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Contents

List of Figures **ix**

List of Tables **xi**

1. Introduction **1**

1.1. Motivation . . . 1

1.2. Outline . . . 3

1.2.1. The Reformed EU ETS - Intertemporal Emission Trading with Restricted Banking . . . 3

1.2.2. Puncturing the Waterbed or the New Green Paradox? . . 4

1.2.3. On the Time-Dependency of MAC Curves and its Implications for the EU ETS . . . 4

1.2.4. One Price Fits All? Wind Power Expansion under Uniform and Nodal Pricing in Germany . . . 4

1.3. Methodological Approaches . . . 5

2. The Reformed EU ETS - Intertemporal Emission Trading with Restricted Banking **7**

2.1. Introduction . . . 7

2.2. Discrete Dynamic Optimization Model . . . 10

2.2.1. Decision-Making of a Representative Firm . . . 10

2.2.2. Market Equilibrium . . . 11

2.2.3. Introduction of the MSR and the CM . . . 12

2.2.4. Model Implementation and Parametrization . . . 13

2.3. Results and Sensitivity Analysis . . . 15

2.3.1. Results under the Current Regulation . . . 15

2.3.2. Sensitivity Analysis . . . 16

2.3.3. Results in the Context of Previous Studies . . . 20

2.4. Impact of the EU ETS Amendments on Emissions, Prices and Economic Performance 21
2.4.1. Decomposition of Effects of the Recent EU ETS Amendments on Prices and Emissions 21
2.4.2. Cost Effectiveness 24
2.5. Conclusion 26

3. Puncturing the Waterbed or the New Green Paradox? 29
3.1. Introduction 29
3.1.1. Motivation 29
3.1.2. Related Literature 30
3.1.3. Contribution and Structure 31
3.2. Methodology 32
3.2.1. Fundamental Model of the EU ETS 32
3.2.2. Decision-Making under Myopia 34
3.3. Numerical Evaluation of Overlapping Policies 34
3.3.1. Modeling of Overlapping Policies and Indicators for Evaluation 35
3.3.2. Results of the Base Scenario 37
3.3.3. Timing of Overlapping Policies under Perfect Foresight . 37
3.3.4. Addressed Volume and Design of Overlapping Policies . . 40
3.3.5. Overlapping Policies under Myopic Decision-Making . . . 41
3.4. Conclusion 43

4. On the Time-Dependency of MAC Curves and its Implications for the EU ETS 45
4.1. Introduction 45
4.2. Prevailing Literature on MAC Curves 46
4.3. Case Study: MAC Curves of the European Power Sector 48
4.3.1. Methodological Approach 48
4.3.2. The Change of MAC Curves Over Time 49
4.3.3. Drivers of Long-term MAC Curves 51
4.4. Implications for the EU ETS 53
4.4.1. The Functioning of the EU ETS 54
4.4.2. Implications of Time-Dependent MAC Curves in the EU ETS 54
4.4.3. Approaches for Time-Dependent MAC Curves in EU ETS Models 56

4.5. Conclusion 57

5. One Price Fits All? Wind Power Expansion under Uniform and Nodal Pricing in Germany 59

5.1. Introduction 59

5.1.1. Motivation 59

5.1.2. Related Literature 61

5.1.3. Contribution and Structure 62

5.2. Methodology, Input Data and Scenario Design 64

5.2.1. Investment and Dispatch Model 64

5.2.2. Grid Modeling 65

5.2.3. Assumptions and Data 67

5.2.4. Scenario Setup 69

5.3. Implications of Wind Power Expansion under Uniform and Nodal Pricing 70

5.3.1. Siting of Wind Power and Implications for Wind In-feed . 70

5.3.2. Regional Electricity Prices 73

5.3.3. Market Values and Subsidies 74

5.3.4. System Costs 77

5.4. Evaluation of G-Components and Grid Expansion Areas 78

5.4.1. Configuration 78

5.4.2. Effects on Siting, In-Feed and System Costs 80

5.5. Discussion of the Methodology 82

5.6. Conclusion 83

A. Supplementary Material for Chapter 2 85

A.1. Optimization of the Firm, Lagrange Function and KKT Conditions 85

A.2. The Impact of Backstop Costs 86

A.3. Effect of the CM with a Reduced LRF 87

B. Supplementary Material for Chapter 3 89

B.1. Parametrization and EU ETS Rules 89

B.2. Rules for the Intake, Reinjection and Cancellation 90

B.3. Results of the Base Scenario under Myopia 91

C. Supplementary Material for Chapter 4 93

C.1. The Power Market Model DIMENSION 93

C.2. Numerical Assumptions 95

C.3. Impact of Fuel Prices on Short-term MAC Curves 97

D. Supplementary Material for Chapter 5 **99**

D.1. Notation 99

D.2. Regional Scope: Germany's Transmission Network and Neighbors 100

D.3. Assumptions on Investment Costs, Demand and Fuel Prices . . . 100

D.4. Trade Flows 102

D.5. North-German Federal States 103

Bibliography **105**

Curriculum Vitae **116**

List of Figures

2.1. Development of emissions, TNAC, MSR, cancellation and allowance prices 15
2.2. Sensitivity analysis for baseline emissions 17
2.3. Effect of baseline emissions on cancellation 18
2.4. Sensitivity analysis for the interest rate 19
2.5. Effect of interest rate on cancellation 19
2.6. Effect of the change in the Linear Reduction Factor 22
2.7. Effect of the Market Stability Reserve and the Cancellation Mechanism 23
2.8. Comparison of discounted abatement costs and emission levels in different scenarios 25

3.1. Marginal abatement cost curves without and with overlapping policies 35
3.2. Prices, emissions, banking and total cancellation in the base scenario 37
3.3. Cumulative overlapping emission reductions, change in TNAC volumes and cumulative change in cancellation for implementing overlapping policies in 2020 and 2030 38
3.4. Overlapping emission reduction, additional cancellation and effectiveness for different implementation years of overlapping policies 39
3.5. Effectiveness for different addressed volumes of overlapping policies and different designs 40
3.6. Additional cancellation and effectiveness of overlapping policies depending on timing and planning horizon 41

4.1. Schematic illustration of the approach for deriving MAC curves . 49
4.2. Short-, medium- and long-term MAC curves and disaggregation of the abatement measures 50
4.3. Long-term MAC curves for different coal/gas price spreads . . . 51
4.4. Long-term MAC curves for different interest rates 52
4.5. Long-term MAC curves for different investment costs 53

4.6. Stylized impact of time-dependent MAC curves on the equilibrium price path and implications for abatement in the short, medium and long term . . . 55

5.1. Regional capacity factors of wind power plants and spatial distribution of wind power plants in 2019 . . . 68
5.2. Difference in spatial distribution of wind capacities in 2030 and cumulative wind expansion by latitude and capacity factor . . . 71
5.3. Difference in spatial distribution of wind generation in 2030 and development of wind generation and curtailment . . . 72
5.4. Difference between weighted-average nodal and uniform prices as well as nodal and uniform prices over latitude and cumulative demand . . . 73
5.5. Market (MV) and system values (SV) under uniform and nodal pricing in 2030 . . . 74
5.6. Boxplots of market and system values as well as required subsidies for wind power investments . . . 75
5.7. Required subsidies vs. system values of newly built wind power plants under nodal and uniform pricing . . . 76
5.8. Derivation of latitude-dependent g-components . . . 79
5.9. Cumulative wind power expansion by latitude and capacity factor until 2030 . . . 80
5.10. Change in in-feed potential, curtailment and realized generation . 81
5.11. Normalized increase of discounted additional supply costs . . . 82

A.1. Effect of the Cancellation Mechanism . . . 88

B.1. Market outcomes for the base scenario under myopia and under perfect poresight . . . 92

C.1. Short-term MAC curves for different coal/gas price spreads . . . 97

D.1. Regional scope and considered grid topology in 2030 . . . 100
D.2. Trade between Germany and its neighbours in 2020 and 2030 . . 102
D.3. The area of the federal states of Mecklenburg-Western Pomerania, Schleswig-Holstein and Lower Saxony . . . 103

List of Tables

2.1. Overview of examined scenarios 21

5.1. Assumed development of installed RES capacities in Germany . . 70
5.2. Average variable electricity supply costs 77
5.3. Yearly investments limit of grid expansion areas 80

B.1. Overview of the model parametrization 89

C.1. Sets, parameters and variables 93
C.2. Technological learning regarding investment costs 95
C.3. Considered technologies and their techno-economic characteristics 96
C.4. Assumptions on fuel prices 96
C.5. Assumed electricity demand per country 96

D.1. Sets, parameters and variables 99
D.2. Development of investment costs for onshore wind power plants . 100
D.3. Considered technologies and their techno-economic parameters . 101
D.4. Development of fuel and carbon prices 101
D.5. Development of demand 102

1. Introduction

1.1. Motivation

I was elected to represent the citizens of Pittsburgh, not Paris.
Donald John Trump (2017)

When announcing to withdraw from the Paris Agreement, the ceding U.S. president pretentiously claimed that he is obliged to the interests of his country, and not to those of the international community. This quote illustrates the dilemma of tackling climate change: while countries have to bear the costs for greenhouse gas (GHG) emission reduction individually, the benefits of limiting global warming is a global common. As a result, free-riding, i.e., not acting on climate change, is individually rational. However, individually rational, nationalist decision-making results in an equilibrium, where everybody is worse off.

In 2015, parties of the United Nations Framework Convention on Climate Change (UNFCCC) signed the Paris Agreement. According to this international environmental agreement, climate change is an *urgent threat*, which requires an *efficient and progressive response*. While the agreement sets the clear target to limit global warming to well below 2°C compared to pre-industrial levels, it relies on voluntary pledges to reduce GHG emissions. Lacking binding reinforcement mechanisms, the Paris Agreement does not tackle the fundamental problem of free-riding but rather promotes it (Nordhaus (2020)). Without a central authority that penalizes free-riding, overcoming the aforementioned dilemma requires international cooperation. The prevailing literature proposes sound concepts for international cooperation, e.g., climate clubs (Nordhaus (2015)) or reciprocal agreements on carbon prices (Cramton et al. (2017)). However, the stagnation in negotiating binding reduction targets after the end of the first Kyoto Protocol commitment period in 2012 underlines the difficulty to establish stable cooperation among sovereign states.

The imminent danger of climate change, though, forces immediate and decisive action. Leading industrialized nations unilaterally increase their - not enforceable - ambitions to mitigate climate change. Recently, the European Union, Japan and South Korea pledged to reach net-zero emissions by 2050. China targets net-zero emissions by 2060. Thereby, regions, which account for almost half of today's GHG emissions, expressed their will to vigorously act on climate change.To ensure that forerunners stick to their pledges and to encourage more states to follow, reducing GHG emissions must not harm the economic competitiveness of these countries. To this end, cost-efficient GHG emission reduction is crucial. An efficient allocation of scarce resources, i.e., investment capital, is further essential to master the required *transformations of gigantic, historic proportions* (Merkel (2020)).

Economic theory provides a clear-cut answer on how to cost-efficiently reduce GHG emissions: internalizing their negative externalities, i.e., the costs they inflict on third parties through climate change. To this end, economists favor implementing market mechanisms such as emissions trading to put a price on GHG emissions (cf. Arrow et al. (1997)). Emissions trading requires emitters to acquire allowances for their GHG emissions. Thus, the total allowance supply limits total emissions. Firms trade these allowances on markets. The resulting allowance prices reflect the scarcity of allowance supply and the firms' marginal abatement costs. Thereby, emissions trading discloses the firms' private information on abatement costs and handles this information so that the emission target is met at the least cost.

While emissions trading can cost-efficiently reduce GHG emissions in theory, political considerations can flaw its design and thus hinder an efficient implementation in practice. In emissions trading, limitations on shifting allowances in time, for instance, forces firms to deviate from their cost-optimal emissions paths. However, such restrictions might be necessary to solve the commitment problem: If firms use their emission budget early on, it can not be ensured that the budget is not increased by future governments.

Not only the design of emissions trading itself but also the design of related markets and their interactions with emissions trading are detrimental for an efficient reduction of GHG emissions. Most notably, the power sector is a frequent subject of governmental interventions due to its special properties and economic relevance[1]. Recently, pressure from climate activists and the political will to reduce power sector emissions led to decisions on phasing-out coal power plants in all Western-European countries. Additionally, the subsidized rise of renewable energies has transformed power systems from concentrated to spatially dispersed electricity generation structures. This development poses new challenges to electricity grids. While the historic power market design of most European power markets does not adequately tackle this problem, adjusting the design is politically challenging due to distributional effects.

Against this background, the thesis at hand studies the market design of the world's largest emissions trading system, namely the European Union Emission Trading System (EU ETS), and of related power markets. It focuses on the latest EU ETS reforms and interactions of the reformed EU ETS with overlapping regulations. This thesis further discusses power market designs for the efficient

[1] Power markets are prone to major uncertainties since long-term electricity storage is not economically feasible. At the same time, the security of supply is paramount due to high economic costs in case of supply interruptions.

expansion of wind power considering network congestion. Each of the following four chapters is based on a paper to which the authors contributed equally:

1. The Reformed EU ETS - Intertemporal Emission Trading with Restricted Banking. Joint work with Johanna Bocklet, Martin Hintermayer and Theresa Wildgrube, *EWI Working Paper 19/04* and published in *Energy Economics*. (Bocklet et al., 2019)
2. Puncturing the Waterbed or the New Green Paradox? *EWI Working Paper 20/07*. (Schmidt, 2020)
3. On the Time-Dependency of MAC Curves and its Implications for the EU ETS. Joint work with Martin Hintermayer and Jonas Zinke, *EWI Working Paper 20/08*. (Hintermayer et al., 2020)
4. One Price Fits All? Wind Power Expansion under Uniform and Nodal Pricing in Germany. Joint work with Jonas Zinke, *EWI Working Paper 20/06*. (Schmidt and Zinke, 2020)

The remainder of the introduction provides an outline of the following chapters (section 1.2), discusses the methodological approaches and hints at opportunities for future research (section 1.3).

1.2. Outline

1.2.1. The Reformed EU ETS - Intertemporal Emission Trading with Restricted Banking

With the increase of the linear reduction factor, the implementation of the market stability reserve and the introduction of the cancellation mechanism, the EU ETS changed fundamentally. Chapter 2 develops a discrete time model of the inter-temporal allowance market that accurately depicts these reforms assuming that prices develop with the Hotelling rule as long as the aggregated bank is non-empty. A sensitivity analysis ensures the robustness of the model results regarding its input parameters. The accurate modelling of the EU ETS allows for a decomposition of the effects of the individual amendments and the evaluation of their cost effectiveness. The market stability reserve shifts emissions to the future but is allowance preserving. A one-time cancellation reduces the overall emission cap, increasing allowance prices in the long run, but does not significantly impact the emission and price path in the short run. The increased linear reduction factor leads with 9 billion cancelled allowances to a stronger reduction than the cancellation mechanism and is therefore the main price driver of the reform.

1.2.2. Puncturing the Waterbed or the New Green Paradox?

By introducing the cancellation mechanism, the reformed EU ETS enables overlapping policies, such as national coal phase-outs, to affect total emissions. Chapter 3 applies a detailed partial equilibrium model of the EU ETS to evaluate the impact of overlapping policies on the EU ETS. Under perfect foresight, overlapping policies decrease total emissions if implemented early on. Though, endogenous cancellation within the EU ETS mitigates the waterbed effect hardly by more than 50%. In contrast, overlapping policies mostly do not affect total emissions significantly or even increase them via the new green paradox effect if implemented late and firms anticipate their long-term impact. If overlapping policies focus on low-cost abatement options, they become more effective in mitigating the waterbed effect, with an effectiveness of up to 60%. The effectiveness of overlapping policies decreases if firms are myopic. Myopia also increases the danger of the new green paradox effect for early implemented overlapping policies. However, the absolute increase in total emissions via the new green paradox remains below a third of today's yearly emissions if overlapping policies permanently reduce allowance demand by 10%.

1.2.3. On the Time-Dependency of MAC Curves and its Implications for the EU ETS

Recently, several articles rely on marginal abatement cost (MAC) curves to analyze the EU ETS. While the assumptions on MAC curves drive the results, the prevailing literature on the EU ETS does not take the shape of MAC curves into account. Hence, chapter 4 discusses the implications of MAC curve properties for the EU ETS. With a partial equilibrium model of the European power sector, the chapter derives two essential properties of MAC curves: First, the shape of MAC curves is convex and depends on economic developments, e.g., fuel prices and interest rates. Second, MAC curves flatten over time, mainly due to enlarging investment opportunities. With convex MAC curves, marginal abatement costs in the EU ETS increase over time, which triggers higher banking of firms. On the contrary, flattening MAC curves over time lead to lower incentives for banking. In particular, short-term MAC curves are steep and thus, raise the price path.

1.2.4. One Price Fits All? Wind Power Expansion under Uniform and Nodal Pricing in Germany

Chapter 5 evaluates investment incentives for wind power under uniform and nodal pricing in Germany. Today's uniform pricing market design does not account for negative externalities of wind power expansion on grid congestion. In contrast, nodal prices reflect grid congestion issues and hence provide theoretically efficient investment signals. By comparing the two market designs, the chapter derives distorting effects of today's market design for the expansion of wind power.

To this end, an electricity system model is developed, which allows for investments into wind power while considering transmission grid constraints in detail. Targeting equally high wind capacities under nodal and uniform pricing until 2030, locations of new wind power plants shift towards sites with lower wind yield under nodal prices. The wind energy fed into the grid, though, is higher under nodal pricing since curtailment is cut to a third. Grid-optimal wind locations require higher subsidy payments but decrease yearly variable supply costs by 1.5% in 2030. However, distributional effects are an obstacle to implementing nodal pricing, where about 75% of German demand faces electricity costs increase of about 5%. For mitigating distorted investment signals of uniform pricing, implementing investment restrictions within grid expansion areas prove to be more promising than a latitude-dependent generator-component in the grid tariff design.

1.3. Methodological Approaches

The chapters of this thesis analyze two different markets, i.e., emissions trading and power markets, and therefore develop and apply different methodologies. Chapters 2 and 3 model the behavior of firms and resulting carbon prices in the EU ETS. Chapter 4 derives optimal emission reduction decisions in the power market. Chapter 5 models spatially high-resolved electricity markets to derive optimal siting of wind power plants.

Each chapter uses fundamental numerical models of real-world markets. This thesis exclusively relies on partial equilibrium optimization models, which isolate single markets and assume developments in other markets exogenously. Further, idealized market structures are assumed to keep the models' computationally tractable. For interpreting the results and transferring them into the real world, understanding the methodological approaches and particularly the underlying assumptions as well as their limitations is decisive.

Chapter 2 introduces a model to analyze the European Emission Trading System (EU ETS). The model considers perfectly rational homogeneous firms, which minimize their costs for abating as well as purchasing emission allowances. Deriving Karush-Kuhn-Tucker conditions, the model is set up as a feasibility problem. Non-linearities in optimality conditions as well as in regulation are linearized. The model is set up as a mixed complementary problem (MCP) and accurately depicts the current regulation.

The market design of the EU ETS with endogenous prices and endogenous allowance supply though allows for multiple equilibria. For receiving a unique solution, the model maximizes emissions. Thereby, the model implicitly assumes that firms within the EU ETS can coordinate themselves towards the cost-optimal, i.e., emission-maximal equilibrium. Further research should explore equilibria and their stability in the EU ETS. While possible equilibria do not diverge significantly in the considered idealized setting, market frictions, e.g., bounded rationality of firms, could enforce the issue of multiple equilibria.

The model further assumes perfect foresight and therefore does not account for uncertainties in the market. Since emission trading represents an intertemporal problem, today's decision depends on expectations of the future. Chapter 3 implements myopia into the model and analyzes its impact on the effectiveness of overlapping policies within the EU ETS. Including uncertainty, e.g., in regulation or due to technological learning, represents a promising subject for future research.

Moreover, EU ETS models typically use marginal abatement cost (MAC) curves to represent allowance demand. The model used in chapter 3 allows for depicting a wide range of MAC curves shapes. However, the literature on the shape of MAC curves and how they evolve over time is scarce. To this end, chapter 4 identifies the fundamental properties of MAC curves via consecutive runs of a power market model. Since MAC curves of the power sector are time-dependent and interact with carbon price paths, integrating models of the allowance demand (i.e., the power sector and energy-intensive industries) and the EU ETS model opens up opportunities for future research. Applying integrated models could shed light on the interactions and distributional effects among member states and sectors.

Finally, chapter 5 develops a dispatch and investment power market model that includes a detailed representation of the German electricity transmission network. The model relies on strong assumptions. It linearizes non-linear power flow constraints and neglects transmission losses. Further, the model requires competitive, efficient markets and perfectly rational market participants with perfect foresight. While most of these assumptions are well-founded (e.g., rational firms) or will not distort the general findings (e.g., power flow approximation), the role of competition and uncertainty in spatially highly-resolved markets is subject to further research. The derived results further hinge on the quality of the input data. Most notably, demand and power plant distributions across Germany, as well as assigning them to network nodes rely on approximations. More computational resources and available data would allow for extending the detailed network representation to Germany's neighbors, which enables assessing interactions of cross-border electricity trading and network congestion issues.

Beyond this discussion, the respective chapters provide comprehensive descriptions of the methodological approaches.

2. The Reformed EU ETS - Intertemporal Emission Trading with Restricted Banking

2.1. Introduction

In 2005, the European Union Emissions Trading System (EU ETS)[2] was introduced as a cornerstone of the EU climate policy (European Parliament and the Council of the European Union, 2003). While many regions (e.g., California, Australia, Japan) have established other functioning carbon markets since, the EU ETS remains the largest one yet. It covers emissions from energy-intensive industries, the electricity sector and inner-European aviation in 31 countries and accounts for 45% of the total EU greenhouse gas (GHG) emissions.

An emission allowance market coordinates abatement among firms, allocating abatement to firms with low and allowances to firms with high abatement costs (e.g., Tietenberg (1985) and Salant (2016)). The environment's capacity to absorb emissions without harm can be thought of as a finite and hence exhaustible resource. This is depicted in current emission trading schemes by the finite number of emission allowances issued to the market. The well known economic theory on exhaustible resources (e.g., oil exploration) is the model developed by Hotelling (1931). Thereby, the market price of emission allowances develops with the interest rate if unrestricted banking and borrowing of allowances, i.e., saving unused allowances for the future and shifting future emissions to the present respectively, is allowed. This enables emission markets to reach dynamic effectiveness.

The Hotelling model was first used in the context of emission trading systems by Rubin (1996). In his seminal paper, Rubin (1996) sets up a dynamic optimization model, where heterogeneous firms minimize their abatement costs given predefined market rules. An intertemporal market equilibrium exists and is cost-effective when firms minimize their costs intertemporally through banking or borrowing. However, nation states are implicitly required by international climate agreements such as the Kyoto Protocol to refrain from allowing borrowing in the design of emission trading systems (UNFCCC, 2000). The UN hereby discourages nation states to sell future allowances and then dropping out of the

[2]The following abbreviations will be used throughout this paper: EU ETS: European Union Emission Trading System, LRF: linear reduction factor, TNAC: total number of allowances in circulation, MSR: market stability reserve, CM: cancellation mechanism

agreement.[3] This restriction may create short-run scarcity in the market, leading to a deviation from the original Hotelling price path. Chevallier (2012) applies the theoretical model developed by Rubin (1996) to the EU ETS and discusses the impact of those restrictions on banking and borrowing given the prevailing EU regulation at that time.

The regulatory framework of the EU ETS has been subject to multiple changes since then. The latest major amendments have been the increase of the linear reduction factor (LRF), the introduction of the market stability reserve (MSR) and the option to cancel allowances from the MSR, referred to as cancellation mechanism (CM). In October 2014, EU leaders adopted the 2030 climate and energy framework for the European Union. This framework comprises i.a. the target of at least 40% GHG reduction in 2030 compared to 1990 levels. To meet this target, the annual reduction of issued allowances in the EU ETS was increased from a LRF of 1.74% in the third trading period (2013-2020) (European Parliament and the Council of the European Union, 2003) to a LRF of 2.2% from 2021 onwards (European Parliament and the Council of the European Union, 2018).

In January 2019, the MSR came into force. Its intended effect is the strengthening of short-run carbon prices in the EU ETS. These were considered to not sufficiently spur investment in low-carbon technologies due to the perceived allowance surplus in phase 3 (European Parliament and the Council of the European Union, 2015). The MSR is a public deposit fed with allowances from the auction volume, whenever the number of allowances in circulation exceeds a certain threshold (European Parliament and the Council of the European Union, 2015). From 2023 onwards, the volume of the MSR is limited to the previous year's auction volume. Allowances in the MSR exceeding this upper limit are invalidated by the CM (European Parliament and the Council of the European Union, 2018).[4]

Recent contributions by Richstein et al. (2015), Perino and Willner (2016) and Beck and Kruse-Andersen (2020) evaluate the impact of the MSR on price and emission paths. Perino and Willner (2016) and Richstein et al. (2015) find that the MSR itself impacts the market price only temporarily and increases price volatility, contrary to its intended purpose. Because the aggregated emission cap is not altered, the MSR is considered allowance preserving. In Perino and Willner (2017) the impact of an exogenous, one-time cancellation of 800 million

[3] Another reason for this restriction is the shape of global damage curves. Since most scholars (e.g., Rubin (1996)) assume that pollution damage functions are convex, early emissions cause greater environmental damage than delayed emissions, thereby requiring a limitation on borrowing.

[4] This paper refrains from the fact that the European Commission and member states will review the final cancellation of allowances (European Parliament and the Council of the European Union, 2018) which introduces uncertainty about whether allowances will be cancelled at all. The first review is scheduled for 2022, further reviews of the MSR and the CM will take place in five-year intervals afterwards (European Parliament and the Council of the European Union, 2015).

allowances is discussed. However, the newly introduced CM decreases the overall emission cap endogenously, i.e., the cancellation depends on the number of allowances in the MSR and thus on the banking decision of the firms.

The original version of the Hotelling model uses a continuous representation of time due to the continuity of fossil fuel extraction. Continuous time models are also used in, e.g., Perino and Willner (2016) and Perino and Willner (2017). This continuous representation of time, however, is not an accurate representation of the EU ETS with the MSR and CM. Clearing of allowances, intake and reinjection of the MSR and the cancellation volume are determined on a yearly basis. Consequently, this paper proposes a discrete time structure to accurately represent current EU ETS regulation.

A discrete time model has also been used by Beck and Kruse-Andersen (2020) who evaluate the impact of national policies in light of the reformed EU ETS with MSR and CM and calibrate their discrete time models to historic market outcomes. The authors solve iteratively a firm's profit maximization problem assuming quadratic abatement costs and technological progress of renewable energies. Hereby, they show that the reform of the EU ETS increases allowance prices and decreases emissions in the short and long run. However, long-run effects are found to be substantially higher than in the short run. Further, they find that the effect of national policies on EU ETS emissions strongly depends on the timing of their implementation. If national abatement measures take place before 2023, they potentially increase the cancellation volume and thus reduce total EU ETS emissions.[5] However, their overall evaluation of the EU ETS amendments is ambivalent: While under the new regulation national policies potentially have an impact on abatement within the EU ETS, the complexity of the regulation may hinder the implementation of cost-efficient national policies. Silbye and Sørensen (2019) take a similar approach assessing the effect of national emissions reduction in light of the latest reforms. They find that if national emission reduction policies take place early, unused allowances will be transferred to the MSR and partially cancelled through the CM. If national reduction policies are implemented at a later point in time, they do not trigger an additional MSR intake and will therefore have no lasting effects on emissions.

The contribution of the paper at hand is threefold: Firstly, we develop a model which incorporates the current EU ETS regulation accurately, namely the change in the LRF and the introduction of the MSR and the CM. The volumes of the MSR and the CM are endogenously determined within a closed-form solution. In particular, the decision algorithm of the EU ETS operates on an annual basis. Therefore it is depicted in a discrete time model. Secondly, the decomposition of the recent amendments into its single components facilitates a better understanding of the underlying economics. This allows us to identify the main price drivers in the market. The sensitivity analysis validates the robustness of the model results and determines which economic effects can be expected

[5] This effect is also found and discussed in Carlén et al. (2019).

under various regulatory scenarios and parameter assumptions. Thirdly, the cost effectiveness of the current EU ETS regulation is compared with theoretical first-best scenarios based on the unaltered Hotelling model. Thereby, we can draw conclusions on the economic implications of the different regulatory instruments by discussing their individual impact on the economic performance.

The remainder of this paper is organized as follows: Section 2.2 develops the model, including the dynamic optimization problem of the firm and the equilibrium conditions in a competitive market given current EU ETS regulation. In section 2.3, the functioning of the model is explained and validated by sensitivity analyses. Further, the underlying economic effects are decomposed. Section 2.4 discusses the implications of the three amendments individually and assesses the cost effectiveness of the new regulation. Section 2.5 concludes.

2.2. Discrete Dynamic Optimization Model

We model the decision making of N polluting firms within the intertemporal market for emission allowances, namely the EU ETS, which is assumed to be perfectly competitive. In the following section, we describe our model which covers the individual decision making on the firm level. In section 2.2.2 the market clearing and equilibrium conditions are derived from the individual optimality conditions. The MSR and the CM are modelled in section 2.2.3 as an exact replication of the current EU regulation. The parameters used for the numeric illustration are presented in section 2.2.4.

2.2.1. Decision-Making of a Representative Firm

We assume a rational firm with perfect foresight which aims to minimize the present value of its total expenditure

$$PV = \sum_{t=0}^{T} \frac{1}{(1+r)^t} C(e(t)) + p(t)x(t). \tag{2.1}$$

In each discrete time period $t = 0, 1, \ldots, T$ the expenditure consists of two parts: the abatement costs $C(e(t))$ and the costs of acquiring of allowances $p(t)x(t)$. The firm can decide on the variables $e(t)$ for yearly emissions and $x(t)$ for yearly acquisition or sales of allowances. In line with Rubin (1996), we assume that the abatement costs follow a quadratic and convex function of the form $C(e(t)) = \frac{c}{2}(u - e(t))^2$. The baseline emission level u and the cost parameter c are exogenously given. Due to the assumption of a perfectly competitive market for allowances, the allowance price $p(t)$ is not influenced by the individual decision of the firm. The yearly costs are discounted at an annual interest rate of r. Let T be the first point in time when no further allowances are issued and all issued allowances are depleted. Hence, for all $t \geq T$ an emission cap of zero is established which makes allowance trading redundant.

As discussed in the previous section, the EU ETS enables firms to bank allowances for later use. This linking between time periods is modelled with the decision variable $b(t)$, which is the volume of acquired allowances in the private bank of the individual firm in period t. As intertemporal borrowing is prohibited, we require $b(t) \geq 0$. Additionally, in each time period the change in the bank $b(t) - b(t-1)$ has to be equal to the difference of net acquisition of allowances $x(t)$ and emissions $e(t)$.[6]

Combining the expenditure minimization with the intertemporal banking constraint yields the optimization problem for the individual firm

$$\begin{aligned} \min \quad & \sum_{t=0}^{T} \frac{1}{(1+r)^t}\left[\frac{c}{2}(u - e(t))^2 + p(t)x(t)\right] \\ & s.t.\ b(t) - b(t-1) = x(t) - e(t) \quad \text{for all} \quad t = 1, 2, \ldots, T \\ & \qquad\qquad b(t) \geq 0 \\ & \qquad x(t),\ e(t) \gtreqless 0. \end{aligned} \tag{2.2}$$

We assign the Lagrange multipliers $\lambda(t)$ and $\mu_b(t)$ to the flow constraint and the positivity constraint, respectively. As the optimization problem is convex and fulfills the Slater condition, the KKT conditions are necessary and sufficient for optimality.[7] These imply that $\mu_b(t)$ is 0 if $b(t)$ is positive.

From the optimality conditions we get

$$c(u - e(t)) = p(t). \tag{2.3}$$

This states that the firm will set emissions $e(t)$ such that the marginal abatement costs equal the price $p(t)$. Economically speaking, the firm expands emissions $e(t)$ and acquires allowances $x(t)$ whenever the allowance price is below the marginal abatement cost. Contrary, the firm abates more emissions if the allowance price exceeds the marginal abatement costs.

2.2.2. Market Equilibrium

While the firm's demand for allowances solely depends on the optimization problem stated above, the price is determined by the market. Supply, i.e., issuance

[6] We formally allow emissions to be negative. However, as borrowing is not allowed in the model, negative emissions do not occur.

[7] See Appendix A.1 for details on the Lagrange function and the exact KKT conditions including complementary conditions.

of allowances, and demand, i.e., the firm's acquisition of allowances, have to be balanced by the price, such that the market clears.

We define the supply $S(t)$ as the path of issued allowances in period t, which is regulated to be decreasing from an initial value $S(0)$ at a linear rate $a(t)$, hence $S(t) = S(t-1) - a(t)S_0$.[8] The issued allowances are partially auctioned ($S_{auct}(t)$) and partially distributed for free.[9]

The price path $p(t)$ is determined in the market such that aggregated emissions over time are smaller than aggregated issued allowances. This is

$$\sum_{\tilde{t}=0}^{t} e(\tilde{t}) \leq \sum_{\tilde{t}=0}^{t} S(\tilde{t}) \text{ for all } t = 0, 1, \ldots, T.$$

We assume that firms are homogeneous. From the individual optimality conditions stated in the previous section, we derive the rule for the development of market prices

$$\frac{p(t+1) - p(t)}{p(t)} = r - (1+r)^{t+1} \frac{\mu_b(t)}{p(t)}. \tag{2.4}$$

Economically speaking, whenever the private bank $b(t) > 0$, the corresponding shadow costs are $\mu_b(t) = 0$ and hence the price rises with interest rate r. This is in line with the continuous model in Hotelling (1931), where the optimal emission path can be achieved if banking and borrowing is possible. If at some point in time $\tau_{b=0}$ the bank becomes 0, firms would implicitly like to borrow allowances from the future, which is forbidden by EU regulation.[10] Therefore, firms have to abate more than in the optimal emission abatement path before $\tau_{b=0}$. This in turn means that the firm abates less than in the optimal abatement path after $\tau_{b=0}$. Consequently, the price will increase at a lower rate than r after $\tau_{b=0}$.[11]

2.2.3. Introduction of the MSR and the CM

With the introduction of the MSR and the CM the supply of allowances is no longer exogenously determined by the regulator. The amount of auctioned allowances $S_{auct}(t)$ additionally depends on the banking decisions of individual firms. To depict the development of the allowance supply correctly, we define the total number of allowances in circulation $TNAC(t) = \sum_{i=1}^{N} b_i(t)$, where b_i represents the individual banking decision of firm i.

[8] S_0 represents the number of allowances in 2010. $a(t)$ is the LRF.

[9] Following EU Directive 2018/410 the share of auctioned allowances is 57%, i.e., $S_{auct}(t) = 0.57\, S(t)$.

[10] We disregard the unlikely case that it could be possible that the path of issued allowances coincides with the optimal emission path. Hence, the bank would be 0 for all t.

[11] If at a later point in time a second banking phase occurs, the Hotelling rule becomes valid again.

The MSR mechanism works as follows: If at some time t the $TNAC(t)$ exceeds an upper limit ℓ_{up}, the number of auctioned allowances will be reduced by a share $\gamma(t)$ of the TNAC of the previous year. This reduction of auctioned allowances is inserted into the MSR. If $TNAC(t)$ drops below a lower limit ℓ_{low}, R allowances from the MSR are auctioned additionally.[12]

The CM states that allowances will be cancelled from the MSR, i.e., become invalid if the number of allowances in the MSR exceeds the auction volume of the previous year (European Parliament and the Council of the European Union, 2018).

These two amendments to the EU ETS are accurately expressed by

$$S(t) = S(t-1) - a(t)S_0 - Intake(t) + Reinjection(t). \tag{2.5}$$

The MSR is then given by

$$MSR(t) = MSR(t-1) + Intake(t) - Reinjection(t) - Cancel(t), \tag{2.6}$$

with

$$Intake(t) = \begin{cases} \gamma(t) * TNAC(t-1) & \text{if } TNAC(t-1) \geq \ell_{up}, \\ 0 & \text{else,} \end{cases} \tag{2.7}$$

$$Reinjection(t) = \begin{cases} R & \text{if } TNAC(t-1) < \ell_{low} \wedge MSR(t) \geq R, \\ MSR(t) & \text{if } TNAC(t-1) < \ell_{low} \wedge MSR(t) < R, \\ 0 & \text{else,} \end{cases} \tag{2.8}$$

and

$$Cancel(t) = \begin{cases} MSR(t) - S_{auct}(t-1) & \text{if } MSR(t) \geq S_{auct}(t-1), \\ 0 & \text{otherwise.} \end{cases} \tag{2.9}$$

2.2.4. Model Implementation and Parametrization

The regulatory decision rules and complementary conditions stated are non-linear. For the implementation and solution of the model with GAMS and CPLEX, they are equivalently reformulated as linear constraints using binary

[12] This regulation started in 2019 with an upper limit ℓ_{up} of 833 million and a lower limit ℓ_{low} of 400 million allowances. The intake rate $\gamma(t)$ into the MSR is 24% of the TNAC until 2024 and 12% afterwards. The reinjection takes place at tranches R of 100 million allowances (European Parliament and the Council of the European Union, 2015).

variables and the big-M method. This allows to combine the exact regulatory rules of the EU ETS with the market equilibrium model derived by the optimality conditions of the firms in an mixed integer linear program.

In 2019, the MSR is initially endowed with 900 million allowances which were backloaded between 2014 and 2016 (European Parliament and the Council of the European Union, 2015). Further, allowances that will remain unallocated at the end of phase 3 of the EU ETS are transferred into the MSR in 2020. These are estimated to amount to 600 million allowances (European Commission, 2015). As initial value for the TNAC in 2017 we use 1645 million allowances as published by the European Commission (2018). The number of issued allowances is calculated based on the 2199 million allowances issued in 2010 (European Environmental Agency, 2018) and reduced on a yearly basis by the corresponding LRF.[13]

Apart from the above mentioned regulatory parameters, the model is fed with further exogenous parameters, namely the interest rate, the baseline emissions and the backstop costs. In section 2.3.2 we discuss how the choice of these parameter values impacts the results. If not stated otherwise, the following values are used in the model: We apply a private interest rate r of 8%, representing the approximated weighted average cost of capital (WACC) of fossil power plants (Kost et al., 2018) and energy-intensive industries (KPMG, 2017). We acknowledge that there is high uncertainty about the baseline emission level in the absence of a cap-and-trade system, e.g., because of technology advancement (Beck and Kruse-Andersen, 2020), economic activity and weather conditions (Borenstein et al., 2018). For the sake of simplicity, we assume constant baseline emissions u of 2000 million tonnes CO_2 equivalent (CO_2e).[14]

We think of the backstop costs as the costs associated with a costly but inexhaustible abatement option, e.g., direct air carbon capture and storage. Assuming backstop costs $\bar{c}$ of 150 EUR/t[15], the cost parameter c is calculated by $c := \bar{c}/u$. By this definition we ensure that the last ton of baseline emissions is abated at backstop costs, i.e., for our quadratic abatement cost function $C'(0) = \bar{c}$.

[13] In our model we assume that without the reform the LRF of 1.74% would have been continuously used. However, the LRF for the time after 2020 had not been defined yet. Likewise, we assume that the increased LRF the factor of 2.2% will be used for all future trading periods. (European Parliament and the Council of the European Union, 2018)

[14] This assumption is similar to Perino and Willner (2016) and Schopp et al. (2015) who use constant baseline emissions of 1900 million tonnes CO_2e and 2200 million tonnes CO_2e, respectively. The sensitivity of this assumption is calculated and further discussed in section 2.3.2.

[15] The backstop costs of 150 EUR/t are in line with medium-range predictions of common Carbon Capture and Storage (CCS) technologies (e.g., Saygin et al. (2012) and Kuramochi et al. (2012)).

2.3. Results and Sensitivity Analysis

With the parametrized model set up above, we are able to assess the development of emissions, prices and MSR movements under the current regulation. Robustness of our results in terms of the parametrization is guaranteed by an extensive sensitivity analysis in section 2.3.2.

2.3.1. Results under the Current Regulation

From Equation 2.4 we know that as long as banking occurs, which is the case as long as sufficient allowances are available, the allowance price increases at the rate of interest (in accordance with the Hotelling rule). Under the current regulation, this development of abatement, emissions and the allowance price takes place until the TNAC is depleted in 2039, as depicted in Figure 2.1. Thereafter, annual emissions equal the number of issued allowances, which decline with the LRF. The allowance price increases at a lower, degressive rate, because marginal abatement costs equal prices (Equation 2.3). When all allowances are used, emissions drop to zero, and the allowance price reaches the marginal costs of the backstop technology (150 EUR/t)[16] and remains at this upper limit. This happens from 2058 onwards.

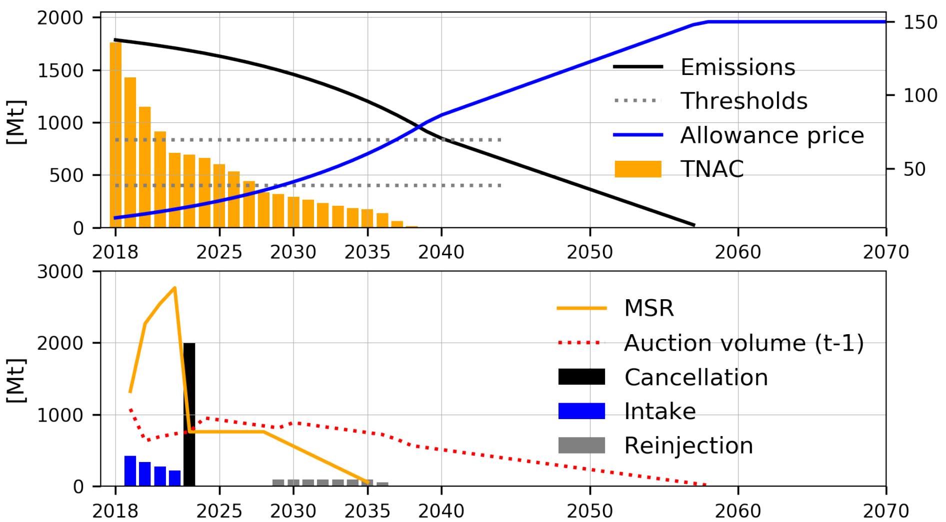

Figure 2.1.: Development of emissions, TNAC, MSR, cancellation and allowance prices

[16]EU ETS regulation imposes a penalty of 100 EUR/t (inflation-adjusted) if firms are non-compliant. The penalty does not release firms from their obligation to surrender allowances (European Parliament and the Council of the European Union, 2003). Therefore, paying the penalty fee is never a rational outcome, independent of the backstop price level.

After the implementation of the MSR in 2019, allowances are inserted into the MSR based on the rules described in section 2.2.3 since the TNAC exceeds the limit of 833 million allowances (see Figure 2.1). Until 2023, the MSR accumulates 2762 million allowances. As the CM enters into force in 2023, allowances become invalid according to the rules described in section 2.2.3. This leads to a one-time cancellation of 2002 million allowances in 2023.[17] This is equivalent to about 5% of all issued allowances from 2018 onwards. In 2028, the TNAC drops below the threshold of 400 million. Thus, from 2029 until the depletion of the MSR in 2037, 760 million allowances are reinjected into the market.

2.3.2. Sensitivity Analysis

As discussed in section 2.2.4, the model uses three exogenous input parameters: backstop costs, baseline emissions and interest rate. Varying these parameters does not change the modus operandi of the model. However, the numerical results are influenced by the assumed parameter values. Therefore, in the following we carry out sensitivity analyses to carve out robust results.

Backstop Costs

Due to the uncertainty when it comes to the realization of specific backstop costs in the future, we analyze its impact in a sensitivity. Ceteris paribus (in particular for a given level of baseline emissions u), a change in backstop costs only shifts the price path, but does not affect the level of emissions, abatement, TNAC, MSR or cancellation. In particular, the point in time at which the TNAC is depleted does not change. This is because the initial quantities still fulfill all equilibrium and regulatory conditions from section 2.2 for a scaled version of the price path. We state and prove this finding formally in A.2.

Baseline Emissions

Since it is not possible to measure baseline emissions, it is essential to take the uncertainty regarding this parameter into account (Borenstein et al., 2018). As the choice of its level has a significant impact on the numerical model results, a sensitivity analysis helps to assess the range of potential outcomes.

If we assume higher baseline emissions then in the standard case from section 2.3.1, the firm has higher emissions and correspondingly lower banking early on (see Figure 2.2). Since this behaviour drives allowance prices up, the firm increases abatement, partially compensating the effect of higher baseline emissions. However, the overall effect on banking remains negative. An increase of baseline emissions from 2000 to 2200 million tonnes CO_2e depletes the TNAC

[17] In this setting cancellation only takes place once. However, this is not inevitable and depends on the parametrization. Thus, multiple cancellation phases are possible.

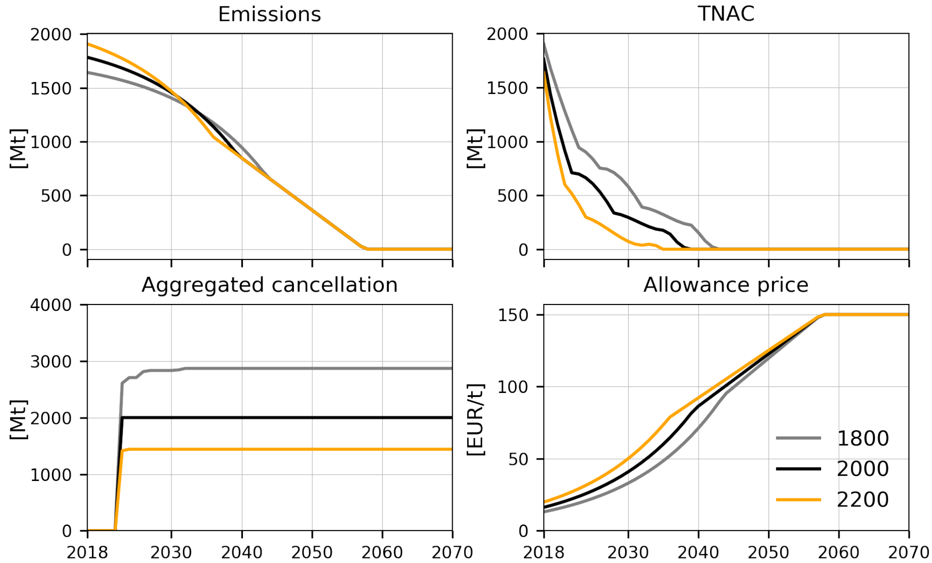

Figure 2.2.: Sensitivity analysis for baseline emissions

four years earlier. By regulation, the decrease of the TNAC leads to a lower intake of allowances into the MSR. Therefore, higher baseline emissions have a twofold negative effect on cancellation: Firstly, the lower MSR intake leads to a lower MSR volume. Secondly, it results in a larger auction volume as the MSR intake is subtracted from the allowances to be auctioned. Additionally, higher baseline emissions require stronger abatement to meet the same emission target. Thus, at any time t, allowance prices are above the ones in the standard case. An increase in baseline emissions from 2000 to 2200 million tonnes CO_2e leads to a price increase by 22% in all years in which the Hotelling rule applies.

Vice versa, lower baseline emissions lead to lower prices, higher TNAC levels and therefore higher intake into the MSR and larger cancellation volumes. Further, TNAC and MSR deplete at a later point in time. However, changes in the baseline emissions impact quantities asymmetrically. If the baseline emissions lie for instance at 1800 instead of 2000 million tonnes CO_2e, about 900 million allowances are cancelled additionally, whereas about 600 million allowances are cancelled additionally if the baseline emissions lie at 2000 instead of 2200 million tonnes CO_2e.

Figure 2.3 assesses the impact of baseline emissions on the aggregated amount of allowances cancelled. The cancellation volume increases overproportionally with a decrease of baseline emissions. In other words, with low baseline emissions, the model reaches higher levels of cancelled allowances. The higher the baseline emissions, the faster the private bank is depleted and thus the lower the MSR and the cancellation volume.

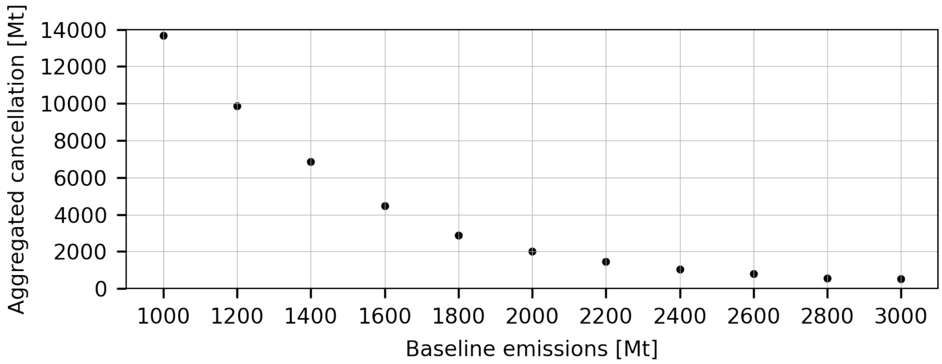

Figure 2.3.: Effect of baseline emissions on cancellation

Over time declining baseline emissions (as assumed by, e.g., Carlén et al. (2019) and Quemin and Trotignon (2018)) require lower abatement efforts. Hence, prices are strictly lower, leading to higher emissions and a lower TNAC in the short run and less cancellation in 2023. As the TNAC and the MSR deplete later, emission levels in the long run are higher compared to the case with constant baseline emissions.

Interest Rate

The interest rate of a firm reflects the opportunity costs of abatement, i.e., the profitability of alternative investments. Therefore, the interest rate impacts the firm's abatement decision directly. Thereby, the emission path and banking decision is affected, finally having an impact even on the MSR and the CM.

Figure 2.4 shows the sensitivity of the model results for interest rates of 3%, 5%, 8% and 16%. With a higher interest rate, the initial price level is lower but increases at a higher rate afterwards. Consequently, firms prefer to delay abatement and therefore increase emissions in the short run. With a similar rationale as in the sensitivity with higher baseline emissions, a higher interest rate leads to fewer MSR intake and less cancellation due to higher emissions in the short run.

In consequence, abatement has to be higher in the medium run to compensate for the initially higher emissions. In our example in Figure 2.4, starting with the depletion of the TNAC in 2030, the emissions in the sensitivity with 16% interest rate are lower than in the standard case with 8%. In the long run after 2040, emissions equal the exogenous supply of allowances in both cases. Hence, the price development is independent of the interest rate.[18]

[18] In both cases the reinjection of allowances from the MSR ends before 2040.

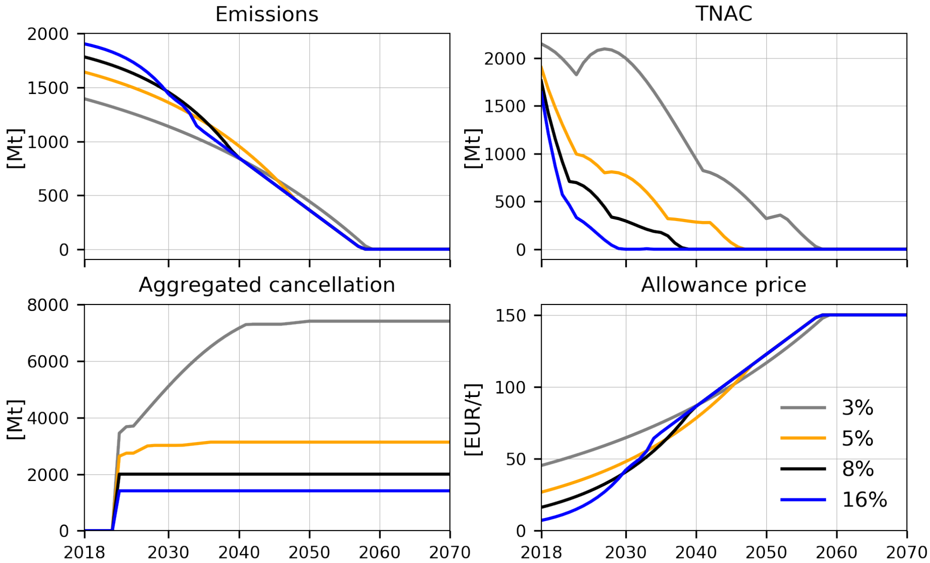

Figure 2.4.: Sensitivity analysis for the interest rate

With a lower interest rate, we can observe the opposite effects. Prices start at a higher level but increase at a lower rate. Emissions decrease in the short run and increase in later periods. A higher TNAC leads to more intake into the MSR and a higher volume of aggregate cancellation. In particular, with a lower interest rate the TNAC is non-empty for a longer time period, which in turn causes the price to longer rise with the interest rate. With an interest rate of 3%, the price rises with the interest rate until 2057.

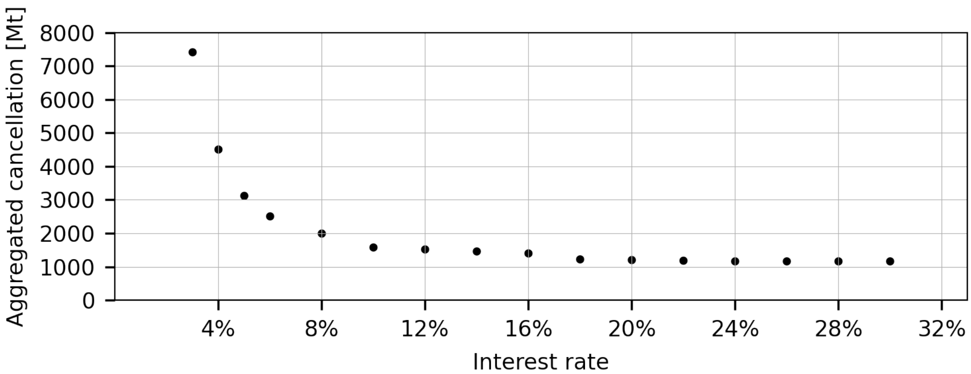

Figure 2.5.: Effect of interest rate on cancellation

Figure 2.5 assesses the impact of the interest rate on the total amount of allowances cancelled. Note that the aggregated cancellation volume and therefore the total abatement only changes significantly for low interest rates. The total number of cancelled allowances cannot fall below a certain level, because the emission level is bounded by the baseline emissions. In other words, the quantity of allowances needed in the short run is limited and therefore some amount of cancellation takes place independent of the interest rate.

Two effects determine the relationship between interest rate and cancellation volume: First, a high interest rate leads to higher emissions and less MSR intake in the short run. Therefore, the cancellation volume in 2023 decreases with the interest rate. Second, as total abatement does not change significantly, a high interest rate leads to higher abatement and a higher TNAC in the medium run, potentially causing more cancellation after 2023. The second effect partially offsets the first effect in terms of the total volume of allowances cancelled.

A high interest rate of firms leads to lower cancellation volumes. Since greater uncertainty in the market is reflected by higher interest rates of market participants, we conclude that the higher the uncertainty perceived in the market, the weaker the impact of the CM.

2.3.3. Results in the Context of Previous Studies

In the following, we put the findings presented in section 2.3.1 in the context of previous studies. Silbye and Sørensen (2019) and Beck and Kruse-Andersen (2020) find that in addition to the cancellation in 2023, further allowances are cancelled during the following years, leading to cumulative cancellation volumes of 5000 million (Silbye and Sørensen, 2019) and 6000 million (Beck and Kruse-Andersen, 2020). The significantly larger cancellation volumes compared to our result can be explained by the underlying model and parameter assumptions: Both studies assume a lower initial baseline emission level which is moreover decreasing over time. [19] As discussed in section 2.3.2, lower baseline emissions cause the TNAC and the MSR to deplete later (e.g., Silbye and Sørensen (2019) find that the TNAC depletes in 2057, while our model suggests a depletion in 2039) and a larger cancellation volume. Another reason for higher cancellation volumes in Beck and Kruse-Andersen (2020) lies in their assumption of a convex marginal abatement cost curve. Compared to a linear curvature, the convexity assumption increases the TNAC and hence cancellation volumes. Further, Silbye and Sørensen (2019) calibrate their model to depict the price spike in 2018 by the assumption of a decrease in interest rate caused by the reform. They assume a demand elasticity that translates to a significantly higher backstop cost level than in our model.[20] While the backstop price itself does not influence banking behavior and cancellation volume (see section 2.3.2), it leads to a higher overall price level.

[19]Their assumption of decreasing baseline emissions implies decreasing backstop costs given that the cost parameter is held constant.

[20]Their sensitivity parameter of allowance demand of 2.2 corresponds to an initial backstop cost level of 760 EUR/t. In other words, the initial cost parameter c implied by Silbye and Sørensen (2019) is nine times larger than the one used in Perino and Willner (2017) and six times larger than the one used in our model.

Despite the different modelling approaches, our numerical results are in line with the findings of Carlén et al. (2019) and Perino and Willner (2017). With their iterative solution approach, Carlén et al. (2019) find a one-time cancellation of 2400 million allowances in 2023. The TNAC is depleted in 2034 and the MSR is empty in 2035. Their slightly higher cancellation volume can be explained by their lower interest rate of 2.5% (see section 2.3.2). One of the scenarios from Perino and Willner (2017) depicts a MSR limited by the auction volume. With assumptions on baseline emissions and interest rate close to ours, their results are similar: Their TNAC is depleted in 2037 and their MSR remains empty from 2036 onwards. Thus, despite different modelling approaches, our numerical results (cancellation volume of 2000 million allowances, MSR depletion in 2037 and TNAC depletion in 2039) are in line with those of the two former studies.

2.4. Impact of the EU ETS Amendments on Emissions, Prices and Economic Performance

We assess the impact of the recent EU ETS amendments on abatement paths, total emissions and price paths. The results of the EU ETS reforms presented in section 2.3.1 are decomposed into the effects of single amendments, namely the increase in the LRF, the MSR and the CM (section 2.4.1). In section 2.4.2 we evaluate the economic performance of the amendments by comparing the single amendments to hypothetical first-best scenarios with the respective emission cap. Table 2.1 depicts the characteristics of the different scenarios used in this section.

	LRF after 2020	MSR	CM
pre-reform	1.74%	no	no
increased LRF	2.20%	no	no
MSR	2.20%	yes	no
post-reform	2.20%	yes	yes
late cancel	2.20%	yes	cancellation from the long end

Table 2.1.: Overview of examined scenarios

2.4.1. Decomposition of Effects of the Recent EU ETS Amendments on Prices and Emissions

Apart from the pre-reform scenario and the post-reform scenario that depicts the current EU ETS regulations discussed in section 2.3, we set up the increased LRF scenario (high LRF from 2021 onwards, but no MSR and CM) to isolate the impact of the increased LRF from the aggregated reform results (see Figure 2.6). The results show that the effect of the lower cap on issued allowances is significant: with the higher LRF of 2.2% the total emission cap is reduced by over 9 billion allowances which equals a 21% reduction of the allowance volume issued after 2020. The last allowances will be issued in 2057 and thus 10 years earlier than with the lower LRF.

This additional scarcity also shows in the price difference between the pre-reform scenario and the increased LRF scenario. The higher LRF increases prices at any point in time but the difference is most noticeable in the long run. The change in the LRF does not impact the banking decision of the firm, and thus at which time $\tau_{b=0}$ the TNAC becomes zero and prices develop at a degressive rate. As the price level at time $\tau_{b=0}$ is higher in the increased LRF scenario, the degressive price path after this point develops from a higher level and at a higher rate. Thus, the price increase resulting from the change in the LRF is most significant in the long run.

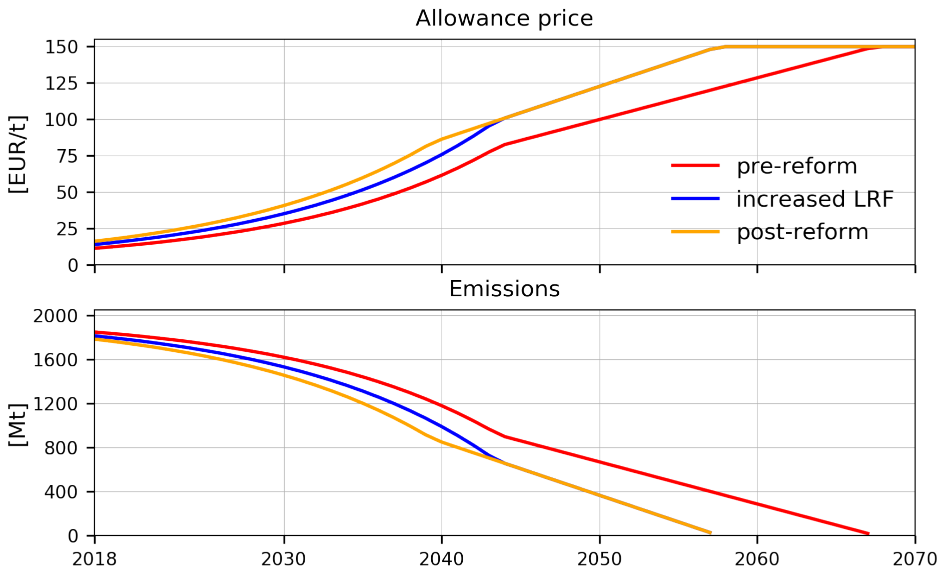

Figure 2.6.: Effect of the change in the LRF

Now, we isolate the effect of the MSR from the change in the LRF, by comparing the introduction of the MSR with the increased LRF scenario. By regulation, the MSR only shifts emissions from the present to the future and thus can be considered an intertemporal smoothing of abatement. This results from storing allowances in the MSR and limiting today's allowance supply, reinforcing abatement in the near future and decreasing abatement later on.

While the intake of allowances in the MSR leads to higher prices in the short run, the reinjection phase reverses this effect in the long run by increasing the auction volume in tranches of 100 million allowances annually compared to the increased LRF scenario. (Figure 2.7). Thus, the MSR remains allowance preserving and does not alter the emission cap itself. This is in line with the findings of, e.g., Perino and Willner (2016) and Richstein et al. (2015).

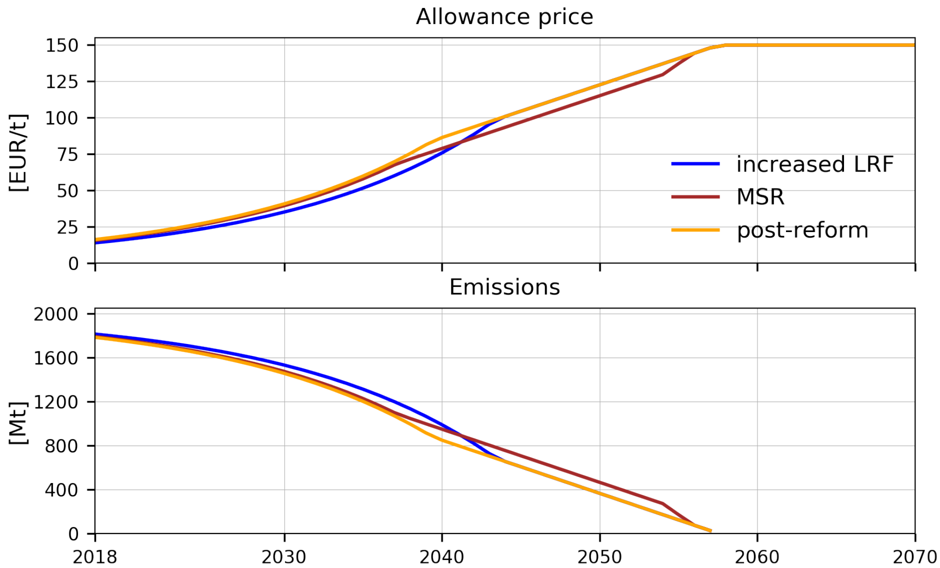

Figure 2.7.: Effect of the MSR and the CM

In contrast, the CM alters the overall emission cap. Thus, fewer allowances are available in the post-reform scenario (including the CM) than in the MSR and increased LRF scenarios. The firms take this into account and choose an emissions path that is slightly lower in the post-reform scenario. Therefore, the overall intake into the MSR is slightly higher than in the MSR scenario. About 2000 million allowances are cancelled in 2023 and the remaining 760 million allowances in the MSR are reinjected into the market from 2029 onwards. The MSR is fully depleted in 2037, i.e., 19 years earlier than in the scenario without the CM. Compared to this MSR scenario, the model reveals only minor price effects of the cancellation in the short term (e.g., 3% price difference in 2030). However, the price difference becomes larger once the MSR is fully depleted in the post-reform scenario and the cancellation causes additional scarcity in the market (e.g., 8.5% price difference in 2040). This finding indicates that while the cancellation takes place at an early time, prices are more affected in the long run.

Conversely, the difference in prices between the increased LRF scenario and the post-reform scenario can only be observed in the short and medium run. Due to the reduced cap and thus additional scarcity in the market, the TNAC depletes at an earlier time $\tau_{b=0}$.[21] Because the MSR is depleted once the TNAC falls below the limit ℓ_{low}, the change in the LRF is the only determining factor causing the higher price path compared to the pre-reform scenario in the long run.

[21] In the increased LRF scenario $\tau_{b=0} = 2042$. This is 4 years later than in the post-reform scenario.

The cancellation volume of 2 billion allowances is significantly smaller than the reduction of 9 billion allowances by the increased LRF.[22] Even though the effect of an increased LRF seems to be well understood by scholars and thus has not been a focus of previous studies, it is important to stress that the increased LRF is the main price driver of the reform. [23]

2.4.2. Cost Effectiveness

In the following, we assess the impact of the reform on the intertemporal economic performance of the EU ETS. Fuss et al. (2018) differentiate between two frameworks for its assessment: Dynamic cost efficiency and dynamic cost effectiveness. Dynamically efficient policies maximize welfare by minimizing the social cost of emission abatement and damages. Those damage costs are commonly referred to as social costs of carbon (SCC). Since the SCC strongly vary with location, time preferences and other underlying factors, the estimates depicted in literature cover a broad range of potential values. Tol (2019) estimates today's global SCC to range from 14 EUR/t carbon to 55 EUR/t carbon, Cai and Lontzek (2018) argue that the SCC can raise to as much as 667 EUR/t carbon by 2100. Given the high uncertainty regarding the SCC and its importance for determining cost efficiency, we follow Fuss et al. (2018)) by refraining from using this framework and instead focus on the concept of dynamic cost effectiveness. This framework assesses whether predefined quantity targets are reached by the lowest aggregated abatement costs without further consideration of external costs of emissions. The design of the EU ETS itself targets cost effectiveness. Allowance supply is predefined such that the system only minimizes the abatement costs.[24]

Figure 2.8 gives an overview of discounted abatement costs and emission levels of the different scenarios. The cost-effective frontier depicts the minimal discounted abatement costs for the respective emission level. This is achieved by a hypothetical scenario in which firms can allocate allowances in time without any intertemporal restriction. The discounted abatement costs are normalized to the discounted abatement costs of the cost-effective abatement path for the emission level where the post-reform allowance supply is fully exploited.

[22] This finding is also depicted in Appendix A.3 where we compare the effect of the CM in the post-reform scenario with a post-reform scenario with the pre-reform LRF of 1.74%.

[23] A survey conducted in 2018 revealed that there are common misconceptions about the main price driver of the reform. Experts from the field expressed their intuition about the main price driver of the allowance price. Only 21% of the respondents named the increased LRF as the main reason for the price increase, while 34 % considered the CM as the main price driver (see Wölfling and Germeshausen (2019)).

[24] A cost-efficient policy ensures that marginal abatement costs are equal to marginal social costs of carbon at each point of time (compare Fuss et al. (2018)).

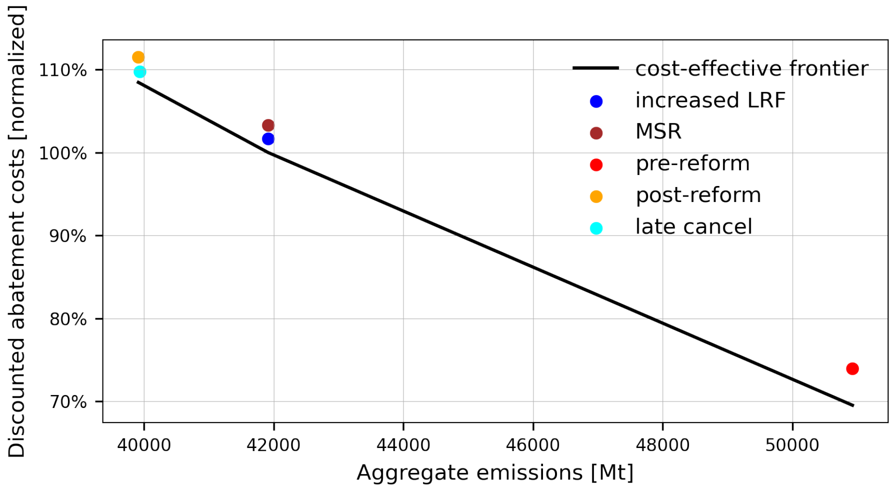

Figure 2.8.: Comparison of discounted abatement costs and emission levels in different scenarios

In general, all scenarios lie above the cost-effective frontier, i.e., firms cannot realize the cost-effective abatement path due to time-restricted availability of allowances. The time restriction on allowance availability is due to the non-borrowing constraint, the issue path of allowances and the temporal shifting of allowances through the MSR. Further, due to the underlying quadratic abatement cost function the curvature of the cost-effective frontier is convex. Higher abatement, leading to lower emissions, is disproportionately cost-intensive.

Comparing the pre-reform scenario (with unrestricted banking and no possibility to borrow) with a LRF of 1.74% and 2.2%, we see that increasing the LRF has a strong effect on the level of emissions, as also discussed in section 2.4.1. At the same time, increasing the LRF closes the gap between the cost-effective frontier and the discounted abatement costs. Increasing the LRF reduces the allowance supply - in particular in later periods - and hence diminishes the additional costs imposed by the non-borrowing constraint since fewer allowances can be borrowed from the future.

The MSR scenario adds a restriction on banking without changing the emission level (since the CM is not active in this scenario). It weakens cost effectiveness by shifting emissions into the future, antagonistic to firms' time preferences.

The CM invalidates about 2 billion allowances in 2023, cutting allowances by approximately 5% of allowances issued after 2017. Counterintuitively, this is not an instantaneous cancellation of allowances early on, but rather a reduction of future allowance supply since it eliminates reinjection from the MSR into the market in later periods (compare section 2.4.1). The cancellation changes little in the short-term abatement, impacting mainly the allowances available in later periods where the shadow costs of the non-borrowing constraint are rather low. Hence, the introduction of the CM slightly reduces the gap to the cost-effective frontier (+3.2%-points in the MSR scenario, +3%-points in the post-reform scenario). The discounted abatement costs increase due to the introduction of the CM according to the additional costs of tightening the emission budget.

To assess the cost effectiveness of the post-reform scenario, an alternative design of the CM is considered: In the late cancel scenario the cancellation is implemented by cutting the allowance supply from the long end, leaving allowances in the MSR unaffected, instead of instantaneously reducing the volume of the MSR in the post-reform scenario.[25] By construction, cost effectiveness in the late cancel scenario improves compared to the post-reform scenario.

As stated before, in the post-reform scenario the allowance supply is reduced by a shortening of the reinjection phase. In contrast, in the late cancel scenario the reinjection phase lasts longer, leading to more available allowances before 2050. Instead, the allowance supply is reduced from the very end and thus the last allowance is issued earlier than in the post-reform scenario. Hence, the alternative cancellation design enables firms to use the allowances more flexibly over time and to partly harmonize their abatement path with their time preferences.

Making the reinjection rate more flexible, e.g., by defining it as share of the previous years emission level or by increasing its value in early periods could further boost dynamic cost effectiveness, and may contribute to making the EU ETS more resilient towards demand shocks, which Perino and Willner (2016) identified as a drawback of the MSR.

Further, our theoretical evaluation of cost effectiveness neglects spillover effects. The price increase caused by the reform may trigger short-term investments into low-emission technologies which lower the costs for future abatement due to technological learning. Since firms do not internalize those spillover effects, the reform may induce benefits for cost effectiveness not accounted for in our model.

2.5. Conclusion

With the change of the linear reduction factor, the implementation of the market stability reserve and the introduction of the cancellation mechanism, the EU ETS changed fundamentally. This paper developed a discrete dynamic optimization model reflecting firms' optimal choice of abatement under the new regulation.

The results for the post-reform scenario including all three amendments show that about 5% of allowances issued from 2018 onwards are invalidated through a one-time cancellation in 2023. All remaining allowances in the MSR are reinjected into the market from 2029 to 2036. The assumed backstop costs of 150 EUR/t are reached in 2057. The level of the backstop costs solely scales the price

[25] The supply reduction is determined endogenously to prevent side effects on the optimization of individual firms.

path, but does not further impact the resulting quantities. Baseline emissions in absence of the EU ETS can only be estimated with significant uncertainty, but the assumption strongly drives model results. Higher baseline emissions increase emissions, abatement and prices and diminish the impact of the MSR and the CM.

Varying the interest rate has a similar effect. If firms have higher private interest rates, they choose to delay abatement and increase emissions in the short run, leading to a smaller MSR intake and cancellation volume. This extensive sensitivity analysis of the underlying parameter assumptions proved the robustness of the model results. While the choice of the parameter values influences the numeric results of the model, it does not impact the underlying modus operandi.

By decomposing the reform into its single amendments, we evaluate the economic impact and the dynamic cost effectiveness of these amendments individually. In the increased LRF scenario, we showed that with the higher reduction factor of 2.2% the total emission cap is reduced by over 9 billion allowances, and thus increases prices in the short and long run. We identify the change in the LRF as the main driver of change in the post-reform EU ETS. The MSR itself shifts emissions from the present to the future. This does not impact the overall emission cap, but adds a restriction on banking and thus deteriorates dynamic efficiency.

The CM changes little in the short run, but mainly reduces the available number of allowances in the long run by about 2 billion. Further, we show that an alternative cancellation of allowances from the long end increases the cost effectiveness within the model. Nevertheless, the MSR increases abatement costs for firms by shifting additional abatement to earlier periods and increasing emissions later on. The initial goal of the reform was to increase today's prices and thereby a signal to invest in low-carbon technology. We find that the intended effect of the introduction of the MSR with CM does not correspond to the design chosen by policy makers which impacts prices and emissions mostly in the long run. To increase the resilience of the EU ETS towards demand shocks and to avoid additional abatement costs stemming from the MSR, a more flexible reinjection rate should be considered by policy makers. Future research should take positive externalities, e.g., learning effects of abatement technologies or other spillover effects, into account which may enhance the advantages of the MSR.

The price increase in the real EU ETS in the aftermath of the reform cannot be explained by the model presented in the paper. This might be due to the fact that the assumptions of a competitive market with perfectly rational firms that optimize themselves under perfect foresight are violated in reality. Several market imperfections might exist that could lead to a deviation from those assumptions: Hedging requirements may for example lead to higher banking volumes independent of market prices. Therefore, the price increase in the aftermath of the current reform may be underestimated by our model. Further, it is possible that firms are myopic and only optimize themselves over the next few years instead of the long run. Thus, firms do not anticipate that allowances in the MSR will become available in the future but rather see the significant short-term cut in allowance supply induced by the reform. This leads to a stronger price increase due to the reform than in the perfect foresight case. Moreover, firms might face uncertainty regarding regulatory reforms. If firms perceive the recent reforms as a signal for increasing scarcity of allowances in the future, they purchase more allowances today, amplifying the price increase of the reform. We therefore argue that the price spike in 2018 is not solely driven by the new regulation but potentially intensified by regulatory uncertainty and bounded rationality, such as myopia and hedging requirements. Thus, further research should evaluate such market imperfections.

3. Puncturing the Waterbed or the New Green Paradox?

3.1. Introduction

3.1.1. Motivation

The European Union Emissions Trading System (EU ETS) is the EU's central instrument to mitigate climate change, covering about 40% of the EU's greenhouse gas emissions. A major reform transformed the EU ETS from a cap-and-trade-system with a fixed cap to a system that endogenously adjusts the allowance supply, in both volume and time, by introducing the Market Stability Reserve (MSR) and the Cancellation Mechanism.

Simultaneously, the level of ambition concerning emission mitigation among EU ETS member states is heterogeneous. Without consensus on the level of ambition among member states, decreasing the allowance supply in the EU ETS as the first best policy option of reducing total emissions is politically not feasible. Hence, overlapping policies[26] are considered a measure to keep more ambitious climate targets within reach (cf. Bertram et al. (2015)). In particular, recent decisions on national coal phase-outs, e.g., in Germany, the Netherlands, and France, underline the political relevance of overlapping policies. But such interventions potentially harm the effectiveness of the EU ETS (cf. Salant (2016)).

Before the reform, overlapping policies aiming at emission reduction in EU ETS sectors led to a spatial or temporal shift of emissions without changing total emissions (waterbed effect). In the reformed EU ETS, the endogenous cancellation of allowances affects total emissions (cf. Perino and Willner (2017),Perino (2018) or Beck and Kruse-Andersen (2020)). If the total number of allowances in circulation (TNAC[27]) is above the intake threshold of 833 Mt a pre-defined share of the TNAC is not auctioned in the following year but transferred to the MSR. The Cancellation Mechanism, which becomes active from 2023 on, invalidates allowances from the MSR exceeding previous years' auction volumes. If the TNAC falls below the reinjection threshold of 400 Mt, allowances from the MSR are re-injected via increased auction volumes. In theory, the reform enables overlapping policies to reduce total emissions via the Cancellation Mechanism (see e.g., Quemin (2020)).

[26]Such as coal phase-outs, national carbon price floors, or renewable support schemes.
[27]The TNAC reflects the number of allowances, which are banked by private firms.

3.1.2. Related Literature

Several articles evaluate the impact of implementing overlapping policies on total emissions. Silbye and Sørensen (2017) find that the implementation of the MSR strengthens the effectiveness of overlapping policies, i.e., subsidies to renewable energies. In a static analysis, Perino (2018) finds that the Cancellation Mechanism temporarily reduces the waterbed effect depending on the policy's timing. Overlapping policies decrease emissions by lowering the demand for allowances, increasing TNAC volumes and hence MSR intake. Ceteris paribus, the Cancellation Mechanism renders more allowances invalid, reducing total emissions. According to Perino et al. (2019), the waterbed effect is reduced by up to 80% for overlapping policies, if implemented early on. In contrast, overlapping policies implemented after 2025 hardly reduce total emissions. Carlén et al. (2019) and Beck and Kruse-Andersen (2020) also highlight the importance of the timing of overlapping policies.

Rosendahl (2019b) argues that this strand of literature does not take into account the dynamic effects of overlapping policies. He states that overlapping policies decrease allowance demand both today and in the future. Since firms anticipate the lower demand in the future, carbon prices drop. As a result of lower prices, emissions increase in the short run and, thus, cancellation volumes decrease. Consequently, the implementation of overlapping policies can have a detrimental effect on total emissions within the reformed EU ETS design.[28] Rosendahl (2019a) labels this effect the new green paradox.[29] All in all, overlapping policies impact total emissions via two opposing effects: The immediate implementation of overlapping policies itself increases cancellation due to immediately lower allowance demand (static effect). In contrast, anticipating lower future allowance demand due to overlapping policies decreases cancellation volumes (dynamic effect) and thus causes the new green paradox effect.

Using a Hotelling setting, Rosendahl (2019a) finds that the dynamic effect is substantial for overlapping policies, that permanently reduce allowance demand: Independent of the timing, it outweighs the higher cancellation via the static effect and thus increases total emissions (new green paradox effect). While Gerlagh et al. (2019) confirm a strong new green paradox effect, Bruninx et al. (2019) cannot replicate the new green paradox effect for permanent overlapping policies. Reacting to Rosendahl (2019b), Perino (2019) acknowledges the finding that overlapping policies can increase total emissions in theory [30] but questions whether the new green paradox effect is as substantial as found in Rosendahl

[28] The reform itself reduces total emissions compared to the pre-reform design. The decrease in total emissions induced by the EU ETS reform, though, might be weakened by implementing overlapping policies compared to a counterfactual scenario without overlapping policies.

[29] The green paradox is introduced by Sinn (2008). He finds that taxing the extraction of fossil resources in the future incentivizes their short-run extraction.

[30] Perino et al. (2019) also show in a two-period setting that overlapping policies after the reform may even backfire by increasing total emissions.

(2019a). Thus, Perino et al. (2019) calls for further quantification of the effects and the role of the addressed volume of overlapping policies.

Perino (2018) and Rosendahl (2019a) evaluate overlapping policies without considering the impact on Marginal Abatement Cost (MAC) curves. In reality, overlapping policies, such as coal phase-outs, address a significant share of baseline emissions within the EU ETS and, thus, affect the MAC curve (cf. Hintermayer et al. (2020)). As the MAC curve reflects the relative change in abatement costs, a change in the MAC curve influences firms' optimal banking and, hence, cancellation volumes.

Analyzing the effect of overlapping policies on banking, Herweg (2020) assumes that overlapping policies randomly target abatement options over the entire MAC curve. He takes the change in TNAC volumes as an indicator for cancellation and analytically points to the drivers for banking in the EU ETS. However, Herweg (2020) acknowledges that a thorough evaluation of the Cancellation Mechanism requires numerical modeling due to its non-linear nature.[31]

Further, Willner (2018), Quemin and Trotignon (2019) and Bocklet and Hintermayer (2020) highlight the importance of considering myopia to explain the firms' behavior within the EU ETS. Myopia reduces the firms' planning horizon and thus their anticipation of future allowance scarcity. Myopia affects the effectiveness of overlapping policies since the dynamic effect is subject to the anticipation of future allowance supply and demand.

3.1.3. Contribution and Structure

The contribution of this research to the prevailing literature is twofold: First, this paper adds to the controversial literature regarding the new green paradox effect of overlapping policies. The design of overlapping policies determines their effectiveness. Notably, the timing and whether overlapping policies target low-cost abatement options are crucial features for effectively reducing total emissions via endogenous cancellation. Under perfect foresight, the effectiveness decreases with the implementation year. For early implemented policies, the Cancellation Mechanism mitigates the waterbed effect partially and lowers total emissions. If firms anticipate late implemented policies early on, however, cancellation volumes decrease and total emissions increase (New Green Paradox Effect). If overlapping policies explicitly target low-cost abatement options, their effectiveness increases and the danger of the new green paradox effect diminishes. Second, this paper sheds light on the role of myopia concerning the effectiveness of overlapping policies. Myopia reduces the effectiveness of overlapping policies. In contrast to perfect foresight, the effectiveness no longer declines with the im-

[31] Cancellation depends on the total intake of allowances into the MSR. The intake is subject to a discrete intake threshold. The MSR absorbs allowances, equalling intake rate times the TNAC volume, as long as the TNAC exceeds the intake threshold. The intake instantly stops when the TNAC falls below the intake threshold.

plementation year but is u-shaped. The effectiveness reaches its lowest point if overlapping policies are implemented at about half of the firms' planning horizon. As a result, even early implementations of overlapping policies are at risk of increasing total emissions if firms are short-sighted.

The remainder of the paper at hand is structured as follows: After introducing the model in section 3.2 , section 3.3 quantifies the impact of overlapping policies on cancellation and total emissions, depending on the timing and design of overlapping policies as well as the planning horizon of firms. Section 3.4 concludes.

3.2. Methodology

3.2.1. Fundamental Model of the EU ETS

For analyzing overlapping policies, this paper applies the discrete optimization model developed in Bocklet et al. (2019). This model builds on the seminal work of Rubin (1996) and Chevallier (2012) and is introduced subsequently.

N symmetric polluting firms compete in an inter-temporal allowance market under perfect competition. Assuming rational and price-taking firms within perfect markets and abstracting from uncertainty, a representative firm faces the following optimization problem.

$$\begin{aligned} \min \quad & \sum_{t=t_0}^{T} \frac{1}{(1+r)^t} \cdot \frac{c(t)}{\alpha+1} \cdot [u(t) - e(t)]^{\alpha+1} + p(t) \cdot x(t) \\ & s.t.\ b(t) - b(t-1) = S(t) - e(t) \quad \text{for all} \quad t = 1, 2, \ldots, T \\ & S(t), b(t) \geq 0 \\ & e(t), x(t) \gtreqless 0 \end{aligned} \tag{3.1}$$

The representative firm minimizes its net present value of expenditures for abating greenhouse gas emissions as well as for purchasing allowances $p(t) \cdot x(t)$[32] over a set of predefined discrete time steps t. The abatement cost function $C(e(t)) = \frac{c(t)}{\alpha+1}(u(t) - e(t))^{\alpha+1}$ increases with the difference between baseline emissions $u(t)$[33] and realized emissions $e(t)$, where the cost parameter $c(t)$ scales the slope and α depicts the curvature of the abatement cost function. Furthermore, firms are allowed to set aside allowances in a private bank $b(t)$ for later use, whereas using allowances before they are issued (borrowing) is - in line with

[32] $x(t)$ covers allowances purchased in auctions $S_{auct}(t)$ or bilateral allowance trade among firms.

[33] Baseline emissions reflect the level of emissions if firms have no incentive to abate, i.e., in absence of the EU ETS.

the EU ETS regulation - prohibited. The cumulative private bank represents the Total Number of Allowances in Circulation (TNAC). The change in TNAC volumes equals the allowance supply to the market $S(t)$, comprising auctioned and freely allocated allowances, minus the chosen level of emissions $e(t)$ in each time step t.

The first-order derivatives of the Lagrange function of the optimization problem provide the market equilibrium conditions (cf. Appendix A.1): First, the marginal abatement costs (MAC) must equal the carbon price in every time step t:

$$c(t)(u(t) - e(t))^{\alpha} = p(t) \tag{3.2}$$

Second, the price follows the Hotelling rule, which is adjusted due to the restriction imposed by the non-borrowing constraint (Hotelling, 1931):

$$\frac{p(t+1) - p(t)}{p(t)} = r - (1+r)^{t+1} \frac{\mu_b(t)}{p(t)} \tag{3.3}$$

As long as the TNAC is non-empty, the shadow costs of the non-borrowing constraint $\mu_b(t)$ equal zero. Hence, carbon prices rise with the interest rate r. Afterwards, the relative price increase is lowered by $(1+r)^{t+1} \frac{\mu_b(t)}{p(t)}$ where $\mu_b(t)$ reflects the shadow costs of the increase in total discounted abatement costs due to the non-borrowing restriction.

For incentivizing emission abatement, the supply of allowances $S(t)$ decreases annually. Due to the non-negativity of the TNAC (no borrowing), the following equation limits the emission path:

$$\sum_{\tilde{t}=0}^{t} e(\tilde{t}) \leq \sum_{\tilde{t}=0}^{t} S(\tilde{t}) + b_0 \tag{3.4}$$

For every discrete time-step t, cumulative emissions $\sum_{\tilde{t}=0}^{t} e(\tilde{t})$ have to be lower than cumulative allowance supply $\sum_{\tilde{t}=0}^{t} S(\tilde{t})$ plus the initial allowance endowment b_0. The regulatory rules for the development of $S(t)$ are presented in Appendix B.2.

While the model used in Bocklet et al. (2019) is restricted to using linear MAC curves ($\alpha = 1$), implementing piece-wise linear approximation into the model allows for depicting more realistic convex curvatures (cf. Hintermayer et al. (2020)).

Formulating the above-mentioned optimization problem as a mixed complementarity problem allows to integrate the non-linear regulatory rules of the reformed EU ETS (cf. Appendix B.2) via mixed-integer optimization. Thereby, the problem becomes a feasibility problem, i.e., a set of constraints, which ensure optimality without optimizing an objective. In this setting, several optimal solutions, i.e., equilibrium price and emissions paths, might exist (compare Gerlagh et al. (2019)). In line with Hintermayer (2020), this paper chooses the equilibrium with the highest total emissions in the case of multiple equilibria. The implicit assumption is that firms in the EU ETS can coordinate themselves to reach the emissions- and thus profit-maximizing equilibrium.

3.2.2. Decision-Making under Myopia

According to Quemin and Trotignon (2018) and Bocklet and Hintermayer (2020), myopia plays a crucial role in understanding the firms' behavior within the EU ETS. Myopia changes firms' reactions to overlapping policies since the dynamic effect depends on whether firms anticipate the long-run impact of overlapping policies. Following the approach of Bocklet and Hintermayer (2020), consecutively solving the optimization problem $\mathcal{M}$ described in equation 3.1 reflects the myopic-decision making of the representative firm with planning horizon H, i.e.:

Algorithm: Rolling horizon optimization of the myopic firm

for $\tau = 0, 1, .., \tilde{T}$ **do**
  Solve $\mathcal{M}(t_0 = \tau, T = \tau + H)$
  Fix $e(\tau), x(\tau), S(\tau), b(\tau)$
end

The representative firm optimizes today's abatement, and hence emissions and banking, anticipating allowance supply and demand of the next H years. Progressing in time, new information becomes available within the planning horizon. The firm again chooses abatement, while state variables of previous periods, e.g., banking $b(t)$, are fixed. Within each planning period, the chosen abatement path is subject to the stated equilibrium conditions (cf. section 3.2.1). From an ex-post point of view, though, the intertemporal link defined by the Hotelling rule does not hold anymore since additional information changes the equilibrium path from period to period (cf. Bocklet and Hintermayer (2020)).

3.3. Numerical Evaluation of Overlapping Policies

This section evaluates the interactions of overlapping policies, which are announced today, and the dynamics within the EU ETS. Overlapping policies directly interfere with the EU ETS by reducing the demand for allowances.[34]

[34]Policies, which target sectors not covered by the EU ETS, such as incentives for electrification of the transport sector, are explicitly not considered within this paper. Such policies increase the allowance demand by transferring emissions into the EU ETS.

Among others, these policies comprise direct subsidies for low-carbon technologies (e.g., support schemes for renewable energy), indirect incentives for low-carbon investments (e.g., national carbon price floor) or technology bans (e.g., coal phase-outs). Section 3.3.1 introduces the framework for evaluating overlapping policies. After presenting the model results without overlapping policies in section 3.3.2, section 3.3.3 assesses the impact of overlapping policies concerning timing. Section 3.3.4 takes a closer look at the impact of the design, i.e., the addressed volumes of overlapping policies and which abatement options are targeted. Finally, section 3.3.5 dissolves the assumption of perfect foresight and analyzes the impact of myopic decision-making on the effectiveness of overlapping policies.

3.3.1. Modeling of Overlapping Policies and Indicators for Evaluation

Overlapping policies reduce the demand for allowances and hence lower baseline emissions, leading to a shorter but steeper MAC curve. This assumption deviates from the prevailing literature, where lowering baseline emissions does not change the slope of the MAC curve, e.g., in Perino and Willner (2017) and Quemin and Trotignon (2018). Instead of decreasing backstop costs (reflecting the MAC of the last abated ton), this article assumes constant backstop costs independent from introducing overlapping policies. For evaluating the design of overlapping policies, this paper considers two stylized impacts of overlapping policies on MAC curves, which are illustrated in Figure 3.1.

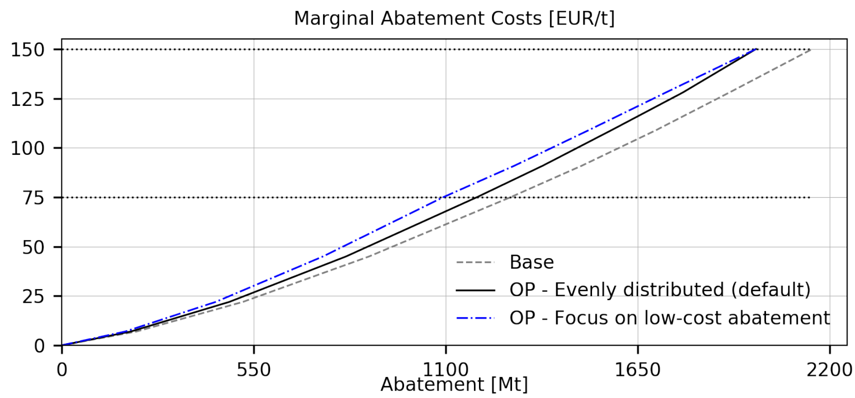

Figure 3.1.: Marginal abatement cost curves without (*base*) and with overlapping policies (*OP - Evenly Distributed* and *OP - Focus on Cheap Abatement*)

The impact of overlapping policies is analyzed by comparing two scenarios, namely a *base* scenario without overlapping policies and a scenario with overlapping policies (*OP*), assuming convex MAC curves. The default assumption for the impact of overlapping policies is in line with Herweg (2020): Overlapping policies address abatement options that are evenly distributed along the MAC curve. Hence, overlapping policies steepen the whole MAC curve, proportionally to the decrease in baseline emissions (*OP - Evenly distributed*). For evaluating the policy design, a variation depicts overlapping policies that target only low-cost abatement options (*OP - Focus on low-cost abatement*). By assumption, such overlapping policies steepen only the first half of the MAC curve - below a cut-off price of 75 EUR/t.

Overlapping policies reduce baseline emissions and lead to *overlapping emission reductions* ($\Delta E_{overlap}$), which reflect emission reductions within the targeted scope of the overlapping policies, e.g., the change in emissions in one country following the implementation of a national overlapping policy.

The indicator *additional cancellation* ($\Delta Cancel$) assesses how total emissions within the EU ETS change as a result of overlapping emission reductions. $\Delta Cancel$ mirrors the difference of cancellation volumes in *Base* and *OP*.[35], i.e.

$$\Delta Cancel = Cancellation_{OP} - Cancellation_{Base} \tag{3.5}$$

Without the Cancellation Mechanism, overlapping policies would only shift emissions in space and time, without affecting total emissions (waterbed effect). With the Cancellation Mechanism in place, overlapping policies can result in higher or lower total emissions. Consequently, they can partially mitigate the waterbed effect but can also have detrimental effects.[36]

For measuring the waterbed effect, the effectiveness reflects the share of *additional cancellation* ($\Delta Cancel$) with regard to *overlapping emission reduction* ($\Delta E_{overlap}$), i.e.

$$Effectiveness = \frac{\Delta Cancel}{\Delta E_{overlap}} \tag{3.6}$$

The effectiveness quantifies the relative degree to which the waterbed effect is mitigated in the reformed EU ETS. An effectiveness of 100% indicates that the waterbed effect is entirely mitigated, while 0% reflects that the waterbed effect persists in full. If the effectiveness becomes negative, overlapping policies have a detrimental effect on total emissions under the reformed EU ETS due to the new green paradox effect. That means the implementation of overlapping policies decreases total cancellation volumes compared to the *base* scenario.

[35] Negative additional cancellation indicate lower cancellation volumes due to the implementation of the overlapping policies compared to the *base* scenario (new green paradox effect).

[36] Total emissions under the reformed EU ETS design are always lower than in the pre-reform setting. Though, overlapping policies can reduce the cancellation volumes compared to the *base* scenario and thus increase total emissions.

3.3.2. Results of the Base Scenario

The model's parametrization follows the current EU ETS regulation. The calibration considers market outcomes in 2018 and 2019, as well as the observed MAC curve slope according to Quemin and Trotignon (2018). Appendix B.1 presents the chosen parametrization. Figure 3.2 visualizes the market results for the *base* scenario without overlapping policies.

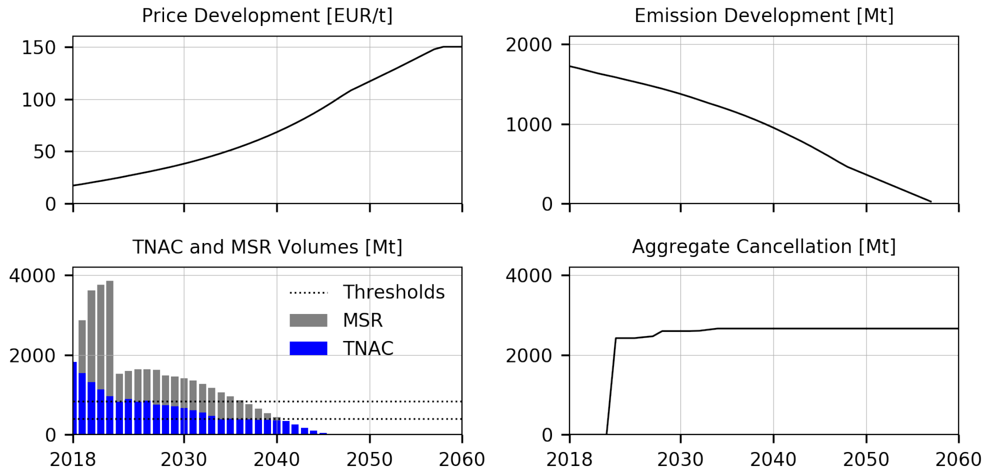

Figure 3.2.: Prices, emissions, banking and total cancellation in the base scenario

According to the Hotelling rule, the price increases with the interest rate as long as firms hold allowances (i.e., TNAC>0). Afterward, the binding non-borrowing constraint reduces the price increase by the constraint's shadow costs. The emissions become zero in 2057 after the last allowances are issued. Until the mid 20s, the TNAC exceeds the intake threshold. Afterward, the TNAC remains slightly below the intake threshold for a couple of years. In the mid-'30s, the TNAC falls below the reinjection threshold. Consequently, about 750 million allowances become available to the market between 2036 and 2042 via MSR reinjection. The TNAC depletes in 2046. The total cancellation volume sums up to about 2800 million allowances. The majority of canceled allowances become invalid just after the activation of the Cancellation Mechanism in 2023. Additionally, the Cancellation Mechanism invalidates small numbers in the subsequent years until the mid 30s.

3.3.3. Timing of Overlapping Policies under Perfect Foresight

This section evaluates the impact of overlapping policies concerning the timing of their implementation[37]. By assumption, overlapping policies reduce baseline emissions by 10% and evenly steepen the entire MAC curve proportionally to

[37] Implementation refers to the point in time, where overlapping policies become active.

the decrease in baseline emissions (cf. section 3.3.1). Firms perfectly anticipate the introduction of overlapping policies, i.e., overlapping policies are announced today and firms perfectly foresee the impact of overlapping policies on baseline emissions and the MAC curve.[38]

To understand how the timing of overlapping policies affects total emissions, figure 3.3 shows their impact on overlapping emission reductions, TNAC volumes without (*Base*) and with overlapping policies (*OP*), and the change in cancellation volumes for implementations in 2020 or 2030, respectively.

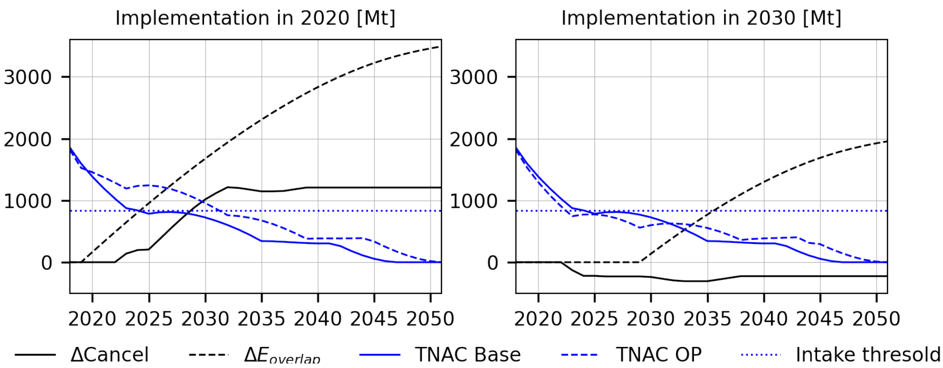

Figure 3.3.: Cumulative overlapping emission reductions ($\Delta E_{overlap}$), change in TNAC volumes and cumulative change in cancellation ($\Delta Cancel$) for implementing overlapping policies in 2020, left, and 2030, right

Overlapping policies lead to overlapping emission reductions from their implementation onward. Overlapping emission reductions depend on the carbon price level. Thus, they decrease in time due to the increasing carbon price in the *base* scenario. For instance, a national coal phase-out has a smaller effect on national emissions in times of high carbon prices than in times of low carbon prices. Under higher carbon prices, inefficient coal power plants would have already decreased their production due to the stronger price signal of the EU ETS.

Whether overlapping emission reductions lead to higher cancellation largely depends on the impact on the TNAC. Only if overlapping emission reductions increase the TNAC volume as long as it is above the intake threshold, the cancellation will increase due to the static effect. For an early implementation in 2020, the TNAC increases significantly. Since the TNAC is above the intake threshold at this time, both direct cancellation increases and the cancellation period is prolonged until the early '30s. If implemented early, the Cancellation Mechanism reduces total emissions by about one-third of the respective overlapping emission reductions. Hence, the static effect mitigates the waterbed effect partially.

[38]Section 3.3.5 dissolves the assumption of perfect foresight.

If implemented in 2030, overlapping policies cause overlapping emissions reductions from 2030 onward. While the TNAC volumes increase accordingly, it does not trigger higher cancellation since the TNAC remains below the intake threshold. Hence, the static effect of overlapping policies does not unfold for late implementation years. In contrast, the dynamic effect, which decreases cancellation volumes compared to the *base* scenario, leads to lower cancellation. By anticipating lower allowance demand due to overlapping emission reductions, the market price drops before overlapping policies become active. As a result, increasing emissions in the short term lower the TNAC and hence cancellation volumes. While about 2800 million allowances are canceled in the *base* scenario, implementing overlapping policies in 2030 reduces the cancellation volume to about 2600 million allowances. Hence, total emissions increase by 200 Mt via the new green paradox effect described by Rosendahl (2019a).

To further evaluate the timing of overlapping policies, figure 3.4 shows total cancellation, total overlapping emission reductions, and the resulting effectiveness for implementing overlapping policies between 2020 and 2035.

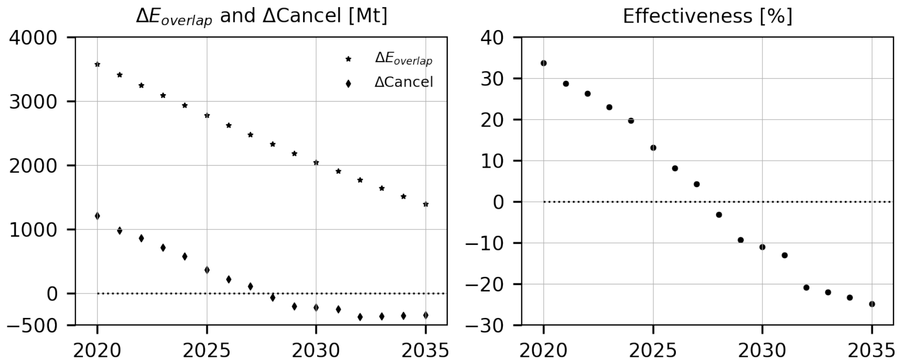

Figure 3.4.: Overlapping emission reduction ($\Delta E_{overlap}$), additional cancellation ($\Delta Cancel$), both left, and effectiveness, right, for different implementation years of overlapping policies

Due to the increasing carbon price in the *base* scenario, total overlapping emission reductions ($\Delta E_{overlap}$) decrease with the implementation year of overlapping policies. While early implemented overlapping policies ensure overlapping emission reduction of up to 3500 Mt, the effect lowers with later implementation. For implementation in 2035, the overlapping emission reduction falls to about 1500 Mt.

Cumulative cancellation decreases with the implementation year and becomes negative for mid- to long-term implementations after 2028. For early implementations, the TNAC volume grows above the intake thresholds, and hence the static effect increases cancellation. This effect vanishes for implementations after 2028. In contrast, the dynamic effect - namely, the price decrease due to lower future allowance demand - triggers higher emissions today and decreases cancellation volumes. That means implementing overlapping policies after 2028 increase total emissions compared to the *base* scenario.

As a result, the consequences of overlapping policies on the waterbed effect, and hence total emissions, crucially depend on the timing. In the short term, about one-third of overlapping emission reductions via overlapping policies are canceled. Hence, the reform can reduce the waterbed effect but will not wholly dispel it. However, the waterbed effect soon regains full strength if implementations of overlapping policies shift towards mid- to end-20's. For later implementations, the effectiveness becomes negative, and hence overlapping policies increase total emissions compared to the *base* scenario via the new green paradox effect.

3.3.4. Addressed Volume and Design of Overlapping Policies

For evaluating the design of overlapping policies, two design parameters are changed: first, the addressed volume of overlapping policies as a share of baseline emissions and, second, the impact of overlapping policies on the MAC curve. The results in section 3.3.3 rely on assuming that overlapping policies target abatement options, which are evenly distributed over the whole range of the MAC curve. For depicting overlapping policies, which focus on low-cost abatement options, they are assumed to affect only the lower half of the MAC curve below 75 EUR/t (cf. figure 3.1). Figure 3.5 illustrates the impact of these variations concerning the effectiveness of overlapping policies and their timing.

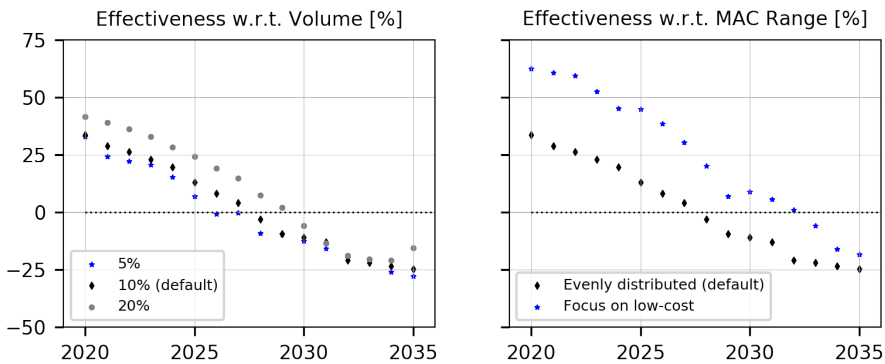

Figure 3.5.: Effectiveness for different addressed volumes of overlapping policies (as share of baseline emissions), left, and different designs, right

The addressed volume has a minor impact on the effectiveness of overlapping policies. For early implementations, increasing addressed volumes manifest in higher mitigation of the waterbed effect. The effectiveness increases to slightly below 50%. The addressed volume hence affects the static effect primarily. Lower short-term allowance demand due to overlapping policies instantly increase TNAC volumes. As long as the TNAC is above the intake threshold, this additional banking increases MSR volumes. Consequently, higher overlapping emission reductions cause relatively higher additional cancellations. The converging effectiveness for late implementations indicates that the dynamic effect is rather independent of the addressed volume. In particular, increasing overlapping emission reductions lead to proportionally increasing total emissions.

If overlapping policies are focused on low-cost abatement options, the mitigation of the waterbed effect roughly doubles. The effectiveness increases to about 60% for early implementations. This is due to the distribution of overlapping emission reductions over time. If overlapping policies focus on the low-cost part of the MAC curve, a larger share of emission reductions become effective early on. Early emission reductions contribute to increasing cancellation volumes via the static effect. With higher shares of expensive abatement options targeted by overlapping policies, the relative contribution to the static effect declines. Even if the policy is implemented early on, its effect will only show later when high-cost abatement measures become necessary. For later implementations, the effectiveness converges independent of the impact of overlapping policies on the MAC curve.

3.3.5. Overlapping Policies under Myopic Decision-Making

The subsequent section dissolves perfect foresight. The representative firm optimizes abatement only within the planning horizon H. In line with the findings of Bocklet and Hintermayer (2020), myopia leads to lower TNAC volumes and carbon prices since myopic firms neglect future allowance scarcity and emphasize short-term abatement costs. The results of the *base* scenario for different planning horizons are given in Appendix B.3.

Figure 3.6 depicts how myopic decision-making affects the effectiveness of overlapping policies for different planning horizons H compared to perfect foresight.

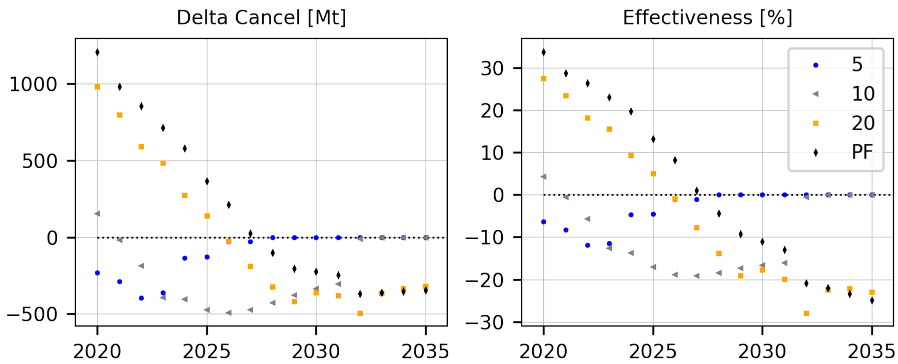

Figure 3.6.: Additional cancellation and effectiveness of overlapping policies depending on timing and planning horizon

When implementing overlapping policies beyond the planning horizon, cancellation does not change and overlapping policies do not affect total emissions. As soon as firms anticipate lower future allowance demand in this setting, TNAC volumes increase but do not exceed the intake threshold anymore. Consequently, myopic decision-making avoids increasing emissions via the new green paradox for late implementations of overlapping policies.

Short- to mid-term implementations of overlapping policies become less effective if firms are myopic than under perfect foresight. While such policies mitigate the waterbed effect partially under perfect foresight, shortsightedness hinders their effectiveness. In contrast to perfect foresight, firms do not anticipate allowance scarcity far into the future under myopia. As a result, a larger share of allowances, which are additionally available in the short term due to the static effect of overlapping policies, is used today rather than saved to alleviate long-term allowance scarcity. If firms are very short-sighted (e.g., for a planning horizon of five years) even short-term overlapping policies have detrimental effects on total emissions since fewer allowances are rendered invalid via the Cancellation Mechanism.

While the effectiveness declines with the implementation year under perfect foresight, its dependence on the implementation year follows an u-shape under myopia. This shape reflects the trade-off between static and dynamic effects. The static effect diminishes with later implementation years independent of the planning horizon leading to less effective overlapping policies for later implementations. However, the dynamic effect changes if firms are short-sighted. Firms anticipate that overlapping policies will lower baseline emissions from their implementation onward and alleviate future allowance scarcity. Under perfect foresight, the anticipation horizon is long and, thus, the dynamic effect does not significantly change with later implementations. Myopia limits the anticipation of firms to the planning horizon. Firms foresee only the allowance demand reduction due to overlapping policies within the planning horizon. As a result of the shorter anticipation horizon, the implementation year significantly affects the dynamic effect under myopia. Consequently, the adverse impact of overlapping policies on total emissions diminishes with later implementations. Due to this trade-off the effectiveness reaches its lowest point if overlapping policies are implemented at about half of the firms' planning horizon.

With increasing planning horizons, the effectiveness of overlapping policies converges to the results under perfect foresight. For example, the results for a planning horizon of twenty years largely replicate the observations under perfect foresight. The same setting reveals the non-linearity of the regulation due to the discrete intake threshold, which can cause outliers, such as the cancellation for an implementation in 2032. While the non-linear regulation can cause such skittish behavior, it does not affect the overall trend.

Bocklet and Hintermayer (2020) consider a planning horizon of about ten years a reasonable assumption to explain observed market results. Consequently, overlapping policies which are implemented about five years after their announcement are least effective. Against this backdrop, such intervals between announcement and implementation are quite frequent in policy-making[39] so that their effectiveness is not per se given by the reformed EU ETS.

3.4. Conclusion

This paper evaluates overlapping policies, such as national coal phase-outs, and their impact on total emissions within the EU ETS. The latest reform transformed the EU ETS into a system that endogenously adjusts allowance supply as a function of firms' banking behaviour, i.e., total allowance supply changes by canceling allowances from the MSR. Whereas total emissions were independent of overlapping policies due to the waterbed effect before the reform, overlapping policies can now affect total emissions.

For evaluating the effectiveness of overlapping policies, a partial equilibrium model of the EU ETS is applied. Overlapping policies entail a static effect that mitigates the waterbed effect and an opposing dynamic effect that potentially leads to higher total emissions (new green paradox effect). While overlapping policies can puncture the waterbed, three aspects determine their effectiveness: First, in line with the prevalent literature (e.g., Carlén et al. (2019), timing is essential. Under perfect foresight, the effectiveness of overlapping policies decreases with later implementations. Only short-term implementations, which foreclose the dynamic adjustment of banking volumes by firms, lead to significant additional cancellation. However, only if designed properly the endogenous cancellation mitigates the waterbed effect by more than 50%. Against this backdrop, overlapping policies increase total emissions if implemented late via the new green paradox effect. Second, if overlapping policies focus on low-cost abatement options, they are more effective in reducing total emissions. Third, higher addressed volumes tend to strengthen the static effect and thus lead to a higher reduction of the waterbed effect.

Myopia reduces the effectiveness of overlapping policies. The higher weight of today's costs reduces banking and hence cancellation. As a result, the waterbed effect is hardly mitigated and the risk of the new green paradox effect increases. Compared to perfect foresight, the role of timing becomes more complex. The effectiveness no longer declines with the implementation year but is u-shaped for myopic decision-making. The effectiveness reaches its lowest point if overlapping policies are implemented at about half of the firms' planning horizon. As a result, also early implementations of overlapping policies are at risk of increasing total emissions if firms are short-sighted.

All in all, the adverse effects of the new green paradox effect remain low. Independent of the considered design and firms' planning horizon, total emissions increase less than 500 Mt due to the new green paradox if overlapping policies

[39] For instance, coal phase-outs in, e.g., the UK or France become active after 2023 and were announced in the last few years.

reduce baseline emissions by 10%. This is below a third of today's yearly emissions within the scope of the EU ETS. Against this backdrop, only deliberate overlapping policies result in waterbed reductions of more than 50%, while most implementations are less effective. Thus, the risk that overlapping policies turn out ineffective remains high under the reformed EU ETS design.

For ensuring the effectiveness concerning total emissions, the reformed EU ETS design grants member states the right to unilaterally withdraw allowances from their auction volumes in case of a nationally determined decommissioning of electricity generation capacity. Beyond coal phase-outs, allowance withdrawals are not explicitly allowed for other overlapping policies, such as subsidies to renewable energies or (multi-)national carbon price floors . A carbon price floor accurately addresses low cost abatement options (cf. Flachsland et al. (2019) or Hintermayer (2020)), and is hence theoretically more effective than other unilateral measures. However, the effectiveness of overlapping policies is hardly predictable due to the complex interactions. When enforcing more stringent climate targets within the new Green Deal, the future design of the EU ETS and the MSR will be reviewed (cf. Osorio et al. (2020)). For avoiding (potentially) ineffective overlapping policies, a compromise on the level of ambition should be a priority in future negotiations.

This paper identifies determinants for effective overlapping policies in an idealized setting. The impact of market distortions besides firms' shortsightedness, such as asymmetric information or risk-aversion under uncertainty, is subject to future research. Further, shapes of MAC curves matter for the impact of overlapping policies on total emissions. For validating the assumptions on MAC curves, they should be analyzed in detail. This paper looks at overlapping policies that reduce allowance demand within the EU ETS. Policy-driven electrification in transport or heating, which increases allowance demand, and their impact on total emissions within the EU ETS could be assessed similarly.

4. On the Time-Dependency of MAC Curves and its Implications for the EU ETS

4.1. Introduction

The mitigation of greenhouse gas emissions requires a fundamental overhaul of the capital stock, i.e., investments in low-carbon technologies. The efficient coordination of investment capital is essential to minimize overall abatement costs. Economists agree that the pricing of emissions is a suitable instrument for allocating capital efficiently (e.g., Coase (1960) and Borenstein (2012)). By introducing the European emissions trading system (EU ETS), the EU has implemented a quantity control system with an endogenous price on emissions. The EU ETS requires that firms in the power sector, energy-intensive industries, and inner-European aviation submit allowances to cover their emissions. Overall, the EU ETS regulates about 40 % of total European emissions.

The latest reform of the EU ETS has introduced the Market Stability Reserve (MSR) and the Cancellation Mechanism (CM), which have fundamentally changed the EU ETS to a system with restricted banking and responsive allowance supply (cf. Bocklet et al. (2019)). A comprehensive literature strand evaluates the reforms' impact via partial equilibrium models of the EU ETS (e.g., Perino and Willner (2016) and Bocklet et al. (2019)). Most of these articles do not model allowance demand endogenously.[40] They assume allowance demand exogenously based on marginal abatement cost (MAC) curves. MAC curves match emission mitigation with abatement costs and have been crucial tools to evaluate environmental policies for decades (e.g., Jackson (1991) or Aaheim et al. (2006)).

In the EU ETS related literature, the assumptions on MAC curves are heterogeneous. While some articles assume linear MAC curves (e.g., Perino and Willner (2016) or Bocklet et al. (2019)), others use convex MAC curves (e.g., Beck and Kruse-Andersen (2020) or Schmidt (2020)). Without evidence from the literature, papers usually presume a time-independent shape of MAC curves. Nevertheless, both the shape as well as its development over time drives results. In particular, these assumptions affect total emissions in the EU ETS due to the responsive allowance supply of the EU ETS.

[40]To the best of our knowledge, Bruninx et al. (2018) present the only approach that combines power market modeling with a depiction of the EU ETS regulation.

This paper assesses the fundamental properties of MAC curves and their implications for the EU ETS. To this end, we carry out a case study to derive stylized MAC curves for the European power sector. Multiple runs of a partial equilibrium model map carbon price paths onto emission abatement. We find that MAC curves are convex. The curvature is subject to economic developments, such as fuel prices and interest rates. Further, MAC curves are time-dependent. In the short term, they are steep since coal-to-gas fuel switching is the only abatement measure. With enlarging investment opportunities and technological learning, MAC curves flatten over time.

Assuming convex instead of linear MAC curves increases banking since future abatement becomes relatively more expensive. On the contrary, flattening lowers incentives for banking. Under idealized assumptions, steep short-term MAC curves shift the equilibrium price path upward while also reducing short-term banking. This effect could cause strong price reactions in the short term when market frictions such as myopia are considered. For a numerical evaluation of these effects, we propose methodological approaches to account for the time-dependency of MAC curves.

The remainder of the paper is organized as follows: Section 4.2 reviews the prevailing literature on MAC curves. Section 4.3 derives stylized MAC curves for the European power sector. Section 4.4 discusses the implications of the identified properties of MAC curves for the EU ETS. Section 4.5 concludes.

4.2. Prevailing Literature on MAC Curves

This section sheds light on the properties of MAC curves discovered in the existing literature. We consider quantitative evaluations as well as qualitative discussions of MAC curves.

The prevailing literature uses four methodological approaches to quantitatively evaluate MAC (compare Huang et al. (2016)): (1) Estimations based on distance functions, (2) expert-based evaluations, (3) top-down models, and (4) bottom-up models.

MAC evaluation via distance functions estimates past and present marginal abatement costs based on historical data (Ma et al. (2019)). For example, Du et al. (2015) find that the marginal abatement costs in the Chinese energy system increase over time in a convex shape. However, these historical observations do not allow statements about future MAC or the construction of MAC curves.[41]

Expert-based evaluations, e.g., performed by McKinsey & Company (2013), derive MAC curves by gathering expert knowledge on abatement costs and po-

[41] In particular, observed marginal abatement costs reflect rather the part of the MAC curve with low mitigation efforts, which likely do not represent MAC for extensive emission mitigation. For a comprehensive and critical review of MAC evaluation by distance functions, the reader is referred to Ma et al. (2019).

tentials. While revealing abatement potential even at negative abatement costs, the derived MAC curve for 2030 is convex-shaped in its positive part.

The use of top-down models, mostly integrated assessment models, covers economy-wide activities, their interactions, and the consequences on the natural environment at a global level.[42] For the EU ETS sectors, Landis (2015) finds that MAC curves are convex in abatement.

In contrast to top-down models, bottom-up partial equilibrium models abstract from global interactions between different economic sectors but allow for more technical details. Kesicki (2013) finds that the MAC curve of the UK energy system in 2030 is convex-shaped and robust to changes in fossil fuel prices, but depends strongly on the underlying interest rate. Delarue et al. (2010) find that short-run abatement in the European power markets depends on the carbon price as well as on the price margin between coal and gas. van den Bergh and Delarue (2015) compare two abatement options, namely fuel-switching from coal to gas and wind investments, with a model of the central-western European power sector. They point out that MAC of the different abatement options are not additive but impact each other.

Summing up, articles with different methodological approaches consent that MAC curves are convex. However, Kesicki and Ekins (2012) generally calls for caution when interpreting MAC curves. MAC curves depend on uncertain assumptions, which are often not transparent. Further, the concept of MAC curves takes the perspective of a perfectly informed central planner who decides cost-efficiently on abatement under perfect foresight. In reality, the decisions on abatement measures depend on individual preferences. If individuals decide solely based on abatement costs and their actions are coordinated in perfect markets, the cost-efficient MAC curve of the central planner coincides with the aggregation of individual decisions on abatement measures. However, individual decision-making is subject to non-financial costs and behavioral aspects. Consequently, MAC curves of a central planner often identify abatement measures with negative abatement costs, which are not realized yet. Moreover, MAC curves are always a static snapshot in time and do not reveal what abatement measures are taken before and after the reference year. Historic abatement and expectations about future abatement drive the shape of MAC curves.[43]

[42] Most integrated assessment models use a computable general equilibrium framework to depict economic interrelations via substitution elasticities. Kuik et al. (2009) provides a comprehensive meta-analysis on the derivation of MAC curves with integrated assessment models.

[43] At the same time, today's decisions on abatement also impact future's abatement costs, e.g., due to technological learning effects.

4.3. Case Study: MAC Curves of the European Power Sector

To illustrate the different properties of MAC curves, this section carries out a case study for the European power sector.

4.3.1. Methodological Approach

Power market model DIMENSION

We derive MAC curves with the partial equilibrium European power market model DIMENSION.[44] By assuming inelastic electricity demand in the short term and perfectly competitive markets without transaction costs, the decision making of individual, profit-maximizing firms under perfect foresight is equivalent to a central planner's cost minimization problem. The central planner minimizes the total discounted costs of investments in power plants and their dispatch to satisfy electricity demand. Appendix C.1 presents the most relevant equations of DIMENSION.

Approach for Deriving MAC Curves

To obtain MAC curves for the European power sector, we feed different carbon price paths $\boldsymbol{\tau}$ into the model and derive the corresponding level of emissions $emissions(y)_{|\boldsymbol{\tau}}$ for each considered year y. The emissions of the baseline scenario (baseline emissions) $u(y) := emissions(y)_{|\boldsymbol{\tau}=0}$ are used to define the abatement level of a carbon price path $\boldsymbol{\tau}$ as $abatement(y, \tau) = u(y) - emissions(y)_{|\boldsymbol{\tau}}$. Figure 4.1 sketches the methodology to derive MAC curves using the power market model DIMENSION.

We assume that carbon prices develop according to the Hotelling rule (cf. Hotelling (1931)), i.e., they rise with the interest rate.[45] The model derives MAC curves in time period t anticipating this price development for a time horizon H of 15 years.

[44]The model DIMENSION has been developed by Richter (2011) and has been used in many analyses, e.g., Bertsch et al. (2016), Peter and Wagner (2018) and Helgeson and Peter (2020).

[45]Emission allowances are a scarce resource. Rational firms with perfect foresight use allowances so that the corresponding carbon price increases with their private interest rate. Otherwise, arbitrageurs could take advantage of inter-temporal price differences. Ex-post, prices develop differently due to external shocks or new information on future costs or demand (cf. Bocklet and Hintermayer (2020)).

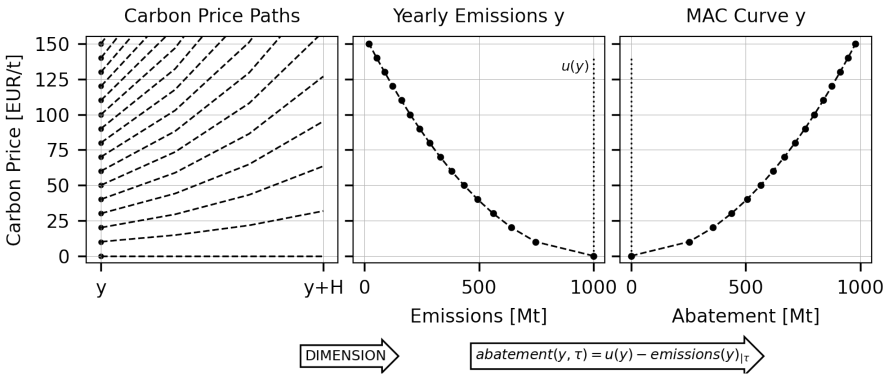

Figure 4.1.: Schematic illustration of the approach for deriving MAC curves

Parametrization

This case study derives stylized facts on MAC curves, using the European power sector as an example. To isolate the impact of single restrictions or input parameter changes, we keep the parametrization as plain as possible. We fix the status quo of European power plants, i.e., we abstract from decommissioning due to technical restraints or political goals. We assume the existing fleet of power plants in 2019 according to the database developed at the Institute of Energy Economics at the University of Cologne, which is continuously updated based on Platts (2016), Bundesnetzagentur (2020a) and ENTSO-E (2020). Net transfer capacities develop according to the ENTSO-E Ten-Year Network Development Plan 2018 (ENTSO-E (2018)). Fuel prices, investment costs, net trade capacities, and electricity demand are as of 2019. By default, we use an interest rate of 8%. Time-series rely on the historical weather year 2014. For keeping the model tractable, 16 representative days approximate the development for one year. Appendix C.2 gives an overview of the considered technologies and their techno-economic parameters.

4.3.2. The Change of MAC Curves Over Time

This section evaluates how different lead times for investment affect MAC curves. In the short term, the power plant fleet is fixed. Switching electricity generation from power plants with higher carbon intensity (e.g., hard coal or lignite) to power plants with lower carbon intensity is the only viable abatement measure (*Fuel Switching*). The existing capacity of the power plants with lower carbon intensity limits the abatement potential of fuel switching. With longer lead times, investment into generation capacities as a reaction to higher carbon prices is possible. Yet, installation capacities or necessary approval processes restrict the speed of changing the power plant fleet via investments. In the long term, freedom to invest is unrestricted. Additionally, demand can react to rising carbon prices, e.g., via investments into energy efficiency or carbon leakage.

For determining the development of MAC curves over time, we make the following stylized assumptions. In the short term, all capacities are fixed and only the dispatch of the generation portfolio can change with the carbon price. In the medium term, the expansion of RES capacities must not be higher than five times the average expansion between 2017 and 2019, reflecting investment lead times of five years. Investments into gas power plants are restricted to about 9 GW per year within the European electricity system. In the long term, investments are not restricted. Further, we assume that the development of long-term demand depends on the carbon price development.[46] Ceteris paribus, figure 4.2 depicts the resulting MAC curves for different time horizons and disaggregates the abatement into static fuel switching, (restricted) investment into power plants, and demand adjustment.[47]

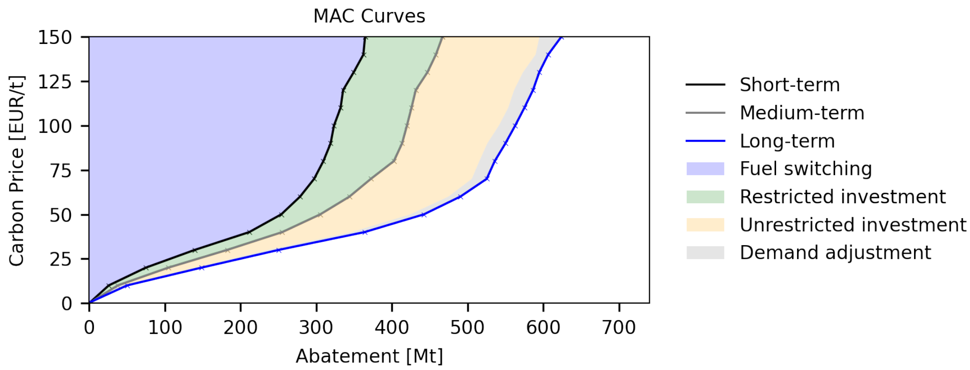

Figure 4.2.: Short-, medium- and long-term MAC curves and disaggregation of the abatement measures

In line with the literature, MAC curves are convex independent of the time horizon. They further flatten over time, primarily due to the increasing investment possibilities. In the short run, replacing coal generation with gas-fired power plants allows to reduce emissions. The short-term MAC curve is convex since modern gas power plants drive inefficient coal power plants out of the market already at low carbon prices. Later on, inefficient gas power plants replace modern coal generators at higher abatement costs.

Progressing in time, fuel switching is not the only abatement option but investments into modern gas power plants and particularly RES power plants are possible. As a result, the MAC curves flatten, i.e., the same carbon price results in higher abatement. While investment restrictions prevail in the medium term, unrestricted investment possibilities further flatten MAC curves in the long term.

[46] We approximate the impact of rising carbon prices on electricity prices via the difference in marginal costs of modern Combined Cycle Gas Turbine Power Plants (CCGT) and assume a demand elasticity of 5 % with regard to the electricity price.

[47] Throughout this paper, the end of the x-axis depicts maximum abatement, i.e., zero emissions.

Besides developments on the supply side, adjustments of the electricity demand further bend MAC curves downward.[48]

While the MAC curves above consider variations in investment freedom and demand adjustment, the following section analyzes how developments in markets beyond the power sector (i.e., fuel prices and interest rates) or technological progress affect long-term MAC curves.

4.3.3. Drivers of Long-term MAC Curves

This section analyzes three exogenous parameters, which influence long-term MAC curves: fuel prices, interest rates, and technological learning.

Fuel Prices

With regard to fuel prices, the power sector is mainly subject to the development of gas and hard coal prices. In particular, the margin between these fuels is considered a major driver. For a stylized illustration of the impact of fuel prices on the MAC curve, we compare three different levels of gas prices (10, 20, or 30 EUR/MWh_{th}, respectively), while the coal price is not varied. The variation of gas prices with constant coal prices alters the margin between coal and gas. Figure 4.3 depicts the corresponding MAC curves.

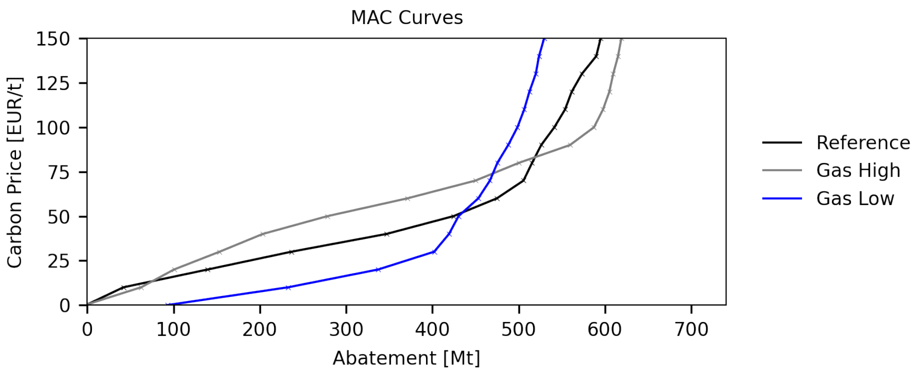

Figure 4.3.: Long-term MAC curves for different coal/gas price spreads

Lower gas prices affect MAC curves in two ways: First, gas power plants are more competitive against carbon-intensive coal generation. As a result, more abatement takes place at lower carbon prices, and the lower end of the MAC curve shifts downward. Second, investments into RES power plants are less competitive to gas power plants, since gas generation becomes cheaper. As a result, the MAC curve becomes steeper at the upper end. For higher gas prices, the same effects hold true vice versa.

[48]Based on our stylized assumptions, demand adjustment is only a minor abatement measure. Whether it is more relevant in reality depends on the assumed elasticity.

The same reasoning holds with a variation of fuel prices in the short term. As there is no investment in the short term, the only effect is the altered margin of fuel switching (see Appendix C.3).

Interest Rates

Apart from fuel markets, the development of financial markets affects the shape of MAC curves. The interest rate reflects the general development of financial markets, i.e., the risk-free interest rate, and the risk premium accounting for sector-specific uncertainty. Figure 4.4 depicts long-term MAC curves for different interest rates on long-term MAC curves.

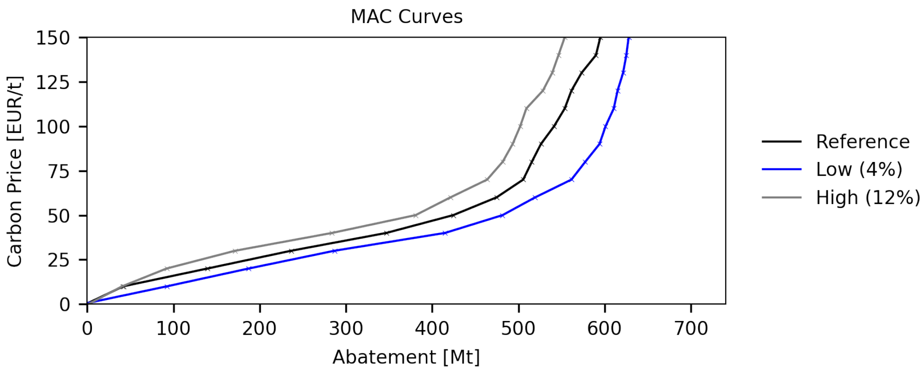

Figure 4.4.: Long-term MAC curves for different interest rates

Interest rates primarily affect the weighted costs of capital. The transformation of the power sector requires capital-intensive installations of RES power plants. With lower interest rates, RES becomes cheaper. As a result, the MAC curve is lower at all abatement levels. Since the lower part of the MAC is dominated by fuel-switching, the effect increases with abatement so that it mainly affects the end of MAC curves. A higher interest rate mirrors the effect of lower interest rates.

Technological Learning

Until now, we refrain from technological learning. However, new technologies exhibit possibilities to drive down investment costs or improve technological parameters such as efficiency. Figure 4.5 depicts the change in long-term MAC curves with projected technological learning of RES power plants. The respective cost assumptions can be found in Appendix C.2.

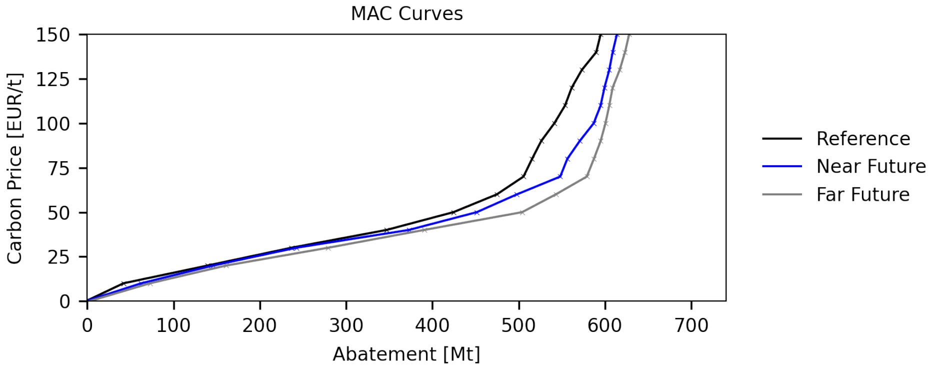

Figure 4.5.: Long-term MAC curves for different investment costs

The impact of technological learning is clear-cut: Lower investment costs drive down costs of RES generation. Hence, uncertainty about the future development of techno-economic properties mainly affects the upper part of MAC curves, i.e., beyond the potential of fuel-switching.

Beyond improvements of existing technologies, the cost development of so-called backstop technologies underlines this finding. These technologies are able to remove an arbitrarily large amount of emissions for a fixed price, the backstop price. In light of recent plans to establish a hydrogen economy, experts consider hydrogen-fueled gas turbines as a potential carbon-free and dispatch-able backstop technology in the power sector. In this case, the backstop price level is subject to future costs of hydrogen. The prevailing literature (e.g., Brändle et al. (2020)) projects costs of carbon-neutral hydrogen of roughly 1.5 to 3 EUR/kg. These prices equal about 45-90 EUR/MW_{th}, the marginal abatement costs to replace gas generation is thus approximately between 125 and 350 EUR/t compared to gas prices of 20 EUR/MW_{th}.[49]

Summing up, this case study of the European power sector reveals: first, MAC curves are convex. Their curvature depends on economic developments such as fuel prices and interest rates. Second, they flatten over time due to technological learning and investment restrictions.

4.4. Implications for the EU ETS

As pointed out in section 4.1, model-based analyses of the EU ETS typically assume static MAC curves. On the contrary, MAC curves are dynamic. They are only a snapshot in time so that they conceal dynamic interactions. Further, MAC curves flatten over time due to restrictions on investments and technological advancements. This section discusses the implications of these findings for the EU ETS.

[49]The (direct) marginal abatement costs reflect the difference in fuel prices between natural gas and hydrogen, divided by the emission factor of natural gas of about 0.2 t_{CO2}/MWt_{th}.

4.4.1. The Functioning of the EU ETS

The EU ETS is a cap-and-trade system, which requires firms to buy allowances to compensate for their emissions. By reducing the yearly supply of allowances to the market, the EU ETS enforces abatement. Firms are allowed to bank allowances for later use while borrowing allowances from future allocations is prohibited.

Firms choose their abatement so that they minimize abatement costs. In equilibrium, carbon prices equal MAC in a friction-less market. In line with the Hotelling rule (cf. Hotelling (1931)), the carbon price rises with the interest rate as long as firms hold a positive bank of allowances. If the aggregate private bank is empty, the price increases at a lower rate according to the yearly issued allowances. (cf. Bocklet et al. (2019))

In this idealized setting, the market determines an initial price, which reflects the discounted backstop costs and fully sets up a price path that sooner (lower initial price) or later (higher initial price) leads to an empty private bank. Market equilibrium paths, which consist of a sequence of price-emission tuples, solve the trade-off between low initial prices and a late point in time where allowances are scarce so that overall (discounted) abatement costs are minimal.

The implementation of the Market Stability Reserve and the Cancellation Mechanism poses additional restrictions on the banking of allowances. First, if banking volumes exceed a pre-defined level, the MSR absorbs allowances from the market. The allowances from the MSR enter the market when the bank falls below the reinjection threshold.[50] Second, the size of the MSR is limited. If the MSR exceeds the previous year's auction volume, the CM invalidates overhanging allowances. As a result of the MSR and the CM, banking decisions affect both the timing and the total volume of allowance supply. In particular, higher banking volumes increase cancellation volumes and thus reduce total emissions within the EU ETS.

4.4.2. Implications of Time-Dependent MAC Curves in the EU ETS

Section 4.3 reveals two properties of MAC curves, which should be considered in models of the EU ETS: MAC curves are convex and they flatten over time.

If the MAC curve is convex instead of linear, the MAC curve becomes steeper with higher abatement, which makes future abatement relatively more costly. Accordingly, firms bank more allowances to smooth the abatement in the steep upper part of the MAC curve. Due to the endogenous supply rules in the reformed EU ETS, a convex MAC curve causes higher banking volumes and more

[50] Allowances from the MSR enter the market in junks of 100 million allowances per year if the previous year's bank is below 400 million allowances.

cancellation compared to a linear MAC. Osorio et al. (2020) provides quantitative evidence by comparing the cancellation volumes of several articles. Modeling approaches that consider convex curvatures (e.g., Bruninx et al. (2018) and Beck and Kruse-Andersen (2020)), exhibit comparatively high cancellation volumes.

Along the same lines, models of the EU ETS usually assume the shape of the MAC curves to be time-independent, neglecting that short-term MAC curves are steeper due to investment restrictions and technological learning. As a result, abatement is more expensive in the short term and becomes cheaper over time. Figure 4.6 visualizes the stylized impact of a steeper short-term MAC curve on the price path in comparison to the assumption of the long-term MAC curve for all points in time.[51]

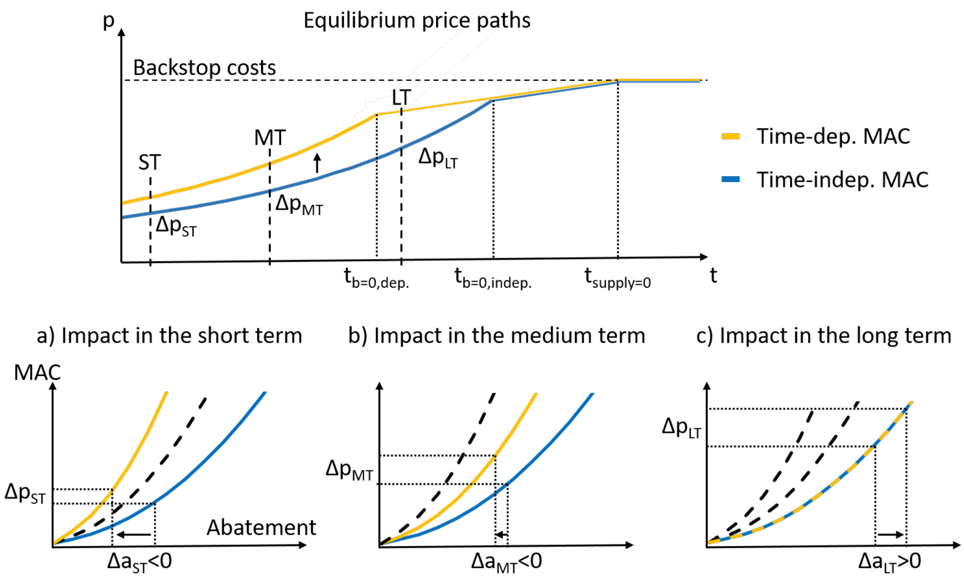

Figure 4.6.: Stylized impact of time-dependent MAC curves on the equilibrium price path and implications for abatement in the short (ST), medium (MT) and long term (LT)

Under perfect foresight, the whole price path is determined already in the first period. Backstop costs are obtained when the last allowance is issued ($t_{supply=0}$ in the upper part of Figure 4.6).[52] The quasi-linear price development after the bank is emptied ($t_{b=0,dep.}$ and $t_{b=0,indep.}$), depends on the allowance supply and the shape of long-term MAC curves.[53] Firms choose a sequence of price-emission

[51]This stylized analysis assumes that there is only one banking phase. If, for example, the flattening of MAC curves overcompensates the firms' interest rate, a second banking phase is economically rational.

[52]This holds true as long as backstop costs decrease slower than the firms' interest rate. In general, backstop costs only shift the price path as long as the rest of the MAC curve is kept constant (compare Bocklet et al. (2019)). Abatement and banking remain unaltered.

[53]After the private bank is empty, abatement decreases linearly with the allowance supply. Correspondingly, the price increases in accordance with the upper part of the MAC curve.

tuples that suffice the two fundamental rules, namely the price development with Hotelling until the bank is empty and the equivalence of MAC and carbon prices. Due to steeper short-term MAC curves (i.e., short-term abatement becomes more expensive), firms increase their short-term emissions, and thus, decrease banking volumes. At the same time, prices increase since the short-term MAC are higher even at the lower abatement level (see Figure 4.6a). In the medium term, the time-dependent MAC curve flattens and the difference in abatement decreases but abatement is still lower (see Figure 4.6b). As a result, the bank empties earlier ($t_{b=0,dep.} < t_{b=0,indep.}$). In the long term, firms need to increase their abatement with time-dependent MAC curves due to lower banking volumes (see Figure 4.6c). Summing up, with time-dependent MAC curves, the price level rises, and banking decreases in the short-term. Since cancellation volumes increase with short-term banking (see Herweg (2020)), the described effect increases total emissions due to lower cancellation volumes.

Beyond this theoretical analysis, myopia is considered important to understand the EU ETS market (compare Bocklet and Hintermayer (2020)). In a myopic setting, steep short-term MAC curves might be an additional driver of the price increase observed after the introduction of the MSR and the CM.

All in all, banking and cancellation volumes increase with convexity while flattening has the opposite effect. Accurate numerical models of the EU ETS should consider the shape and dynamic evolution of MAC curves to quantify the overall effects.

4.4.3. Approaches for Time-Dependent MAC Curves in EU ETS Models

In general, there are two approaches to account for the time-dependency of MAC curves: using exogenous but time-dependent MAC curves in EU ETS models or coupling of models for allowance demand and the EU ETS.

Exogenous dynamic MAC curves for the power sector can be derived via modeling, e.g., as described in Section 4.3. Deriving MAC curves for the energy-intensive industries - as the other large sector within the EU ETS - is more challenging, since industry processes are more heterogeneous and data availability is limited. Further, it is important to depict interactions between the sectors to account for the non-additivity of abatement measures. For example, the electrification of industry processes saves carbon in the industry sector but interacts with the MAC curves of the power sector. Feeding the derived time-dependent MAC curves into a model of the EU ETS improves the accuracy of the results. However, this approach neglects that MAC curves are interrelated, i.e., they are not a sequence of static curves but rather a family of curves, that depends on the carbon price path.

For considering interactions between the allowance demand and the EU ETS price path, it is worth to consider the coupling of an allowance demand-side model (covering the power sector and energy-intensive industries) and an EU ETS model. Via soft-coupling, the EU ETS model feeds the derived price paths to the allowance demand-side model, which then updates the MAC curves. By iterating these steps, a consistent model framework is set up if the model runs converge. Alternatively, the two models could be hard-coupled, i.e., a simultaneous equilibrium is calculated by an integrated approach. For example, the implementation as a mixed complementary problem (MCP) allows to derive a consistent solution with an endogenous depiction of allowance demand and the EU ETS market. Both variants of model-coupling open up possibilities to evaluate alternative EU ETS designs (e.g., the implementation of carbon price floors) or related environmental policies, such as electrification efforts.

4.5. Conclusion

Recent literature relies on MAC curves to analyze the design of the EU ETS as the key emission abatement instrument in Europe. While the assumptions on MAC curves drive the results, the literature on the shape of MAC curves within the scope of the EU ETS is scarce. Against this backdrop, this paper identifies implications of MAC curve properties for the EU ETS.

In a case study, we derive MAC curves for the European power sector. To this end, a partial equilibrium model is fed with carbon price paths to determine corresponding emission and abatement levels. We identify two fundamental properties of MAC curves of the European power sector: First, the shape of MAC curves is convex for all points in time. The curvature depends on economic developments, such as fuel prices and interest rates. Second, MAC curves flatten over time. In the short term, fuel-switching is the only abatement option and thus, the MAC curve is steep. With longer investment horizons, the degree of freedom for investment grows and enables the transformation of the capital stock. This additional abatement option flattens the MAC curve. Further, technological learning and demand adjustments lowers in particular the upper part of the MAC curve.

Idealized market equilibrium paths in the EU ETS consist of price-emission tuples that minimize overall abatement costs and comply with the allowance supply path. Emission decisions and thus market prices are a trade-off between emissions today and in the future. After introducing the Market Stability Reserve and the Cancellation Mechanism, the total allowance supply and thus total emissions decrease with banking volumes. With convex MAC curves, marginal abatement costs increase over time, which makes future abatement relatively more expensive compared to today's abatement. Thus, firms increase banking volumes compared to linear MAC curves. On the contrary, MAC curves flatten over time, which lowers the incentives for banking. Considering steeper MAC curves in the short term leads to a higher price path and an earlier depletion of the firms' bank. For quantifying these effects, the time-dependency of MAC curves should be depicted. A model of the allowance demand side could derive MAC curves, which are fed into a model of the EU ETS. Ideally, the allowance demand-side model is coupled with the EU ETS model to derive consistent equilibrium paths.

Beyond the power sector, MAC curves within energy-intensive industries should be analyzed to cover the whole scope of the EU ETS. Since MAC curves are only snapshots of a dynamic context, path dependencies and uncertainties are worth considering. In particular, the impact of global deep decarbonization and its implications for MAC curves are a subject of further research.

5. One Price Fits All? Wind Power Expansion under Uniform and Nodal Pricing in Germany

5.1. Introduction

5.1.1. Motivation

For lowering greenhouse gas emissions intensity within the European power sector, wind power capacities have increased significantly over recent years. As the share of intermittent generators rises, their location becomes increasingly important. On the one hand, spatially distributed locations can flatten the skittish nature of their in-feed (balancing effects) and hence relieve the need for dispatchable generation capacities. On the other hand, sites with high wind yield usually do not coincide with main load centers (cf. Borenstein (2012)). A high concentration of wind power plants at productive but remote sites imposes challenges to the grid. The siting of wind power plants is thus often a trade-off between high wind yield and grid congestion. This trade-off becomes more critical with increasing market shares of renewable energy sources (RES).

This article considers Germany as a case study. Germany is a pioneer in the expansion of wind power plants. In 2019, 25% of the electricity demand was covered by wind energy, and further expansion is a clear political goal. The typical pattern that remote locations offer better wind conditions applies also to Germany: Wind yield peaks in Northern Germany on the shore of the North and Baltic Seas. Demand for electricity, however, is highest in the densely populated and industry-rich areas of Southern and Western Germany. As a direct consequence, there have been increasing problems with the integration of RES generation into the grid in recent years.[54] In the current market design, the electricity price is uniform throughout Germany and does not take grid bottlenecks into account. As a result, scheduled generation[55] may be adjusted after market-clearing to align with grid restrictions, often referred to as redispatch.[56] Both redispatch volumes and costs have risen over recent years. For minimizing elec-

[54] Government decisions on phasing-out coal and nuclear power plants further exacerbate the problem, since these plants are usually located close to load centers.

[55] The dispatch of power plants is usually scheduled on wholesale markets before delivery, namely day-ahead and intraday markets.

[56] Within redispatch, usually remote intermittent RES are curtailed and replaced by ramping up conventional power plants close to load to overcome congestion.

tricity supply costs, coordinating wind power expansion with grid bottlenecks is crucial.

In liberalized electricity systems, grid expansion is subject to regulatory decisions whereas wind power plants are built by private investors. Due to long approval and construction periods, grid expansion projects are fixed for the long term, usually before the decision to invest in new generation capacity is taken.[57] In Germany, as in many other European countries, the expansion of wind power is subsidised by the government. In addition to the revenue on the electricity market, wind turbines receive a market premium for electricity fed into the grid. The level of the market premium is determined in capacity-based pay-as-bid auctions. New wind power projects bid according to their expected revenue, which consist of expected electricity prices, expected wind yield at the respective location and the correlation between wind availability and electricity price. Incentives for spatial diversification are only set by regionally different wind in-feed patterns and resulting balancing effects (cf. Schmidt et al. (2013)). However, wind yield at respective sites dominate balancing effects under uniform pricing due to high correlation of in-feed patterns (cf. Eising et al. (2020)). As a result, wind power investors rather seek to maximize wind feed-in. Hence, wind power has been mainly deployed at high wind-yield sites in Northern Germany.

There is a broad consensus among economists on how to efficiently coordinate wind power expansion with grid constraints. The expansion of intermittent electricity generation exerts negative externalities on the electricity grid. Pricing of externalities is the economically desirable instrument to overcome their detrimental effects (cf. e.g., Hogan (1999), Borenstein (2012) or Wagner (2019)). While uniform prices fail to reflect grid externalities, nodal pricing regimes internalise them in market prices, which reflect both generation costs and grid constraints (cf. Weibelzahl (2017)). If, for example, the wind power feed-in in Northern Germany is too high to be integrated into the grid, low electricity prices arise there. If such situations occur frequently, the electricity price level drops and investments become unprofitable. This mechanism creates dynamic incentives in nodal price regimes for an efficient coordination of investments in wind energy with the existing grid (cf. Green (2007)).[58]

In order to counteract problems with the grid integration of wind energy under uniform pricing, the amendment to the Renewable Support Scheme in 2017 (*Erneuerbaren-Energien-Gesetz 2017*) introduced the so-called grid expansion area (*Netzausbaugebiet*). In this area, an investment restriction prevents excessive expansion of wind turbines at windy but grid-critical locations. Another in-

[57] Höffler and Wambach (2013) argue that an early commitment to grid extension is also welfare-optimal as long as the investment costs of the companies do not represent private information. The investment costs for wind power plants are transparent such that an early commitment to grid expansion is economically desirable.

[58] This applies also to demand side or flexibility investments: building energy-intensive industries becomes more attractive in regions with lower electricity prices, flexibility is increasingly built into regions with large electricity price fluctuations.

strument to coordinate wind power investments with grid restrictions under uniform pricing are spatially differentiated grid tariffs for generators (e.g., Haucap and Pagel (2014) or Grimm et al. (2019)). They can be designed to internalize the electricity generation's external effects on grid congestion under uniform pricing and hence positively affect social welfare (e.g. Agency for Cooperation of Energy Regulators (ACER) (2015) and Daxhelet and Smeers (2007)). Several European countries have introduced spatially differentiated g(enerator)-components in their grid tariff scheme, e.g., Sweden, the UK and Norway (cf. ENTSO-E (2019)). While perfectly defined (node-specific) g(enerator)-components can replicate the efficient investment signals, a more simple approach eases information gathering for investors and tariff setting for regulators. Since distorted signals of uniform prices develop mainly along the North-South axis (cf. Obermüller (2017)), we follow the Swedish grid tariff design and assess latitude-dependent g-components in this paper (THEMA (2019)).

The paper at hand quantifies the effects of nodal and uniform prices on the spatial distribution of wind power expansion, welfare losses stemming from distorted incentives set by uniform prices as well as distributional effects, which result from introducing nodal prices. Further, this paper evaluates to which extent welfare losses resulting from inefficient wind power siting can be mitigated by complementing uniform pricing with latitude-dependent g-components in grid tariffs or grid expansion areas.

5.1.2. Related Literature

The paper at hand is based on two strands of literature:

The first strand uses the concept of market values to evaluate the worth of power generation facilities. In recent years, several articles have used market values to analyze efficient RES expansion paths. Joskow (2011) introduces market values to evaluate intermittent power generators. Among others, Grubb (1991), Jägemann (2014) and Hirth (2013) discuss how RES market penetration affects their market value. Higher penetration of RES undermine their market value due to cannibalization effects (e.g., Prol et al. (2020)). With increasing wind capacities, the electricity price drops in hours with high intermittent in-feed, especially when there is a high degree of simultaneity, lowering the market revenue of wind power plants. Grothe and Müsgens (2013), Elberg and Hagspiel (2015) and most recently Eising et al. (2020) use market values to shed light on the optimal distribution of wind power plants in Germany. However, these articles only consider the current uniform pricing market design. Accordingly, the market values only reflect the correlation of local wind in-feed with the uniform price signal and do not cover grid restrictions. Consequently, the problem of coordination between RES deployment and grid bottlenecks is not tackled.

The second strand examines the trade-off between grid expansion and investment or analyzes nodal market designs as a theoretically efficient instrument to solve this coordination problem. Lamy et al. (2016) examines the trade-off between grid expansion and investments in wind power plants at less productive locations. Their results show that building new wind power plants close to load is economically desirable. Opportunity costs of choosing sites with lower wind-yield are lower than avoided grid expansion costs. In a scenario comparison for Germany, though, Böing et al. (2017) find the opposite. Grid expansion imposes fewer costs than an increased deployment of wind power plants in the low-wind south of Germany. In an early work on nodal prices, Green (2007) uses a 13-node model to investigate the welfare effects of switching from uniform to nodal prices in England/Wales. He finds that, in a static setting, the introduction of nodal prices avoids welfare losses of 1.5% concerning spot market revenues of electricity producers. He suggests that the efficient dynamic incentive effects of nodal prices should significantly increase welfare gains. Leuthold et al. (2008) conducts a similar, static investigation of uniform and nodal market designs for Germany and finds comparable welfare effects. They also emphasize the advantages of nodal prices in a dynamic context. Pechan (2017) sheds light on the dynamic incentives of nodal pricing. Using a simplified 6-node model, she investigates the effects of uniform and nodal pricing on the siting of wind turbines. The spatial distribution of wind turbines changes significantly if the siting of wind power plants considers negative grid externalities. Closest to this article, Obermüller (2017) combines the two strands of literature. He uses a static dispatch model to examine the market values of wind power plants under uniform and nodal pricing in Germany for 2014. He derives diverging market values and concludes that uniform prices set inefficient investment incentives for wind power plants. Yet, a dynamic evaluation to quantify the resulting inefficiencies is missing.

The prevailing literature on evaluating spatially differentiated grid tariffs or grid expansion areas to mitigate inefficient investment signals of uniform pricing is scarce. Lück and Moser (2019) assess the German grid expansion area and its impact on redispatch volumes but do not evaluate its benefits from an economic perspective. Numerically evaluating spatially differentiated g-components, Bertsch et al. (2016) and Grimm et al. (2019) find only small positive effects of their implementation on congestion costs and welfare.

5.1.3. Contribution and Structure

The paper at hand sheds light on the dynamic coordination of wind power investments for given grid expansion under nodal and uniform pricing. Our contribution is fourfold: First, an electricity system model is developed. The model allows for investments into power plants, while considering a detailed depiction of transmission grid constraints in a closed form solution. For isolating the effects of the spatial distribution of wind power plants, this paper considers only endogenous investments into wind power, while conventional power plants follow an exogenous path. Existing dynamic modelling approaches either decouple investment decisions and grid modelling, and approximate an equilibrium solution by iterative model runs (e.g., Bertsch et al. (2016), Fürsch et al. (2013), Hagspiel et al. (2014) or most recently Fraunholz et al. (2020)) or use highly aggregated grid depictions with only few nodes or zones (e.g., Grimm et al. (2016b)). For accurately addressing the spatial distribution of wind power plants and its impact on grid congestion, the model considers a 380 node-depiction of the German transmission grid. To the best of our knowledge, existing highly spatially resolved models are static and abstract from investments in power plant capacities (e.g., Obermüller (2017) or Breuer and Moser (2014)). Second, the efficient expansion of wind power plants in Germany is derived using nodal pricing. Third, inefficiencies implied by the current uniform pricing market design are quantified. In order to do that, we compare market values of wind power plants under nodal and uniform pricing, derive necessary subsidies as well as the resulting welfare losses and distributional effects. Fourth, this paper investigates latitude-dependent g-components as well as grid expansion areas to remedy welfare losses due to inefficient siting of wind power plants under uniform pricing.

Our main findings are as follows:

First, building the same amount of wind capacities at grid-friendly sites rather than at sites with maximal wind yield increases the amount of wind energy fed into the grid. The reduced need for curtailment overcompensates losses in wind yield.

Second, we quantify distorted signals of uniform prices for siting of wind power and their consequences. Sites which require low (or even no) subsidies have low system values and hence increase redispatch and curtailment. In general, uniform prices lower subsidies for wind power but lead to yearly welfare losses amounting to 1.5% of variable supply costs in 2030 due to inefficient wind power expansion.

Third, latitude-dependent g-components fall short in reflecting distortions of uniform pricing adequately. Their potential in mitigating inefficient wind power expansion remains limited. A single grid expansion area, as currently implemented in Germany, outperforms latitude-dependent g-components. Yet, a further differentiation into multiple grid expansion areas can significantly enhance these positive effects.

Fourth, spatially differentiated signals of nodal prices for wind power investments lead to distributional effects. Consumers in Northern Germany representing about 25% of German demand would benefit from up to 30% lower nodal electricity prices compared to uniform prices in 2030. In contrast, electricity prices in Western and Southern Germany would increase by about 5% under nodal prices. As a result, electricity consumers in the load centers in Western and South-Western Germany would bear higher costs while electricity generators in Northern Germany face declining revenue and vice versa.

The remainder of this paper is structured as follows: Section 5.2 introduces the model, the input data and central assumptions. The differences in investment locations, electricity generation, market values as well as welfare and distributional implications triggered by switching from uniform to nodal pricing regime are explained in section 5.3. Latitude-dependent g-components and grid expansion areas as complementary measures to mitigate distorted investment signals of uniform pricing are analyzed in section 5.4. Section 5.5 provides a critical discussion of applied methodology and section 5.6 concludes.

5.2. Methodology, Input Data and Scenario Design

The paper at hand uses the notation presented in Table D.1. For distinguishing exogenous parameters and endogenous optimization variables, the latter are written in capital letters.

5.2.1. Investment and Dispatch Model

Within this paper, the novel investment and dispatch model SPIDER (Spatial Planning and Investments of Distributed Energy Resources) is developed, which considers a detailed depiction of the German transmission grid. It is based on the power market model DIMENSION[59]. SPIDER is a partial equilibrium model of the European power sector. By assuming perfect markets and no transaction costs, the profit maximization of firms corresponds to a cost minimization of a central planner. The competition of profit-maximizing symmetric firms constitutes the dual optimization problem to a central planners' cost minimization. The central planner invests into new power plants and dispatches generation capacities such that the net present value of the variable (VC) and fixed costs (FC) is minimized, where β represents the discount factor.

The objective is hence:

$$min!\ TC = \sum_{y \in Y} \beta(y) \cdot [VC(y) + FC(y)].$$

Installed electricity generation capacities (CAP) are modeled endogenously: The model invests in new generation capacities (CAP_{add}) and decommissions capacities (CAP_{sub}), which are not profitable. For a realistic depiction of European energy markets, existing as well as under construction capacities ($cap_{add,min}$) and decommissioning due to end-of-lifetime or technology bans ($cap_{sub,min}$) are given exogenously. These parameters serve as lower bounds for building or decommissioning capacities, respectively. The fixed costs per year comprise the annualized investment costs (δ) plus fixed operation and maintenance costs (σ) per installed capacity. The following equations describe these interrelations.

[59]DIMENSION was used in numerous analyses, e.g., in Bertsch et al. (2016) and Peter (2019). For a thorough introduction to DIMENSION and its characteristics, the reader is referred to Richter (2011).

$$
\begin{aligned}
CAP(y,m,i) &= CAP(y-1,m,i) + CAP_{add}(y,m,i) - CAP_{sub}(y,m,i)\\
CAP_{add}(y,m,i) &\geq cap_{add,min}(y,m,i)\\
CAP_{sub}(y,m,i) &\geq cap_{sub,min}(y,m,i)\\
&\forall y \in Y, \forall m \in M, \forall i \in I
\end{aligned}
$$

$$
\begin{aligned}
FC(y) = &\sum_{m \in M, i \in I} CAP(y,m,i) \cdot \sigma(i)\\
&+ \sum_{y1: y-y1 < econ\_lifetime(i)} CAP_{add}(y1,m,i) \cdot \delta(y,i)
\end{aligned}
$$

Electricity generation (GEN) in each market and timestep (t) has to level the (inelastic) demand (d) minus the trade balance ($TRADE\_BAL$), which depicts the net imports of trade flows ($TRADE$) from other markets. Availability of power plants ($avail \cdot CAP$), which, e.g., considers maintenance shutdowns limit their generation. Trade flows between markets are limited by interconnection capacities ($linecap$). Yearly total variable costs (VC) result from the generation per technology times the technology-specific variable operation costs (γ), which mainly comprise costs for burnt fuel and required CO_2 allowances.

$$
\begin{aligned}
\sum_{i \in I} GEN(y,t,m,i) &= d(y,t,m) - TRADE\_BAL(y,t,m)\\
GEN(y,t,m,i) &\leq avail(y,t,i) \cdot CAP(y,m,i)\\
TRADE\_BAL(y,t,m) &= \sum_{n} (1 - l(n,m)) \cdot TRADE(y,t,n,m) - TRADE(y,t,m,n)\\
TRADE(y,t,m,n) &\leq linecap(y,m,n)\\
&\forall y \in Y, \forall m,n \in M \;\; \& \;\; m \neq n, \forall i \in I\\
VC(y) &= \sum_{m \in M, i \in I, t \in T} GEN(y,t,m,i) \cdot \gamma(y,i)
\end{aligned}
$$

The presented equations constitute the backbone of SPIDER. Beyond that, the model features, e.g., constraints to depict the utilization of storage as well as constraints on energy potentials, e.g., for biomass.

5.2.2. Grid Modeling

Within this paper, the inner-German transmission grid infrastructure is considered within a linear optimal power flow problem (LOPF). Non-linear AC power flow restrictions are approximated via linear DC power flow constraints. While this approach is consistent with Kirchhoff's current as well as voltage law, it neglects grid losses (cf. van den Bergh et al. (2014)). For implementing DC power flow, the cycle-based Kirchhoff formulation is used. In an extensive comparison of different LOPF formulations, Hörsch et al. (2018) identifies this approach as favorable concerning model run times, particularly in the context of generation investment optimization problems.

Kirchhoff's current law is implemented directly via mapping active power injections in each market m (which equal the trade balance $TRADE\_BAL$) on line power flows ($FLOW$) via the incidence matrix $\kappa(m,l)$, i.e.:

$$TRADE\_BAL(y,t,m) = \sum_{l \in L} \kappa(m,l) \cdot FLOW(y,t,l)$$

$$,\kappa(m,l) = \begin{cases} 1 & \text{if line } l \text{ ends in bus } m, \\ -1 & \text{if line } l \text{ starts at bus m } m, \\ 0 & \text{else} \end{cases}$$

The transmission grid is assumed to be a directed graph. With $|L|$ representing the number of lines and $|N|$ the number of nodes, the graph is uniquely determined by $|C| = |L| - |N| - 1$ linear independent cycles. To fulfill Kirchhoff's voltage law, power flows ($FLOW$) times line reactances (x) along each of these cycles have to sum up to zero. Thereby, the model considers interactions of electricity generation and power flows endogenously. The cycle matrix ($\phi(l,c)$) assigns lines to the respective cycles.

$$\sum_{l \in L} \phi(l,c) \cdot x(y,l) \cdot FLOW(y,t,l) = 0$$

$$,\phi(l,c) = \begin{cases} 1 & \text{if line } l \text{ is element of cycle } c, \\ -1 & \text{if reversed line } l \text{ is element of cycle } c, \\ 0 & \text{else} \end{cases}$$

$$\forall c \in C, \forall y \in Y$$

Investments in transmission grid lines are not considered endogenously but are exogenous assumptions. Incorporating a detailed depiction of grid constraints as well as endogenous investments into generation is computationally challenging. Thus, the model underlies several limitations to keep it tractable: To avoid mixed-integer optimization, ramping and minimum load constraints are approximated. The model does not depict combined heat and power plants. Further, the model abstracts from uncertainty and assumes perfect foresight. Further, the model is able to use representative days to reduce the temporal dimension of the optimization problem.

5.2.3. Assumptions and Data

Scope and Transmission Grid

The regional focus of the model is Germany with a spatial resolution at transmission grid node level, i.e., 220 kV to 380 kV voltage levels. For the depiction of the transmission grid, grid information from multiple sources is combined, e.g., Matke et al. (2016) and 50Hertz et al. (2019). Grid extensions follow the latest version of the German grid development plan (cf. Bundesnetzagentur (2019)). The model covers Germany and its neighboring countries, depicted as one node without inner-country grid restrictions. Interconnectors to as well as between neighboring countries are approximated via Net Transfer Capacities based on ENTSO-E (2018). Overall, the model incorporates 380 nodes and 606 connecting lines within Germany. The regional scope and the depiction of the German transmission network is visulized in Appendix D.2.

The temporal scope covers the years 2019, 2020, 2025 and 2030, represented by 12 representative days in an hourly resolution. The representative days are derived using k-medoids clustering concerning residual load (cf. Kotzur et al. (2018)).

The technological scope comprises the most common conventional and renewable power plant types, as well as pumped storage. Table D.3 provides an overview of the considered technologies, including their techno-economic parameters. Endogenous investments are only allowed for onshore wind power plants in Germany. The capacity development of all other technologies is exogenous. It follows the *National Trends* scenario in ENTSO-E (2018) and *Scenario B* in 50Hertz et al. (2019). The development of power plant capacities follows political announcements. For instance, the phase-out of German lignite and coal power plants is implemented according to the latest public information. The German coal power plant fleet is decommissioned in order of the installation year to comply with target capacities for coal power plants. The exogenous development of conventional generation capacities is sufficient to meet demand at any time, i.e., we assume that the electricity market design triggers sufficient investments into backup power plants such as open-cycle gas turbines. Appendix D.3 discloses further assumptions on demand development per country, investment costs as well as fuel prices.

Input data: Time-series and Regionalization

Demand time-series are based on hourly national demand in 2014, according to ENTSO-E (2020). The German demand is distributed to the nodes similar to the approach in 50Hertz et al. (2019). Based on sectoral demand shares on federal state level (cf. Energiebilanzen (2020)), household demand is broken down to nodes via population shares. For regionalizing industry and commercial demand, regional data on gross value added is used for the respective sectors (cf. EUROSTAT (2020)).

For modeling intermittent renewable in-feed of photovoltaics and wind power, data provided by Pfenninger and Staffell (2016a) and Pfenninger and Staffell (2016b) is used for Germany and its neighbors. Since this paper investigates wind power expansion, we use regional in-feed within Germany based on Henckes et al. (2017), which applies a novel meteorological reanalysis model to derive wind speeds for several vertical layers and in high spatial resolution (6kmx6km). The derived wind speeds were transformed into in-feed time-series, calibrated to historical in-feeds of wind parks.

Existing power plant capacities, as well as their distribution across Germany, are derived from data of the German regulator Bundesnetzagentur.[60] Power plants are distributed via their postcodes to the nearest transmission grid node. The future distribution of offshore wind farms and solar power plants is in line with 50Hertz et al. (2019).

Figure 5.1 displays the regionally differentiated capacity factors for onshore wind power plants as well as the initial distribution of wind power plants across Germany in 2019.

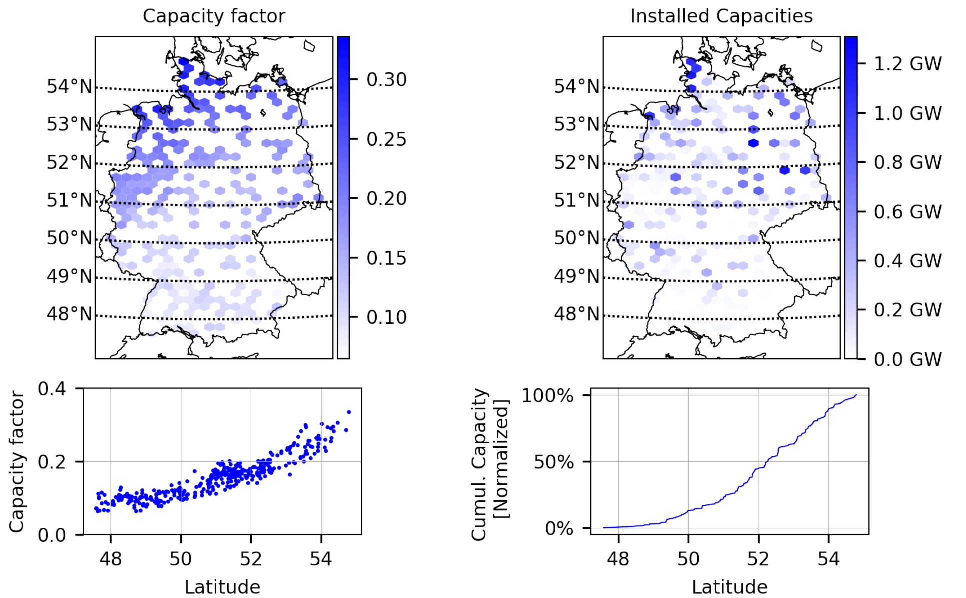

Figure 5.1.: Regional capacity factors of wind power plants (left) and spatial distribution of wind power plants in 2019 (right)

[60]Conventional power plants are based on the power plant list (Bundesnetzagentur (2020a), Renewables on *Marktstammdatenregister* (Bundesnetzagentur (2020b)).

Capacity factors of wind power plants in Northern Germany range from 25% up to 35%. Towards the south, capacity factors decrease gradually. Though, wind yield in Western Germany stays above a capacity factor of 20% until the 51st parallel, followed by a sharp decrease in the Southern direction. In Southern Germany, most sites offer only around 10% to 15%. As a result, about 75% of existing capacity are located above the 51 parallel. Yet, wind power capacities are low in densely populated Western Germany although the above average wind conditions.

5.2.4. Scenario Setup

The paper at hand analyzes investment decisions into wind power plants under different market designs. Besides the uniform price market design, a nodal pricing regime is set up to derive efficient locations for new wind power plants. Under nodal pricing, each transmission grid node constitutes a market and grid constraints are taken into consideration within the price formation. Uniform pricing considers only nation-wide electricity markets where prices do not reflect inner-German grid bottlenecks. Like Germany, several European countries use uniform pricing.[61] Modeling-wise, the only difference between the nodal and uniform pricing regime is the consideration of grid constraints within Germany. While the transmission grid constraints are modelled via DC power flow (cf. section 5.2.2) for the nodal pricing regime, these constraints are turned off under uniform pricing. Inner-German power flows are hence not restricted under uniform pricing. We consider two scenarios:

- *Nodal*, where invest and dispatch is derived under nodal pricing.
- *Uniform*, where invest and dispatch is derived under uniform pricing. The scheduled dispatch after market clearing, however, might violate physical grid restrictions and hence necessitates curative redispatch measures. The subsequent redispatch is assumed to derive the cost-efficient dispatch decision under the given power plant fleet.[62]

Additionally, section 5.4 evaluates the effects of complementing uniform pricing with either latitude-dependent g-components or grid expansion areas. Both instruments are proposed to mitigate inefficient investment signals of uniform pricing.

For both nodal and uniform pricing, we assume a homogeneous RES expansion target. The overarching target of Germany is to reach a 65% share of RES generation with regard to gross electricity demand according to the government

[61] Exemptions are e.g. Norway, Sweden and Italy where the electricity market is split into bidding zones.

[62] Within this run, the cost-efficient dispatch decision is derived including optimal trade flows. In reality, market clearing under uniform pricing pre-determine trade flows which renders system optimal trade in redispatch impossible. Cross-border redispatch is only viable based on bilateral contracts.

coalition agreement in 2018. For meeting this target, RES capacities are extended linearly according to announced capacity targets - i.e., 20 GW of Wind Offshore in 2030 - or capacities stated in the Grid Extension Plan (cf. scenario B in 50Hertz et al. (2019)). Table 5.1 shows the assumed RES expansion in Germany.

Table 5.1.: Assumed development of installed RES capacities in Germany, based on 50Hertz et al. (2019)

[GW]	2019	2020	2025	2030
Wind Onshore	53.4	55.9	68.7	81.5
Wind Offshore	7.5	8.7	14.3	20.0
Photovoltaics	49.2	53.0	72.1	91.3

The expansion of photovoltaics as well as offshore wind power plants is exogenous, the spatial distribution of new capacities follows the development in the latest grid extension plan (50Hertz et al. (2019)). For the expansion of onshore wind power plants, we require the model to expand capacities by 2.56 GW per year. The assumptions on RES expansion is in line with the goal of the German government to provide 65% of gross electricity demand via RES power plants.

In order to avoid an unrealistic concentration of new wind power plants, upper bounds for yearly expansion at each transmission node based on area-corrected historical expansion rates (data retrieved from Bundesnetzagentur (2020b)) are implemented. There are two reasons for defining the wind onshore target with regard to capacity instead of energy feed-in: First, the current auction design in Germany is capacity based. The government auctions off a pre-defined amount of capacity to be built. Second, a capacity target ensures that investment costs are the same under uniform and nodal pricing. Resulting changes in total costs are only due to different incentives to coordinate wind power investments and the grid topology.

5.3. Implications of Wind Power Expansion under Uniform and Nodal Pricing

The subsequent section compares the spatial distribution of wind power plants investments under nodal and uniform pricing. Further, the implications on electricity generation, market values, subsidies as well as welfare and distributional effects are shown.

5.3.1. Siting of Wind Power and Implications for Wind In-feed

In both market settings, uniform and nodal pricing, the gross wind capacity expansion equals 2.56 GW per year. Besides regional investment bounds, e.g., due to acceptance and potential, the market-based incentives for the spatial distribution between both settings differ: Under uniform pricing, new wind power plants are usually built where the best wind conditions prevail. Only different in-feed patterns and resulting balancing effects trigger a spatial differentiation. Under nodal pricing, market revenue reflects costs resulting from grid congestion. Hence, nodal pricing incentivizes grid-friendly locations. Figure 5.2 visualizes the impact of market design on the siting of wind power plants until 2030.

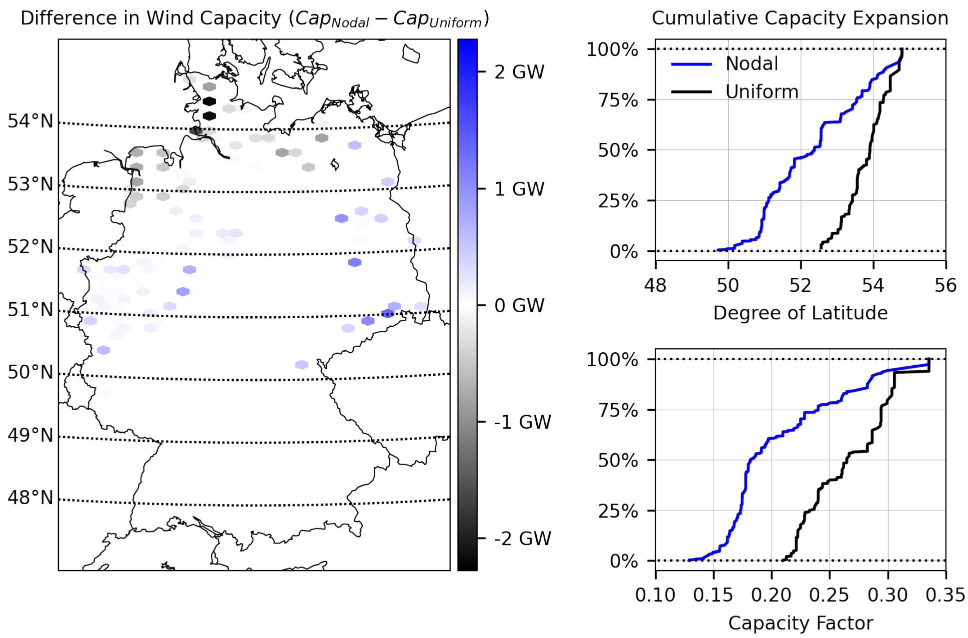

Figure 5.2.: Difference in spatial distribution of wind capacities in 2030 (left) and cumulative wind expansion by latitude and capacity factor (right)

Under uniform pricing, wind power expansion concentrates on Northern Germany. Sites above the 53rd parallel cover approximately 90% of wind power expansion. Under nodal pricing, the investment pattern differs in two aspects: First, wind energy investments spread over more nodes than under uniform pricing. Second, locations for new wind power plants move southwards. Nodal pricing leads to a decrease of capacity additions at windy sites above the 53rd parallel. Instead, sites at latitudes between 51 and 53 attract about 75% of new wind power plants. As a result, capacity factors of newly installed wind power decrease: While wind power is exclusively expanded at sites with a capacity factor of at least 20% under uniform pricing, only about 40% of new wind power plants reach an equally high factor under nodal pricing. Uniform pricing set rather low incentives for spatial diversification, wind yield and wind power investments are strongly correlated. Nodal pricing triggers spatial diversification. Wind power expansion spreads to mediocre wind yield sites in Western and Eastern Germany. These sites are either close to load or own comparatively low existing wind capacities (cf. Figure 5.1). Both aspects ease the grid integration of wind power. In Southern Germany, nodal pricing does not trigger additional investments. On the one hand, gains through grid relief do not compensate for the lower capacity factors in Southern Germany, since the main grid bottlenecks are between Northern and Central Germany.[63] On the other hand, high proportions of photovoltaic and hydropower plants within Germany and particularly in the neighboring countries of Austria and Switzerland further decrease the profitability of wind power plants in Southern Germany.

As a consequence of different investment patterns, feed-in of wind power plants as well as curtailment volumes change. Figure 5.3 depicts the spatial generation pattern of wind power plants and the development of actual in-feed as well as curtailment. As discussed in section 5.2.4, this analysis assumes capacity-based RES expansion targets. Hence, installed wind capacities are equal under nodal and uniform pricing.

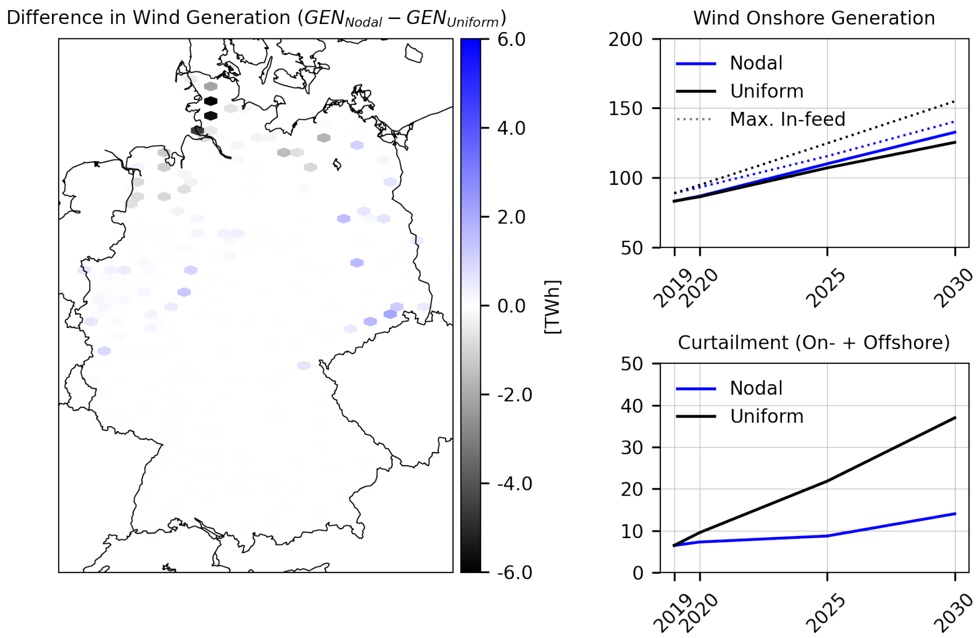

Figure 5.3.: Difference in spatial distribution of wind generation in 2030 (left) and development of wind generation and curtailment (right)

First, the southward shift of capacity additions goes hand in hand with a shift of generation in the same direction. Second, the internalization of grid costs under nodal prices reduces grid congestion significantly. Both existing and newly installed wind power plants are capable of feeding a higher proportion of potential generation into the grid. Consequently, overall wind power curtailment in 2030 is cut to a third under nodal prices compared to uniform pricing. All in all, the decrease of curtailment overcompensates lower wind yield potentials, and thus more wind energy is fed into the grid in the nodal pricing setting.

[63] The high wind capacities of Germany's Northern neighbor reinforces these bottleneck.

5.3.2. Regional Electricity Prices

Wind power investments strongly interact with electricity prices under nodal pricing. Nodal prices joint with total wind yield and its temporal pattern set spatially differentiated signals for wind power expansion. Though, wind power investments depress nodal prices locally if the grid is congested (cannibalization effect). Figure 5.4 illustrates uniform and nodal electricity prices in 2030.

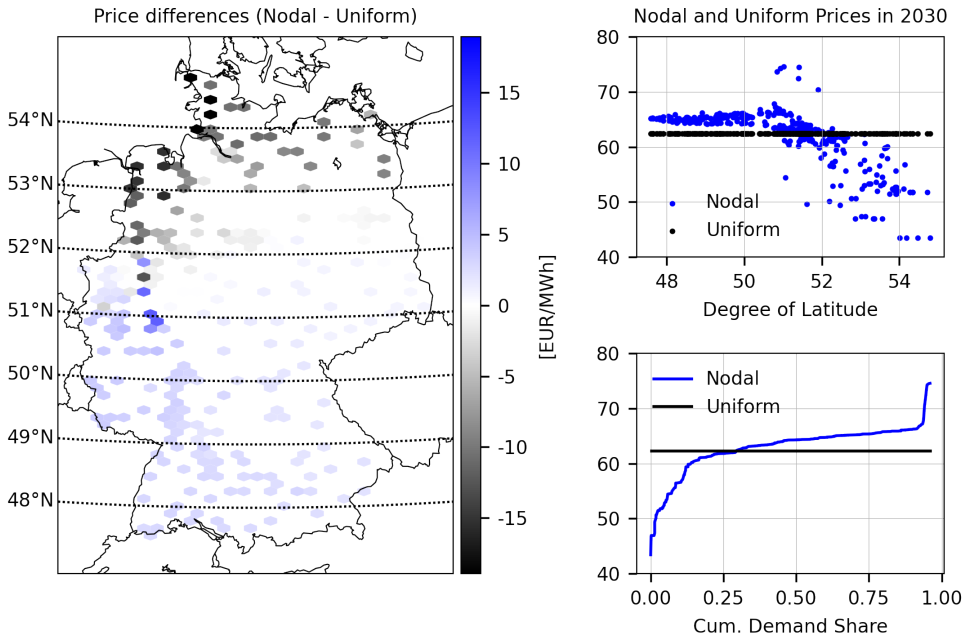

Figure 5.4.: Difference between weighted-average nodal and uniform prices (left) as well as nodal and uniform prices over latitude and cumulative demand (right)

Given the assumptions on power plant phase-outs, fuel and carbon prices, the weighted average of Germany-wide uniform electricity prices rises to slightly above 61 EUR/MWh in 2030 compared to about 38 EUR/MWh in 2019. Nodal electricity prices differ between regions. Average nodal electricity prices in Northern Germany are significantly lower than the uniform price, falling as low as 43 EUR/MWh at single nodes. About 25% of German electricity consumption would benefit from lower prices, whereas the rest would face higher electricity prices.[64] The majority of demand faces a price increase of about 5%. However, electricity prices at single nodes increase up to 75 EUR/MWh. These price peaks occur mostly in Western Germany where demand is high, RES capacities low, and conventional capacity is short due to phase-outs of lignite power plants. Further, Western Germany is not as well connected to wind-rich Northern Germany as Southern Germany, whose interconnection enhances due to three new DC lines after 2025. Nodal prices in Southern Germany also profit from high

[64]In contrast to uniform prices, nodal prices already reflect grid congestion costs. Hence, we include redispatch costs of 1.5 EUR/MWh (see section 5.3.4) in uniform electricity prices.

shares of PV and Hydro, including flexible Pumped Hydro. Additionally, imports from nuclear and hydropower dominated neighbors in the South, namely France, Switzerland and Austria, reduce price peaks in Southern Germany.

Nodal prices change trade flows between Germany and its neighbors. Grid bottlenecks are not visible under uniform prices. Consequently, high wind feed-in in Northern Germany leads to a low electricity price throughout Germany, which triggers exports to all neighboring countries, even to the south. If the wind in-feed in Northern Germany does not comply with grid constraints, power plants in Southern Germany need to ramp up for delivering scheduled exports. In such situations, however, electricity imports from neighboring countries in the south would be favorable. Nodal prices reflect grid congestion issues and hence prevent inefficient incentives for cross-border trade. Net trade indicates that inefficient trade flow incentives of uniform prices will become more problematic with higher RES shares in German electricity generation (see Appendix D.4).

5.3.3. Market Values and Subsidies

This paper uses the concept of market values to reflect the electricity market revenue of power plants.[65] In contrast to nodal pricing, market values under uniform pricing fail to reflect the actual value of power plants. To evaluate whether market values under uniform pricing set distorted incentives, we derive system values of wind power plants in the uniform market design from an optimal nodal dispatch given invest decisions derived under uniform pricing. Under nodal pricing, market and system values are equal. Figure 5.5 depicts the market and system values of wind power plants in 2030 under uniform and nodal pricing.

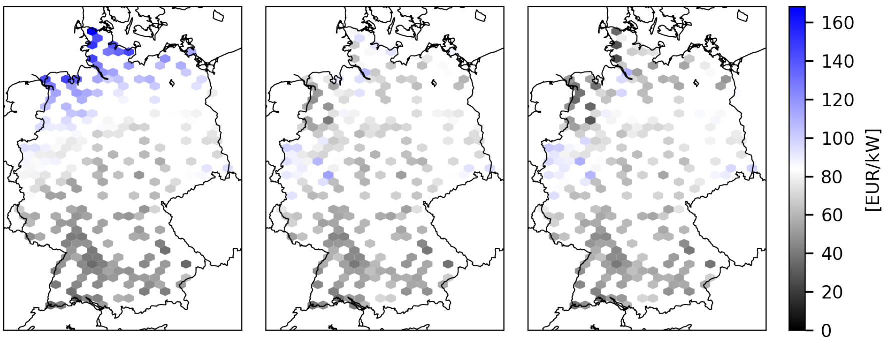

Figure 5.5.: Market (MV) and system values (SV) under uniform and nodal pricing in 2030

Market values under uniform pricing strongly correlate with wind conditions. Market values peak in Northern Germany close to the shore, where the best wind conditions prevail despite there is already a lot of wind power installed. Since

[65]In our definition, market values reflect revenue under the respective market design per capacity.

the market area is large and grid restrictions are not visible in uniform prices, high local wind power investments are possible before market prices would drop due to cannibalization effects. Market values in a nodal dispatch run given investments under uniform pricing reflect the corresponding system values. In contrast to market values, the system values are low in Northern Germany. The difference between market and system values indicates that uniform prices send distorted signals for the siting of wind power plants. Market revenue triggers high investments in Northern Germany, although the actual system values are low due to grid bottlenecks. Under nodal prices, though, market values at Northern Germany's shores are significantly lower than under uniform pricing. Wind power plants in Western Germany close to load with mediocre wind yield become more valuable than under uniform pricing. As a result, wind power expansion is spatially wide-spread.

To further assess the incentives set by uniform and nodal pricing, the subsequent paragraph compares the distribution of market values and the system values of wind power investments. We further derive the required subsidies from the difference between fixed costs of wind power plants and market values divided by the actual in-feed.[66] Figure 5.6 depicts the distribution of market and system values of newly built wind power plants and the required subsidies with boxplots.[67]

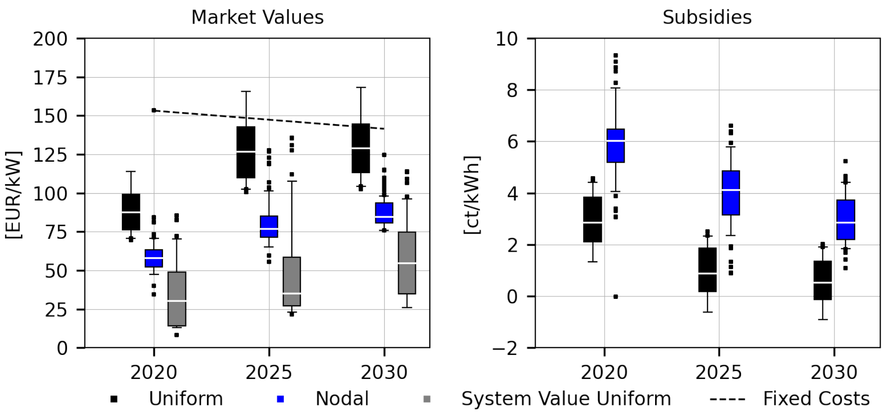

Figure 5.6.: Boxplots of market and system values as well as required subsidies for wind power investments

Under uniform pricing, market values of wind power investments exceed 75 EUR/MW and even the best sites are not profitable without subsidies. Required

[66] In line with real auctions, we indicate the subsidies in terms of electricity production (ct/kWh).

[67] Boxplots visualize the range of values. The boxes represent the 25 and 75% percentiles, the whiskers the 5 and 95% percentiles. The line within the boxes represents the median, outliers are scattered.

subsidies range from about 1.5 up to just below 5 ct/kWh.[68] Until 2025, market values increase due to rising electricity market prices as a result of higher fuel and carbon prices as well as the Nuclear phase-out until the end of 2022. At the same time, fixed costs decrease due to the assumed learning rates in investment costs (cf. Appendix D.3). Consequently, almost 25% of wind power capacity additions become economically feasible without subsidies, while most of the residual sites require subsidies 0 to 2 ct/kWh.[69] Between 2025 and 2030, market values and subsidies remain relatively constant under uniform pricing.

Market values under nodal pricing are significantly lower than under uniform pricing. Wind power cannibalizes itself and lowers market revenue at sites with high wind power installations due to grid bottlenecks. As a result of soaring electricity market prices as well as grid expansion, nodal market values increase steadily from 2020 to 2030. Subsidies under nodal pricing are about double as high as under uniform prices. However, the higher subsidies under nodal pricing include grid integration costs. If negative externalities of wind power plants on the grid are considered for wind power plant additions under uniform pricing, their system value is significantly lower than the respective market value.

To evaluate whether market prices set efficient signals for the siting of new wind power plants, figure 5.7 visualizes the required subsidies over system values under uniform and nodal pricing.

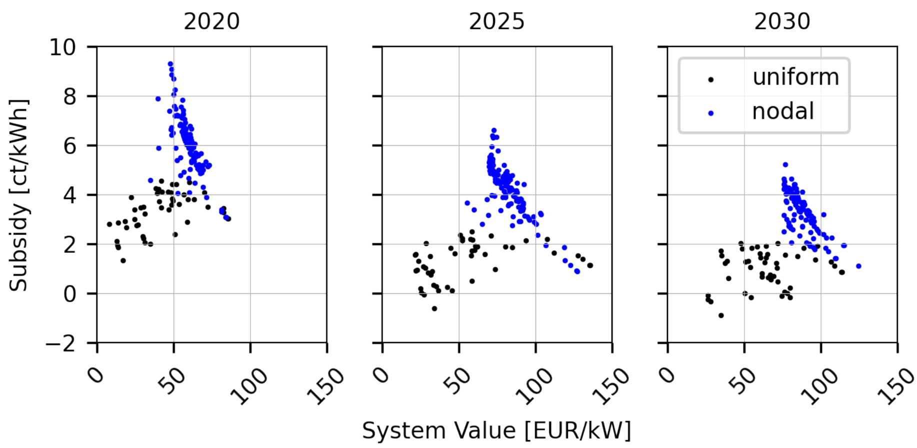

Figure 5.7.: Required subsidies vs. system values of newly built wind power plants under nodal and uniform pricing

Under nodal pricing, subsidies naturally reflect system values and stimulate an efficient siting of wind power. Under uniform pricing, though, particularly sites,

[68]Historical auction tenders in 2017 are in the same range. At the moment, auctions are not competitive due to issues in approval processes and subsidies are close to the regulated maximum bid of 6.2 ct/kWh.

[69]Uniform prices do not not reflect negative grid externalities of wind power investments. Wind power plant investments are cross-subsidized by electricity consumers, which have to bear these externalities, i.e., redispatch costs, via higher grid tariffs.

where little subsidies are needed, have low system values. Hence, uniform prices set inefficient incentives: productive but grid-hostile sites are tendered first in auctions under uniform pricing.

Summing up, uniform prices do not reflect negative externalities of wind power plants to grid congestion. Grid congestion costs are not reflected in market revenue under uniform prices. Hence, investments into wind power are close to profitability and require only comparatively low direct subsidies. Wind power plants though receive indirect subsidies as their integration is in-transparently borne by consumers via grid charges. Auctions that minimize subsidy costs under uniform prices lead to inefficient wind power expansion. Nodal prices internalize negative grid externalities. As a result, subsidies double compared to uniform prices, but wind power expansion shifts to system-optimal sites.

5.3.4. System Costs

Comparing the system costs provides insights into welfare losses due to inefficient siting of wind power plants. Average electricity supply costs reflect the total variable costs of electricity supply divided by aggregate electricity demand. Table 5.2 compares variable supply costs for the two scenarios.

Table 5.2.: Average variable electricity supply costs

[EUR/MWh]	2019	2020	2025	2030
Uniform	17.5	18.3	23.8	22.8
incl. redispatch costs	0.6	0.9	1.3	1.5
Nodal	17.5	18.3	23.6	22.4
Delta Uniform - Nodal	0.0	0.04	0.24	0.34

The average variable supply costs increase until 2025 for both scenarios driven by increasing fuel and carbon prices as well as the phase-out of nuclear power plants in Germany. After 2025, costs decrease since the expansion of intermittent RES with low variable costs overcompensates the slight increase in fuel prices after 2025.

Supply costs in *Uniform* reflect the costs after (optimal) redispatch. The development of redispatch costs is given separately. Despite grid expansion, redispatch costs increase from 0.6 EUR/MWh in 2019 to 1.5 EUR/MWh until 2030 due to distorted investment signals of uniform pricing.

The difference between *Nodal* and *Uniform* reflects the lower bound of welfare losses implied by distorted wind power investment signals under uniform pricing.[70] Consequently, there is no cost difference in 2019. Until 2025, the additional costs per year due to sub-optimal siting of new wind power plants increase to about 0.24 EUR/MWh. Due to grid expansion, particularly the installation of DC lines between Northern and Southern Germany in 2026, the increase in electricity supply costs slows down afterward. It reaches 0.34 EUR/MWh in 2030, which corresponds to an annual cost increase of 1.5% compared to the least-costs electricity supply under nodal pricing. If we only consider the direct costs of wind power generation, an efficient siting of wind power plants and thus higher wind in-feed, the average levelized costs of electricity generation of new wind power plants decreases to 79.8 EUR/MWh in 2030, which is about 15% lower than the average cost of 93.3 EUR/MWh under uniform prices.

5.4. Evaluation of G-Components and Grid Expansion Areas

As shown in section 5.3, uniform pricing sets inefficient signals for the siting of new wind power plants. This section analyzes two instruments to reduce these distorting effects of uniform prices: first, spatially differentiated grid tariffs, i.e., latitude-dependent g(eneration)-components and second, grid expansion areas. Both instruments are already implemented in European power market designs: For instance, Sweden charges energy-based g-components, which linearly increase with the latitude. Germany restricts wind power expansion within a grid expansion area, which is dynamically adjusted and usually covers Germany's most Northern federal states.

5.4.1. Configuration

G-Components

This paper considers capacity based g-components. These spatially differentiated grid charges can be considered a grid connection fee, which depicts grid externalities of wind power at the respective sites. Optimally, the g-component reflects the distorting signals of uniform prices and thus equals the difference in market values between uniform and nodal pricing. We derive g-components by regressing this difference on the latitude and consider two designs: G-components, which either linearly (*Lin. g-comp.*) or cubically (*Cub. g-comp.*) depend on the latitude. Figure 5.8 visualizes the development of the derived g-components.

[70] We assume cost-optimal redispatch with optimal trade flows between countries. Therefore, the neighbouring countries partly bear the costs caused by inner-German bottlenecks. In reality, though, market clearing under uniform pricing predetermines cross-border trade. Hence, optimal trade flows are usually not feasible since cross-border redispatch is limited to bilateral contracts.

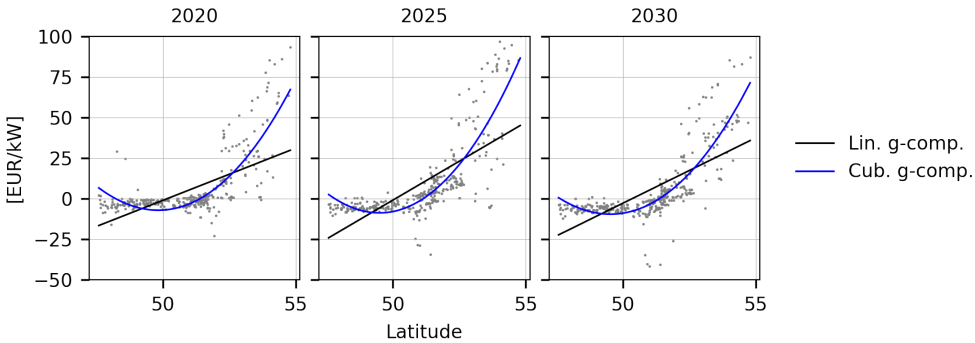

Figure 5.8.: Derivation of latitude-dependent g-components from the differences in market values between *Uniform* and *Nodal*

The difference in market values is (slightly) negative in Southern Germany (below the 50th parallel). Uniform prices underestimate the system value of Southern Wind power plants. In contrast, sites in Northern Germany largely exhibit strong distortions (above the 52nd parallel). The market revenue of wind power plants at these sites is higher than their system value. The distorting signals of uniform pricing do not develop linearly with the latitude but increase convexly. Thus, linear g-components are particularly far off for sites with high wind yields in Northern Germany. Cubical g-components better reflect the non-linear correlation of market value distortions and latitude, in particular above the 52nd parallel.

Grid Expansion Areas

Further, this paper considers two designs of grid expansion areas, in which an annual investment limit restricts the wind power expansion. First - close to the currently implemented design[71] - this paper evaluates a single grid expansion area (*GEA1*), which covers the three coastal states of Mecklenburg-Western Pomerania (MP), Schleswig-Holstein (SH) and Lower Saxony (LS) as well as the city-states of Hamburg and Bremen). Appendix D.5 visualizes their geographical situation. Second, we subdivide this region into three grid expansion areas (*GEA3*) to assess whether further differentiation would be beneficial. The three grid expansion areas are in line with the three aforementioned federal states. The investment limit for wind power expansion within the defined grid expansion areas equals the efficient investments under nodal pricing and is given in table 5.3.

[71]The specific configuration is subject to bi-annual reviews. From 2017 to 2020, the grid expansion area limited wind power expansion within MP, SH and the Northern part of LS including the city-states of Hamburg and Bremen to 902 MW per year (cf. Lück and Moser (2019)). From 2020 on, the annual limit decreases to 786 MW and changes the spatial configuration by including also the Southern part of LS while excluding MP.

Table 5.3.: Yearly investments limit [MW/a] for the two designs of grid expansion areas

Variation name	2020	2025	2030
GEA1	646	889	1289
GEA3	LS: 436 SH: 33 MP: 177	LS: 457 SH: 220 MP: 212	LS: 441 SH: 670 MP: 178

The investment limit in *GEA1* equals the sum of the three limits in *GEA3*. Until 2030, the investment limit rises, in particular for the most Northern state of SH, due to grid investments, which improve the connection between Northern and Southern Germany. The subsequent section discusses the impact of complementing uniform prices with the aforementioned additional instrument.

5.4.2. Effects on Siting, In-Feed and System Costs

Siting of Wind Power Plants

For understanding the effects on the siting of wind power plants, figure 5.9 depicts the spatial distribution of wind power if uniform pricing is complemented with the four aforementioned instruments compared to the two pure market designs *Nodal* and *Uniform*.

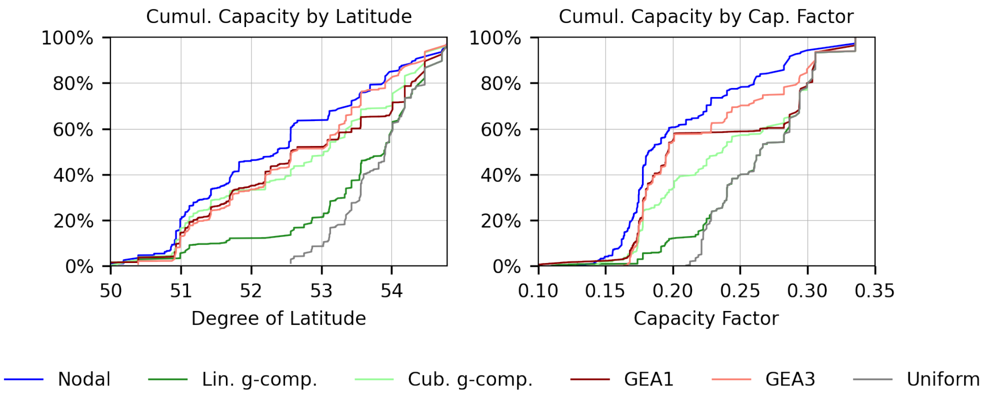

Figure 5.9.: Cumulative wind power expansion by latitude (left) and capacity factor (right) until 2030

The investment pattern with linear g-components is very similar to *Uniform*. The high distortions for very productive sites are not sufficiently internalized so that expansion in the very North of Germany hardly changes. About 50% of the installed capacity is still allocated above the 54th degree of latitude. The siting of the remaining half of investments shifts a bit southward. Cubical g-components address the distorting signals more accurately and shift the investment pattern with regard to latitude closer to the *Nodal* pattern. Looking at the investments concerning the capacity factors reveals that still very productive sites are preferred. But below the few very windy sites, cubical g-components significantly trigger investments at sites with lower capacity factors.

Under a single grid expansion area (*GEA1*), the sites with the highest capacity factors are still utilized, while the expansion stagnates between capacity factors of 20% and roughly 27%. This is intuitive: The best sites are still exploited while the investment limit prohibits to develop less attractive sites within the grid expansion area. Splitting the single grid expansion into three parts (*GEA3*) prevents such a clear cut. However, the very best wind conditions, which are also subject to the highest distortions, are still exploited. Yet, the investment pattern under *GEA3* comes close to the outcomes of nodal pricing.

Feed-In and Curtailment

Figure 5.10 depicts the impact on potential and realized in-feed as well as curtailment resulting from the changed investment pattern, i.e., it shows the difference to *Nodal*.

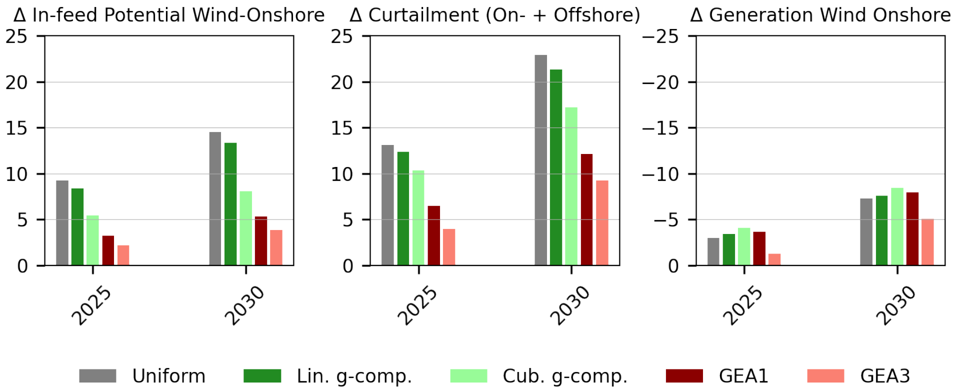

Figure 5.10.: Change in in-feed potential, curtailment and realized generation compared to *Nodal*

Under all considered market designs, the in-feed potential is higher than under nodal pricing since wind power plants are built at sites with higher capacity factors. All of the instruments also decrease curtailment compared to *Uniform*. The actual wind power in-feed is the difference between generation potential and curtailment. Compared to *Uniform*, only *GEA3* performs better and allows for higher wind power feed-in, while all other instruments slightly lower the realized compared to *Uniform*. For evaluating the efficiency of the instruments, though, wind power in-feed is not decisive. Lower grid congestion could improve the overall working of the electricity system, e.g., by allowing an efficient dispatch of conventional power plants. In particular, grid expansion areas significantly lower curtailment by prohibiting excessive wind power expansion at very productive but grid-critical sites. For evaluating whether the considered instruments avoid welfare losses through inefficient siting of wind power, the next section analyzes system costs.

System Costs

Figure 5.11 depicts the discounted increase of variable supply costs compared to the efficient benchmark (*Nodal*) for the considered market designs.

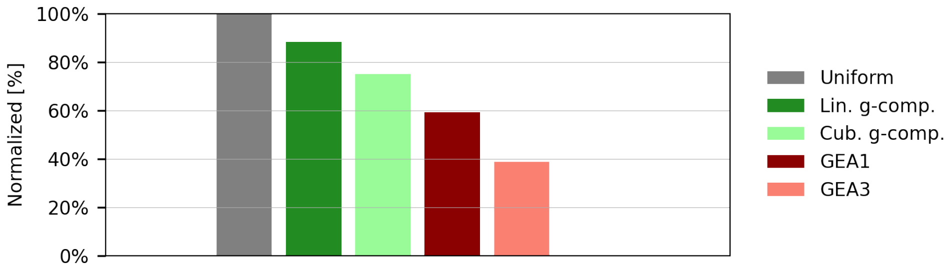

Figure 5.11.: Normalized increase of discounted additional supply costs compared to *Nodal*

Linear g-components reduce the costs increase due to uniform pricing by about 15%. Cubical g-components better reflect high distorting signals for productive sites in Northern Germany and hence drive additional costs down by about 20%. Both designs of grid expansion areas perform better than latitude-dependent g-components. A single grid expansion area (*GEA1*) cuts the welfare losses implied by uniform pricing to 60%. Yet, a further differentiation into multiple grid expansion areas (*GEA3*) leads to a significant additional welfare gain, reducing additional costs to 40% compared to pure uniform pricing.

Summing up, this paper evaluates selected designs of g-components and grid expansion areas. In general, the bandwidth of design options for these instruments is broad. Nonetheless, this paper finds that latitude-dependent g-components do not adequately reflect the distortions of uniform prices in Germany. Hence, such grid charges struggle to mitigate adverse effects from inefficient investment signals under uniform pricing. In particular, linearly dependent g-components are hardly beneficial. Grid expansion areas are superior in addressing these inefficiencies. In particular, a well-considered differentiation into several areas, which account for inter-dependencies of wind power expansion and grid congestion, can significantly lower welfare losses.

5.5. Discussion of the Methodology

This article relies on several strong assumptions, e.g., perfect foresight, no transaction costs, exogenous siting of new conventional power plants and inelastic exogenous demand.

First, future nodal prices are sensitive to other firms' actions or grid expansion decisions, while uniform prices are robust due to the market size. Ceteris paribus, investors would adjust their risk premia according to the higher risk. Second, nodal prices increase transaction costs for actors (e.g., Breuer and Moser (2014)), particularly for setting up a new market environment and corresponding regulations. Third, demand reacts to power prices, particularly in the long-term, e.g., via the siting of new industrial plants or investments into energy efficiency. The siting of conventional plants also depends on expected revenue under different market designs. All of the aspects mentioned above affect welfare gains or distributional effects of implementing nodal markets.

This paper quantifies the distorting effects of uniform pricing for the isolated problem of coordinating wind power investments with (given) grid restrictions. The derived welfare loss is rather a conservative estimation since lock-in effects in redispatch, e.g., due to scheduled trades or ramping constraints of power plants, are neglected. Widening the scope, allocating flexibility options and incentivizing optimal grid expansion is crucial for an efficient integration of RES into electricity systems. In particular, interactions between regulated grid expansion and electricity generation competition among firms are neglected.

Whether nodal prices raise market power issues (cf. Weibelzahl (2017)), or market power stems from physical realities, i.e., grid bottlenecks, and market design only determines where it unfolds (cf. Hogan (1999) or Bertsch (2015)) is beyond the scope of this paper. Zonal prices, i.e., splitting the uniform pricing market into several bidding zones, are an alternative for spatially differentiated prices (cf. Grimm et al. (2016a)). Besides spatially differentiated investment incentives, zonal pricing mitigates the inherent weakness of uniform prices to set distorted incentives for cross-border trade due to the single price signal for all neighbors. Our results suggest that a division into a Northern, a Southern and a Western zone might appropriately reflect grid congestion issues. Yet, zone configuration based on nodal prices has to be interpreted with caution and requires a more sophisticated approach. (e.g., Ambrosius et al. (2020)) Further, the interactions of the discussed policy measures on incentives for grid expansion must be considered (e.g., Ruderer and Zöttl (2018)).

5.6. Conclusion

We set up a power system model that allows for investments in electricity generators, i.e., wind power plants, and incorporates a detailed DC power flow depiction of the German transmission grid. Applying the model, this paper investigates the siting of wind power plants in Germany under nodal and uniform pricing until 2030 and its implications on the electricity system, welfare and distributional effects.

Uniform prices fail to incentivize spatial diversification of wind power expansion. Investments in wind power strongly concentrate on high wind yield sites. Since uniform prices do not reflect negative externalities on the grid, wind power expansion requires low direct subsidies and is partly even profitable without subsidies. The large market size forecloses significant cannibalization effects. Hence, wind capacities at productive but grid-hostile sites have a competitive edge in subsidy minimizing auctions, i.e., low subsidy requirements correlate strongly to low system values under uniform pricing.

Nodal pricing as the efficient benchmark shifts investments closer to load centers at the expense of lower potential wind yield. However, curtailment is cut to a third so that more wind energy is actually fed into the grid under nodal pricing when installed capacities are equal in both market designs. By harmonizing wind power expansion with grid restrictions, variable generation costs in 2030 under nodal pricing are 1.5% lower than under uniform prices only due to system-optimal wind power expansion. However, distributional effects might pose political challenges to the introduction of spatially differentiated electricity prices. Only about 25% of German electricity demand would profit from lower wholesale electricity prices, while wholesale electricity prices would increase by about 5% for densely populated and industry rich regions such as Western Germany.

If introducing nodal or zonal pricing render politically impossible due to distributional effects, additional instruments like spatially differentiated, i.e. latitude-dependent, g(enerator)-components in grid tariffs or grid expansion areas to incentivize grid-friendly siting of wind power are worth considering. This paper finds that both instruments are effective in partly mitigating the inefficient investment signals of uniform prices but their design matters. G-components, which increase linearly with the latitude, are not able to depict the distortions of uniform prices at the very productive Northern sites adequately. Cubical g-components address these distortions more accurately. However, grid expansion areas are more effective in mitigating distorted signals of uniform pricing for wind power investments. Differentiating a large grid expansion area as in the current German market design into several areas could significantly enhance the efficiency gains. Grid expansion areas though are technology-specific investment restrictions, while g-components could be generalized to include other generators such as gas power plants. Beyond generation, nodal pricing incentivizes an efficient allocation of demand and discloses information on grid bottlenecks.

Future research could extend the model to shed light on efficient integration of flexibility, such as power-to-heat applications or electrolysis plants. Implementing the grid topology of neighboring states would allow investigating inefficiencies stemming from limited possibilities for cross-border redispatch. Further, the optimal layout of price zones could be investigated by clustering nodes to price zones. Finally, including endogenous grid investments in the model allows for analyzing efficient incentives for coordinating power plant and grid investments.

A. Supplementary Material for Chapter 2

A.1. Optimization of the Firm, Lagrange Function and KKT Conditions

Assuming a perfectly competitive allowance market the optimization problem of a rational firm with perfect foresight is given as

$$
\begin{aligned}
\min \quad & \sum_{t=0}^{T} \frac{1}{(1+r)^t}[\frac{c}{2}(u-e(t))^2 + p(t)x(t)] \\
s.t. \quad & b(t) - b(t-1) - x(t) + e(t) = 0 \quad \text{for all} \quad t = 1, 2, \dots, T \\
& b(t) \geq 0 \\
& x(t),\, e(t) \gtreqless 0.
\end{aligned}
\tag{A.1}
$$

By assigning Lagrange multipliers $\lambda(t)$ and $\mu_b(t)$ to the banking flow constraint and the positivity constraints, respectively, we derive the following Lagrangian function:

$$
\begin{aligned}
&\mathcal{L}(\mathbf{x}, \mathbf{e}, \mathbf{b}, \lambda, \mu_{\mathbf{b}}) = \\
&= \sum_{t=0}^{T} \frac{1}{(1+r)^t}[\frac{c}{2}(u - e_i(t))^2 + p(t)x_i(t)] + \\
&\quad + \sum_{t=1}^{T} \lambda(t)[b(t) - b(t-1) - x(t) + e(t)] - \\
&\quad - \sum_{t=0}^{T} \mu_b(t)b(t).
\end{aligned}
\tag{A.2}
$$

As the optimization problem is convex and fulfills the Slater condition, we know that the corresponding KKT conditions are necessary and sufficient for optimality. We derive these conditions by the above Lagrangian function for all $t = 0, 1, 2, \dots, T$:

Stationarity conditions:

$$
\begin{aligned}
\frac{\partial \mathcal{L}}{\partial x(t)} &= \frac{1}{(1+r)^t} p(t) - \lambda(t) &= 0 \quad \forall\, t = 1, 2, \ldots, T && \text{(A.3)}\\
\frac{\partial \mathcal{L}}{\partial e(t)} &= (-1)\frac{1}{(1+r)^t} c(u - e(t)) + \lambda(t) &= 0 \quad \forall\, t = 1, 2, \ldots, T && \text{(A.4)}\\
\frac{\partial \mathcal{L}}{\partial b(t)} &= \lambda(t) - \lambda(t+1) - \mu_b(t) &= 0 \quad \forall\, t = 1, 2, \ldots, T. && \text{(A.5)}
\end{aligned}
$$

Primal feasibility:

$$
\begin{aligned}
b(t) - b(t-1) - x(t) + e(t) &= 0 \quad \forall\, t = 1, 2, \ldots, T && \text{(A.6)}\\
x(t),\ \ e(t) &\gtrless 0 \quad \forall\, t = 1, 2, \ldots, T. && \text{(A.7)}
\end{aligned}
$$

Dual feasibility and complementarity:

$$
\begin{aligned}
0 \le b(t) \perp \mu_b(t) &\ge 0 \quad \forall\, t = 1, 2, \ldots, T && \text{(A.8)}\\
\lambda(t) &\gtrless 0 \quad \forall\, t = 1, 2, \ldots, T. && \text{(A.9)}
\end{aligned}
$$

A.2. The Impact of Backstop Costs

Lemma *Different backstop costs do not change the level of emissions, abatement, TNAC, MSR or cancellation. Only the price path shifts up- or downwards with higher or lower backstop costs, respectively.*

Proof Let bc be some backstop costs, with corresponding cost parameter $c(t)$ and optimal emissions $e(t)$, abatement $u - e(t)$, $TNAC(t)$, $MSR(t)$ and $Cancel(t)$ and the price level $p(t)$. We know that these variables fulfill both the individual KKT conditions of the firm stated in Appendix A.1 and the regulatory conditions from sections 2.2.2 and 2.2.3.

Now let $\tilde{bc}$ be some other backstop costs. We now want to show that the individual KKT conditions from Appendix A.1 and the regulatory conditions are fulfilled for the same variables and a scaled version of the price path. From the definition of backstop costs, we know that $\tilde{c} = \frac{\tilde{bc}}{u} = \frac{\tilde{bc}}{bc}c$. We further define

$$\tilde{p}(t) := \frac{\tilde{bc}}{bc}p(t)$$
$$\tilde{\lambda}(t) := \frac{\tilde{bc}}{bc}\lambda(t)$$
$$\tilde{\mu_b}(t) := \frac{\tilde{bc}}{bc}\mu_b(t).$$

Then we can easily check that $\tilde{p}(t), \tilde{\lambda}(t)$ and $\tilde{\mu_b}(t)$ together with the unchanged quantities $e(t)$, $TNAC(t)$, $MSR(t)$ and $Cancel(t)$ satisfy all KKT conditions and regulatory market conditions. Hence they give a solution to the problem with backstop costs $\tilde{bc}$ with the same values for the quantities and a scaled price path $\tilde{p}(t)$.

■

As the lemma states, the concrete parameter of the cost function does not affect the underlying mechanisms of the EU ETS. Only the absolute price level changes with $\frac{\tilde{p}(t)}{p(t)} = \frac{\tilde{bc}}{bc}$. The lemma also holds true for other definitions of c as long as $c \cdot u$ is not affected by the change of the backstop costs. In particular it also holds true for time dependent $u(t)$ and $c(t)$ as long as $u(t) \cdot c(t)$ is not affected.

A.3. Effect of the CM with a Reduced LRF

In Figure A.1 we compare the effect of a CM with the amended LRF of 2.2% to the effect of a CM given the pre-reform intake rate of 1.74%. The results indicate that the CM only slightly decreases emissions and increases prices in the short run. The change in the LRF however, is the main price driver and responsible for the long-run emission reduction.

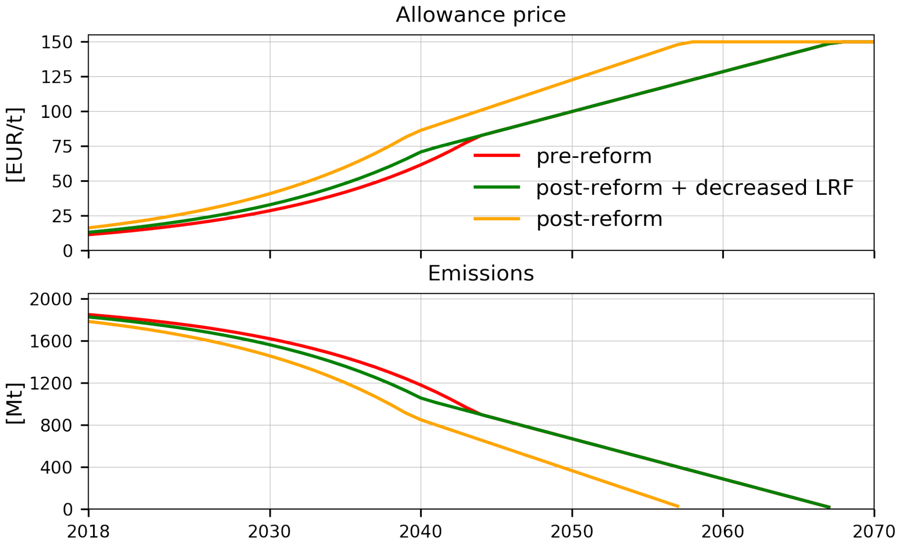

Figure A.1.: Effect of the CM

B. Supplementary Material for Chapter 3

B.1. Parametrization and EU ETS Rules

Table B.1 provides an overview of the chosen parametrization in the base scenario.

Table B.1.: Overview of the model parametrization

Parameter	Value	References
Linear reduction factor $lrf(t)$	1.74% until 2020, 2.2% afterwards based on emissions of 2199 Mt in 2005	Current regulation[72]
Auction share	57% of issued allowances	Current regulation
MSR intake threshold	ℓ_{up}=833 Mt	Current regulation
MSR intake rate $\gamma(t)$	Reduction of auction volume by 24% of TNAC volume until 2023, 12% afterwards	Current regulation
MSR reinjection threshold	ℓ_{low}=400 Mt	Current regulation
MSR reinjection tranches	R=100 Mt	Current regulation
Cancellation Mechanism	Active from t=2023 onward	Current regulation
Initial endowment MSR	MSR(t_0)=1500 million (900 million backloaded, 600 million unallocated in 2020)	European Parliament and the Council of the European Union (2015), European Commission (2015)
Initial endowment TNAC	$b(t_0)$=1647 million , TNAC (2018)	European Commission (2018)

[72] cf. European Parliament and the Council of the European Union (2018), European Parliament and the Council of the European Union (2015), European Commission (2018), European Commission (2015)

Discount rate	$r = 6\%$	Similar to Quemin and Trotignon (2018) or Schopp et al. (2015)
Baseline emissions	$u(t) = 2150Mt$	In the range of literature assumptions of 1800 - 2200 Mt, e.g. Perino and Willner (2016) or Schopp et al. (2015).
Backstop costs	150 EUR/t	Best estimates for CCS costs, cf. Saygin et al. (2012) and Kuramochi et al. (2012).
Cost parameter	$c(t) = \frac{c_{backstop}}{u(t)} = 0.0698 \cdot 10^{-3}$ EUR/t^2	cf. Bocklet et al. (2019)
MAC curvature	$\alpha = 1.35$	Calibrated to observed slope (cf. Quemin and Trotignon (2018)).

B.2. Rules for the Intake, Reinjection and Cancellation

A predefined share of allowance supply ($S(t)$) is auctioned off (S_{auct}) while the rest is allocated for free (S_{free}). Overall allowance supply decreases year by year according to the linear reduction factor ($a(t)$):

$$S(t) = S_{auct}(t) + S_{free}(t) \tag{B.1}$$

$$S_{auct}(t) = auction\_share(1 - \sum_{t=0}^{t} lrf(t)) \cdot S(0) + Reinjection(t) - Intake(t) \tag{B.2}$$

$$S_{free}(t) = (1 - auction\_share) \cdot (1 - \sum_{t=0}^{t} lrf(t))S(t_0) \tag{B.3}$$

TNAC volume:

$$b(t) = b(t-1) + S(t) - e(t) \tag{B.4}$$

MSR volume:

$$MSR(t) = MSR(t-1) + Intake(t) - Reinjection(t) - Cancel(t) \tag{B.5}$$

Rules for MSR intake, reinjection and cancellation mechanism:

$$Intake(t) = \begin{cases} \gamma(t) \cdot TNAC(t-1) & \text{if } TNAC(t-1) \geq \ell_{up}, \\ 0 & \text{else}, \end{cases} \tag{B.6}$$

$$Reinjection(t) = \begin{cases} R & \text{if } TNAC(t-1) < \ell_{low} \wedge MSR(t) \geq R, \\ MSR(t) & \text{if } TNAC(t-1) < \ell_{low} \wedge MSR(t) < R, \\ 0 & \text{else}, \end{cases} \tag{B.7}$$

$$Cancel(t) = \begin{cases} MSR(t) - S_{auct}(t-1) & \text{if } MSR(t) \geq S_{auct}(t-1), \\ 0 & \text{otherwise}. \end{cases} \tag{B.8}$$

B.3. Results of the Base Scenario under Myopia

Myopic firms have a limited planning horizon H and hence do not anticipate information beyond $t + H$. Figure B.1 visualizes market outcomes for the base scenario under myopic-decision making, namely planning horizons of 5,10 or 20 years, respectively, and compares them to the results under perfect foresight.

Under myopia, firms do not anticipate future allowance scarcity at the beginning. As a result, the initial carbon price drops with shortening planning horizons. Consequently, emissions increase, TNAC and MSR volumes decrease in the short term, resulting in lower cancellation.

Progressing in time, myopic firms update their information and adjust their behavior accordingly. Under myopia, the lower initial banking efforts amplify allowance scarcity in the long run. As a result, prices increase stronger for myopic decision-making. Under perfect foresight, firms choose the optimal abatement path, where prices develop over the whole time-span according to the Hotelling rule stated in equation 3.3. Shortsighted firms ex-ante plan their abatement according to Hotelling within the planning horizon. When time passes and more information becomes available, they adjust the price according to the increased allowance scarcity. As a result, the (ex-post) price development deviates from Hotelling.

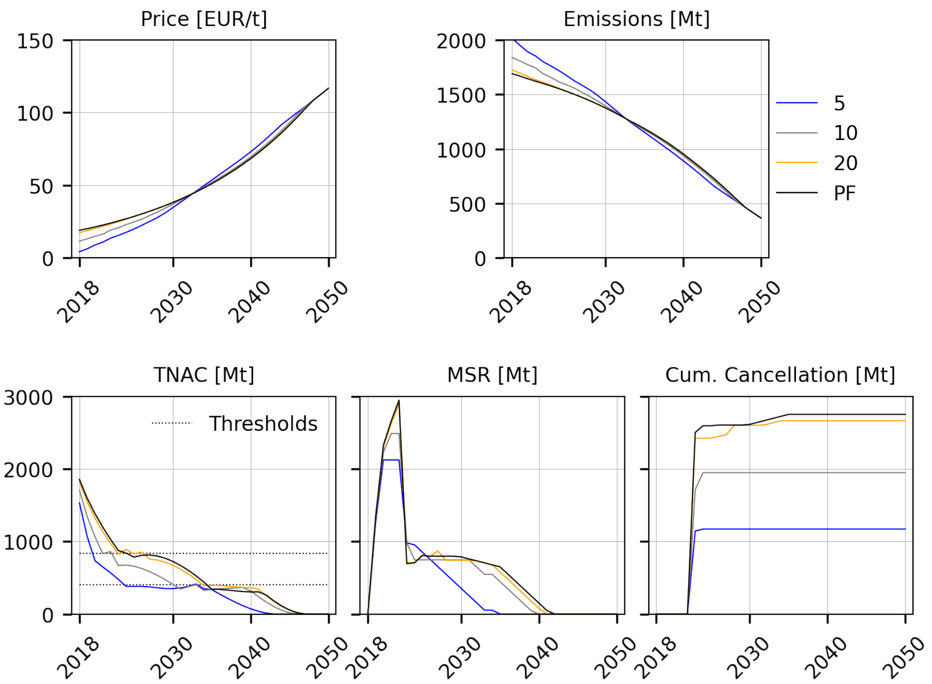

Figure B.1.: Market outcomes for the base scenario under myopia (for planning horizons of 5,10 and 20 years) and under perfect poresight (PF)

C. Supplementary Material for Chapter 4

C.1. The Power Market Model DIMENSION

Table C.1 presents the notation used within this paper. Capitalized terms represent endogenous decision variables. Lower case terms denote exogenous parameters.

Table C.1.: Sets, parameters and variables

Sets		
$i \in I$		Electricity generation and storage technologies
$m, n \in M$		Countries
$y \in Y$		Years
$t \in T$		Representative time steps
Parameters		
$d(y,t,m)$	[MWh]	Electricity demand
r	[-]	Discount rate
$avail(y,t,m,i)$	[-]	Availability of electr. generation
$ntc(y,m,n)$	[MW]	Net transmission capacity
$\eta(i)$	[MWh/MWh_th]	Generation efficiency
$\delta(y,i)$	[EUR/MW]	Annualized investment cost
$\sigma(i)$	[EUR/MW]	Fixed operation and maintenance cost
$\gamma(y,i)$	[EUR/MWh]	Variable fuel cost
$\tau(y)$	[EUR/tCO2eq]	Carbon price
$\nu(i)$	[tCO2eq/MWh_th]	Fuel-specific emission factor
$cap_{add,min}(y,m,i)$	[MW]	Existing or under construction capacity
$cap_{sub,min}(y,m,i)$	[MW]	Decommissioning due to lifetime or policy
$l(m,n)$	[-]	Relative transmission losses
Variables		
$CAP(y,m,i)$	[MW]	Electricity generation capacity
$GEN(y,t,m,i)$	[MWh]	Electricity generation
$EM(y,t,m,i)$	[tCO2eq]	Emissions
$CAP_{add}(y,m,i)$	[MW]	Investments in electr. generation capacity
$CAP_{sub}(y,m,i)$	[MW]	Decommissioning of electr. generation capacity
$TRADE(y,t,m,n)$	[MWh]	Trade flow of electr. from m to n
TC	[EUR]	Total costs
$FC(y)$	[EUR]	Invest and fixed operation & maintenance costs
$VC(y)$	[EUR]	Variable generation costs

The central planner minimizes total discounted costs for serving the electricity demand. Consequently, she decides on the investment in capacity and the dispatch of power plants. The total discounted costs consist of fixed (FC) and variable (VC) costs, i.e.,

$$TC = \sum_{y \in Y} (1+r)^{-(y-y_0)} \cdot [FC(y) + VC(y)], \tag{C.1}$$

where the fixed costs per year comprise the annualized investment costs and the fixed operation and maintenance costs for installed capacity. The variable costs embody generation-dependent costs, namely for fuel and emission allowances.The installed capacity of electricity generators develops endogenously according to equation C.2.

For a realistic depiction of European energy markets, equations C.3 and C.4 account for existing as well as under construction capacities ($cap_{add,min}$) and decommissioning due to end-of-lifetime or technology bans ($cap_{sub,min}$). Equation C.5 formally defines the fixed costs.

$$CAP(y,m,i) = CAP(y-1,m,i) + CAP_{add}(y,m,i) + CAP_{sub}(y,m,i) \tag{C.2}$$

$$CAP_{add}(y,m,i) \geq cap_{add,min}(y,m,i) \tag{C.3}$$

$$CAP_{sub}(y,m,i) \geq cap_{sub,min}(y,m,i) \tag{C.4}$$

$$FC(y) = \sum_{\substack{\tilde{y}: \\ y-\tilde{y}<lifetime(i)}} CAP_{add}(\tilde{y},m,i) \cdot \delta(\tilde{y},i) + \sum_{m \in M, i \in I} CAP(y,m,i) \cdot \sigma(i) \tag{C.5}$$

Further, technical constraints restrict the dispatch of installed capacities. First, for every time step, electricity generation has to balance the inelastic demand adjusted by the trade flows from and to neighboring countries (Equation C.6). Second, electricity generation of each technology and in each time step is bound by the available capacity (Equation C.7). The availability factor accounts for maintenance shutdowns of conventional power plants or the infeed profile of renewable energy. The trade flows are restricted by the net transfer capacities between countries and have to be symmetric, i.e., exports from m to n are imports from n to m (Equations C.8 and C.9). Variable costs comprise fuel costs and costs for emissions (Equation C.10). The former is calculated as the product of generation per technology and the technology-specific variable fuel costs. The latter is the product of the carbon price and realized emissions which are calculated through the fuel input and the fuel-specific emission factor (Equation C.11).

$$\sum_{i\in I} GEN(y,t,m,i) = d(y,t,m) + \sum_{n\neq m}(1-l(m,n))\cdot[TRADE(y,t,m,n)-TRADE(y,t,n,m)] \tag{C.6}$$

$$GEN(y,t,m,i) \leq avail(y,t,i)\cdot CAP(y,m,i) \tag{C.7}$$

$$TRADE(y,t,m,n) \leq ntc(y,m,n) \tag{C.8}$$

$$TRADE(y,t,m,n) = -TRADE(y,t,n,m) \tag{C.9}$$

$$\forall y \in Y, m,n \in M,\ i \in I$$

$$VC(y) = \sum_{m\in M, i\in I}\sum_{t\in T}[GEN(y,t,m,i)\cdot\gamma(y,i) + EM(y,t,m,i)\cdot\tau(y)] \tag{C.10}$$

$$EM(y,t,m,i) = GEN(y,t,m,i)\cdot\frac{\nu(i)}{\eta(i)} \tag{C.11}$$

The presented equations constitute the core functionality of DIMENSION: The objective function in equation C.1 is minimized over the feasible region, which is defined by the constraints C.2-C.11.

Moreover, the model incorporates features such as ramping and storage constraints as well as area restrictions for RES. For a thorough introduction of DIMENSION and its characteristics, the reader is referred to Richter (2011).

C.2. Numerical Assumptions

Table C.2.: Technological learning regarding investment costs [EUR/kW], based on the World Energy Outlook 2019 (IEA (2019))

Technology	Status quo	Near Future	Far Future
Wind Onshore	1580	1503	1430
Wind Offshore	3985	3038	2600
PV (roof)	883	688	580
PV (base)	750	585	480
OCGT	412	412	412
CCGT	900	900	900

Table C.3.: Considered technologies and their techno-economic characteristics based on Knaut et al. (2016) and Peter (2019)

Technologies	Efficiency	Fixed Operation Costs (EUR/kWa)
Nuclear	0.33	101 - 105
Lignite	0.32 - 0.46	45 - 60
Coal	0.37 - 0.46	40 - 60
Combined Cycle Gas Turbines (CCGT)	0.39 - 0.60	24 -30
Open Cycle Gas Turbines (OCGT)	0.28 - 0.40	12 - 17
Oil	0.4	7
Biomass	0.3	120
PV	1	15 - 17
Wind Onshore	1	13
Wind Offshore	1	93
Hydro	1	11.5
Pumped Storage	0.76	11.5

Table C.4.: Assumptions on fuel prices [EUR/MWh_{th}]

Fuel	Price
Uranium	3
Lignite	3
Coal	10
Natural Gas	20
Oil	33

Table C.5.: Assumed electricity demand per country [TWh], based on 2019 levels according to ENTSO-E (2020)

Country	Demand	Country	Demand
AT	67	IE	29
BE	85	IT	307
BG	32	LT	12
CH	62	LV	7
CZ	63	NL	114
DE	530	NO	128
DK	35	PL	156
EE	8	PT	49
ES	248	RO	52
FI	86	SE	132
FR	456	SI	14
GR	51	SK	28
HR	17	UK	263
HU	41		

C.3. Impact of Fuel Prices on Short-term MAC Curves

Figure C.1 depicts the impact of different gas prices (10, 20 or 30 EUR/MWh$_{\text{th}}$) on short-term MAC curves, i.e., if no investments are possible.

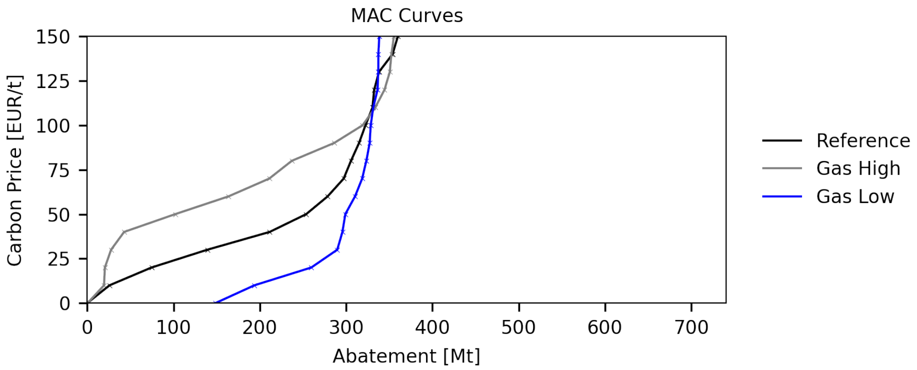

Figure C.1.: Short-term MAC curves for different coal/gas price spreads

The lower part of the MAC curve reflects the margin between coal and gas prices. Under lower gas prices, modern gas power plants replace inefficient coal generation even without a carbon price signal. Higher gas prices have the opposite effect. Only below 10 EUR/t, higher gas prices do not impact fuel switching as the margin between coal and gas is not closed by such low carbon prices. The upper part of the MAC curve is similar since the fuel-switching potential is reached independently of the gas price. Only minor shifts in the dispatch of, e.g., biomass affect the MAC curve.

D. Supplementary Material for Chapter 5

D.1. Notation

Throughout the paper at hand, the notation presented in Table D.1 is used. To distinguish (exogenous) parameters and optimization variables, the latter are written in capital letters.

Table D.1.: Sets, parameters and variables

Sets		
$i \in I$		Electricity generation and storage technologies
$m, n \in M$		Markets
$l \in L$		Transmission Grid Lines
$c \in C$		Linear independent cycles of modelled grid
$y, y1 \in Y$		Years
$t \in T$		Representative timesteps
Parameters		
$d(y,t,m)$	[MWh]	Electricity demand
$avail(y,t,m,i)$	[-]	Availability of electricity generation technology
$linecap(y,m,n)$	[MW]	Available transmission capacity
$\beta(y)$	[-]	Discount factor
$\delta(y,i)$	[EUR/MW]	Annualized investment cost
$\sigma(i)$	[EUR/MW]	Fixed operation and maintenance cost
$\gamma(y,i)$	[EUR/MWh]	Variable generation cost
$cap_{add,min}(y,m,i)$	[MW]	Capacities under construction
$cap_{sub,min}(y,m,i)$	[MW]	Decommissioning of capacity due to lifetime or policy bans
$l(m,n)$	[-]	Relative transmission Losses
$\kappa(m,l)$	[-]	Incidence matrix
$\phi(l,c)$	[-]	Cycle matrix
Variables		
$CAP(y,m,i)$	[MW]	Electricity generation capacity
$GEN(y,t,m,i)$	[MWh]	Electricity generation
$CAP_{add}(y,m,i)$	[MW]	Investments in electricity generation capacity
$CAP_{sub}(y,m,i)$	[MW]	Decommissioning of electricity generation capacity
$TRADE(y,t,m,n)$	[MWh]	Electricity trade from m to n
$TRADE\_BAL(y,t,m)$	[MWh]	Net trade balance of m
$FLOW(y,t,l)$	[MWh]	Power flow along line l
TC	[EUR]	Total costs
$FC(y)$ / $VC(y)$	[EUR]	Yearly fixed or variable costs

D.2. Regional Scope: Germany's Transmission Network and Neighbors

Figure D.1 visualizes the regional scope. Within Germany, this paper considers a detailed depiction of the transmission network. Connections to neighbors are approximated via Net Trade Capacities (NTC).

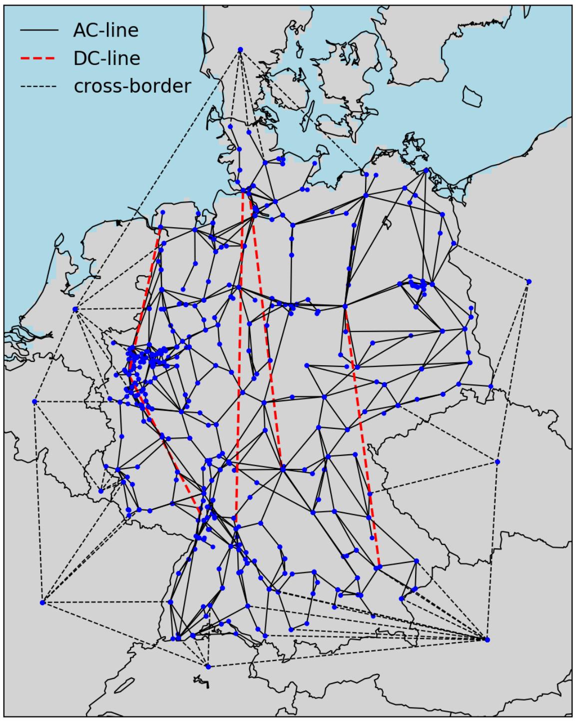

Figure D.1.: Regional scope and considered grid topology in 2030

D.3. Assumptions on Investment Costs, Demand and Fuel Prices

Table D.2.: Development of investment costs [EUR/kW] for onshore wind power plants based on The Boston Consulting Group and Prognos (2018)

Technology	2020	2025	2030
Wind Onshore	1200	1150	1100

Table D.3.: Considered technologies and their techno-economic parameters, assumptions based on scenario *Stated Policies* in World Energy Outlook 2019 (IEA (2019)) and Knaut et al. (2016)

Technologies	Efficiency	Fixed Operation Costs (EUR/kW/a)
Nuclear	0.33	85
Lignite	0.4	45
Coal	0.45	45
Combined Cycle Gas Turbines (CCGT)	0.5	25
Open Cycle Gas Turbines (OCGT)	0.38	15
Oil	0.4	7
Biomass	0.3	150
PV	1	17
Wind Onshore	1	12
Wind Offshore	1	93
Hydro	1	11.5
Pumped Storage	0.78	11.5

Table D.4.: Development of fuel and carbon prices [EUR/MWh_{th}], based on scenario *Stated Policies* in World Energy Outlook 2019 (IEA (2019))

Fuel	2019	2020	2025	2030
Uranium	3.0	3.0	3.0	3.0
Lignite	3.9	4.2	5.6	5.6
Coal	7.9	8.1	9.1	9.3
Natural Gas	13.6	15.2	23.2	23.2
Oil	33.1	34.7	42.3	45.9
Biomass	21.0	22.0	22.5	23.0
Carbon [EUR/tCO2]	24.9	26.2	35.5	38.8

Table D.5.: Development of demand [TWh], based on scenario *National Trends* in ENTSO-E (2018) and *Scenario B* in 50Hertz et al. (2019))

Country	2019	2020	2025	2030
AT	67	69	77	79
BE	85	85	87	91
CH	62	62	62	61
CZ	63	65	73	78
DE	530	529	528	544
DK	35	38	52	46
FR	456	463	496	486
NL	114	114	114	119
PL	156	160	181	182

D.4. Trade Flows

The modeled trade flows underlie three simplifications which are necessary to keep the model tractable: First, the age structure of national power plants fleets is not considered. Second, interconnectors are depicted as NTC constraints without power flow restrictions. Third, other countries than German neighbours are not in the scope of this paper. Due to these shortcomings, the derived trade flows are not realistic. The derived patterns among the three scenarios, however, shed light on the impact of market design on electricity trade between Germany and its neighbours. Figure D.2 visualizes German net imports in the years 2020 and 2030.

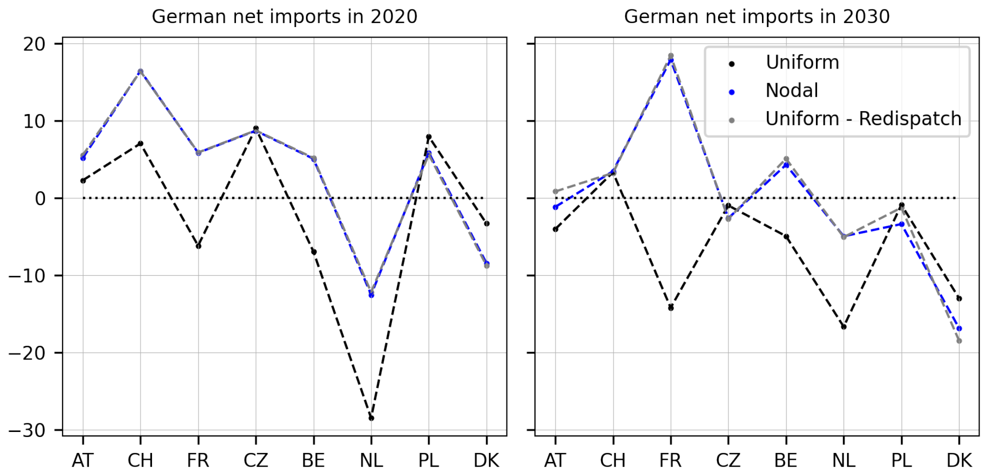

Figure D.2.: Trade between Germany and its neighbour countries in 2020 and 2030

In general, uniform prices trigger higher exports in all directions. Nodal prices incentivize, in particular in Southern and Western Germany, higher imports while exports to Denmark increase. The difference in trade between nodal and uniform prices can be observed best at the example of France. Instead of significant net export under uniform pricing, optimal dispatch under nodal pricing requires high net imports in 2030.

D.5. North-German Federal States

Figure D.3 visualizes the three most Northern federal states of Germany.

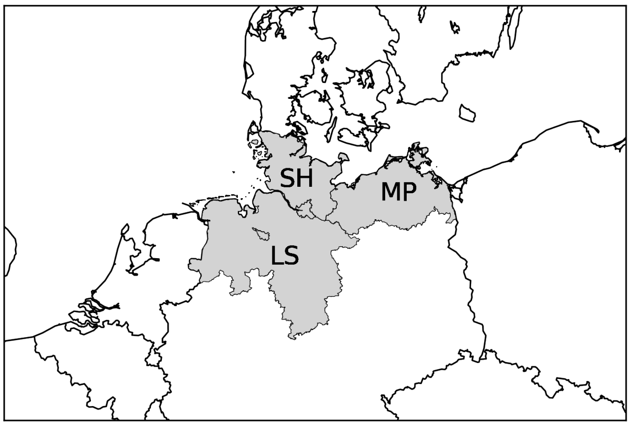

Figure D.3.: The area of the federal states of Mecklenburg-Western Pomerania (MP), Schleswig-Holstein (SH) and Lower Saxony (LS)

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Curriculum Vitae

CURRICULUM VITAE

Lukas Schmidt

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RESEARCH INTERESTS

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10/2010 - 10/2014	**RWTH Aachen University** Bachelor of Science in Mechanical Engineering and Business
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LANGUAGES

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PUBLICATIONS

Articles in Peer-Reviewed Journals:

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- J. Bocklet, M. Hintermayer, L. Schmidt, T. Wildgrube (2019). The Reformed EU ETS – Intertemporal Emission Trading with Restricted Banking. *EWI Working Paper* 19/04.
- L. Schmidt, J. Zinke (2020). One price fits all? – Wind power expansion under uniform and nodal pricing in Germany. *EWI Working Paper* 20/06.
- L. Schmidt (2020). Puncturing the Waterbed or the New Green Paradox? – The Effectiveness of Overlapping Policies in the EU ETS Under Perfect Foresight and Myopia. *EWI Working Paper* 20/07.
- M. Hintermayer, L. Schmidt and J. Zinke (2020). On the time-dependency of MAC curves and its implications for the EU ETS. *EWI Working Paper* 20/08.

Further Publications:

- S. Lorenczik, M. Gierkink, L. Schmidt., O. Hennes, C. Rehtanz, M. Greve, U. Häger, C. Wagner, M. Tretschok (2018). Kosteneffiziente Umsetzung der Sektorenkopplung. (*Cost-efficient Realization of Sector Coupling.*) *EWI study on behalf of the Ministry of Economic Affairs, Innovation, Digitalisation and Energy of the State of North Rhine-Westphalia.*
- K. Siala, M. Miers, L. Schmidt., L. Torralba-Diaz, S. Sheykkha, G. Savvidis (2020). Which model features matter? An experimental approach to evaluate power market modeling choices. *preprint arXiv:2010.16142.*

PRESENTATIONS AND TALKS

- Implikationen der Koordination von Ladevorgängen (*Implications of Coordinated EV Charging.*) *EWI Energy Conference.* November 2017. Cologne.
- The Reformed EU ETS – Assessing Shocks and Overlapping Policies in the EU ETS – Can the reform live up to its promises? *16th IAEE European Conference.* August 2019. Ljubljana, Slovenia.
- One price fits all? Wind power expansion under uniform and nodal pricing in Germany. (accepted but postponed due to COVID-19). *16th IAEE International Conference.* June 2020. Paris, France.