Considerations for the Regulatory Design of Electricity Markets in Transition

DISSERTATION

zur Erlangung des Grades einer Doktorin

rer. pol.

der Fakultät III - Wirtschaftswissenschaften, Wirtschaftsinformatik
und Wirtschaftsrecht der Universität Siegen

vorgelegt von

Lisa Altvater, M.Sc.

Erstgutachter: Univ.-Prof. Dr. Carsten Hefeker
Zweitgutachter: Univ.-Prof. Dr. Karl-Josef Koch

Datum der Disputation: 1. März 2023

Dekan der Fakultät III: Univ.-Prof. Dr. Marc Hassenzahl

Contents

List of Figures

List of Tables

List of Abbreviations

CCS	Carbon Capture and Storage
CER	Corporate Environmental Responsibility
CfD	Contract for Differences
CO_2	Carbon Dioxide
CSR	Corporate Social Responsibility
EEA	European Energy Agency
EEG	Erneuerbare-Energien-Gesetz (Renewable Energies Act)
EEX	European Energy Exchange
EKC	Environmental Kuznets Curve
ESD	Effort Sharing Decision
ETS	Emissions Trading System
EU	European Union
EUR	Euro
FiT	Feed-in Tariff
GDP	Gross Domestic Product
GHG	Greenhouse Gas Emissions
GWh	Gigawatt Hour
HRG	High Resistance Group
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IR	Inframarginal Rent
kWh	Kilowatt Hour
LCOE	Levelized Cost of Electricity Generation
LRG	Low Resistance Group
MAC	Marginal Abatement Cost
MD	Marginal Damage
MM	Missing Money
MRG	Medium Resistance Group
Mt	Million Ton
MWh	Megawatt Hour

NF_3	Nitrogen Trifluoride
NFFO	Non-Fossil Fuel Obligation
OECD	Organisation for Economic Cooperation and Development
OTC	Over the Counter
PER	Peak Energy Rent
RES	Renewable Energy Sources
RO	Reliability Option
SDG	Sustainable Development Goals
t	Ton
TSO	Transmission System Operator
TWh	Terawatt Hour
UK	United Kingdom
UNFCCC	United Nations Framework Convention on Climate Change
USD	U.S. Dollar

Chapter 1

Overall Introduction

“This is all wrong. I shouldn’t be up here. I should be back in school on the other side of the ocean. [...] You have stolen my dreams and my childhood with your empty words. And yet I’m one of the lucky ones. People are suffering. People are dying. Entire ecosystems are collapsing. We are in the beginning of a mass extinction and all you can talk about is money and fairy tales of eternal economic growth. How dare you! For more than 30 years, the science has been crystal clear. How dare you continue to look away and come here saying that you’re doing enough, when the politics and solutions needed are still nowhere in sight.” (NPR 2019)

The voice of a generation, climate activist Greta Thunberg, calling out country leaders for prioritizing economic growth over the environment even though the planet is in crisis and demanding more action at the 2019 UN climate action summit in New York. The environmental crisis is a result of treating the environment as subordinate to economic interests and assuming that there are no ecological limits to economic growth (Wanner 2015).

Major global environmental threats comprise overconsumption of resources like water, forests and fossil fuels, destruction of ecosystems, unsustainable land use, unabated release of toxins and emissions driving climate change. Steps need to be taken to reduce greenhouse gas emissions, protect endangered species, restrict the depletion of resources and regulate excessive consumption, especially by developed countries. Political intervention so far is criticized, however, for being insufficient. Sustainability and sustainable development are seen as political and normative ideas and not necessarily as precise scientific concepts (Burns 2011).

The planetary boundaries framework attempts to close this gap. Within this approach to global sustainability, nine planetary boundaries are defined with respect to climate change, ocean acidification, stratospheric ozone, biogeochemical nitrogen cycle and phosphorus cycle, global freshwater use, land system change, biological diversity, chemical pollution and atmospheric aerosol loading. The boundaries are interdependent in the sense that transgressing one or several boundaries may lead to transgressing thresholds related to other boundaries leading to non-linear and catastrophic environmental change in the worst case (Rockström et al. 2009). The framework aims to define limits within which it is safe for humanity to operate and develop (Rockström et al. 2009) thereby forming a basis for sustainability governance and policy initiatives (Downing et al. 2019). According to Steffen et al. (2015) four of the nine planetary boundaries (climate change, loss of biosphere integrity which replaces biological diversity, land-system change, altered biogeochemical phosphorus cycle and nitrogen cycle) have been crossed whereas climate change and loss of biosphere integrity are core boundaries and of fundamental importance for environmental stability. Moreover, ecological footprint measures suggest that global resource limits have been reached in 1986. Since then resource use has exceeded biocapacity (Akenji 2014).

The economy and hence economic growth, rely on the ecological system so there cannot be infinite growth on a finite planet (Costanza, Daly, and Bartholomew 1991; Weiss and Cattaneo 2017). But human culture largely depends on short-run payoffs while long-term sustainability issues are mostly ignored (Costanza, Daly, and Bartholomew 1991). The Brundtland hypothesis states that main threats to sustainable development are poverty-driven depletion of environmental resources in developing countries and consumption-driven pollution of the biosphere in developed countries. Consequently, the environment is threatened by the extremes of poverty and affluence alike. Environmental consequences of growth in higher income countries tend to be transferred to either geographically distant members of the current generation or to future generations (Perrings and Ansuategi 2000).

Achieving sustainability is a wicked problem. It requires a multi-dimensional approach covering ecological, social and economic considerations. It is also an inter-temporal and inter-generational problem as it comprises the challenge how to maintain development potentials for current generations without threatening potentials for future generations (Simonis 1990; Illge and Schwarze 2009).

There are two notions of sustainability: weak sustainability and strong sustainability. From a weak sustainability perspective natural goods and services can be substituted by human-made goods and services to a sufficient degree. From a strong sustainability perspective this is not possible (Baumgärtner and Quaas 2010). In the first case, efficiency gains allow for sustainable consumption. In the second case, sufficiency is required (Akenji 2014).

Initially, neoclassical economics neglected environmental conditions before incorporating the concept of externalities in the 1960s after the occurrence of environmental crises as a consequence of high exhaustion of natural resources and industrial pollution (Centemeri 2009). According to neoclassical environmental economics, sustainability does not require restrictions of consumption. Instead it is achievable by fundamental changes of the economic system and the use of the environment (natural resources, air, water, etc.) can be directed to sustainable levels by setting adequate prices (Illge and Schwarze 2009). Attempts to do so, take for instance the European Emissions Trading System (ETS), show that setting the right prices is challenging, though (see Chapter 3). There also seems to be an underlying optimism when it comes to innovation such that once resources are scarce technological progress will provide alternatives (Illge and Schwarze 2009).

Economic growth still plays a key role in the context of sustainability and environmental quality. One can find an increasing number of discussions on green growth and degrowth. Green growth stipulates that economic growth can be decoupled from material throughput and conventional energy use, suggesting that a growth rate exists which is environmentally sustainable (Hoffmann et al. 2011; Jacobs et al. 2012; Wanner 2015). Green growth is supposed to achieve economic, social and environmental sustainability (Wanner 2015).

Related to this notion is the research body on so-called environmental Kuznets curves (EKC). In these studies, see for instance Grossman and Krueger (1995), the authors analyze the relationship between air pollution and some other measures of environmental quality and national GDP. They find an inverted U-shaped relationship; pollution increases with low levels of income and decreases with high levels of income. The EKC theory has been widely contested by scholars who criticize that the identified relationship between economic growth and environmental quality applies only for some pollutants and are not applicable to environmental quality in general (Arrow et al. 1995; Max-Neef 1995; Ekins 1997).

Conversely, supporters of degrowth demand to prioritize human well-being and ecological sustainability as well as social equity over GDP. Declining economic growth is not a goal but an accepted side effect (Schneider, Kallis, and Martinez-Alier 2010; O'Neill 2012). These considerations are largely based on the Easterlin paradox that GDP per capita does not correlate with happiness above a certain level of satisfied basic needs (Schneider, Kallis, and Martinez-Alier 2010). By critics, GDP is seen as a poor indicator for society's progress and social welfare (Simonis 1990; Van den Bergh 2011; Hoffmann et al. 2011; Schmalensee 2012; Jakob and Edenhofer 2014). O'Neill (2012) goes even so far to state that GDP as an indicator has undermined social welfare. Nevertheless, GDP is said to affect all major policy decisions and to be a hurdle to strong environmental policies (Van den Bergh 2011; Brand 2012).

Why is it a hurdle? Measures that are a threat to growth are difficult to enforce politically as growth and employment are core interests of firms and voters. Conventional industries will lose from environmental policies and therefore oppose them (Jacobs et al. 2012).

There is an interesting study by Bujold and Karak (2021) exploring how behavior change can be achieved and scaled using social proof and social pressure. Individuals (in this case farmers) are sorted into groups depending on their level of resistance (low, medium, high), see Figure 1.1. The low resistance group is targeted first as they require minimal evidence to be convinced to adopt a new concept. The medium resistance group is targeted by using the results from the low resistance group as evidence for success. To convince the high resistance group, the low and medium resistance group are leveraged to generate social pressure to adopt the new concept (Bujold and Karak 2021). Increasingly popular lifestyles in developing countries like minimalism, frugality, living in tiny houses and vans, veganism, etc. suggest that people are reshaping their consumption patterns and reevaluate what generates happiness for them. The rising number of firms engaging in sustainable production shows that there is a growing market for sustainable products. A few politicians rethink established concepts as well. New Zealand, Iceland and Scotland shifted their focus from GDP to measures of well-being, like the OECD's well-being measures, as core indicators to assess the country's progress (IWA 2019). Amsterdam is imposing stricter environmental standards on firms and demanding them to be part of the solution instead of opposing them. Maybe the approach to scaling behavior change developed by Bujold and Karak (2021) could be adapted to induce behavior change among policymakers showcasing that enforcing the required rules will not lead to unfavorable outcomes for them.

The multi-faceted discussion underlines that solving the environmental crisis comes with technical, political and social challenges as well as players with partially conflicting interests and incentives. While every player gains from not deteriorating the environment and can contribute to mitigation, the question is which player has the greatest power to enforce action and what are the incentives to do so? In a democratic market economy, there would be continued production only if there was a market for it suggesting that households' choices shape production. But certain decisions are beyond their immediate control. Households are the end consumer but not involved in underlying processes and thus not the most powerful stakeholder in the value chain (Akenji 2014; Levitt 2022). Households have very limited options to contribute and

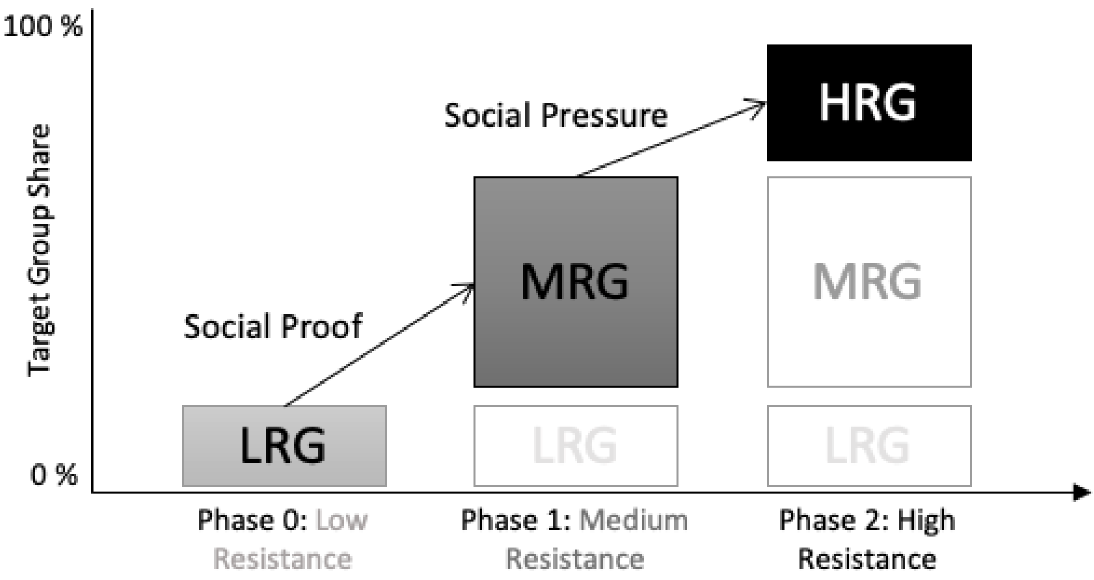

Figure 1.1: Diffusion of behavior change from low (LRG) to high resistance group (HRG) using social proof and social pressure. Illustration adapted from Bujold and Karak (2021).

on a comparably low scale.

Changing production processes and levels are key levers but what are incentives for firms themselves to do so? As of today, in many cases unsustainable production is less expensive as external costs are mostly not priced in or only insufficiently. From an economic perspective, there is no incentive to change production patterns at least not in the short to medium run. There might be moral incentives to switch to sustainable production. Voluntary corporate social responsibility (CSR) or corporate environmental responsibility (CER) concepts have been on the rise (Croson and Treich 2014). Though, for the majority of rather unsustainable firms this seems to be an instrument for signaling green behavior ("green washing") rather than taking action.

Policymakers have the power to set adequate rules. They can make bad options less desirable or take them out of the market and define limits to resource extraction and pollution as has been done successfully in the past, e.g. by rules to reduce air and water pollution and the release of toxins (Akenji 2014; Levitt 2022). They can enforce preventive environmental policy measures instead of reactive ones (Simonis 1990; Costanza, Daly, and Bartholomew 1991). Strong rules could induce the necessary infrastructure change so that primary energy does not release carbon which is the key objective as energy is the backbone of the economy (Levitt 2022).

This transformation does not seem to be delayed because of technical restrictions but rather due to a lack of political will to enforce strong rules and reshape legacy energy systems (Diesendorf and Elliston 2018). Studies show that a 100 % renewable based electricity system is feasible (Diesendorf and Elliston 2018; Kanellopoulos 2018; Zappa, Junginger, and Van Den Broek 2019). Heard et al. (2017) are sceptic and criticize the lack of empirical or historical evidence that proves actual feasibility under realistic conditions. However, Blakers et al. (2019) provide an example with evidence of accelerated deployment of renewables.

Even though several issues, challenges and approaches towards sustainability are still disputed, it is undisputed, however, that a transformation of the electricity sector has to take place to achieve decarbonization. Which will also be fundamental to decarbonizing production processes and additional sectors by electrification. And it is undisputed that countries at large are not doing enough to transform the energy sector, especially the electricity sector, in time. Key questions in this context and in scope of this thesis are:

1. What hampers the transformation process if not technical limitations?
2. What can be done to overcome these impediments?

The technical conditions and implications from an electrical engineering perspective are beyond the scope of this thesis. This thesis analyzes system and market challenges revolving around decarbonizing the electricity sector efficiently and offers policy recommendations and solutions. The thesis contributes to the literature by taking a holistic approach to overcoming the most pressing challenges to decarbonizing electricity sectors. Solutions are illustrated and recommendations provided to accelerate decarbonization while incorporating politically feasibility by considering impacts for households, firms and policymakers.

This thesis is structured as follows. The next Chapter discusses, taking Europe as an example, decarbonization targets, strategies and countries' progress. Based on a descriptive approach it is analyzed whether it can be observed that fossil capacities are phased out, that countries are on track with respect to their decarbonization targets and which countries are high performers when it comes to decarbonization progress. Focusing on the high performers, certain factors discussed in the literature are assessed. Results do not suggest that low energy demand is an enabler, but high energy demand might be an impediment for decarbonization progress. Among the top performing countries, we see countries with high initial shares of fossil capacity which suggest that carbon lock-in is not inevitable. There is no clear pattern regarding the role of nuclear energy as a required low-emission technology for sector transformation. Europe's progress with respect to decarbonization leaves room for improvement. The required sector transformation has not yet taken place in most countries.

Chapter 3 provides basic information on the legacy structure of electricity markets and illustrates challenges that arise from the transformation of electricity markets to meet climate goals. The simplified and generalized descriptions apply to electricity markets with initially rather high shares of fossil energy sources. The fundamentals of an energy exchange are described using the European Energy Exchange as an illustrative example. Next to challenges that arise from an increasing share of renewable energy, mainly missing money and missing flexibility, additional challenges that are relevant in the context of transforming the electricity sector are discussed briefly and clarified by real world examples. Hence, this chapter lays the foundation for a basic understanding of the structure, functioning and challenges of electricity markets that Chapters 4 to 6 build on.

Chapter 4 focuses on today's electricity markets' flaws to provide sufficient investment incentives for new generating capacity. One issue being increased spot market risks. Capacity auctions with reliability options are introduced as a possible instrument to provide those incentives. The auction design and mechanism are formalized and their effectiveness is analyzed with comparative statics. Chapter 4 also answers how these capacity auctions interact with promotion policies for renewable energy, varying emission prices and the existing capacity mix. The analysis shows that capacity auctions provide investment incentives for new capacity. If the electricity market is not distorted, capacity auctions also solve the missing flexibility problem which results from the inability to balance intermittent electricity generation by wind and solar power plants.

Chapter 5 builds on the analysis conducted in Chapter 4. The concept of capacity auctions with reliability options is elevated by accounting for mitigated emissions by the promotion of renewable energy. Paid subsidies for RES-based electricity generation or the levelized costs of electricity generation from RES are used to approximate the true degree of internalization of CO_2 costs. Individual power plant's emission levels are considered and captured by a price markup to cluster them into groups. This ensures that emission-intensive power plants receive lower payments than low-emission power plants. The result is an endogenous discrimination of prices based on emission thresholds. As a consequence, incentives are more efficient to direct the capacity mix to the long-run low-emission equilibrium where discriminated prices converge to one equilibrium capacity price. The system constitutes a powerful regulation to improve and accelerate the transition process of electricity markets.

Chapter 6 develops a reverse auction which accounts for particularities of intermittent RES. Determining the quantity, tendered by the regulator, is internalized and directly linked to two main objectives. On the one hand, the regulator seeks a high share of renewable energy. On the other hand, the regulator wants to limit promotion costs. Determining the target quantity endogenously in contrast to setting the quantity exogenously, constitutes an optimal solution to the regulator's trade off. The design additionally considers regional features such as grid and generating capacity to optimize the deployment of RES from a system's perspective. The mechanism design tackles several shortcomings of current renewable energy auctions employed for instance in Germany.

The last Chapter concludes. Most countries are simply not doing enough when it comes to decarbonization progress and there is a need for more ambitious action. There are major challenges regulators face when transforming electricity sectors: Inadequate targets, conflicting regulation like subsidies for fossil fuels, missing money, missing flexibility, incomplete internalization of emission cost and sub-optimal promotion of RES. These challenges, if not treated effectively, delay and hinder the transformation process. Politically feasible solutions, namely incorporating a target indicator that is robust to demand fluctuations, introducing a capacity auction with features that correct distortions at the electricity market and revising reverse auctions for renewables. Transforming the electricity sector faster and more efficiently is feasible if there is the political will to do so. It seems that political will is the central issue and policymakers are the crucial players to focus on for achieving a needed acceleration of decarbonization.

Policymakers are aware and committed in the sense that they defined climate goals and designed decarbonization strategies. Execution, however, needs significant improvement. Identifying the key obstacles and levers to decarbonization may offer lessons learned for tackling the remaining environmental challenges by efficient policy design. Understanding policymakers incentives is the starting point for deriving strategies to convince them to be willing to enforce needed (but in the eyes of some stakeholders unpopular) change.

Chapter 2

Decarbonization in the EU - Performance, Progress and Patterns

2.1 Introduction

Targets and goals to mitigate climate change have been in place for years. The Kyoto Protocol was adopted in 1997 and became effective in 2005 (United Nations Climate Change 2022). The EU introduced targets in line with the Kyoto Protocol in 2010 (European Commission 2011). Adoption of the so-called Sustainable Development Goals (SDGs) by all member states of the United Nations followed in 2015 (United Nations 2022). Targets and goals are important to hold countries accountable and quantify their progress but without committed execution they are nothing more than empty pledges. More and more people experience the consequences of climate change firsthand as many regions suffer from extreme weather. The Intergovernmental Panel on Climate Change (IPCC) stresses the increased risk for such events to happen more often in the future (European Commission 2021).

The IPCC also highlights that even though the majority of countries worldwide are part of the Kyoto Protocol's successor, the Paris Agreement, net anthropogenic greenhouse gas (GHG) emissions have increased globally across all major sectors since 2010 (IPCC 2022). According to the IPCC (2022), the continued installation of fossil fuel infrastructure is a major impediment to reducing GHG emissions. According to the latest IPCC report, existing policies need to be strengthened with special emphasis on the energy sector which requires major transitions. That means, substantially reducing fossil fuel use, substituting fossil fuels by low-emission energy sources, increasing energy efficiency and promoting energy conservation. Regarding mitigation technologies, wind and solar energy are seen as the most cost effective mitigation measures in the energy sector. Carbon capture and storage (CCS) displays rather low effectiveness at high cost (IPCC 2022). Hopes have been high for CCS technology as it would allow fossil power plants to stay in the market and not require a large-scale transformation of the system. The International Energy Agency (IEA) emphasizes the need for urgent action in this decade to fight climate change, too. The IEA also sees a substantial transformation of the way energy is generated, transported and consumed at the center of required action (International Energy Agency 2021).

The message is clear and there is wide consensus on the need to reduce GHG emissions. The energy sector plays a crucial role in doing so, but progress so far is unsatisfactory and national as well as international politics are falling short to drive decarbonization at the required pace (Papadis and Tsatsaronis 2020; Levitt 2022). But the most important question has not yet been answered: How do we accelerate decarbonization? Is the key challenge about behavior change among consumers, producers or government's willingness to enforce rules? What are the drivers and enablers?

Broadly speaking, technological, economic, social and political aspects matter in the context of decarbonization (Papadis and Tsatsaronis 2020). There are arguments that changing the rules for industries would drive the needed change in infrastructure as examples from the past like rapid progress regarding reducing air and water pollution or toxins has been achieved largely by adequate regulation. In general, consumers buy the end product and have little influence on underlying processes. Therefore, changing laws is seen as the driver for progress (Levitt 2022).

Other driving forces discussed in the literature regarding energy transitions range from a combination of demand-pull and technology-push policies (see Blackburn, Harding, and Moreno-Cruz (2017) for a literature review), over multi-level approaches focusing on the overlap of different systems and developments (Geels et al. 2017; Rockström et al. 2017; Sovacool 2016) to factors like lobbying, quality of governance, political ideology and political support among others (Cadoret and Padovano 2016; Cheon and Urpelainen 2013). In practice, a combination of all these aspects might matter to a varying degree depending on the respective country or region.

The design of sensible targets and accompanying indicators matters as well. Spaiser et al. (2017) investigate potential contradictions in the SDGs. They find that because of the current economic system which is based on growth and consumption, some of the SDGs are incompatible as environmental quality is under-prioritized. Their results show for example that GDP per capita has a mainly negative effect on reducing CO_2 emissions. Another factor is that the SDGs have only a weak theoretical foundation, if any. The authors state that their data-driven approach is limited because of rather poor data quality regarding data on the environment. So, results should be interpreted with caution (Spaiser et al. 2017). Nevertheless, this study mentions two important aspects to be considered; First, targets should not be conflicting. Second, a lack of theoretical foundation may cause problems.

A paper in the literature that analyzes countries' decarbonization progress focusing on the electricity system is the study by De Leon Barido, Avila, and Kammen (2020) who use data mining methods such as visualization, clustering, exploration of relationships and dependencies on eleven global datasets on different indicators to explore factors favoring or hampering decarbonization progress. They define decarbonization progress as the difference between the total percentage of electricity generation from renewable energy sources (RES) other than hydropower at the start and end of the time series. Furthermore, they identify overperformers by clustering countries into two income groups, calculate median income values for each cluster and derive a relative progress score for each country by subtracting the country's individual decarbonization progress from the respective median progress score. The authors identify features that best predict decarbonization progress which they sort along three dimensions:

1. Inherent characteristics: Population, land size, income per capita, inequality, quality of governance, level of foreign energy dependency, level of dependency on resource rents
2. Enabling environments: Renewable energy policies, investments in renewable energy per area and per capita, energy prices
3. Motivations: Social progress, local sustainability, energy independence, climate change mitigation, political leadership

From their analysis, the authors derive hypotheses, suggesting that certain inherent characteristics facilitate decarbonization progress even in the absence of policy measures. They conclude that decarbonization should not solely rely on policies and targets, but take into account country-specific underlying conditions with respect to their defined three dimensions: inherent characteristics, enabling environments and motivations (De Leon Barido, Avila, and Kammen 2020).

In contrast to the paper by De Leon Barido, Avila, and Kammen (2020) this chapter focuses on decarbonization progress in Europe and employs additional indicators next to the share of renewable energy to analyze goals and conditions for decarbonization. Many European countries come from a capacity mix with historically high shares of fossil fuels. As stated above, phasing out fossils and transforming energy sectors is the main challenge today. So looking at Europe might offer valuable insights to derive policy implications that may apply beyond Europe. A larger set of measures for decarbonization is used in the analysis as a higher share of renewables must not lead to a satisfactory phase out of fossil fuels in the short and medium run as the analysis will show. Next to analyzing the main target indicators corresponding to the EU 20-20-20 goals, the analysis includes an indicator for fossil electricity generation capacities as a measure for the true sector transformation as opposed to relying solely on the share of renewables or fossil fuels in energy/electricity supply or demand.

In a first step, countries' progress will be assessed while correcting for distorting effects because of the COVID-19 pandemic that lead to misleading results in 2020. Introducing an additional indicator, installed fossil capacity, which does not respond to demand changes in the short and medium term compared to other generation-based indicators, provides more robust results in assessing countries' decarbonization progress.

While Europe's decarbonization strategy and targets are rooted in straightforward theoretical considerations, the key question is whether the designed strategy and goals lead to action. The analysis shows that there are weaknesses in the current design of the EU's targets and decarbonization strategy. First, as the COVID-19 pandemic caused a decline in economic activity leading to reduced energy demand and hence emissions, including unmodified data for the year 2020 produces misleading results. In the analysis the year 2020 is therefore treated as an outlier to provide a more robust assessment of countries' progress. Second, installed fossil capacity is included as an indicator for sector transformation which is not yet included in the EU's target and supplementary indicators.

The analysis aims to add to the literature by answering the following key questions: Can we observe that fossil capacities are phased out as the major prerequisite to transform the energy system? Are countries on track? Which countries are high performers? Can we observe patterns that are related to the EU's decarbonization strategy in the data? Which policy implications can be drawn from these observations?

The chapter is structured as follows. The next section explains and discusses Europe's decarbonization strategy. Section 2.3 introduces the data, explains the indicators, data preparation and the methodological approach which is based on a descriptive analysis. Section 2.4 presents the main results, finding different evaluations of countries' decarbonization progress when comparing the 20-20-20 target indicators with alternative indicators for decarbonization. Year over year progress with respect to phasing out of fossil fuel capacities is slow for the majority of countries. Only three countries appear in the top performance clusters in both assessment scenarios, revealing weaknesses of the current set of progress indicators. The last section concludes.

2.2 Decarbonization in Europe

The need for a greater sense of urgency with respect to decarbonization is no news in Europe. The European Commission emphasized already in 2011 that more political ambition is required to transform the energy system in time. The EU's 20-20-20 goals were said to be ambitious, even though it was already clear at that time that they alone will not be enough to reach the 2050 decarbonization objective (aiming at less than 50 % of the decarbonization goal set in 2011) (European Commission 2011).

The key aspects of the EU's Energy 2020 strategy are depicted in Figure 2.1. On the highest level, decarbonization can be achieved by either reducing emissions (left branch in Figure 2.1) or removing emissions (right branch in Figure 2.1) or a combination of both which might be necessary in the future (Levitt 2022). The EU's decarbonization strategy focuses on reducing emissions by promoting renewable energy to progressively substitute fossil fuels and reducing energy demand by increasing energy efficiency with defined step-wise targets to be reached by the member countries until 2020, 2030 and 2050. Energy conservation by successful behavior change could also reduce energy demand but prime focus of the EU is on energy efficiency (European Commission 2011).

Back in 2011, the European Commission seemed to have high hopes for CCS technologies to be available by 2030 as they would allow for continued use of coal-fired power plants and put less pressure on transforming the energy system. Coal is seen as adding to a diversified energy portfolio and contributing to security of supply (European Commission 2011). As of today, CCS technology does not seem to be mature and affordable enough to play a major role in the near future (IPCC 2022). In the context of further developing renewables, increasing storage capacities need to accompany the rising deployment of renewables for electricity generation to ensure system stability (European Commission 2011).

The EU's decarbonization strategy is accompanied by the so-called 20-20-20-goals that commit Europe to reduce CO_2 emissions by 20 percent compared to 1990 levels, to increase the share of RES of final energy consumption to 20 percent and to improve energy efficiency by 20 percent until 2020 (European Commission 2017). Climate neutrality (which is the long-term goal), in the absence of CCS technology which is still too immature, implies a nearly 100 percent decarbonization of the electricity sector.

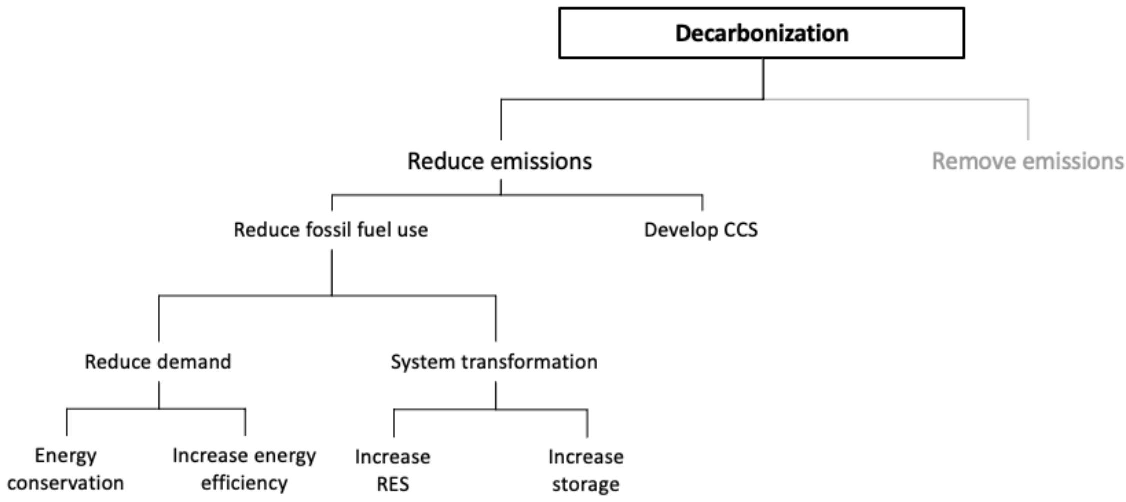

Figure 2.1: Illustration of the EU's decarbonization strategy. Own illustration based on European Commission (2011).

The reasons being, firstly that the sector is the largest source of emissions. Secondly, that it is more difficult to decarbonize other sectors. Thirdly, that decarbonization of other sectors will be based on their electrification once electricity generation is carbon neutral. For instance switching to electric vehicles in the transportation sector (European Commission 2011; IPCC 2022).

There is no contradiction within the EU strategy or goals per se. In theory, this is a sound strategy. Reducing energy demand, relieves pressure from transforming the energy sector as renewable energy and other low-carbon technologies need to substitute existing generating capacities to a lower extent compared to constant or even increasing energy demand. Achieving energy demand reduction by increasing energy efficiency is easier to pursue as it does not require behavior change even if energy conservation would help the cause additionally. Setting targets for renewable energy deployment are easier to enforce politically than targets for phasing out fossil fuels as incumbent industries will oppose such targets strongly. In practice, there are several issues.

First, efficiency increases are slowly reaching thermodynamic limits. Consequently, additional improvements become more expensive and at some point impossible. Second, rebound effects exist creating adverse results in the sense that increased efficiency leads to increasing, not decreasing, energy demand (Papadis and Tsatsaronis 2020). Conversely, according to Papadis and Tsatsaronis (2020) past energy crises have shown that with rising energy prices, energy demand per capita decreases. Consequently, they conclude that energy must become more expensive, for example by introducing a carbon tax.

Third, regarding the strategy and target to promote renewables, it is not clear why deploying renewables will phase out fossil fuels in the absence of targets for phase out. Focusing solely on increasing renewables does not automatically lead to a phase out of fossil fuels as the analysis will show, especially in the absence of energy demand decline. Furthermore, the phasing out of fossils is only captured within the target framework by an indicator that fluctuates with demand (share of fossil fuels in gross available energy). Therefore it is not straightforward to track progress with respect to true sector transformation. Based on these considerations, I would expect countries with a high initial share of fossil fuels not to perform well regarding decarbonization.

In this context it is not surprising that many European countries are not yet committed to phasing out coal. As of 2021, nine out of the 27 member countries have phased out coal, 13 have made national commitments with a specific date, four countries are considering end dates (European Commission 2021). In Poland, Germany, Greece and Croatia new coal-fired capacity has been installed recently or will be installed until 2025 (Kanellopoulos 2018). This also shows in the results of the analysis that follows: These four countries end up in the medium (Croatia, Germany, Poland) or low performance cluster (Greece) in the scenario treating the energy demand shock. Lastly, fossil fuels are still subsidized nationally in some European countries up to this day (EUR 52 billion in 2020) providing incentives that go against the phasing out of fossil fuels and hampering competition for renewables by artificially lowering cost for fossil fuels (European Commission 2021).

The EU 20-20-20 targets implicitly consider economic growth by focusing on energy efficiency and accounting for growth trajectories when setting energy demand targets, even though research suggests that pursuing economic growth and environmental quality at the same time is not feasible. If this was a valid point, this should show in the results of countries' performance.

2.3 Data and Methodology

The analysis is based on annual time series data from Eurostat and the European Environment Agency (EEA) for the EU 27 member countries: Austria, Belgium, Bulgaria, Croatia, Cyprus, Czechia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden.

The Eurostat dataset comprises the following indicators:

- The 20-20-20 target indicators:
  - Greenhouse gas emissions in Effort Sharing Decision (ESD) sectors
  - Primary energy consumption
  - Final energy consumption
  - Share of renewable energy in gross final energy consumption
- Share of fossil fuels in gross available energy
- Fossil electricity production capacities
- Energy productivity
- Total environmental taxes

Data on total emissions according to the United Nations Framework Convention on Climate Change (UNFCCC) are taken from the EEA (EEA 2022).

Greenhouse gas emissions in ESD sectors

This indicator covers emissions per country in million tonnes of CO_2 equivalent under the ESD which sets national annual binding targets for emissions not accounted for by the EU ETS. ESD emissions are calculated by subtracting ETS emissions, CO_2 emissions from domestic aviation and NF_3 emissions from national total emissions. The time period covered in the dataset is 2005 to 2020 with 2020 values being provisional (Eurostat 2022e).

Primary energy consumption

Primary energy consumption captures the gross inland consumption in million tonnes of oil equivalent and constitutes a true measure for energy consumption in the context of the EU 2020 targets. All non-energy use of energy carriers is excluded. The target percentage of savings is calculated by forecasting 2005 values to 2020. The target is reached when actual 2020 values amount to savings of 20 % compared to the forecast values for 2020. The time period covered in the dataset is 1990 to 2020 (Eurostat 2022f).

Final energy consumption

Final energy consumption captures all energy supplied to industry, transportation, households, services and agriculture. It is the final destination of energy use. Deliveries to the energy transformation sector and energy industries themselves are excluded. Calculation and evaluation of the target is the same as for primary energy consumption using forecasts of 2005 values and aiming at a savings level of 20 %. The time period covered in the dataset is 1990 to 2020 (Eurostat 2022d).

Share of renewable energy in gross final energy consumption

This indicator displays the percentage share of energy generated from renewable sources in gross final energy consumption. The target share for the EU overall is 20 %. Individual targets differ to account for country-specific characteristics. Malta has the lowest target share amounting to 10 %. The highest individual target share belongs to Sweden amounting to 49 %. The time period covered in the dataset is 2004 to 2020 (Eurostat 2022h).

Share of fossil fuels in gross available energy

This indicator displays the percentage share of energy generated from fossil fuels in gross final energy consumption. The time period covered in the dataset is 1990 to 2020 (Eurostat 2022g).

Fossil electricity production capacities

This indicator is based on own calculations using Eurostat data on electricity production capacities by main fuel groups and operator in MW (main activity producers and autoproducers). Out of the box there is no fuel group "fossil fuels" as the category combustible fuels includes renewable fuels. To obtain fossil electricity production capacities, total quantities of renewable fuels (solid biofuels, pure biogasoline, pure biodiesels, other liquid biofuels, biogases, waste) are subtracted from total combustible fuels for every year and country. The time period covered in the dataset is 1990 to 2020 but there are missing values in the beginning of the time series for some countries (Bulgaria, Croatia, Cyprus, Estonia, Malta, Slovakia, Slovenia). The time periods for these countries are as follows: Bulgaria (1998 to 2020), Croatia (2005 to 2020), Cyprus (1995 to 2020), Estonia (1999 to 2020), Malta (2006 to 2020), Slovakia (1995 to 2020), Slovenia (1992 to 2020) (Eurostat 2022a).

Energy productivity

This indicator is calculated dividing GDP in million EUR (in chain-linked volumes to the reference year 2010 at 2010 exchange rates) by gross available energy in kilogram of oil equivalent for a given year. Gross available energy is equal to primary production plus recovered and recycled products plus imports minus exports plus stock changes. It is a measure for the productivity of energy consumption to assess the degree of decoupling of energy use from economic growth. The higher the energy productivity value the greater is the degree of decoupling. The time period covered in the dataset is 2000 to 2020 as 2000 is the earliest year available (Eurostat 2022b).

Total environmental taxes

This indicator includes total environmental taxes in million EUR for all economic activities plus households, non-residents and not allocated activities. Values for 2020 are either missing or provisional for most countries in the dataset. Therefore 2020 values are excluded for the analysis. Except for Cyprus, the range of the time series used in the analysis is from 1995 to 2019. In the case of Cyprus the time series starts in 2008 because of missing values (Eurostat 2022c).

Total emissions

This indicator is constructed by combining data on emissions from the EEA greenhouse gas data viewer and proxys for 2020 which are countries' national projections that have been reviewed by the EEA. Total emissions are depicted in tonnes of CO_2 equivalent and include all greenhouse gases. Emissions from international aviation are excluded. The time period covered in the dataset is 1990 to 2020 (EEA 2022).

Methodology

The method applied is based on a descriptive analysis of countries' performance across all indicators over the time series. The analysis studies relative changes to ensure comparability of the 27 countries as countries' levels differ significantly driven by energy demand which depends on population size and economic activity.

In a first step countries' performance regarding the 20-20-20 goals is evaluated by calculating the relative distance to every individual target and ranking countries from highest to lowest achievement. Hence, the country with the greatest overperformance will be ranked in first place while the country with the largest underperformance takes last place. In a second step, the average (mean) ranking of the individual rankings is calculated for a concise evaluation of countries' performance.

In contrast, countries progress regarding the additional indicators reflecting decarbonization is analyzed by calculating the relative change from the start of the time series to 2019 even though in most cases data for 2020 is available. This is done to account for the energy demand shock caused by the COVID-19 pandemic which positively impacts countries' performance as energy demand declined and therefore fossil generation and associated emissions. Energy consumption and emissions are expected to rise again as economic activity bounced back in 2021. Similar developments can be seen for the past financial crisis where energy demand, fossil generation and emissions strongly decreased in 2009 and bounced back afterwards. As energy demand shocks do not strongly impact installed capacity in the short run, initial levels are compared to 2020 levels for the indicator fossil capacity.

Countries' performance is compared for the 20-20-20 target indicators and the additional decarbonization indicators. The analysis also comprises indicators related to technological progress (energy productivity) and tax regulation (environmental taxes) to help identify potential patterns.

In a last step, average relative year over year progress for the period prior to enactement of the 20-20-20 targets and after are calculated for the additional indicators. Both, mean and median progress rates are calculated as to account for outliers, e.g. the financial crisis and the COVID-19 pandemic, with the median being more robust in the presence of outliers. Comparing the two periods might offer insights into the effectiveness of the 20-20-20 targets as binding objectives to drive decarbonization. The aim of this analysis is to shed more light on the true progress of the EU 27 countries regarding decarbonization, hence the introduction of additional indicators.

2.4 Countries' Performance

Overall the EU achieved all the 20-20-20 goals, although some countries missed their individual targets (see Table 2.1). Bulgaria, Cyprus, Germany, Ireland and Malta missed their individual ESD emission reduction targets. Belgium, Bulgaria, Malta and Poland missed their energy efficiency targets with respect to primary energy consumption. Austria, Belgium, Bulgaria, Germany, Hungary, Lithuania, Malta, Slovakia and Sweden missed their energy efficiency targets with respect to final energy consumption. The Netherlands missed its target regarding the share of RES in gross final energy consumption by a very small margin (0.01 % as the relative underachievement compared to the target level) while France missed its target significantly (16.92 % underachievement). In general, countries have been more successful in promoting RES than reducing energy consumption and emissions. 13 countries met all of their individual targets.

The decrease in economic activity caused by the COVID-19 pandemic helped most countries (which otherwise would have missed their individual targets) to achieve the emission reduction and primary/final energy consumption targets (European Commission 2021; International Energy Agency 2022). Energy demand and emissions bounced back strongly in 2021 (International Energy Agency 2022). Overall, progress on decarbonization until now is disappointing. Trends go in the right direction but the level of progress is insufficient to transform the energy sector and achieve the EU's objectives. Looking beyond 2020, national long-term strategies submitted by the member countries are not ambitious enough to collectively achieve the targets set out for 2050 (European Commission 2021).

We want to derive the top performers with respect to the 20-20-20 goals as a baseline to identify potential weaknesses in the target setup. In the cluster of the top 9 performing countries according to the average ranking of countries regarding the EU 2020 indicators (see Table 2.1) are:

1. Greece
2. Croatia
3. Portugal
4. Italy
5. Romania
6. Latvia
7. Slovenia
8. Slovakia
9. Finland

The assessment of the 20-20-20 target achievement is misleading without further analysis because of the effects resulting from the COVID-19 pandemic. Figures 2.2, 2.3, 2.4 show the evolution of primary energy consumption since 1990 for each country. The energy demand shock in 2020 in most countries is clearly visible in those figures.

To check the robustness of the identified top performing countries according to the EU 2020 indicators, we will look at the alternative indicators: total emissions, share of fossil fuels in gross available energy (abbreviated as "share of fossils in available energy" in the tables) and fossil electricity production capacities (abbreviated as "fossil capacity" in the tables). To evaluate countries' performance, we calculate the mean ranking from these alternative indicators and group all countries in three clusters: the 9 top performing countries, the 9 medium performers and the 9 low performers. In a next step we compare the two top performance clusters to see if results differ in both scenarios.

In the cluster of the top 9 performing countries according to their average ranking across the three alternative indicators (in order of their average ranking from 1 to 9) are: Estonia, Denmark, Bulgaria, Romania, Slovakia, Sweden, Lithuania, Finland, Czechia. In the cluster with the medium 9 performing countries (10 to 18 in respective order) are: Latvia, France, Croatia, Hungary, Luxembourg, Italy, Austria, Germany, Poland. In the cluster with the lowest 9 performing countries (19 to 27 in respective order) are: Belgium, Slovenia, Greece, Netherlands, Malta, Ireland, Portugal, Spain, Cyprus.

Those 9 top performers according to the average ranking based on the 20-20-20 target indicators are evenly spread across the three clusters resulting from the alternative ranking. Only Romania, Slovakia and Finland remain in the cluster of the top performing countries (see Table 2.2 where the top 9 performing countries from the first ranking are depicted in bold while the top 9 performing countries from the second ranking are depicted in italics).

While the share of fossil fuels in gross available energy declined for all countries, although to a varying extent, the picture is mixed looking at total emissions and fossil capacity. Total emissions are higher for five countries in 2019 compared to the beginning of the time period (see Table 2.3). Overall, only 14 out of the 27 countries display lower levels of fossil capacity in 2020 than in 1990. Median annual relative changes are low in general and on a significantly lower level than median annual relative additions of RES capacity.

The supposedly strong performance by Greece, Portugal and Slovenia who end up in the low performance cluster in the alternative ranking, tends to be connected to strong energy demand drops in the aftermath of COVID-19 rather than actual decarbonization progress. Greece is performing strong on increasing the share of RES in contrast to the other two countries but this does not yet seem to lead to true sector transformation and lower total emissions resulting from lower shares of fossils

Rank	Country	Emission Target	Primary Energy Consumption Target	Final Energy Consumption Target	Share of RES Target
1	Greece	1 (30.42 %)	5 (20.32 %)	2 (22.12 %)	7 (20.83 %)
2	Croatia	5 (18.02 %)	2 (30.40 %)	13 (7.57 %)	1 (55.12 %)
3	Portugal	3 (20.50 %)	9 (13.16 %)	6 (13.68 %)	12 (9.62 %)
4	Italy	12 (12.76 %)	7 (16.25 %)	3 (17.15 %)	9 (19.76 %)
5	Romania	11 (13.53 %)	3 (28.09 %)	1 (22.34 %)	22 (1.99 %)
6	Latvia	9 (15.47 %)	4 (21.11 %)	4 (14.22 %)	21 (5.33 %)
7	Slovenia	4 (19.52 %)	8 (16.03 %)	5 (13.92 %)	24 (0 %)
8	Slovakia	2 (24.78 %)	13 (7.62 %)	25 (-14.89 %)	5 (23.89 %)
9	Finland	22 (0 %)	6 (16.99 %)	7 (12.81 %)	11 (15.27 %)
10	Estonia	21 (0.99 %)	1 (33.69 %)	18 (0.71 %)	8 (20.28 %)
11	Czechia	16 (4.31 %)	15 (5.38 %)	15 (3.24 %)	3 (33.10 %)
11	Spain	7 (15.56 %)	11 (12.33 %)	12 (7.92 %)	19 (6.10 %)
12	Luxembourg	17 (3.13 %)	10 (12.44 %)	10 (9.29 %)	18 (6.35 %)
12	Sweden	10 (15.30 %)	20 (3.64 %)	19 (-2.08 %)	6 (22.70 %)
13	Denmark	15 (7.00 %)	12 (11.95 %)	11 (8.68 %)	20 (5.49 %)
13	Netherlands	6 (15.83 %)	19 (3.82 %)	8 (12.80 %)	25 (-0.01 %)
14	Cyprus	24 (-2.21 %)	23 (0 %)	9 (12.78 %)	4 (29.84 %)
15	Austria	18 (2.50 %)	14 (5.62 %)	22 (-3.86 %)	13 (7.49 %)
16	Lithuania	14 (8.87 %)	18 (4.15 %)	26 (-23.49 %)	10 (16.40 %)
17	France	13 (10.00 %)	16 (5.25 %)	16 (0.89 %)	26 (-16.92 %)
18	Hungary	8 (15.55 %)	22 (0.87 %)	27 (-25.07 %)	17 (6.54 %)
19	Poland	20 (1.67 %)	24 (-0.13 %)	17 (0.84 %)	14 (7.35 %)
20	Germany	23 (-1.51 %)	17 (5.10 %)	21 (-3.79 %)	15 (7.29 %)
21	Bulgaria	25 (-5.17 %)	26 (-1.72 %)	24 (-10.93 %)	2 (45.74 %)
22	Ireland	27 (-17.63 %)	21 (3.38 %)	14 (4.44 %)	23 (1.00 %)
23	Belgium	19 (2.47 %)	25 (0.41 %)	20 (-2.43 %)	24 (0 %)
24	Malta	26 (-11.43 %)	27 (5.71 %)	23 (-8.00 %)	16 (7.14 %)

Table 2.1: Ranking by average rank with respect to achievement of the 20-20-20 target indicators. Own calculations based on Eurostat data.

in available energy and lower fossil capacity since Greece ranks rather low here (see Table 2.2). The same tendencies can be observed for Italy, even though to a lesser extent, placing Italy in the medium performance cluster in the alternative ranking.

What can be observed focusing on the top 9 performers from the second ranking? Are there patterns regarding energy productivity and environmental taxes in the sense that comparatively strong decarbonization progress tends to be connected to higher energy efficiency and taxes? Does energy intensity play a role, in the sense that the top performers display relatively low demand? Can we observe tendencies regarding carbon lock-in, in the sense that top performers have historically low shares of fossil capacity? And lastly, what role does nuclear energy play? How many of the top performing countries rely on nuclear energy as a low-emission technology next to RES and did nuclear capacity increase?

The distribution of ranks of the top performers is more consistent regarding the alternative indicators in contrast to the EU 2020 indicator ranking. Except for Denmark, Sweden and Finland, the top performers also show comparatively strong progress with respect to energy productivity. The same observation applies to environmental taxes.

With respect to energy demand, the majority of the top 9 performers are sorted into the medium energy demand cluster. Estonia belongs to the low energy demand cluster while Romania and Czechia belong to the high energy demand cluster. However, Romania and Czechia are at the lower end of energy demand levels with energy demand being roughly a seventh of Germany's energy demand and a quarter of France's energy demand. With Germany and France being the two countries with the highest energy demand. These observations may suggest that, low demand does not seem to be an enabler for decarbonization per se but high demand could be an impediment.

Regarding the relevance of carbon lock-in and thus initial shares of fossil capacity, the top performing countries display varying initial shares. Estonia, Denmark and Czechia started with high shares of fossil capacity amounting to ca. 100%, ca. 96 % and ca. 79 % respectively. Data for Bulgaria is incomplete therefore it is sensible to exclude Bulgaria here. Then only two countries, Slovakia and Sweden display very low initial shares of fossil capacity while the rest of the top 9 performing countries places in the middle field. In contrast to my initial expectations, both Estonia and Denmark reduced fossil capacity significantly despite high initial shares, suggesting that there are possibilities to overcome path dependency and carbon lock-in. Based on these findings, the two countries can be labeled as positive deviants and it would be interesting to investigate them in more detail to understand how they managed a comparably strong phase out of fossil fuels.

Rank	Total Emissions	Share of Fossils in Available Energy	Fossil Capacity	Energy Productivity	Environmental Taxes
1	*Estonia*	*Estonia*	*Sweden*	***Romania***	*Estonia*
2	*Lithuania*	***Finland***	*Estonia*	Ireland	**Latvia**
3	***Romania***	*Denmark*	*Bulgaria*	***Slovakia***	*Bulgaria*
4	**Latvia**	**Latvia**	*Denmark*	*Lithuania*	*Lithuania*
5	***Slovakia***	***Romania***	*Lithuania*	*Estonia*	***Romania***
6	*Bulgaria*	***Slovakia***	Luxembourg	*Bulgaria*	Poland
7	*Czechia*	*Bulgaria*	***Slovakia***	Poland	***Slovakia***
8	*Denmark*	*Sweden*	France	*Czechia*	**Croatia**
9	Germany	*Czechia*	**Croatia**	Hungary	Malta
10	Hungary	France	***Romania***	**Latvia**	*Czechia*
11	*Sweden*	**Italy**	***Finland***	**Slovenia**	Hungary
12	***Finland***	Hungary	Austria	*Denmark*	Ireland
13	**Croatia**	**Croatia**	*Czechia*	Cyprus	Netherlands
14	Belgium	Austria	Belgium	*Sweden*	**Slovenia**
15	France	*Lithuania*	Malta	Germany	Belgium
16	**Italy**	Poland	Hungary	**Croatia**	Luxembourg
17	Netherlands	**Greece**	**Slovenia**	Belgium	***Finland***
18	Poland	**Slovenia**	Germany	Netherlands	Austria
19	**Greece**	Ireland	Netherlands	Luxembourg	Spain
20	Malta	Luxembourg	Poland	Spain	**Greece**
21	Luxembourg	**Portugal**	**Italy**	France	**Italy**
22	**Slovenia**	Germany	**Greece**	***Finland***	France
23	Austria	Cyprus	**Latvia**	**Greece**	*Sweden*
24	**Portugal**	Netherlands	Ireland	**Portugal**	**Portugal**
25	Spain	Spain	**Portugal**	**Italy**	*Denmark*
26	Ireland	Malta	Spain	Austria	Germany
27	Cyprus	Belgium	Cyprus	Malta	Cyprus

Table 2.2: Countries' progress on other indicators. Countries are listed according to their respective ranking. The top 9 performing countries according to the average ranking regarding the 20-20-20 targets are depicted in bold. The top 9 performing countries according to the average ranking with respect to the alternative indicators (total emissions, share of fossils in available energy, fossil capacity) are depicted in italics. Own calculation based on Eurostat and EEA data.

Country	Total Emissions	Share of Fossils in Available Energy	Fossil Capacity	Energy Productivity	Environmental Taxes
Austria	1.81 % (23)	-13.76 % (14)	-15.38 % (12)	11.98 % (26)	127.96 % (18)
Belgium	-19.95 % (14)	-3.01 % (27)	-0.86 % (14)	36.36 % (17)	137.28 % (15)
Bulgaria	-44.03 % (6)	-21.11 % (7)	-35.43 % (3)	86.93 % (6)	936.27 % (3)
Croatia	-24.79 % (13)	-14.35 % (13)	-21.55 % (9)	39.56 % (16)	372.83 % (8)
Cyprus	58.67 % (27)	-8.14 % (23)	117.03 % (27)	44.22 % (13)	2.00 % (27)
Czechia	-38.03 % (7)	-19.48 % (9)	-4.96 % (13)	64.20 % (8)	280.98 % (10)
Denmark	-37.58 % (8)	-29.77 % (3)	-31.79 % (4)	46.88 % (12)	67.57 % (25)
Estonia	-64.19 % (1)	-30.05 % (1)	-37.64 % (2)	88.10 % (5)	3373.41 % (1)
Finland	-25.50 % (12)	-30.00 % (2)	-19.32 % (11)	25.73 % (22)	130.40 % (17)
France	-19.86 % (15)	-16.80 % (10)	-23.00 % (8)	30.81 % (21)	84.54 % (22)
Germany	-35.14 % (9)	-8.48 % (22)	27.34 % (18)	41.37 % (15)	45.23 % (26)
Greece	-17.10 % (19)	-11.26 % (17)	62.49 % (22)	22.20 % (23)	115.23 % (20)
Hungary	-32.02 % (10)	-14.66 % (12)	4.37 % (16)	51.58 % (9)	257.11 % (11)
Ireland	9.88 % (26)	-9.69 % (19)	87.22 % (24)	124.88 % (2)	220.55 % (12)
Italy	-19.36 % (16)	-15.44 % (11)	51.21 % (21)	15.97 % (25)	87.98 % (21)
Latvia	-56.98 % (4)	-27.09 % (4)	85.38 % (23)	51.25 % (10)	2345.28 % (2)
Lithuania	-57.38 % (2)	-12.47 % (15)	-29.49 % (5)	99.39 % (4)	859.83 % (4)
Luxembourg	-15.59 % (21)	-8.95 % (20)	-26.52 % (6)	34.19 % (19)	132.83 % (16)
Malta	-16.21 % (20)	-3.27 % (26)	3.33 % (15)	-0.82 % (27)	294.57 % (9)
Netherlands	-18.04 % (17)	-4.72 % (24)	36.24 % (19)	36.29 % (18)	146.38 % (13)
Poland	-17.89 % (18)	-11.55 % (16)	37.05 % (20)	70.48 % (7)	626.32 % (6)
Portugal	8.08 % (24)	-8.81 % (21)	91.89 % (25)	20.49 % (24)	77.77 % (24)
Romania	-57.25 % (3)	-24.17 % (5)	-20.41 % (10)	135.45 % (1)	847.76 % (5)
Slovakia	-45.57 % (5)	-23.68 % (6)	-25.08 % (7)	114.86 % (3)	499.95 % (7)
Slovenia	-8.15 % (22)	-10.65 % (18)	26.55 % (17)	47.67 % (11)	138.81 % (14)
Spain	8.46 % (25)	-4.62 % (25)	100.75 % (26)	32.31 % (20)	120.71 % (19)
Sweden	-28.52 % (11)	-20.35 % (8)	-38.06 % (1)	42.81 % (14)	80.14 % (23)

Table 2.3: Countries' progress on other indicators. Countries are listed in alphabetical order. Progress depicted as relative change from start and end of each country's time series. Rank for the respective indicator in parenthesis. Own calculations based on Eurostat and EEA data.

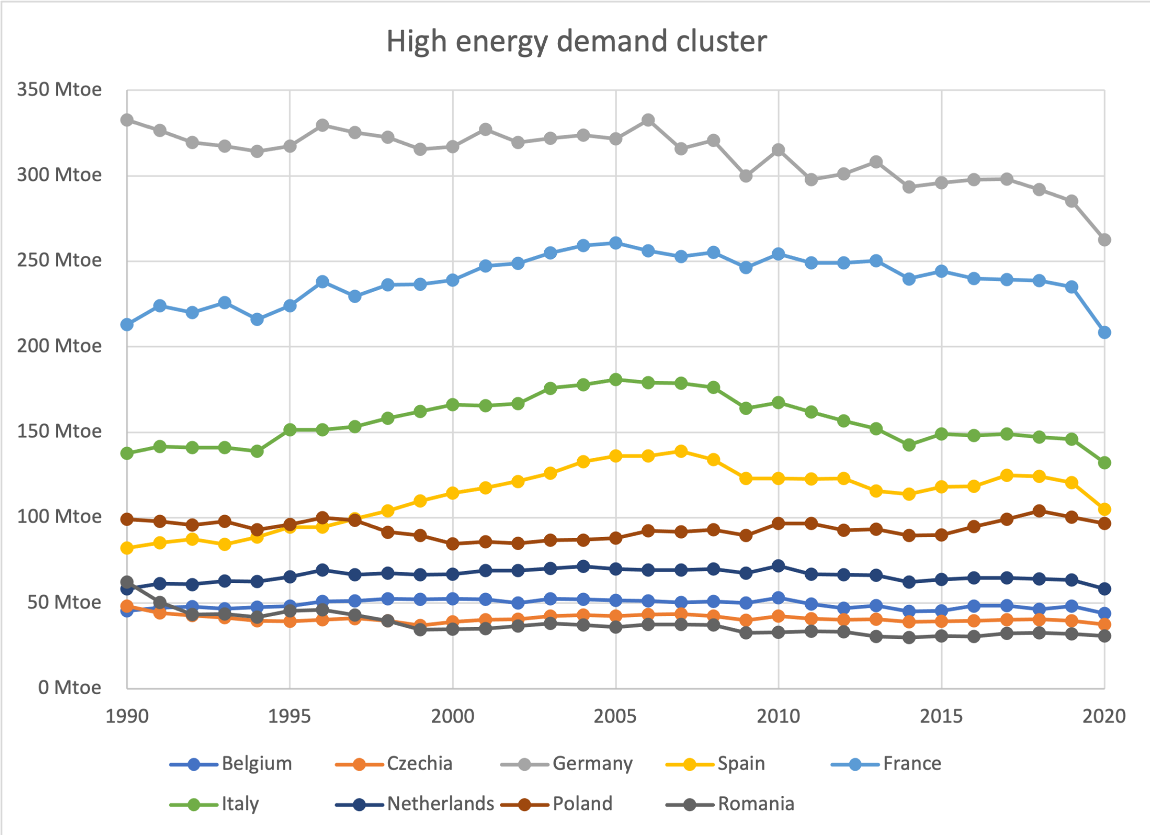

Figure 2.2: Evolution of primary energy consumption for the high energy demand cluster. Countries are grouped by their primary energy consumption in 1990. Own illustration based on Eurostat data.

According to the data on electricity production capacities (Eurostat 2022a), the capacity mix of 6 out of the top 9 performing countries includes or included nuclear energy. Lithuania phased out nuclear energy until 2010. Nuclear capacity is decreasing in Sweden. In Finland, Slovakia and Romania it has been rather constant in recent years. Only in Bulgaria and Czechia nuclear capacity has been (slightly) increasing in recent years. Therefore nuclear energy might be an enabler for the sector transformation, but countries' varying trends (decreasing, constant, increasing capacity levels) suggest that additional factors play a role in this context, too.

Let us compare countries' progress, measured as the mean/median year over year percentage changes in the period prior to the enactement of the 20-20-20 targets and after regarding the alternative decarbonization indicators as well as energy productivity and environmental taxes. I will focus on comparing the median values here as the median is more robust to outliers than the mean. Progress in the second period is stronger for the majority of countries for total emissions, the share of fossil fuels in gross available energy and fossil electricity production capacities. Around half of the countries display stronger progress when it comes to energy productivity. For only five

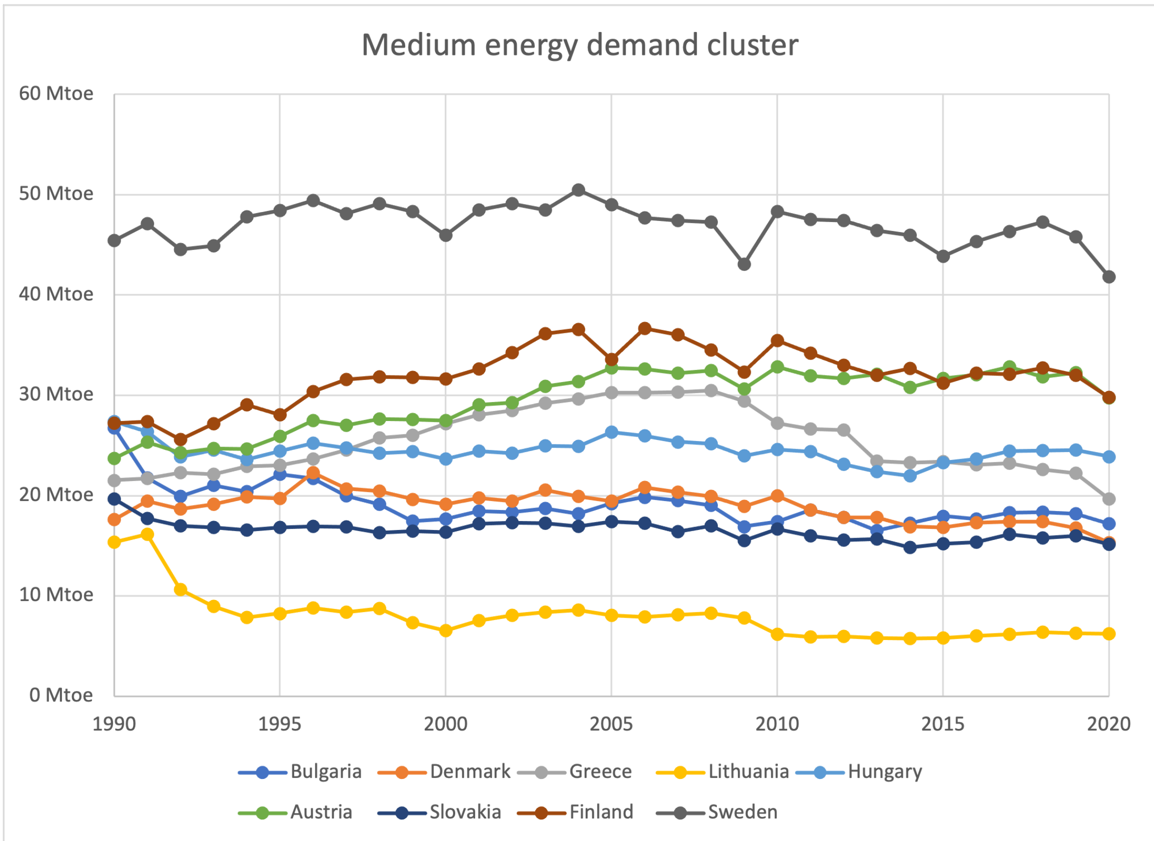

Figure 2.3: Evolution of primary energy consumption for the medium energy demand cluster. Countries are grouped by their primary energy consumption in 1990. Own illustration based on Eurostat data.

countries, the annual median change rate is higher in the second period with respect to environmental taxes.

The majority of the top 9 performing countries (according to the alternative ranking) show stronger progress in the period after enactement of the 20-20-20 targets with respect to the share of fossil fuels in gross available energy, fossil electricity production capacities and total emissions. So, the targets could have provided an incentive for countries to strengthen decarbonization efforts but this simple approach does not allow for strong conclusions. A structural break analysis seems to be more appropriate to analyze the effectiveness of the 20-20-20 targets.

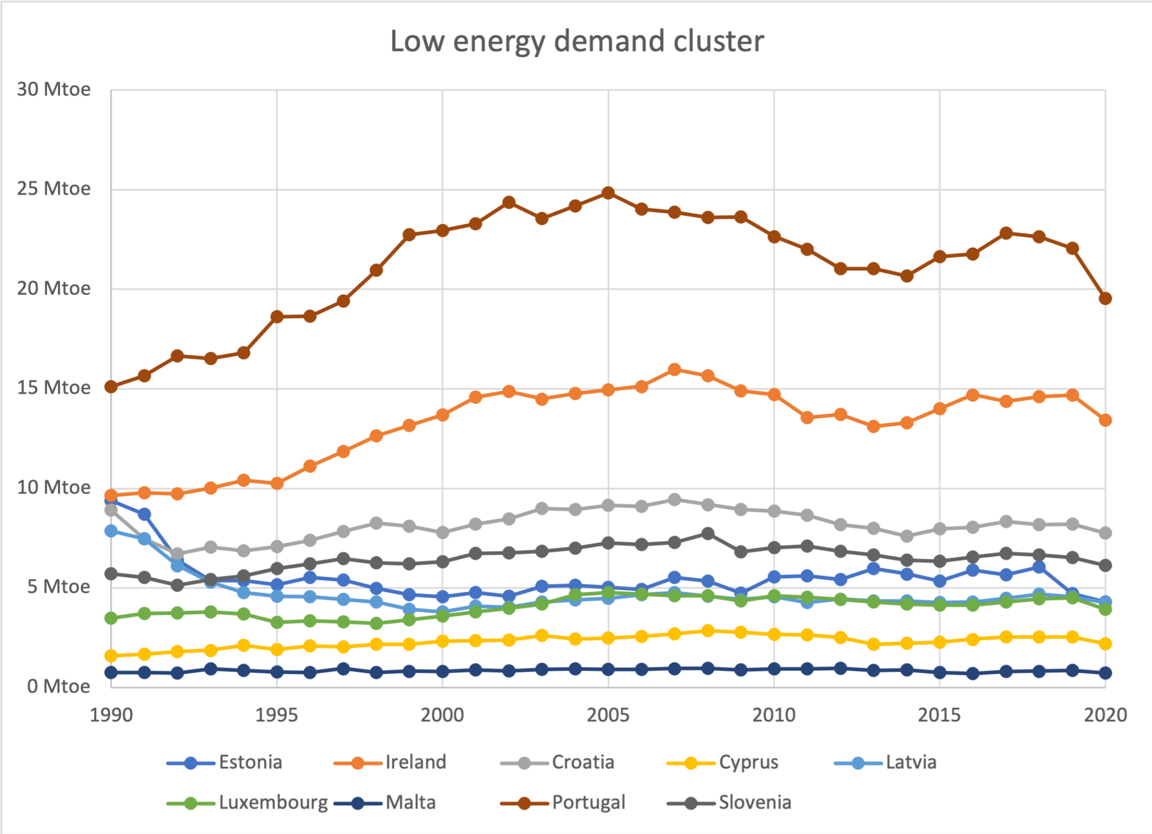

Figure 2.4: Evolution of primary energy consumption for the low energy demand cluster. Countries are grouped by their primary energy consumption in 1990. Own illustration based on Eurostat data.

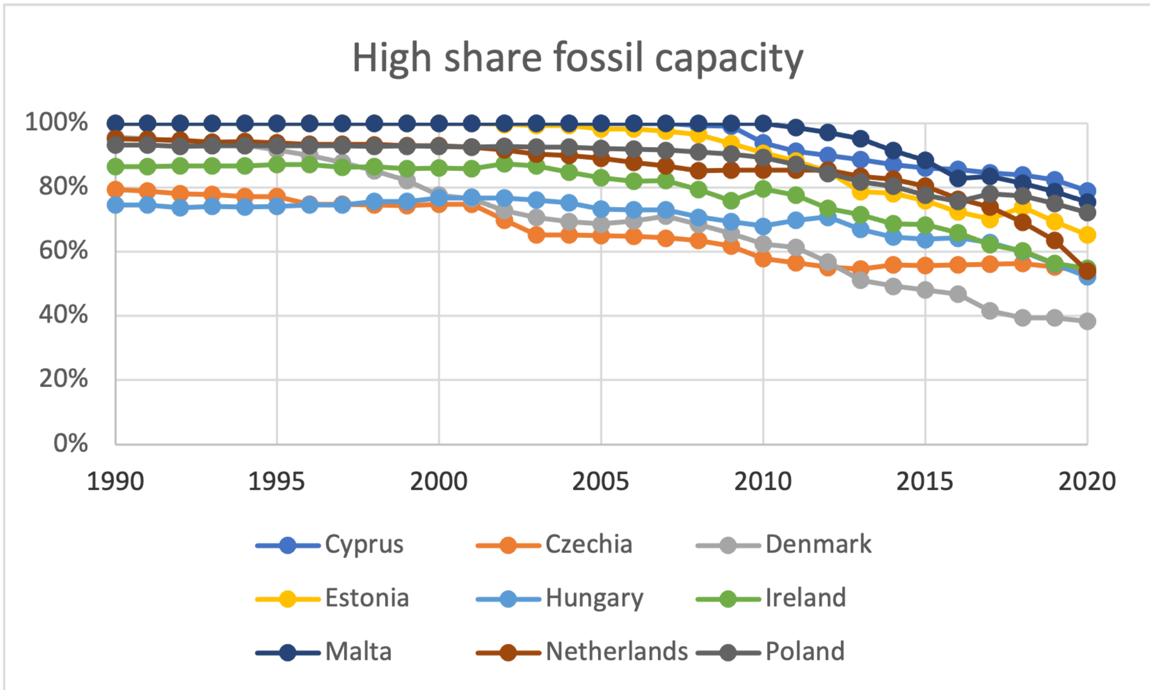

Figure 2.5: Evolution of the share of fossil capacity for the high fossil capacity share cluster. Countries are grouped by their initial share of fossil capacity in 1990. Own illustration based on Eurostat data.

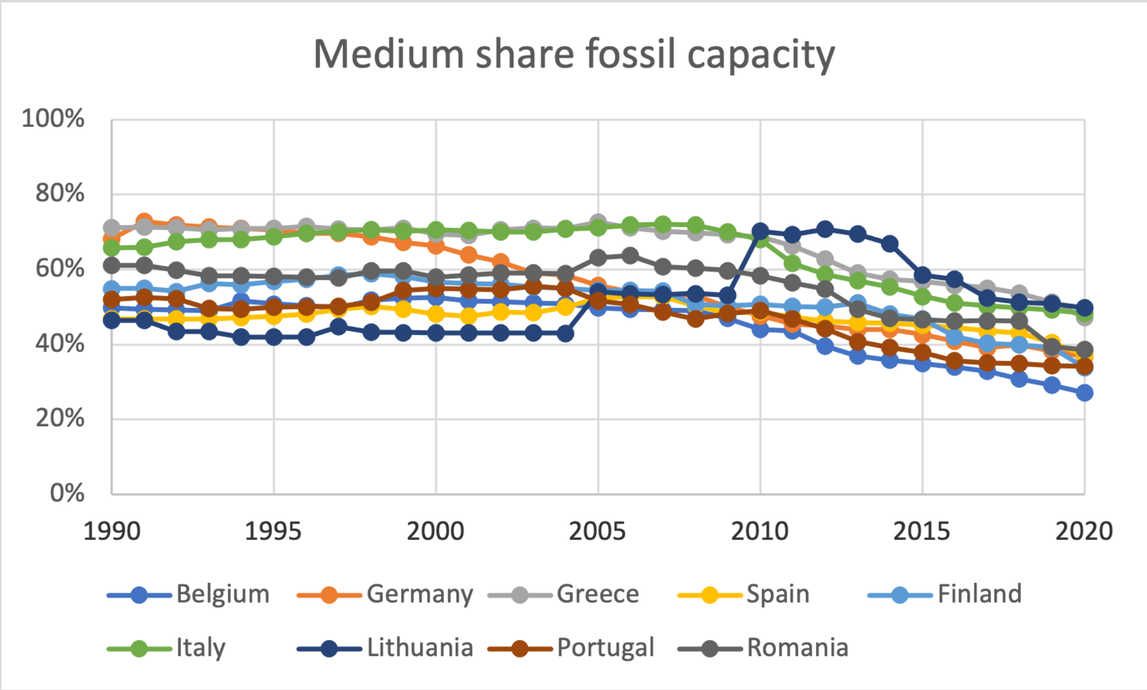

Figure 2.6: Evolution of the share of fossil capacity for the medium fossil capacity share cluster. Countries are grouped by their initial share of fossil capacity in 1990. Own illustration based on Eurostat data.

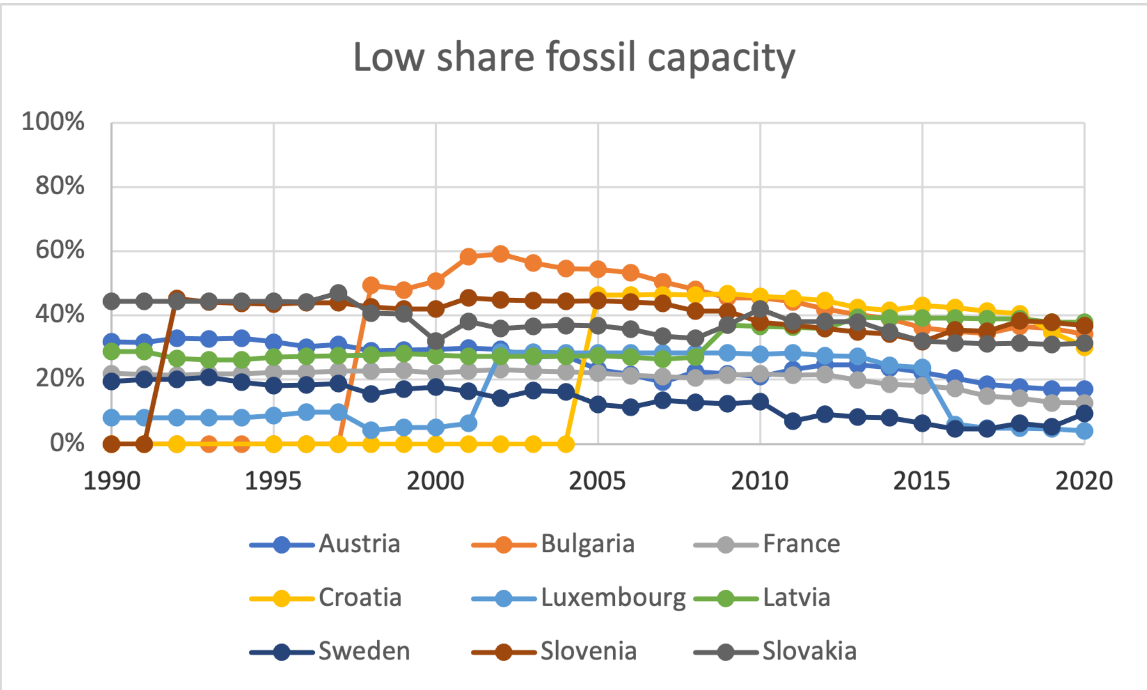

Figure 2.7: Evolution of the share of fossil capacity for the low fossil capacity share cluster. Countries are grouped by their initial share of fossil capacity in 1990. Own illustration based on Eurostat data.

Country	Mean 1990-2009	Median 1990-2009	Mean 2010-2020	Median 2010-2020
Austria	0.16 %	0.29 %	-0.65 % ↓	0.48 %
Belgium	-0.70 %	-0.07 %	-1.33 %↓	-1.05 % ↓
Bulgaria	-2.68 %	-1.62 %	-0.70 %	-2.32 % ↓
Croatia	-0.35 %	1.18 %	-1.70 % ↓	-1.41 % ↓
Cyprus	3.03 %	3.41 %	-1.33 % ↓	-1.76 % ↓
Czechia	-1.84 %	-2.45 %	-1.30 %	-1.47 %
Denmark	-0.29 %	-3.68 %	-3.82 % ↓	-5.06 % ↓
Estonia	-4.07 %	-3.30 %	-2.14 %	-3.83 % ↓
Finland	0.01 %	-2.03 %	-2.84 % ↓	-5.79 % ↓
France	-0.40 %	-1.12 %	-2.07 % ↓	0.20 %
Germany	-1.64 %	-1.61 %	-1.79 % ↓	-1.75 % ↓
Greece	1.02 %	1.20 %	-4.54 % ↓	-3.82 % ↓
Hungary	-1.86 %	-1.57 %	-0.21 %	0.03 %
Ireland	0.76 %	1.49 %	-0.68 % ↓	-0.58 % ↓
Italy	-0.10 %	0.21 %	-2.44 % ↓	-2.40 % ↓
Latvia	-4.27 %	-4.17 %	-0.15 %	-0.78 %
Lithuania	-3.74 %	0.82 %	0.09 %	0.14 %
Luxembourg	-0.23 %	0.64 %	-1.92 % ↓	-2.04 % ↓
Malta	0.79 %	0.55 %	-2.31 % ↓	0.12 %
Netherlands	-0.48 %	0.00 %	-1.68 % ↓	-2.15 % ↓
Poland	-0.94 %	-1.25 %	-0.45 %	-0.72 %
Portugal	1.27 %	1.51 %	-1.94 % ↓	-2.82 % ↓
Romania	-3.77 %	-2.88 %	-1.12 %	-2.01 %
Slovakia	-2.48 %	-1.30 %	-1.50 %	-1.05 %
Slovenia	0.30 %	1.28 %	-1.66 % ↓	-0.99 % ↓
Spain	1.42 %	2.87 %	-2.71 % ↓	-2.03 % ↓
Sweden	-0.98 %	-0.65 %	-1.80 % ↓	-2.40 % ↓

Table 2.4: Mean and median year over year change rates for total emissions before and after enactment of the 20-20-20 targets in 2010. Arrows indicate stronger progress in the second period than in the first. Own calculations based on EEA data.

Country	Mean 1990-2009	Median 1990-2009	Mean 2010-2020	Median 2010-2020
Austria	-0.58 %	0.01 %	-0.63 % ↓	-0.35 % ↓
Belgium	-0.06 %	-0.34 %	-0.12 % ↓	0.29 %
Bulgaria	-0.65 %	-1.11 %	-1.43 % ↓	-2.31 % ↓
Croatia	-0.30 %	-0.36 %	-0.92 % ↓	-1.21 % ↓
Cyprus	-0.17 %	0.01 %	-0.73 % ↓	-0.62 % ↓
Czechia	-0.71 %	-0.78 %	-1.06 % ↓	-1.30 % ↓
Denmark	-0.47 %	-1.52 %	-3.04 % ↓	-4.14 % ↓
Estonia	-1.06 %	-0.67 %	-2.03 % ↓	-2.09 % ↓
Finland	-0.37 %	-1.99 %	-2.64 % ↓	-3.16 % ↓
France	-0.63 %	-0.55 %	-0.86 % ↓	-0.50 %
Germany	-0.39 %	-0.40 %	-0.31 %	-0.05 %
Greece	-0.13 %	-0.20 %	-1.16 % ↓	-1.51 % ↓
Hungary	-0.57 %	-0.28 %	-0.49 %	0.11 %
Ireland	-0.18 %	-0.06 %	-0.77 % ↓	-1.19 % ↓
Italy	-0.46 %	-0.38 %	-0.89 % ↓	-1.10 % ↓
Latvia	-1.37 %	-1.46 %	-0.94 %	-0.10 %
Lithuania	-1.38 %	-1.62 %	2.08 %	-0.50 %
Luxembourg	0.05 %	-0.01 %	-1.31 % ↓	-1.00 % ↓
Malta	0.00 %	0.00 %	-0.27 % ↓	-0.15 % ↓
Netherlands	-0.10 %	-0.07 %	-0.45 % ↓	-0.31 % ↓
Poland	-0.27 %	-0.08 %	-0.72 % ↓	-0.68 % ↓
Portugal	-0.10 %	-0.59 %	-1.06 % ↓	-2.46 % ↓
Romania	-1.15 %	-0.85 %	-0.61 %	-1.11 % ↓
Slovakia	-0.81 %	-0.57 %	-1.03 % ↓	-0.42 %
Slovenia	-0.18 %	0.44 %	-1.04 % ↓	-1.08 % ↓
Spain	0.24 %	0.77 %	-1.26 % ↓	-1.32 % ↓
Sweden	-0.12 %	-0.43 %	-1.89 % ↓	-1.92 % ↓

Table 2.5: Mean and median year over year change rates for the fossil share in gross available energy before and after enactment of the 20-20-20 targets in 2010. Arrows indicate stronger progress in the second period than in the first. Own calculations based on Eurostat data.

Country	Mean 1990-2009	Median 1990-2009	Mean 2010-2020	Median 2010-2020
Austria	-0.47 %	-1.30 %	0.08 %	-1.52 % ↓
Belgium	0.96 %	-0.01 %	-1.53 % ↓	-1.44 % ↓
Bulgaria	-1.86 %	-3.94 %	-1.15 %	-2.66 %
Croatia	1.27 %	0.33 %	-2.30 % ↓	0.00 % ↓
Cyprus	5.67 %	0.52 %	0.57 %	-0.19 % ↓
Czechia	-0.34 %	-0.48 %	0.21 %	0.28 %
Denmark	0.08 %	-0.56 %	-3.41 % ↓	-1.15 % ↓
Estonia	-1.19 %	-0.92 %	-2.70 % ↓	-4.45 % ↓
Finland	0.40 %	-0.11 %	-2.22 % ↓	-0.28 % ↓
France	0.73 %	-0.39 %	-3.35 % ↓	-3.68 % ↓
Germany	0.81 %	-0.34 %	1.23 %	-0.10 %
Greece	2.80 %	2.68 %	-0.23 % ↓	-0.06 % ↓
Hungary	0.76 %	0.17 %	-0.69 % ↓	-0.50 % ↓
Ireland	3.05 %	2.80 %	0.79 %	0.08 %
Italy	3.50 %	3.67 %	-2.07 % ↓	-1.40 % ↓
Latvia	2.99 %	0.51 %	1.87 %	0.03 %
Lithuania	0.09 %	0.00 %	-2.74 % ↓	-0.04 % ↓
Luxembourg	26.52 %	0.26 %	-10.06 % ↓	0.00 % ↓
Malta	0.00 %	0.00 %	0.77 %	0.00 %
Netherlands	1.52 %	1.78 %	0.33 %	-0.20 % ↓
Poland	0.74 %	0.67 %	1.75 %	-0.44 % ↓
Portugal	4.29 %	2.18 %	-1.01 % ↓	-0.15 % ↓
Romania	0.91 %	0.00 %	-3.14 % ↓	-1.02 % ↓
Slovakia	-0.53 %	-0.71 %	-0.47 % ↓	0.21 %
Slovenia	0.69 %	0.00 %	1.54 %	-0.18 % ↓
Spain	4.66 %	2.73 %	-1.30 % ↓	-0.94 % ↓
Sweden	-1.42 %	-0.56 %	4.78 %	-1.53 % ↓

Table 2.6: Mean and median year over year change rates for installed fossil capacity before and after enactment of the 20-20-20 targets in 2010. Arrows indicate stronger progress in the second period than in the first. Own calculations based on Eurostat data.

Country	Mean 2000-2009	Median 2000-2009	Mean 2010-2020	Median 2010-2020
Austria	0.31 %	0.84 %	0.92 % ↑	0.58 %
Belgium	1.84 %	2.60 %	1.92 % ↑	1.69 %
Bulgaria	5.58 %	7.44 %	1.45 %	0.94 %
Croatia	1.59 %	2.59 %	1.57 %	2.02 %
Cyprus	1.83 %	1.37 %	2.70 % ↑	2.94 % ↑
Czechia	2.89 %	2.22 %	2.33 %	2.79 % ↑
Denmark	1.26 %	2.50 %	3.27 % ↑	2.95 % ↑
Estonia	4.08 %	7.14 %	3.72 %	7.79 % ↑
Finland	1.59 %	0.36 %	1.27 %	1.81 % ↑
France	0.97 %	1.04 %	2.04 % ↑	2.27 % ↑
Germany	1.21 %	0.74 %	2.56 % ↑	2.23 % ↑
Greece	2.10 %	2.98 %	0.72 %	1.46 %
Hungary	2.02 %	2.49 %	2.00 %	3.90 % ↑
Ireland	2.42 %	3.48 %	7.17 % ↑	7.07 % ↑
Italy	0.26 %	0.69 %	1.18 % ↑	1.45 % ↑
Latvia	2.50 %	5.36 %	2.39 %	2.85 %
Lithuania	2.81 %	2.95 %	4.67 % ↑	2.29 %
Luxembourg	0.97 %	-0.38 %	3.19 % ↑	3.35 % ↑
Malta	-1.04 %	-3.27 %	1.24 % ↑	2.23 % ↑
Netherlands	0.93 %	-0.22 %	2.17 % ↑	2.2 3% ↑
Poland	3.33 %	2.99 %	2.31 %	0.82 %
Portugal	0.83 %	1.33 %	1.37 % ↑	1.64 % ↑
Romania	5.88 %	6.45 %	3.23 %	4.25 %
Slovakia	567 %	4.10 %	2.50 %	1.95 %
Slovenia	2.03 %	1.55 %	2.25 % ↑	1.48 %
Spain	1.60 %	1.22 %	1.40 %	1.16 %
Sweden	2.36 %	3.69 %	1.92 %	2.90 %

Table 2.7: Mean and median year over year change rates for energy productivity before and after enactment of the 20-20-20 targets in 2010. Arrows indicate stronger progress in the second period than in the first. Own calculations based on Eurostat data.

Country	Mean 1995-2009	Median 1995-2009	Mean 2010-2019	Median 2010-2019
Austria	3.95 %	3.40 %	2.96 %	2.53 %
Belgium	3.21 %	2.05 %	4.44 % ↑	3.54 % ↑
Bulgaria	18.74 %	16.78 %	6.20 %	5.90 %
Croatia	9.05 %	6.46 %	4.41 %	7.05 % ↑
Cyprus	-9.60 %	-9.60 %	1.38 % ↑	2.53 % ↑
Czechia	7.94 %	8.68 %	3.14 %	4.45 %
Denmark	3.25 %	4.00 %	1.08 %	1.67 %
Estonia	24.23 %	17.96 %	8.11 %	5.55 %
Finland	3.34 %	4.35 %	4.21 % ↑	1.56 %
France	1.28 %	1.14 %	4.56 % ↑	4.93 % ↑
Germany	2.05 %	0.87 %	1.02 %	0.62 %
Greece	3.11 %	3.32 %	3.86 % ↑	2.83 %
Hungary	7.81 %	6.41 %	2.96 %	2.56 %
Ireland	7.06 %	9.82 %	2.75 %	2.63 %
Italy	2.60 %	3.35 %	3.02 % ↑	1.49 %
Latvia	22.18 %	17.76 %	6.69 %	7.01 %
Lithuania	14.25 %	11.44 %	5.54 %	7.54 %
Luxembourg	5.15 %	4.53 %	1.68 %	1.98 %
Malta	6.31 %	3.14 %	6.13 %	6.80 % ↑
Netherlands	4.91 %	6.65 %	2.48 %	3.11 %
Poland	11.65 %	15.46 %	5.40 %	6.06 %
Portugal	2.73 %	2.90 %	2.59 %	3.56 %
Romania	13.38 %	12.90 %	8.17 %	10.48 %
Slovakia	9.63 %	10.00 %	6.09 %	3.28 %
Slovenia	5.51 %	6.49 %	2.49 %	2.58 %
Spain	4.14 %	4.54 %	2.63 %	0.90 %
Sweden	3.48 %	2.32 %	1.61 %	1.36 %

Table 2.8: Mean and median year over year change rates for total environmental taxes before and after enactment of the 20-20-20 targets in 2010. Arrows indicate stronger progress in the second period than in the first. Own calculations based on Eurostat data.

2.5 Conclusions

Europe's progress with respect to decarbonization leaves room for improvement. Additional efforts are needed urgently to meet the even more ambitious roadmap ahead. Electricity markets will have to undergo significant structural changes to achieve these goals which has not largely occurred across Europe yet, emphasized by the results of the analysis above.

The analysis based on different indicators for decarbonization and additional indicators on energy productivity, environmental taxes and the capacity mix studies the performance, progress and patterns in the context of decarbonization for the EU 27 countries. The descriptive approach offers some observations regarding structural patterns as a starting point for further research. It would be interesting to analyze the top performers in more detail, especially Denmark which is a country with a high initial share of fossil capacity to identify best practices. Even though overall progress is unsatisfying, the analysis of the top performing countries offers some insights into relevant factors.

Questions on the importance of energy intensity, energy productivity and carbon lock-in are addressed. Relatively strong performance regarding decarbonization tends to be related to increasing energy productivity and environmental taxes. Results do not suggest that low energy demand is an enabler, but high energy demand might be an impediment for decarbonization progress. Among the top performing countries, we see countries with high initial shares of fossil capacity which suggest that carbon lock-in is not inevitable. There is no clear pattern regarding the role of nuclear energy as a required low-emission technology for sector transformation.

The EU 20-20-20 targets implicitly consider economic growth by focusing on energy efficiency and accounting for growth trajectories when setting energy demand targets, even though research suggests that pursuing economic growth and environmental quality at the same time is not feasible. Several observations underline this notion. First, even though energy efficiency increased across countries, energy demand is not declining significantly. For the majority of countries the strongest decline in energy demand with a positive effect on decarbonization is observable in years of economic shocks. Demand and emissions rebound strongly when the economy recovers.

Flaws in the current indicator setup are detected. Indicators fluctuate if there are demand fluctuations which leads to misleading results. Furthermore, as of yet, there is no indicator capturing the degree of sector transformation. It is recommended to include such an indicator, for example fossil electricity production capacity.

The results also underline the issue mentioned in Section 2.2 of focusing strongly on the deployment of RES but not on the phasing out of fossils. The analysis shows that most countries have been successful in promoting RES and many countries significantly overperformed compared to their targets but there is no true sector transformation yet. Somewhat surprisingly, Estonia and Denmark perform comparably strong with respect to phasing out fossil fuels. It would be interesting to investigate these two cases in more detail to understand how they managed a comparably strong phase out of fossil fuels.

That member countries announced phase out dates for coal is a start. But in light of the urgency to accelerate the decarbonization progress, individual binding targets for phasing out fossils are recommended. Phasing out fossil subsidies as soon as possible and prohibiting the construction of new fossil capacities are sensible, too. These constitute unpopular measures for fossil-based industries and may be hard to enforce politically in the presence of lobbying and strong opposition by incumbent industries. However, if Europe wants to move from pledges to action this is the transformative path to take.

Chapter 3

Electricity Market Fundamentals and Challenges[1]

3.1 Electricity Market Fundamentals

The electricity market is a system consisting of the commercial trade of electricity, physical delivery as well as matching of demand and supply by balancing energy. A contract between a supplier and a consumer specifies the supply of electricity in exchange for money at a certain point in time.

Before the liberalization of most electricity markets in the 1990s end consumers had no chance to choose their electricity supplier, therefore a wholesale market for electricity did not exist (Spicker 2010).

In Europe, with the implementation of the EU energy directive 96/92/EG into national law, the supply of electricity was open to competition by enabling consumers to freely choose their electricity supplier and forbidding discrimination regarding grid access for new market agents. In the beginning of this liberalization process, the wholesale market was governed by so-called over the counter (OTC) trades, i.e. bilateral contracts. Soon energy exchanges developed. The main energy exchange in Europe is the European Energy Exchange (EEX), a merger (in 2001) of the energy exchanges in Leipzig and Frankfurt (Ockenfels, Grimm, and Zoettl 2008). Electricity is still traded both via OTC and at the EEX. Nevertheless, the wholesale electricity price for these bilateral contracts is guided by the wholesale price determined at the

1. The Sections 3.1, 3.1.1, 3.1.2 and 3.1.3 are based on my master thesis with the title "Reforms of the German Electricity Market" submitted to the University of Siegen, Faculty III: School of Economic Disciplines on August 19, 2013.

EEX (Ockenfels, Grimm, and Zoettl 2008; EEX 2013). Hence the EEX and its pricing mechanism are presented briefly below.

3.1.1 The European Energy Exchange

At the EEX a variety of energy products are traded. Those are mainly greenhouse gas emission certificates, gas, coal and electricity. Electricity can be traded in the day ahead and intraday auctions but also futures on the day ahead price are tradeable (Ockenfels, Grimm, and Zoettl 2008). Since all these auctions trade electricity of different maturities, they are closely linked and thus interdependent (von Hirschhausen, Weigt, and Zachmann 2007).

The central auction is the daily (on weekdays only) day ahead auction where the price is determined in a two-sided auction. Participants provide information on which quantity at what price they wish to buy or sell until 12 AM for every hour of the following day (Pilgram 2010). Bids can be placed for single hours or for hours organized in blocks (Ockenfels, Grimm, and Zoettl 2008). Negative price bids are allowed since October 2008. Before 2008, the lower bound was set to 0 EUR/MWh (Andor et al. 2010). In a first step all price-quantity combinations are transformed into continuous curves using linear interpolation. In a second step all individual bid curves for every hour are added up, thereby obtaining an aggregated supply and demand curve. This is just a simplified description because the treatment of bids on blocks is not explicitly considered (Pilgram 2010).

The intersection of the supply and demand curve form the equilibrium price and volume for every hour of the following day. Every supplier obtains the same price in a specific hour that every consumer has to pay in that respective hour. In brief, the highest bid that needs to be considered in order to satisfy demand determines the price all other bidders obtain. In principle the market clears every hour. Therefore the auction is called clearing price auction. It is a uniform price auction as every participant trades at the same market clearing price (Ockenfels, Grimm, and Zoettl 2008).

3.1.2 Physical Delivery

The physical delivery of electricity does not take place at the same time as the deal. Generators communicate how much electricity they will feed into the grid at what time on the next day to the transmission system operator (TSO). The demand side does the same for the amount they will take out of the grid. These schedules have to be submitted to the TSO on the previous day (Pilgram 2010).

The balancing of demand and supply takes place in the transmission grid implying that every kWh fed into the grid must be consumed at the same time. If more electricity is supplied than consumed the power line frequency rises and vice versa. As this frequency must be constant in order to ensure grid stability, the TSO is responsible for correcting imbalances. This is done by adding or reducing power plant output which is organized by the market for balancing energy (Riechmann 2008).

TSOs manage the grid and are responsible for grid stability. Germany's grid is for instance governed by four TSOs with each of them being responsible for a certain geographic area (Spicker 2010). The generated electricity is fed into the transmission grid from where it is distributed further to the place of consumption. The transmission grid has to deal with long distances for the transportation of electricity thus requiring extra high voltage. In general higher distance requires higher voltage due to physical and economic characteristics of electricity transportation (Riechmann 2008).

To handle fluctuating demand, an optimal system of power plants consists of base, medium and peak load power plants. Traditionally, base load power plants are characterized by high fixed costs and low variable costs whereas peak load power plants display low fixed costs and high variable costs. Consequently base load power plants operate economically at a high annual degree of utilization whereas peak load power plants should run at a low annual level from an economic perspective (Riechmann 2008).

In most cases, nuclear and lignite power plants function as base load power plants, hard coal power plants are used to cover medium load and gas or oil power plants serve peak load. In contrast to base and medium load power plants, peak load power plants have to be flexible in the sense that they can ramp up and down in a short period of time. So how do renewable energy sources (RES) fit into this system? Before answering this question, the general terms fixed cost and variable cost are specified in the context of total costs for the generation of electricity.

Total costs for electricity generation comprise the following four components. First, fixed costs that consist to a great extent of capital costs for the construction of the power plant plus dismantling and disposal cost. Second, fixed costs that can be reduced, including labor costs, those maintenance charges independent from depreciation and costs for periodical technical inspection. Third, variable costs which are primarily fuel costs, costs for manufacturing equipment and costs for cooling water if necessary. The fourth component form costs resulting from ramping up and down.

The decision of a power plant operator whether to generate electricity or not is mainly based on the minimized sum of variable costs plus costs for ramping the power plant up and down (Riechmann 2008).

3.1.3 Renewable Energy Sources and the Electricity Market

RES display high capital cost and variable costs of essentially zero. Electricity generation by wind and solar power plants, the renewable technologies with the highest shares among RES in most countries, is intermittent as it depends on the availability of wind and the sun.

Generally four situations can take place on the electricity market due to fluctuations of wind and solar power supply. First, low load and low wind and solar power supply. Second, high load and high supply. Third, low load and high supply. Fourth, high load but low supply. The third situation affects grid stability because it requires balancing of demand and supply in the grid. Furthermore this case explains the existence of negative spot prices. If large amounts of electricity generated by wind and solar are fed into the grid while load is low, conventional power plants should ramp down as they are not needed to satisfy demand (Nicolosi and Fürsch 2009). There are several reasons why this does not happen in situations when negative prices are observed. On the one hand base load power plants like nuclear power can not be ramped down on short notice. On the other hand some power plant operators are rather willing to receive negative prices for not shutting down their power plant if opportunity costs from a shut down are higher (Andor et al. 2010). In the case of high load but low supply from wind and solar power plants, conventional power plants are needed to satisfy demand. This will then drive up the price since peak load power plants with high variable costs are used.

The impact of wind and solar power on the use of conventional power plants reduces economic efficiency of the complex of power plants because base load power plants operate less often but would need high annual utilization to be profitable (Riechmann 2008). The impact of fluctuating RES on conventional peak load power plants is twofold. On the one hand, if in-feed from RES is high enough to satisfy demand without those power plants, *missing money* becomes a problem as a result from declining wholesale prices. On the other hand, due to the fluctuating in-feed of RES peak load power plants have to shut down and start more often. Therefore they are more frequently run in stand-by which is not efficient. More flexibility is required for system stability, even though increasing RES generation drives flexible peak-load power plants out of the market. In the context of reduced economic efficiency for conventional power plants and increased price risks, capacity markets are discussed to provide investment incentives despite uncertainty (Tietjen 2012).

From a technical perspective, fluctuating electricity generation of RES puts pressure on the grid. It must be guaranteed that a high supply of RES can be handled and low supply can be compensated to ensure grid stability (Riechmann 2008).

Overall, increasing electricity generation from RES requires more flexibility with respect to generation, storage and demand management. With increasing shares of RES, wholesale electricity prices will decrease to lower levels reducing revenues for all generators. Increasing price volatility and lower price levels constitute major risks for investors in the sense that they might not be able to recover capital and fixed costs (European Commission 2011). That is why a transformation of existing structures to a system directed at the peculiarities of renewable energies is necessary. In addition to technical challenges, most countries face multiple obstacles in transforming their electricity markets.

3.2 Additional Challenges

The previous section explains various factors for structural incompleteness of electricity markets that require central coordination and intervention by regulators. Regulation plays a central role in designing functional markets (Glachant and Ruester 2014) and is also the main driver for achieving the European climate and energy goals that translate into binding targets for all national governments. Efficient regulation is especially challenging because of the complexity of electricity markets. Central challenges discussed in the literature are lobbying, technological shocks, lack of public acceptance, structural demand side changes, market failures and lock-in risks.

Lobbying is a core issue in the electricity sector, both on the supply side by incumbent fossil generators and on the demand side by energy-intensive industries. Up to this day fossil generators receive subsidies by governments hampering decarbonization efforts in many countries. Effects from lobbying on the demand side are exemptions from surcharges, as for example (partial) exemptions from the EEG surcharge in the case of Germany (Cludius et al. 2014; Fabra et al. 2015; Joskow 2008; Strunz, Gawel, and Lehmann 2016). Energy intensive industries have been either completely or partially exempted from the EEG surcharge for years. Therefore the remaining industries and households have to carry a higher financial burden. The German government claimed that these exemptions are necessary to prevent energy-intensive industries from shifting their production to other countries with lower energy prices, known as carbon leakage (BMWi 2018). Cludius et al. (2014), however, doubt that exemptions to this extent are justified since the large industries are able to buy electricity directly at the energy exchange, therefore profiting from lower wholesale prices. Moreover exemptions do not provide incentives to increase energy efficiency and/or reduce energy consumption. Interestingly, Germany missed its energy efficiency target relating to final energy consumption for 2020 despite the energy demand shock caused by the COVID-19 pandemic.

One example for unpredictable impacts of technological developments like shocks and revolutions on existing generating technologies is the nuclear phase out in Germany in the aftermath of the Fukushima incident. Prior to this decision, nuclear power was seen as a bridging technology transitioning to a low carbon economy. After the nuclear catastrophe in Fukushima the German government decided to phase out nuclear power until 2022 (Glachant and Ruester 2014). Another example is the evolution of shale gas especially in the US, causing domestic coal demand to decrease, hence leading to declining market prices for coal (with at the same time too low emission prices for coal) and thereby providing incentives for investing in new coal power plants in other countries.

A general challenge in the context of public acceptance is the design of socially viable mitigation measures (Papadis and Tsatsaronis 2020). A specific public acceptance problem is for example the 'not in my backyard attitude' evident in local opposition to the construction of wind parks and extensions of the electricity grid. This phenomenon can be observed, for instance, in Germany where public support for renewable energy exists in general but there is often a significant opposition to wind and solar power projects by affected local communities. The same is true for the construction of transmission lines to connect the North of Germany, where many wind power plants are installed, to the South, where a lot of energy-intensive industry is located. Opposition to infrastructure projects leads to significant project delays in most cases (Bigerna and Polinori 2015).

Structural demand side changes could facilitate decarbonization efforts by balancing increasingly intermittent electricity supply provided by wind and solar power. The future electricity market is supposed to be characterized by smart grids, flexible demand, large shares of intermittent electricity generation and potentially alternative pricing mechanisms. Currently, daily load curves in most countries display increasing demand in the morning hours, peak in the middle of the day, decrease in the afternoon and increase again in the evening before remaining at a low level over night. With a changing electricity market system these load curves might change. So far it is not clear how different measures will impact the structure of load curves and whether this results in risks rather than benefits for supply security (Boßmann and Staffell 2015).

A prominent example for market failure is the European Emissions Trading System (EU ETS) that has been characterized by too low emission prices resulting from an oversupply of certificates. Regulatory measures have been largely ineffective in increasing prices. Prices have been low, especially in the aftermath of the financial crisis in 2007. Only recently, around 2021 did prices start to increase significantly. Moreover, the lack of coordination between the EU ETS and subsidies for renewables aggravated the price deterioration even further. Consequently, the EU ETS has largely failed to induce the required emission reduction so far (Newbery 2016b; Papadis and Tsatsaronis 2020).

Countries with historically high shares of fossil fuels in energy generation are prone to carbon lock-ins, potentially struggling to substitute fossil fuels by RES and to adapt the existing infrastructure to high shares of RES. One prominent example is Germany. Germany has successfully promoted RES over the past years increasing the share of RES significantly. At the same time, Germany is struggling to reduce fossil generation and hence emissions as the previous chapter illustrates. In contrast to Germany, Denmark which is also a country with historically high shares of fossil fuels, managed to phase out fossil fuels progressively. This contrasting example demonstrates that carbon lock-ins are not inevitable.

Chapter 4

The Functioning of a Capacity Market in Light of Key Market Impacts[1]

4.1 Introduction

In the past, electricity sectors around the world were ruled by monopolies which were in charge of generation, retail and operation of the grid. About 20 years ago advanced economies in Europe, the US and parts of South America started liberalizing their electricity sectors by unbundling these monopolies and forming a market for electricity (Ranci and Cervigni 2013). The established systems are complex, consisting of a wholesale market where electricity is traded on the spot, intraday and future markets. Since the wholesale market exclusively deals with the physical and financial trade of electricity it is also called energy-only market. A necessary complement to this system is the balancing market which ensures short-run security of supply.[2]

Concerns have been raised whether the restructured electricity market system incentivizes sufficient investments in new generating capacity in the aftermath of liberalization (De Vries 2007; Joskow 2008). If missing investment incentives were a problem, they would not be recognized as such for quite some time as most electricity systems are characterized by significant overcapacity caused by regulatory and political intervention before the liberalization process (Ockenfels et al. 2013). There is, however, a considerable time lag between setting sufficient incentives for investments and the installation of additional capacities as planning and construction may take years. Thus,

1. This chapter is based on a joint work with Dr. Sebastian Schäfer published as Sebastian Schäfer and Lisa Altvater (2019). "On the functioning of a capacity market with an increasing share of renewable energy." *Journal of Regulatory Economics*, 56, 59-84.

2. See Ranci and Cervigni 2013 for a detailed overview of the structure and functioning of electricity markets.

today there is an ongoing discussion on the introduction of additional instruments to ensure resource adequacy.[3] Regulatory challenges in this context arise from the promotion of renewable energy. Renewable energy is promoted outside the market because the internalization of emission costs is still incomplete. This has an impact on the electricity market.

Spot markets with perfect competition are characterized by marginal cost pricing. Renewable energy sources display lowest marginal costs as fuel costs are essentially zero. The more electricity is generated from renewable sources, the less is required from fossil sources to satisfy rather inelastic demand. As a consequence, renewables will squeeze out fossil peak-load power plants which show highest marginal costs. Therefore, the average spot price level will decrease, known as the merit order effect of renewable energy (De Miera, Río González, and Vizcaíno 2008; Sensfuß, Ragwitz, and Genoese 2008).

Even though peak-load power plants are the most expensive in terms of marginal costs, they are a crucial component of the capacity mix. While base-load power plants usually run all the time, peak-load power plants run only in times of peak demand. They must be able to ramp up and down fairly quickly at low cost. Since flexibility is crucial to balance intermittent electricity generation from renewables, an increasing share of renewables needs more flexible power plants that are able to balance fluctuating supply by renewable energy sources (RES). Consequently, the merit order effect creates a price signal at spot markets in the short run which counteracts the optimal capacity mix with more flexible power plants in the long run.

In principle the merit order effect will vanish in the long run because the power plant mix adjusts and at a certain point missing flexibility will lead to increasing spot prices (Wissen and Nicolosi 2007). However, there are doubts if this correction of the price signal is early enough to prevent a massive flexibility and capacity problem (Keles et al. 2016). In the German electricity sector, which faces a high share of subsidized renewables without a capacity market, we can observe interventions to satisfy resource adequacy. The transmission system operators (TSOs) have created a so-called capacity reserve by granting payments to generators who would have decommissioned their power plants otherwise (§13c Energy Industry Act 2017). This is a direct market intervention which leads to distortions (Federal Network Agency 2018).

The studies by Keles et al. (2016), Bothwell and Hobbs (2017), Höschle et al. (2017),

3. Resource adequacy denotes the system's ability to satisfy demand at all times and in the long run. Security of supply, in contrast, describes the ability to balance sudden changes in demand (Regulatory Commission for Electricity and Gas 2012, 7). Resource adequacy can therefore be defined as long-term security of supply. Section 4.2 deals with the additional instruments that are discussed in the literature.

and Bhagwat et al. (2017) consider RES with respect to capacity mechanisms. Bothwell and Hobbs (2017) derive a method for crediting RES capacity so that it may be included in a capacity mechanism. The other three studies use simulation models to compare the outcome of different capacity mechanisms. They add to the literature by discussing the optimal capacity mechanism in the presence of electricity generation from RES. Keles et al. (2016) and Bhagwat et al. (2017) use an agent-based modeling approach while Höschle et al. (2017) present a game-theoretic equilibrium model.

In contrast to those studies, the analysis in this chapter employs a theoretical approach using comparative statics in an equilibrium model supplemented by numerical examples to illustrate the model findings. We focus on understanding several important aspects of the functioning of capacity markets whereas the simulations in the studies cited above present scenarios resulting from various overlapping effects. So far, there are only few papers modeling capacity markets from such a formal perspective (Crampes and Creti 2006; Creti and Fabra 2007; Elberg and Kranz 2014; Bajo-Buenestade 2017). However, these models do not consider the impact of RES.

In Section 4.3 we develop a simple model which is based on a capacity auction with reliability options (ROs) described first by Vázquez, Rivier, and Pérez-Arriaga (2002) and developed further by Cramton and Ockenfels (2012) and Cramton, Ockenfels, and Stoft (2013) (see Section 4.2). The model allows to derive the equilibrium condition for capacity auctions and to study bidding strategies of participating bidders whereas strategic bidding is not considered in the three scenario models cited above. Only Keles et al. (2016) model a capacity market with ROs while they do not focus on aspects of strategic bidding. We refine the auction design by introducing a mechanism to determine an optimal explicit penalty. This lessens incentives for generators to pretend higher generating capacities without distorting the capacity market outcome. Thus, contributing to mitigating strategic bidding behavior.

In Section 4.4 we use the model to analyze the impact of power plant maturity, emission costs and an increasing share of RES on the power plant mix. We find comparative advantages for mature power plants and discuss the impact of sunk costs on bidding strategies. This is an important aspect as an increasing share of RES is expected to induce a change in the optimal power plant mix. According to our model, there are comparative advantages for less carbon-intensive technologies, if emission costs are increasing. Furthermore, an increasing share of renewable energy induces comparative advantages for flexible power plants. This counteracts the previously described merit order effect of renewable energy at energy-only markets.

The model findings are illustrated with numerical examples in Section 4.5. One of the examples shows that a capacity market with overcapacity does not necessarily result in additional costs. Thus, a capacity market can be an efficient instrument to allow for a smooth transition from overcapacity to a setting which requires new investments.

4.2 Capacity Auctions with Reliability Options

Before we focus on capacity auctions with ROs, let us briefly recap some basic principles of energy-only markets. Under perfect competition all generators bid prices corresponding to their marginal costs. Bids are then ordered from the lowest to the highest, forming the so-called merit order. In general, spot market auctions at the energy-only market follow uniform pricing so that the last power plant needed to satisfy demand sets the price for all successful generators.

All successful generators except for the price-setting generator gain a rent when generating electricity. This rent is called infra-marginal rent (IR) and is used to cover capital costs. Since supply and demand vary over time, different power plants will be price-setting. Peak-load power plants which face comparatively high marginal costs, gain an IR less often than base-load power plants. This is not problematic per se, as peak-load power plants display lower capital costs than base-load power plants. The peak-load power plant with highest marginal costs forms the right end of the merit order and is therefore never able to obtain an IR. This power plant covers its capital costs via a so-called peak energy rent (PER) in times of scarcity. If demand is high, but supply is at its limit, the spot price rises above marginal costs of the last power plant in the merit order so that all generating power plants gain a PER. There might be reasons why a power plant is not generating electricity, although the spot price exceeds its marginal costs. An example is unforeseen maintenance.

In theory, IRs and PERs of an ideal energy-only market are sufficient to cover generators' capital costs (Caramanis 1982). An ideal energy-only market thus reflects adequate price signals to incentivize necessary capacity investments. Nevertheless, energy-only markets face two problems. First, there is asymmetric information. The regulator does not know if a power plant is not running because of e.g. unforeseen maintenance or because market power is used to provoke a scarcity event. That is why most spot markets have a price cap to limit the spot price level, preventing market power abuse in times of high demand. A too low price cap might therefore cut the PER substantially, resulting in missing money (MM) to cover capital costs. In this case the energy-only market does not provide incentives for sufficient investments in generating capacity. Asymmetric information also prevents the regulator to introduce an optimal price cap. An optimal price cap depends on the market situation and is thus not constant (see Section 4.5). A price cap which is optimal in one situation might result in MM in a second or in market power abuse in a third situation. Setting a price cap is a difficult task.

Second, there is a high investment risk for generators. Scarcity events must occur sufficiently often and induce high enough scarcity prices to cover capital costs. Since scarcity events are not predictable, spot prices are very volatile and depend on actions of other generators. This induces a high risk. Following Neuhoff and De Vries (2004), energy-only markets may not provide sufficient investment incentives for risk-averse bidders. Bhagwat et al. (2016) find increasing investment risks with a growing share of renewable energy which underlines this issue for current electricity markets. Moreover, constant political interventions to reduce CO_2 emissions, exacerbate investment risks. According to Newbery (2016a), this can lead to a situation in which necessary capacity investments are not undertaken even in the absence of MM, because generators do not perceive adequate price signals (missing market problem).

There is an ongoing debate on how to solve these problems. Jaffe and Felder (1996) suggested capacity payments in the course of California's electricity market liberalization. An early and well-written paper discussing the impact of capacity markets is presented by Hobbs, Iñón, and Stoft (2001) while many other studies on this topic followed. See for instance, Stoft (2002), Joskow and Tirole (2007), De Vries (2007), Cramton and Ockenfels (2012), and Newbery (2016a).

To this day, different capacity mechanisms (for example strategic reserves or capacity payments) are under discussion to tackle the missing money problem, De Vries (e.g. 2007), Pfeifenberger, Spees, and Schumacher (2009), Meyer and Gore (2015), and Bhagwat et al. (2016). One promising option is a capacity market with ROs (Finon and Pignon 2008; Joskow 2008; Siegmeier 2011; Flinkerbusch and Scheffer 2013). This market design takes into account different aspects of strategic bidding behavior (Hobbs, Iñón, and Stoft 2001). Furthermore, a capacity market with ROs allows to reduce investment risks for generators because the volatile PER is exchanged by an annual payment (Vázquez, Rivier, and Pérez-Arriaga 2002). That is why we focus on this kind of capacity mechanism in this paper. We explicitly do not want to engage in the discussion about which mechanism might be the best. Instead this paper examines the impacts of emission reduction policies (in particular the promotion of RES) on the outcome of a capacity market with ROs.

The first authors to design a capacity auction with ROs were Vázquez, Rivier, and Pérez-Arriaga (2002). They suggest that the TSO buys ROs from electricity generators on behalf of demand. ROs are a call option for the TSO as soon as the spot price p_{spot} rises above a previously defined strike price p_{strike}. In this case, generators that participate in the capacity auction have to make a payment to the TSO amounting to the difference between p_{spot} and p_{strike} for the contracted volume. This payment can be offset by selling electricity at the spot market. Consequently, necessary incentives to actually deliver the contracted electricity are provided. As the call option ensures reliability of electricity generation in times of scarcity, it is called RO. In addition to this implicit penalty, non-fulfillment of the contract is punished by an explicit financial penalty to prevent bidders to pretend a higher capacity than available. In return, generators receive a premium as a continuous payment over one year. This premium is determined in a uniform price auction.

Prior to the auction the regulator defines the total amount of options (amounting to the required capacity $\underline{C}$), the penalty, the time horizon for the continuous payment and the strike price p_{strike}. Vázquez, Rivier, and Pérez-Arriaga (2002) recommend to set the strike price at a level that lies 25 % above marginal cost of peak-load power plants, though emphasizing that the level of the strike price is not critical. If the strike price is lower, required premiums must be higher and vice versa.

In the auction every bidder offers a single price-quantity pair. These bids are ordered from lowest to highest until the target capacity $\underline{C}$ is satisfied. The price of the last accepted bid determines the premium per capacity unit that all generators receive. This premium corresponds to the equilibrium price p^*.

In this design, p_{strike} acts as a price cap that hedges load against high spot prices and generators against price fluctuations. Generators exchange a possibly high, but volatile PER, for a fixed premium resulting in income stabilization and risk reduction. This provides a more stable investment environment which cannot be offered by spot markets alone.

The suggested design fulfills most requirements for a successful capacity mechanism, but the issue of possible market power abuse is admittedly not fully addressed. The design does not control for incentives of generators with already existing power plants to demand a higher price than required or to withhold capacity to achieve a higher clearing price. An extension of the proposal by Cramton and Ockenfels (2012) and Cramton, Ockenfels, and Stoft (2013) tackles this problem of strategic bidding behavior by enforcing that already existing power plants are obliged to participate in the auction with total capacity. Their bid is restricted to a price of zero. Since they assume that existing capacity is not sufficient to meet required capacity, existing power plants do not influence the equilibrium price p^*. In Section 4.4.2 we modify this approach to include cases with overcapacity of existing power plants.

Still, incentives for bidders to offer a higher amount of capacity than actually available remain because they, in contrast to Vázquez, Rivier, and Pérez-Arriaga (2002), do not introduce an explicit penalty. This problem is addressed by a new approach to determine an optimal penalty in Section 4.3.3 after establishing a suitable framework to analyze spot market rents and their relation to investment incentives.

4.3 Spot Market Equilibrium in the Presence of a Capacity Market

Figure 4.1 depicts an imaginary spot price distribution over one year t and resulting potential rents for generator i. The potential IR per capacity unit of generator i corresponds to the integral from marginal costs $C_{t,i} = C_{G,t,i} + C_{E,t,i}$ to p_{strike}. Marginal costs consist of $C_{G,t,i}$ as generating costs and $C_{E,t,i}$ as emission costs.[4] p_{strike} and p_{cap} are fixed for a longer period of time and are thus lacking the index t.

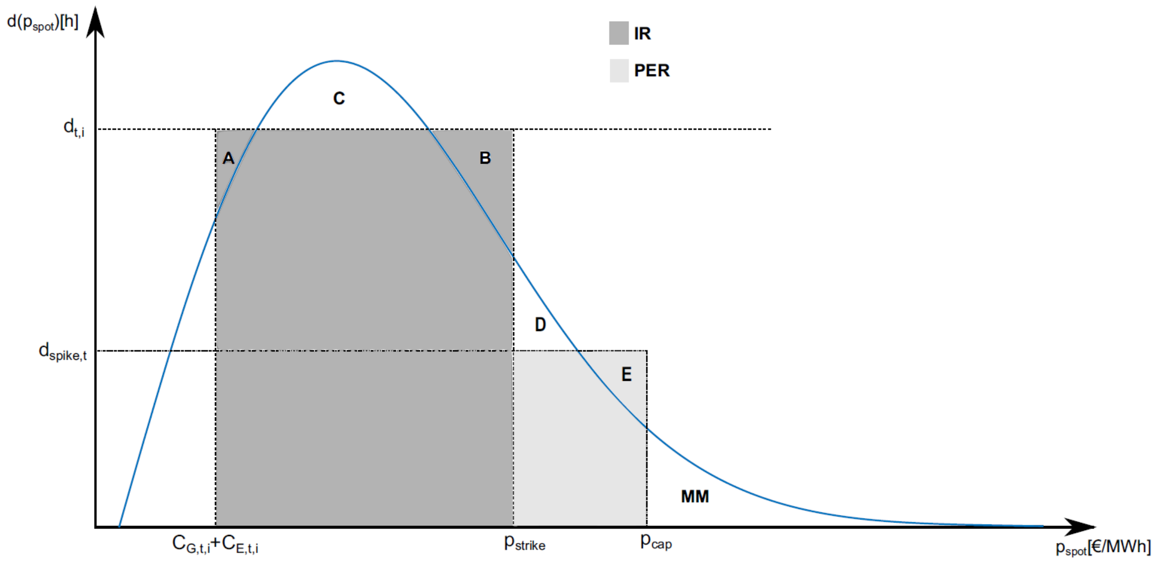

Figure 4.1: Schematic illustration of the distribution of electricity spot market prices for one year in €/MWh. The duration of power plant i's production in hours is a function of the spot price.

To simplify the notation in the subsequent analysis, $d_{t,i}$ is defined as the normalized duration. $d_{t,i}$ is defined such that, referring to the example in Figure 4.1, $A + B = C$. Thus, we can replace the integral by the product of the normalized duration and the

4. Emission costs are assumed to stem from an emissions trading scheme or carbon taxes.

difference of the strike price and marginal costs (see dark gray rectangular in Figure 4.1). This yields

$$\begin{aligned} IR_{t,i} &= \int_{C_{G,t,i}+C_{E,t,i}}^{p_{strike}} d(p_{spot,t})\ \mathrm{d}p_{spot,t} \\ &= d_{t,i}\left(p_{strike} - C_{G,t,i} - C_{E,t,i}\right). \end{aligned} \tag{4.1}$$

Analogously, we can determine the potential PER, whereas the respective normalized duration $d_{spike,t}$ is defined such that $D = E$ (see Figure 4.1)

$$\begin{aligned} PER_{t} &= \int_{p_{strike}}^{p_{cap}} d(p_{spot,t})\ \mathrm{d}p_{spot,t} \\ &= d_{spike,t}\left(p_{cap} - p_{strike}\right). \end{aligned} \tag{4.2}$$

The potential IR is distinct for every generator as marginal costs are distinct. In contrast, the potential PER is equal for all generators as the strike price is larger than or equal to marginal costs of any power plant.

According to Figure 4.1, a higher price cap decreases MM to the same extent as the PER increases. Without a price cap MM is completely included in the PER. However, that means a high risk for market power abuse.

Figure 4.1 depicts potential spot market rents, assuming that power plants are always generating electricity as soon as the spot price exceeds their marginal costs. In reality, unforeseen maintenance and non-linear behavior of power plants with respect to marginal costs may prevent permanent availability. For instance, it does not make sense to cold start base-load power plants to operate solely for one hour since ramping up and down is costly. This means power plants are not always running although the spot price exceeds marginal costs. There is a certain failure rate $X_{t,i}$ so that a certain share of potential spot market profits will be lost. Conversely, $1 - X_{t,i}$ corresponds to the availability rate of power plant i in year t. The product of the availability rate for generator i and potential spot market rents yields actual spot market rents for generator i.

Each generator can estimate an individual availability rate based on historical values. Availability rates may also show a dependency on the spot price level since incentives to keep a power plant running differ for low and high spot prices. Hence, the failure rates that lead to losses in IR and PER are distinct for every generator $(X_{IR,t,i}, X_{PER,t,i})$.

4.3.1 Incentives for Investing in Power Plants

Next, we examine necessary conditions for an investment in power plants. We assume a depreciation of the power plant by a constant, but individual rate δ_i. This depreciation rate also includes an interest rate (or profit margin) and an individual risk premium. The risk premium is modeled proportionally to the current capital stock as old power plants face lower risks because of lower remaining capital costs. The interest rate and the main part of depreciation also relate to the current capital stock. A simple approach, in continuous time, to describe the capital stock of power plants over time may be

$$K_{t,i} = K_{0,i}\mathrm{e}^{-\delta_i t} \qquad \forall 1 > \delta_i \geq 0 \tag{4.3}$$

with $K_{0,i}$ corresponding to investment costs.

Despite described reasons for degressive depreciation, particularly with respect to the risk premium and the interest rate, there might be reasons for a partly linear depreciation. Furthermore, an approach in discrete time may be more realistic under consideration of the capacity market's annual setup. Thus, we suggest

$$K_{t,i} = K_{0,i}(1 - \delta_i)^t - K_{0,i}\tilde{\delta}_i t \qquad \forall 1 > \delta_i, \tilde{\delta}_i \geq 0 \tag{4.4}$$

with $\tilde{\delta}_i$ as the rate of linear depreciation.

After a lifespan of T years the capital value will reduce to the residual value $K_{T,i}$. Hence, $K_{0,i} - K_{T,i}$ is the depreciation of the power plant during its lifespan. Decommissioning costs D_i which the generator may have to face do not need to be considered explicitly as they can be captured in the investment costs $K_{0,i}$.

We assume that all market participants have symmetric information. From symmetric information follows that spot price expectations are identical, leading to equal expectations about PER and MM for each generator. A rational generator i will invest $K_{0,i}$ to build a power plant if total depreciation $K_{0,i} - K_{T,i}$ is covered by expected spot market rents and capacity payments. Considering Eq. 4.4, this yields

$$
\begin{aligned}
K_{0,i} - K_{T,i} &= \sum_{t=1}^{T} \big((1 - X^e_{IR,t,i}) IR^e_{t,i} + (1 - X^e_{PER,t,i}) PER^e_t + (1 - X^e_{PER,t,i}) MM^e_t\big) \\
&= \sum_{t=1}^{T} (K_{t-1,i} - K_{t,i}) := \sum_{t=1}^{T} k_{t,i} \\
&= K_{0,i} \sum_{t=1}^{T} \left((1 - \delta_i)^t \frac{\delta_i}{1 - \delta_i} + \tilde{\delta}_i\right) \\
&= K_{0,i}(1 - (1 - \delta_i)^T + \tilde{\delta}_i T). \qquad (4.5)
\end{aligned}
$$

With e denoting respective expected values. In contrast to an energy-only market, MM is available for generators in a capacity market setting via annual payments. That is why MM appears in Eq. 4.5 jointly with IR and PER to cover capital costs. Without a capacity market, incentives to invest in power plants may be insufficient. Only if the regulator introduced a sufficiently high price cap, MM would vanish and would be included in the PER.

$\mathrm{IR}^e_{t,i}$, PER^e_t, MM^e_t are annual values and may be subject to high variance with respect to time. They form expected potential profits of generator i. Multiplying with the respective availability factors yields expected profits. Over a power plant's lifespan T expected profits should cover a power plant's depreciation. We assume the same availability rate for PER and MM because in both cases the spot price exceeds marginal costs of any power plant significantly. This leads to comparable incentives to generate electricity.

Capacity markets usually provide annual payments. Thus, the summands of Eq. 4.5 are of particular interest regarding the bidding behavior in a capacity market (see Section 4.3.2). We define annual capital costs as

$$
\begin{aligned}
k_{t,i} :&= (1 - \delta_i)^t \frac{\delta_i}{1 - \delta_i} + \tilde{\delta}_i \\
&= (1 - X^e_{IR,t,i}) IR^e_{t,i} + (1 - X^e_{PER,t,i}) PER^e_t + (1 - X^e_{PER,t,i}) MM^e_t. \qquad (4.6)
\end{aligned}
$$

Since a capacity market converts volatile PER into an annual payment, the generators' capital risk decreases. In the model, this corresponds to a lower $\delta_{t,i}$ eventually leading to lower $k_{t,i}$. This is an additional advantage of a capacity market beyond covering MM.

4.3.2 Rational Bidding Behavior in a Capacity Market

The previously described capacity auction with ROs forms the basis to derive the equilibrium price p^* which is the clearing price of the uniform price capacity auction. The equilibrium price reflects annual payments per capacity unit. Every existing power plant is obliged to place a bid in the capacity auction while participation of new power plants is voluntary. Following Vázquez, Rivier, and Pérez-Arriaga (2002), generators who do not provide the contracted amount of electricity when the spot price exceeds p_{strike}, have to pay a penalty $\varrho^e_{t,i}$ in addition to PER_t.

Capacity payments equal the difference of each generator's expected costs and expected profits at the spot market if they bid truthfully. Costs consist of annual capital costs $k_{t,i}$, the expected penalty for non-delivery $\varrho^e_{t,i}$ and the expected potential PER because generators commit to pay the difference between p_{spot} and p_{strike} as soon as the spot price rises above the strike price. This equals the potential PER. Profits at the spot market are the sum of potential IR and potential PER multiplied by respective individual availability rates. To determine the clearing price, submitted bids of all n power plants are sorted in ascending order. If $m \leq n$ power plants are necessary to provide the required capacity $\underset{\sim}{C}$, the equilibrium price equals the bid of generator m

$$p^*_t = p_t(\underset{\sim}{C}) = p_t(\sum_{i=1}^{m} C_{t,i}) = k_{t,m} + X^e_{PER,t,m} PER^e_t + \varrho^e_{t,m} - (1 - X^e_{IR,t,m}) IR^e_{t,m}, \quad (4.7)$$

given that generators bid truthfully.

There are, of course, incentives for generators to manipulate the clearing price to receive additional payments. However, inflating prices by withholding capacity will not work because all existing power plants are obliged to take part in the capacity auction. Pretending a higher capacity than available, which leads to a lower clearing price but an additional profit for the deceiver, can be prevented by an optimal penalty (see Section 4.3.3). Only collusion between generators of new power plants to anticipate the price-setting power plant remains as a strategy to manipulate prices. We assume that there is sufficient competition to prevent collusion, such that Eq. 4.7 serves as a reference case to analyze incentives for truthful bidding.

Most capacity market designs work with annual payments, but the contracted time may be longer (Keles et al. 2016). In this case each generator will estimate the difference between expected costs and expected profits at the spot market for all future years and calculate a respective average price bid.

4.3.3 Incentive Regulation

Vázquez, Rivier, and Pérez-Arriaga (2002) suggest to apply an explicit penalty in a capacity market. Also, Mastropietro et al. (2016) emphasize the necessity of a penalty. However, a mechanism to determine an optimal penalty has not yet been derived. To determine the optimal penalty $\varrho_{t,i}$ we insert Eq. 4.6 for generator m into Eq. 4.7 leading to

$$p_t^* = PER_t^e + (1 - X_{PER,t,m}^e)MM_t^e + \varrho_{t,m}^e. \tag{4.8}$$

This equation follows from the assumption that the spot market and the capacity market are in equilibrium. According to this equation, the capacity auction premium for the last successful generator m will reflect their expectations about potential PER, MM and the individual penalty. Assuming truthful bidding, the regulator gets the potential PER back and, if there is no electricity generation, the regulator receives the penalty from the generator who failed to deliver electricity. Therefore, in line with Hobbs, Iñón, and Stoft (2001), the modeled capacity market compensates only MM and consequently provides sufficient investment incentives at no extra cost. At the same time, Eq. 4.8 reveals the incentive for generators to pretend a higher capacity than actually available if the penalty $\varrho_{t,i}^e$ is too low (Cramton, Ockenfels, and Stoft 2013).

To clarify, let us assume that there is no penalty and a bidder without any capacity ($X_{PER,t,i}^e = X_{PER,t,i} = 1$) as an illustrative example. This *deceiver* would always be able to underbid any competitor since MM is not needed to cover non-existent capital cost (see Eq. 4.8). In contrast, competitors face MM, leading to an equilibrium price that includes their expectation about MM. In this case the *deceiver* gets p_t^* while paying only the potential PER to load because of ROs. $(1 - X_{PER,t,m}^e)MM$, which is included in the clearing price, is left as a profit.

An explicit penalty $\varrho_{t,i}^e$ to prevent this deception leads to a markup on the capacity bid, since rational generators account for their expected penalty according to Eq. 4.8. Thus, the markup must be higher for *deceivers* when compared to actual generators so that they will not be successful in a capacity auction. There are several factors that need to be considered for setting the optimal penalty. If the penalty is too low, incentives to deceive remain. A too high penalty implies a higher risk for all generators caused by a higher markup. Eventually, this may lead to extra costs, since the penalty may affect the equilibrium (Mastropietro et al. 2016). In the optimum the penalty should eliminate the deceivers' profit to discourage their participation. Also, increasing the failure rate $X_{t,i}$ should not allow a lower price bid. The optimal penalty thus is

$$\varrho^e_{t,i} = X^e_{PER,t,i} MM^e_t. \tag{4.9}$$

Inserting the optimal penalty into Eq. 4.8 yields $p^*_t = PER^e_t + MM^e_t$ which is independent of $X^e_{PER,t,i}$. A rational *deceiver* ($X^e_{PER,t,i} = 1$) will not underbid real bidders anymore because their penalty equals MM now. The *deceivers'* profit is eliminated.

The regulator can determine MM^e_t ex post. Considering the optimal penalty (see Eq. 4.9), MM^e_t is the difference of the clearing price p^*_t and expected potential PER per capacity unit. Based on this finding, the regulator can define a penalty factor as the ratio of the clearing price and expected potential PER per capacity unit to set the penalty

$$\xi_t := \frac{p^*_t}{PER^e_t}. \tag{4.10}$$

The penalty is applied by multiplying payments to the regulator, which result from ROs, by the penalty factor if no electricity is delivered when the spot price exceeds p_{strike}. This leads to an expected annual payment of $X^e_{PER,t,m} PER^e_t \cdot \xi_t = X^e_{PER,t,m} \cdot p^*$ instead of $X_{PER,t,m} PER^e_t$ for generator m. In case of the *deceiver* with $X_{PER,t}$=1 the annual payment is thus equal to p^*_t (see Eq. 4.10). Consequently, the incentive to pretend the availability of higher than actual capacity in a capacity auction vanishes.

Although the regulator can calculate ξ_t only after the equilibrium price p^*_t is known, the described calculation of the penalty can be applied if the procedure is announced before the auction takes place. If the regulator communicates their own expectation for potential PER per capacity unit prior to the auction, this can help to create symmetric information for all market participants.

The described mechanism to determine the optimal penalty implies that the penalty equals zero if there is no MM. In this case, the equilibrium price p^*_t is equal to the expected PER. A capacity market is not needed to cover MM. Nevertheless, the capacity market converts the expected PER into an annual payment at no extra cost. This reduces price risks for generators leading to lower capital costs (see Section 4.3.1). In addition, in the context of a transition to high shares of RES-based electricity generation, a capacity market offers additional benefits (see Section 4.4).

4.3.4 Equilibrium Condition

We want to use the previous findings to evaluate the equilibrium condition for capacity auctions. In a first step, we look at two generators i and j in a spot market equilibrium with an optimal price cap and sufficient incentives to invest in generating capacity

(Eq. 4.6 is fulfilled). For an optimal price cap, MM vanishes as it is included in the PER. We differentiate between PER and MM nevertheless to illustrate the functioning of a capacity market in the following analysis. Calculating the difference of the two generators' annual capital costs ($k_{t,j} - k_{t,i}$) according to Eq. 4.6 yields

$$\begin{aligned} k_{t,j} - k_{t,i} = {} & (1 - X^e_{IR,t,j})IR^e_{t,j} - (1 - X^e_{IR,t,i})IR^e_{t,i} \\ & - (X^e_{PER,t,j} - X^e_{PER,t,i})PER^e_t \\ & - (X^e_{PER,t,j} - X^e_{PER,t,i})MM^e_t. \end{aligned} \tag{4.11}$$

In short,

$$\begin{aligned} \Delta k_{t,j-i} = {} & (1 - X^e_{IR,t,j})IR^e_{t,j} - (1 - X^e_{IR,t,i})IR^e_{t,i} - \Delta X^e_{PER,t}PER^e_t \\ & - \Delta X^e_{PER,t}MM^e_t. \end{aligned} \tag{4.12}$$

In the spot market equilibrium, the difference in capital costs is equal to the expected power plants' availability rates multiplied by the respective expectations for potential IR, PER and MM. Higher capital costs have to be compensated by higher availability rates or lower marginal costs, producing a higher IR and vice versa.

In a second step, we assume that the two generators i and j bid truthfully according to Eq. 4.7. The difference in the generators' price bids ($p_{t,j} - p_{t,i}$) under consideration of Eq. 4.9 and 4.12 yields

$$\begin{aligned} \Delta p_{t,j-i} :& = p_{t,j} - p_{t,i} \\ & = \Delta k_{t,j-i} + \Delta X^e_{PER,t}PER^e_t + \Delta \varrho^e_t + (1 - X^e_{IR,t,i})IR^e_{t,i} - (1 - X^e_{IR,t,j})IR^e_{t,j} \\ & = \Delta \varrho^e_t - \Delta X^e_{PER,t}MM^e_t \\ & = 0. \end{aligned} \tag{4.13}$$

Eq. 4.13 reflects the zero-arbitrage principle. It implies that in equilibrium every generator is expected to place the same bid in a capacity auction. If there was for instance a power plant with lower marginal costs than j, this advantage would be compensated by higher capital costs. Otherwise it could not be part of an equilibrium because investments in this superior technology would yield positive profits. Consequently, price bids are equal for all power plants in equilibrium while $\Delta p \neq 0$ indicates a disequilibrium. The greater the price difference, the greater the deviation from equilibrium. However, the zero-arbitrage principle does not imply that there will be only one technology in equilibrium. This may be illustrated by the evolution of Eq. 4.13.

Electricity generation is usually allocated to base-load, medium-load and peak-load power plants. In the following we focus on base-load and peak-load power plants, since they are of particular interest with respect to an increasing share of renewable electricity generation. On the one hand, looking at Germany for instance, base-load is mostly covered by emission-intensive coal-fired power plants which will be substituted by clean renewable technologies in the long run to meet climate goals. On the other hand, renewable electricity generation requires more flexible power plants to balance their intermittent supply. Peak-load power plants provide this flexibility since they are able to ramp up and down quickly at comparatively low cost. Since Eq. 4.13 reflects the equilibrium condition for every power plant it is also valid for any group of power plants.

We introduce a representative base-load and a representative peak-load power plant that covers all power plants of each group. For clarity, we assume that the strike price p_{strike} equals marginal costs of the representative peak-load power plant $p_{strike} := C_{G,t,peak} + C_{E,t,peak}$. This eliminates any IR for peak-load power plants (see Eq. 4.1) reducing the set of variables but this does not change the analysis. Profits for the representative peak-load power plant at the spot market are thus restricted to the PER, whereas the base-load power plant gains an additional IR. Rewriting Eq. 4.13 for a representative peak-load and a representative base-load power plant yields

$$\begin{aligned}
\Delta p_{t,base-peak} :&= p_{t,base} - p_{t,peak} \\
&= \Delta k_{t,base-peak} + \Delta X^e_{PER,t} \underbrace{(p_{cap} - p_{strike})\, d^e_{spike,t}}_{PER_t} + \Delta \varrho^e_t \\
&- (1 - X^e_{IR,t,base}) \underbrace{\Delta C^e_{t,base-peak} d^e_{t,base}}_{IR_{t,base}} \\
&= \Delta \varrho^e_t - \Delta X^e_{PER,t} MM^e_t \\
&= 0.
\end{aligned} \tag{4.14}$$

Let us assume that the capacity market is not in equilibrium and thus $\Delta p_{t,base-peak}$ is less than zero. This means a comparative advantage for base-load power plants leading to an incentive to invest in base-load capacity. If, after some time, new base-load capacity is installed, this has an impact on the equilibrium. The more competitive base-load power plant will induce a partial shift of electricity generation from peak-load to base-load power plants. The utilization of peak-load power plants decreases. This means a lower duration $d_{t,base}$ of electricity generation above marginal costs for base-load power plants. Eventually, the IR decreases leading to a comparative disadvantage for base-load power plants. Thus, the zero-arbitrage principle implies that in equilibrium there will be a mix of different technologies.

4.4 Market Impacts

A simple comparative static analysis is sufficient to provide first insights into the effects of different impact factors on the capacity auction's outcome. The outcome depends essentially on bidders' incentives and consequently their behavior. The equilibrium condition of the capacity market model from Section 4.3.4 reflects this behavior. Different impact factors lead to distortions of the equilibrium creating comparative advantages for some power plants. First, we focus on power plant maturity as the capacity mix is characterized by power plants of different age. In this context, we also consider the effect of sunk costs. Second, we examine the influence of carbon emission costs resulting from an emissions trading scheme or a carbon tax. Third, we analyze how an increasing share of renewable energy influences the capacity auction's outcome.

4.4.1 Impact of Power Plant Maturity

According to Eq. 4.4, investment costs for power plant i during its lifespan T amount to $K_{0,i} - K_{T,i}$. These costs have to be covered by annual profits at the spot market and the premiums obtained in the capacity auction. To evaluate the effect of power plant maturity we again assume that there are two power plants i and j. They are identical except for their age. That means both power plants have the same availability factors and marginal costs leading to an identical amount for PER, IR, MM and the same penalty. According to Eq. 4.7, the difference of their price bids in a capacity auction is

$$\begin{aligned}\Delta p_{t,j-i} &= \Delta k_{t,j-i} + \Delta X^e_{PER,t} PER^e_t + \Delta \varrho^e_t + (1 - X^e_{IR,t,i}) IR^e_{t,i} - (1 - X^e_{IR,t,j}) IR^e_{t,j} \\ &= \Delta k_{t,j-i}. \end{aligned} \tag{4.15}$$

Since power plants i and j are identical except for their age, we can simplify the notation using t for power plant i and $t + \Delta t$ for power plant j together with $i = j$. Then Eq. 4.15 changes to

$$\Delta p_{t,j-i} = \underbrace{K_{0,i=j}(1-\delta_{i=j})^t \frac{\delta_{i=j}}{1-\delta_{i=j}}}_{\geq 0} \left[(1-\delta_{i=j})^{\Delta t} - 1\right] - K_{0,i=j}\tilde{\delta}_{i=j}\Delta t \delta_{i=j} \tag{4.16}$$

if Eq. 4.4 and 4.6 are taken into account. Assuming a reasonable value for the degressive depreciation ($1 > \delta_{i=j} > 0$), the square bracket in Eq. 4.16 is negative for $\Delta t > 0$ and positive for $\Delta t < 0$. The same behavior applies to the subtrahend in Eq. 4.16 with respect to Δt. This means $\Delta p_{t,j-i}$ is negative for $\Delta t > 0$ indicating a comparative advantage for generator j while we find a comparative advantage for generator i if Δt is positive.

The derivative of Eq. 4.16 yields

$$\begin{aligned}\frac{\partial \Delta p_{t,j-i}}{\partial \Delta t} &= K_{0,i=j}(1-\delta_{i=j})^t \frac{\delta_{i=j}}{1-\delta_{i=j}} \ln(1-\delta_{i=j}) \left((1-\delta_{i=j})^{\Delta t} - 1\right) - K_{0,i=j}\tilde{\delta}_{i=j}\delta_{i=j} \\ &\leq 0 \end{aligned} \tag{4.17}$$

which indicates that $\Delta p_{t,j-i}$ increases for decreasing Δt and vice versa. Thus, the described comparative advantages for generator i and j intensify with an increasing/decreasing value of Δt. Eventually that means a comparative advantage for the operator with the older power plant. Moreover, the advantage increases with the difference in age. The described effect of power plant maturity would only vanish if there was no degressive depreciation ($\delta_{i=j}$=0) which is not a plausible assumption.

Identical power plants except for differing age are not part of a capacity market equilibrium. The newer power plant needs a superior cost structure to compete with the older power plant. The advantage of lower risk because of lower remaining capital is directly transferred to the capacity market. The dependency on age reduces the risk for existing power plants to be substituted by new more efficient ones.

4.4.2 Impact of Sunk Costs

The findings in Section 4.4.1 are based on the assumption of truthful bidding according to Eq. 4.7. However, the bidding behavior probably changes once an investment has been made because of sunk costs. For these already existing generators it is more appealing to cover at least a part of annual capital costs than none while the investment decision for new power plants will only be made if capital costs will be fully covered.

Operators of existing power plants have an incentive to place a minimum bid which equals the PER per capacity unit[5] although spot market rents might be too low to cover capital costs (then MM occurs). On the one hand, the minimum bid is sufficient to cover the generator's costs associated with the capacity market because of their commitment to pay the PER to the regulator. On the other hand, this strategy increases the probability to place a successful bid. Since all successful generators receive the clearing price as a premium, the chance to benefit from a clearing price

5. Recall that a penalty only occurs for price bids exceeding PER per capacity unit (see Section 4.3.3).

p_t^* above the individual bid remains. Bidding the PER per capacity unit is thus the optimal bidding strategy for existing power plants.

As a consequence of these considerations, the clearing price converges to the PER per capacity unit in a market with sufficient competition and overcapacities of existing power plants. A capacity market should thus not cause any extra costs for consumers even though there might be excess capacities. Still, generators, especially those with several power plants, might try to inflate the clearing price by withholding capacity. Cramton and Ockenfels (2012) and Cramton, Ockenfels, and Stoft (2013) suggest that all generators with existing power plants are forced to take part in the capacity auction with a price bid of zero. Following our considerations, this suggestion should be modified to an obligatory price bid for existing power plants amounting to the expected PER per capacity unit. Then a clearing price above the PER per capacity unit is only possible if new capacity is required to ensure resource adequacy. As discussed in Section 4.3.3, it seems appropriate that the regulator announces the expected PER per capacity unit before the capacity auction takes place.

In general, it makes sense to organize capacity auctions in a way that the contracted period reflects the main component of a power plant's lifespan (twenty or thirty years) as this reduces investment risks significantly (Keles et al. 2016). Then generators do not take part in the capacity auction every year but once before the power plant is realized. In this case the obligation to take part with a bid equal to the PER per capacity unit applies only to those power plants which have been installed before introduction of a capacity market.

The preceding findings and the results in Section 4.4.1 indicate that the optimal capacity mix, resulting from a capacity market, is path-dependent. A thought experiment illustrates what path dependency means in this context. Imagine two cases. In the first case, the share of renewables increases slowly to the target share with a certain age distribution of fossil power plants. In the second case, the same target share of renewables is introduced, but all fossil power plants are built at once (static one-shot scenario). Thus, all fossil power plants display the same maturity in years. In the second case, the capacity mix is a best response to the share of renewable energy. In the first case, already existing capacity with its age distribution has to be considered as well. The outcome of capacity auctions in case one and case two will be different. In a transition process to less emission-intensive electricity generation, the advantage of already existing and old power plants produces a "delayed" phase out of these power plants and as a consequence a delayed transformation of the capacity mix.

In other studies analyzing capacity markets in the presence of RES the impact of sunk costs is treated differently. Bothwell and Hobbs (2017) and Höschle et al. (2017) neglect the effect of sunk costs as they present an equilibrium of a static one-shot scenario. While Keles et al. (2016) and Bhagwat et al. (2017) consider sunk costs implicitly in their investment algorithm of the agent-based models.[6] However, they do not provide a static one-shot scenario for comparison which would be necessary to point out the effect of sunk costs on the capacity mix.

4.4.3 Impact of Carbon Emission Costs

Many countries introduced a carbon tax or an emissions trading system which usually apply a stepwise increase in the tax rate or tightening of the emission cap. Both systems result in a (partial) internalization of emission costs. They price emissions with the effect that emission costs are included in marginal costs for generators. Since capacity prices consider marginal costs of generators, the effect of emission costs should transfer to the capacity auction's outcome.

To examine if the model reflects this expected effect, we assume two power plants i and j with different emission costs per capacity unit and define

$$\Delta C^e_{E,t} := C^e_{E,t,j} - C^e_{E,t,i} \tag{4.18}$$

as the difference of expected emission costs.

Then the derivative of Eq. 4.13 with respect to the difference in emission costs yields

$$\begin{aligned}
\frac{\partial \Delta p_{t,j-i}}{\partial \Delta C^e_{E,t}} &= (1 - X^e_{IR,t,j})\frac{\partial IR^e_{t,j}}{\partial \Delta C^e_{E,t}} - (1 - X^e_{IR,t,i})\frac{\partial IR^e_{t,i}}{\partial \Delta C^e_{E,t}} \\
&= (1 - X^e_{IR,t,j})\frac{\partial \left(p_{strike} - C^e_{V,t,j} + C^e_{E,t,i} + \Delta C^e_{E,t}\right)}{\partial \Delta C^e_{E,t}} d^e_{t,j} \\
&- (1 - X^e_{IR,t,i})\frac{\partial \left(p_{strike} - C^e_{V,t,i} + C^e_{E,t,j} - \Delta C^e_{E,t}\right)}{\partial \Delta C^e_{E,t}} d^e_{t,i} \\
&= (1 - X^e_{IR,t,j}) d^e_{t,j} + (1 - X^e_{IR,t,i}) d^e_{t,i} \\
&> 0
\end{aligned} \tag{4.19}$$

because all terms except the IR do not depend on $\Delta C^e_{E,t}$ and therefore vanish. Eq. 4.19 indicates that an increase in the difference of expected emission costs ΔC^e_E leads to a higher price difference Δp_{j-i} and vice versa. ΔC^e_E increases if emission costs increase faster for generator j than for generator i. This means a comparative advantage for

6. A detailed description of the investment algorithm is given in Bhagwat (2016).

power plant i which is indicated by an increasing Δp_{j-i}. Lower emission costs are thus an advantage in a capacity market.

If for instance the price for emission allowances or the emission tax rate increase, the power plant, which is less emission-intensive, faces a lower increase in emission costs per capacity than the more emission-intensive one. In general, less emission-intensive power plants will face a comparative advantage in capacity auctions if emission costs per emitted CO_2 unit increase. The difference in emission costs has a direct influence on profits realized at the spot market. The equilibrium condition (Eq. 4.13) shows that this cost effect is transferred to capacity auctions.

This result is not surprising but it is still important to point out. If there is an inadequate internalization of emission costs, an artificially low price signal will be transferred from the spot market to the capacity auction. This will suppress comparative advantages for less emission-intensive power plants leading to non-optimal investment decisions (Schäfer and Schulten 2014).

4.4.4 Impact of an Increasing Share of Renewable Energy

To this day, electricity markets are usually characterized by an incomplete internalization of emission costs. This prevents a complete market integration of renewable energy. Therefore, renewable energy is currently introduced outside of the market via different support mechanisms. With respect to the electricity market, the share of renewables is thus given exogenously.

The promotion of renewables leads to an excess of fossil capacity, which will be reduced only gradually because of the long lifespan of fossil-based power plants. Therefore, adjustments to the equilibrium will take place in a sequential manner. An energy-only market which is affected by the merit order effect provokes a reduction of excess capacity by shutting down some peak-load power plants first, since they face highest variable costs. This results in increasing inflexibility and an increasingly inefficient utilization of base-load power plants because of excess capacity. In a second step, base-load power plants will be shut down. Finally, if too many peak-load power plants have been shut down in step one, investments in this technology will be undertaken to increase flexibility again.

The question arises whether this sequential process is an inter-temporally efficient solution for the transition phase. The answer is yes, if the mitigated capital erosion caused by the reduction in peak-load instead of base-load capacity is larger than additional costs stemming from increasing inflexibility. It is beyond the scope of this paper to answer this question but we want to investigate if introducing a capacity market has an impact on the described sequential process. The energy-only market does not provide a direct link between capital costs and spot prices, but a capacity market does. Therefore it is of particular interest to explore if premiums in a capacity auction react to an increasing share of renewable energy.

Let φ_t be the share of renewable energy in year t. The merit order effect can then be described by

$$\frac{\partial \bar{p}_{spot,t}}{\partial \varphi_t} < 0.$$

If the share of renewables increases, fossil electricity generation will decrease resulting in decreasing average spot prices $\bar{p}_{spot,t}$. Operation times for peak-load power plants and the duration of scarcity events will decrease. This implies a decreased normalized duration $d_{base,t}$ and $d_{spike,t}$, since the integrals in Eq. 4.1 and Eq. 4.2 become smaller. This leads to

$$\frac{\partial d_{t,base}}{\partial \varphi_t} < 0, \qquad \frac{\partial d_{t,spike}}{\partial \varphi_t} < 0. \tag{4.20}$$

The cost structure of fossil power plants is not influenced by an increasing share of renewable energy. These power plants, nevertheless, face a decrease in spot market rents because of lower $d_{t,base}$ and $d_{t,peak}$. Consequently, MM will increase as it is the difference between capital costs and spot market profits.[7]

Implications of Eq. 4.20 with respect to flexibility of the power plant mix can be derived by examining a representative peak-load and base-load power plant. The impact of the capacity auction is given by the derivative of the equilibrium condition (Eq. 4.14) with respect to the share of renewables under consideration of Eq. 4.9

$$\begin{aligned}\frac{\partial \Delta p_{t,base-peak}}{\partial \varphi_t} &= \overbrace{(p_{cap} - p_{strike})\frac{\partial d^e_{spike,t}}{\partial \varphi_t}}^{\frac{\partial PER^e_t}{\partial \varphi_t}} \Delta X^e_{PER,t} + \frac{\partial MM^e_t}{\partial \varphi_t}\Delta X^e_{PER,t} \\ &- \Delta C^e_t(1 - X^e_{IR,t,base})\frac{\partial d^e_{t,base}}{\partial \varphi_t} \\ &> 0.\end{aligned} \tag{4.21}$$

In the following, we will explain why Eq. 4.21 is always positive. The first summand in Eq. 4.21 corresponds to the change in potential PER multiplied by the power plants'

7. Recall that Figure 4.1 depicts a spot market in equilibrium. Then MM corresponds to the duration integral from p_{cap} to infinity. This relation is no longer valid in a distorted equilibrium. Thus, MM increases for decreasing spot market rents.

difference in availability rates $\Delta X^e_{t,PER}$. The difference in availability rates will be rather small in practice as most modern power plants achieve very high availability rates. However, it is very likely that the higher flexibility of peak-load power plants results in slightly higher availability rates compared to base-load power plants ($\Delta X^e_{t,PER}$>0). Considering Eq. 4.20, the first summand in Eq. 4.21 is negative, although its absolute value is rather small.

The second summand in Eq. 4.21 reflects the change in MM which is also multiplied by the power plants' difference in availability rates $\Delta X^e_{t,PER}$. Taking into account the higher flexibility of peak-load power plants ($\Delta X^e_{t,PER}$>0), the second term is positive while its absolute value is again rather small. As we assume that the capacity market is in equilibrium before the share of renewable energy increases, any decrease in spot market rents creates missing money. If only the PER decreases, MM will increase to the same extent. If the IR decreases as well, MM will overcompensate the decrease in the PER (see also example in Section 4.5). Therefore we find $|\frac{\partial PER^e_t}{\partial \varphi_t}| \leq |\frac{\partial MM^e_t}{\partial \varphi_t}|$. The result is that the sum of the first two summands is never negative.

The third summand in Eq. 4.21 illustrates the change in IR multiplied by the availability of base-load power plants. The decrease in IR affects only base-load power plants. Considering Eq. 4.20, the third summand is positive. Thus, Eq. 4.21 is always positive. An increase in the share of renewable energy leads to an increase in the price difference $\Delta p_{base-peak}$. This represents a comparative advantage for peak-load power plants. An increasing share of RES should thus lead to a higher share of peak-load power plants in the residual fossil capacity mix.

A higher share of peak-load power plants in this context compared to a pure energy-only market can be found in the studies of Keles et al. (2016), Höschle et al. (2017), and Bhagwat et al. (2017). However, both Keles et al. (2016) and Höschle et al. (2017) use an exogenously given development path of RES for their scenario calculations but they do not present a baseline scenario without RES. Thus, we do not know if the high share of peak-load capacity in capacity markets is a result of higher system reliability or a higher share of RES. The same applies to Bhagwat et al. (2017) although they present scenarios for a capacity market with and without subsidized RES. However, the system reliability is higher in the scenario with subsidized RES than without subsidized RES. In contrast to these studies, we concentrate on the impact of an increasing share of RES in our analysis avoiding overlapping effects.

4.5 Numerical Example

We illustrate the functioning of the described capacity market with a numerical example. Generators place bids for one year t. We assume symmetric information. Thus, expectations are subject to the same variance for all generators. We make use of a representative base-load and a representative peak-load power plant with the following properties (numbers are fictional but in a realistic range):

capital costs peak-load	$k_{t,peak}$	490,000 €/MW
failure rate peak-load	$X^e_{PER,t,peak}$	0.02
capital costs base-load	k_{base}	871,000 €/MW
failure rate base-load	$X^e_{IR,t,base}$	0.035
	$X^e_{PER,t,base}$	0.03
$\mathrm{IR}^e_{t,base}$	$(p_{strike} - C_{G,t,base} - C_{E,t,base})d_{t,base}$	400,000 €/MW
PER^e_t	$(p_{cap} - p_{strike})d^e_{spike,t}$	500,000 €/MW

4.5.1 Market Equilibrium

Assuming perfect competition and thus applying Eq. 4.7 yields

$$\begin{aligned} p_{base} &= 871{,}000 \text{ €/MW} + 0.03 \cdot 500{,}000 \text{ €/MW} + \varrho^e_{t,base} - 0.965 \cdot 400{,}000 \text{ €/MW} \\ &= \mathbf{500{,}000 \text{ €/MW}} + \varrho^e_{base} \\ p_{peak} &= 490{,}000 \text{ €/MW} + 0.02 \cdot 500{,}000 \text{ €/MW} + \varrho^e_{t,peak} \\ &= \mathbf{500{,}000 \text{ €/MW}} + \varrho^e_{peak} \end{aligned}$$

as price bids of the representative power plants in a capacity auction. The (truthful) price bids are sufficient to cover capital costs, but they do not include any extra profits for generators. Considering Eq. 4.8, we find that expected MM is zero leading to an expected markup for both power plants ($\varrho^e_{t,base}$, $\varrho^e_{t,peak}$) which is equal to zero, too (see Eq. 4.9). Thus, the clearing price in the capacity auction is $p^*_t = p_{t,base} = p_{t,peak} =$ 500,000 €/MW. The equilibrium price corresponds exactly to the expected potential PER which generators have to pay back because of their commitment enforced by ROs. According to Section 4.4.2, this clearing price also corresponds to the minimum bid, which is expected by operators of already existing power plants.

To examine the example for an electricity market without a capacity market, we calculate expected spot market rents. The operator of the representative peak-load power plant would expect to obtain $R^e_{t,peak} = PER^e_t(1-X^e_{PER,t,peak}) = 490{,}000$ €/MW while the base-load power plant would expect to earn $R^e_{t,base} = PER^e_t(1-X^e_{PER,t,base})+$

$IR^e_{t,base}(1 - X^e_{IR,t,base}) = 871{,}000$ €/MW. If we assume identical capital costs for a scenario with a capacity market we will see that capital costs are also covered without a capacity market. A capacity market would not be necessary to provide MM in this case.[8]

The impact of a capacity market on consumers' expenses for electricity can be examined by comparing expenses in an energy-only market $\xi^e_{eo,t}$ or with an additional capacity market $\xi^e_{c,t}$. This yields

$$\begin{aligned}\xi^e_{c,t} &= \rho_{t,base} \underline{C}_t \cdot R^e_{t,base} + \rho_{t,peak} \underline{C}_t \cdot R^e_{t,peak} \\ &\quad + \rho_{t,base} \underline{C}_t (p^*_t - PER^e_t - \varrho^e_{t,base}) + \rho_{t,peak} \underline{C}_t (p^*_t - PER^e_t - \varrho^e_{t,peak}) \\ \xi^e_{eo,t} &= \rho_{t,base} \underline{C}_t \cdot R^e_{t,base} + \rho_{t,peak} \underline{C}_t \cdot R^e_{t,peak} \end{aligned} \tag{4.22}$$

with $\rho_{t,base}$ and $\rho_{t,peak}$ being the shares of contracted base-load and peak-load capacity respectively. The second line of Eq. 4.22 reflects payments in the capacity market. Since the equilibrium price p^*_t equals the expected potential PER, the markups $\varrho^e_{t,base}$ and $\varrho^e_{t,peak}$ are zero, such that consumers face identical expenses with or without a capacity market ($\xi^e_{c,t} = \xi^e_{eo,t}$).

4.5.2 Risk Reduction

The advantage of a capacity market as described in Section 4.5.1 (equilibrium without MM) shows if results at the energy-only market deviate from expectations. An economic shock might cause those deviations. Let us assume both the PER and the IR are 10 % above/below the expected level. Referring to our example again, in both cases generators would receive a capacity payment of 500,000 €/MW anyway. The regulator would not issue a penalty because the basis for determining the penalty is the expected PER (see Eq. 4.10).

The outcomes at the energy-only market are $R_{t,peak} = 0.9 \cdot R^e_{t,peak} = 441{,}000$ €/MW and $R_{t,base} = 0.9 \cdot R^e_{t,base} = 783{,}900$ €/MW if spot market rents are 10 % below expected values. The operator of the peak-load power plant receives 500,000 €/MW as a capacity payment, has to pay $0.9 \cdot 500{,}000$ €/MW = 450,000 €/MW to the regulator because of the ROs and earns 441,000 €/MW at the energy-only market. Eventually, the generator receives 491,000 €/MW which constitutes an overcompensation of capital costs by 1,000 €/MW. The same calculation for the base-load power plant yields 833,900 €/MW which is 37,100 €/MW lower than capital costs. A capacity

8. Other advantages (e.g. risk reduction or adapting to an increasing share of renewable energy sources) may still justify a capacity market as we will see in the further discussion of this example.

market increases payments for both generators by PER^e-PER = 50,000 €/MW when compared to revenues $R_{t,base}$, $R_{t,peak}$ of an energy only-market.

Spot market rents 10 % above expected values yield $R_{t,peak} = 1.1 \cdot R^e_{t,peak} = 539{,}000$ €/MW and $R_{t,base} = 1.1 \cdot R^e_{t,base} = 958{,}100$ €/MW. In case of a capacity market the generator receives a total payment of 489,000 €/MW for the peak-load power plant (1,000 €/MW less than capital costs) and 908,100 €/MW for the base-load power plant (37,100 €/MW above capital costs). In this case, a capacity market decreases payments for both generators by PER^e-PER = -50,000 €/MW when compared to revenues of an energy only market. The deviation from expectations has a higher impact for the base-load power plant because the capacity market only compensates a deviation in the PER. The overcompensation/undercompensation of 1,000 € for the peak-load power plant results from the product of availability rate and deviation in the PER. The lack of compensation for base-load power plants when there is a deviation in the IR has to be considered.

The capacity market significantly absorbs the impact of an economic shock. This decreases the risk for generators which allows them to assume a lower risk premium (included in $\delta_{t,i}$). The result is lower capital costs in the setting of a capacity market when compared to a pure energy-only market.

4.5.3 Impact of an Increasing Share of Renewable Energy

The impact analyses of power plant maturity and increasing emission costs in Sections 4.4.1 and 4.4.3 show quite intuitive results. Older power plants face lower capital costs which are a direct advantage in a capacity market while it does not matter in an energy-only market. Less emission-intensive power plants face comparatively lower marginal costs if there are high emission prices. The analysis of an increasing share of renewable energy is not that simple, so we use the example above to clarify the underlying mechanisms.

If the equilibrium in the example above is distorted by an increasing share of renewables, a result may be:

capital costs peak-load	$k_{t,peak}$	490,000 €/MW
failure rate peak-load	$X^e_{PER,t,peak}$	0.02
capital costs base-load	k_{base}	871,000 €/MW
failure rate base-load	$X^e_{IR,t,base}$	0.035
failure rate base-load	$X^e_{PER,t,base}$	0.03

$\mathrm{IR}^e_{t,base}$	$(p_{strike} - C_{G,t,base} - C_{E,t,base})d_{t,base}$	250,000 €/MW
PER^e_t	$(p_{cap} - p_{strike})d^e_{spike,t}$	400,000 €/MW

The expected potential PER decreases less than the expected potential IR in this example as empirical data suggests (Nicolosi and Fürsch 2009). Applying Eq. 4.7 as above, we obtain

$$p_{t,base} = 641,750 \text{ €/MW} + \varrho^e_{base},$$
$$p_{t,peak} = 498,000 \text{ €/MW} + \varrho^e_{peak}.$$

Using Eq. 4.8 we can calculate expected MM for both generators. This yields $\mathrm{MM}^e_{t,base}$ = 241,750 €/MW and MM^e_{peak} = 98,000 €/MW which are individual values as they consider individual availability rates. Since MM occurs, generators have to consider a markup in the capacity auction which can be calculated as the product of expected potential MM and the failure rate (Eq. 4.9). Expected potential MM is the ratio of individual expected MM and availability. Therefore, we get

$$\varrho^e_{t,base} = 241,750 \text{ €/MW} \cdot 0.03/(1-0.03) = 7,476.8 \text{ €/MW},$$
$$\varrho^e_{t,peak} = 98,000 \text{ €/MW} \cdot 0.02/(1-0.02) = 2,000 \text{ €/MW}$$

for the respective expected penalties. Now, resulting price bids can be recalculated as

$$p_{t,base} = 649,226.8 \text{ €/MW},$$
$$p_{t,peak} = 500,000 \text{ €/MW}.$$

Price bids show a significant comparative advantage for peak-load power plants. However, that does not mean all base-load power plants will be substituted by peak-load power plants as a consequence. As we learned in Section 4.4.2 a rational bidder with an existing power plant will place a bid corresponding to the PER per capacity unit although annual capital costs are not completely covered.[9] In this case both power plants will place the same bid leading to a clearing price of 400,000 €/MW which corresponds to the PER per capacity unit.

This outcome for existing power plants changes if we assume that new capacity is necessary to satisfy resource adequacy for the next step of the analysis. Then the comparative advantage for peak-load power plants will lead to investments in this technology. According to Section 4.4.1, we assume that a new peak-load power plant

9. It is also possible that the regulator commits already existing generators to a maximum bid which is equal to the PER per capacity unit.

will face higher capital costs $\tilde{k}_{t,peak}$ than the existing representative peak-load power plant leading to $\tilde{k}_{t,peak} = k_{t,peak} + X > k_{t,peak}$. For simplicity, we assume no difference in availability rates for old and new peak-load power plants. Since new capacity is required, the new peak-load power plant will determine the clearing price. Inserting $\tilde{k}_{t,peak}$ into Eq. 4.7 and 4.9 yields

$$p_t^* = \left(500,000 + \frac{X}{1 - X^e_{PER,t,peak}}\right) \text{€/MW}$$

including the penalty.

The regulator derives the penalty factor according to Eq. 4.10

$$xi = (500,000 + X/(1 - X^e_{PER,t,peak}))/400,000 = 1.25 + X/392,000.$$

In this case the expected penalty for the existing base-load power plant will be

$$\begin{aligned}\varrho^e_{t,base} &= ((1.25 + X/392,000) \cdot 400,000 \text{ €/MW} - 400,000 \text{ €/MW}) \cdot 0.03 \\ &= 3,000 + \frac{0.03}{0.98} X \text{ €/MW}.\end{aligned}$$

The expected penalty for the existing peak-load power plant will be

$$\begin{aligned}\varrho^e_{t,peak} &= ((1.25 + X/392,000) \cdot 400,000 \text{ €/MW} - 400,000 \text{ €/MW}) \cdot 0.02 \\ &= 2,000 + \frac{0.02}{0.98} X \text{ €/MW}.\end{aligned}$$

Without a capacity market, we find for the already existing power plants

$$\begin{aligned}R^e_{t,peak} &= PER^e_t(1 - X^e_{PER,t,peak}) = 392,000 \text{ €/MW}, \\ R^e_{t,base} &= PER^e_t(1 - X^e_{PER,t,base}) + IR^e_t(1 - X^e_{IR,t,base}) = 629,250 \text{ €/MW}\end{aligned}$$

as respective expected spot market profits.

Referring to Eq. 4.22, expected consumers' expenses in a capacity market for the already existing power plants are

$$\begin{aligned}\xi^e_c = \rho_{base} C_t \cdot 726,250 + \left(1 - \frac{X^e_{PER,t,base}}{1 - X^e_{PER,t,peak}}\right) X \text{ €/MW} \\ + \rho_{peak} C_t \cdot 492,000 + \left(1 - \frac{X^e_{PER,t,peak}}{1 - X^e_{PER,t,peak}}\right) X \text{ €/MW}.\end{aligned}$$

Subtracting capital costs from these expenses provides information about capital cost coverage leading to

$$\begin{aligned}
&\xi_c^e - \rho_{t,base}\,\underline{C}_t \cdot k_{t,base} - \rho_{t,peak}\,\underline{C}_t \cdot k_{t,peak} \\
&= \underbrace{\rho_{t,peak} \cdot \left(1 - \frac{X^e_{PER,t,peak}}{1 - X^e_{PER,t,peak}}\right) X\,\underline{C}_t}_{\geq 0} \text{ €/MW} \\
&\underbrace{-\rho_{t,base} \cdot (144,750 + \left(1 - \frac{X^e_{PER,t,base}}{1 - X^e_{PER,t,peak}}\right) X)\,\underline{C}_t}_{<0} \text{ €/MW.}
\end{aligned} \tag{4.23}$$

On the one hand, this means an overcompensation of capital costs for the existing representative peak-load power plant (first summand in Eq. 4.23 is positive or zero) which receives more compensation than required regarding the age. Overcompensation is, however, limited to the age effect which depends on X. On the other hand, the respective base-load power plant receives a higher payment than without a capacity market but it is still not sufficient to cover capital costs (second summand in Eq. 4.23 is negative). Nevertheless, the capacity market guarantees a sufficient payment for necessary investments in new capacity.

In principle, it is possible to exclude existing power plants from capacity payments (Keles et al. 2016). This may reduce costs for electricity consumers but it distorts the equilibrium of a capacity market. Schäfer and Schulten (2014) suggest a capacity market with endogenously discriminated prices instead.

The numerical example illustrates that in an optimal capacity market overcapacity does not lead to higher expenses for consumers than an energy-only market. If new capacity is needed the capacity market provides sufficient investment incentives. This allows a smooth transition from a scenario with overcapacity to one which requires new investments. Furthermore, there is a comparative advantage for peak-load power plants with an increasing share of renewable energy. The capacity auction will therefore lead to a more flexible fleet of power plants as soon as necessary.

4.6 Conclusions

Building on Vázquez, Rivier, and Pérez-Arriaga (2002), Cramton and Ockenfels (2012), and Cramton, Ockenfels, and Stoft (2013), we model the functioning of capacity auctions with ROs. We add to the literature by deriving an optimal penalty to punish manipulation by bidders, which enhances incentive regulation. This helps to limit costs associated with capacity auctions which is crucial in terms of efficiency and public acceptance.

Based on the model, we deduce the equilibrium condition of a capacity market considering the spot market for electricity. We find that the capacity market does not cause any extra cost in equilibrium given there is symmetric information and sufficient competition. Thus, it can solve the missing money problem efficiently. This result also holds if there is overcapacity. The capacity market also reduces investment risk at no extra cost as it transforms volatile PERs into continuous annual payments.

The modeled capacity market equilibrium also serves as a reference case for a comparative static analysis. This allows to study three different impact factors of capacity markets. First, the capacity auction design shows advantages for older power plants because of lower risks to lose remaining capital. Under sufficient competition already existing power plants have an incentive to place lower bids (equal to the PER per capacity unit) than any new power plant because they can consider their capital costs as sunk costs. Second, less emission-intensive power plants will have a comparative advantage if costs per emission unit from a carbon tax or emissions trading system increase. Cost advantages on the spot market transfer to the capacity market. Third, an increasing share of renewable energy creates higher investment incentives for peak-load power plants, which increases flexibility. This is a remarkable result as it counteracts the merit order effect of renewable energy at electricity spot markets which leads to decreasing flexibility.

We also discuss why spot markets show a delayed response to an increasing share of renewable energy. This delay raised doubts whether an energy-only market can provide necessary incentives to ensure that investments happen in time. According to our findings, a capacity auction can create the right answer to more intermittent electricity generation from RES with respect to flexibility issues. We find that capacity auctions with ROs are a market-based tool to solve both the missing money and the missing flexibility problem.

However, distortions at the spot market will translate to capacity auctions and limit their effectiveness. Especially the promotion of renewable energy outside the market leads to distorted price signals. The transformation process thus calls for adjustments in market design (Schäfer and Schulten 2014).

Generalizations of this analysis are restricted by assuming symmetric information and profit maximization by generators who participate in the auction. Further research could focus more explicitly on strategic bidding behavior by generators. This promises practical insights into capacity markets.

Chapter 5

Capacity Auction Design for Electricity Markets in Transition[1]

5.1 Introduction

There are doubts if today's liberalized electricity markets (e.g. in the US, EU and UK) are able to provide sufficient investment incentives to guarantee stable electricity supply at all times (resource adequacy). Resource adequacy can be defined as long-term security of supply (Cramton and Stoft 2005; Joskow 2008; Riechmann et al. 2014; Matthes et al. 2015).

These doubts intensified by decreasing spot prices induced by subsidized renewable energy (merit order effect), since lower spot prices decrease the return on investment that power plant operators assumed when the investment was made (Bucksteeg et al. 2014; Praktiknjo and Erdmann 2016; Keles et al. 2016).

There is an ongoing discussion about the necessity of different capacity mechanisms to tackle this problem. See for instance Hobbs, Iñón, and Stoft (2001), De Vries (2007), Pfeifenberger, Spees, and Schumacher (2009), Meyer and Gore (2015), and Bhagwat et al. (2016). In addition to the traditional system of a liberalized electricity market, which mainly consists of an electricity market where generated electricity is traded (energy-only markets), a capacity mechanism shall provide resource adequacy by a payment for provided capacity. Eventually, this creates a stable investment environment. Capacity auctions with reliability options (ROs) are discussed as one promising

1. This chapter is based on a joint work with Dr. Sebastian Schäfer published as Sebastian Schäfer and Lisa Altvater (2021). "A Capacity Market for the Transition towards Renewable-Based Electricity Generation with Enhanced Political Feasibility." *Energies*, 14 (18), 5889.

possibility (Finon and Pignon 2008; Joskow 2008; Siegmeier 2011; Flinkerbusch and Scheffer 2013).

In this system, electricity consumers buy ROs from power plant operators offered in an auction. The regulator who may be represented by the transmission system operator (TSO) may do so on behalf of electricity consumers.

ROs act like a call option to hedge the buyer against high electricity prices. Power plant operators offer ROs based on their expectations about future revenues from generated electricity (Vázquez, Rivier, and Pérez-Arriaga 2002).[2] The first authors who described this type of capacity markets were Pérez-Arriaga (1999) and Vázquez, Rivier, and Pérez-Arriaga (2002).

This market design was extended by Cramton and Ockenfels (2012) suggesting a uniform price auction of ROs. Uniform pricing may result in capacity payments above the placed bids for a certain type of power plants. Thus, operators of such power plants receive a higher payment than necessary leading to an additional profit. This is a desired effect because it increases investments in this type of power plants. Higher investments result in a capacity increase of this superior type. In a next step, this reduces the cost advantage until it finally vanishes.

In a stable environment, a situation without cost advantages for any power plant will emerge in the long-run. Then, the capacity market is in equilibrium and the mix of different types of power plants is optimal meaning that total costs for electricity generation are minimized (see Schäfer and Altvater (2019) for a detailed and formal description of the equilibrium). The described market behavior is comparable to the equilibrium at the spot market.

However, most of today's electricity markets are transitioning towards high shares of renewable energy. In this situation, a so-called *general capacity auction* as described above might not be an adequate tool. There are two problems. First, incomplete internalization of emission costs prevents a *general capacity auction* to reach the described equilibrium with an optimal mix of power plants. The reason is the disparate effect of applied policy instruments on electricity prices although they all aim at reducing emissions.

On the one hand, carbon taxes and an emission trading system (ETS) set a price for CO_2 emissions. This leads to an internalization of emission costs changing electricity generation costs. On the other hand, renewable-based electricity generation, despite substantial cost reductions and partial internalization of emission costs, still highly

2. See also Section 5.2 for details.

depends on subsidies.[3] These subsidies are usually charged to electricity consumers or tax payers. Thus, in contrast to an ETS or a carbon tax, subsidies do not lead to an emission-based increase of electricity prices at the energy-only market.

There is no internalization of emission costs induced by subsidized RES although they contribute to the desired emission reduction. Electricity prices, thus, indicate an emission intensity of generated electricity which is higher than the true emission intensity under consideration of subsidized RES. There is, of course, an indirect effect of subsidized RES on prices at the energy-only market (merit order effect). However, subsidies do not increase generation costs for emission-intensive power plants.

This results in a cost advantage for emission-intensive power plants, which directly affects the outcome of a capacity auction because offers of power plant operators are based on their expectations about future revenues for generated electricity. Thus, the capacity auction will guide investments to power plants with a too high emission intensity. This slows down the transition process. The slowdown is enhanced by the fact that already existing power plants have a comparative advantage when compared to new power plants (Schäfer and Altvater 2019).

The second problem of a *general capacity auction* is insufficient acceptance from electricity consumers. As explained above, cost advantages play an important role to direct the capacity mix to its long-run optimum. However, many of today's electricity markets will not reach this long-run optimum, characterized by vanishing cost advantages, for years or even decades because there is a transition towards RES-based electricity generation. Cost advantages for several power plants will persist for years as long as the transition period to a RES-based electricity generation lasts. This means windfall profits for their operators. According to Rutherford (2000) a windfall profit is defined as an unexpected profit arising from a circumstance not controlled by a firm or an individual. These profits constitute transitory income and may lead to unusual consumer behavior. The introduction of a capacity market generates windfall profits for already existing power plants during the transition phase.

Windfall profits create inefficiencies by a distorted market outcome and reduce the acceptance for a policy instrument. Take for instance, the debate on windfall profits after the EU ETS has been introduced (Skjærseth and Wettestad 2008). Especially, emission-intensive power plants will realize windfall profits because they face cost advantages as a result of the missing internalization of subsidies for RES (see the first problem described above).

In Germany, for example, consumers might accept costs stemming from capacity

3. See penultimate paragraph of Section 5.3.2 and Schäfer (2019) and Kost et al. (2021).

payments to allow a transition to less emission-intensive electricity generation, but there is no acceptance for payments to emission-intensive power plants (Matthes et al. 2012). While windfall profits should always be avoided, the level of public acceptance for payments to emission-intensive power plants may differ from country to country (Sokołowski 2019). Windfall profits for power plant operators compromise political feasibility since consumers will request fair burden-sharing.

Considering these problems, Matthes et al. (2012) suggest a capacity auction that targets certain types of technology. In contrast to a *general capacity auction*, this so-called *focused capacity auction* formulates critical values for emission factors, flexibility requirements and annual utilization times of power plants. Only low emission and flexible power plants with a low annual utilization (e.g. specific gas or biomass power plants) are eligible for capacity payments.

Even though such exogenous limits deal with the discussed two problems of a *general capacity auction*, they create other challenges. First, these limits are direct market interventions which prevent the long-run equilibrium with lowest cost to realize. Second, lobbying may lead to additional inefficiencies (Growitsch, Matthes, and Ziesing 2013) as there are groups with conflicting interests and the regulator has only incomplete information. For example, manufacturers of efficient power plants are interested in strict emission limits while manufacturers of coal power plants prefer a tolerance for higher emission intensity. The regulator does not know the *right* values. The risk to produce an inefficient market outcome persists over the complete transition period because there is a need to adjust these values repeatedly over time.

In this context, we contribute to the literature on capacity mechanisms by introducing endogenously discriminated prices to the *general capacity auction*. This mechanism treats the acceptance and the internalization problem while it avoids the described shortcomings of a *focused capacity auction*. We abstain from engaging in the discussion on whether the introduction of a capacity mechanism is necessary in the first place.

Although RES are still largely subsidized, we assume that RES will dominate electricity generation in the future to achieve long-run objectives for emission reduction (Sandén and Azar 2005; De Jonghe et al. 2009). In fact, the levelized costs of electricity generation (LCOE) from RES are already in the range of new fossil-based power plants (Kost et al. 2021). Consequently, we develop a capacity auction that enhances the adjustment of residual fossil capacity to renewable electricity generation, which is currently still subsidized and, thus, exogenously given from a market perspective.

The suggested mechanism is relevant for all electricity markets with the following properties. First, there is a liberalized electricity market. Second, a capacity market with ROs is discussed as a possible instrument to ensure resource adequacy or has been introduced already. Third, an increasing share of electricity is generated from RES. Fourth, RES-based electricity generation is still subsidized and subsidies are not internalized (e.g. paid by electricity consumers or tax payers). Declining subsidies due to decreasing LCOE from RES do not affect our mechanism since discriminated prices adapt endogenously. These four properties apply to most electricity markets in Europe, USA and parts of South America.

The next section briefly describes the *general capacity auction* developed by Pérez-Arriaga (1999) and Vázquez, Rivier, and Pérez-Arriaga (2002) and extended by Cramton and Ockenfels (2012) as the basis for our model. In Section 5.3, we describe our model, which allows to account for subsidized renewable energy in a capacity auction. The result is a capacity auction with endogenously discriminated prices that converge to a single price in the long-run when full internalization of emissions from electricity generation is achieved and subsidies for RES become obsolete.

We provide an exemplary calculation for Germany to demonstrate our model. With endogenously adjusting prices further market interventions become obsolete. Discriminated prices treat both the internalization problem and the acceptance problem. The functioning of this capacity market is illustrated schematically in Section 5.4 and implications are briefly discussed in Section 5.5. The last section concludes.

5.2 General Capacity Auction Design

The model is based on a capacity auction with so-called ROs presented in the previous chapter. The key elements (target capacity, ROs, bidding strategy by power plant operators and auction design) are briefly revisited. The target capacity needs to be evaluated as a first step. The target capacity is the capacity that limits unsatisfied electricity demand to a certain tolerable extent. The tolerable extent can be, for example, determined by an average system interruption of ten minutes per year and consumer or a similar value. The target capacity is the basis of the capacity auction.

In these auctions ROs are offered by (future) power plant operators. The ROs act like a call option for the buyer during a predefined time period. Since the call option ensures reliability of electricity generation in times of scarcity, it is called RO. In the contracted time period, the buyer acquires the right to be delivered with the contracted amount of electricity for a certain strike price, which is also defined and published before the auction.

In practice, this means that, for spot market prices above the strike price, the seller of the RO has to pay the difference between the spot market price and the strike price to the holder of the ROs. Power plant operators can offset the payment by selling electricity at the spot market during periods with prices above the strike price. Consequently necessary incentives to actually deliver contracted electricity are provided.

A rational power plant operator who wants to take part in the capacity auction calculates the bid in several steps. First, they estimate the expected amount that has to be paid to the future buyer due to ROs when the spot price exceeds the strike price. This payment in periods of spot prices above the predefined strike price is called peak energy rent (PER). The PER per capacity unit determines the minimum bid for the capacity auction because it simply is a temporal redistribution of money. The capacity market transforms the volatile PER into a continuous capacity payment.

In a second step, the power plant operator calculates the expected revenue from selling electricity at the electricity market. The main part of this revenue will consist of revenues from the energy-only market. Additional revenue may be generated by offering balancing energy. In a third step, the operator evaluates if expected revenues at the electricity market are sufficient to cover all costs (including an appropriate profit). If this is the case, they can simply place the minimum bid amounting to the PER per capacity unit. Otherwise the bid is increased until cost coverage is achieved which does, however, reduce the chance of a successful bid.

All power plant operators who take part in the capacity auction place bids offering a certain quantity of ROs for a certain price (sealed bid reverse auction). In a reverse auction, the roles of buyer and seller are reversed. Several sellers place bids, while there is only one buyer. In a sealed bid auction bidders only place one bid and do not know the other participants' bids (Cheng 2008).

Bids are sorted from lowest to highest price until the target capacity determining the number of necessary ROs is reached. This assures that the target capacity is met with lowest costs. The first authors who designed such a *general capacity auction* were Pérez-Arriaga (1999) and Vázquez, Rivier, and Pérez-Arriaga (2002). Cramton and Ockenfels (2012) suggested the use of uniform pricing in the capacity auction leading to an equilibrium with an optimal capacity mix (see Schäfer and Altvater (2019) for a formal and detailed description of the equilibrium).

Strategic bidding behavior may distort the path to the equilibrium. For example, operators with several already existing power plants have an incentive to withhold capacity of some power plants in order to increase the clearing price for all other power plants they own. The same effect would occur if they placed an inflated bid for some of their power plants. Since only the bidder knows if they bid truthfully or place an inflated bid, the regulator is confronted with asymmetric information. The bidder's type is private information. Thus, the solution to the capacity auction is the solution to an adverse selection problem (McAfee and McMillan 1986).

In response to that problem, Cramton and Ockenfels (2012) and Cramton, Ockenfels, and Stoft (2013) suggested that the already existing capacity is obliged to participate in the capacity auction with a bid of zero. This idea works as long as there are new power plants necessary to meet the target capacity. Then, new power plants set the clearing price while existing power plants cannot interfere. A problem will occur if the existing power plants are sufficient to meet the target capacity as, in this case, operators would not receive any payment while they still have to pay the difference between the spot market price and the strike price if the strike price is exceeded.

This would apply across Europe, for example in Germany, Spain, the Netherlands, Portugal or Italy and also in China, where we find a temporary excess of generation capacity (Moret et al. 2020). As suggested in the previous chapter, operators of already existing power plants should be allowed to bid a minimum bid amounting to their expectation about the PER per capacity unit. Since the minimum bid is equal for all operators, it can be calculated and published by the auctioneer (Schäfer and Altvater 2019).

A capacity auction with a clearing price above the minimum bid incentivizes generators to pretend higher capacities than actually available. Then, operators receive more money than what they have to pay during periods with spot prices above the strike price, although they do not provide any capacity. The payment obligation of the ROs, which works like an implicit penalty, is not sufficient to offset this incentive. A solution for this problem is introducing an explicit penalty that operators have to pay additionally when they do not deliver electricity although the spot price is above the strike price.

In the following, we take the described *general capacity auction* designed by Vázquez, Rivier, and Pérez-Arriaga (2002) and Cramton and Ockenfels (2012) and Cramton, Ockenfels, and Stoft (2013) with the extensions presented in the previous chapter as a basis for necessary adjustments to account for subsidized renewable energy. First, we discuss the internalization of external costs (Section 5.3.1). Based on this theoretical foundation, we derive a model to consider subsidies for renewable energy in capacity auctions (Section 5.3.2). This allows to derive a price markup to be used in our modified capacity auction (Section 5.3.3).

5.3 Modeling the Internalization of External Costs

For several decades, it has been a well-known fact that CO_2 emissions are the driving force for anthropogenic climate change (Houghton, Jenkins, and Ephraums 1990). Climate change and, thus, CO_2 emissions cause huge costs (see Stern (2007) as a popular example). As long as there is no regulation to charge for emissions, these costs are paid by the general public. They are external costs. Thus, carbon pricing is widely seen as the key instrument to combat climate change (Lilliestam, Patt, and Bersalli 2021). This pricing system makes polluters pay for their CO_2 emissions. It internalizes external emission costs. Emissions trading systems and carbon taxes are the most prominent examples in this context.

5.3.1 Theoretical Background on External Costs

In an ETS, every emitted unit of CO_2 requires a respective certificate. The total number of certificates is limited and determines the level of emissions that is allowed. Thus, certificates become a scarce good resulting in a positive certificate price. A carbon tax is a market-based policy instrument as well but it works the other way round (Hockenstein, Stavins, and Whitehead 1997). It directly prices emissions, while the residual amount of emissions is the resulting variable. The ETS sets the target quantity while a carbon tax sets the target price.

Introducing a carbon price incentivizes emission abatement. If an emitter has the choice to either pay, e.g. 1,000 USD for a measure to reduce emissions or to pay 1,200 USD for allowances/taxes instead, they will reduce emissions. If the carbon price is below 1,000 USD, they will not adopt the measure.

A rational emitter will always reduce emissions if costs for CO_2 abatement are lower than the equivalent value of certificates in case of the ETS or potential tax savings in case of a carbon tax. In an optimal system, a carbon tax and certificate price correspond to abatement costs of the last marginal emission unit. Therefore, the certificate price and carbon tax rate can be regarded as being approximately equal to marginal abatement cost (MAC). In practice, the certificate price or the carbon tax may include other factors, like speculation.

Standard environmental economics assumes increasing MAC with increasing emission savings (Nordhaus 1991). This is a plausible assumption because a progressive decrease in emissions requires a sequential introduction of more and more expensive measures.[4] Emission reduction with respect to electricity generation may be achieved by rather cheap efficiency gains in the use of fossil fuels at the beginning.

Any additional increase in efficiency will be more and more difficult and, thus, increasingly costly and will reach thermodynamic limits eventually. Then, a transition to less carbon intensive fuels may be necessary causing even higher costs than the previous mitigation measure. Eventually, RES will replace fossil fuels. Due to the vast potential of renewables, they can be regarded as the last necessary mitigation measure with the highest MAC in electricity generation.

Carbon pricing affects prices for generated electricity. The introduction of an ETS or a carbon tax translates to higher costs for emission-intensive power plants compared to clean power plants (Endres 2011). This changes the merit order. Emission-intensive power plants will be used less, and their revenues from generated electricity will decrease. This will also change the bidding behavior in a capacity market. Lower revenues from the energy-only market can only be compensated by higher bids in the capacity auction. However, this decreases the chance to succeed in the auction. A high carbon price leads to advantages for clean power plants and, thus, more investments in this technology.

The internalization of emission costs via carbon pricing does not take place at once but gradually (Owen 2011). There are, for instance, different trading periods for the ETS with a decreasing number of certificates from one trading period to the next (Schäfer 2019). Higher emission savings cause higher MAC, eventually leading to an increasing carbon price. A carbon tax also increases over time to achieve higher emission reductions (Bowen 2011).

Based on these considerations, RES (which face comparatively high MAC) will enter the market as soon as the carbon price reaches the MAC level of renewables. Until now, this level has not been reached in most countries because RES-based power plants have to compete with already running old (or subsidized) fossil-based power plants. Thus, renewable-based electricity generation, despite substantial cost reductions, still requires subsidies (Schäfer 2019).

Figure 5.1 illustrates the considerations above. The schematic diagram depicts CO_2 emissions with a linearly increasing MAC curve for decreasing emission levels. This reflects an increasing mitigation effort. E^{MAX} corresponds to the emission level in the absence of any emission regulation like carbon pricing. Consequently MAC(E^{MAX}), which is equal to the tax rate or the certificate price, is zero.

4. See e.g. Grubb et al. (1993), Kesicki (2012), and Gillingham and Stock (2018).

Assuming a perfect carbon tax, p_t' in Figure 5.1 corresponds to a possible tax rate with E_t' as the resulting emission level. In a perfect ETS, the quantity of emissions is controlled, such that E_t' reflects the emissions cap and p_t' is the resulting certificate price. The area below the MAC curve corresponds to the abatement costs C_{ab}.

Thus, the integral with respect to MAC from $E_t^{'}$ to E^{MAX} equals abatement costs $C_{ab}(E_t^{'}, E^{MAX})$, which are necessary to reduce emissions from E^{MAX} to $E_t^{'}$. The integral from zero to $E_t^{'}$ equals future abatement costs $C_{ab}(0, E_t^{'})$, which would be necessary to mitigate all remaining emissions. The crosshatched area B corresponds to the tax revenue or the ETS costs. It is the component of abatement costs, which are internalized because of the carbon price p_t'. We define this as internalized costs $C_{int}(E_t^{'})$. The rest of future abatement costs are still external costs.

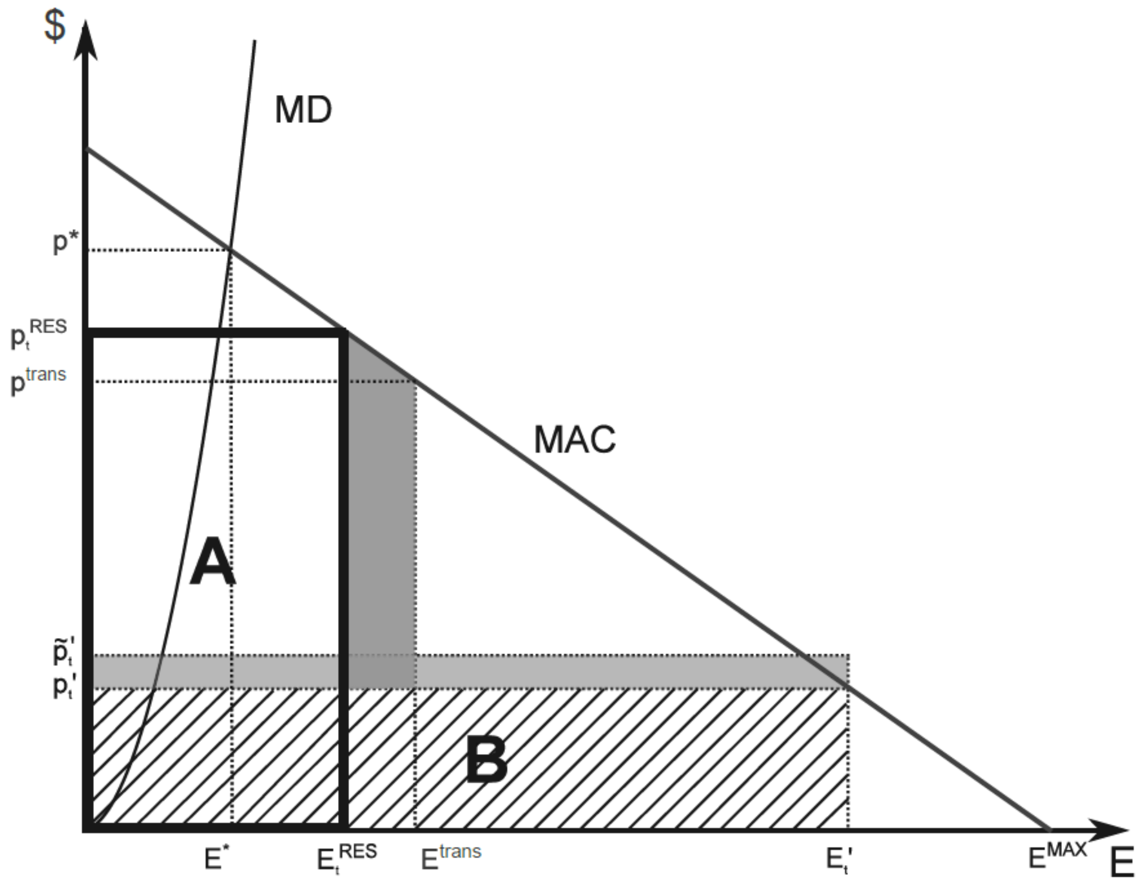

Figure 5.1: CO_2 emissions with respective marginal abatement costs (MAC) and marginal damage (MD). The figure depicts prevailing emission levels for different scenarios on the x-axis and associated price levels on the y-axis. The long-run emission objective is indicated by the optimal emission level E^* and corresponding price p^*.

For our further analysis, we will use the ratio of internalized costs of future abatement costs and define it as the degree of internalization

$$\Delta(E_t^{'}) := \frac{C_{int}(E_t^{'})}{C_{ab}(0, E_t^{'})}. \tag{5.1}$$

The degree of internalization is also used as a concept to describe the progress of internalization in the transportation sector (Van Essen et al. 2019; Vierth and Merkel 2020). According to Equation 5.1, a high degree of internalization, e.g. 0.8, indicates that 80 % of costs stemming from CO_2 emissions are already internalized. A low degree of internalization, e.g. 0.2, means that 20 % of emission costs are internalized, whereas 80 % are still not covered by the polluter. We use the carbon price as an indicator for the degree of internalization in the following analysis.

In Figure 5.1, t indicates the time dependency as certificate price/tax rate and respective emission levels vary over time. Every increase of the carbon price leads to an additional reduction of CO_2.[5] The negative externalities associated with CO_2 emissions are illustrated by the marginal damage curve (MD).

The intersection of MAC and MD results in E^* characterizing the optimal long-run emission level with the resulting price p^*. This value is easily identified in theory, but it can only be assumed in practice and follows from a political objective. The long-run objective of the EU, for instance, claims 80-95 % CO_2 mitigation until 2050 when compared to 1990 levels (Council of the EU 2009). The EU ETS, which was introduced in 2005, is the main instrument to achieve this goal (Fitch-Roy, Fairbrass, and Benson 2020).

The transition price p^{trans} corresponds to the MAC level from which on renewable energy becomes the cheapest mitigation measure. It indicates the transition to a RES-based electricity generation. E^{trans} is the resulting emission level. There are good reasons why renewable energy may face less increasing or even decreasing MAC. Moreover, MAC are not static but may depend on the use of RES as learning effects have an impact on MAC, see e.g. Sorrell and Sijm (2003) and Kalkuhl, Edenhofer, and Lessmann (2012).

Since these effects are not decisive for the purpose of this analysis, we assume linearly increasing and static MAC of identical slope for all CO_2 reduction measures. If, as depicted in Figure 5.1, there is a gap between p^{trans} and the present carbon price p_t', carbon pricing is not sufficient to incentivize renewable-based electricity generation. This is still the case in many countries (e.g. in most EU Member States and USA).

5. This is a schematic simplification since the MAC curve is more likely a step function (Gillingham and Stock 2018).

5.3.2 The Effect of Subsidies for Renewable Energy

Subsidies for RES bridge the gap between the carbon price and MAC induced by emission abatement from RES-based electricity generation. Referring to Figure 5.1, this corresponds to the gap between p'_t and p^{trans}. In practice, however, different renewable energy technologies exist that also differ in their cost structure. Thus, we regard p^{trans} as an average of these prices in the following analysis.

This chapter focuses on how to design a capacity market to receive the best answer to the simultaneous subsidization of RES. A capacity market cannot correct potential shortcomings of the support scheme for RES (e.g. too high remuneration resulting in too fast capacity increases of RES). These are spill-over effects to the energy-only market and, consequently, to the capacity market as bids are based on expectations about prices at the energy-only market.

Nevertheless, the discussion about an efficient support scheme[6] is beyond the scope of this analysis. We therefore assume a perfect support scheme for RES and static MAC. Today's subsidies for RES are seen as shifting investments (which would have been undertaken under a higher carbon price in the future anyway) to an early stage. Thus, subsidies for RES correspond to abatement costs, which also would have been paid in the future without a support scheme for RES as soon as the carbon price reached a corresponding high level.

Impact of Subsidized Renewable Energy on Internalization

Despite the assumed perfect support scheme for RES, there is a decisive difference with respect to the capacity market outcome when comparing a scenario with subsidies for RES to one without subsidies. Without subsidies, RES enter the market when the carbon price reaches a certain level (p^{trans} in Figure 5.1).

This comparatively high carbon price reflects a corresponding high degree of internalization. In contrast, this does not necessarily apply to a scenario with subsidies for RES. Subsidies are usually financed by taxes or levies, but they are not charged to polluters in line with their emission intensity. Thus, subsidies for RES do not lead to an internalization of emission costs among power plant operators. Although subsidized RES lead to additional emission reduction, there is no proportional increase of the carbon price. This affects prices on the electricity market and thus the outcome of the capacity auction.

6. See e.g. Lesser and Su (2008), Haas et al. (2011), and Haufe and Ehrhart (2018).

The following thought experiment illustrates the consequences of the considerations above. Let us assume two scenarios. First, we assume that a model economy sets a carbon price which reduces CO_2 emissions by 20 %. Second, the same model economy sets a lower carbon price, which cuts emissions by only 10 %, while another 10 % of CO_2 is mitigated by subsidies for RES. In both scenarios, there is an emission reduction of 20 %.

However, the carbon price in the first scenario is higher than in the second scenario. Hence emission-intensive power plants have an advantage in the second scenario compared to the first. Since bids in the capacity auction depend on expected profits at the electricity market, this result translates to the capacity market. Thus, in the scenario with subsidies for RES, a capacity market without adjustments directs investments to more emission-intensive power plants.

There are several approaches to this problem. First, the problem will vanish if there is no support scheme for RES. However, this trivial solution is not desirable as it would eliminate the advantages of subsidized RES, such as the exploitation of learning effects, see e.g. Sorrell and Sijm (2003) and Kalkuhl, Edenhofer, and Lessmann (2012).

Second, the described problem will disappear if costs for the support scheme are charged to the polluters proportional to their emission intensity leading to higher spot market prices. This is, without a doubt, the economically efficient solution. However, it is not without reason that the support schemes for RES are usually financed by taxes or levies. Apart from possible implementation difficulties this approach faces a high risk of failure because of a lack of political feasibility. Every increase of the carbon price and hence the spot price entails the risk of competitive disadvantages because of carbon leakage (Aichele and Felbermayr 2015; Böhringer, Rosendahl, and Storrøsten 2017).

Moreover, higher carbon prices decrease the profit for emission-intensive power plants which is, on the one hand, a desired effect. On the other hand, it increases the risk of sunk investments, consumers will pay for in the end. Indeed, there are often controversial debates about the carbon price so that the introduction of efficient measures is eventually abandoned (Carattini et al. 2017; Carattini, Kallbekken, and Orlov 2019; Fesenfeld 2020).

While the described lack of political feasibility prevents a correction of low internalization degrees at spot markets, conditions are different for capacity markets. Instead of cutting profits for existing power plants, a capacity market uses payments as incentive to direct investments to an efficient equilibrium.

Among power plant operators, opposition against capacity markets is, thus, lower than against a higher carbon price. However, it is necessary to correct the distorted degree of internalization on the level of the capacity market to direct investments to the equilibrium. This is not only a question of efficiency but also of political feasibility because electricity consumers who have to pay for capacity markets will not accept to pay for a support of emission-intensive power plants. This demands a well-balanced capacity mechanism.

Next, we present a mechanism to correct the distorted degree of internalization on the level of a capacity market. The result is a capacity price that depends on emission intensity. In Section 5.4, we show how to use this mechanism to prevent generous payments to emission-intensive power plants. This enhances political feasibility.

Correcting the Distorted Degree of Internalization

In the following, we use Figure 5.1 again for a helpful thought experiment. Let us assume our model economy from Section 5.3.1 with a carbon price $p(E_t^{'})$ and the respective emission level $E^{'}$ also introduces subsidies for RES-based electricity generation. The support scheme of the economy may reduce emissions from E^{trans} to E_t^{RES}. Assuming an efficient promotion mechanism, paid subsidies S_t are equal to abatement costs $C^{ab}(E_t^{RES}, E^{trans})$, which correspond to the integral of MAC from E^{trans} to E_t^{RES}.

In analogy to Section 5.3.1, we can also calculate the internalized costs $C_{int}(E_t^{RES})$ as a product of $MAC(E_t^{RES})$ and the remaining emissions E_t^{RES} (bordered area A in Figure 5.1). However, in this case, the internalized costs are nothing more than a theoretical value because these costs are not covered by the polluter. Only the part of area A that overlaps with the crosshatched area B is internalized because of the carbon price $p(E_t^{'})$. The additional subsidies for RES, in contrast, do not internalize any costs although they contribute to emission reductions.

Thus, the carbon price $p(E_t^{'})$ does not reflect the true degree of internalization. The capacity mix is already less emission-intensive than the carbon price indicates. Considering the contribution of RES to emission reduction, the adjusted emission price $\tilde{p}_t' = p_t' + \Delta p_t$ should be somewhere between $p(E^{'})$ and $p(E^{RES})$ to reflect the true degree of internalization. This implies to assume that the promotion of renewable energy does not violate the optimal mitigation path. Referring to Figure 5.1, the abatement by renewables must not exceed E^{*} in this case (Schäfer 2018).

There are different approaches to define such an adjusted emission price. We could stipulate that the adjusted emission price should reflect MAC, which would have occurred if emission reduction by renewables ($E^{trans} - E_t^{RES}$) would have been induced by emissions trading or a carbon tax instead. Both lead to a higher carbon price. The result would be $\tilde{p}'_t :\overset{?}{=} MAC(E'_t - (E^{trans} - E_t^{RES}))$ (see Figure 5.1). The problem is that we know $MAC(E'_t)$ but we do not know the course of MAC for higher emission abatement (lower emissions) in practice.

A second approach is to use the price difference caused by subsidies for renewables ($p^{RES} - p^{trans}$) as a markup for the emission price. The result would be $\tilde{p}'_t :\overset{?}{=} p'_t + p_t^{RES} - p^{trans}$. For linearly increasing MAC both approaches lead to the same result. However, $p_t^{RES} - p^{trans}$ can be zero or negative if MAC for renewables is constant or even decreasing. The adjusted emission price would be lowered in this case, although the degree of internalization increased. That goes against common sense because the decrease in MAC after the market entry of RES requires a significant increase first (until $MAC(E_t^{trans})$ is reached). Following the second approach neglects this increase.

We suggest to use the gap between MAC assigned to renewables and the carbon price ($p_t^{RES} - p'_t$) together with a weighting factor to define the markup Δp_t. We choose the weighting factor in a first step as a ratio between emissions abated by renewable energy ($E^{trans} - E_t^{RES}$) and emissions $E'_t - E_t^{RES}$, which define the gap in carbon pricing and emission reduction with RES. This yields

$$\Delta p_t :\overset{?}{=} (p_t^{RES} - p'_t)\frac{E^{trans} - E_t^{RES}}{E'_t - E_t^{RES}} \tag{5.2}$$

$$\approx \frac{S_t}{E'_t - E_t^{RES}} \tag{5.3}$$

with S_t corresponding to subsidies ($\int_{E_t^{RES}}^{E^{trans}} MAC(E)\mathrm{d}E$) for RES in year t. In fact subsidies S_t are a bit lower than $(p_t^{RES} - p'_t)(E^{trans} - E_t^{RES})$ if MAC are increasing with abatement (see Figure 5.1). Therefore, the use of subsidies in Equation 5.3 leads to a slight underestimation of Δp_t for increasing MAC. Assuming linearly increasing MAC, Equation 5.2 leads to the same result as the first and second approach because, according to the intercept theorem, we find $\Delta p_t = p_t^{RES} - p_t^{trans}$ in this case. The advantage of Equation 5.3 compared to the other two approaches is that the future course of MAC does not need to be known and that Δp_t is positive even in the case if $p_t^{RES} - p^{trans}$ is negative.

As we do not know $E'_t - E_t^{RES}$ in practice we suggest to use the approximation E'_t instead.[7] It can be calculated with data that is easily available (see Section 5.3.3) and

7. Note that E'_t also includes emissions, which have been mitigated by RES already ($E^{trans} - E_t^{RES}$).

results in a conservative estimate for Δp_t eventually.

Including the preceding considerations, we define the markup as

$$\begin{aligned}\Delta p_t &:= (p_t^{RES} - p_t^{'})\frac{E^{trans} - E_t^{RES}}{E_t^{'}} \\ &\approx \frac{S_t}{E_t^{'}} \end{aligned} \tag{5.4}$$

Referring to Figure 5.1, the product of Δp_t and $E_t^{'}$ yields the light-shaded area between p_t', $\tilde{p}_t'$ and $E_t^{'}$, 0 which is as large as the dark-shaded one because both amount to subsidies for RES S_t. The suggested mechanism regards subsidies for RES as internalized costs and transforms them into a proportional markup.

5.3.3 Calculation of the Adjusted Emission Price

To calculate the price markup Δp_t, it is necessary to find both annual data for subsidies of electricity generation from renewable energy sources (S_t) and for emissions of fossil power plants as well as emissions which are mitigated by the use of RES summing up to $E_t^{'}$.

Annual subsidies for RES are well-known in reality. In countries that use a remuneration for renewables (fixed or determined in reverse auctions) they are mainly the difference between the remuneration for renewables and the market value of generated electricity from the respective renewable energy source, denoted as difference costs.

Using difference costs as subsidies neglects the merit order effect of RES, which leads to a decrease of the respective market value resulting in higher difference costs. This inflates subsidies at least in the short run. Moreover, high profits for generators of renewable-based power plants may inflate subsidies. In this case, there is no efficient promotion scheme for RES Thus, subsidies do not reflect MAC and it might be better to use another estimate for MAC.

The estimation of total annual emissions and emissions that are already mitigated by the use of renewable energy requires two steps. Annual emissions E_t of all k fossil power plants ($\sum_{i=1}^{k} E_{t,i}$) are well known in developed countries. For European countries, they are published in the national inventory reports, which are part of the reporting obligations of the EU ETS.

The identification of those emissions, mitigated by renewable energy, cannot be observed directly. Following Schäfer (2018), we can assume that renewable energy will substitute fossil power plants with average emission intensity in the long run. Since fluctuating renewables (wind and solar) require some backup or storage capacity, reduced emissions may be less than the average emissions from fossil power plants.

This is indicated by the factor ρ_i, which equals one for adjustable power plants while it is lower than one for non-adjustable power plants. Memmler et al. (2009) suggest $\rho = 0.93$ for wind and solar power plants. The annual emission reduction by renewables can be calculated if the amount of individual annual electricity generation $Q_{t,i}$ of all k fossil and all $n-k$ renewable energy power plants is known.

Since the individual annual electricity generation is usually subject to taxation, information on the generated amount of electricity is available. This yields

$$E_t^{'} = \sum_{i=1}^{k} E_{t,i} \frac{(\sum_{i=1}^{k} Q_{t,i} + \sum_{i=k+1}^{n} Q_{t,i}\rho_i)}{\sum_{i=1}^{k} Q_{t,i}} \tag{5.5}$$

with n being the total number of power plants. $Q_{t,i}$ corresponds to generated electricity of power plant i in year t. Since fossil power plants are always adjustable in the sense that they do not depend on a fluctuating energy source like wind or sun, ρ_i is only applied to these types of renewable power plants. The ratio in Equation 5.5 is the ratio between the total annual electricity generation and electricity which is generated solely by fossil energy sources per year.

In the following, we will show two different ways to calculate the markup for Germany as an example. Icha and Kuhs (2020) reported total emissions from German electricity generation in 2018 amounting to 269 Mt. AG Energiebilanzen e.V. (2021) provided data on electricity generation for the same year, which allows to calculate the ratio in Equation 5.5 to be 1.51. This yields, according to Equation 5.5, $E_{2018}^{'}$=406.2 Mt. The total subsidies paid for RES-based electricity generation in Germany was € 25.6 billion in 2018 (Informationsplattform der deutschen Übertragungsnetzbetreiber 2018). With these data, the markup is Δp_{2018}=63 €/t. In the same year the certificate price of the EU ETS was 15.29 €/t on average (Fraunhofer ISE 2021). This shows the potential for distortions in a capacity market if subsidies for RES are not considered.

However, Δp_t may be overestimated due to inflated promotion costs. First, the merit order effect leads to lower spot prices which automatically increases the difference between paid remuneration and spot prices. Second, promotion costs may include high rents for generators. That was the case for instance, when solar power boomed in Germany around the year 2010 (Frondel, Schmidt, and Vance 2014). This effect still inflates subsidies for RES because remuneration is fixed for 20 years.

Thus, it might be reasonable to calculate the price markup using estimates for recent

RES-based generation costs instead of paid subsidies. This yields an estimate for subsidies necessary to generate the same amount of electricity with today's costs. In a first step, we can calculate difference costs for different renewable energy sources using levelized cost of electricity (LCOE) according to Kost et al. (2018) and the 2018 average market value for the different RES ranging from 3.18 €-cents/kWh for wind energy to 4.45 €-cents/kWh for biomass (Burger 2019).

This yields a difference in costs ranging from 0.81 to 5.05 €-cents/kWh for wind power plants, from -0.68 to 3.84 €-cents/kWh for solar power plants and from 5.69 to 10.29 €-cents/kWh for biomass. Negative difference cost indicate that subsidies are not necessary. This applies for good sites of solar power plants. The product of difference costs and generated electricity from subsidized RES and dividing by E'_{2018}=406.2 Mt yields a price markup Δp_{2018} ranging from 7.1 €/t to 27.5 €/t while wind, solar and biomass covered more than 95 % of German electricity generation from subsidized RES in 2018. The significant price markup indicates that renewable-based electricity generation still highly depends on subsidies.

The integration of the price markup into the capacity auction requires its transformation into a measure per capacity unit as a last step. A capacity auction ensures sufficient payments to cover total costs of a generator. Thus, a truthful bid is the difference between revenue and cost. If the markup was applied at the spot market, it would produce additional cost, which are given by multiplying the price markup by the generator's expectations about emissions. Since price bids in a capacity auction refer to capacity units, these costs have to be divided by the individual capacity $C_{t,i}$ of each generator i. This yields

$$\Delta \tilde{p}_{t,i} = \frac{E^{exp}_{t,i}}{C_{t,i}} \Delta p_t \tag{5.6}$$

reflecting the price markup per capacity unit for each power plant i. While the price markup Δp_t can be easily calculated by the auctioneer based on reliable data, expected emissions are individual information of every power plant operator. The next section offers an example to illustrate how to deal with this problem and other aspects of the suggested market design.

5.4 Illustration of Results by an Exemplary Capacity Auction Outcome

We propose a step-wise procedure that incorporates up to four different capacity premiums with respective limits for emission intensity. Power plants are handled differently depending on whether they were installed before a capacity market was in place (existing power plants) or after (new power plants). If the investment decision has been made already, a capacity payment is actually not necessary because capacity markets shall only provide incentives for critical future investments. Nevertheless, capacity payments might make sense in a scenario of decreasing spot prices induced by subsidized RES to reduce price risks. Figure 5.2 illustrates the simplified sequence of events and Figure 5.6 summarizes the procedure in a decision tree.

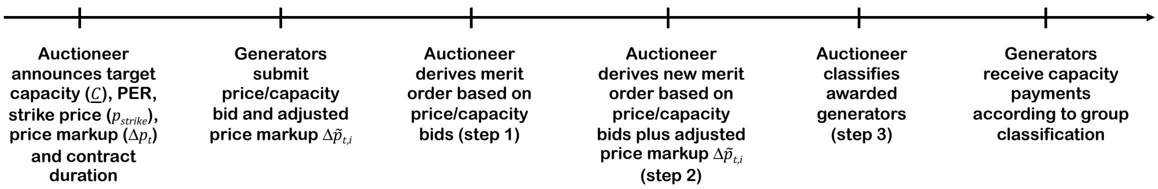

Figure 5.2: A simplified sequence of events of the step-wise procedure leading to the classification of groups of power plant operators.

In our mechanism, new power plants emitting only a low amount of emissions can achieve the highest payments. Existing and more emission-intensive power plants will receive less or no payment at all. We suggest a time horizon for the capacity market of one year for existing power plants and a longer period for new power plants. This decreases the investment risk for new power plants, while it obtains the flexibility of a faster substitution of existing power plants by superior new power plants in the following years.

At first, generators offer their capacity for example in a sealed-bid reverse auction. A descending-clock reverse auction as suggested by Cramton and Ockenfels (2012) is also feasible.[8] The result of the reverse auction is a merit order of capacities as depicted in the lower graph of Figure 5.3 as an example.

8. However, see for example Harbord and Pagnozzi (2014) for a critical assessment of the descending-clock auction in the context of capacity auctions.

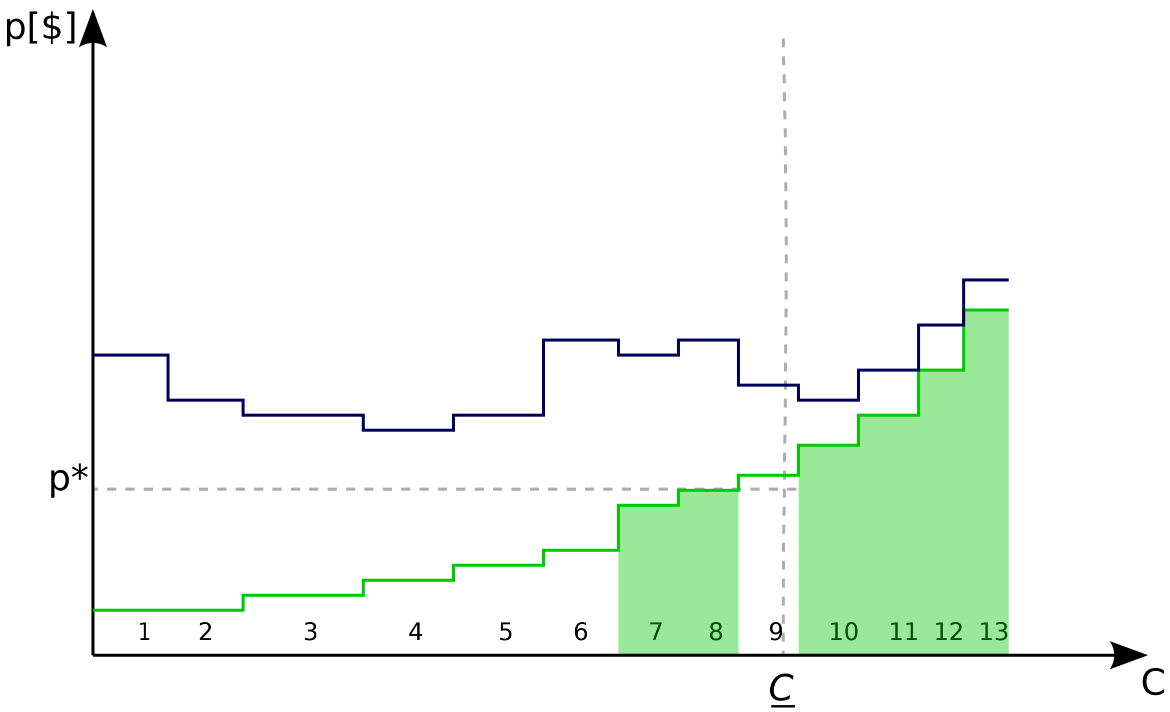

Figure 5.3: Example for a merit order of capacity (lower graph) with respective adjusted price markups (upper graph) for 13 exemplary power plants identifiable by the respective number $n = 1, \ldots, 13$ and ordered by increasing price bids (step 1).

To reduce market power abuse, all existing power plants have to participate in the auction or to leave the market permanently. In contrast to Cramton and Ockenfels (2012), Cramton, Ockenfels, and Stoft (2013), and Schäfer and Altvater (2019), we accept positive bids from existing power plants since these bids are used for a differentiation in step 2 and 3 of the suggested mechanism.

Nevertheless, only the last new power plant which is needed to meet the target capacity $\underline{C}$, is considered for price determination. The resulting clearing price p^* of the first step is in accordance with Cramton and Ockenfels (2012) if new power plants are needed to satisfy the target capacity. In Figure 5.3, power plant 8 determines the clearing price, although number 9 is also needed to satisfy the target capacity.

For the second step in our mechanism, the auctioneer needs to know the adjusted price markup $\Delta\tilde{p}_{t,i}$ according to Equation 5.6 for every participating power plant. This, at first, requires to estimate the price markup Δp_t. The simplest way to determine Δp_t is to refer to historic data while applying a forecast for the next years is possible as well. Δp_t is equal for all generators and can be calculated with already available data. The auctioneer announces Δp_t before the auction takes place. The higher Δp_t, the more pronounced are emission costs, severely impacting emission-intensive power plants. Individual capacity $C_{t,i}$ which, according to Equation 5.6, is necessary to transform the price markup Δp_t into the adjusted price markup $\Delta\tilde{p}_{t,i}$, is known as generators have to report it to participate in the capacity auction.

Estimating expected emissions for each generator ($E_{t,i}^{exp}$), the last necessary variable to calculate the adjusted price markup, is more challenging. While recent emissions of existing power plants are known because of reporting obligations, emissions of new power plants have to be estimated. There is an incentive to claim lower emission levels as it decreases the price markup. This may lead to a higher chance to be awarded in the auction. Nevertheless, estimations for generators entering the market can be corrected ex post if necessary.

The auctioneer is able to verify the claimed emissions by simulating the awarding process one year after the auction has been held using an adjusted price markup based on observed ex-post emissions for each formerly awarded bidder. If the ex-post analysis results in a different classification of formerly awarded bidders, the auctioneer validates if for each formerly awarded bidder that is in a new group now, this result remains unchanged although emissions are reduced/raised by e.g. 10 %. In that case, the capacity payment is corrected as this suggests that estimated emission levels deviate from actual emission levels.

The correction can be combined with an additional penalty if a too low markup was declared to incentivize to report true information. If this correction mechanism is applied, bidders may simply specify their individual adjusted price markup when they place the bid since it minimizes the regulatory effort and a deviation is corrected ex post according to existing reporting obligations.

Summing up the adjusted price markup and the price bid yields the upper graph of Figure 5.3, which reflects the total costs for generators considering a more realistic degree of internalization. The merit order of capacities may change and the new hypothetical clearing price increases to $\tilde{p}^*$ because it includes the respective adjusted price markup (see Figure 5.4). If generators with a successful bid received $\tilde{p}^*$ as a capacity payment, they could cover subsidies for renewable energy. Since this is conceivable in principle but rather not feasible politically (see Section 5.3.2), we use step 2 solely to identify the proper merit order of capacity.

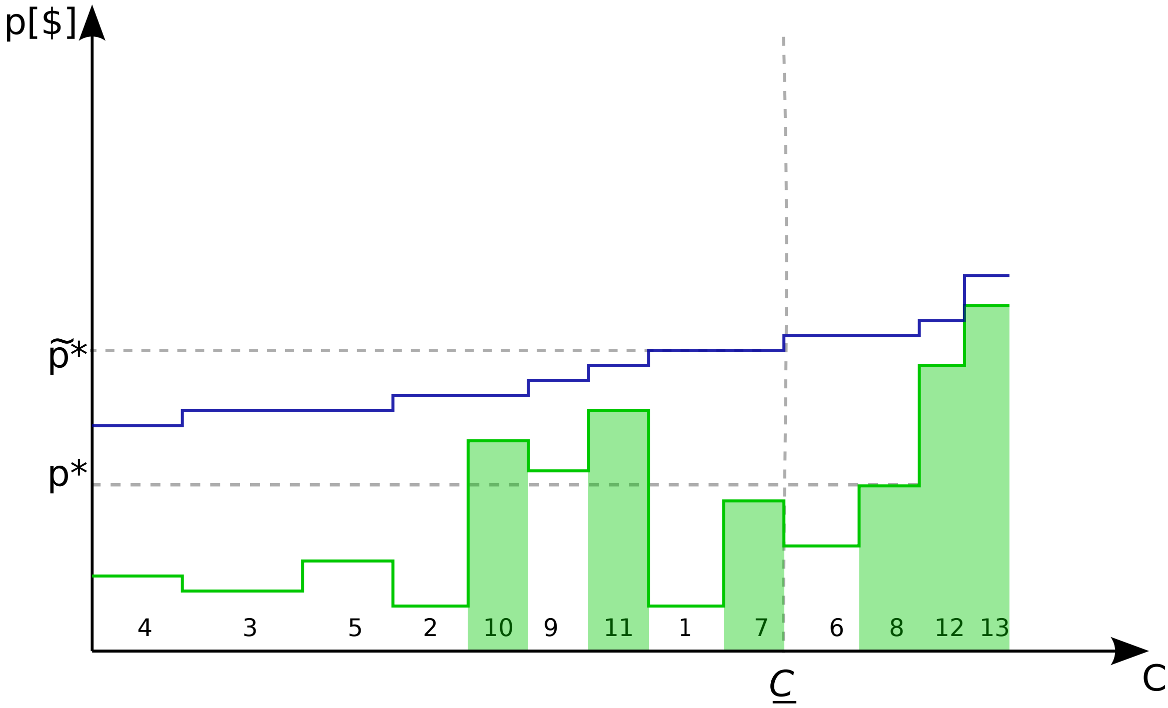

Figure 5.4: Merit order for the same sample of 13 exemplary power plants as depicted in Figure 5.3 again identifiable by the respective number $n = 1, \ldots, 13$ under consideration of capacity bids (lower graph) and respective adjusted price markups (upper graph) for power plants ordered by increasing total costs (step 2).

Step two of the mechanism enables the auctioneer to classify four groups by price discrimination (see Figure 5.5). Existing power plants with a successful bid in step 1 only (power plant 6 in our example) emit so much CO_2 that they would leave the market if the proper degree of internalization was applied. They form group I and do not receive any capacity payment ($p_1^* = 0$) to induce their phase out instead of providing incentives for further investments in such a technology. No capacity payment means a financial burden for these power plants as they are obliged to pay the PER to electricity consumers because of the reliability options. This acts like a carbon tax for power plants with highest emission intensity.

To prevent market power abuse, existing power plants that placed a bid higher than new power plants in step 1 but were still successful in step 2 (power plant 9 in Figure 5.3), receive only the PER per capacity unit. This means neither a disadvantage nor a big advantage when compared to the situation without a capacity market. The same can be applied to existing power plants which do not belong to group I (zero payment) and which are behind new power plants in the adjusted merit order (power plant 1 and 9 in Figure 5.5). These power plants form group II. The hazard of being penalized with a capacity premium that is limited to the PER per capacity unit decreases incentives for generators to place bids above their costs.

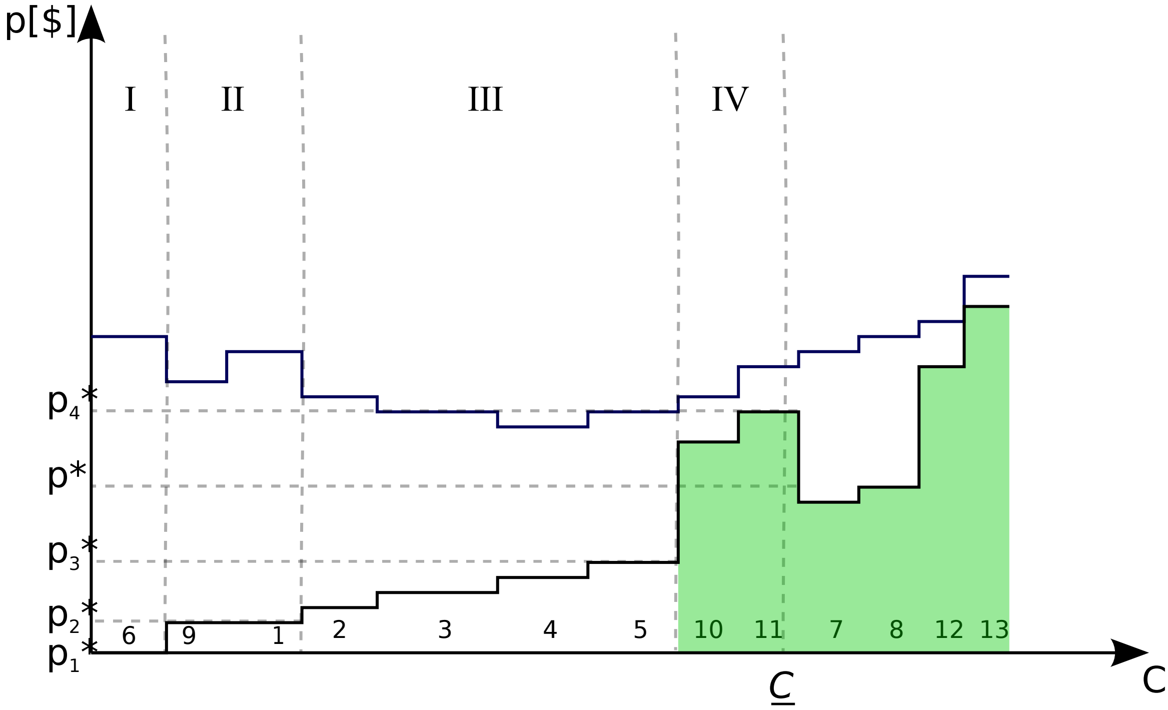

Figure 5.5: Merit order of capacity (lower graph) and respective adjusted price markup (upper graph) of the successful power plants identifiable by the respective number $n = 1, \ldots, 13$ ordered by increasing price bids within each of the four groups (step 3).

All other already existing power plants which are necessary to satisfy $\underline{C}$ form group III. These power plants provide capacity at relatively low cost even though the adjusted merit order is considered. In a scenario of decreasing spot prices induced by the promotion of renewable energy, a capacity payment corresponding to the PER per capacity unit may not be sufficient to incentivize further market participation.

It might be more profitable to shut down an old power plant and to enter the capacity auction with a new power plant. Therefore, power plants of group III might receive a payment p_3^*, which equals the highest price bid of this group (power plant 5 in the example). This provides incentives to stay in the market, which limits costs following from capital erosion. Nevertheless, it is also possible to forego a differentiation between group II and III so that all existing generators only receive the PER per capacity unit.

Group IV consists of new power plants that are necessary to satisfy demand. The highest bid in this group determines the respective capacity price p_4^*. Capacity costs including the adjusted price markup $\Delta\tilde{p}_i$ are decisive for the success of new power plants. That is why power plant 11 is part of our optimal capacity mix instead of 7 (see Figure 5.5). Group IV payments incentivize investments in power plants considering the actual degree of internalization.

Non-awarded bidders do not receive any capacity payment but they also do not have to pay the PER like awarded bidders of group I have to. At first sight, this is an advantage compared to awarded bidders in group I. Thus, operators of emission-intensive power plants could have an incentive to place a higher bid so that they are not awarded instead of facing an additional payment in group I. However, non-awarded bidders who are not awarded again should be forced to leave the market because they are obviously not needed to satisfy demand. The awarding process is summarized in Figure 5.6.

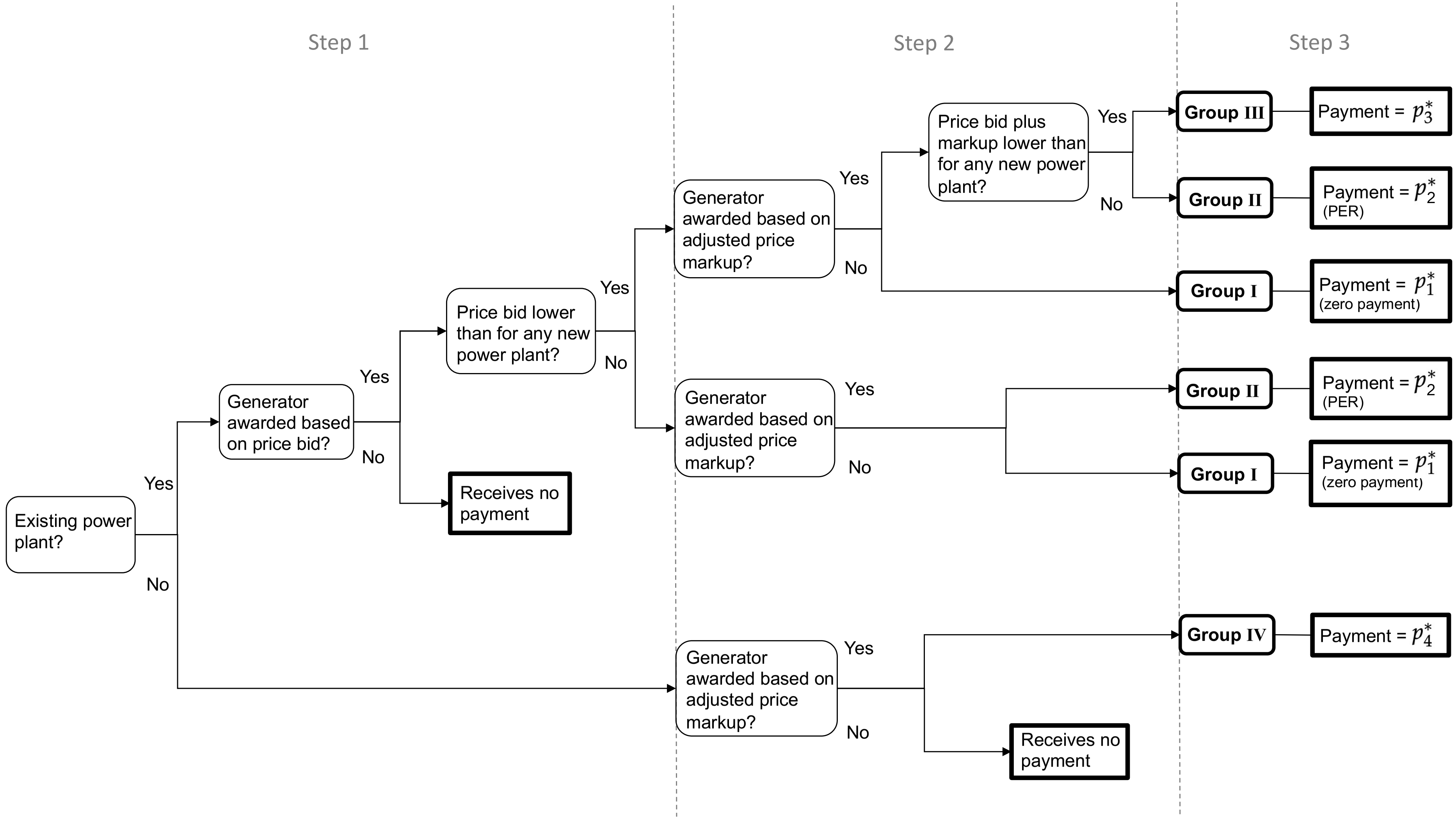

Figure 5.6: Decision tree of the awarding process. All awarded bidders are included in one of the four groups. Bidders of group I receive no payment but still have to pay the PER due to ROs. In contrast, non-awarded bidders do not have to pay the PER, while they also do not receive any payment. However, they have to leave the market permanently if they are not awarded again.

5.5 Discussion of the Suggested Capacity Auction Design

Considering subsidies for RES-based electricity generation allows to design a *general capacity auction* with endogenous limits for emission levels. This leads to discriminated prices without direct market interventions. Furthermore, the limits adjust endogenously over time.

In the long run, the price markup and associated price discrimination will vanish as soon as the carbon price induced by the ETS or a carbon tax is high enough to incentivize an investment in renewable energy without subsidies.[9] Connecting the price markup to the carbon price also increases certainty for investments in emission reduction. An increasing carbon price leads to a decreasing price markup and vice versa. Therefore, emission costs are more predictable leading to decreasing risk premiums for investors.

Emission-intensive power plants, for instance, coal or lignite power plants that could not place successful bids under consideration of the adjusted price markup (group I) will leave the market earlier because they do not receive a capacity payment but still have to make payments due to their obligations from ROs. In contrast, power plants with low emission intensity and low utilization rates (group IV), e.g. highly efficient gas turbines, can get higher payments than in a *general capacity auction* to enter the market earlier.

This corrects the distorted degree of internalization so that the capacity market directs investments to the equilibrium. Price discrimination therefore incentivizes investments in power plants with lower emission levels and hampers investments in less clean technologies. This accelerates the transition process towards less emission-intensive electricity generation. The comparatively low payments to emission-intensive power plants (group I-III) will also increase consumers' acceptance to pay for this mechanism. This enhances political feasibility.

In a *focused capacity auction*, numerous power plants do not receive payments. This motivates generators to close down old power plants and build new ones instead. The design is criticized for this incentive, since it might cause extra costs (Riechmann et al. 2014). This criticism does not apply to our framework because only those power plants, which should leave the market if there was no distortion of the degree of internalization, receive no payment. All other required power plants receive a

9. The negative difference costs for good solar sites calculated in Section 5.3.3 indicate that this scenario will start in the near future.

capacity payment.

The suggested market design with its division into groups also reduces potential market power abuse. A generator knows neither in which group their power plants will appear, nor the size of the group as it depends on other market participants' behavior. Withholding capacity by old power plants (by placing a very high bid) does not make sense, as it is penalized. Competition will increase, since market entry barriers are reduced because of lower risks associated with continuous capacity payments.

5.6 Conclusions

We develop modifications to the *general capacity auction* developed by Pérez-Arriaga (1999) and Vázquez, Rivier, and Pérez-Arriaga (2002) and extended by Cramton and Ockenfels (2012) and Schäfer and Altvater (2019). We use paid subsidies for RES-based electricity generation or the levelized costs of electricity generation from RES to approximate the true degree of internalization of CO_2 emission costs. The result is a price markup per capacity unit depending on the power plant's individual emission level.

Thus, it considers the emission-intensity and utilization time. This can be easily calculated by the auctioneer of the capacity market with data available from established reporting obligations. The comparison of successful bids with and without the price markup allows the auctioneer to calculate three threshold values for emissions. This leads to four different groups of power plants with increasing capacity payments as a result of decreasing emissions.

The first group receives no premium because power plants emit so much CO_2 that the true degree of internalization would make them leave the market. Group two receives the PER per capacity unit as minimum bid which neutralizes the introduction of a capacity market for group members. The remaining two groups receive premiums determined by the last required power plant (highest bid) in each group. The fourth group with the cleanest technology gets the highest payments, while power plants in the second and third group receive lower premiums. Moreover, analyzing the bids allows to identify power plants that intend to gain additional profits. To restrict this behavior, these are penalized by receiving only the PER per capacity unit.

This market-based mechanism regulates the necessary adjustment of residual fossil capacity to an increasing share of renewables. It presents several advantages compared to other mechanisms, which are mostly based on direct market interventions. The endogenously determined emission limits ensure that an exogenous readjustment of the limits is not necessary. This enhances the robustness and efficiency in contrast to mechanisms with exogenously defined threshold values for emissions. It also avoids lobbying as an ongoing discussion about these exogenous limits is redundant.

Price discrimination of capacity payments evolves endogenously leading to a redistribution of money from emission-intensive to cleaner power plants. This sets sufficient incentives to direct the capacity mix to its long-run equilibrium where discriminated payments converge to one equilibrium price. Furthermore, it accelerates the transition process and prevents capital erosion, since phasing out of the emission-intensive first group is induced. Redistribution will also increase consumer acceptance because avoided payments for emission-intensive power plants do not result in full insurance for generators but in fairer burden sharing. These results improve political feasibility.

The suggested mechanism is applicable to liberalized electricity markets with subsidized RES in transition to RES-based electricity generation. Most electricity markets in Europe, USA and parts of South America are subject to these conditions. In this context, the suggested *endogenous capacity market* has advantages compared to a *general capacity market.*

Future research should refine the calculation of the adjusted capacity price and study the effects of discriminated prices in more detail. Moreover, the effect of possible strategic bidding behavior in this context will be an interesting topic to explore further.

Chapter 6

Promotion of Renewable Energy with Reverse Auctions[1]

6.1 Introduction

In the context of support schemes for electricity generation from renewable energy sources (RES), more and more countries have started to use reverse auctions to auction off subsidies for renewables instead of offering a remuneration which is set by the regulator via so-called feed-in tariffs (FiTs) (REN21 2014). A reverse auction is an auction in which the role of buyer and seller are reversed compared to standard auctions. The buyer (auctioneer) announces what object or service she wants to buy and sellers (bidders) then offer a price at which they are willing to sell this object or service (Alcalde and Dahm 2016). This procedure is commonly used to award procurement contracts as it is seen as an efficient price discovery tool that is supposed to minimize costs (Tunca and Wu 2009).

Government-regulated FiTs offer project developers high planning certainty via fixed remunerations above average spot prices over a long period of time (mostly 20 years). This reduces risks for project developers and made FiTs successful in promoting renewables (Mitchell, Bauknecht, and Connor 2006; Del Río 2008; Lesser and Su 2008; Butler and Neuhoff 2008; Mendonca, Jacobs, and Sovacool 2010; Couture and Gagnon 2010; Kim and Lee 2012; Dong 2012). For the regulator it is challenging to set the right level of FiTs. An inadequate level of FiTs can either choke off the deployment

1. This chapter is based on a working paper with Dr. Sebastian Schäfer published as Sebastian Schäfer and Lisa Schulten (2015). "Efficient promotion of renewable energy with reverse auctions." MAGKS Joint Discussion Paper Series in Economics, No. 20-2015, Philipps-University Marburg, Faculty of Business Administration and Economics, Marburg.

of renewable energy or it involves too generous subsidies (Del Río and Gual 2007; Stokes 2013). Too high subsidies are not efficient and endanger public acceptance for renewable energy as the subsidies are generally paid by consumers by means of surcharges on their electricity bill. The challenge in designing efficient instruments to promote renewable energy is to balance the trade-off between income security for project developers and an adequate level of subsidies (Del Río and Gual 2007; Stokes 2013; Buckman, Sibley, and Bourne 2014).

Reverse auctions are supposed to solve this trade-off by awarding projects that deliver best value for money so that the market determines the level of subsidies (Buckman, Sibley, and Bourne 2014). As with all types of auctions, designing reverse auctions to be efficient is challenging. First, reverse auctions are only advantageous to other instruments if competition among bidders exists. Too high target quantities and/or too little participation on the bidders' side hamper competition. Without competition, resulting clearing prices will be higher compared to competitive auctions. Second, reverse auctions are characterized by information asymmetry. That is each bidder knows their own cost parameters before submitting bids, while the regulator does not (Kjerstad and Vagstad 2000). This allows bidders to exploit their information advantage to bid strategically. Either adding a mark up on their bid to get additional profits or to lower the bid to secure market shares. The regulator interprets an inflated price bid as high costs for the bidder while it is an additional profit to the bidder.

The aim of this chapter is to develop a reverse auction that produces the optimal target quantity for renewable energy projects. We design a reverse auction in which the tendered quantity is not defined ex ante, but results from optimizing the regulator's objective function. This objective function directly incorporates the trade-off between increasing the promotion of renewables and limiting associated costs in the form of subsidies. This is a contribution to the design of renewable energy support schemes by addressing current challenges. First, to determine the optimal target quantity by developing a reverse auction that internalizes the determination. Second, to consider an optimized deployment with respect to potential grid bottlenecks which endanger grid stability. The reverse auction procedure and outcome are simulated using spot market data for Germany.

6.2 Reverse Auctions for Renewable Energy

Countries' experience with reverse auctions for RES offer a variety of lessons to be learned. Cozzi (2012) mentions underbidding as the key risk in reverse auctions designs. An early example of an unsuccessful reverse auction design is UK with its so-called non-fossil fuel obligation (NFFO) in place from 1990 to 1998. In this period five reverse auctions were held for renewable energy (Mitchell and Connor 2004). In the early rounds bid prices and completion rates were high. When bid prices decreased in the later reverse auctions, realization rates fell drastically (Hartnell 2003). Mitchell and Connor (2004) detect two main characteristics in the mechanism design that might explain this outcome. First, the regulator's budget and thus the tendered quantity was too small. According to Mitchell and Connor (2004) this led to fierce competition. Second, no penalties were in place to punish bidders who did not complete a project. The combination of these two characteristics led to uneconomically low bids. As a result many awarded projects were not realized. This experience shows the difficulty of the regulator to set an adequate quantity to be tendered in the reverse auction.

Del Río and Linares (2014) provide an overview of reverse auction designs in several countries. As positive features of reverse auctions they consider subsidies that are lower compared to other support mechanisms and declining subsidy levels over time. Nevertheless, there are also countries for which these two observations are not true. The list of problems is much longer, with the utmost flaw being low outcome effectiveness as it was the case in the UK. Projects were either not built or the contracted capacity was lower than the initial target (Del Río and Linares 2014; Liu and Kokko 2010; Mastropietro et al. 2014). According to Elizondo Azuela, Barroso, and Cunha (2014) prequalification requirements are essential to exclude speculators and projects with poor financing from participating in the reverse auction to mitigate non-delivery risks.

The Australian Capital Territory Government has been using reverse auctions to promote solar energy since 2012. The mechanism accounts for non-delivery risks by applying certain eligibility criteria for projects in a prequalification stage. Only those project developers who pass the prequalification stage are able to place a bid in the reverse auction. Projects are then selected based on their value for money and receive a payment for 20 years (Buckman, Sibley, and Bourne 2014). Buckman, Sibley, and Bourne (2014) conclude that Australia's reverse auction design seems to mitigate non-delivery risks and too generous subsidies. Martin and Rice (2015), however, criticize Australia's planning and permitting processes to be cumbersome and lengthy with processes taking up to three years and budgetary outlays of one to two percent of project costs.

Also Germany switched from FiTs to reverse auctions for new renewable energy installations with a certain generating capacity with the reform of its EEG in 2017.

Technology-specific auctions are conducted by the federal grid agency about three times a year depending on the technology. Admission requirements apply to ensure projects' eligibility. Additionally, safety deposits are supposed to ensure sincere bids. A target quantity and a maximum price are communicated prior to the auction. The pricing mechanism is pay-as-bid pricing. Projects have to be realized within a certain time, for onshore wind energy the time horizon is for instance two years. Bidders submit their project's projected electricity generation and a price in €/kWh. Bids are ranked from lowest to highest price. All bidders that are necessary to satisfy the target quantity are awarded as long as their price does not exceed the maximum price. Successful bidders will receive contracts for differences (CfDs) amounting to their price bid (Bundesnetzagentur 2018).

6.3 Information Asymmetry in Reverse Auctions

To see how information asymmetry affects the outcome of a reverse auction, we describe a simple game as depicted in Figure 6.1 which is similar to that of Akerlof (1970). The game can be described by $n = 2 + 1$ players, since the principal (regulator) faces two types of agents (bidders) who want to maximize profits. The "low cost" type (L) faces comparatively low unit costs. Therefore L needs a comparatively low subsidy. In contrast the "high cost" type (H) requires a high subsidy for project realization. The principal does not know the agent's type. This introduces adverse selection to reverse auctions (McAfee and McMillan 1986).

In a uniform price reverse auction the last successful bidder determines the payment which all successful bidders receive. All bidders with lower price bids than the clearing price will gain an additional profit. Incentives to inflate price bids instead of bidding true project costs are therefore minimal since only the pivotal bidder determines the clearing price and ex ante it is uncertain who will be the pivotal bidder. Additional profits for bidders correspond to the information rent that the regulator has to pay so that bidders reveal their true type.

Germany's reverse auction format requires potential participants to fulfill eligibility requirements and auctions off CfDs, therefore the adverse selection problem should be contained. Although Germany applies pay-as-bid pricing, inflated price bids do not seem to be an issue for now. Modifications to the German reverse auction design concentrate on deriving the optimal target quantity of renewable energy and proposing measures to ensure an optimized deployment of renewables in this chapter. Because of the benefits of uniform pricing as outlined in the previous chapters, the reverse auction design presented here relies on uniform pricing.

6.4 Reverse Auction Model

The regulator's aim is to deploy a certain quantity Q of renewable energy. The costs for doing so equal the subsidies she has to pay to project developers for a certain period of time t. The subsidy level is determined in a reverse auction to ensure cost-efficiency by awarding the bidders who offer best value for money. The reverse auction can be described as a sequential game which consists of six stages as depicted in Fig. 6.1.

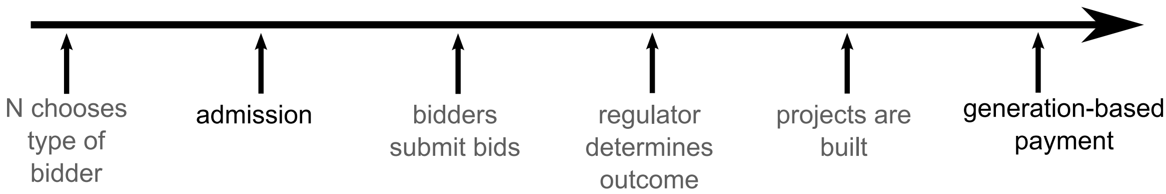

Figure 6.1: Timing of events.

In the first stage, bidders' types are randomly determined. While bidders know their own types, the regulator does not. In the second stage bidders have to fulfill eligibility criteria to be admitted to the reverse auction. The admission stage is crucial to reduce non-delivery risks and ensure high project realization rates. All eligible bidders take part in the reverse auction. In stage three each bidder i offers a certain quantity q_i in kWh, which is expected to be generated during t years, for a price $p(q_i) := p_i$ in €/kWh. The regulator restricts the clearing price to a maximum price p_{max} that equals the current FiT. If the clearing price exceeds the current FiT level the reverse auction misses its goal of reducing promotion costs for renewable energy. If the reverse auction design induces truthful bidding true expectations about unit costs k_i are revealed ($p_i = k_i$). In the next stage the regulator determines the outcome of the reverse auction. Submitted bids are ordered from lowest to highest. All bidders which are needed to satisfy Q, which is the ex ante determined quantity to be tendered, are awarded. Awarded projects are realized in the next stage and respective project developers receive a payment per generated electricity unit for t years in the last stage.

The major challenge for the regulator in this setting is to determine the target quantity Q. On the one hand, too low Q may induce fierce competition. Fierce competition may lead bidders to submit bids that will not cover their project costs. While large energy firms may be willing to accept losses in exchange for market shares and have the ability to absorb these losses, small energy suppliers, e. g. small energy collectives, are not able to do so. Consequently realization rates may be low or only large energy firms will participate in the reverse auctions contradicting the aim of diversity among players. Too high Q, on the other hand, will lead to high costs. Since the end consumers bear the promotion costs for renewable energy, the financial burden has to be limited. Too high costs, perceived by the public, endanger public support for the promotion of renewable energy. As stated in the introduction, public acceptance is crucial for a successful energy transition. The optimal target quantity Q therefore is the optimal solution to the trade-off the regulator faces: deploy renewable energy while limiting associated costs.

6.4.1 The Regulator's Utility

The regulator's utility depends on both opposing objectives: increase the promotion of renewable energy on the one hand and minimize promotion costs on the other hand. Therefore both objectives are arguments in the regulator's utility function

$$u(\chi, \varphi) \tag{6.1}$$

whereas χ represents the promotion of renewables and φ is a cost measure. Both arguments χ and φ depend on the bids placed in the reverse auction and the resulting ranking of bids which determines the number of successful bidders l. With $\chi(l)$ and $\varphi(l)$, the regulator's utility is a function of l. It is assumed that bidders are equally informed about the market so that we abstain from modeling bidder's expectations for simplicity. Furthermore, it is assumed that bidders are risk averse implying that participating in the auction is costly so that bidders will avoid to participate repeatedly. With these simplifying assumptions, the regulator's utility is maximized for the optimal number of awarded bidders l^*. From l^* directly follows the optimal quantity

$$Q^* := \sum_{i=1}^{l^*} q_i \tag{6.2}$$

the regulator tenders at the clearing price

$$p^* := p(q_{l^*}) \tag{6.3}$$

in the reverse auction.

To display potentially different preferences of the regulator we model a CES utility function:

$$u = \left[\alpha\chi(l)^\theta + \beta\varphi(l)^\theta\right]^{1/\theta}, \tag{6.4}$$

with $\alpha + \beta = 1$ and $\alpha, \beta \geq 0$ ensuring constant returns to scale. θ is a substitution parameter with $\sigma = \dfrac{1}{1-\theta}$ as elasticity of substitution. This utility function includes the whole range of elasticities of substitution from perfect complements if θ approaches negative infinity ($\sigma = 0$, $\theta = -\infty$) to perfect substitutes if θ approaches 1 ($\sigma = \infty$, $\theta = 1$). The parameterization results from the regulator's preferences regarding the two objectives. We will rely on two different exemplary parameterizations in the later numerical simulation of the reverse auction mechanism.

6.4.2 Objective One: Promotion of Renewable Energy

Germany formulated expansion corridors for the deployment of renewables for steering and planning purposes. We consider the upper bound of the expansion corridor as a restriction of the tendered quantity Q^* of renewable energy. This maximum quantity Q_{max} is exogenous. If Q_{max} is binding ($Q^* > Q_{max}$) the optimal quantity can no longer be determined endogenously as the optimal solution to the trade-off. Instead, the reverse auction design becomes the standard reverse auction format where a target quantity is set ex ante and the promotion costs are determined in the reverse auction. We combine both concepts into the objective function by modeling the sum of awarded bidders' quantities $\sum_{i=1}^{l} q_i$ as a share of the maximum quantity Q_{max}, normalized to range from 0 to 1. This yields $\chi(l)$ as the normalized aggregated quantity of renewable energy

$$\chi(l) := \min\left\{\frac{\sum_{i=1}^{l} q_i}{Q_{max}}, 1\right\} \tag{6.5}$$

with

$$\frac{\partial u}{\partial \chi(l)} \geq 0.$$

6.4.3 Objective Two: Minimal Promotion Costs

The second objective of the regulator is to restrict the costs in the form of a subsidy S for the deployment of renewables. Subsidies for renewable energy are necessary because revenues at the spot market R are insufficient to cover project developers' costs K. Uncovered costs

$$C = K - R \tag{6.6}$$

remain that are compensated by the subsidy. Because of the nature of uniform price auctions every awarded bidder, except for the pivotal bidder, will receive not only the subsidy, but will gain an additional profit. For the reverse auction outcome to be cost-efficient, the share of additional profits of the subsidy should be minimal. The higher the share of uncovered costs of the subsidy, the lower are additional profits for awarded bidders. Therefore the regulator's second objective depends on the ratio of aggregated uncovered costs and aggregated subsidies of all l awarded bidders, defined by

$$\varphi(l) := \frac{C(l)}{S(l)} \tag{6.7}$$

with

$$\frac{\partial u}{\partial \varphi(l)} \geq 0.$$

If all bidders bid their uncovered costs truthfully[2] aggregated uncovered costs will be the sum of awarded bidders' subsidy-quantity pairs:

$$C(l) = \sum_{i=1}^{l} s_i q_i \tag{6.8}$$

with

$$s_i = p_i - \overline{p}_{spot}. \tag{6.9}$$

Whereas $\overline{p}_{spot}$ corresponds to next year's average expected spot price. The regulator can rely on the spot price futures traded at the European Energy Exchange (EEX) to determine $\overline{p}_{spot}$.

Since every awarded bidder receives the same subsidy rate s_l corresponding to the subsidy rate of the last successful bidder ($i = l$), overall costs for the regulator for all l awarded bidders equals the product of the subsidy rate and individually expected electricity generation (q_i):

$$S(l) = s_l \sum_{i=1}^{l} q_i. \tag{6.10}$$

Ranking the bidders according to their individual subsidy rate instead of price bids ensures that total payable subsidies are as low as possible.

6.4.4 Determining the Optimal Quantity

The regulator calculates their utility u repeatedly by means of Eq. 6.4 for $l = 1, 2, ..., n$. That number of bidders that maximizes the utility function is denoted by l^*. All

2. As outlined in Section 6.3 incentives to inflate price bids are minimal. Moreover, the German reverse auctions produced clearing price levels below the prevailing FiT. These outcomes do not indicate inflated price bids.

bidders, ranked from 1 to l^*, are awarded. From l^* follows the optimal quantity

$$Q^* = \min \left\{ \sum_{i=1}^{l^*} q_i, Q_{max} \right\}. \tag{6.11}$$

The utility maximizing number of bidders l^* also determines the clearing price p^* and the respective subsidy rate that follows from Eq. 6.9. The subsidy will be paid in the form of a CfD, valid for t years. That is, successful bidders do not receive the clearing price p^* as a payment per generated electricity unit, but the difference between the clearing price and the average spot price of electricity generation (weighted by generation-type) which is obtained ex post.

6.5 Optimized Deployment of Renewables

By choosing the weights of the utility function α and β the regulator is able to tailor the objective function in such a way that it represents the relative importance of both objectives to the regulator. If for instance the regulator decides to set the weight for low promotion costs to zero ($\beta = 0$) this objective is not considered at all. This reflects the situation of a fixed FiT system. The reverse auction design thus allows a smooth transition from government-regulated FiTs to reverse auctions by adjusting the weights. This is advantageous, since a gradual change is accompanied by higher regulatory certainty.

Germany's auctions are differentiated with respect to expected electricity generation as to establish a level-playing field for projects with less favorable conditions. These considerations can be implemented easily into the suggested reverse auction design by clustering bidders into groups according to the project's characteristics. Total maximum utility is defined as the sum of each group's utility maximum

$$u_{max} = \sum_{ii=1}^{nn} u_{ii,max}. \tag{6.12}$$

It is not necessary to define Q_{max} for each of the nn groups because total utility u can simply be maximized subject to $\sum_{ii=1}^{nn} q_{ii}^* \leq Q_{max}$. Thus, the marginal utility

$$MU_{ii,i} = \frac{u_{ii,i} - u_{ii,i-1}}{q_{ii,i} - q_{ii,i-1}} \tag{6.13}$$

is decisive. The group with the lowest utility loss should be the first to face reductions of the tendered quantity if necessary. This procedure continues until the constraint is satisfied.

Clustering bidders into different groups results in price differentiation. This increases competition within groups while in an undifferentiated uniform price reverse auction additional rents would occur for projects with best conditions.

6.5.1 Consideration of Grid Capacity

Regions with favorable site conditions are not necessarily located in areas of high electricity demand and grid capacity might be tight. Additional electricity generation in those regions might endanger grid stability such that grid stabilizing measures or costly grid expansions might be necessary. Conversely, the transmission grid is relieved by decentralized renewable energy generation in regions where demand is higher than supply. In Germany, this effect is quantified by avoided network charges that are calculated for each renewable energy power plant by the transmission system operators according to specific calculation guidelines (Verband der Netzbetreiber 2007). The higher the avoided network charges, the more valuable is the power plant in terms of grid stability. To account for this advantage in the reverse auction, bidders are obliged to submit the project's expected annual electricity generation and grid connection point as part of the admission requirements. With avoided network charges p_i^{grid} the individual subsidy rate is determined by

$$s_i = p_i - \overline{p}_{spot} - p_i^{grid}. \tag{6.14}$$

This reverse auction design therefore optimizes deployment costs of renewable energy in terms of promotion costs and mitigates additional system costs by incorporating grid capacity.

6.5.2 Numerical Simulation

To illustrate the reverse auction design we will simulate an onshore wind energy auction with ten participating bidders. Each bidder's quantity in GWh is denoted by q_i. The defined maximum quantity Q_{max} is set to 10 TWh which is about 1.5 % of annual gross electricity generation in Germany.[3] Individual price bids in €/MWh are denoted by p_i. The German FiT for onshore wind energy projects amounts to

3. As long as $Q_{max} < Q^*$ the maximum quantity is not binding.

roughly 75 €/MWh as of January 2018. Therefore bids are given by random numbers between 65 and 75 €/MWh in our example.

We use spot market data for Germany. The expected average spot price $\overline{p}_{spot}$ is approximated by the average monthly Phelix Base Year Future 2017, traded at the EEX, amounting to 32.38 €/MWh (Bundesverband der Energie- und Wasserwirtschaft e.V. 2018). Moreover we consider avoided grid costs via exemplary avoided network charges.

With these components we calculate the subsidy rate for every bidder s_i according to Eq. 6.14. Tab. 6.1 depicts the subsidy rates of the ten bidders in an ascending order. The first column indicates the ranking if it is based solely on the individual price bids instead of the individual subsidy rates that consider avoided network charges. The last two columns show the regulator's utility from the two objectives, increasing renewable electricity generation χ and limiting promotion costs φ. Both depend on the last awarded bidder l. The values therefore depict the regulator's utility for the case that only one bidder ($l = 1$) is awarded, then two are awarded ($l = 2$) and so on until in the final case all bidders are awarded ($l = 10$).

i	q_i	p_i	$\overline{p}_{spot}$	p_i^{grid}	s_i	$\chi(l)$	$\varphi(l)$
5	320	66.74	32.38	5.26	**29.10**	0.032	1.000
8	300	72.07	32.38	5.83	**29.28**	0.062	0.999
1	260	57.49	32.38	3.40	**29.59**	0.088	0.976
9	160	73.37	32.38	3.41	**29.60**	0.104	0.974
7	80	69.22	32.38	1.76	**32.37**	0.112	0.957
3	340	65.39	32.38	2.72	**33.33**	0.146	0.948
6	150	68.43	32.38	2.05	**34.79**	0.161	0.934
4	110	66.51	32.38	4.43	**35.21**	0.172	0.876
2	290	65.37	32.38	2.57	**38.42**	0.201	0.869
10	100	74.69	32.38	2.97	**39.34**	0.211	0.850

Table 6.1: Simulated auction outcome ranked by individual subsidy with expected generation q_i in GWh, price bids p_i, average expected spot price $\overline{p}_{spot}$ and individual avoided network charges p_i^{grid}. Individual subsidy rates s_i result from $p_i - \overline{p}_{spot} - p_i^{grid}$. All prices in €/MWh.

The optimal quantity in this setting depends on $\chi(l)$ and $\varphi(l)$, the utility function and its parameterization. To illustrate the regulator's possibilities for calibration we model both a Cobb-Douglas utility function

$$u_l = \chi(l)^{\alpha}\varphi(l)^{\beta}$$

and perfect substitutes

$$u_l = \alpha\chi(l) + \beta\varphi(l)$$

as examples.

			Cobb-Douglas		Perfect Substitutes	
i	$\chi(l)$	$\varphi(l)$	$u_l^{\alpha=0.5}$	$u_l^{\alpha=0.2}$	$u_l^{\alpha=0.5}$	$u_l^{\alpha=0.2}$
1	0.032	1.000	0.178	0.502	0.516	0.806
2	0.062	0.999	0.248	0.573	0.530	**0.812**
3	0.088	0.976	0.293	0.603	0.532	0.798
4	0.104	0.974	0.318	0.623	0.539	0.800
5	0.112	0.957	0.327	0.623	0.534	0.788
6	0.146	0.948	0.372	0.652	0.547	0.787
7	0.161	0.934	0.387	**0.657**	**0.548**	0.779
8	0.172	0.876	0.388	0.633	0.524	0.735
9	0.201	0.869	0.418	0.648	0.535	0.736
10	0.211	0.850	**0.423**	0.643	0.530	0.722

Table 6.2: Simulated auction outcome for different utility functions (Cobb-Douglas and Perfect Substitutes) and different calibration of weights α and β, with $\beta = 1 - \alpha$. All prices in €/MWh. Respective utility maximum is given in bold.

Table 6.2 depicts the regulator's utility given that power plant $l = i$ sets the price. The utility maximum determines the optimal quantity of renewable energy which is the outcome of the auction. This simulation shows that depending on the underlying utility function and the regulator's preferences regarding their two objectives, which are expressed by the weights, the auction outcome varies. Putting more emphasis on low promotion costs compared to increasing the share of renewable energy by choosing a relatively small α leads to less projects being awarded. In the case of a Cobb-Douglas utility function seven projects will be awarded compared to all projects if both objectives are weighted equally. In the case of Perfect Substitutes only two projects will be awarded compared to seven.

The modeled auction format provides a flexible tool to determine the optimal quantity of renewable energy to be promoted. How both objectives relate to each other is determined by choosing the utility function while the weights assigned to the two objectives incorporate their relative importance to the regulator. The auction format could be augmented by considering regional spot prices or regional capacity prices if regional spot prices or a regionally organized capacity market exist. These features would ensure a harmonization between those instruments in terms of generating capacity and consequently the promotion of projects in regions where they are needed.

6.6 Conclusions

Reverse auctions for renewable energy applied in practice have in common that they are auctioning off a predetermined quantity of renewable energy. Determining this quantity is, however, challenging for the regulator. High deployment rates of renewable energy are connected to high promotion costs. Too low quantities may produce fierce price competition among project developers which might lead to low project realization rates.

In our model the tendered quantity is not defined ex ante, but results from the trade off between the regulator's objectives to increase the deployment of renewables on the one hand and to limit promotion costs on the other hand. We introduce a utility function which depends on the two quantified objectives. The regulator may calibrate the parameters of this utility function according to their preferences. Then the quantity to be tendered is determined by maximizing the regulator's utility. Moreover, we show how grid capacities can be included in the reverse auction using avoided network charges. This is beneficial since installing generating capacities where demand is low leads to increased system costs for grid stability measures.

Finally our mechanism allows a smooth transition from fixed FiTs to reverse auctions by adjusting the weights for both objectives accordingly. Because of the simplicity of the reverse auction design it is feasible to substitute the current reverse auction formats with this design. Thereby promoting renewable energy in a cost-efficient way and accounting for challenges in terms of limited grid capacity.

Hence, in contrast to the existing literature, we focus not only on improving the efficiency of reverse auction designs but also explore strategies to optimize the transition to high shares of RES from a system perspective. We show that by incorporating grid capacity overall system costs can be managed more efficiently. Additionally, the presented auction design can be applied to countries with regional spot and/or capacity markets. The numerical simulation illustrates how the reverse auction might work in practice.

Further research can build on the presented reverse auction design to explore technology-neutral reverse auctions since the German government started testing this format. Furthermore it is of particular interest to analyze how the auction design can be tailored to accompany the complete phase out of subsidies for renewable energy in the near future.

Chapter 7

Overall Conclusion

There is not only scientific evidence, but consensus that the current environmental crisis is caused by humans. There is awareness for urgent action among policymakers. There are goals, targets and strategies. There are loud demands, not just by climate activists, as more and more people suffer from extreme weather conditions. And still, action falls short. Why? That is the focus of this thesis, outlined in the introduction.

Chapter 2 assesses Europe's climate target setup, decarbonization strategy and progress using a descriptive analysis based on annual time series data for the EU 27 countries across nine indicators. The results show that Europe's progress with respect to decarbonization leaves room for improvement. Additional efforts are needed to meet the even more ambitious roadmap ahead. To achieve these goals, electricity markets will have to undergo significant structural changes which has not yet occurred in the majority of the EU 27 countries. Denmark and Estonia are positive deviants as they show comparatively strong progress even though they come from initially high shares of fossil energy.

Chapter 3 explains the legacy structure of electricity markets and illustrates challenges that arise from the transformation of electricity markets towards high shares of renewable energy. Challenges that arise from an increasing share of renewable energy, namely missing money and missing flexibility are explained. Additional challenges that are relevant in the context of transforming the electricity sector are discussed. Those are: lobbying, technological shocks, lack of public acceptance, structural demand side changes, market failures and lock-in risks. Chapter 3 lays the foundation for a basic understanding of the structure, functioning and challenges of electricity markets that Chapters 4 to 6 build on.

Chapter 4 deals with risks to resource adequacy (long-term security of supply) due to the missing money problem and analyzes capacity markets as a possible solution. Capacity auctions with reliability options (RO) are identified as an adequate measure to mitigate those risks by providing sufficient investment incentives for new capacity. The impact of power plant maturity, emission costs and an increasing share of renewable energy is analyzed with comparative statics. The analysis demonstrates that a capacity auction with ROs can provide the right answer to more intermittent electricity generation from renewable energy with respect to flexibility issues. Consequently, capacity auctions with ROs are a market-based tool to solve both the missing money and the missing flexibility problem.

Chapter 5 builds on the findings and model setup derived in Chapter 4. Subsidies paid for electricity generation by renewable energy sources (RES) or the levelized costs of electricity generation from RES are used to approximate the true degree of internalization of CO_2 emission costs. The result is a price markup per capacity unit depending on the power plant's individual emission level as a basis for price discrimination. Price discrimination of capacity payments evolves endogenously leading to a redistribution of money from emission-intensive to cleaner power plants. This accelerates the transition process and prevents capital erosion, since phasing out of emission-intensive power plants is induced. Redistribution will also increase consumer acceptance because avoided payments for emission-intensive power plants do not result in full insurance for generators but in fairer burden sharing improving political feasibility.

Chapter 6 focuses on the promotion of renewable energy which is a major instrument in most decarbonization strategies. As RES have reached a certain level of maturity in most countries, regulators are transitioning from feed-in tariffs to reverse auctions to determine the subsidy level for new RES projects. A reverse auction design based on best practice elements from various case studies is developed that produces the optimal quantity of renewable energy endogenously instead of setting this quantity exogenously which is problematic. In contrast to the existing literature, this reverse auction design is more efficient. By incorporating grid capacity considerations, overall system costs are managed more efficiently to optimize the transition to high shares of RES.

This thesis contributes to the literature on sustainability with focus on decarbonizing the electricity sector to achieve defined climate goals and combat the climate crisis eventually. Transforming the electricity sector is challenging because of the importance of electricity, the system's fragility, very limited influence by end users, strong opposition by incumbents and distorted price signals. It is shown that these challenges can be overcome by efficient regulatory design. But this requires commitment from policy makers.

Some facts give rise to the concern that there is a lack of political will to enforce a fast transition to accelerate decarbonization:

- Subsidies for fossil fuels
- Too low internalization of external costs
- Particular focus on measures that do not interfere with economic growth (energy efficiency over energy conservation)

The transformation to sustainable electricity generation is a multi-faceted and therefore complex issue. The electricity market structure is complex with particularities that need to be considered to ensure high system stability. Still, this thesis demonstrates that solutions must not be complex. Recommendations and solutions are available to mitigate inherent design flaws. These considerations lead to the conclusion that policymakers lack the will to enforce stricter regulation. The transformation process can be accelerated by enhancing regulatory design with practical, yet simple enough modifications to be politically feasible. More attention should be directed to the issue of political will and policymakers as the crucial players to focus on.

The thesis focuses on the European context, especially the German electricity market when it comes to the illustration of the suggested mechanisms by simulating market outcomes. The findings should be applicable to other countries and markets with the same core characteristics but the thesis does not provide evidence for general applicability. This could be a topic for further research.

The derived models are subject to simplifications regarding the modeling of bidders' preferences, for example risk preferences. The robustness of the model findings should be contested by more differentiated assumptions regarding bidders' preferences. The issue of strategic bidding behavior should also be analyzed in more detail.

From the analyzed aspects that may enable or hinder decarbonization progress, it is concluded that the key focus should be on enhanced regulatory design and thus policymakers as the most powerful player to administer change. Exploring policymakers' inherent incentives and potential strategies to influence them are beyond the scope of this thesis. This is an important field for further research. Behavioral science and behavioral economics may offer relevant insights and approaches to analyze cornerstones of behavior change and its diffusion. Sustainability is a global challenge and requires all countries to participate.

The key questions addressed in this thesis are timely and important. Identified challenges and derived solutions are relevant for the discussion on how to solve the climate crisis as the electricity sector is a key component for emission reduction pathways. In contrast to most policymakers' rhetoric, this thesis offers concrete recommendations and strategies apart from technological innovations for an accelerated way forward.

In light of the current war in Ukraine, there is increased attention on policymakers in Europe which find themselves at a crossroads. Strong dependency on restricted Russian gas and high energy prices add to the inherent pressure on policymakers. Even though, Europe pledged to stay committed to its climate goals, it will be interesting to see to what extent conventional energy sources, especially coal will see a revival to ensure reliable energy supply.

Moreover, it will be interesting to see if the soaring energy prices will lead to increased energy conservation and more importantly if energy demand would rebound once energy prices decline again. The discussed impact of the COVID-19 crisis emphasizes that there can be strong and favorable effects but without structural change they will not be long-lasting to induce sustainable change.

References

AG Energiebilanzen e.V. 2021. *Stromerzeugung Nach Energieträgern (Strommix) von 1990 bis 2020 (in TWh) Deutschland insgesamt.* Accessed July 31, 2021. https://ag-energiebilanzen.de/index.php?article_id=29%5C&fileName=ausdruck%5C_strerz_abgabe%5C_feb2021%5C_a10%5C_.xlsx.

Aichele, Rahel, and Gabriel Felbermayr. 2015. "Kyoto and Carbon Leakage: An Empirical Analysis of the Carbon Content of Bilateral Trade." *Review of Economics and Statistics* 97:104–115.

Akenji, Lewis. 2014. "Consumer scapegoatism and limits to green consumerism." *Journal of Cleaner Production* 63:13–23.

Akerlof, G. A. 1970. "The Market for "Lemons": Quality Uncertainty and The Market Mechanism." *The Quarterly Journal of Economics* 84:488–500.

Alcalde, José, and Matthias Dahm. 2016. "Dual sourcing with price discovery." *CeDEx Discussion Paper Series* No. 2016-03.

Andor, Mark, Kai Flinkerbusch, Matthias Janssen, Björn Liebau, and Magnus Wobben. 2010. "Negative Strompreise und der Vorrang Erneuerbarer Energien." *Zeitschrift für Energiewirtschaft* 34:91–99.

Arrow, Kenneth, Bert Bolin, Robert Costanza, Partha Dasgupta, Carl Folke, Crawford Holling, Bengt-Owe Jansson, Simon Levin, Karl-Göran Mäler, Charles Perrings, et al. 1995. "Economic growth, carrying capacity, and the environment." *Ecological economics* 15 (2): 91–95.

Bajo-Buenestade, R. 2017. "Welfare implications of capacity payments in a price-capped electricity sector: A case study of the texas market (ercot)." *Energy Economics* 64:272–285.

Baumgärtner, Stefan, and Martin Quaas. 2010. "Sustainability economics - general versus specific, and conceptual versus practical." *University of Lüneburg Working Paper Series in Economics* 169.

Bhagwat, P. C. 2016. "Security of supply during the energy transition: The role of capacity mechanisms." PhD diss., Delft University of Technology. Accessed July 25, 2019. https://doi.org/10.4233/uuid:9dddbede-5c19-40a9-9024-4dd8cbbe3062.

Bhagwat, Pradyumna, Kaveri Iychettira, Jörn Richstein, Emile Chappin, and Laurens De Vries. 2017. "The effectiveness of capacity markets in the presence of a high portfolio share of renewable energy sources." *Utilities Policy* (September): 76–91. https://doi.org/10.1016/j.jup.2017.09.003.

Bhagwat, Pradyumna, Jörn Richstein, Emile Chappin, and Laurens De Vries. 2016. "The effectiveness of a strategic reserve in the presence of a high portfolio share of renewable energy sources." *Utilities Policy* 39:13–28.

Bigerna, S., and P. Polinori. 2015. "Assessing the determinants of renewable electricity acceptance integrating meta-analysis regression and a local comprehensive survey." *Sustainability* 7:11909–11932.

Blackburn, Christopher, Anthony Harding, and Juan Moreno-Cruz. 2017. "Toward deep-decarbonization: an energy-service system framework." *Current Sustainable/Renewable Energy Reports* 4:181–190.

Blakers, Andrew, Matthew Stocks, Bin Lu, Cheng Cheng, and Ryan Stocks. 2019. "Pathway to 100% renewable electricity." *IEEE Journal of Photovoltaics* 9 (6): 1828–1833.

BMWi. 2018. *Sechster Monitoring Bericht zur Energiewende. Berichtsjahr 2016.*

Böhringer, Christoph, Knut Einar Rosendahl, and Halvor Briseid Storrøsten. 2017. "Robust policies to mitigate carbon leakage." *Journal of Public Economics* 149:35–46.

Boßmann, T., and I. Staffell. 2015. "The shape of future electricity demand: Exploring load curves in 2050s Germany and Britain." *Energy* 90:1317–1333.

Bothwell, Cynthia, and Benjamin F. Hobbs. 2017. "Crediting Wind and Solar Renewables in Electricity Capacity Markets: The Effects of Alternative Definitions upon Market Efficiency." *The Energy Journal* 38 KAPSARC Special Issue.

Bowen, Alex. 2011. "The Case for Carbon Pricing." *Policy Brief, Grantham Research,* accessed September 6, 2021. https://www.cccep.ac.uk/wp-content/uploads/2015/09/PB_case-carbon-pricing_Bowen.pdf.

Brand, Ulrich. 2012. “Green economy - the next oxymoron? No lessons learned from failures of implementing sustainable development.” *GAIA-Ecological Perspectives for Science and Society* 21 (1): 28–32.

Buckman, Greg, Jon Sibley, and Richard Bourne. 2014. “The large-scale solar feed-in tariff reverse auction in the Australian Capital Territory, Australia.” *Energy Policy* 72:14–22.

Bucksteeg, M., L. Niesen, P. Himmes, D. Schober, C. Weber, B. Baumgart, T. Plöger, D. Willemsen, D. Nailis, L. Schuffelen, et al. 2014. “Marktdesign für zukunftsfähige Elektrizitätsmärkte unter besonderer Berücksichtigung der vermehrten Einspeisung von erneuerbaren Energien.” *Endbericht, Studie im Auftrag des Bundesministeriums für Wirtschaft und Energie, Duisburg,* accessed August 2, 2018. https://www.ewl.wiwi.uni-due.de/fileadmin/fileupload/BWL-ENERGIE/Dokumente/DESIRE_Workshop14/141024_Endbericht_DESIRE_FINAL_Lang.pdf.

Bujold, P., and M. Karak. 2021. *To Scale Behavior Change: Target Early Adopters, Then Leverage Social Proof and Social Pressure.* Accessed June 23, 2022. https://behavioralscientist.org/to-scale-behavior-change-target-early-adopters-then-leverage-social-proof-and-social-pressure/.

Bundesnetzagentur. 2018. *Ausschreibungen für EE- und KWK-Anlagen.* Accessed June 19, 2018. https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Ausschreibungen/Ausschreibungen_node.html.

Bundesverband der Energie- und Wasserwirtschaft e.V. 2018. *Strompreisanalyse Mai 2018.*

Burger, B. 2019. *Öffentliche Nettostromerzeugung in Deutschland im Jahr 2018.* Accessed July 31, 2021. https://www.ise.fraunhofer.de/content/dam/ise/de/documents/news/2019/Stromerzeugung_2018_3.pdf.

Burns, Tom. 2011. “The Sustainability Revolution: A Societal Paradigm Shift - Ethos, Innovation, Governance Transformation.” *Sociologisk forskning* 48 (3): 93–108.

Butler, Lucy, and Karsten Neuhoff. 2008. “Comparison of feed-in tariff, quota and auction mechanisms to support wind power development.” *Renewable energy* 33:1854–1867.

Cadoret, Isabelle, and Fabio Padovano. 2016. “The political drivers of renewable energies policies.” *Energy Economics* 56:261–269.

Caramanis, Michael. 1982. "Investment decisions and long-term planning under electricity spot pricing." *IEEE Transactions on Power Apparatus and Systems* 101 (12): 4640–4648.

Carattini, Stefano, Andrea Baranzini, Philippe Thalmann, Frédéric Varone, and Frank Vöhringer. 2017. "Green Taxes in a Post-Paris World: Are Millions of Nays Inevitible?" *Environmental and Resource Economics* 68:97–128.

Carattini, Stefano, Steffen Kallbekken, and Anton Orlov. 2019. "How to win public support for a global carbon tax." *Nature* 565:289–291.

Centemeri, Laura. 2009. "Environmental damage as negative externality: Uncertainty, moral complexity and the limits of the market." *e-cadernos CES* 5 (05).

Cheng, Chi-Bin. 2008. "Solving a sealed-bid reverse auction problem by multiple-criterion decision-making methods." *Computers & Mathematics with Applications* 56:3261–3274.

Cheon, Andrew, and Johannes Urpelainen. 2013. "How do competing interest groups influence environmental policy? The case of renewable electricity in industrialized democracies, 1989–2007." *Political Studies* 61 (4): 874–897.

Cludius, J., H. Herrmann, F.C. Matthes, and V. Graichen. 2014. "The merit order effect of wind and photovoltaic electricity generation in Germany 2008–2016: Estimation and distributional implications." *Energy Economics* 44:302–313.

Costanza, Robert, Herman Daly, and Joy Bartholomew. 1991. "Goals, agenda and policy recommendations for ecological economics." *Ecological economics: The science and management of sustainability* 3:1–21.

Council of the EU. 2009. *Presidency Conclusions. Cover Note of the the Brussels European Council (29/30 October 2009).* Accessed October 19, 2018. http://ec.europa.eu/regional_policy/sources/cooperate/baltic/pdf/council_concl_30102009.pdf.

Couture, Toby, and Yves Gagnon. 2010. "An analysis of feed-in tariff remuneration models: Implications for renewable energy investment." *Energy policy* 38:955–965.

Cozzi, Paolo. 2012. "Assessing reverse auctions as a policy tool for renewable energy deployment." *Center for International Environment & Resource Policy (CIERP),* no. 007, accessed June 26, 2022. http://fletcher.tufts.edu/CIERP/Publications/more/~/media/Fletcher/Microsites/CIERP/Publications/2012/May12CozziReverseAuctions.pdf.

Crampes, Claude, and Anna Creti. 2006. "Capacity Competition in Electricity Markets." *Economia Delle Fonti di Energia e dell'Ambiente* 48 (2) (February): 59–82.

Cramton, Peter, and Axel Ockenfels. 2012. "Economics and Design of Capacity Markets for the Power Sector." *Zeitschrift für Energiewirtschaft* 36:113–134.

Cramton, Peter, Axel Ockenfels, and Steven Stoft. 2013. "Capacity market fundamentals." *Economics of Energy & Environmental Policy* 2:27–46.

Cramton, Peter, and Steven Stoft. 2005. "A capacity market that makes sense." *The Electricity Journal* 18 (7): 43–54.

Creti, Anna, and Natalia Fabra. 2007. "Supply security and short-run capacity markets for electricity." *Energy Economics* 29 (2): 259–276.

Croson, Rachel, and Nicolas Treich. 2014. "Behavioral Environmental Economics: Promises and Challenges." *Environmental and Resource Economics* 58 (3): 335–351.

De Jonghe, Cedric, Erik Delarue, Ronnie Belmans, and William D'haeseleer. 2009. "Interactions between measures for the support of electricity from renewable energy sources and CO_2 mitigation." *Energy Policy* 37 (11): 4743–4752.

De Leon Barido, Diego Ponce, Nkiruka Avila, and Daniel Kammen. 2020. "Exploring the enabling environments, inherent characteristics and intrinsic motivations fostering global electricity decarbonization." *Energy Research & Social Science* 61:1–15.

De Miera, Gonzalo Sáenz, Pablo del Río González, and Ignacio Vizcaíno. 2008. "Analysing the impact of renewable electricity support schemes on power prices: The case of wind electricity in Spain." *Energy Policy* 36 (9): 3345–3359.

De Vries, Laurens. 2007. "Generation adequacy: Helping the market do its job." *Utilities Policy* 15 (1): 20–35.

Del Río, Pablo. 2008. "Ten years of renewable electricity policies in Spain: An analysis of successive feed-in tariff reforms." *Energy Policy* 36 (8): 2917–2929.

Del Río, Pablo, and Miguel A. Gual. 2007. "An integrated assessment of the feed-in tariff system in Spain." *Energy policy* 35:994–1012.

Del Río, Pablo, and Pedro Linares. 2014. "Back to the future? Rethinking auctions for renewable electricity support." *Renewable and Sustainable Energy Reviews* 35:42–56.

Diesendorf, Mark, and Ben Elliston. 2018. "The feasibility of 100% renewable electricity systems: A response to critics." *Renewable and Sustainable Energy Reviews* 93:318–330.

Dong, C.G. 2012. "Feed-in tariff vs. renewable portfolio standard: An empirical test of their relative effectiveness in promoting wind capacity development." *Energy Policy* 42:476–485.

Downing, Andrea, Avit Bhowmik, David Collste, Sarah E Cornell, Jonathan Donges, Ingo Fetzer, Tiina Häyhä, Jennifer Hinton, Steven Lade, and Wolf Mooij. 2019. "Matching scope, purpose and uses of planetary boundaries science." *Environmental Research Letters* 14 (7): 073005.

EEA. 2022. *EEA greenhouse gases - data viewer.* Accessed March 11, 2022. https://www.eea.europa.eu/data-and-maps/data/data-viewers/greenhouse-gases-viewer.

EEX. 2013. "Factors for the Success of the Energy Turnaround: Market and Europe," June. Accessed August 16, 2013. https://cdn.eex.com/document/137479/20130618_EEX%20Energy%20Policy%20Cornerstones_EN.pdf.

Ekins, Paul. 1997. "The Kuznets curve for the environment and economic growth: examining the evidence." *Environment and Planning A: Economy and Space* 29 (5): 805–830.

Elberg, Christina, and Sebastian Kranz. 2014. "Capacity mechanisms and effects on market structure." *EWI Working Paper* No. 14/04.

Elizondo Azuela, Gabriela, Luiz Barroso, and Gabriel Cunha. 2014. "Promoting Renewable Energy through Auctions: The Case of Brazil." *Live Wire* 13.

Endres, Alfred. 2011. *Environmental Economics: Theory and Policy.* Cambridge University Press: New York, NY, USA.

Energy Industry Act (Energiewirtschaftsgesetz – EnWG). 2017. Accessed July 29, 2018. https://www.gesetze-im-internet.de/enwg_2005/EnWG.pdf.

European Commission. 2011. *Energy Roadmap 2050.* COM/2011/0885 final.

———. 2017. *2030 climate and energy framework.*

———. 2021. *State of the Energy Union 2021 - Contributing to the European Green Deal and the Union's recovery (pursuant to Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action).*

Eurostat. 2022a. *Electricity production capacities by main fuel groups and operator.* Retrieved from: https://ec.europa.eu/eurostat/databrowser/view/nrg_inf_epc/default/table?lang=en. Accessed March 2, 2022.

———. 2022b. *Energy productivity.* Retrieved from: https://ec.europa.eu/eurostat/databrowser/view/t2020_rd310/default/table?lang=en. Accessed March 2, 2022.

———. 2022c. *Environmental taxes by economic activity.* Retrieved from: https://ec.europa.eu/eurostat/databrowser/view/env_ac_taxind2/default/table?lang=en. Accessed March 2, 2022.

———. 2022d. *Final energy consumption.* Retrieved from: https://ec.europa.eu/eurostat/databrowser/view/sdg_07_11/default/table?lang=en. Accessed March 2, 2022.

———. 2022e. *Greenhouse gas emissions in ESD sectors.* Retrieved from: https://ec.europa.eu/eurostat/databrowser/view/env_air_esd/default/table?lang=en. Accessed March 23, 2022.

———. 2022f. *Primary energy consumption.* Retrieved from: https://ec.europa.eu/eurostat/databrowser/view/sdg_07_10/default/table?lang=en. Accessed March 2, 2022.

———. 2022g. *Share of fossil fuels in gross available energy.* Retrieved from: https://ec.europa.eu/eurostat/databrowser/view/nrg_ind_ffgae/default/table?lang=en. Accessed March 2, 2022.

———. 2022h. *Share of renewable energy in gross final energy consumption.* Retrieved from: https://ec.europa.eu/eurostat/databrowser/view/t2020_rd330/default/table?lang=en. Accessed March 11, 2022.

Fabra, N., F.C. Matthes, D. Newbery, M. Colombier, M. Mathieu, and A. Rudinger. 2015. *The energy transition in Europe: initial lessons from Germany, the UK and France. Towards a low carbon European power sector.* Centre on Regulation in Europe.

Federal Network Agency (Bundesnetzagentur). 2018. *Kraftwerksliste Bundesnetzagentur (bundesweit; alle Netz- und Umspannebenen) Stand 02.02.2018.* Accessed July 30, 2018. https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html.

Fesenfeld, Lukas Paul. 2020. "The political feasibility of transformative climate policy–public opinion about transforming food and transport systems." PhD diss., ETH Zürich.

Finon, Dominique, and Virginie Pignon. 2008. "Electricity and long-term capacity adequacy: The quest for regulatory mechanism compatible with electricity market." *Utilities policy* 16 (3): 143–158.

Fitch-Roy, Oscar, Jenny Fairbrass, and David Benson. 2020. "Ideas, coalitions and compromise: reinterpreting EU-ETS lobbying through discursive institutionalism." *Journal of European Public Policy* 27:82–101.

Flinkerbusch, Kai, and Fabian Scheffer. 2013. "Eine Bewertung verschiedener Kapazitätsmechanismen für den deutschen Strommarkt." *Zeitschrift für Energiewirtschaft* 37 (1): 13–25.

Fraunhofer ISE. 2021. *Annual Electricity Spot Market Prices in Germany.* Accessed July 31, 2021. https://energy-charts.info/charts/price_average/chart.htm?l=en&c=DE&year=-1&interval=year.

Frondel, Manuel, Christoph Schmidt, and Colin Vance. 2014. "Revisiting Germany's solar cell promotion: an unfolding disaster." *Economic Analysis and Policy* 44:3–13.

Geels, Frank, Benjamin Sovacool, Tim Schwanen, and Steve Sorrell. 2017. "Sociotechnical transitions for deep decarbonization." *Science* 357 (6357): 1242–1244.

Gillingham, Kenneth, and James Stock. 2018. "The Cost of Reducing Greenhouse Gas Emissions." *Journal of Economic Perspectives* 32:53–72.

Glachant, Jean-Michel, and Sophia Ruester. 2014. "The EU internal electricity market: Done forever?" *Utilities Policy* 31:221–228.

Grossman, Gene, and Alan Krueger. 1995. "Economic growth and the environment." *The Quarterly Journal of Economics* 110 (2): 353–377.

Growitsch, Christian, Felix Christian Matthes, and Hans-Joachim Ziesing. 2013. "Clearing-Studie Kapazitätsmärkte." *Report for the Federal Ministry for Economic Affairs and Energy (BMWi), Cologne, Berlin,* accessed September 5, 2021. https://www.oeko.de/oekodoc/1847/2013-516-de.pdf.

Grubb, Michael, Jae Edmonds, Patrick Ten Brink, and Michael Morrison. 1993. "The Costs of Limiting Fossil-Fuel CO_2 Emissions: A Survey and Analysis." *Annual Review of Energy and the environment* 18:397–478.

Haas, Reinhard, Chrisitan Panzer, M. Ragwitz, Gemma Reece, and Anne Held. 2011. "A Historical Review of Promotion Strategies for Electricity from Renewable Energy Sources in EU Countires." *Renewable and Sustainable Energy Reviews* 15:1003–1034.

Harbord, David, and Marco Pagnozzi. 2014. "Britain's electricity capacity auctions: lessons from Colombia and New England." *The Electricity Journal* 27:54–62.

Hartnell, G. 2003. "Renewable Energy Development 1990-2003." *Renewable Power Association, London.*

Haufe, Marie-Christin, and Karl-Martin Ehrhart. 2018. "Auctions for renewable energy support–Suitability, design, and first lessons learned." *Energy Policy* 121:217–224.

Heard, B.P., B.W. Brook, T.M.L. Wigley, and C.J.A. Bradshaw. 2017. "Burden of proof: A comprehensive review of the feasibility of 100% renewable-electricity systems." *Renewable and Sustainable Energy Reviews* 76:1122–1133.

Hobbs, Benjamin, Javier Iñón, and Steven Stoft. 2001. "Installed capacity requirements and price caps: oil on the water, or fuel on the fire?" *The Electricity Journal* 14 (6): 23–34.

Hockenstein, Jeremy, Robert Stavins, and Bradley Whitehead. 1997. "Crafting the next generation of market-based environmental tools." *Environment: Science and Policy for Sustainable Development* 39:12–33.

Hoffmann, Ulrich, et al. 2011. "Some reflections on climate change, green growth illusions and development space." UNCTAD Discussion Papers 205, United Nations Conference on Trade and Development Geneva.

Höschle, Hanspeter, Cedric De Jonghe, Hélène Le Cadre, and Ronnie Belmans. 2017. "Electricity markets for energy, flexibility and availability—Impact of capacity mechanisms on the remuneration of generation technologies." *Energy Economics* 66:372–383.

Houghton, J.T., G.J. Jenkins, and J.J. Ephraums. 1990. "Climate change: the IPCC scientific assessment." *American Scientist; (United States)* 80 (6).

Icha, Petra, and Gunter Kuhs. 2020. "Entwicklung der spezifischen Kohlendioxid-Emissionen des deutschen Strommix in den Jahren 1990-2019," accessed July 22, 2021. https://www.umweltbundesamt.de/sites/default/files/medien/1410/publikationen/2020-04-01_climate-change_13-2020_strommix_2020_fin.pdf.

Illge, Lydia, and Reimund Schwarze. 2009. "A matter of opinion - How ecological and neoclassical environmental economists and think about sustainability and economics." *Ecological Economics* 68 (3): 594–604.

Informationsplattform der deutschen Übertragungsnetzbetreiber. 2018. *EEG-Mengentestat 2018 auf Basis von Prüfungsvermerken.* Accessed July 31, 2021. https://www.netztransparenz.de/portals/1/EEG-Jahresabrechnung_2018.pdf.

International Energy Agency. 2021. *World Energy Outlook 2021.* Paris. Accessed July 9, 2022. https://www.iea.org/reports/world-energy-outlook-2021.

———. 2022. *Electricity market report - January 2022.* Paris. Accessed July 9, 2022. https://www.iea.org/reports/electricity-market-report-january-2022.

IPCC. 2022. "Summary for Policymakers." Edited by Priyadarshi R. Shukla, Jim Skea, et al. *Climate change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change.*

IWA. 2019. *Wellbeing worldbeaters: New Zealand, Scotland and Iceland.* Accessed July 9, 2022. https://www.iwa.wales/agenda/2019/10/wellbeing-worldbeaters-new-zealand-and-scotland/.

Jacobs, Michael, et al. 2012. "Green Growth: Economic Theory and Political Discourse." *GRI Working Papers* 92 (92).

Jaffe, Adam, and Frank Felder. 1996. "Should electricity markets have a capacity requirement? If so, how should it be priced?" *The Electricity Journal* 9:52–60.

Jakob, Michael, and Ottmar Edenhofer. 2014. "Green growth, degrowth, and the commons." *Oxford Review of Economic Policy* 30 (3): 447–468.

Joskow, Paul. 2008. "Lessons learned from electricity market liberalization." *The Energy Journal* Special Issue. The Future of Electricity: Papers in Honor of David Newbery:9–42.

Joskow, Paul, and Jean Tirole. 2007. "Reliability and competitive electricity markets." *The RAND Journal of Economics* 38:60–84.

Kalkuhl, Matthias, Ottmar Edenhofer, and Kai Lessmann. 2012. "Learning or lock-in: Optimal technology policies to support mitigation." *Resource and Energy Economics* 34:1–23.

Kanellopoulos, K. 2018. "Scenario analysis of accelerated coal phase-out by 2030: A study on the European power system based on the EUCO27 scenario using the METIS model." *Publications Office of the European Union 2018.*

Keles, Dogan, Andreas Bublitz, Florian Zimmermann, Massimo Genoese, and Wolf Fichtner. 2016. "Analysis of design options for the electricity market: The German case." *Applied energy* 183:884–901.

Kesicki, Fabian. 2012. "Intertemporal issues and marginal abatement costs in the UK transport sector." *Transportation research Part D: Transport and environment* 17:418–426.

Kim, Kyoung-Kuk, and Chi-Guhn Lee. 2012. "Evaluation and optimization of feed-in tariffs." *Energy policy* 49:192–203.

Kjerstad, Egil, and Steinar Vagstad. 2000. "Procurement auctions with entry of bidders." *International Journal of Industrial Organization* 18:1243–1257.

Kost, C., S. Shammugam, V. Fluri, D. Peper, A. Davoodi, and T. Schlegl. 2021. "Levelized Cost of Electricity: Renewable Energy Technologies (Version 2021)," accessed July 30, 2021. https://www.ise.fraunhofer.de/content/dam/ise/en/documents/publications/studies/EN2021_Fraunhofer-ISE_LCOE_Renewable_Energy_Technologies.pdf.

Kost, C., S. Shammugam, V. Jülich, H.T. Nguyen, and T. Schlegel. 2018. "Levelized Cost of Electricity: Renewable Energy Technologies," accessed August 31, 2018. https://www.ise.fraunhofer.de/content/dam/ise/en/documents/publications/studies/EN2018_Fraunhofer-ISE_LCOE_Renewable_Energy_Technologies.pdf.

Lesser, Jonathan, and Xuejuan Su. 2008. "Design of an Economically Efficient Feed-in Tariff Structure for Renewable Energy Development." *Energy policy* 36:981–990.

Levitt, S. D. (Host). 2022. *Solar Geoengineering Would Be Radical. It Might Also Be Necessary.* Podcast, People I Mostly Admire, Episode 79, Freakonomics Radio Network. https://freakonomics.com/podcast/solar-geoengineering-would-be-radical-it-might-also-be-necessary/.

Lilliestam, Johan, Anthony Patt, and Germán Bersalli. 2021. "The effect of carbon pricing on technological change for full energy decarbonization: A review of empirical ex-post evidence." *Wiley Interdisciplinary Reviews: Climate Change* 12.

Liu, Yingqi, and Ari Kokko. 2010. "Wind power in China: Policy and development challenges." *Energy Policy* 38:5520–5529.

Martin, Nigel, and John Rice. 2015. "Improving Australia's renewable energy project policy and planning: A multiple stakeholder analysis." *Energy Policy* 84:128–141.

Mastropietro, Paolo, Carlos Batlle, Luiz Barroso, and Pablo Rodilla. 2014. "Electricity auctions in South America: Towards convergence of system adequacy and RES-E support." *Renewable and Sustainable Energy Reviews* 40:375–385.

Mastropietro, Paolo, Ignacio Herrero, Pablo Rodilla, and Carlos Batlle. 2016. "A model-based analysis on the impact of explicit penalty schemes in capacity mechanisms." *Applied Energy* 168:406–417.

Matthes, Felix, Hauke Hermann, Carsten Diermann, and Ben Schlemmermeier. 2015. "Die Leistungsfähigkeit des Energy-only-Marktes und die aktuellen Kapazitätsmarkt-Vorschläge in der Diskussion." *Kommentierung und Bewertung der Impact-Assessment-Studien zu Kapazitätsmechanismen im Auftrag des Bundesministeriums für Wirtschaft und Energie sowie die Einordnung des Fokussierten Kapazitätsmarktes. Öko-Institut,* accessed August 2, 2018. http://um.baden-wuerttemberg.de/fileadmin/redaktion/m-um/intern/Dateien/Dokumente/5_Energie/Versorgungssicherheit/Leistungsfaehigkeit_EOM.pdf.

Matthes, Felix, Ben Schlemmermeier, Carsten Diermann, H. Hermann, and C. von Hammerstein. 2012. "Fokussierte Kapazitätsmärkte. Ein neues Marktdesign für den Übergang zu einem neuen Energiesystem, Studie für die Umweltstiftung WWF Deutschland, Öko-Institut, LBD, Raue, Berlin." *Institut für angewandte Ökologie (Hrsg.). Berlin,* accessed October 19, 2018. https://www.oeko.de/oekodoc/1586/2012-442-de.pdf.

Max-Neef, Manfred. 1995. "Economic growth and quality of life: a threshold hypothesis." *Ecological economics* 15 (2): 115–118.

McAfee, R. Preston, and John McMillan. 1986. "Bidding for Contracts: A Principal-Agent-Analysis." *The RAND Journal of Economics,* 326–338.

Memmler, Michael, Elke Mohrbach, Sven Schneider, Marion Dreher, and Reinhard Herbener. 2009. "Emissionsbilanz erneuerbarer Energieträger-Durch Einsatz erneuerbarer Energien vermiedene Emissionen im Jahr 2007." *Climate Change* 12. Accessed August 12, 2013. http://www.umweltdaten.de/publikationen/fpdf-l/3761.pdf.

Mendonca, Miguel, David Jacobs, and Benjamin Sovacool. 2010. "Powering the Green Economy–the feed-in tariff handbook." *Energy* 35:4618–4619.

Meyer, Roland, and Olga Gore. 2015. "Cross-border effects of capacity mechanisms: Do uncoordinated market design changes contradict the goals of the European market integration?" *Energy Economics* 51:9–20.

Mitchell, Catherine, Dierk Bauknecht, and Peter Connor. 2006. "Effectiveness through Risk Reduction: A Comparison of the Renewable Obligation in England and Wales and the Feed-in System in Germany." *Energy Policy* 34:297–305.

Mitchell, Catherine, and Peter Connor. 2004. "Renewable energy policy in the UK 1990–2003." *Energy policy* 32:1935–1947.

Moret, Stefano, Frédéric Babonneau, Michel Bierlaire, and François Maréchal. 2020. "Overcapacity in European power systems: Analysis and robust optimization approach." *Applied Energy* 259. https://doi.org/https://doi.org/10.1016/j.apenergy.2019.113970.

Neuhoff, Karsten, and Laurens De Vries. 2004. "Insufficient incentives for investment in electricity generations." *Utilities Policy* 12:253–267.

Newbery, David. 2016a. "Missing money and missing markets: Reliability, capacity auctions and interconnectors." *Energy policy* 94:401–410.

———. 2016b. "Towards a green energy economy? The EU Energy Union's transition to a low-carbon zero subsidy electricity system – Lessons from the UK's Electricity Market Reform." *Applied Energy* 179:1321–1330.

Nicolosi, Marco, and Michaela Fürsch. 2009. "The impact of an increasing share of RES-E on the conventional power market—the example of Germany." *Zeitschrift für Energiewirtschaft* 33 (3): 246–254.

Nordhaus, William D. 1991. "To slow or not to slow: the economics of the greenhouse effect." *The Economic Journal* 101:920–937.

NPR. 2019. Transcript: Greta Thunberg's Speech at The U.N. Climate Action Summit. September 23, 2019 by NPR Staff. Accessed July 9, 2022. https://text.npr.org/763452863.

O'Neill, Daniel. 2012. "Measuring progress in the degrowth transition to a steady state economy." *Ecological economics* 84:221–231.

Ockenfels, Axel, Veronika Grimm, and Gregor Zoettl. 2008. *Strommarktdesign. Preisbildungsmechanismus im Auktionsverfahren für Stromstundenkontrakte an der EEX.* Gutachten im Auftrag der European Energy Exchange AG zur Vorlage an die Sächsische Börsenaufsicht.

Ockenfels, Axel, Roman Inderst, Günter Knieps, Klaus Schmidt, and Achim Wambach. 2013. *Langfristige Steuerung der Versorgung im Stromsektor.* Accessed August 2, 2018. https://www.bmwi.de/Redaktion/DE/Publikationen/Ministerium/Veroeffentlichung-Wissenschaftlicher-Beirat/wissenschaftlicher-beirat-langfristige-steuerung-der-versorgungssicherheit-im-stromsektor.pdf?__blob=publicationFile&v=1.

Owen, Anthony. 2011. "The economic viability of nuclear power in a fossil-fuel-rich country: Australia." *Energy Policy* 39:1305–1311.

Papadis, Elisa, and George Tsatsaronis. 2020. "Challenges in the decarbonization of the energy sector." *Energy* 205:1–15.

Pérez-Arriaga, I. 1999. "Reliability and generation adequacy." In *Reliability in the new Market Structure,* edited by W.S. Read, W.K. Newman, I.J. Pérez-Arriaga, H. Rudnick, M.R. Gent, and A.J. Roman, vol. 19. 12.

Perrings, Charles, and Alberto Ansuategi. 2000. "Sustainability, growth and development." *Journal of economic studies* 27 (1/2): 19–54.

Pfeifenberger, Johannes, Kathleen Spees, and Adam Schumacher. 2009. "A comparison of PJM's RPM with alternative energy and capacity market designs," accessed July 29, 2018. http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.644.9890&rep=rep1&type=pdf.

Pilgram, Thomas. 2010. "Formen des Handels an der EEX." In *Handbuch Energiehandel,* edited by Hans-Peter Schintowski, 339–456. Erich Schmidt Verlag.

Praktiknjo, Aaron, and Georg Erdmann. 2016. "Renewable electricity and backup capacities: An (Un-) resolvable problem?" *The Energy Journal* 37:89–106.

Ranci, P., and G. Cervigni. 2013. *The Economics of Electricity Markets: Theory and Policy.* Cheltenham: Edward Elgar.

Regulatory Commission for Electricity and Gas. 2012. *Study on capacity remuneration mechanisms.* Accessed October 19, 2018. http://www.creg.info/pdf/Etudes/F1182EN.pdf.

REN21. 2014. *Renewables 2014.* Accessed June 5, 2015. http://www.ren21.net/Portals/0/documents/Resources/GSR/2014/GSR2014_full%5C%20report_low%5C%20res.pdf.

Riechmann, C., F. Höffler, B. Schlemmermeier, A. Flamm, M. Peek, J. Ecke, and F. Matthes. 2014. "Auf dem Weg zum neuen Strommarktdesign: Kann der Energy-only Markt 2.0 auf Kapazitätsmechanismen verzichten?" *Agora Energiewende.,* accessed August 2, 2018. https://www.agora-energiewende.de/fileadmin/Projekte/2012/Kapazitaetsmarkt-oder-strategische-Reserve/Agora_Energiewende-Kapazitaetsmarkt-Reader_2014_web.pdf.

Riechmann, Christoph. 2008. "Stromwirtschaft. Ein Praxishandbuch." Chap. Funktionen in der Elektrizitätsversorgung, edited by Michael Bartsch, Peter Salje, and Andreas Röhling, 1–6. Carl Heymanns Verlag.

Rockström, Johan, Owen Gaffney, Joeri Rogelj, Malte Meinshausen, Nebojsa Nakicenovic, and Hans Joachim Schellnhuber. 2017. "A roadmap for rapid decarbonization." *Science* 355 (6331): 1269–1271.

Rockström, Johan, Will Steffen, Kevin Noone, Åsa Persson, F. Stuart Chapin, Eric F. Lambin, Timothy M. Lenton, Marten Scheffer, Carl Folke, Hans Joachim Schellnhuber, et al. 2009. "A safe operating space for humanity." *Nature* 461:472–475.

Rutherford, Donald. 2000. *Routledge Dictionary of Economics.* Routledge.

Sandén, Björn A, and Christian Azar. 2005. "Near-term technology policies for long-term climate targets—economy wide versus technology specific approaches." *Energy policy* 33:1557–1576.

Schäfer, Sebastian. 2018. "Reconciling emissions trading and the promotion of renewable energy." *MAGKS Joint Discussion Paper Series in Economics* No. 36-2018.

———. 2019. "Decoupling the EU ETS from subsidized renewables and other demand side effects: Lessons from the impact of the EU ETS on CO_2 emissions in the German electricity sector." *Energy Policy* 133.

Schäfer, Sebastian, and Lisa Altvater. 2019. "On the functioning of a capacity market with an increasing share of renewable energy." *Journal of Regulatory Economics* 56:59–84.

Schäfer, Sebastian, and Lisa Schulten. 2014. "A capacity market for electricity sectors with promotion of renewable energy." *MAGKS Joint Discussion Paper Series in Economics* No. 39-2014.

Schmalensee, Richard. 2012. "From "Green Growth" to sound policies: An overview." *Energy Economics* 34:S2–S6.

Schneider, François, Giorgos Kallis, and Joan Martinez-Alier. 2010. "Crisis or opportunity? Economic degrowth for social equity and ecological sustainability. Introduction to this special issue." *Journal of cleaner production* 18 (6): 511–518.

Sensfuß, Frank, Mario Ragwitz, and Massimo Genoese. 2008. "The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany." *Energy policy* 36 (8).

Siegmeier, Jan. 2011. "Kapazitätsinstrumente in einem von erneuerbaren Energien geprägten Stromsystem." *Electricity Markets Working Papers* 45. Accessed August 2, 2018. https://tu-dresden.de/bu/wirtschaft/ee2/ressourcen/dateien/lehrstuhlseiten/ordner_programmes/ordner_projekte/ordner_electricitymarkets/ordner_ge/wp_em_45_Siegmeier_Kapazittsinstrumente.pdf?lang=de.

Simonis, Udo. 1990. *Beyond growth: elements of sustainable development.* Berlin: edition sigma.

Skjærseth, Jon Birger, and Jørgen Wettestad. 2008. *EU Emissions Trading: Initiation, Decision-making and Implementation.* Chap. 5. Ashgate Publishing, Ltd.

Sokołowski, Maciej M. 2019. "When black meets green: A review of the four pillars of India's energy policy." *Energy Policy* 130:60–68.

Sorrell, Steven, and Jos Sijm. 2003. "Carbon trading in the policy mix." *Oxford review of economic policy* 19:420–437.

Sovacool, Benjamin. 2016. "How long will it take? Conceptualizing the temporal dynamics of energy transitions." *Energy Research & Social Science* 13:202–215.

Spaiser, Viktoria, Shyam Ranganathan, Ranjula Bali Swain, and David J. T. Sumpter. 2017. "The sustainable development oxymoron: quantifying and modelling the incompatibility of sustainable development goals." *International Journal of Sustainable Development & World Ecology* 24 (6): 457–470.

Spicker, Jörg. 2010. "Formen des OTC-Handels." In *Handbuch Energiehandel,* edited by Hans-Peter Schintowski, 31–336. Erich Schmidt Verlag.

Steffen, Will, Katherine Richardson, Johan Rockström, Sarah E. Cornell, Ingo Fetzer, Elena M. Bennett, Reinette Biggs, Stephen R. Carpenter, Wim De Vries, Cynthia A. De Wit, et al. 2015. "Planetary boundaries: Guiding human development on a changing planet." *Science* 347 (6223).

Stern, Nicholas. 2007. *The Economics of Climate Change: The Stern Review.* Cambridge University Press, UK.

Stoft, Steven. 2002. *Power system economics: designing markets for electricity.* IEEE Press Piscataway & Wiley-Interscience.

Stokes, Leah. 2013. "The Politics of Renewable Energy Policies: The Case of Feed-in Tariffs in Ontario, Canada." *Energy Policy* 56:490–500.

Strunz, S., E. Gawel, and P. Lehmann. 2016. "The political economy of renewable energy policies in Germany and the EU." *Utilities Policy* 42:33–41.

Tietjen, Oliver. 2012. *Kapazitätsmärkte. Hintergründe und Varianten mit Fokus auf einen emissionsarmen deutschen Strommarkt.* Germanwatch.

Tunca, Tunay, and Qiong Wu. 2009. "Multiple sourcing and procurement process selection with bidding events." *Management Science* 55:763–780.

United Nations. 2022. *Sustainable Development Goals History.* Accessed July 9, 2022. https://sdgs.un.org/goals#history.

United Nations Climate Change. 2022. *What is the Kyoto Protocol?* Accessed July 9, 2022. https://unfccc.int/kyoto_protocol.

Van den Bergh, Jeroen. 2011. "Environment versus growth - A criticism of "degrowth" and a plea for "a-growth"." *Ecological economics* 70 (5): 881–890.

Van Essen, H., L. van Wijngaarden, A. Schroten, D. Sutter, M. Schmidt, M. Brambilla, S. Maffii, K.E. Beyrouty, S. Morgan-Price, and E. Andrew. 2019. "State of play of internalisation in the European transport sector," accessed January 13, 2021. https://op.europa.eu/de/publication-detail/-/publication/696d402f-a45a-11e9-9d01-01aa75ed71a1.

Vázquez, Carlos, Michel Rivier, and Ignacio Pérez-Arriaga. 2002. "A market approach to long-term security of supply." *IEEE Transactions on power systems* 17 (2): 349–357.

Verband der Netzbetreiber. 2007. *Kalkulationsleitfaden §18 StromNEV.* Accessed March 26, 2016. http://www.tennet.eu/de/fileadmin/downloads/Kunden/2007-03-03_vdn-kalkulationsleitfaden_18_stromnev.PDF.

Vierth, Inge, and Axel Merkel. 2020. "Internalization of external and infrastructure costs related to maritime transport in Sweden." *Research in Transportation Business & Management.*

von Hirschhausen, Christian, Hannes Weigt, and Georg Zachmann. 2007. *Preisbildung und Marktmacht auf den Elektrizitätsmärkten in Deutschland.* VIK.

Wanner, Thomas. 2015. "The new 'passive revolution' of the green economy and growth discourse: Maintaining the 'sustainable development' of neoliberal capitalism." *New Political Economy* 20 (1): 21–41.

Weiss, Martin, and Claudio Cattaneo. 2017. "Degrowth - taking stock and reviewing an emerging academic paradigm." *Ecological economics* 137:220–230.

Wissen, Ralf, and Marco Nicolosi. 2007. "Anmerkungen zur aktuellen Diskussion zum Merit-Order Effekt der erneuerbaren Energien." *EWI Working Papers* 07.

Zappa, William, Martin Junginger, and Machteld Van Den Broek. 2019. "Is a 100% renewable European power system feasible by 2050?" *Applied energy* 233-234:1027–1050.