altogether, one has to note that retail prices or tariffs for electricity and their composition are very diverse even within countries, which makes them an ill-fitted parameter for comparing the effects of a price zone split. However, the generation of procurement costs and consequently the wholesale power prices are always a crucial part. Therefore, they are used here as an indicator for affordability.

Generally speaking, retail prices for electricity tend to be relatively stable, whereas wholesale power prices are volatile. If there is a sustained rise or fall of average wholesale power prices, the additional costs or savings arising are not necessarily directly passed on to the consumers and so, certain market participants along the value chain either benefit or lose out. Within the energy industry, generators profit from higher prices whereas suppliers might suffer if the additional costs cannot be passed on to consumers. Altogether, high electricity prices tend to have negative effects on the overall economic growth of a country (NRECA, 2015; Wiegert, 2013). The subsequent conclusions are that higher electricity prices in a country resulting from the price zone split affect the policy objective of affordability negatively. Vice versa, lower prices have a positive effect on affordability.

5.3.1.1 Austria

The most substantial effects are observed In Austria as the computations show that wholesale power prices rise significantly as a result of the new situation. The NTC restriction enables less electricity from sources with low marginal costs (such as renewables or coal- and lignite-fired power plants) in Germany to flow to Austria, leading to rising prices in the new Austrian zone. In the breakup scenario, the yearly average power prices are higher by 1.00 EUR_{2015}/MWh in 2020 and 0.85 EUR_{2015}/MWh in 2024 compared with those same years without a NTC limitation which equals a change of roughly 3 per cent.

Consequently, the energy policy objective of affordability is clearly affected negatively in Austria. It becomes obvious why the Austrian regulator E-control and Austrian industry associations such as Wirtschaftskammer Österreich and Industriellenvereinigung are opposing the price zone split and contesting it on multiple levels. Aside from the aforementioned legal actions there are also academic studies and position papers arguing in favour of a continuation of the common price zone or addressing problems arising from a price zone split (see E-Control, 2015; Graf and Irschik, 2016; Klotz and Hofmann, 2015).

5.3.1.2 Germany

The opposite effect would take place in Germany. Indeed, calculations indicate lower power prices in Germany in the case of a price zone split. The drop in Austrian demand reduces the overall load, while the low marginal cost generation units in Germany remain in place. The yearly average power prices drop by almost 0.50 EUR_{2015}/MWh in 2020 and by 0.25 EUR_{2015}/MWh in 2024 in relation to a scenario without a bidding zone split. This represents a change of around 1.5 and 0.75 per cent respectively.

The decrease of wholesale power prices in Germany following a price zone split along the German-Austrian border should in theory have a positive effect on the policy objective of affordability in the two countries. However, given the high penetration of renewables along with the support scheme mechanism funded by a surcharge on the electricity prices for final consumers, the situation is in fact more complex than one might initially assume. Renewable plant owners commonly receive a somewhat fixed remuneration per injected unit of electricity in the grid through a feed-in or feed-in premium tariff. To incentivise investments in renewable plants and reduce risks for investors, these tariffs are set well above current price levels. The surcharge electricity consumers pay for the deployment of renewables is largely used to finance the gap between the price at which electricity is sold on the wholesale market and fixed renewable remuneration levels. Lower wholesale prices consequently increase the overall sum required to finance renewable deployment and might therefore trigger a higher renewable surcharge for electricity consumers, potentially mitigating the price-decreasing effect of lower wholesale prices but not fully offsetting it. However, the precise effects of this phenomenon are yet to be researched.

Matters are complicated further by the fact that the energy intensive industry and large industrial electricity consumers in Germany are largely exempted from the renewably levy and other surcharges[24]. Since the policy objective of affordability encompasses by definition the costs for both businesses and households, one cannot make a valid general statement on the effects of lower average wholesale prices on the policy objective of affordability. Large industrial consumers exempted from the renewable levy and other surcharges are likely to profit whilst non-privileged consumers might have to face some additional costs.

5.3.1.3 All other countries

In Belgium, Denmark, Luxembourg, Norway and Sweden, the calculations show a slight decrease in yearly average wholesale power prices (see Figure 17). The policy objective of affordability is thus positively affected by a split of the German-Austrian price zone. Luxembourg is split into three price zones of which the largest by far is the portion of the German-Austrian price zone, and it is assumed that it would remain part of the German zone in the event of a breakup. The phenomenon observed in Germany, where the positive effects of the price decrease may be partially offset by potential rise of the renewable levy, could in part also apply to Belgium, Denmark, Luxembourg, Norway and Sweden.

In the Czech Republic, Hungary, Slovakia, Slovenia and Switzerland yearly average wholesale prices rise as a result of a split of the German-Austrian bidding zone (see Figure 17). The increase is less significant than in Austria but still notable and causes the policy objective of affordability to be negatively affected by the price zone split.

It should be noted at this point that the TSOs of the Czech Republic, Hungary, Poland and Slovakia pushed for the price zone split (ČEPS et al., 2013). Interestingly enough, the regulators of the four countries also support this position (ERO et al., 2015). This means that unlike in Austria where the regulator E-Control strongly opposes the price zone split, the regulators in the Czech Republic, Hungary, Poland and Slovakia lobby in favour of the German-Austrian price zone split. This may seem odd, given that in the Czech Republic, Hungary and

[24] For a closer discussion on the exemptions and the subsequent redistribution effects see Cludius et al. (2014).

Slovakia the policy objective of affordability is affected negatively as a result of the price zone breakup. However, they place greater value on other factors:

> "The splitting of the German-Austrian bidding zone will significantly mitigate the blackout risk, enhance business opportunities for energy companies in the V4 countries, and make German and Austrian partners begin participating in the payment of the costs caused by the loop flows" (ERO et al., 2015).

Interestingly enough, the statement explicitly mentions the objective of supporting local energy companies. Energy producers do in fact profit from higher wholesale power prices yet the overall economic effects of higher power prices are seen as negative.

According to the model calculations, the yearly average wholesale prices in France, Italy, the Netherlands and Poland would be virtually unaffected by a split of the German-Austrian bidding zone. Changes of less than 0.5 per cent between the breakup scenario and continuation of the common zone are hereby seen as insignificant, and France, Italy, the Netherlands and Poland fall into this category. The energy policy objective of affordability therefore remains neither positively nor negatively affected by a breakup of the German-Austrian price zone.

5.3.1.4 Overview

Figure 17 illustrates the yearly average wholesale price changes as a result of the German-Austrian price zone split in a radar chart. The red line shows the price changes in EUR_{2015}/MWh for the year 2020 and the blue line the changes for 2024. It can be observed from the radar chart that the changes in 2020 with the smaller NTC value are more significant than in 2024 with the larger NTC value.

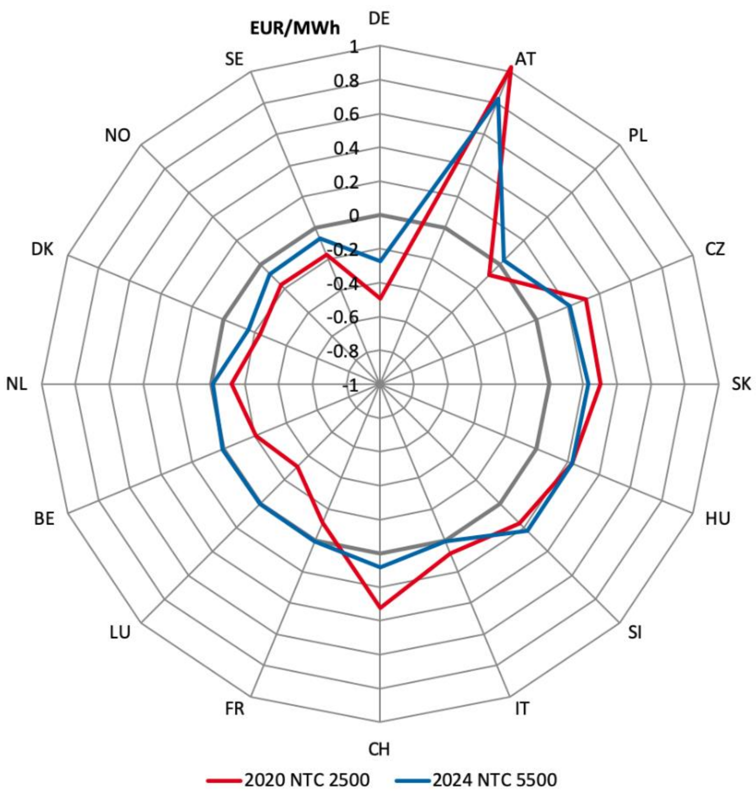

Figure 17: Model results of yearly average wholesale power price changes in EUR/MWh

One can use the changes in the yearly average prices to measure additional costs or savings arising from the price changes. In a simplified calculation, the expected consumption was multiplied by the modelled price change for every country. This gives an approximate estimation of the expected yearly costs or savings as result of a price zone split. Austria is expected to face additional yearly costs of around EUR 80 million (2020) and EUR 65 million (2024) through the price increase. In Germany, the yearly savings due to the price zone split are roughly EUR 265 million in 2020 and EUR 150 in 2024. Considering all the countries that were researched, the yearly overall cost savings would be around EUR 250 million in 2020 and EUR 60 million in 2024.

5.3.2 Security of Supply

In addition to yearly average prices, the fundamental model also calculates hourly prices from which one can derive a level of security of supply. It is the objective of every energy policy to guarantee a high degree of security of supply and minimise the risk and duration of power cuts. Blackouts do not only cause substantial economic harm and hinder everyday human activities, but they also represent a serious catastrophe scenario if they are not fixed in a timely fashion. The European Commission also underlines the importance of the security of supply in its latest energy package (the Winter Package) (European Commission, 2016a). In this discussion, the role of security of supply in the national security policy of a state should not be underestimated. In political realism, a low level of security of supply represents a threat to national security and within this context, states strive to strengthen security of supply and minimise risks and dependencies (Baumann, 2008).

The level of security of supply can be measured in a number of ways. For the purpose of this study and the analysis within the energy policy objective triangle, a price signal is used to measure a degree of security of supply. Once prices reach a high level that can be classified as clear price spike level, they serve as an indication of scarcity and peak power plants, often existing only to serve demand in times of scarcity, ramp up production. In Europe, there are power plants with very high marginal costs that are only used in times of highest demand and corresponding price peaks. During high price spikes, even inefficient, polluting and often ageing oil-fired generation plants or natural gas turbines are included on the market. This methodology of a high price signal to measure security of supply relates to the other policy objectives of affordability and sustainability, since the deployed peak power plants are polluting and commonly characterised by the highest marginal costs.

It must be noted that this methodology has its down sides. It neither provides a realistic assessment of how close a system is to a blackout nor addresses the questions of autarky and self-sufficiency, i.e. how much of the generation takes place in the observed country. Furthermore, congestions within countries, such as certain congestions within Austria and the described congestions between northern and southern Germany, are not portrayed. Nevertheless, in the scope of this study and in the context of an interconnected Europe, the price signal can act as a meaningful indicator of the security of supply and how this is affected by a breakup of the common German-Austrian price zone.

To this end, the hours that can be classified as clear price spikes are calculated once without and once with a price zone split along the German-Austrian border. They are then compared and analysed for all countries that are subject to this research. An increase in the number of hours indicates a lower level of security of supply, affecting the policy objective negatively. Vice versa, a lower number of these price spikes shows an increased security of supply.

5.3.2.1 All Countries

The fundamental model calculations do not predict any clear price spikes in the researched countries for the years 2020 and 2024. Any hours that could be classified as high price spikes are neither recorded in the breakup scenario nor in the scenario with a continuation of the common zone. In fact, the highest priced hours that the model finds are virtually the same in the different scenarios and far from what could be seen as clear price spikes. These comparable low prices indicate that there are no scarcities in the researched countries for the given years.

Consequently, a splitting of the German-Austrian price zone would not affect the security of supply as defined above. In terms of the policy objective one can note that the states can see their security of supply neither enhanced nor diminished as a result of the price zone split.

It should be clarified at this point that a different definition of security of supply may deliver other results. The Czech, Hungarian, Polish and Slovakian TSOs call for splitting the German-Austrian bidding zone in order to tackle the issue of unplanned flows that affects the ability to manage the security of supply of their networks (ČEPS et al., 2013).

Thus, they expect a price zone split to result in an enhanced security of supply. However, this aspect of security of supply (referring to grid stability) is not included in the price spike methodology used for this study.

For a closer examination, it is worth looking at the price duration curves of Austria and Germany which are shown in Figure 18 and Figure 19. The figures show the price duration curves of Germany and Austria for the years 2020 (Figure 18) and 2024 (Figure 19) with the corresponding NTC limitations of 2500MW and 5500MW as well as the price duration curve without a breakup of the zone. The prices are shown in relation to the yearly average price in case of a continuation of the common zone. It can be observed from Figure 18 that the most expensive 1,000 hours are priced lower in Austria, following the price zone split. The lowest priced 5,000 hours are then, however, significantly higher priced than in Germany or in the event of a continuation of the common price zone. This causes the discussed increase of the yearly average wholesale price and altogether, the gap between the highest and the lowest priced hours decreases, which may undermine the economic viability of some pumped hydro power plants. The decrease of yearly average prices in Germany is caused by the slightly lower prices of the lowest priced 4,000 hours.

Figure 19 shows that the price changes in 2024 are generally of a smaller magnitude than those in 2020, predominately due to the higher NTC value. The highest priced 1,000 hours are now virtually the same in Austria and Germany – the lowest priced 4,000 hours are however still more expensive in Austria than in Germany or in the event of a continuation of the common zone.

The price duration curves in both figures show that even the highest priced hours are not in the range of what could be considered as high price spikes or critical from a security of supply perspective.

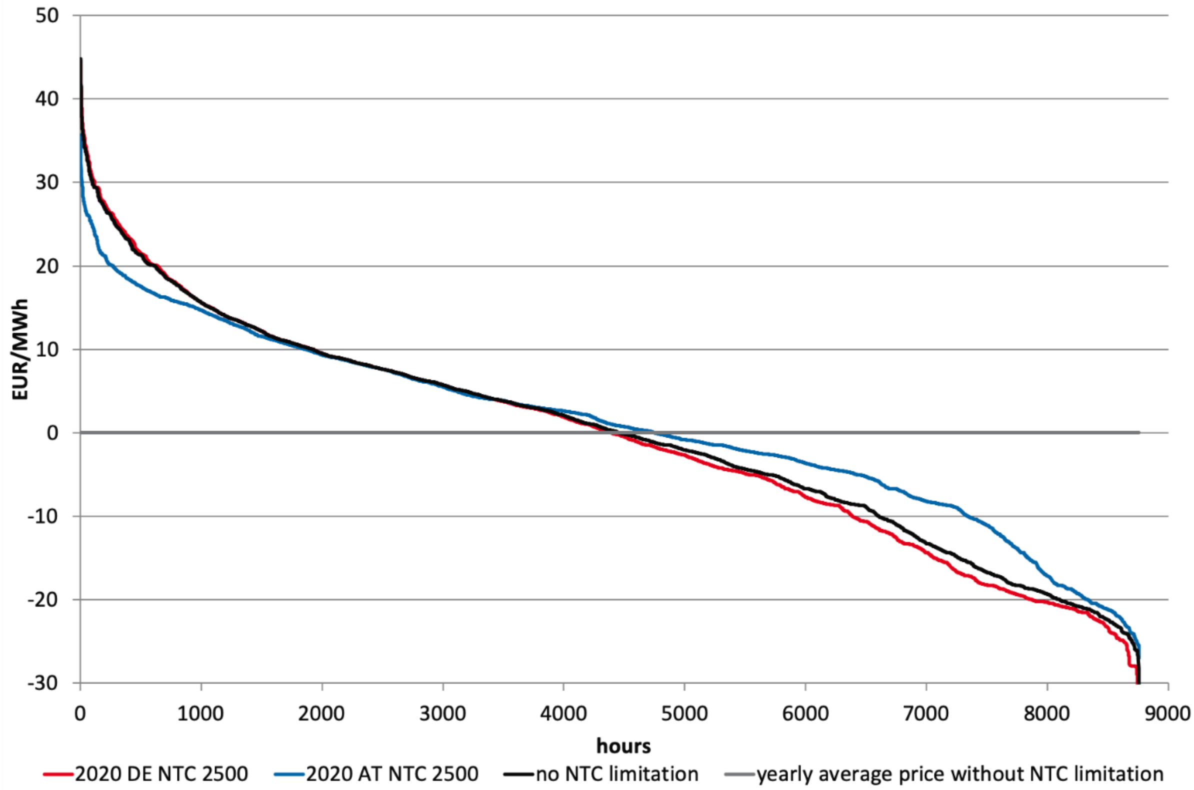

Figure 18: Price duration curve 2020 according to the model results

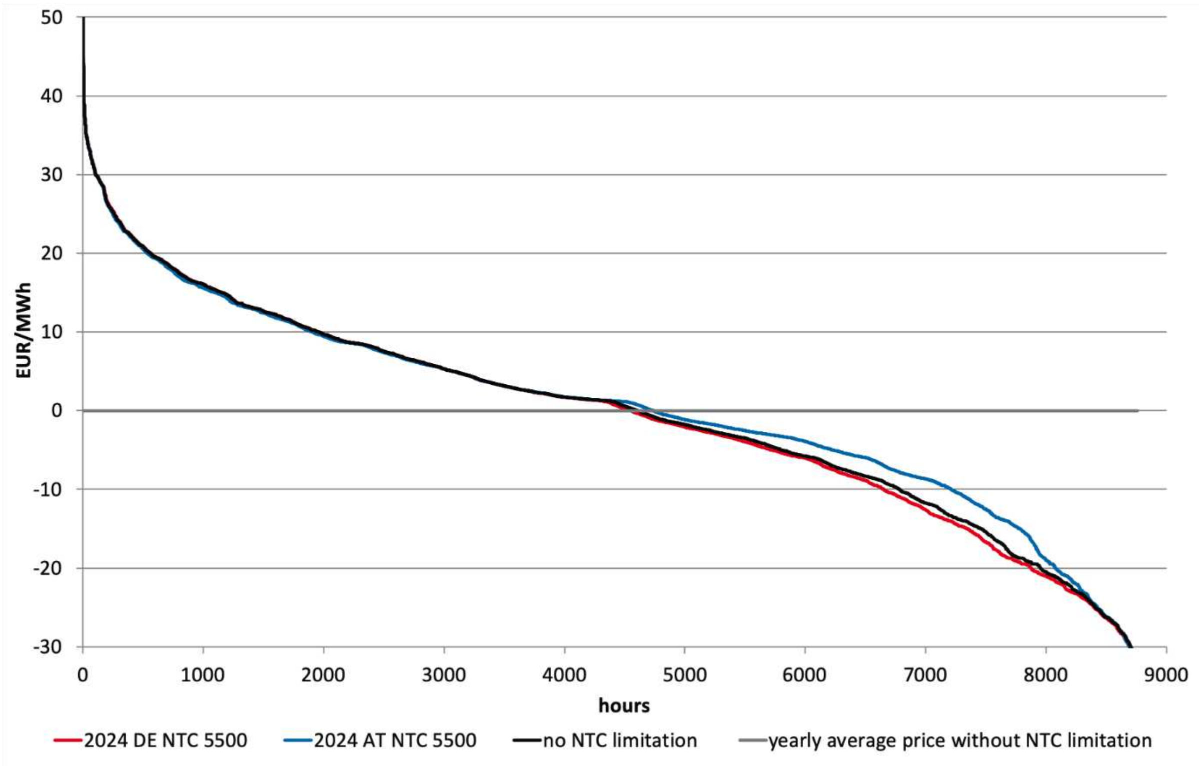

Figure 19: Price duration curve 2024 according to the model results

Last but not least, one should note that the model does not speculate or incorporate any events that may cause large shares of the generation capacities to be unexpectedly unavailable (which in turn would result in higher prices and scarcity price spikes). However, such events can occasionally occur as exemplified by the recent French nuclear power crisis during which up to 19 of the 58 French reactors were offline in late October 2016[25], or by the German 'Atom-Moratorium' in March 2011 following the Fukushima nuclear disaster.

5.3.3 Sustainability

In addition to the average yearly prices and hourly prices, the fundamental model also computes the expected power plant dispatch for every hour of the years 2020 and 2024, once with the price zone split and corresponding NTC values and once without. From this expected power plant dispatch, the subsequent CO_2 emissions can be calculated and the resulting level of sustainability. To this end, the model Green-X utilises an up-to-date power plant list to determine exactly which power plants will be generating electricity at any given hour by providing power plant-specific emission data.

The sustainability of the power sector has become an ever more important factor in recent decades. The Paris agreement illustrates the global efforts to fight climate change and reduce emissions. It is the objective of any energy policy to minimise negative externalities such as particulate matter pollution and NOx as well as CO_2 emissions. Indeed, CO_2 emissions have become a common standard to measure levels of sustainability and are hence used as the benchmark here.

The decarbonisation of the electricity sector takes a central role in the global fight against climate change. There are two main reasons for this: firstly, there is the significant contribution of the sector to overall emissions and secondly, it is a sector where there are already mature low-emission or emission-free technologies on the market. The EU and European states see themselves holding a leading role in the clean energy transition and seek to achieve global leadership in renewable energies (European Commission, 2016b). Drastic steps are necessary in order to achieve the ambitious targets of the Paris agreement, which is why Miguel Arias Cañete, Commissioner for Climate Action and Energy, sees Europe on a brink of a clean energy revolution (Arias Cañete in European Commission, 2016c).

The calculations of the yearly average prices and hourly prices have shown that by far the most significant changes resulting from a breakup of the common German-Austrian bidding zone are set to take place in Germany and Austria. Given this finding and the complexity of calculating power-plant specific CO_2 emissions, the policy objective of sustainability is only analysed for Germany and Austria.

As a final aspect, and in relation with the first policy objective of affordability, it is important to mention the concept of carbon leakage[26]. Higher wholesale prices for business do not only correspond with a loss of competitiveness but might even persuade some to move production abroad due to the additional risk of carbon leakage. Even though the term carbon leakage is

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[25] See Eckert and Vukmanovic (2016)

[26] The European Commission defines carbon leakage as “the situation that may occur if, for reasons of costs related to climate policies, businesses were to transfer production to other countries... This could lead to an increase in their total emissions. The risk of carbon leakage may be higher in certain energy-intensive industries” (European Commission, 2016c).

predominately used with reference to the emission pricing systems such as the EU Emissions Trading System, the principle also applies to electricity prices for electricity intensive industries.

5.3.3.1 Austria

The CO_2 emissions in Austria would rise as a result of the breakup of the German-Austrian bidding zone. Following the breakup, there is less electricity flowing from Germany to Austria and consequently, the Austrian generation rises. Indeed, the use of natural gas-fired power plants would increase, which in turn leads to rising CO_2 emissions. The calculations show that the CO_2 emissions of the power generation sector would be a remarkable 5 per cent higher (for 2020; and 3 per cent for 2024) in a breakup scenario, compared with a continuation of the common price zone. The policy objective of sustainability would thus clearly be negatively affected in Austria.

5.3.3.2 Germany

In Germany, CO_2 emissions would drop in the event of a breakup of the common bidding zone. Due to the reduced load from Austria, less generation is necessary and the generation from CO_2-intensive lignite and coal-fired power plants decreases slightly.

The model computations show that the CO_2 emissions in Germany would be around 0.4 per cent (2020) and 0.3 per cent (2024) lower, compared with the scenario of a continuation of the common price zone. Hence, a breakup of the zone would have positive effects on the policy objective of sustainability in Germany.

Considering CO_2 emissions reductions and increases, in Germany and Austria respectively, it can be shown that the overall CO_2 emissions would decrease by 0.2 per cent. This is due to the relative size of the German market compared with the Austrian market. A breakup of the common zone would thus result in lower total emissions, influencing the policy objective of sustainability positively. Interestingly enough, this finding contradicts statements by the German Chamber of Commerce in Austria (DHK), which supports a continuation of the common zone and lists higher overall CO_2 emissions as an argument against the breakup of the common zone (in Hundt, 2016).

5.4 Conclusion

One can surmise that a split of the German-Austrian bidding zone would have a wide range of consequences, not only for Germany and Austria but also for a number of neighbouring countries. This study analysed the market effects of this price zone split with respect to the energy policy objective triangle of (i) affordability, (ii) security of supply and (iii) sustainability. A fundamental model displayed the breakup of the common zone with two set NTC values for the years 2020 and 2024. The subsequent step was to compare these results with a continuation of the common bidding zone scenario.

The yearly average prices were used to analyse the consequences for the policy objective of affordability. The most significant results by far were observed in Germany and Austria. Austrian prices rise significantly with the price zone split, which in turn affects the policy objective of affordability negatively. Germany experiences the reverse effect. Lower yearly average prices have a positive influence on the affordability even though a share of this might be diminished due to the potential rise of the renewably levy. Slight but still notable positive effects on affordability are found for Belgium, Denmark, Luxembourg, Norway and Sweden. In the Czech Republic, Hungary, Slovakia, Slovenia and Switzerland the price zone split is set to affect the policy objective of affordability in a negative way. There are no or only minimal changes for affordability in France, Italy, the Netherlands and Poland.

The hourly prices calculated by the model enabled an analysis of the policy objective of security of supply. High price spikes indicate a scarcity situation which in turn is a threat to security of supply. The results of the computation show that there are no significant changes in high price spikes for the years 2020 or 2024. Consequently, no effects on the policy objective of security of supply are found with the methodology used here. The price duration curves of Germany and Austria (Figure 18 and Figure 19) show that there are fewer high priced hours in Austria in 2020 following a breakup of the common price zone. Moreover, this is not in a price area that could be regarded as critical from a security of supply perspective.

The policy objective of sustainability was analysed with the expected power plant dispatch and corresponding CO_2 emissions. It is shown that the breakup of the common zone has significant negative effects on the sustainability of Austrian power generation. More natural gas-fired power plants are used resulting in higher CO_2 emissions. The opposite effect can be observed in Germany where the CO_2 emissions decline slightly. Due to the relative size of the German market compared with the Austrian one, overall emissions drop. The price zone split therefore has, in sum, positive effects on the policy objective of sustainability.

With respect to the energy policy objective triangle, the same weight is usually attributed to the three objectives and they are often considered to be competition with each other. A breakup of the common German-Austrian bidding zone as an energy policy measure appears to be compatible with multiple objectives. Indeed, the breakup would enhance the German energy policy objectives of affordability and sustainability, whilst not affecting security of supply negatively. However, for Austrian energy policy, the splitting of the common bidding zone would bring about negative implications not only for affordability but also for the sustainability of the system.

6 A unilateral climate and supply market model

6.1 Energy policy and the concept of direct and multiple steering

It is the objective of modern energy policies to decarbonise without jeopardising other policy objectives. Within this context, one usually refers to the energy policy objective triangle of i) security of supply, ii) affordability and iii) sustainability. In order to tackle climate change and fight global warming, governments strive to reduce emissions. Carbon dioxide (CO_2) in particular has become a common standard to measure the sustainability of a given system and quantify emissions growth or reduction. CO_2 is emitted by a variety of sources from different sectors; the power and transport sector being amongst the most prominent. Depending on the sector, there are different energy policies and strategies to initiate emission reductions.

Focusing on the power sector, one can differentiate between two theoretical policy concepts: direct and multiple steering. The former centres around the idea of pricing and internalising CO_2 or, more generally, greenhouse gas emission costs. In practice, this can be put into effect by introducing a CO_2 tax and/or an emission trading system such as the European Union Emissions Trading Scheme (EU ETS). Given the declared objective of decarbonisation, this approach can be seen as plausible and straightforward. Putting a price on CO_2 emissions should reduce the overall output and thus give rise to further decarbonisation. This approach directly targets CO_2 emissions, which is why we refer to it as 'direct steering'.

In contrast, an indirect steering method would indirectly work towards achieving the same objective, for example by setting other incentives to reduce emissions or promote alternatives, which entail less or no emissions. Examples would include taxes on emission-intensive fuels or support for renewables.

If multiple policy measures coincide and interact with the common objective of reducing emissions, one speaks of a multiple steering model (Everts et al., 2016)[27]. For example, a CO_2 tax and trading system can be a part of a multiple steering model. Indeed, most governments nowadays have a range of policies in place that not only price CO_2 but also incentivise emission reduction in other ways. It is an advantage of this multiple steering model that policy makers have greater control over emission reduction contributions of different sectors, technologies used and general concepts. There are, however, several problems with those designs which currently prevail.

6.2 Current issues of the EU ETS

There is an extensive body of literature on the weak performance of the EU ETS and the continuous drop in price of allowances since the financial crisis; from about 30 EUR/tCO_2 to

[27] Multiple steering models usually include direct and indirect measures.

below 5 EUR/tCO_2[28]. The low allowances price level has led to circumstances in which there exist great uncertainty as to whether the EU ETS is still and can be a main driver for decarbonisation, despite being designed to fulfil exactly this role (Marcou et al., 2016). In general, scholars regard the price level as too low to fulfil the intended functions (Abrell et al., 2016; Rogge et al., 2011; European Commission, 2014). It has been argued that at the current price level, costs of negative externalities stemming from carbon emissions are no longer properly internalised (Carbon Market Watch, 2015). Further, the price of allowances is too low to trigger investments in low carbon technologies and facilitate innovation (Carbon Market Watch, 2015; Hepburn et al., 2016; Rogge et al., 2011).

This points towards the prevailing problems of the EU ETS and a necessity for reform. However, reforming the EU ETS has proven a difficult political matter, given the diverse interests of the stakeholders and parties involved. Currently, there is an ongoing reform process of the EU ETS for which the European Parliament voted and on which the European Council recently agreed a position (European Council, 2017). However, observers remain sceptical that the proposed changes will be sufficient to end the run of very low allowance prices (Boffey, 2017; Rattay, 2017).

This run of very low allowance prices (on average 6.2 EUR/tCO_2 during the last five years)[29] has also had subsequent effects. It is part of the concept of the multiple steering model to maintain some level of price neutrality with respect to wholesale power prices. But CO_2 pricing systems such as the EU ETS have a price-increasing effect on wholesale power prices, whilst the deployment of low marginal cost renewables have a price-decreasing effect, which is why both policies together have the potential of retaining overall price neutrality. Power prices have fallen drastically since the financial crisis and the price decline of CO_2 allowances and the deployment of low marginal cost renewables have been found to be the most contributing factors to this wholesale power price drop in Germany (Bublitz et al., 2017; Everts et al., 2016; Hirth, 2016).

This development of wholesale power prices has in turn increased the focus on the so-called 'missing money problem'[30] – a problem which might threaten the long-term security of supply. If there is no investment rationale for investments in flexible generation capacity to balance intermittent renewable production or in conventional backup capacity, security of supply is threatened. As a consequence, many governments have recently introduced mechanisms to provide market participants with more incentives for building or maintaining generation capacities in order to guarantee that power demand can be met at all times. In theory, there should be no need for such market interventions, as the energy-only market should provide sufficient incentives for new capacity with scarcity price spikes. Therefore some see capacity

[28] Koch et al. provide a concise overview of current state of research on the EU ETS and the causes of the price drop (Koch et al., 2014)

[29] Average ICE EUA futures 2012-2016 (Intercontinental Exchange, 2017)

[30] The 'missing money problem' describes a situation in an energy-only market where low power prices and few price spikes do not provide sufficient (long-term) investment incentives in new (flexible) generation capacity. For a closer examination of the missing money problem see Crampton & Stoft (2006), Joskow (2008) and Newbery (2016).

remuneration mechanisms[31] as market distortions (European Commission, 2016d; Hancher et al., 2015).

It should be noted at this point that the investment cycles in the energy industry are generally characterised by their long-term nature and high capital costs. Power plants have long life times with high upfront costs. The high capital intensity amplifies the impact of investment cycle changes and raises the risk of excessive or insufficient capacities (Lu et al., 2015). A low-price outlook as well as regulatory uncertainties may exacerbate this effect. This, combined with technology innovations and doubts over future market designs, has made traditional investments in power plants with an expected lifetime of half a century or longer rather complex.

The dearth in investment incentives has also been identified by the European Commission as a market failure. It is commonly acknowledged that further policy measures targeting emissions reductions and addressing concerns on (long-term) investment incentives are needed (European Commission, 2016d). Electricity supply is now more than ever a vital good in modern societies and is also in liberalised markets regarded as a public good[32] (Abbott, 2001; de Vries and Hakvoort, 2003; Finon and Pignon, 2008). Insufficient investments to guarantee long-term security of supply can thus be seen as a market failure, and capacity mechanisms represent a regulatory market intervention to address the issue.

6.3 Existing carbon taxation models

The following section briefly presents and examines other CO_2 taxation models; namely, a differential taxation model, the use of border tax adjustments and the current CO_2 taxation model of the United Kingdom.

6.3.1 Differential Taxation

Cottier et al propose a CO_2 taxation model described as differentiated electricity tax (Cottier et al., 2014a). It aims to replace renewable support schemes and act as a steering system. They suggest different tax rates based on the technology used to generate electricity, aiming not only to reduce consumption but also to promote renewables. Renewable energy sources would profit from exemptions and tax rates for electricity produced from non-renewable sources would depend on their carbon intensity (Cottier et al., 2014b). Guarantees of origin (or alternatively specifically designed renewable energy certificates) occupy a central role by determining the corresponding tax rate. The scholars discuss four main, different varieties of the model in detail with respect to the legal considerations they entail.[33]

They find that offering exemptions in their model only for domestic renewable electricity – effectively treating domestic and foreign production differently – would most likely constitute discrimination under the GATT (Holzer et al., 2017). One approach which could circumvent

[31] Whilst capacity remuneration mechanisms can take different forms, they generally provide monetary payments towards generators for available generation capacity.

[32] A public good is commonly defined by the characteristics of nonrivalry and non-excludability, i.e. additional consumers add no additional costs (zero marginal costs) or reducing the good's availability for others and people cannot be excluded from consuming the good.

[33] See Holzer et al., 2017 and Cottier et al., 2014b, 2014a

this is introducing additional requirements and constraints for imported electricity eligible for tax exemptions. Yet, even in that case, compliance with WTO law remains uncertain, depending on the exact criteria (Holzer et al., 2017). A central issue associated with also offering unrestricted exemptions for foreign renewable production is the significant availability of guarantees of origin at very low prices in the EU, especially from Nordic hydropower. Producers could simply purchase those guarantees of origin instead of paying the – it is assumed – costlier carbon tax.

In contrast to the proposed climate and supply market model with one uniform CO_2 levy, the differentiated electricity tax aims to tax electricity at different rates depending on the electricity source. Even though both models use guarantees of origin, their functions differ. In the proposed climate and supply market model, the guarantees act as a source of additional income for renewable producers due to their – at times – significant increase in value. Cottier et al's legal analysis of their model regards a limitation of tax exemptions only for domestic renewable electricity as problematic, whereas the structure of the proposed climate and supply market model enables a lawful increase in value of exclusively domestic guarantees of origin from CO_2-neutral production.

6.3.2 Carbon tax with border tax adjustments

Border tax adjustments (BTA) have in recent years been increasingly discussed in relation to enforcing an environmental tax on imported goods within WTO law. A particular focus of research has been the interplay of emission trading schemes and BTA, and how BTA can be used to avoid carbon leakage[34]. Regarding the power sector, one could introduce an environmental CO_2 tax on power generation. BTA could then be used to tax imports in order to prevent competitive disadvantages for domestic production. If the tax shall depend on the CO_2 intensity of the technology used to generate the electricity, one effectively applies a differential taxation model such as the aforementioned model.

In practical terms, one aspect which comes hand in hand with the problem is that the origin of electricity is not always known and guarantees of origin are often only issued for renewables. Guarantees of origin would need to be introduced for all technologies and, possibly, also certify the CO_2 footprint of the electricity. It remains an open question how imports without guarantees of origin would be handled. A subsequent question in this cross-border context is if one can legally differentiate between electricity produced from CO_2-neutral sources (green electricity) and electricity produced from unknown or fossil energy sources (grey electricity). As a matter of fact, there exists significant legal debate among scholars as to whether green and grey electricity are considered 'like' or 'unlike' products under WTO law – thus far this question has not been subject to WTO jurisprudence (Holzer et al., 2017; Kreiser et al., 2015).

If all electricity was considered a 'like' product independent of its method of production and origin, equal treatment is required from a legal perspective. In this case, imported grey electricity could not be treated less favourably than domestically produced green electricity[35].

[34] See Ismer and Neuhoff, 2007; Kuik and Hofkes, 2010; Panezi, 2015.

[35] It should be noted that Art. XX GATT on exceptions may leave some room for policy measures, potentially enabling a justification of violation of the non-discrimination rules. See Cottier et al., 2014c, pp. 34–37 for a detailed discussion.

A flat tax on all electricity generation would fail to set incentives for low or carbon free production. In case grey and green electricity are deemed 'unlike' products, a taxation model taxing them at different rates and using BTA seems theoretically feasible. However, a unilateral implementation of such a market design would face the aforementioned practical issue of a significant availability of renewable guarantees of origin at comparably low prices in the EU. Treating domestic electricity from CO_2-neutral sources differently than that from foreign CO_2-neutral sources would - as discussed - most likely contravene GATT rules.

6.3.3 United Kingdom: Carbon Price Floor

In 2013, the British government's Department of Energy and Climate Change (DECC) established a carbon price floor for electricity generation taxing fossil fuels used to generate electricity. It can be described as a 'top-up' of the EU ETS. The carbon price floor was initially introduced at 16 GBP/tCO_2 and was supposed to reach 30 GBP/tCO_2 in 2020 and 70 GBP/tCO_2 in 2030 (in real 2009 prices). To this end, the government charges power generators a top-up of the EU ETS called Carbon Price Support (CPS) making up the difference between the floor price and the EU ETS allowances price. The amount of this CPS is announced with budget statement by the British Treasury two years in advance.

Due to the lower than expected EU ETS allowance prices, the CPS was frozen at 18 GBP/tCO_2 until 2021 in order to limit the competitive disadvantage faced by businesses and prevent electricity bills from rising (HM Revenues & Customs, 2014; HM Treasury, 2016).

The carbon price floor was introduced with the intention of correcting the market distortions created by the low EU ETS prices. It was supposed to underpin the price of carbon at a level that drives low carbon investment (Ares and Delebarre, 2016). The mechanisms contributed to a significant drop in electricity generation from coal-fired power plants due to higher costs associated with such generation, which in turn helped to reduce emissions (Clark, 2017).

Analysing the design of the carbon price floor, it is essential to highlight that the carbon price floor affects only producers in Great Britain. Electricity imports to Great Britain are not subject to the carbon price floor; charging producers abroad would most likely violate the General Agreement on Tariffs and Trade (GATT) (in particular Article III)[36]. The subsequent competitive disadvantages for electricity producers in Great Britain compared with those abroad are rather limited due to the relatively low interconnector capacity of Great Britain with other countries (4GW) as a result of its natural geographically isolated island location (Ofgem, 2017). In a more interconnected market, the design of the carbon price floor that only charges national producers would not be sensible as it would disadvantage national production disproportionately. This is also the reason why Northern Ireland is exempted from the carbon price floor (Foster in Sync Ni, 2013).

Currently there are ongoing discussions about the future of the carbon price floor[37]. There are both calls to phase out the mechanism as well as calls to maintain it. Of particular interest,

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[36] The role and classification of electric power as a good under WTO law and the subsequent legal implications are subject to substantial legal debate. (Cottier et al., 2014c, pp. 34–37) provide an overview of handling electricity under WTO law and Horn and Mavroidis (2011) discuss the legality of Border Tax Adjustments for climate purposes. It is generally agreed that CO_2 taxation regimes not limited to domestic production may easily violate WTO (GATT) rules.

[37] For an overview see the recent research note by Policy Exchange (Howard, 2016)

there are studies that project the carbon price floor to lead to an overall *increase* in emissions. An increased interconnection capacity with planned interconnectors to mainland Europe and Iceland might, together with the carbon price differential, cause European wide-emissions to rise as natural gas-fired generation in Britain might be undercut by coal-fired generation in mainland Europe. (Aurora Energy Research, 2016). In light of Brexit, there remains policy uncertainty regarding the future of interconnectors and the UK's participation in the EU ETS (Howard, 2016). The UK Government has, however, signalled its intention to maintain the carbon price floor mechanism at its current rate until 2021 (HM Treasury, 2016).

The example of CO_2 taxation in Great Britain as well as the model proposed by Cottier et al illustrate the economic and legal constraints of CO_2 steering models. Reforms on a European level haven proven difficult, levying only domestic power producers results in competitive disadvantages, and taxes on imports are likely to violate international law. For countries with a low share of interconnector capacity, a carbon price floor such as the British model - levying only domestic production - effectively counters low EU ETS allowance prices and can (re-)establish carbon prices as a driver for decarbonisation. The networks of most European countries are, however, much more deeply integrated and connected, which is why the British model does not represent an appropriate solution.

In the absence of effective European reforms, the suggested climate and supply market model can therefore offer an alternative way of pricing CO_2 on a national basis, internalising the costs of CO_2 emissions and clearing market distortions originating from EU ETS allowance prices which are too low without violating international trade agreements or EU law.

6.4 Unilateral climate and supply market model

It has been shown that, regarding energy policy objectives, further policy measures targeting emissions reductions as well as addressing concerns over (long-term) investment incentives are needed. The authors propose a climate and supply market model that tackles not only the aforementioned climate issue but also the insufficient investment incentives provided by the energy-only market.

Given the difficulties in reforming emission trading systems such as the EU ETS at a multilateral level, the climate and supply market model suggests a unilateral approach in which a state introduces a CO_2 levy that internalises the external costs of CO_2 emissions at a national level. It aims to correct the aforementioned market distortions caused by the low EU ETS price level and its subsequent effects by reintroducing a significant carbon price for the power sector. The model exempts the consumption of CO_2-neutral electricity from the new CO_2 levy, using national guarantees of origin (which already exist in many countries). The levy is introduced for suppliers who pass the costs on to the final electricity consumers. The EU ETS allowance price is taken into account, whereby the proposed CO_2 levy decreases when the EU ETS allowance price rises. The government, relevant ministry or institution in question sets the amount of the national CO_2 levy. This amount could be related to the social costs of carbon[38] or if available, existing CO_2 taxation on fuels.

[38] The social costs of carbon is a scientific approach to measure the marginal costs of emitting an additional unit of CO_2 or CO_2 equivalents at a given time. The comprehensive scientific approach tries to incorporate climate change-related costs to estimate the social costs of carbon. See National Academies of Sciences, Engineering, and Medicine (2017) for a recent overview of social costs of carbon estimates.

In the suggested model, producers report their production to a certification body (in many cases already existing and responsible for handling guarantees of origin) and receive corresponding guarantees or certificates. Suppliers report to the certification body their deliveries to the final consumers and they pay the corresponding CO_2 levy or present national guarantees of CO_2-neutral origin instead[39]. Guarantees of origin are traded and as long as national CO_2-neutral production does not surpass the national demand, the guarantee price should roughly equal the CO_2 levy, since suppliers have either to pay the CO_2 levy or present the guarantees of CO_2-neutral origin[40]. It should be noted at this point that the certificate market remains independent and separate from the energy-only market on which electricity is traded.

In order not to discriminate against any form of production (thus adopting a principle of non-discrimination), the CO_2 levy applies generally to every unit of electricity consumed within the country and does not differentiate between technologies – apart from the fact that only guarantees of origin from CO_2-neutral sources offer an exemption from the levy. Costs associated with CO_2 (such as the social costs of carbon) are usually expressed per tonne of CO_2. For the purpose of the climate and supply market model, a calculation to express the costs per unit of electricity (i.e. MWh) is necessary. The CO_2 intensity of either the national power sector or a European Economic Area (EEA) average can be used for this, resulting in the following formula which also incorporates the EU ETS:

$$\left(L_{tco_2} - P_{ETS}\right) * I_{co_2} = L_{co_2} \tag{14}$$

Whereby
L_{tCO_2}....CO_2 levy (in EUR per tonne of CO_2)
P_{ETS}.....EU ETS price (in EUR per tonne of CO2)
I_{CO_2}...... CO_2 intensity (in tonnes of CO_2 per MWh)
L_{CO_2}...... CO_2 levy (in EUR per MWh)

Consequently, the final CO_2 levy decreases if the EU ETS allowance price rises or the CO_2 intensity is reduced. In terms of decarbonisation, this means the model is designed to eventually become redundant if the decarbonisation of the power sector progresses and/or EU ETS reforms lead to a higher level of allowance prices[41]. In order to reach the objective of a CO_2-neutral supply covering national demand, the guarantees of origin remain valid only for a specific period of time. This ensures that the investment incentives are set in a way that incentivises CO_2-neutral production when it is insufficient to cover national demand. In this way, the climate and supply market model strengthens security of supply and makes a country less dependent on imports. As soon as CO_2-neutral sources satisfy the national demand during the chosen time periods, the model becomes obsolete. In the case of renewable power plants

[39] It is assumed that foreign guarantees of origin cannot offer exemptions as long as there is no such agreement.

[40] If national production exceeds final national consumption, the guarantees of origin have no additional value.

[41] The EU ETS allowance price used in the formula can be determined by either using past (*ex-post*) or future (*ex-ante*) allowances prices.

that are currently supported through some form of renewable support mechanism such as feed-in tariffs or quota schemes, the support scheme administrative authority (rather than the plant operator) should receive the certificates[42]. Those guarantees can then be sold on the market and used, for example, to finance the costs of the existing renewable support scheme.

Currently, several governments in Europe have some form of CO_2 levy in place usually concerning fuels used in the transport or heating sector[43]. The emissions originating from electricity generation for electric radiators or vehicles is, in contrast, often only charged through EU ETS and there is no true cross-sector approach. CO_2 levies for fuels could be used and applied to other sectors, in order to implement a cross-sector carbon price. Such a cross-sector approach would help to clear market distortions and effectively reward the most carbon-efficient approach in fields such as heating or mobility. Introducing the climate and supply market model inevitably leads to higher electricity bills for consumers, due to its financing structure. The exact costs would be country specific and depend amongst other things on the set CO_2 levy, the country's electricity generation mix, import/export balance, potential exemptions of some customers and the final consumption of electricity. In this regard, the test case presented later shows an acceptable level of costs for consumers.

Aside from the additional cost burden that comes with the climate and supply market model one should also address the drawbacks entailed by a uniform CO_2 levy. In order not to discriminate against certain forms of production the CO_2 levy of the climate and supply market model is uniform and applicable to all forms. Guarantees of origin offer exemptions only for electricity produced from CO_2-neutral sources, which in turn means that all electricity produced from fossil sources faces the same uniform CO_2 levy. Electricity from emission-intensive lignite- or coal-fired power plants is thus not treated differently than that produced from less emission-intensive natural gas-fired and combined-cycle power plants. This consequently makes the climate and supply market model an ill-fitted model for countries that seek to replace coal-fired generation capacities with natural gas-fired capacities through the introduction of a CO_2 levy.

[42] This is done to prevent windfall profits for operators of renewable power plants already supported through some form of support mechanism as the value of the guarantees of origin would increase significantly through the introduction of the climate and supply market model. Those operators will have to be compensated in some way as they will not be able to sell their guarantees of origin. A direct financial compensation or an introduction of new distinct certificates serving the same purpose as guarantees of origin yet not eligible for the climate and supply market model would be possible ways of doing so.

[43] Examples of carbon taxes can be found in Switzerland, Sweden, Finland and Denmark (see World Bank et al., 2016).

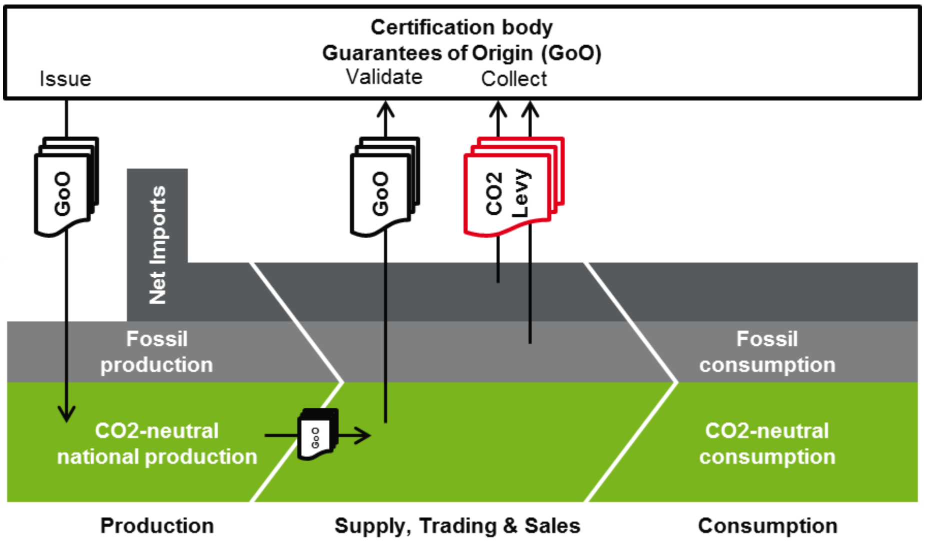

Figure 20: Climate and supply market model

6.5 Legal considerations with respect to international and EU law

The concept of pricing CO_2 on a unilateral level is not new and there have been various studies regarding its legal status in the past[44]. In order to initiate a public debate on a concept such as the suggested climate and supply market model, it is necessary to clarify the legal considerations such a market design entails. Any potential market design has to be compatible with existing legislation and in particular with WTO law, EU law and other trade agreements, since CO_2 taxation regimes have to be carefully designed in order not to violate them. A professional legal assessment of the suggested climate and supply market model by a leading Swiss law firm found the model to be in line with all relevant international and EU legislations.

Fundamental for the legal compatibility of the suggested model is the two-fold approach of putting a levy on the final electricity consumption (rather than production) and the clear separation of the national guarantees of origin market on the one hand, and the energy-only market on the other. Generally, guarantees of origin are not considered goods or products under internal trade law since they are not tangible and have no customs tariff number in the Harmonized Commodity and Coding Systems (short Harmonized System [HS]) of international law (Petsonk, 1999)[45]. They are also generally not considered as services under the General Agreement on Trade in Services (GATS) even though the subsequent trading of the certificates may be regarded as such (Delimatsis and Mavromati, 2009).

Also as concerns EU law, guarantees of origin are not handled as goods which fall under the free movement of goods within the single market. Court rulings by the European Court of Justice underline that green certificates or guarantees of origin are not treated as goods and that guarantees do not have to be recognised by other Member states. One can refer at this

[44] See for instance (Cottier et al., 2014b, 2011; Holzer, 2014; Panezi, 2015)

[45] It should be noted that there is no clear definition of what exactly constitutes a good in international law and thus far, guarantees of origin or certificates as part of renewable support schemes (often referred to as quota obligation or green certificates) have not been regarded as goods or services (Buchmüller, 2013; Delimatsis and Mavromati, 2009; Howse, 2009; Petsonk, 1999).

point to the prominent case of Åland Vindkraft and a following similar case relating *inter alia* to Belgian guarantees of origin.

The Åland Vindkraft court ruling (which gained prominence by confirming the national character of renewable support schemes) clarified that Member States only have to recognise foreign guarantees of origin to a limited extent (European Court of Justice, 2014a). In a similar case, one of the involved parties explicitly argued that the intangible nature of guarantees of origin prevents their categorisation as goods. The court refrained hereby from ruling definitely, answering that "even if it were accepted that guarantees of origin […] constitute 'goods'" it would not change the question at stake (European Court of Justice, 2014b). Accordingly, it is fair to say that thus far, guarantees of origin have not been treated as goods in international law and EU law, which is crucial for the legal compatibility of the suggested climate and supply market model.

Finally, as regards this legal perspective, it is worth taking a brief look at the EU state aid law vis-a-vis the suggested model. The support of companies or industries with state resources is considered state aid by the European Commission. The legal assessment asserts that the climate and supply market model does not constitute state aid. The associated costs arising through the CO_2 levy of the suggested model are borne by consumers and the amounts paid for the CO_2 levy are not received by producers. The fact that the value of guarantees of origin experience a substantial increase through a state intervention does not change this principle. Strictly speaking, the model does therefore not constitute state aid in this context. However, even if the model was considered state aid, it would likely be considered proportionally and approvable (similar to other permitted measures). This should be seen in the broader context of approved measures regarding support for renewables and mechanisms strengthening the security of supply.

6.6 Climate and supply market model example: Switzerland

One can use Switzerland as an example to illustrate the proposed climate and market model. Switzerland's domestic power production is virtually CO_2 neutral. Yet during the winter months, Switzerland relies on imports to meet its demand. The validity for guarantees of origin could therefore be set for one month. During summer months, when Switzerland is a net exporter of electricity, the guarantees of origin from CO_2-neutral sources would be without additional value and no CO_2 levy applies. However, in winter months when Switzerland imports electricity, the value of guarantees of origin from CO_2-neutral sources would rise to approximately that of the CO_2 levy to be paid for non-CO_2-neutral production (i.e. imports). Existing Swiss laws include a CO_2 levy on thermal fuels of 84 CHF/tCO_2 (≈78 EUR/tCO_2) (Federal Office for the Environment, 2016; Bundesrat, 2011). The suggestion is to apply the same carbon price level to the power sector. Consequently, in winter months when imports are necessary, suppliers would need to pay the CO_2 levy for the electricity that cannot be exempted with guarantees of origin (imports).

For the calculation of the applicable CO_2 levy, an estimated average EEA[46] power generation carbon intensity of 0.23 tCO_2/MWh[47] can be used. To take the EU ETS price into account that has already been paid, one can deduct the EU ETS allowance price off the Swiss carbon price. With a carbon price of 78 EUR/tCO_2 and a 2016 average EU ETS allowance price of about 5.3 EUR/tCO_2 the suggested CO_2 levy would thus equal:

$$\left(78\left[\frac{EUR}{tCO2}\right]-5.3\left[\frac{EUR}{tCO2}\right]\right)*0.23\left[\frac{tCO2}{Mwh}\right]=16.7\left[\frac{EUR}{MWh}\right]. \qquad (15)$$

Swiss suppliers would therefore have the choice of either buying national guarantees of origin from CO_2-neutral sources or paying the CO_2 levy. Given the certificate scarcity in import months (i.e. when Swiss national CO_2-neutral production does not cover demand) the price for the guarantees of origin would equal that of the CO_2 levy of 16.7 EUR/MWh – since for every MWh delivered suppliers have to provide either a guarantee of origin or pay the CO_2 levy.

An increase of the EU ETS allowance price level or a decrease of the EEA power generation carbon intensity leads to a lower CO_2 levy without further adjustments. In summer months, when Switzerland is traditionally an exporter of electricity and its domestic CO_2-neutral production exceeds consumption, the guarantees of origin have no additional value.

This example shows that the climate and supply market model would reward CO_2-neutral production in times when the national CO_2-neutral production is not sufficient to cover the demand and set incentives for expanding capacities that produce CO_2-neutral electricity during those times.

A subsequent step is to calculate the economic impact and overall costs arising from a CO_2 levy of 16.7 EUR/MWh. Over the last five years (2012-2016), there were on average four months per year during which the final electricity consumption was greater than the total energy production in Switzerland (Swissgrid, 2017).

The average final electricity consumption over those four months equalled 21,119,886 MWh (21.12 TWh). A CO_2 levy of 16.7 EUR/MWh would hence result in costs of around EUR 353 million per year. It should be noted at this point that this sum may vary depending mostly on the number of months during which the final electricity consumption exceeds the production of CO_2-neutral electricity. The total annual Swiss final electricity consumption has been just below 60 TWh in the last couple of years (Bundesamt für Energie (BFE), 2017). The costs of

[46] An EEA plus Switzerland average rather than EU average is used here for legal reasons. The economic area of the EEA plus Switzerland encompasses a wider European market and does not discriminate specific countries or on the basis of political Union.

[47] Estimation based on a published EU CO2 emission intensity of 0.276 tCO_2/MWh for 2014 (European Environment Agency, 2016). Assuming a similar CO_2 emission intensity reduction as in previous years and taking the virtually CO_2-free Swiss, Norwegian, Icelandic and Liechtenstein production into account to form an EEA + Switzerland average, one can use 0.23 tCO_2/MWh as a rough estimation for 2016 (Amt für Statistik, 2016; European Environment Agency, 2016; Norwegian Water Resources and Energy Directorate (NVE), 2017; Orkustofnun, 2017; Swissgrid, 2017).

EUR 350 million per year would thus equal additional costs of around 0.6 cents/kWh, which can arguably be seen as an acceptable level of additional costs.

6.7 Variations of the climate and supply market model

The model can be altered in many ways to incorporate specific requirements or change its effects. The most straightforward steering instrument is the government-set CO_2 levy in EUR/tCO_2, which together with the EU ETS allowance price and the carbon intensity translates into the final levy expressed in EUR/MWh. Policy makers can choose whichever price is perceived as appropriate to work towards given policy objectives. This might result in a cross-sector carbon price as in the described example or one that relates to the social costs of carbon.

One recurring aspect of CO_2 taxation regimes are exemptions or special conditions for energy-intensive industries. Such measures can be included in the suggested climate and supply market model in case policy makers choose not to place additional burdens on the energy-intensive industry.

It may also be in the interest of a government to choose which particular CO_2-neutral generation technologies should profit from the guarantees of origin value increase. It could for example be restricted to CO_2-free rather than CO_2-neutral technologies thereby excluding technologies such as biomass or landfill power plants.

Another central element of the suggested model is the time period for which guarantees remain valid. In the presented example, the time period is set to one month, but different time frames are possible. Depending on the country’s requirements and circumstances, the administrative body could set a longer time frame (i.e. quarters or seasons) or shorter one (i.e. weeks, days or even hours). A shorter time frame represents a more precise steering instrument but increases potential market power abuses[48]. Additionally, it comes at higher administrative costs and efforts for market participants and the administrative body.

In the suggested version of the model, suppliers have to provide one guarantee of origin from CO_2-neutral production for every MWh delivered or pay the CO_2 levy. But the administrative body could also require suppliers to provide more or less than one guarantee per unit of energy delivered. This way, one could steer the demand for guarantees and it enables setting targets of a desirable share of production from CO_2-neutral sources for the chosen time period.

6.8 Adaption potential for the climate and supply market model

The concept of the climate and supply market model was developed in a European context and the focus of this research rested on European countries. The general principle of a CO_2 price component with exemptions for CO_2-neutral production using guarantees of origin can

[48] If in a chosen time period, domestic CO_2-neutral production is projected to be only marginally greater than the final consumption, producers might abuse their market power to transform it into an import period by withholding generation capacity. This could increase their income as the value of the guarantees of origin from CO_2-neutral sources would rise to that of the CO_2 levy. The shorter the time period, the smaller the generation capacity necessary to do so, as long as market data are available to project if domestic production will exceed or fall short of final consumption.

theoretically also be applied elsewhere. Naturally this would entail some necessary adaptions such as the removal of the EU ETS pricing in the formula of the CO_2 levy and further legal assessments.

The model is particularly attractive for countries with a high share of traditional CO_2-neutral production (e.g. hydro, biomass) and looking for ways to maintain or increase it. Newer forms of CO_2-neutral/free production such as photovoltaics (PV) and wind are commonly supported through some form of feed-in scheme. As mentioned, operators of plants receiving subsidies through such a scheme would not be eligible for support through the climate and supply market model, since it would result in windfall profits.

With compensation levels of support schemes continuously decreasing due to the cost reductions of renewables technologies, learning curves and further innovation, one may question for how long governments will continue their feed-in support schemes. Recent competitive tenders have again led to a decrease in compensation levels and the first German offshore wind auction gained prominence as companies bid to build offshore wind parks without a guaranteed minimum strike price[49]. In this light, it seems plausible that policy makers discuss the future of support schemes with the climate and supply market model comprising a potential option.

Since the climate and supply market model aims to incentivise CO_2-neutral power production during times when the targeted share of this production type is not met, it seems most apt for countries that already have a relatively high share of CO_2-neutral production in their electricity mix. Aside from the aforementioned example of Switzerland, the following European countries have a large CO_2-neutral share (over 65%) in their gross electricity production (according to data published by the European Commission, 2017): Austria, Croatia, Denmark, Finland, France, Slovakia, Slovenia and Sweden.

Given the functioning of the climate and supply market model described herein, the composition of the power sectors of these countries make them ideal candidates for a potential adaption of the model or discussion thereof. This is not to say that the climate and supply market model is not a useful fit for other countries. If policy makers set a lower amount of required guarantees of origin for suppliers per MWh delivered (e.g. 0.5 rather than 1), the model can also be attractive for countries with a lower share of CO_2-neutral production. As mentioned earlier, the fact that the CO_2 levy of the model is uniform means that all electricity is treated the same independent of exact CO_2 intensity of the production and only guarantees of origin from CO_2-neutral sources offer exemptions. Therefore, the model does not represent an adequate instrument for countries that seek to introduce a CO_2 levy to lift the economic viability of natural gas-fired power generation over that of coal-fired generation.

6.9 Conclusion

It has been argued that the power sector is facing a series of difficulties in light of energy transitions and decarbonisation. Low EU ETS allowance prices have led to a state of uncertainty regarding its role as a driver for decarbonisation. Previous reform processes have

[49] In 2017, EnBW and Dong Energy were awarded the right to build wind farms in the North Sea with submitted bids of 0 EUR/MWh. It should be noted that they will still receive some form of subsidy as they gained the right to operate those parks for 25 years and network charges for electricity consumers finance the costly grid connection(s) (Bundesnetzagentur, 2017).

had limited success and some countries have looked towards unilateral action to tackle the issue.

A run of very low wholesale power prices in Europe, partly caused by low EU ETS allowance prices, has led to concerns over long-term generation adequacy (the 'missing money problem') and the introduction of capacity remuneration mechanisms to counter the issue. The authors propose a unilateral climate and supply market model to address these aforementioned concerns. The model's core component is an introduction of a CO_2 levy on final electricity consumption. Exemptions from the levy are offered for electricity produced from CO_2-neutral sources. Suppliers have to provide guarantees of origin from CO_2-neutral production for every MWh delivered or pay the CO_2 levy. The government sets the amount of the levy and the time period guarantees of origin remain valid for. This way the climate and supply market model incentivises the power production from CO_2-neutral sources during times when it does not cover demand or the target share of production.

The model can be used to implement a cross-sector carbon price as the analysis of the example of Switzerland illustrates. The example also shows that the model can be realised at an acceptable level of costs for consumers even though the exact costs depend on a number of the factors discussed, first and foremost the set CO_2 levy.

CO_2 pricing schemes targeting the power sector have to be carefully designed in order to comply with international and EU law. Some models, such as the British model, therefore exclude electricity imports from their CO_2 price floor. In other countries with greater transfer capacity to grids abroad, excluding imports would disproportionally disadvantage domestic power producers, which is why the British model only has limited adaption potential abroad. A legal assessment of the proposed climate and supply market model came to the conclusion that the suggested design complies with relevant legal frameworks.

The model offers various steering instruments for policy makers and it can be altered to suit a given country. Aside from setting the level of the CO_2 levy, the government can specify the time period for which guarantees of origin remain valid and impose the number of guarantees of origin required for suppliers per MWh delivered. Together, these mechanisms enable the government to work towards a targeted share of CO_2-neutral production during any time period and incentivise the deployment of additional CO_2-neutral generation capacity.

Finally, even though the model has been developed in a European context, the general principle could also be used elsewhere. Within Europe, there are several countries for which the proposed climate and supply market model might represent a potential policy option.

7 Drivers of wind and PV value factors and capture prices

7.1 Background

Capture prices of a given power generation unit describe the average market prices that unit earns (Byrne et al., 2016). If a generation unit were constantly producing electricity, its capture prices would equal base prices. Non-dispatchable generation units such as solar photovoltaics (PV) and wind turbines produce electricity whenever there is sufficient solar radiation or wind. Their capture prices are therefore set by the market prices they achieve during the hours they operate[50]. Wholesale market prices are, in turn, determined by the intersection of supply and demand at any given hour[51].

A growing deployment of wind or PV increases the supply during hours they generate electricity, which in turn leads to lower market prices. The higher the penetration of wind or PV, the lower the capture prices they earn. One refers to this as *cannibalisation* as each additional unit of wind or PV *cannibalises* the market revenues of the existing units by shifting the residual load curve to the left during sunny or windy hours[52].

In economics, the term cannibalisation has been used predominately in marketing to describe how the sales of a new product *cannibalises* i.e. reduces the sale of an existing product by the same company. Energy economists only started using the term in the last decade to describe the aforementioned phenomenon of lower capture prices at higher penetration rates of variable generation sources i.e. wind and PV (Troy and Twohig, 2010).

Historically, market shares of wind and PV have been rather low compared with conventional generation technologies. Furthermore, they used to be – and still are in many cases – supported through some form of support mechanism, some of them (still) offering operators a fixed strike price per unit of electricity generated, independent or largely independent of market prices. Under such circumstances, the cannibalisation of wind and/or PV is not a pressing issue for renewable plant operators.

However, with a growing penetration of renewable electricity sources in a given system, the question arises as to what extent wind and PV cannibalise their own market revenues. This is becoming an increasingly pertinent issue as nowadays many renewable support schemes are more market-based, requiring operators to sell the electricity they produce themselves (direct marketing). Moreover, in Europe, subsidy-free renewables projects are on the horizon. In this context, it is increasingly suggested that Power Purchase Agreements (PPAs) are in the

[50] Capture prices of renewables are sometimes also referred to as 'market value of variable renewable energy sources (VREs)'.

[51] For a more detailed discussion on price-setting on short-run electricity markets see Blume-Werry et al., 2019.

[52] The residual load is commonly defined as the difference between actual power demand and the non-dispatchable stochastic power generation of photovoltaics and wind turbines (Schill, 2014). A shift of the residual load to the left as a result of increased supply from variable renewable sources has been labelled the 'merit-order effect' (Sensfuß et al., 2008). This merit-order effect describes the impact of the low marginal cost renewables on base prices, whereas cannibalisation refers to capture prices of wind or PV.

process of taking over government support schemes for renewables as the central instrument to mitigate market risk for investors and operators of renewables (Evans, 2017; Heiligtag et al., 2018; Huneke et al., 2018; Klinger and Driemeyer, 2019). Indeed, an ancillary question is which factors influence the cannibalisation of renewable energy sources? It is the core objective of this article to analyse different drivers of cannibalisation in order to obtain a clearer picture of how different factors influence the cannibalisation of wind and PV in Europe.

Even though capture prices are often given in absolute terms, the use of relative prices can be more revealing as they enable a better comparison across different studies and markets over time (Hirth, 2016b, 2013). We therefore use relative prices expressed as a percentage relative to the base price and refer to them as value factors[53]. In other words: a wind turbine with a value factor of 0.85 achieves market prices of 85 per cent of the base price. If the base price that a constantly-producing generator would earn was, for example, 100 EUR/MWh over the duration of a given time period (i.e. one year) the capture price of the wind turbine would equal 85 EUR/MWh. In mathematical terms the value factor describes the wind- or PV-weighted average electricity price over a given time period (usually one year), i.e. the achieved hourly market prices of wind or PV generation divided by the base price[54].

$$value\ factor_{wind/PV} = \frac{avg.capture\ price_{wind/PV}}{base\ price} \qquad (16)$$

Along with the decreasing value factors of wind and PV that come with higher market shares, the variable or intermittent nature of wind and PV brings with it system integration challenges. Systems with a high share of wind and PV typically experience higher balancing needs and costs (Batalla-Bejerano and Trujillo-Baute, 2016; Farahmand and Doorman, 2012). Further, any power system with significantly increasing shares of variable renewables requires notable network expansions to accommodate the new intermittent technologies (Lumbreras et al., 2017). The fact that suitable wind sites are often located far from demand centres increases the need for (often costly) grid expansions. These system integration costs are, however, not the focus of this study. But it remains important to keep these aspects in mind when discussing power systems with high penetration rates of wind and/or PV.

7.2 Literature review

Numerous scholars have researched capture prices and the value factors of wind and PV at different penetration levels. Hirth (2016) groups the existing literature into three clusters based on the methodology used. These three clusters - *«market data», «theoretical (analytical) models»* and *«numerical (computer) models»* - help to categorise the literature.

> Market data literature determines historic value factors or capture prices of renewables based on existing market data. Sensfuß (2007) researches the value of renewable production in Germany at comparable low penetration rates in the 2000s. He finds value factors just below 1 for wind, and value factors above 1 for

[53] In the literature the terms 'value factors' and 'market value factors' are used interchangeably.

[54] Sometimes referred to as time-weighted price or simple average price, in contrast to the load-weighted price.

PV (Sensfuß, 2007; Sensfuß and Ragwitz, 2011). Hirth (2015, 2013) complements this work and finds lower value factors at higher penetration rates. Other analyses of market data such as those by Clò and D'Adamo (2015) or Ederer (2015) support this (Riva et al., 2017; Welisch et al., 2016; Zipp, 2017). Whilst market data analyses provide real world evidence of lower value factors of wind and PV at higher penetration rates, it is not suitable for predicting value factors in systems with large shares of variable renewable production. This is due to the fact that currently only few markets with high penetration rates exist and experience from those markets may not be transferable. The Danish power system, for instance, is characterised by large shares of wind energy yet it is heavily influenced by the much larger German market as well as the largely flexible Norwegian market – and is therefore not representative for other markets.

Literature based on theoretical or analytical models supports the understanding of different dynamics and mechanisms. The research shows *inter alia* that value factors of wind and PV are driven by the corresponding production patterns and are higher if they coincide with demand peaks (Grubb, 1991; Hirth and Radebach, 2015; Lamont, 2008). At higher market shares, value factors of generation technologies are higher if the generation is less intermittent – which explains why PV value factors decline more significantly with higher penetration rates than wind value factors (Hirth and Radebach, 2015). In order to obtain quantitative results and estimate value factors at different penetration levels under different circumstances, most scholars employ numerical computer models rather than theoretical analytical models.

The largest strand of literature on the matter is based on numerical computer models quantifying value factors and capture prices. The authors agree on the general dynamic of shrinking value factors of wind and PV with a growing market share of the respective generation technology (Green and Vasilakos, 2010; Hirth, 2016b, 2015, 2013; Hirth and Müller, 2016; Höfling, 2013; Kopp et al., 2012; Mills and Wiser, 2014a, 2014b, 2012; Obersteiner and Saguan, 2009; Odeh and Watts, 2019; Riva et al., 2017; Sioshansi, 2011; Valenzuela and Wang, 2011; Winkler et al., 2016). The models the researchers use differ amongst other things in their scope, input data, accuracy, time and geographical resolution. As a result, computed value factors also differ – yet the principle of lower value factors at higher penetration rates is a core commonality.

Fewer authors have researched what factors other than the penetration rate or market share drive the value factor of wind or PV. Winkler et al. (2016) model a range of scenarios and find that CO_2- and fuel prices influence not only base prices but also value factors of PV and wind significantly. In their greenfield setting, (i.e. without a given power plant portfolio) the scenario-dependent conventional capacity portfolios also comprise an influential factor. Hirth (2013) analyses a range of PV and wind value factors influencing parameters in North-western Europe. He observes that fuel price variations can have different effects on value factors depending first and foremost on scenarios and scenario-dependent conventional capacity mixes, which means that higher fuel prices may result in lower value factors of renewables (Hirth, 2013). Similarly, in his analysis higher carbon prices can result in lower wind value factors, even though lower carbon prices strictly lead to reduced value factors of wind and PV (Hirth, 2013). A number of these findings – of both Winkler et al. (2016) and Hirth (2013) –

stem *inter alia* from model built conventional capacity parks that in some cases are far from real-world settings in Europe.

This is a central aspect in which our analysis differs from those of Winkler et al. (2016) and Hirth (2013), as the capacity mix in our model computations is not greenfield but based on the current (2019) European power plant portfolio and further (less radical) developments. We therefore try to stay closer to a real-world setting and expected developments. To this end, the sensitivities researched such as fuel and CO_2 price changes are less extreme than in the two analyses described, which is also what Winkler et al. articulate a call for (Winkler et al., 2016). The models used differ in their geographical scope. Whereas we model 20 interconnected European countries, Hirth models six and Winkler et al. no specific countries (Hirth, 2013; Winkler et al., 2016)[55]. A wider geographical approach is useful as other research has found that value factors of renewables can profit from flexible generation (such as flexible hydropower in the Alps or Nordics) and higher interconnector capacities (Hirth, 2016b; Mills and Wiser, 2014a; Riva et al., 2017).

Given the rapid deployment of wind and PV in Europe and changes in deployment projections over the last years, it is prudent to analyse value factors of wind and PV using newer, more up-to-date data. Offshore wind in particular has matured as a generation technology over the last years and experienced significant cost reductions, becoming most evident in several recent tenders in Germany, Denmark, the United Kingdom and the Netherlands. We will therefore evaluate offshore wind value factors in the same way as onshore wind and PV – which not all previous studies were able to do.

7.3 Methodology

It is the objective of this work to acquire insights into the driving factors of value factors and capture prices of variable renewable generation, i.e. PV and onshore and offshore wind. In order to do so, the authors use the techno-economic model Green-X[56] to model the European power market. The modelling process incorporates the dispatch and investment in power plants, minimisation of total investment costs as well as production and trade decisions, all with a range of technical constraints. In economic terms, the model is a partial equilibrium model of wholesale electricity markets, focussing on the supply side. It includes an up-to-date power plant database[57] of all 20 countries including plants that are planned or set to be decommissioned, as well as an up-to-date database of all interconnectors among those countries.

[55] For further model specific descriptions see Winkler et al. (2016) and Hirth (2013).

[56] Green-X is a fundamental power model covering 20 interconnected European countries. It allows for the investigation of future deployments in the power and renewable sector including accompanying costs and benefits. It enables the derivation of a detailed quantitative assessment of renewable electricity sources deployed in a real-world policy context on a national and European level for the power, heat and transport sectors. It has been successfully applied for the European Commission within several tenders and research projects to assess the feasibility of '20% renewable electricity sources by 2020' and for assessments of its developments beyond that time horizon. In addition, Green-X can be used for a detailed quantitative assessment of the hourly market prices of the European power markets (Everts et al., 2016; Huber, 2004).

[57] Small-scale plants and non-hydro renewables are grouped into clusters.

Aside from the Green-X model power plant database, the model also adds further capacities endogenously. The endogenous capacity additions are based on economic criteria with support schemes and political frameworks taken into account, which is especially important for renewable technologies; first and foremost wind and photovoltaics.

The actual modelling can be described as a three-level process. In a first step, the endogenous and exogenous capacity additions/deductions (the latter from the aforementioned power plant database) are determined. The second step consists of computing the hourly power plant dispatch based on the determined power plant portfolio (taking into consideration interconnector capacities, power plant availability and power demand). A marginal cost-based merit order curve determines the marginal power plants for every hour in addition to country-specific power prices. The third step examines the economic viability of new power plants and calculates final market prices. For the latter, the model also estimates incomes from ancillary services based on information provided by TSOs (on historic ancillary services).

The model was calibrated in a way so as to most accurately represent the current European power market and replicate hourly day-ahead prices on the power exchanges. As far as market data are available, market data are used for most primary energy sources that were taken from the Intercontinental Exchange (ICE) at the time of the modelling (autumn of 2019).

For transfer capacities between countries, the model uses current data and planned additions from the European network of transmission system operators for electricity (ENTSO-E). Within countries, the model assumes that no congestions exist. To model yearly power demand, historic GDP and power consumption data of different providers are used for an accurate calibration. The influence of energy policies on power consumption such as increases and reductions in demand through the deployment of electric vehicles or energy saving measures is taken into account. For the modelling of the hourly demand, the model uses historic load profiles, whereby changes in consumption behaviour are considered.

For this research, a series of model runs covering a time horizon from 2019 to 2050 were completed. A base scenario functions as a reference and a series of runs simulate different developments. These are higher and lower natural gas, coal and carbon prices[58] as well as higher and lower wind and/or PV production. *Ceteris paribus* these input factors (natural gas, coal and CO_2 prices) were, respectively, varied by 2, 5 and 10 EUR_{2018}/MWh_{th} (natural gas), by 2 and 4 EUR_{2018}/MWh[59] (hard coal) and by 5, 10, 15 and 20 EUR_{2018}/tCO_2 (CO_2) to observe subsequent changes of value factors. These changes always relate to the reference scenario, i.e. the variations of prices apply to the prices used in the reference scenario.

As for renewable production, we modelled 10 per cent variations of yearly production of: wind (both onshore and offshore), PV, wind onshore only, and wind (onshore and offshore) together with PV. It should be noted that the capture prices across the scenarios are not comparable, since base prices are not constant across the scenarios. Instead we use annual value factors to determine the influence of the different parameters as they reflect a relative rather than an absolute value. By subtracting the reference scenario value factor for every

[58] more specifically European Union Emission Trading Scheme (EU ETS) European Union Allowances (EUAs) prices.

[59] Prices for hard coal with a calorific value of 6000 kcal/kg in USD/t were converted to EUR/MWh with a calorific value of 7000 kcal/kg using an FX rate of 1.15 EUR-USD and a conversation factor of 6.98. A change of 4 EUR/MWh represents a relative variation of approximately 40 per cent at current prices.

generation technology from the corresponding scenario-specific value factor, we obtain a figure indicating the changed parameter's influence on the value factor. The value factors are set together by the average capture prices of the specific generation technology and the base price of the researched scenario.

Last but not least, one crucial element driving capture prices of variable renewables is the weather. In order to ensure comparability, all aforementioned scenarios were modelled using the same typical year with respect to solar radiation, wind speeds, and hydrological conditions. Nevertheless, we analysed 30 years of weather data to assess ranges of full load hours for wind and PV. The results of this analysis are then compared and set in relation to researched drivers of wind and PV cannibalisation.

7.4 Results

This section presents how wind and PV value factors and capture prices are influenced by different drivers. First, the impact of fuel prices (natural gas and coal prices) are analysed before the influence of carbon prices is evaluated. The last drivers that are analysed are different availabilities of PV, followed by wind, and finally wind and PV combined.

7.4.1 Natural gas prices

In order to assess the influence of natural gas prices on value factors of wind and PV, six scenarios with a natural gas price variation of 2, 5 and 10 EUR_{2018}/MWh_{th} were modelled. The expectations were that natural gas price changes have a significant impact on wind and PV capture prices – given that natural gas-fired power plants are usually regarded as the most influential price-setting technology on many European power markets (Blume-Werry et al., 2018; Genoese et al., 2015; Roques et al., 2008). A subsequent question is how this impact on capture prices and power prices generally translates into value factors.

We find that natural gas prices have indeed a very significant impact on value factors of PV as well as onshore and offshore wind turbines. Across different modelled countries, higher natural gas prices lead to lower value factors of all three generation technologies. This happens even though absolute capture prices of the technologies rise due to a higher overall power price level as a result of the increased natural gas price. However, PV and wind producers profit less from this overall higher price level than baseload producers[60], which is why one can observe shrinking value factors. The discrepancy between value factors of the reference scenario and the scenarios with higher and lower natural gas prices grows over time.

The reason for this is that during times when there is less renewable production, the merit order curve shifts to the left as we observe a reverse merit-order effect. Consequently, prices tend to be higher during times of low renewable infeed. With growing penetration of renewables, this effect becomes more pronounced over time, i.e. value factors shrink as more renewables are deployed in decarbonising power systems. It should be emphasised that this market phenomenon is not exclusive to scenarios with altered natural gas prices.

[60] With the notable exception of gas-fired generators who incur higher costs in the scenario with higher natural gas prices.

With respect to higher and lower natural gas prices, we can differentiate between two effects on value factors. The first relates to hourly price setting. Hours during which natural gas-fired power plants set the price become more expensive in the event of higher natural gas prices. During these hours there tends to be a lower renewable infeed –the significant differences between power systems notwithstanding. This means that a wind or PV operator may profit less from higher prices than a peak-load or even a base-load generator[60] and we observe lower value factors than in the reference scenario. Vice-versa cheaper natural gas prices consequently trigger higher PV and wind value factors.

The second effect relates to developments of power generation portfolios over time and the growing decarbonisation of power systems. In the scenario with lower natural gas prices, more natural gas-fired capacities remain in the system compared with the reference scenario. These resulting different generation portfolios are a profound driver of renewable value factors. This means that higher value factors for renewables in this period are partly due to less renewable deployment and thus less cannibalisation than in the reference scenario, which is an indirect result of the lower natural gas prices. Vice versa, in case of higher natural gas prices, natural gas-fired generation is lower than in the reference scenario and slightly more wind and PV capacities are deployed. This causes a higher cannibalisation of value factors than in the reference scenario.

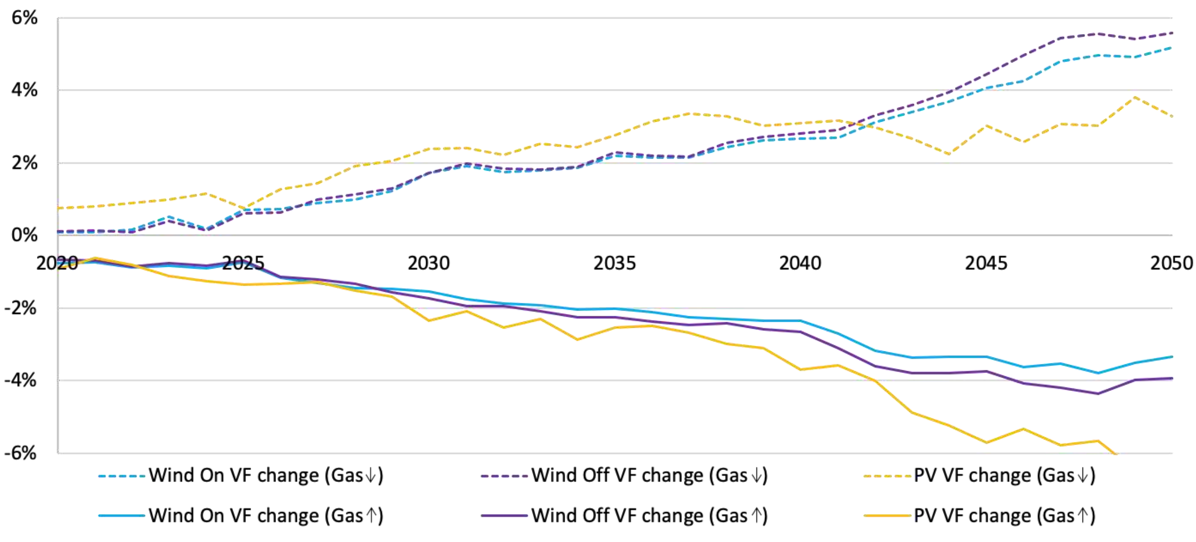

Figure 21: Changes of wind and PV value factors (VF) to the reference scenario at higher and lower natural gas prices (± 5 EUR$_{2018}$/MWh$_{th}$). Natural gas prices variations have significant effects on both wind and PV value factors in Germany. Value factors rise compared with the reference scenario in case of lower natural gas prices (dotted lines) and decline in the scenario of higher natural gas prices (solid lines)

Altogether natural gas price changes have notable effects on the value factors of wind and PV. This mainly stems from the fact that natural gas is an important price-setting technology on many power markets, thereby influencing general power price levels. In all cases, higher natural gas prices lead to lower value factors and vice versa. This shows that even though capture prices rise following higher natural gas prices, renewable producers profit less than baseload producers.[60] In most cases, PV value factors tend to be slightly more affected by natural gas price changes than wind value factors. However, this does not hold true for all researched countries. Figure 21 shows the changes in relative wind and PV value factors compared with the reference scenario for Germany. It illustrates that the difference in value factors grows over time, driven as aforementioned partly by different developing power plant portfolios.

In absolute terms, reverse effects take place. As a result of a general higher price level in the scenarios with higher natural gas prices, capture prices of wind and PV are significantly higher than capture prices in the reference scenario. Vice versa, in scenarios with lower natural gas prices, capture prices of wind and PV are also lower. At the beginning of the researched time horizon, a variation of 5 EUR_{2018}/MWh_{th} of natural gas prices results in capture prices approximately 4-8 EUR_{2018}/MWh lower/higher than in the reference scenario. The greater the role of natural gas in a given power system, the larger the change in capture prices. The difference in capture prices compared with the reference scenario declines over time, reaching virtually the level of capture prices in the reference scenario in most researched countries by 2050.

7.4.2 Coal prices

Four scenarios with coal price variations of 2 and 4 EUR_{2018}/MWh show how coal price changes affect value factors of PV panels and wind turbines. Previous studies have shown causal relationships between coal and power prices (Ferkingstad et al., 2011; Mohammadi, 2009; Moutinho et al., 2011). This influence of coal prices on power prices stems *inter alia* from the fact that coal-fired power plants - similar to natural gas-fired power plants - represent an important price-setting technology on several markets. However, many European countries have presented coal phase-outs plans or are discussing ways to replace carbon intensive coal-fired power generation. In this light one can expect coal price variations to have at most negligible effects on wind and PV value factors towards the end of the researched time horizon (up to 2050).

Our results indicate that this is also the case for the near time horizon and that the modelled coal price changes have only marginal effects on PV and wind value factors. This is a notable result given the large, relative variation of coal prices modelled.[9] In countries where coal-fired generation only takes a small share of the generation portfolio, the modelled coal price changes have virtually no effect on value factors of renewables. Yet even in places with significant coal-fired generation such as Poland or Germany, the coal price variations affect PV and wind value factors only marginally (see Figure 22).

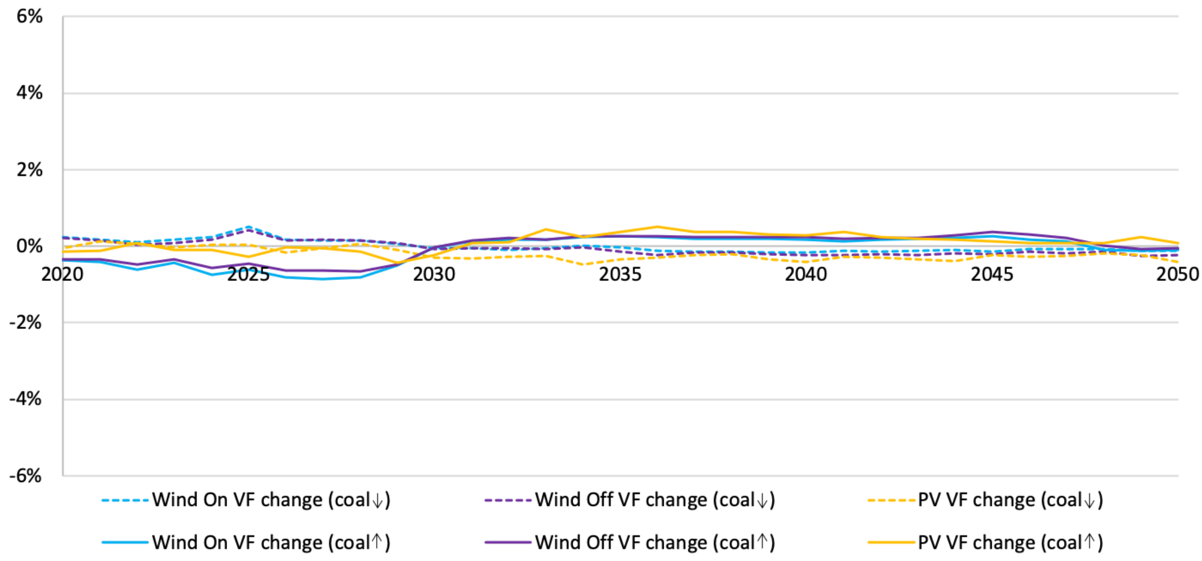

Figure 22: Wind onshore, wind offshore and PV value factors (VF) in Germany are only affected marginally in scenarios with higher (solid lines) and lower (dotted lines) coal prices (± 4 EUR$_{2018}$/MWh) compared with the reference case.

Capture prices, picturing the value of PV and wind in absolute terms, reveal that in the near time horizon (until the mid 2020s), incomes for PV and wind operators are higher in case of higher coal prices and lower in case of lower coal prices. However, the higher coal prices also trigger an accelerated fuel switch (from coal to natural gas-fired generation) compared with the reference scenario, causing the effect to switch into reverse for the second half of the 2020s.

Altogether, the marginal changes of wind and PV value factors show that the renewable capture prices change at a very similar magnitude as the base price. The coal price variations therefore have different effects on wind and PV value factors to natural gas price variations. Whereas we see significant changes in value factors as a result of gas price variations, changes resulting from coal price variations are only marginal and, in many cases, negligible.

7.4.3 Carbon prices

Carbon prices represent a notable share of the marginal costs of fossil fuel-based power plants. An increase or decrease of carbon prices therefore changes the marginal cost of lignite, coal and natural gas-fired power plants and in turn the marginal cost-based bidding prices on power markets. Carbon prices are expected to rise over the next decades to incentivise a further decarbonisation of the power sector and the subsequent question is therefore how carbon price changes affect value factors of variable renewables. Carbon prices were varied by 5, 10, 15 and 20 EUR$_{2018}$/tCO_2 in eight scenarios.

The results show somewhat similar effects on value factors and capture prices as changed natural prices. This is due to the fact that marginal costs of natural gas-fired power plants are set by a combination of natural gas prices and prices for carbon allowances.

The results indicate slightly different effects depending on power systems. In carbon intensive power systems such as Germany or Poland with considerable coal- and lignite-fired generation capacities, higher carbon prices trigger an accelerated fuel switch from coal- and lignite-fired generation towards natural-gas fired generation. Lower carbon prices delay this fuel switch compared with the reference scenario. In less carbon-intensive power systems, the effects on value factors and capture prices do indeed resemble those of varied natural gas prices closely.

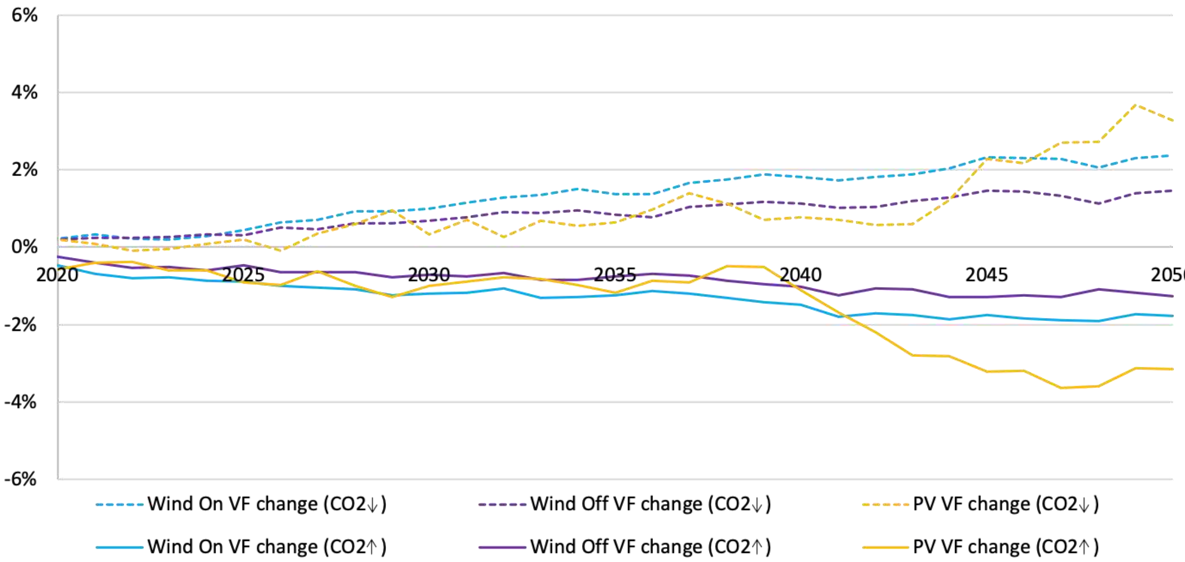

Figure 23: Higher carbon prices (+15 EUR_{2018}/tCO_2) than in the reference scenario trigger lower wind and PV value factors (solid lines) in France whilst lower carbon prices (-15 EUR_{2018}/tCO_2) result in higher value factors (dotted lines) compared with the reference case.

Across the different power systems, higher prices for carbon allowances trigger lower factors of wind and PV and vice versa. PV and wind value factors are affected in a similar fashion with no specific pattern recognisable across the researched countries. The higher and lower value factors compared with the reference scenario are due to the same reasons as in the scenarios with varied natural gas prices (see above).

Additionally, higher and lower prices for carbon allowances also impact the marginal costs of other fossil fuel-based power generation technologies: first and foremost coal- and lignite-fired generation. As discussed, varied marginal costs of coal-fired power plants have little effects on value factors of renewables. The results for countries with a considerable share of lignite-fired generation such as the Czech Republic indicate that this also applies to lignite-fired generation, which is consistent given the baseload production profile of lignite-fired power plants.

Absolute capture prices show that the varied carbon prices change capture prices the most in carbon-intensive power systems. Generally, wind and PV capture prices are significantly higher/lower towards the beginning of the researched time horizon compared with the reference scenario. Analogous to the scenarios with varied natural gas prices, that difference in capture prices declines over time until there is virtually no more difference by 2050.

7.4.4 PV production

In two further scenarios, PV production profiles were increased and decreased by 10 per cent. The results indicate how PV and wind value factors change if PV production was 10 per cent higher or lower compared with the reference scenario. Higher PV production should result in a stronger cannibalisation and thus lower value factors for PV, whilst lower production should increase relative PV value factors compared with the reference scenario.

Indeed, increasing PV production profiles by 10 per cent lowers PV value factors considerably compared with the reference scenario. The opposite can be said for decreased PV production profiles. These effects can be described as significant, with PV value factors being about 4 per cent lower/higher in most researched countries post 2030. In the time horizon until 2030, this effect is weaker since PV capacities are substantially lower compared with later stages of the researched time horizon resulting in lower overall cannibalisation of value factors. The 10 per cent increase (and decrease) of PV production has, of course, the most profound impact on value factors in countries with high shares of PV. In Spain, for example (Figure 24), the impact on PV value factors is stronger than in Poland due to a higher share of PV in the generation mix.

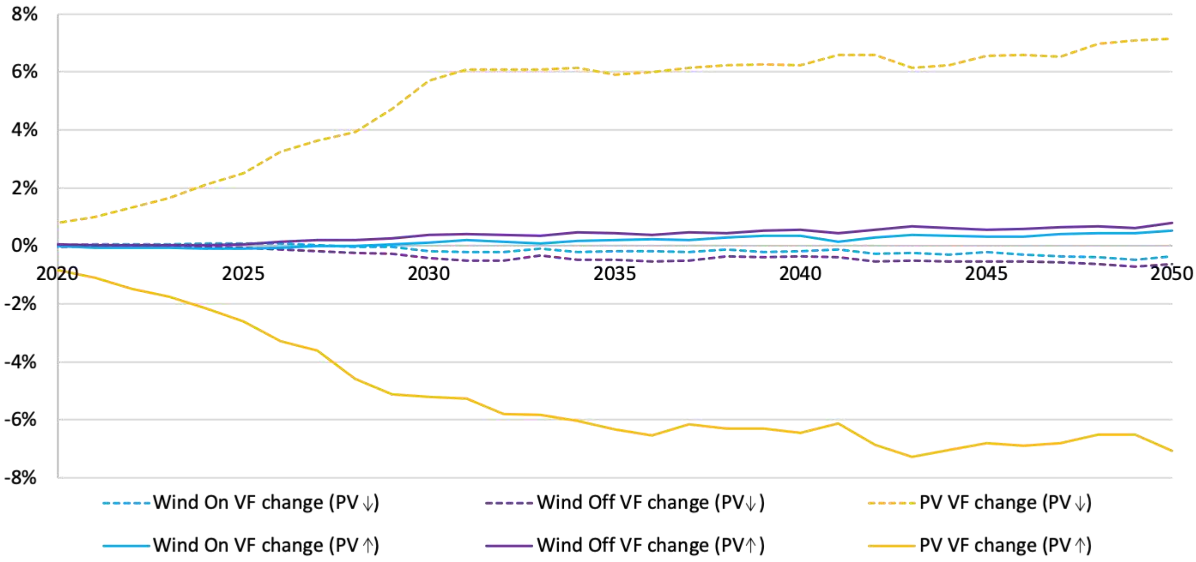

Figure 24: A 10 per cent decrease (dotted lines) and increase (solid lines) of PV production profiles has profound impacts on PV value factors (VF) in Spain compared with the reference scenario. The curves show a steep slope until 2030 and a gentler slope thereafter.

It is noteworthy that the results show a steep slope of decreasing/increasing value factors for the near time horizon (2020-2030). But post-2030 one can observe a plateau in the curve (see Figure 24). The steep slope until 2030 relates to a considerable decline in PV value factors until 2030 in the reference scenario. Whilst current PV value factors are, in most researched countries, around 0.9 to 1, they decline until 2030 to approximately 0.7 to 0.8 due to a substantial increase of PV's share in countries' generation mix. Indeed, our modelled runs indicate a strong growth of PV until about 2030 and a more moderate growth thereafter. Simulating a 10 per cent increase and decrease of PV production profiles hereby shows profound effects on value factors. The plateauing is a result of the modest growth post-2030 which is mirrored in the marginal increase of PV's share in the generation mix.

In terms of onshore and offshore wind value factors, the modelled changes of PV production profiles have only negligible effects. Thus, wind value factors are largely independent of PV production. The results demonstrate that PV cannibalises its own value factors but not those of either onshore or offshore wind.

With respect to capture prices (rather than value factors), one can note that increased or decreased PV production has some effect on wind capture prices. The changes are, however, within those of base prices – which is why the effect does not translate into changes of value factors. A 10 per cent higher PV production slightly lowers base prices (merit-order effect) and with it wind capture prices. Decreased production has reverse effects. In most countries, wind capture prices do not rise or fall more than 1 EUR_{2018}/MWh as a result of the altered PV production. There is virtually no difference between onshore and offshore wind in this respect.

7.4.5 Wind onshore production

Modelled 10 per cent changes of onshore wind production profiles delivered very similar results as the same changes in onshore *and* offshore wind production profiles, due to a strong correlation between onshore and offshore wind. Subsequently, only the results of the runs with combined altered onshore and offshore wind production profiles are presented and discussed as follows.

7.4.6 Wind production (onshore and offshore)

Production profiles or onshore and offshore wind were changed by 10 per cent to observe how value factors react to altered wind productions. These changes are expected to notably influence wind value factors. A subsequent question might be how significant this is, and whether PV factors are also affected.

We find that the changes trigger reduced and increased wind value factors. As expected, reduced wind profiles result in higher and increased wind profiles in lower onshore and offshore value factors. The effect is significant but less marked than the PV profile change for PV value factors. Indeed, wind onshore and offshore value factors change by 1 to 4 per cent depending on the time and country as a consequence of the altered profiles. Generally, the effect is more substantial in systems with a large share of wind in the generation mix, and differences between countries are more evident than in the case of altered PV profiles.

In countries where considerable offshore capacities are installed, offshore and onshore value factors are similarly affected. Elsewhere, the altered profiles have a slightly larger impact on onshore wind value factors. All in all, there is a strong correlation between the two.

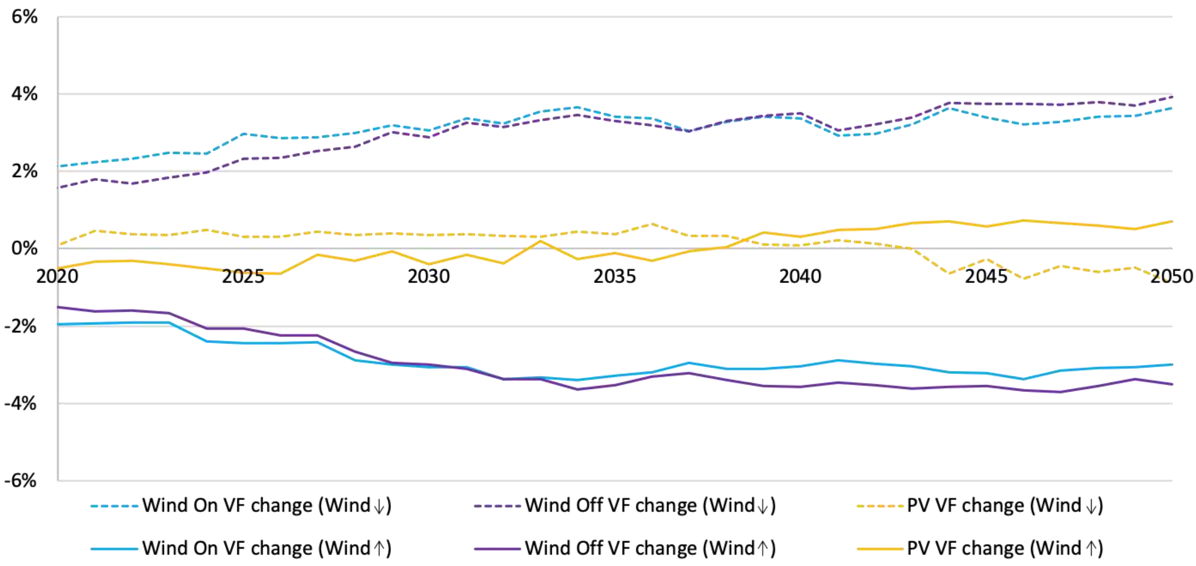

Figure 25: Decreasing wind profiles by 10 per cent (dotted lines) in Germany triggers higher wind value factors (VF) compared with the reference scenario whilst increased wind profiles (solid lines) result in lower wind value factors.

As for PV value factors, one can observe a marginal effect. Even though PV value factors are more affected that wind value factors in the scenarios of altered PV production profiles, there is no distinctive pattern recognisable across researched power systems. The authors therefore attribute the minor effect simply to the larger production volumes of wind compared with PV.

Given that across the different power systems, onshore and offshore wind take a larger share in the generation mix than PV, we observe a greater merit-order effect – and with it greater effects on capture prices. In some central European countries such as Germany and France, PV capture prices change as much as in the scenarios of altered PV profiles.

7.4.7 Renewable production (PV and wind onshore as well as wind offshore)

The final scenarios researched are combinations of increased and decreased wind *and* PV profiles. For these, wind and PV profiles were increased by 10 per cent in one scenario and decreased by 10 per cent in the other, which represents a combination of the scenarios described above. This represents a stronger and weaker renewable deployment than anticipated in the reference scenario.

We find that the changes in relative value factors are almost identical to those of aforementioned scenarios in which only one technology profile (PV *or* wind) was altered. In other words, wind value factors changes are here virtually identical to those in the scenarios with only altered wind profiles. And PV value factors changes are virtually identical to those of the scenarios with only altered PV profiles.

Increasing or decreasing wind and PV profiles by 10 per cent has a greater impact on PV value factors than it does on wind value factors. This is due to the fact that PV generation is concentrated in less hours per year compared with wind generation. Whilst there is a plateauing effect for PV value factors post-2030 (see above), the change in wind value factors compared with the reference scenario grows over time with increasing shares of wind in generation mixes – yet stays below that of PV. The higher the share of wind or PV in a power system, the greater the change in value factors following a 10 per cent alteration of generation profiles.

The fact that the changes in value factors are almost identical to those of the previously described scenarios with only one (PV or wind) altered generation profile indicates that there is no significant cross cannibalisation of wind and PV. However, this only holds true in relative terms. With respect to absolute capture prices, there is a merit-order effect impacting both PV and wind, as observed previously.

The magnitude of this merit-order effect is almost exactly the sum of the merit-order effects noted in the scenarios of altered wind and PV production profiles. Ergo, the merit-order effects (and reversed merit-order effects) cumulate.

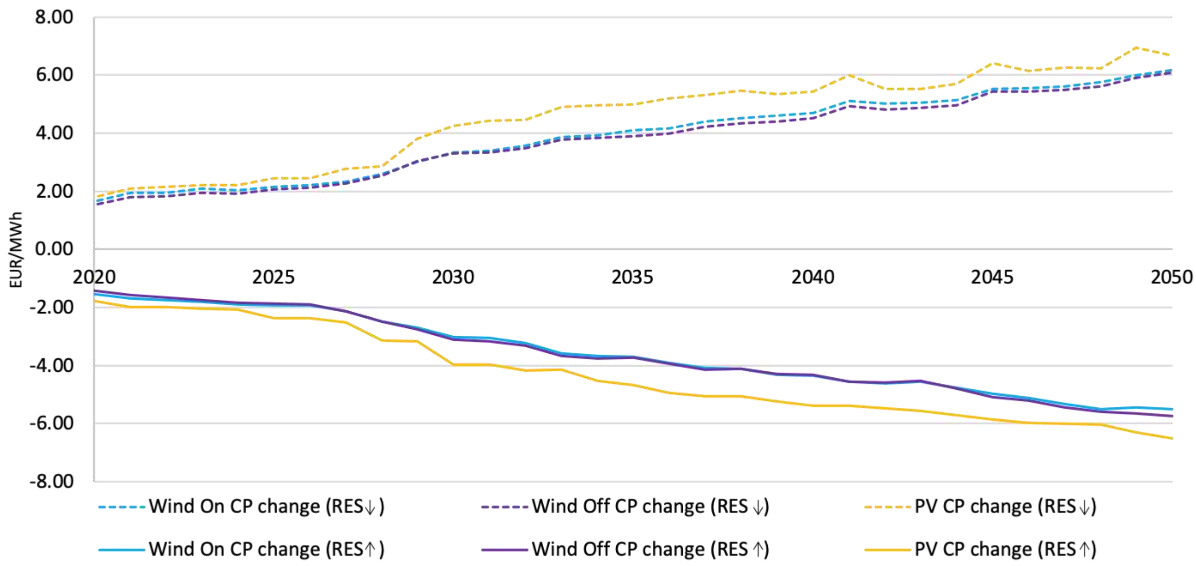

Figure 26: Changes in French wind and PV capture prices (CP) compared with the reference scenario in EUR_{2018}/MWh. In the scenario with a ten per cent decrease in wind and PV (RES) profiles (dotted lines) capture prices are higher than in the reference case whereas they are lower in the scenario with a ten per cent increase in wind and PV profiles (solid lines).

Just as for relative value factors, PV capture prices react more sensitively than wind capture prices to the researched changes in generation profiles. However, the difference between the curves is on a smaller scale. Figure 26 shows that changing wind and PV production profiles by 10 per cent has profound impacts on wind and PV capture prices due to cannibalisation and merit-order effects.

7.5 Discussion

The results of the model runs reveal a series of key findings that facilitate our understanding of the drivers of wind and PV value factors and capture prices. Value factors decline with a growing penetration of the respective technology; confirming the results of the aforementioned previous studies. However, factors other than wind and PV penetration rates also drive and influence wind and PV cannibalisation. Natural gas and carbon prices are significant drivers of wind and PV value factors and capture prices, whilst the influence of coal prices is limited.

Regarding renewable deployments, we observe significant changes to value factors and capture prices as a result of increasing or decreasing wind and/or PV profiles by 10 per cent. This means that regulatory changes for instance that may spur higher or lower wind or PV deployments (and with it, total production volumes of wind or PV) than anticipated have substantial effects on revenues of wind or PV operators. For them the cannibalisation risk is therefore substantial, yet market risks such as uncertainties regarding natural gas prices are also considerable.

We find a high degree of correlation between onshore and offshore wind value factors as they react very similarly to natural gas, coal and carbon price changes as well as changes in wind and PV production profiles. Depending on the power system and parameter researched (natural gas, coal and carbon prices), PV value factors may diverge from wind value factors – yet altogether they share the general trend and react similarly to natural gas, coal and carbon price variations.

One can attribute the changes of value factors in the scenarios with varied natural gas and carbon prices to two market effects. The first relates to the production profile of natural gas-fired power plants. The variations of natural gas and carbon prices change the marginal costs of gas-fired power plants, which are commonly regarded as the most important price-setting technology on European power markets. Notwithstanding considerable differences among power systems, renewable infeed tends to be lower than average during hours when natural gas-fired power plants set the price. Hence, factors that change the marginal costs of natural gas-fired power plants upwards – such as higher natural gas and carbon prices – drive renewable value factors down and vice versa.

The second market effect and the more impacting driver relates to developing power plant portfolio in the researched scenarios. Higher natural gas and carbon prices indirectly trigger more model endogenous renewable deployment than in the reference scenario. As a result, there is a higher cannibalisation and lower value factors, whilst the reserve effect is taking place in the scenarios with lower natural gas and carbon prices. However, it was not within the scope of this study to quantifiably differentiate between these direct and indirect market effects. Further research could contribute to a deeper understanding of the matter.

A key finding with respect to absolute capture prices is that in power systems with a large share of wind in the generation mix – such as those of Germany, the United Kingdom and Denmark - a 10 per cent increase/decrease of wind production profiles affects PV capture prices as much as a 10 per cent increase/decrease of PV production profiles. This means that PV project risk analyses should pay attention to potential divergences of wind deployment with the anticipated deployment path, since it has a significant impact on the profitability of PV projects. In other words, the merit-order effect of additional wind deployment may affect the revenues of PV operators as much as the cannibalisation effect *and* merit-order effect of additional PV deployment put together.

The merit-order effect that comes with increased PV production is less substantial due to the smaller share of PV in the generation mix of most European power systems and, ergo, has a less profound effect on the profitability of wind projects.

A subsequent question might be how the discussed drivers of value factors compare with the most natural driver, the weather. An analysis of 30 years of weather data for the researched countries reveals bandwidths of wind and PV availabilities. We find a bandwidth of approximately 10 per cent for PV and approximately 15 per cent for onshore as well as offshore wind. In other words, over 30 years yearly PV full load hours diverge about five per cent from the average value, whilst yearly onshore and offshore wind full load hours diverge slightly more. There are, by all means, differences among the researched power systems (i.e. in Spain, Portugal and Italy there is a lower bandwidth for PV) yet across the 20 researched European countries the aforementioned bandwidths can serve as a general orientation. The naturally occurring yearly production fluctuation is therefore within the realm of the researched/discussed 10 per cent production profile variations. In the short run, the weather can therefore be a very influential driver of PV and wind value factors and capture prices.

7.6 Conclusions

The objective of this study was to analyse different drivers of cannibalisation to obtain a clearer picture of how different factors influence the cannibalisation of wind and PV in Europe.

The results demonstrate that changes in natural gas prices substantially influence value factors and capture prices. Generally, wind and PV operators profit less from higher natural gas or carbon prices than pure baseload producers[61], as capture prices rise less than the base price. Vice versa, in the instance of lower natural gas or carbon prices, value factors of wind and PV rise, i.e. wind and PV capture prices fall less than the base price. In contrast to natural gas, coal price alterations comprise another driver in this research, and have only very limited influence on wind and PV value factors.

Changes in production profiles by 10 per cent – reflecting (slightly) higher or lower PV and wind deployments – have significant impacts on wind and PV value factors and capture prices and thus on the incomes of wind and PV operators. We find no significant cross cannibalisation of wind and PV. Changes in PV production profiles have no effects on wind value factors, whilst changes of wind production profiles have only marginal effects on PV value factors. We attribute this marginal effect to the larger share of wind in the generation mix, yet do not consider it as significant.

In absolute terms (i.e. capture prices) the merit-order effects of PV and wind profile changes are substantial. Increasing or decreasing PV and/or wind production profiles by 10 per cent has a measurable merit-order effect or indeed reverse merit-order effect. Even though altered PV production profiles have no effect on wind value factors, the subsequent merit-order effect or reverse merit-order effect influences wind capture prices. Given that wind value factors are not affected, the capture price changes are of the same magnitude as base price changes due to the merit-order effect. For PV producers in countries with a sizeable wind portfolio, the merit-order effect of additional wind production can be greater - in terms of absolute capture prices - than the merit-order effect and cannibalisation effect of additional PV production combined. Hence, PV operators in those markets should follow wind deployment paths even though we find no significant cross-cannibalisation of wind and PV.

Future research in this area might seek to shed light on the impact of increased sector coupling and the accompanying increases in system flexibility on value factors of wind and PV. Indeed, increased flexibility provision might prove an important driver of wind and PV value factors.

[61] With the exception of producers who incur higher costs as a result of higher natural gas or carbon prices.

8 Summary of key findings

The next paragraphs recap key findings of the studies presented, refer back to the core objectives set out in section 1.2, and emphasise the contributions of this thesis.

8.1 Ex-post analysis of wholesale power price drivers

The first discussed study analyses drivers that caused German wholesale power prices to plummet, in order to quantify the impact of different drivers. An objective here was to research how political drivers compare with market effects. The *ex-post* model based on quantitative analyses finds among other elements that the price decline was due to a combination of different political drivers and market-based effects. This challenges the belief that the deployment of low marginal cost renewables in Germany was to blame for price decline and adds new aspects and views to the public debate.

The findings further the knowledge of how different factors influence and affect wholesale power prices by answering the research question on the causes of the wholesale price decline in Germany. Whilst the deployment of wind and PV had a substantial effect, it was - within the researched time period - no greater than the effect stemming from the price decline of primary energy sources, namely natural gas and hard coal. The comparable small downturn in demand had a greater effect than one may have anticipated. Additionally, it was established that carbon prices are a significant driver of wholesale power prices which is why this thesis looked at carbon pricing in greater detail in further studies. These findings have since been backed by other researchers such as Hirth (2017), Bublitz (2017) and Kallabis (2016).

The results illustrate the influence of both political drivers and market effect on wholesale power prices, and indicate that both contributed to the observed price decline. A fall of primary energy prices and weaker demand were the central market effects, whilst renewable support schemes as policy measures led to the aforementioned wind and PV deployment. The additional policy of shutting down nuclear power plants had an upwards effect on power prices as low marginal cost capacities were taken off the market. Carbon prices can arguably be seen either as a political or a market-based driver. Ultimately, the employed policy of multiple steering which introduced a carbon pricing and trading scheme as well as support schemes for renewable energy sources simultaneously failed to deliver the expected results in terms of the energy policy objective triangle of affordability, sustainability and security of supply. The low price environment resulted in greater profitability of coal-fired power plants compared with natural gas-fired power plants. This led to a situation on the power market in which coal-fired power plants recorded high capacity factors while some natural gas-fired power plants were mothballed. As a consequence, the German electricity mix continued to be carbon intensive, hampering the policy objective of sustainability despite investments in renewable energy sources.

8.2 Price setting on European electricity markets

The study focused on the price setting on European power markets. It identified a distinct gap in the literature: many assume and state that coal- and/or natural gas-fired power plants are the price-setting units during most hours of the year without providing evidence for this or looking deeper into price setting beyond referring to observed causal relationships between coal and/or natural gas prices and wholesale power prices. The study quantifies how many hours a year different generation technologies set prices across different markets, and therefore challenges the conventional wisdom.

Even though the study confirms that natural gas-, lignite- and coal-fired power plants provide the price-setting units for the majority of hours a year across all researched countries, it finds a more nuanced picture than the conventional wisdom suggests.

Indeed, it shows a very heterogeneous price setting across different power markets and price levels. Next to the mentioned gas-, lignite and coal-fired power plants, other generation technologies such as hydro storage and pump storage – as well as wind, biomass and nuclear – also take their share in the price setting. Especially in the low price segment, the study finds nuclear and non-hydro renewables setting prices for a considerable share of hours per year. In the higher price segments, hydro storage and pump-storage power plants are major price-setting technologies.

Further findings touch on price setting across borders. The study shows a high level of interconnection between countries. The price setting of some countries can be dominated by (larger) neighbouring countries. This in turn demonstrates that energy policies potentially affecting price-setting mechanisms are of high relevance – not only for the implementing country but also for connected countries.

To this end the study analysed the potential effects of two different carbon price floors. It finds that the general price-setting structure remains largely unaffected by the carbon price floors researched. However, the price floors have significant effects on cross-border flows and carbon emissions as one can observe production shifts to other countries. Carbon price floors as policy measures therefore have impacts beyond the implementing country or countries, and influence in particular the policy objective of sustainability by increasing the marginal costs of carbon-intensive generation technologies.

While not necessarily contradicting the conventional wisdom expressed by Finon (2013), Geiger (2011), Genoese et al (2015) and Pietroni (2017) this study challenges the premise of these arguments related to price-setting technologies. Indeed, it demonstrates that it is not merely coal and natural gas-fired power plants that set prices. The quantification of hours during which different technologies set prices adds a higher level of detail to the subject and fills the identified gap in the literature.

8.3 Case Study: Impact of the German-Austrian bidding zone split on European energy objectives

The case study on the German-Austrian price zone split was conducted at a time when there was great uncertainty on the outcomes of the decision to split the common bidding zone. The study questions how the price zone split impacts the energy policy objectives of the countries in the region and evaluates the price zone split using the energy policy objective triangle as a framework.

It finds that a higher price level in Austria and lower prices in Germany cause the policy objective of affordability to be influenced negatively in Austria and positively in Germany. Neighbouring countries are also affected by the breakup of the common zone, albeit less substantially. The results show slightly higher prices – following the price zone split – in the Czech Republic, Hungary, Slovakia, Slovenia and Switzerland, and slightly lower prices in Belgium, Denmark, Luxembourg, Norway and Sweden.

Regarding the policy objective of security of supply, no noteworthy effects can be reported with the chosen methodology. As for the objective of sustainability the results show higher emissions in Austria and lower emissions in Germany following the price zone split as well as lower emissions overall considering all researched countries.

This case study was one of the first to quantify the potential impacts of the bidding zone split and therefore contributed new insights to the public debate. Indeed, it concludes that the breakup has a positive influence on the objectives of affordability and sustainability for Germany, whilst negatively impacting the same objectives for Austria. The public debate on the price zone split at that time was accompanied by strong interests from numerous market participants. Analysing the effects of the policy decision independent of market participants' interests opened room for more academic discussions on the matter and proved to be a central contribution of the study.

8.4 A unilateral climate and supply market model

The core objectives of this market design study were to explore the challenges of unilateral carbon pricing and come up with a potential market design. The study finds that many policy makers and economists call for unilateral carbon prices in addition to the EU ETS, such as a carbon price floor. However, the challenges of the practical implementation are often neglected. Existing pricing mechanisms such as the British Carbon Price Floor disregard electricity imports (i.e. imports are not charged) resulting in competitive disadvantages for domestic producers. Whilst this is not a detrimental issue for an island power system with limited interconnector capacities, it would result in disproportional disadvantages for domestic producers in more interconnected markets. Ergo, it is not an adequate solution for most central European countries, at least not on a unilateral basis. The central issue with including electricity imports in any carbon pricing schemes is that it easily violates the non-discrimination principle of the WTO.

In order to ensure compliance with WTO principles the authors propose a carbon pricing model that circumvents the aforementioned issue by using Guarantees of Origin. A CO_2 levy is introduced and suppliers are forced to provide a national Guarantee of Origin from a carbon neutral source or pay the CO_2 levy for every unit of electricity delivered. Following this, Guarantees of Origin gain in value equalling that of the CO_2 levy. The so-called climate and supply market model thereby provides additional revenues for carbon neutral production and disincentives power generation from fossil fuels and imports to which the CO_2 levy applies.

In effect, the market design exercise runs through the economic implications of a new policies: in this case, the introduction of a CO_2 levy and an extended role of Guarantees of Origin. In the example presented, the study looks at the costs and benefits that the proposed market design would entail.

The study and the proposed model add new aspects to the public debate on carbon price floors and unilateral carbon pricing initiatives. Further, they raise awareness of legal and economic issues that accompany carbon pricing. The contribution of the study is reflected in the fact that the published book chapter is part of a literature recommendation of the library of the German parliament as concerns the issue of carbon taxation and certificate trading. In Switzerland, the proposed climate and supply market model was discussed and considered by policy makers before the government eventually opted for a strategic reserve and subsidies for hydro power plants to address some of the raised issues.

8.5 Drivers of wind and PV value factors and capture prices

This study researched how future developments affect value factors and capture prices of wind and PV. Although declining wind and PV value factors and capture prices with growing market shares have been researched by numerous scholars, few have looked how other factors affect value factors and capture prices. The study asks how different factors drive wind and PV capture prices and value factors. Analysing the so-called cannibalisation of the technologies by solely looking at the market shares neglects the influence of other drivers. Indeed, the study finds that natural gas and carbon price changes have a significant impact on wind and PV value factors and capture prices. The results demonstrate that wind and PV capture prices react less sensitively to gas and carbon price changes than the base price. This means that wind and PV value factors rise when gas or carbon prices fall, and vice versa. Coal price changes are found to have only marginal effects on wind and PV value factors.

Furthermore, the results indicate that there is no cross-cannibalisation between wind and PV in terms of relative value factors. This means that additional wind or PV deployment does not reduce value factors of the other technology. Interestingly enough, this holds true only for relative value factors since in absolute terms (i.e. capture prices) additional wind or PV deployment causes a merit-order effect on capture prices. It is a key finding in this respect that PV capture prices in power markets with a considerable share of wind can be more greatly affected by the merit-order effect of additional wind deployment, than by the combined merit-order effect and cannibalisation effect of additional PV deployment.

The central contribution of this study lies in the research of value factor and capture price drivers that look beyond the market share. Indeed it echoes the call for further research in the area articulated by Winkler et al (2016), who along with Hirth (2013), are some of the few scholars that researched this matter. But the study differs from the research of Winkler et al (2016) and Hirth (2013) in several aspects (see 7.2) and expands the understanding of how different drivers impact capture prices and value factors. Policy makers and investors in wind and PV might take the findings into account when assessing cannibalisation risks and the effects of market and policy developments on revenues of wind and PV operators.

9 Conclusions

Overall, this thesis set out to explore how energy policy affects and shapes the market. The thesis intended to examine the consequences of political and regulatory decisions or potential policies and market designs. The work aimed to further public debate that accompany or precede political decisions and contribute to the field of study by providing thorough evaluation of market effects of different energy policies. It explored this objective in the form of different studies with varied questions on the outcomes of energy policies and market effects on power markets

The results demonstrate that some of the decisions researched trigger more fundamental outcomes than others and affect different aspects of the markets. Taking all the chapters into account one can note that power markets are driven by a combination of policies and market effects. The regulatory environment in which European electricity markets are embedded is subject to changing energy policies. The overarching energy policy objective is therefore to provide sustainable, secure and affordable electricity, illustrated in the energy policy objective triangle. With respect to this triangle we find measurable effects of many researched energy policies. Whether the motivation of a policy is primarily technical (e.g. price zone split) or driven by decarbonisation efforts (e.g. carbon price floor), we find notable outcomes on the energy policy objectives.

In particular, the studies show that carbon pricing is a powerful measure with far reaching market effects. Higher carbon prices lead to higher marginal costs for coal- and gas-fired power plants which in turn raise wholesale price levels. This consequently changes the affordability and sustainability of a power system even though the general price setting principles remain largely unaffected. Wind and PV record lower relative value factors yet higher capture prices if carbon prices rise and fossil fuel based generation is disincentivised. Price floors on a unilateral level face significant legal and economic challenges as elaborated earlier. The effectiveness of unilateral action is further questioned by the research result concerning the Dutch carbon price floor, where we find a production shift with reduced emissions in the Netherlands being offset by increased emissions in other European countries. This offset can be prevented if a price floor takes a wider geographical approach. Even if an EU-wide carbon price floor seems currently politically unfeasible, a common price floor of several countries as depicted in the second study is found to reduce overall emissions. It should be noted that this positive influence on the policy objective of sustainability comes at the expense of the objective of affordability.

Another reoccurring theme and influential factor is the deployment of renewable energy sources. This rapid deployment of low marginal cost renewable generation technologies, namely wind and PV, has thus far been primarily down to some form of support scheme, which is why it is regarded as a political measure here. This thesis finds a considerable merit-order effect of deployed wind and PV capacities in the first study. This merit-order effect drives down wholesale prices, thereby appearing to affect the affordability of a system positively. However, depending on the design of relevant support schemes, the costs are in most cases born by final consumers, causing their respective affordability to be impacted negatively. In any case, deployments of wind and PV capacities are found to boost the sustainability of a given power system.

The research result reveal that deployments of wind or PV lead to lower value factors of the respective technology. We find no cross-cannibalisation between the wind and PV in terms of relative value factors. However, we find merit order effects impacting absolute capture prices of both technologies. These results indicate that future cost reductions of wind and PV will to some extent be offset by lower value factors, placing a question mark on the future competitiveness of these technologies. Policy instruments such as carbon price floors or the proposed market design of the climate and supply market model offer solutions for policymakers to address this issue.

In the studies discussed, the thesis underlines the interconnectivity of European power markets. Many energy policies are formulated and implemented on a national level. In many cases, there are EU guidelines and frameworks to which the governments adhere to yet most substantial policies apply primarily to the national level. Across the different studies, this thesis shows that those policies can have effects beyond the implementing state. The study on the price setting of European power markets shows a high level of interconnectivity among European countries and how prices in many countries are set abroad. The results indicate that national policies such as unilateral carbon price floors can be ineffective, resulting in production shifts to other countries and thereby not reducing emissions overall. Indeed, the decision of the German regulator to discontinue the common price zone had effects beyond the German (and Austrian) border(s). The thesis demonstrates that whilst policies are often designed and adopted at the national level, the subsequent market effects go beyond national boundaries. There are questions on the impact of energy policy on the market that remain unanswered. Yet whilst this thesis answers some questions and furthers our understanding of the interplay of energy policy and markets, there remain various limitations.

9.1 Limitations and outlook

First, four of the discussed studies use quantitative data from model simulations. Power market models such as the Green-X model are adequate and available tools used to research power markets and the impacts of energy policy choices on these, yet cannot claim to perfectly represent these markets. Consequently, there are some methodological limitations. For example, power market models fail to integrate macroeconomic phenomena such as general equilibrium effects by depicting only a limited number of markets. Their geographical scope is limited and modellers are still studying the best options to integrate increased flexibility provisions of future power systems into the models. Further, results from power market models such as Green-X depend on a wide range of assumptions and data inputs. The sheer number of assumptions that go into the modelling process make it virtually impossible to communicate them effectively and in a fully transparent manner. It is beneficial if research based on power market models is replicated by other scholars using different power market models that build on different approaches and assumptions. This helps not only to confirm model results but also to verify research results. The results of the first study have been backed by other researchers who researched and modelled the same market phenomenon. The second study was the first to quantify hours to which different generation technologies set prices on European power markets. Here it is appropriate to call for further research of price setting technologies with other power market models to support or challenge the results presented in this thesis.

Second, with regards to empirical issues it should be noted that the analysis of the German-Austrian price zone split was conducted *ex-ante* after the breakup of the common zone was officially decided, but before it actually occurred and framework parameters were set. At the time of writing, the (formerly) common zone has been split for approximately 1.5 years. An *ex-post* analysis of the situation would be a logical subsequent step for providing empirical evidence.

Third, the field of research dealing with the impact of energy policy on the market includes aspects that were not discussed here. Capacity remuneration mechanisms in particular are key political measures with far reaching impacts for power markets. It was not within the scope of this thesis to research the effects different kinds of capacity remuneration mechanisms have and might have on power markets, or how they affect the three objectives of the energy policy objective triangle. Comparing different kind of capacity remuneration mechanisms and their impact on power markets thus represents an area of further research.

Last but not least, researching the effects of energy policy on the market leaves one with several pending thoughts. It is questionable that power markets can sustain long-term the energy-only design, remunerating only power that has been produced. With capacity markets implemented or in the process of being implemented in various countries one can express doubts over the future of energy-only markets. It remains an open question whether energy-only markets with a high share of low marginal cost renewables can provide sufficient investment incentives in storage and flexible generation capacities, whilst delivering competitive prices for the electrification of the heating and transport sectors at the same time. In other words: it remains unclear whether the energy-only market will remain the optimal design option for the provision of secure and sustainable electricity at affordable prices in the coming decades.

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