An efficient mechanism for cross-border support of renewable electricity in the European Union

Sebastian Busch
Fakultät für Elektrotechnik und Informationstechnik
Technische Universität Wien

This dissertation is submitted for the degree of

- Dr. rer. soc. oec. -
Doktor der Sozial- und Wirtschaftswissenschaften

Supervisor: Prof. Dr. Reinhard Haas (TU Wien)
Reviewer: Prof. Karsten Neuhoff, Ph.D. (DIW Berlin, TU Berlin)
Reviewer: Prof. Dr. Mario Ragwitz (Fraunhofer ISI, Universität Freiburg)

Wien, Februar 2017

I would like to dedicate this thesis to my parents Regine Busch and Siegfried Busch

Declaration

Hiermit erkläre ich, dass ich diese Arbeit selbständig verfasst habe, dass ich die verwendeten Quellen und Hilfsmittel vollständig angegeben habe und dass ich die Stellen der Arbeit - einschließlich Tabellen, Karten und Abbildungen -, die anderen Werken oder dem Internet im Wortlaut oder dem Sinn nach entnommen sind, auf jeden Fall unter Angabe der Quelle als Entlehnung kenntlich gemacht habe.

I hereby declare that except where specific reference is made to the work of others, the contents of this dissertation are original and have not been submitted in whole or in part for consideration for any other degree or qualification in this, or any other University. This dissertation is the result of my own work and includes nothing which is the outcome of work done in collaboration, except where specifically indicated in the text.[1]

Sebastian Busch
Wien, Februar 2017

[1] An excerpt of the contents of this thesis intended to address a policy audience has been pre-published as policy paper within the Towards 2030 research project (Busch et al., 2016). The LaTeX template which has been used and modified for this thesis is provided by Krishna Kumar under the MIT License.

Acknowledgements

The preparation of this thesis is indivisible linked to my work at the Energy Economics Group, Vienna University of Technology (TU Wien) over the past seven years. During this time I had the opportunity to participate in exciting research projects, develop as a scientist and lecturer, make new friendships and experience many fun moments. I wish the group to keep on with the high performance :-)

Next I would like to mention my work at the International Institute for Applied Systems Analysis (IIASA) that I will also continue in the post PhD era and at the German Advisory Council on Global Change (WBGU). I have perceived the exchange across-disciplines I had there and the many good interactions with colleagues that offered me new insights to be very enriching and also as valuable in order to reflect on my thesis.

At both TU Wien and IIASA / WBGU I had the opportunity to directly work at the science-policy interface, which I truly enjoyed. Various conferences and seminars that I was given the possibility to attend and my research stay at the Energy Analysis Department of Lawrence Berkeley National Laboratory helped me to deepen my understanding of different topics in energy economics and to get connected with interesting people in my research field. During all these activities also several good friendships emerged. To all the friends and colleagues who supported me on this way and made it such an enjoyable time goes a big thank you! Several people however deserve special mentioning.

First I would like to thank the members of my thesis committee. Reinhard Haas, for being an excellent supervisor and for providing me with the right mix of freedom to explore my own research interests, as well as guidance and encouragement when I needed it to stay on track. Karsten Neuhoff and Mario Ragwitz for serving as reviewers of my thesis, and what´s more for being friendly colleagues and for inspiring me both as researcher and as person throughout the last years. It was also Mario who initially encouraged me to explore the research question of my thesis.

The next big thank you I owe to the head of my working group at TU Wien Gustav Resch for all his kind support along the way, for his guidance, for giving me the opportunity to work in exciting projects and introducing me into a network of wonderful colleagues at other institutes and for giving me the freedom and opportunities to embark on the research endeavors of my choice.

I would moreover like to thank André Ortner with whom I last shared office at TU Wien. Our many discussions and his advice were immensely helpful for me in writing this thesis. I also enjoyed a lot all our common activities inside and outside the energy arena and appreciate our friendship. Without you it would not nearly have been as much fun.

At IIASA I would in particular like to thank Nebojsa Nakicenovic and Pat Wagner for their continuous, friendly support, for the breadth of opportunities offered to me and Naki for giving me the possibility to work with him at the WBGU for five years.

Thanks go also to Roman Mendelevitch for supporting me in the development of the electricity market model, for always being available to discuss questions with me and give advice, for having me as a guest in Berlin during my short term research stay at the German Institute for Economic Research and for our good friendship.

Finally, but no less importantly, I thank my family and friends - I am very glad to have you all in my life Annika, Christiane, Gisela, Kate, Korinna, Kristian, Linda, Marius, Olivia, Simone, Thomas, Werner and all my dears I have not mentioned here personally. A special thanks goes to my parents, who are always there for me and who have always encouraged me to follow my interest and provided me with the opportunities to do so.

Abstract

In this thesis I propose and develop a new mechanism for cross-border support of renewable electricity generating capacity in the European Union. The ability to exchange renewable electricity generating capacity between European Union Member States improves the welfare of all Member States since potentials and demands for renewable electricity capacity vary across the European Union. This notion is reflected in the promotion of so called cooperation mechanisms in the renewable energy directive (European Council and European Parliament, 2009). The existing mechanisms appear, unfortunately, to be insufficient to facilitate the efficient level of trade in capacity across the European Union; only a small quantity of energy is expected has been subject to cooperation mechanisms. In this thesis I identify several characteristics of the market for renewable electricity capacity that contribute to the failure of the market as is and the mechanism is designed in a way to overcome these failures.

The new mechanism consists of two main elements: (i) a cross-border impact factor that indicates the spill-overs of benefits between Member States induced from additional renewable electricity generating capacity; and (ii) an European Union wide cross-border auction in which Member States and generators of renewable electricity bid to buy, respectively to supply additional renewable electricity generating capacity and the auctioneer offers to serve that set of bids, which maximizes net surplus. In the auction the cross-border impact factor is used to spatially weight and disaggregate each Member State's offer bids for renewable electricity generating capacity for each suitable location in the European Union. Through a slight modification of the auction design the mechanism could be extended to also function as an European Union instrument that not only facilitates cross-border support, but also can be used to "fill" a possible gap with respect to some given European Union renewable energy sources target trajectory. Such an option is explicitly listed in the European Commissions's proposal on the governance of the Energy Union (European Commission, 2016a).

When testing the design of the mechanism in a numerical application at European Union level and comparing it against two alternative reference cases I find that it offers significant potential for efficiency gains. In comparison to a case of solely national

support of renewable electricity capacities the mechanism would increase economic efficiency about 20 percent. The mechanism also performs superior in comparison to a case where renewable electricity capacity is allocated across Europe such that the cumulative expansion costs would be minimized. The reason is that the mechanism explicitly considers impacts in terms of benefits, respectively avoided opportunity costs of alternative allocations.

Kurzfassung

Im Rahmen dieser Dissertation entwickele Ich einen neuen Mechanismus zur grenzüberschreitenden Förderung erneuerbarer Stromerzeugungskapazitäten in der Europäischen Union. Die sogenannten Kooperationsmechanismen, welche Bestandteil der Erneuerbare-Energien-Richtlinie (European Council and European Parliament, 2009), bieten Mitgliedsstaaten die Möglichkeit beim Ausbau erneuerbarer (Strom-) Erzeugungskapazitäten zu kooperieren. Die zu Grunde liegende Idee ist, dass der Handel mit erneuerbaren Stromerzeugungskapazitäten wohlfahrtssteigernd ist, da die Potentiale und die Nachfrage innerhalb der Europäischen Union ungleich verteilt sind. Die bestehenden Mechanismen erscheinen jedoch, aufgrund zahlreicher Charakteristika des Marktes für erneuerbare Stromerzeugungskapazitäten, ungeeignet, einen effizienten Handel anzureizen. Das Design, des von mir vorgeschlagenen Mechanismus, ist explizit darauf ausgelegt, die bestehenden Defizite zu überwinden.

Der neue Mechanismus hat zwei Hauptbestandteile: (i) Ein Faktor, der die grenzüberschreitende Verteilung des Nutzens von erneuerbarer Stromerzeugungskapazität signalisiert, welche in einem Mitgliedsstaat bereitgestellt wird; und (ii) eine Unionsweite grenzüberschreitende Auktion in welcher Mitgliedsstaaten und erneuerbare Stromerzeuger Preise bieten, welche ihre Zahlungsbereitschaft für, bzw. ihre Kosten für einen zusätzlichen Ausbau erneuerbarer Stromerzeugungskapazitäten signalisieren, und der Auktionator, diejenigen Gebote auswählt, welche die Wohlfahrt maximieren. Dabei werden die Preise , welche von den Mitgliedsstaaten geboten werden, durch den grenzüberschreitenden Faktor räumlich aufgelöst gewichtet, so dass die Zahlungsbereitschaft eines Mitgliedstaates für den Zubau erneuerbarer Stromerzeugungskapazität an einem bestimmten Ort in der Union in Relation zu dessen Zufluss an Nutzen von diesem Ort steht. Eine erweiterte Funktionalität des Mechanismus besteht darin, dass die Auktion auch dazu benutzt werden kann eventuelle Fehlmengen zu beschaffen die dazu benötigt werden, das von der Europäischen Kommission anvisierte 2030 Ziel für erneuerbare Energien zu erreichen (European Commission, 2016a).

Eine numerische Anwendung des Mechanismus am Beispiel der Europäischen Union zeigt auf, dass signifikante Effizienzpotentiale gehoben werden können. Im Vergleich

zu einem Referenzfall, bei dem der Zubau von erneuerbaren Stromerzeugungskapazitäten nur national gefördert wird, könnte die ökonomische Effizienz um 20 Prozent gesteigert werden. Der Mechanismus ist hinsichtlich ökonomischer Effizienz auch gegenüber weiteren Referenzfall im Vorteil, bei dem der Zubau von erneuerbaren anhand der kostenminimalen Potentiale erfolgt. Der Grund dafür ist, dass bei einer reinen Kostenminimierung des Zubaus die Zahlungsbereitschaft der Mitgliedsstaaten, und damit implizit deren erzielte Nutzen, keine Berücksichtigung finden, wohingegen der Mechanismus den besten Kompromiss aus minimierten Kosten und erzielten Nutzen implementiert.

Contents

List of Figures

List of Tables

Chapter 1

Introduction

1.1 Introduction

Energy generation from renewable energy sources (RES) has experienced significant growth rates globally more in recent years; this regards in particular sources for renewable electricity (RES-e) generation and among those in particular the ones with variable output, such as wind and solar. The year 2015 has seen the largest global capacity additions to date, with 147 GW of renewable power capacity being added yielding a total of 785 GW and 38 GW_{th} renewable heating capacity being added yielding a total of 435 GW_{th} (REN 21, 2016)[1]. Even though energy generation from RES is becoming more and more cost competitive these capacity additions to a large extent were driven by support policies, which in 2015 have been implemented in 173 countries globally. The motivation to transform energy systems towards RES generation was initially spurred during the oil crises in the 1970s, but diminished again after oils prices had dropped to pre-crisis levels. It however gained new momentum at the beginning of the 1990s in particular in Europe when several countries introduced RES support policies mainly due to environmental concerns. Also during the 1990s the European Commission (EC) started to adopt measures in order to implement RES policies at an European Union (EU) wide level. The first target for RES deployment at EU level, which mandated to increase the share of RES in primary energy consumption from 5.4 percent to 12 percent between 1997 and 2010 was published in a white paper by the European Commission (1997) and was later on substantiated by two directives, which foresaw requirements for Member States to introduce RES support policies. Since then the policy framework for RES at EU level has been shaped continuously, in particular support policies for RES-e

[1]These numbers do not include biomass that accounts for the highest portion of renewable heating capacity

have been geared towards a stronger market orientation. The current framework for RES is given by directive 2009/28/EC (European Council and European Parliament, 2009), which entered into force in June 2009, and which established a binding target of 20 percent RES in the gross final consumption of energy at EU level. The 20 percent target is translated into binding national targets for the EU Member States; the biofuels target is translated into a 10 percent RES target in the final consumption of transport energy that applies to each Member State individually Klessmann, C.B. (2012). A new element that has been introduced to the RES directive are different types of cooperation mechanisms which may be used by Member States to statistically transfer RES target shares or to achieve their targets jointly. The aim of introducing these cooperation mechanisms is to allow for a better exploitation of low-cost RES potentials across Europe and a more cost-efficient RES target achievement at EU level (Klessmann, C.B., 2012). Due to several barriers and shortcomings the existing mechanisms appear, unfortunately, to be insufficient to facilitate the efficient level of trade in RES-e capacity across the EU; only Sweden and Norway have made use of the mechanisms so far. Additional advocacy for using the cooperation mechanisms has come from the state aid guidelines for environmental protection and energy that call on the Member States to make better use of these cooperation mechanisms. Article 122 states that support schemes should in principle be open to other Member States and that the EC will consider positively schemes that are open to other Member States in notifications of new regulations (European Commission, 2014a). This principle has also been adopted in the proposal of a new RES directive (European Commission, 2016b) for the post 2020 period, where Article 5 establishes a gradual and partial opening of support schemes to cross-border participation in the electricity sector. As part of the state aid approval for Germany's Renewable Energy Sources Act 2014, the German government and the EC agreed that from 2017 onwards, 5 percent of the newly auctioned RES-e capacity per year will be opened to installations from other EU Member States (BMWi, 2016). However, given significant lead times of new projects and the absence of a scalable framework only a small quantity of energy can be expected to be subject to cooperation mechanisms under the current directive. The role of the cooperation mechanisms under the successive renewable energy directive II, which is currently under development, is not clear yet, in parts since the EU target of at least 27 percent for the share of renewable energy consumed in the EU in 2030 will not be translate into national targets anymore. Nonetheless it has been emphasized already by the EC that regional cooperation is meant to play a more prominent role under the new directive (European Commission, 2015b): "A more coordinated regional approach to renewable energy – including support schemes – could deliver considerable gains, among others by promoting cost - efficient development of renewable generation in optimal geographic locations. This would enlarge the market for renewable energies, facilitate their integration and promote their most efficient use. While Member States are becoming increasingly open to enhanced regional cooperation, practical difficulties remain. A concrete framework for cross - border participation in support schemes could address these practical difficulties."

1.2 Research question and applied methodology

The situational setting described above is the motivation for this thesis. Starting from a thorough analysis of the status quo my goal is to identify a novel approach to facilitate cross-border support of renewable energies at a significant scale. The design of the approach shall be guided by economic theory, yet with an eye on practicability. Since each sector requires different analytical treatment in this thesis I focus on the electricity sector, which being a network industry naturally offers the best prerequisites for cross-border cooperation. This leads me to the following research question.

Research Question
How can a mechanism be designed that enables efficient cross-border support of RES-e capacity and that is capable to overcome the barriers to the use of the cooperation mechanisms currently in place?

In order to answer the research question I make use of and integrate concepts and methods from various disciplines such as microeconomics, game theory, operations research, mechanism design, policy analysis or power systems engineering, reflecting the interdisciplinary nature of the research question. In the following I Introduce some concepts and methods from game theory and operations research that will be applied throughout this thesis (cf. Huppmann (2014)).

In designing the mechanism, in a first step, one needs to identify all players that are involved (directly and indirectly) in the expansion decision for RES-e capacity. In order to be able to predict each player's actions a common way is to state their decision rationale as optimization problem of the following form, where each player maximizes her own payoff. An optimization problem consists of an objective function and a feasible region, which is often expressed using functional constraints.

$$
\begin{aligned}
&\max_{x} f(x) \\
s.t.\ &g_k(x) \leq 0 \\
&h_l(x) = 0
\end{aligned}
$$

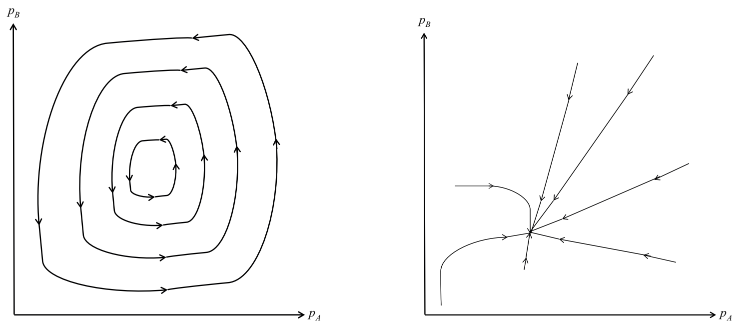
By constructing the Lagrangian function of the optimization problem and taking the derivatives we receive the Karush Kuhn Tucker (KKT), or first-order optimality conditions, which are necessary conditions for a solution to be optimal. Provided that some constraint qualifications are satisfied optimal solutions to the KKT system and the initial optimization problem coincide. In this formulation, λ and μ are the dual variables (or Lagrange multipliers) of the constraints $g(x)$ and $h(x)$. They can be interpreted as the improvement of the problem's objective value given a marginal relaxation of the associated constraint.

$$
\begin{aligned}
0 = \nabla f(x^\star) + \sum_k \lambda_k^\star \nabla g_k(x^\star) + \sum_l \mu_l^\star \nabla h_l(x^\star)\ ,\ x^\star\,(free) \\
0 \geq g_k(x^\star) \perp\ \lambda_k^\star \geq 0 \\
0 = h_l(x^\star)\ ,\ \mu_l^\star\,(free)
\end{aligned}
$$

To have a solution to the mechanism we have to find an equilibrium, which means that we have to consider many players $i \in I$, each with an individual objective function and individual or shared constraints, simultaneously. A concept commonly used in game theory and mechanism design to formalize the strategic interaction between several players and to derive stable outcomes of a game is that of a *Nash equilibrium*. Therefore the optimization problem of player i is re-formulated as shown below, where x_i denotes player $i's$ own decision variable, $x_{i'}$ denotes the decision variable of all players $i' \in I \setminus i$, which by player i is seen as a parameter, and K_i denotes the set of feasible strategies.

$$
\begin{aligned}
&\max_{x_i} f_i(x_i, x_{i'}) \\
&s.t.\ x_i \in K_i
\end{aligned}
$$

A Nash equilibrium is a vector $x_i^\star$ such that for each player $i \in I$ the following inequality holds:



(a) Tatonnement process

(b) Mixed Complementarity Problem

Figure 1.1: Predicted price patterns leading to Nash equilibrium, source: adapted from Goeree and Lindsay (2012)

$$f_i\left(x_i^\star, x_{i'}^\star\right) \geq f_i\left(y_i, x_{i'}^\star\right) \; \forall \, y_i \in K_i$$

This can be interpreted as follows: given what all other players $i' \in I \setminus i$ do, no single player can improve her payoff by deviating from the equilibrium strategy and do better. The process how such a game can converge to an equilibrium has first been described by Cournot (1938) and is known as tatonnement process: each player updates her own strategy based on the observed actions by the others player; this process is continued until no more profitable deviation from a strategy is found.

In order to find equilibrium solution mathematically there is a more immediate way that can be pursued by solving the Mixed Complementarity Problem (MCP) which arises from the joint consideration of the KKT conditions of several player's optimization problems. A solution to the MCP is a decision vector for each player such that the Nash equilibrium condition is satisfied. Figure 1.1 illustrates the predicted price patterns leading to the Nash equilibrium.

1.3 Thesis overview and contributions

This thesis consists of eight chapters. **Chapter 1** introduces to the research field and derives the research question. **Chapter 8** reflects on the findings of this thesis and makes suggestions for further research. The body and main contributions of this thesis are contained in chapters 2 to 7.

Chapter 2 lays out out the theoretical and conceptual foundation for this thesis.

At first I define measurable costs and benefits as the system boundaries that shall be used to analyze and measure the preconditions for and possible gains of cooperation in RES-e. This is followed by a literature review where I attempt to structure and consolidate the costs and benefits that are often listed in the literature in three categories, namely (i) the power system, (ii) external effects and (iii) macro effects. Next I investigate what could be possible (economic) rationales to pursue cross-border cooperation in RES-e expansion. I identify two main rationales: on the one hand various synergies such as comparative cost advantages or economies of scale and scope that can possibly exploited by cooperation. On the other hand market failures caused by the public good characteristics cause inefficiencies in RES-e capacity expansion. These failures can however be overcome if RES-e capacity is provided jointly by Member States. Despite strong rationales in support of RES-e cooperation it has hardly taken place in practice. I identify several barriers listed in the literature that contribute to this failure. This chapter concludes by discussing possible elements of a market design that is capable to overcome the identified barriers and facilitate efficient cross-border support of RES-e capacity.

Next **chapter 3** picks up the elements outlined in the conclusions of chapter 2 and concretizes them in order to elaborate a concept of a mechanism for cross-border support for RES-e. In particular two new elements are developed: (i) a cross-border impact factor that indicates the spill-overs of benefits between Member States induced from additional RES-e generating capacity; and (ii) an EU wide cross-border auction in which Member States and generators of RES-e bid to buy, respectively to supply additional RES-e generating capacity and the auctioneer offers to serve that set of bids, which maximizes net surplus. Moreover in this chapter I contrast the mechanism to the economic theory background developed in chapter 2 and describe which refinements are necessary to adapt it to the particular context. Finally I derive a conceptual framework that serves a blueprint for the mechanism and discuss a modeling approach that can sufficiently reproduce this framework, in order to obtain numerical results for the mechanism. In the following chapters 4, 5 and 6 the elements constituting the mechanism and the actors participating are developed in detail.

In **chapter 4** the cross-border impact matrix is developed from the scratch. At first I discuss which metrics could serve as plausible indicators of the cross-border impact of RES-e capacity and then come up with cost savings resulting from the changes in net generation pattern induced by RES-e capacity as indicator, which I term *Benefit Distribution Factor* (BDF). As a next step I discuss the physical and economic principles that govern the flow of electricity and from these I derive the formula for the BDF. In order to make the BDF operational I discuss next which data-sets could be used for the calculation, whereby I recommend to integrate the calculation in the process of the Ten Year Network Development Plan prepared by ENTSO-e in regular intervals.

In **chapter 5** I introduce the participants in the cross-border auction, Member States and RES-e generators, and discuss their rationales in determining their optimal supply and demand bids. Then I develop an equilibrium model of the European electricity market, which is formulated as MCP, in order to derive numerical results on the supply and demand bids. I also use the model to calculate the BDF.

Chapter 6 connects the dots and brings together the elements developed so far in the cross-border auction that is acting the central coordination mechanism. At first I explain the optimization problem of the RES-e auctioneer and then describe exemplary how the mechanism can converge to an equilibrium using strong Nash equilibrium as solution concept. I then discuss an almost obvious extension of the cross-border auction, i.e., how it could be used simultaneously to function as EU instrument that could procure additional RES-e capacities in case a gap towards the 2030 target achievement trajectory arises. I conclude this chapter with a proposal for the institutional set-up of the mechanism.

In **chapter 7** I apply the instruments and concepts developed in the preceding chapters to an illustrative example of the mechanism for the EU. With the calculation of the BDF matrix for the EU I provide a complete and consistent comparison of how the benefits from RES-e capacity spill over in EU across Member States. I also find that the BDF matrix is not symmetric, which implies an uneven distribution of benefits. The implication of the differing values in the BDF matrix is that - ceteris paribus - Member States with higher values would rather act as "importers" of RES-e capacity than Member States with lower values. The uneven distribution is however neither an advantage nor disadvantage if it is reflected in the design of the support mechanism. Next I calculate the RES-e premia that would be required to reach predetermined RES-e expansion targets in each of the Member States. Here also significant differences can be observed across Member States with premia ranging between 330,000 and 1,200,000 Euros per MW. From the perspective of cross-border cooperation this is however beneficial, since differences in support costs are a prerequisite for cooperation gains. Finally the mechanism is applied with the derived input parameters and compared against a reference case where only national support is possible, respectively a further reference case where capacity is allocated in a way such that support costs are minimized. The comparisons reveal that cross-border support would increase the net benefit compared to national support at a rate of ~20 percent. What is maybe more surprisingly is the fact that the mechanism would also increase the net benefit at a even higher rate compared to a case, where the mechanism allocates new RES-e capacity in a way, such that procurement costs are minimized. This is the case since the mechanism trades-off costs and benefits in such a way that new RES-e capacity gets installed at locations with both low support costs and high impacts in terms of benefits, respectively avoided opportunity costs of alternative allocations.

Chapter 2

Renewable electricity generation capacity expansion in the European Union: a case for cooperation?

This chapter investigates under which conditions cooperation in RES-e capacity expansion can be beneficial. Thereby the scope is limited to effects that can be related to some sort of economic reasoning and usually can be identified with costs and benefits, though not necessarily exactly. Thus I do not attempt to address here notions of cooperation rooted in other research fields such as political science, ethics, fairness or philosophy.

2.1 Costs and benefits of RES-e expansion revisited

As renewable energies have experienced a strong diffusion in the last two decades globally, the literature that analyzes the effects of renewable energy expansion has also steadily grown. This chapter selectively revisits some of the literature on costs and benefits of RES-e expansion. Furthermore, in this chapter also the attempt is made to structure and consolidate the effects that are often listed in the literature into three categories: it is argued that many of the effects that are frequently mentioned occur within the boundaries of (i) the power system. This comprises all actors that have chosen to incur effects that relate to the provision of electricity as useful energy. On the other hand all other effects that result from activities within the power system, but are not part of the electricity value chain are termed externalities. Often the actors that are affected by externalities did not choose to incur a certain cost or benefit (e.g. air pollution) or at least the relationship is largely implicit (e.g. green jobs). As some of the externalities can be directly linked to activities within the power system whereas for others the mode of action is less immediate or direct the former category is termed (ii) external effects and the latter (iii) macro effects.

Effects within the power system

A general distinction that is often made is between direct and indirect effects of RES-e expansion (Breitschopf and Held, 2014; Klessmann et al., 2010; Klinge Jacobsen et al., 2014; Pade et al., 2012). Direct effects refer to the immediate cost impact of RES-e support that originates from the difference between the long-term (incl. capacity) costs of generation and the electricity market earnings of the respective RES-e generation technology. This categorization emphasizes the supply perspective of the policy maker, as these are the cost effects that can be directly observed and best controlled (through the design of the support mechanisms) by the policy maker when bringing new RES-e generation to the market. As the support expenditures are usually fully allocated to electricity bill payers, the same effect is also reflected by changes in the consumer surplus (Meeus et al., 2013), defined as the difference between the maximum price consumers are willing to pay for electricity and the actual electricity price plus surcharges. The expansion of RES-e also induces effects in the residual power system (encompassing non-RES-e generation, grids and system operation that are termed integration costs in Hirth et al. (2015)). According to Hirth et al. (2015) three different integration cost components can be distinguished that need to be evaluated against a (conventional) benchmark technology. In this respect it is important to distinguish between dispatchable RES-e generation that will not have a much different impact on the residual system compared to the conventional benchmark alternative and variable RES-e generation. The effects of system integration, which mainly refer to variable generation, are caused by the variability, limited predictability and location specificity (this effect might also apply for dispatchable RES-e generating capacities that are sited in remote areas) are termed (i) profile costs, (ii) balancing costs and (iii) grid-related costs respectively. Another way to understand profile costs is to see them as the change in the time-dependent market value of RES-e generation (Borenstein, 2012). Profile costs occur due to the fluctuations in output of variable RES-e. This corresponds to effects on the generation mix in Pade et al. (2012) and system capacity costs in Klessmann et al. (2010). Balancing costs result from errors in the day-ahead forecast of RES-e output and are also included in the system-capacity costs. And grid-related costs occur if the connection of RES-e generating capacity to the grid requires additional grid expansion or enforcement.

Apart from the engineering side of the power system further effects that are listed in the literature are transaction costs (Breitschopf and Held, 2014; Klessmann et al., 2010) for the administration or enforcement of regulation and "market benefits" (Meeus et al., 2013) such as increased liquidity.

Moreover other effects induce a transfer of costs or benefits between different actors within the power system, but from an overall accounting perspective the net effect on costs and benefits is zero. In this category belong the merit order effect (Breitschopf and Held, 2014; Pade et al., 2012) and the "sell out of low cost potentials" (Klessmann et al., 2014). However in the view of single actors within the power system these effects will occur as costs or benefits and therefore play an important role in RES-e policy design and need to be balanced in an appropriate way.

External effects

The effects within this category all relate to some form of environmental impact. On the benefit side usually stand avoided emissions, whereas impacts on the landscape or biodiversity are generally added to cost components. The avoided emission benefits arise if RES-e generation displaces fossil fueled generation and thereby reduces emissions and their associated costs (assuming that the RES-e generation itself does not produce local pollution, thus biomass would be an exception in this case). For local pollutants, the cost varies across fuel and plant types and depends very much on the population density, climate and geography around the plant, as well as the presence of other pollutants (Borenstein, 2012). For greenhouse gases, the damage is not localized, so valuation is much more uniform across locations. The extent, to which RES-e generation displaces emissions from fossil fueled electricity generation, depends on its timing and location. While for avoided emissions of greenhouse gases the benefits are usually difficult to localize, the benefits of greenhouse gas savings can at least implicitly be reflected by setting up a price for CO_2 as it is the case with the EU ETS. In that case the benefits of reducing greenhouse gas emissions would be internalized in the generation costs of the power system, assuming the price for CO_2 appropriately reflects the external costs of greenhouse gas emittance. As the energy density of RES-e resources is comparatively low, a large area of land is required for electricity generation, which generally goes along with impacts on biodiversity and landscape or visual impacts in the surrounding area where the plants are installed (Borenstein, 2012; Meeus et al., 2013). However, the overall effect may improve, at least in the long term, if the gradual substitution of fossil energy carriers by RES-e also avoids harmful extraction processes of fossil fuels (Klessmann et al., 2010). Moreover it can also be assumed that local and environmental costs have at least partly already been internalized in the infrastructure costs, by defining certain minimum standards in the granting process for construction permits.

Macro effects

Macro effects largely fall into three different areas: security of supply, employment effects and innovation effects. Security of supply has two dimensions. One is on the geopolitical level and one on the level of system security. In particular if a high share of variable RES-e generation is added to the system, this may challenge system security and induce additional demand for balancing energy or grid reinforcements. However, these effects are already included in the dynamics of the power system and therefore do not require further consideration here. Electricity systems dominated by RES-e sources are also more distributed and modular in nature than conventional power systems and thus show a higher resilience against unplanned outages, be it for technical reasons or from attacks. The geopolitical effect of security of supply materializes if less energy needs to be imported to fulfill the domestic energy demand. This reduces the risk of price shocks (in the short term) or energy shortages (in the longer term). The extent, to which this effect comes into play, depends on, in a similar way as for the emissions, which fuels are displaced by the RES-e generation, which in turn depends on the characteristics of the power system under consideration. If the energy fuels that are displaced are mainly imported the effect can become large, otherwise not. The employments effects of renewable energies are more disputed in the literature. There is a static component and a dynamic component to this question (Borenstein, 2012). The static view is that RES-e is a more labor-intensive technology for producing energy than conventional electricity generation and thus has the potential to generate more and possibly "higher quality" jobs. However this alone does not imply that the job effects are overall welfare improving. To the extent that RES-e costs more, – at least in the static, short term perspective, it absorbs more resources to produce the same value of output – a unit of electricity – and thus lowers gross domestic product compared to conventional sources. The dynamic view of employment effects is strongly related to innovation effects (Klessmann et al., 2010), early deployment benefits and network effects (Meeus et al., 2013). Following this argument up-front investments create network externalities and learning opportunities that spill-over much more strongly intranationally than internationally, thus (temporarily) creating a sustainable advantage for the country making the investment and triggering a sustainable new sector providing local job opportunities (Borenstein, 2012). Technological learning – one element of innovation effects - is already internalized in the costs of the power system if regarded from a dynamic perspective. Table 2.1 provides a consolidation and structuring of the effects described above.

Table 2.1: Literature review on costs and benefits of RES-e expansion

Literature Source	Categories of costs and benefits (system boundaries)	Effects within each category	Consolidated categories
Borenstein (2012)	Levelized costs	Levelized costs vs. value of RES-E	Power system
	Environmental Externalities	Greenhouse gases	Externalities
		Local air pollutants	
	Non-Environmnetal Externalities	Energy security	Macro effects
		Non-appropriable intel. prop.	
		Green jobs	
		Lowering costs of fossil fuel energy	
Breitschopf and Held (2014)	Direct system-analytic	Difference costs of ele generation	Power system
	Distributional Effects	Merit-order effect	
	Indirect system-analytic	Balancing costs	
		Grid expansion costs	
		Transaction costs	
		Reduced air pollution	Externalities
		Environmental benefits	
	Macroeconomic	Employment / Economic growth	Macro effects
Hirth (2015)	Power system	Profile costs	Power system
		Balancing costs	
		Grid-related costs	
Klessmann et al. (2010)	Direct	Primary support costs	Power system
		RES target compliance	
	Indirect	Transactions costs	
		grid reinforment costs	
		Balancing costs	
		System capacity costs	
		"Sell out of low hanging fruits"	
		Societal and environmental costs	Externalities
		Reduced air pollution	
		Reduced CO_2 Emissions	
		Other environmental benefits	
		Security of supply	Macro effects
		Local job creation	
		Innovation effects	
Meeus et al. (2013)	Power system	Infrastructure costs	Power system
		Production costs	
		Consumer surplus	
		Market benefits	
	Externalities	CO_2 Emissions	Externalities
		Local environmental and social costs	
	Macroeconomic	Early deployment benefits	Macro effects
		Jobs / Economic growth	
Pade et al. (2012)	Direct	Costs of target compliance	Power system
		Grid related costs	
	Indirect	Price effects	
		Generation mix	
		Generation efficiency	
		Environmental / Health effects	Externalities
		Employment effects	Macro effects
		Security of supply	
		Technological development	

2.2 Rationale for cooperation

From an economic perspective the potential for cooperation by a group of Member States is given, if cooperation leads to an allocation of both RES-e capacity and corresponding costs, respectively benefits, such that the benefit an individual Member State or a group of Member States experiences from RES-e capacity is increased compared to the allocation of RES-e capacity that would be achieved under non-cooperative behavior. In our context an economic allocation refers to the geographic allocation of new RES-e capacity in space, i.e., new capacity is assigned to a node in the electricity network. To determine if there is potential for cooperation gains one may want to ask whether an economic system is producing an "optimal" economic outcome. An essential requirement for any optimal economic allocation is that it possesses the property of *Pareto efficiency* (or Pareto optimality). An allocation that is Pareto efficient uses society's resources and technological possibilities efficient in the sense that there is no alternative way to organize the production and distribution of goods that make some consumer better off without making some other consumer worth off. This does not insure that an allocation is in any sense equitable; it does however, at very least, say that there is no waste in the allocation of resources in society (Mas-Colell et al., 1995).

In principle, the analysis of Pareto efficient outcomes and competitive equilibria requires the simultaneous consideration of the entire economy. "Partial equilibrium analysis can be thought of as facilitating matters in two accounts. On the positive side it allows to determine the equilibrium outcome in the particular market under study in isolation from all other markets. On the normative side it allows to use the *Marshallian* aggregate surplus as a welfare measure that can be thought of as the total benefit generated from the consumption of the RES-e capacity less its cost of production and corresponds to the area lying vertically between the aggregate demand and supply curves" (Mas-Colell et al., 1995).

The surplus sharing game

In this section I introduce some formal notation borrowing from cooperative game theory in order to describe and analyze allocation problems of the type as described above. Cooperative game theory considers values created by different actors coming together and forming a coalition and provides solution concepts to distribute those values. Many of the salient features of allocating costs or benefits can be captured in the following simple format (Brandenburger, 2007; Young, 1994a; Young and International Institute for Applied Systems Analysis, 1985). A cooperative game consists of two elements: (i) at

Table 2.2: Selected notation of chapter 2

Sets	
$i, j \in I$	...players in the game
$S \in I$	...coalitions of players
Variables	
x	...consumption of RES-e capacity
q	...supply of RES-e capacity
$\star$	...denotes equilibrium value of prices / quantities
Functions	
v	...value of cooperation
c	...cost of supplying RES-e capacity
b	...benefit of consuming RES-e capacity

set of players, and (ii) a characteristic function specifying the value created by different subsets of players in the game. Let $I = \{1, 2, ..., n\}$ be the finite set of players, and let i, where i runs from 1 through n, index the different members of I. The characteristic function is a function, denoted v that associates with every subset S of I, a number, denoted $v(S)$, where a subset is called a coalition. The number $v(S)$ is interpreted as the benefit created when members of S come together and cooperate. In sum, a cooperative game is a pair (I, v), where I is a finite set and v is a function mapping subsets of I to numbers. The set I, which contains all players is called the grand coalition.

A special case of the cooperative game is a cost sharing game. Therefore, let (c_i)be the cost of i for providing an aspired service by a player herself, and for each subset $S \subseteq I$, let $c(S)$be the cost of providing the service jointly. Then, for each coalition S the surplus value of cooperation is given by:

$$v(S) = \sum_{i \in S} c_i - c(S) \tag{2.1}$$

The possible synergies of cooperation that lead to the surplus will are discussed in the following sub-sections with help of figure 2.1.

Synergies in space, time and scale

This section discusses different sources of synergies that can be realized if RES-e expansion is conducted cooperatively by Member States.

Resource endowment

There are two dimensions of relevance for resource endowment: (i) one concerns all resources that have an impact on the direct cost of electricity generation, such as the level of solar radiation; (ii) the other one regards all resources that have an indirect impact on the costs of electricity generation, such as the flexibility of the power system and its capability to accommodate (variable) RES-e generation. The former type of synergy is the one most often referred to in the literature in the context of RES-e cooperation (European Commission, 2013; Klessmann et al., 2010; Klinge Jacobsen et al., 2014; Unteutsch and others, 2014), since it is the most intuitive one and moreover offers the largest potential for cost savings. The latter one has not been mentioned yet so often in the context of RES-e cooperation, partly because the potential cost-savings are probably much smaller and partly because the benefits are less intuitive; the discussion at EU level is however evolving.

Taken together both dimensions constitute a marginal (integration) cost curve for RES-e. The possible synergies shall be illustrated with the help of figure 2.1a. In this figure stylized marginal cost curves for two fictive Member States A and B are shown, as well as a joint cost curve for both Member States. In the non-cooperative case each Member State achieves a targeted level of RES-e expansion by only accessing resources based on her own territory. In the cooperative case the whole pool of resources would be accessible to both Member States. Cooperation would lead to value since Member State B could partly also make use of the comparably lower cost potentials based in Member State A so that the joint expansion target could be achieved at overall lower cost than the sum of the individual targets.

Economies of scope

Economies of scope derive from the contemporaneous sharing of tangible or intangible assets in the production of multiple products, resulting in lower joint costs of production per unit of output (Bailey and Friedlaender, 1982; Helfat and Eisenhardt, 2003; Panzar and Willig, 1981). It is appealing to link economies of scope to the existence of sharable inputs; that is, inputs which, once procured for the production of one output, would be also available (either wholly or in part) to be used in the production of other outputs. It would seem most natural to define an input as sharable between the productions of product sets $S'$and S'' if the joint production of these outputs enables some of the input to be conserved, vis-a-vis separate production, while the utilization of all other inputs were not expanded (Panzar and Willig, 1981). For any nontrivial partition of I, there are economies of scope if and only if c is strictly sub-additive in the relevant range (cf. eq. 2.2).

$$c(S' \cup S'') \leq c(S') + c(S'') \quad \forall \quad S', S'' \subseteq I \text{ with } S' \cap S'' = \varnothing \tag{2.2}$$

With regards to RES-e immediate economies of scope can for instance arise from Member States jointly organizing processes, such as the agency conducting the RES-e auction or joint cost benefit analyses. Moreover, economies of scope arise from synergies in space, where the need for a back-up system decreases if output from variable RES-e generation at different sites is considered jointly (Hirth et al., 2015; Neuhoff et al., 2013; Newbery et al., 2013; Nicolosi, 2012): interconnecting RES-e power plants at different locations can lead to considerable smoothing of the accumulated supply. Wind and solar power plants are dependent on wind and solar input and it can be expected that the supply variability decreases with distance, at least up to distances of the same size as a typical weather system (Patt et al., 2011). Several studies have addressed this issue for variable RES-e generation and confirmed spatial synergies (Archer and Jacobson, 2007; Grothe and Schnieders, 2011; Hoff and Perez, 2012; Katzenstein et al., 2010).

"Whereas stochastic smoothing makes use of reduced correlation between geographically dispersed power plants of the same type, a diverse power mix can make use of low, or sometimes negative, correlations between different recurring weather and climate patterns. For example, the European summer is sunnier than the winter, and cloudy days are more often windy than are sunny days. Wind and sun are to some extent negatively correlated, so that the accumulated output of a wind-solar power plant fleet can be expected to have a more stable output than that of a one-technology fleet. A more diverse power mix will thus be less impacted by adverse weather" (Patt et al., 2011).

One further reason for economies of scope could be that investors could perceive the financing risk to be lower under a cooperatively organized EU instrument compared to a national auction, which would enable RES-e generators to offer capacity at lower costs. A lower financing risk could derive from a higher credibility of an EU instrument compared to a national instrument and from the fact that each project would be financed by a portfolio of Member States, which minimizes the contingency risk. The impact on the improvement in financing costs could be significantly high, since financing risks often outweigh the impact of resource conditions when it comes to financing costs (Brückmann, 2015).

The effect of economies of scope on the joint cost curve is that the per-unit costs are reduced over-proportionally as illustrated in figure 2.1b.

Economies of scale

Economies of scale are present if specific costs decrease with larger production facilities, since certain cost components are fixed independent of the level of output so that the need for input factors increases at a disproportionally lower rate than output (Panzar and Willig, 1977). RES-e generating technologies exhibit some of the features that typically allow for scale economies: they are of modular type and the costs of capital typically account for the largest share in costs. This means that higher output induced by higher demand is associated with lower costs. In general, economies of scale go along with convexity, i.e., concave cost functions.

$$v\left(S'+i\right)-v\left(S'\right)\leq v\left(S+i\right)-v\left(S\right)\quad\forall\quad S'\subseteq S \tag{2.3}$$

The interpretation of eq. 2.3 is that the incentive to cooperate increases with the size of the coalition. Next I illustrate with the help of figure 2.1c for the example of Member State B how cooperation between Member States could enable the realization of scale economies. In this example both the marginal and total average cost curves of Member State B are displayed. As we already know the slope of the marginal cost curve increases with the level of RES-e capacity expansion. In order to arrive at the total costs for the erection of the new RES-e infrastructure one has to add to the marginal generation costs some fixed costs that arise independent of the level of RES-e generation and only accrue once, such as production facilities for RES-e plants, market intelligence, permission procedures or certain construction costs. These kind of costs generally exhibit economies of scale that increase with the level of RES-e capacity expansion and need to be traded-off against the increase in marginal generation, respectively integration costs. The level of RES-e generation required to exploit the full potential of scale economies might however be too large to be covered by the expansion target of a single Member State alone, as can be seen in figure 2.1c for the case of Member State B.

Inter-temporal economies of scope and scale

The timing of RES-e capacity expansion is not directly another source of synergies, but it adds a time dimension to economies of scope and scale, which provides further potential for cooperation. The reason therefore is that constraints both on the supply and the demand side determine the potential for synergies at any given point in time: on the supply side a more rapid scale-up might be constrained by diffusion constraints in the energy innovation system (Gallagher et al., 2012; Grübler et al., 1999); that is, the transformation can only take place at limited speed, due to, for instance, physical or legal boundaries or costs increasing at an exponential rate after a certain threshold, whereas on the demand side the limited adaptability of the residual system due to the longevity of pertinent infrastructure (Dangerman and Schellnhuber, 2013) might hinder the scale-up of RES-e capacity expansion. Examples for the former are the effect of technological learning on the costs of RES-e capacities or the effect of land-use regulation on the availability of RES-e generation sites and thus the resource endowment or the status of the power system of a Member State and its potential to accommodate high shares of RES-e generation. An examples for the latter is the flexibility of the residual system to adapt to increasing shares of RES-e generation; if RES-e generation is deployed quicker than it can be integrated into the system this comes at additional cost since its value in displacing conventional capacity would be disproportionally low. If more flexibility sources are deployed this would allow for a better integration of RES-e generation, but on the other hand additional costs could arise if this would force less flexible generation to go out of the market before its technical lifetime has been reached.

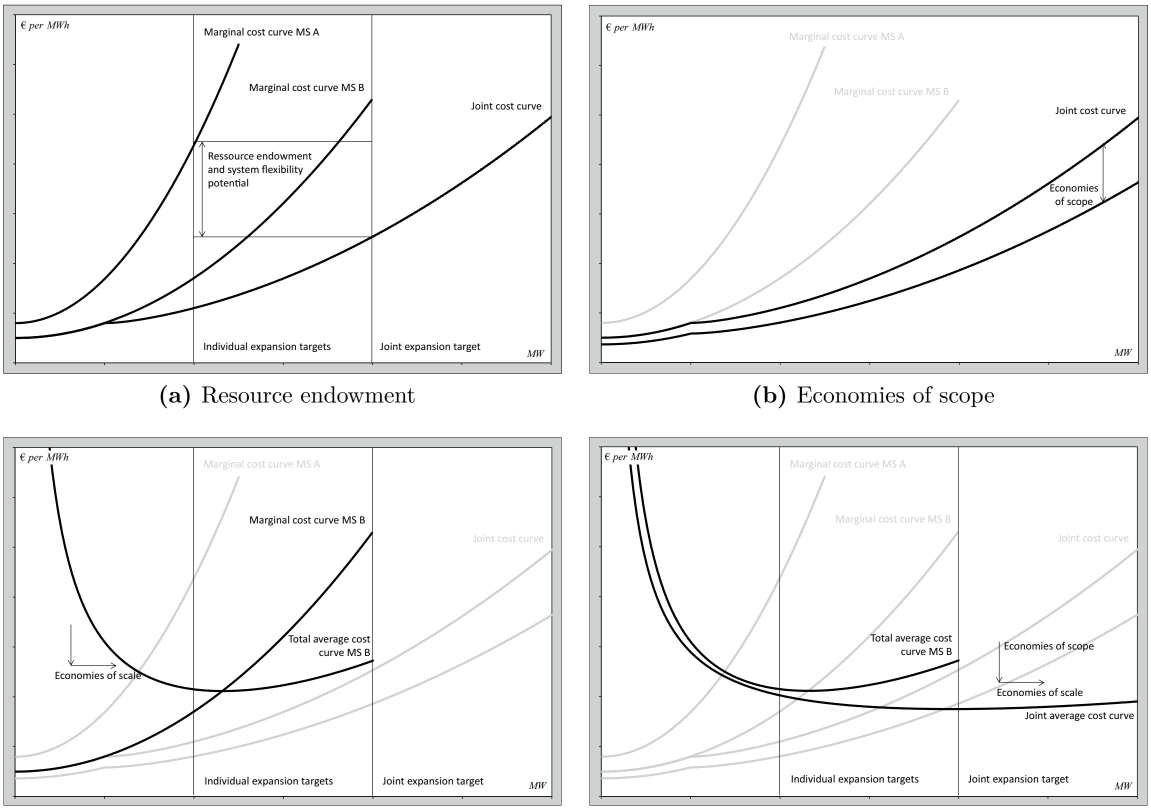
The essence of the above said is that options for the least cost deployment and integration of RES-e generation are not uniformly available, but differ in their constitution both in space and time. Therefore Member States can cooperate by pooling their resources and balancing their demands for RES-e expansion across time, such that the allocation of RES-e expansion both in time and space takes place in a way where synergies are exploited and the total joint costs are minimized.

Multilateral externalities

Besides synergies through more efficient resource usage another rationale for cooperation is given by the presence of externalities; in this case the efficient level of RES-e capacity can only be determined jointly by all concerned Member States.

In the electricity sector externalities are present where the consumption decision of one Member State also affects other Member States. This is due to the particular network structure of the electricity system, where new RES-e capacity, once provided, is shared between all interconnected Member States and its power output is allocated to where it is most valuable. Moreover physical properties induce that power tends to flow from regions with surplus generation to nearest demand centers. In doing so it is not restrained to a certain path; it rather takes all available paths at the same time.

These externalities share to some extent the properties of a public good. If one Member State provides an additional unit of RES-e generating capacity all Member States benefit. Economically speaking, this constitutes as Nash game between Member States, each of them taking as given the amount of RES-e capacity being purchased by



(a) Resource endowment

(b) Economies of scope

(c) Economies of scale

(d) Time dimension

Figure 2.1: Sources of cooperation gains

other Member States, in determining their optimal provision of RES-e capacity. Each Member State has an incentive to enjoy the benefits of RES-e capacity provided by others while providing it insufficiently herself as it is shown in the following.

Public good characteristics of RES-e capacity

The two properties that characterize a public good are nonrivalrousness and nonexcludability (Eecke, 2013; Gronberg):

1. The nonrivalrous property holds when the consumption of a unit of the good under consideration by one consumer does not preclude or diminish the benefit from another consumer using the same unit of the good. Thus there is jointness in consumption of the good— one unit of the good produced generates multiple units of consumption. The degree of rivalrousness can be defined by the size of the marginal opportunity cost of an additional user. While in principle a unit of RES-e capacity can be considered private in nature, i.e., consumption by one

Member State reduces the supply available for other Member States, due to the special characteristics of coupled electricity markets it is not: the reason is that RES-e capacity in coupled electricity markets - in practical terms - is not readily allocable, because it is decided by the market coupler in which Member State its use is most valuable, which in turn depends on the state of the electricity system that is different in each hour and not under the control of a Member State. Thus from the perspective of a Member State experiencing a benefit from RES-e capacity her level of consumption is not reduced by the consumption of other Member States, since the benefits from RES-e could not be have been allocated differently and thus no direct opportunity costs exists. According to Mas-Colell et al. (1995) the analytical implications of rivalrousness, but nonallocable externalities parallel those of nonrivalrousness ones.

2. The nonexcludable property holds when it is impossible to prevent others from jointly consuming a unit of the good once it is produced. Here the same logic applies as above: due to the special characteristic of interlinked electricity markets a Member State investing in a new unit of RES-e capacity cannot exclude another Member State from experiencing a share in the benefit. Therefore actually it is the nonexcludable property, which makes the RES-e capacity also become nonrivalrous.

From this, we can conclude that RES-e capacity can be classified as impure public good that is nonexcludable and only partially rivalrous.

Pareto efficient amount of RES-e capacity

For the discussion in this section (cf. Mas-Colell et al. (1995)) and onwards let us assume that Member State haves quasilinear utility functions with respect to levels of RES-e capacity and that we operate in a partial equilibrium setting.[1]

Letting x denote the consumption of RES-e capacity, I denote Member State i‘s benefit from the RES-e capacity by $b_i(x)$. I assume that benefit is linear in money and that it can be identified with willingness to pay. Note that for ease of notation and without loss of generality I do not yet account for spatial preferences of Member States regarding the provision of the RES-e capacity at this point. The costs of supplying q units of RES-e capacity is $c(q)$[2].

[1] Therefore the statements in this section may differ slightly in notation compared to the Pareto optimality conditions for public goods provided elsewhere

[2] I assume that $b_i(x)$ and $c(q)$ are twice differentiable with $b_i^{''}(x) < 0$ and $c^{''}(q) > 0$. Due to the public good properties of RES-e capacity x does not have a subscript i

From the fundamental theorems of welfare economics it is known that Pareto efficiency is reached when the level q of RES-e capacity[3] maximizes the net benefit (i.e., benefit net of cost) for Member States (cf. eq. 2.4).

$$\max_q \sum_i b_i(q) - c(q) \tag{2.4}$$

From eq. 2.4 the first-order optimality condition for the optimal quantity of RES-e capacity q^{opt}can be derived as shown in eq. 2.5.

$$\sum_i b_i^{'}\left(q^{opt}\right) - c^{'}\left(q^{opt}\right) = 0 \tag{2.5}$$

The condition in eq. 2.5 is known as *Samuelson condition* (Samuelson, 1954) and it states that at the optimal level of RES-e capacity the sum of Member States' marginal benefits from RES-e capacity is set equal to the marginal cost of providing it.

Inefficiency of unilateral provision of RES-e capacity

The way a new unit of RES-e capacity typically is provided, is by a Member State giving generators of RES-e a financial incentive to construct it, for instance by setting up an auction, and paying a market price p to the RES-e generators. In doing so each Member State maximizes her utility from new RES-e capacity solving

$$\max_{x_i} b_i\left(x_i + \sum_{j\neq i} x_j^\star\right) - p^\star \cdot x_i \tag{2.6}$$

In determining the amount x_i of RES-e capacity to incentivize each Member State i takes as given the amount of RES-e capacity provided by each other Member State in equilibrium, which is the standard assumption in a *Nash equilibrium* (Nash and others, 1950). Let superscript * denote the equilibrium prices and quantities with $x^\star = \sum_i x_i^\star$, then for each Member State i the following first-order optimality condition must hold:

$$b_i^{'}(x^\star) - p^\star = 0 \tag{2.7}$$

A representative RES-e generator representing the supply side of the market on the other hand must solve $\max_q p^\star \cdot q - c(q)$ and therefore in equilibrium must satisfy the

[3]Strictly speaking the level of RES-e generation leads to the benefits, rather than RES-e capacity. The two variables are however linked by a fixed proportion, so that the former implies the latter.

following first-order optimality condition:

$$p^{\star} - c^{'}\left(q^{\star}\right) = 0 \tag{2.8}$$

In order to clear the market, i.e., all consumption by a Member State is matched by supply of the RES-e generator, $q^{\star} = x^{\star}$ must hold. From the first-order optimality conditions in eqs. 2.7 and 2.8 and $x^{\star} = \sum_i x_i^{\star}$ we can derive eq. 2.9.

$$\sum_i \delta_i \cdot \left[b_i^{'}\left(q^{\star}\right) - c^{'}\left(q^{\star}\right)\right] = 0 \tag{2.9}$$

Letting $\delta_i = 1$ if $x_i^{\star} > 0$ and $\delta_i = 0$ if $x_i^{\star} = 0$, eq. 2.9 can only hold if $b_i^{'}\left(q^{\star}\right) - c^{'}\left(q^{\star}\right) = 0 \perp x_i^{\star} = 0 \; \forall \, i$; that is, in equilibrium the marginal benefit a Member State enjoys from a unit of RES-e capacity has to equal the marginal costs of providing it, otherwise the provision of RES-e capacity will be zero.

To show more clearly why this is the case let us assume that $b_1^{'}\left(x\right) < \ldots < b_n^{'}\left(x\right)$, i.e., Member States can be ordered by the marginal benefit they derive from a unit of RES-e capacity. Then in fact there is only one possible equilibrium outcome where eq. 2.9 holds, this is where Member State n, who derives the largest benefit from a unit of RES-e capacity provides it and all other Member States set their provision of RES-e capacity to zero. The interpretation of this behavior is given by the Nash equilibrium concept: in the absence of cooperation, each Member State decides unilaterally on her optimal provision of RES-e capacity taking as given the decisions by the other Member States. Since all Member States would anticipate that the Member State with the highest marginal benefit from a unit of RES-e capacity would set her supply to $x_n^{\star} = x^{\star}$ if they provided nothing ($\sum_{i \neq n} x_i^{\star} = 0$; cf. eq. 2.6) this is an optimal strategy for them.

This can however not be optimal in the sense of Pareto efficiency: since for the Member State with the highest marginal benefit providing the unit of RES-e capacity we have $b_n^{'}\left(q^{\star}\right) - c^{'}\left(q^{\star}\right) = 0$, and other Member States' marginal benefit from the same unit of capacity is larger than zero $\left(b_i^{'}\left(x\right) > 0\right)$ we get $\sum_i b_i^{'}\left(q^{\star}\right) - c^{'}\left(q^{\star}\right) > 0$; that is, in equilibrium the cumulative marginal benefit all Member States enjoy from a unit of RES-e capacity is larger than the marginal cost of providing it, which cannot be optimal according to condition 2.5. Since $b_n^{'}\left(x\right) - c^{'}\left(q\right)$ is decreasing in q, because we have $b_i^{''}\left(x\right) < 0$ and $c^{''}\left(q\right) > 0$, we know that a solution that satisfies condition 2.5 must have a larger value than $q^{\star}$, i.e., in the non-cooperative equilibrium the amount of RES-e capacity is lower than the optimal amount ($q^{\star} < q^{opt}$). The inefficiency of non-cooperative provision of RES-e capacity is furthermore illustrated in 2.2. It displays the demand curves corresponding both to the individual (non-cooperative) and the joint

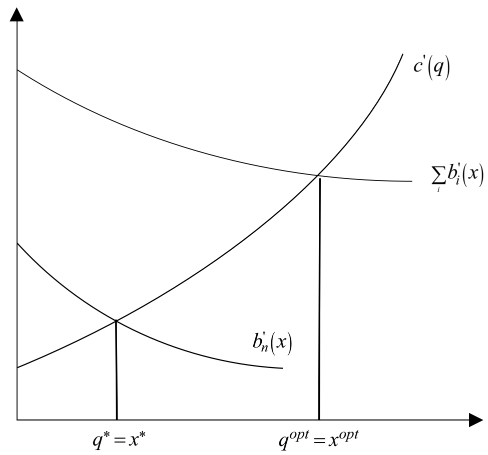


Figure 2.2: Uncooperative provision of RES-e capacity leads to a less than optimal level of supply, source: adapted from Mas-Colell et al. (1995)

(cooperative) provision of RES-e capacity, whereby the joint demand curve is the vertical aggregation of individual Member States' demand for RES-e capacity.

2.3 Why has no market for cross-border trade of RES-e capacity emerged?

Despite potential synergies and despite strong political interest cross-border support of RES-e capacity has not gained any significant momentum yet. This is due to several persistent barriers.

Barriers reported in empirical literature

In a study for the European Commission by Klessmann et al. (2014) the following barriers were detected:

- "*Political barriers* include public acceptance for cooperation mechanisms, the determination of governments to engage in cooperation on RES target achievement and uncertainty on the continuity of the RES framework beyond 2020. These factors go beyond mere technical considerations on how to jointly match excess and surplus of RES production.

- *Technical barriers* include barriers that prevent countries with political will to engage in cooperation from doing so. Interview with Member States conducted in this study have shown that there is still a high degree of uncertainty on quantifiable costs and benefits, design options of cooperation mechanisms and difficulties for Member States to forecast their own RES target fulfillment. Uncertainty also surrounds the sanctions for non-compliance of the RES targets. Lacking transmission infrastructure and market integration were also mentioned as barriers for cooperation.

- *Legal barriers* include potential incompatibility of cooperation mechanisms with national and EU legislation".

A research paper by Klinge Jacobsen et al. (2014) identifies as additional barriers:

- *Distributional effects* may be significant in cases; apparently benefits outside the power system carry more weight from the perspective of Member States in this respect. A directly related problem is the difficulty to find *compensatory prices* for cross-border effects.
- Another relevant barrier is the one arising as a result of *different policy objectives* of the support schemes such as (i) maintaining support for diversified technologies in order to increase political acceptance or (ii) targeting the support in order to develop specific RES-e technologies and industries.
- Finally, there are several other issues that can constitute possible barriers, such as how to structure the agreements legally or how to allocate cost of joint support into the Public Service Obligations payments for consumers.

Barriers to market formation

In this section I paraphrase the barriers described above from an economic theory angle in on order to provide an entry point for economic market regulation and mechanism design. In this respect the term *cooperation mechanisms* from an economic perspective seems somewhat far-fetched, since essentially the cooperation mechanisms provide a legal basis for cooperation rather than a fully spelled economic instrument that is capable to address barriers to market formation.

I identify four characteristics of the market for RES-e capacity that contribute to the failure of the market as is.

- First, the costs and benefits of adding a unit of RES-e capacity are not entirely born by Member States making the expansion decision; that is, RES-e capacity generates *externalities* in the market. If one Member State provides an additional unit of RES-e generating capacity all Member States benefit. The failure of each Member State to consider the benefits for others of her provision of RES-e capacity is often referred to as free-rider problem: each Member State has an incentive to enjoy the benefits of RES-e capacity provided by others, while providing it insufficiently herself (Mas-Colell et al., 1995). Therefore, bi- or multilateral negotiations alone are unlikely to result in efficient RES-e capacity, as has been shown in section 2.2.

- Second, significant *information asymmetries* exist: the willingness of Member States to pay for RES-e capacity and the cost of firms supplying that capacity is the private information of individual Member States and RES-e generators respectively. Strategic considerations cause these actors to misrepresent this private information in negotiations, leading to inefficient outcomes.

- Third, information regarding costs and benefits of RES-e expansion is partially *missing*, *uncertain* or *complex* to assess, thus even if Member States and generators of RES-e were to state their true costs and benefits it might be difficult put a monetary valuation on all relevant effects.

- Finally, the *transaction costs* of bi- or multilateral negotiations are very high since they require parliamentary approval in several Member States. The lack of a standardized, transferable design of a cooperation agreement requires that each project carries out its own cost-benefit calculations and involves lengthy negotiations on the allocation of costs and benefits. In particular, establishing the share of costs and benefits seems to have derailed cooperation between Sweden and Norway (Klessmann et al., 2010).

In combination, these market characteristics have hampered the formation of a price signal that would allow for efficient trade in RES-e capacity. Instead, in the identification of possible cooperation projects often national political priorities stood in the foreground, making it questionable if cooperation would lead to any efficiency gains at all.

2.4 Conclusions for market design

In section 2.2 I have identified various sources of synergies where cooperation in RES-e capacity expansion can create value. Leaning back to the cooperative game theory framework, figure 2.3 displays the relation between various classes of cooperative games, whereby the advantage to cooperate increases for stronger assumptions on decreasing costs. I find that cooperation in RES-e capacity expansion fulfills at least the requirements of supperadditive games, but in general also the requirements for convex games. I have also analyzed in section 2.2 that the provision of RES-e capacity goes along with (positive) externalities, so that each Member State deciding individually on the expansion level and bearing the whole costs cannot be optimal, which implies that cross-border coordination beneficial. Therefore, in principle a strong rationale is given to cooperate, since this could lead to welfare improvements for all involved Member States.

In practice however, several barriers in the market for RES-e lead to a failure of the market as it is, and will have to be addressed in order to incentivize an efficient allocation of RES-e capacity. A market institution that in principle can address the externality caused by the public good characteristics of RES-e capacity is known as *Lindahl pricing*, what can be thought of as having for each Member State a personalized market of her willingness to pay for the benefit she enjoys from RES-e capacity, with p_i^L denoting the personalized price (Young, 1994b), and where a superscript ^{L} indicates that we are dealing with prices and quantities under Lindahl pricing. Therefore, with analogy to eq. 2.7 in equilibrium, Member State $i's$ first order optimality condition is given by eq. 2.10 with the only difference that the price p and consumption level x now have a subscript i, indicating the personalized market.

$$b_i^{'}\left(x_i^{\star L}\right) - p_i^{\star L} = 0 \tag{2.10}$$

The RES-e generator in turn provides the level of RES-e capacity that maximizes his profits by solving $\max_q \sum_i p_i^L \cdot q^L - c\left(q^L\right)$. It should be noted that due to the public good characteristics of RES-e the generator provides the unit of capacity only once, but is paid prices p_i^L according to each Member State $i's$ individual valuation of the unit. His corresponding first-order optimality condition than writes as in eq. 2.11.

$$\sum_i p_i^{\star L} - c^{'}\left(q^{\star L}\right) = 0 \tag{2.11}$$

The market clearing condition in eq. 2.12 states that each Member States $i's$ consumption of RES-e capacity equals supply.

$$x_i^{\star L} - q^{\star L} = 0 \tag{2.12}$$

From eqs. 2.10 to 2.12 we derive eq. 2.13, which is the same as eq. 2.5 thus telling us that Lindahl prices in equilibrium provide the efficient level of RES-e capacity $q^{\star L} = q^{opt}$.

$$\sum_i b_i^{'} \left(q^{\star L}\right) - c^{'} \left(q^{\star L}\right) = 0 \tag{2.13}$$

A critical assumption of the Lindahl equilibrium and all other approaches to address the externality problem in order to provide for Pareto efficiency is that the individual demands of all Member States are known. In fact, even when Member States agree to cooperate through cross-border support, they may have an incentive to misreport their true willingness to pay for additional RES-e capacity in order to free ride. The question then is how to design a mechanism that controls this incentive for misreporting and as a consequence leads to a Pareto efficient outcome.

This issue was first addressed by Vickrey (1961) who showed that a particular pricing rule makes it a dominant strategy for bidders to report their values truthfully. For a single item the mechanism is commonly referred to as the *second-price sealed-bid auction*, or simply the *Vickrey auction* that can be described as follows (cf. Ausubel and Milgrom (2002)): each bidder is asked to report to the auctioneer his entire demand schedule for all possible quantities. The auctioneer uses that information to select the allocation that maximizes surplus. He then requires each buyer to pay an amount equal to the lowest total bid the buyer could have made to win his part of the final allocation, given the other bids. Vickrey showed that, with this payment rule, it is in each bidder's interest to make his "bid" correspond to his actual demand schedule, regardless of the bids made by others. Subsequent work by Clarke (1971), Groves (1973) and Groves and Ledyard (1977) demonstrated that a generalization of the Vickrey mechanism leads to the same properties in a much wider range of applications; in particular they showed how the Vickrey auction can be used to overcome the free-rider problem and elicit true valuation for a public good. Here the government plays the role of a benevolent auctioneer, seeking to provide the public good at minimum cost and maximize the public's economic surplus. This extended mechanism is commonly referred to as *Vickrey-Clarke-Goves* or *VCG* mechanism (Ausubel et al., 2006). The salient feature of the VCG mechanism is that it induces truth telling as a dominant strategy, which (i) "reduces the costs of the auction by making it easier for bidders to determine their optimal bidding strategies and by eliminating bidders' incentives to spend resources learning about competitors' values or strategies" and (ii) "adds reliability to the efficiency prediction, because it means that the conclusion is not sensitive to assumptions about what bidders may know about each others' values and strategies" (Ausubel et al., 2006). Despite this desirable property the VCG mechanism has hardly ever been applied in practice due to several shortcomings that matter in a real world setting (Ausubel and Milgrom, 2002; Ausubel et al., 2006; Rothkopf, 2007): probably the most important disadvantage of the Vickrey auction is that the revenues it yields can be very low or zero, even when the goods being auctioned are quite valuable, so that possibly not all costs can be covered. Moreover, it can generate highly inequitable (though efficient) outcomes, it can leave individual players worse off than before the mechanism was run if cost coverage is required. In this case the additional flat-rate surcharges are levied on all bidders, so anybody who bid less than the surcharge will be worse off than before). The VCG mechanism also poses very high requirements on the participants ability to compute different outcomes.

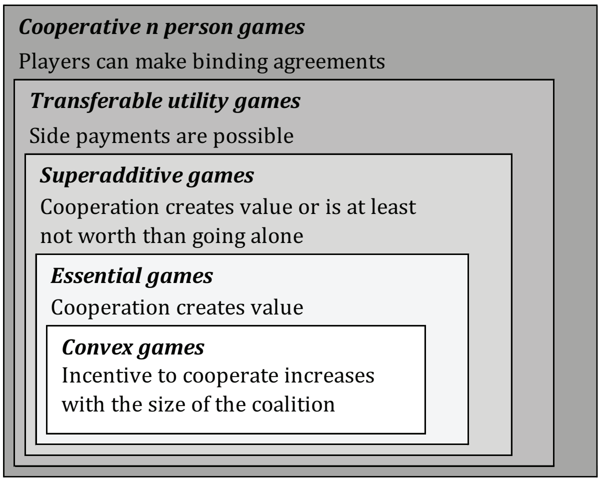


Figure 2.3: Classes of cooperative games, source: adapted from Fromen (2013)

"Because of these dead-ends, economists more-or-less abandoned the VCG mechanism (outside the auctions literature) through the 1980s and 1990s, working instead on mechanisms whose desirable outcomes obtain from Nash equilibrium behavior (or refinements of Nash equilibrium) instead of dominant strategy behavior" (Healy, 2007). "And while one might question whether Nash equilibrium is the right strategic behavioral model, these mechanisms have been shown in economics experiments to work in practice. That is, humans using these processes do arrive at the allocations predicted by the theory" (Leyard, 2007). Alternative auctions designs have been explored to elicit Nash equilibria, such as multiple round pay-as-bid auctions. "The multiple rounds feature provides feedback to bidders, economizes on bidder evaluation efforts, and conceals the winning generating bidder's maximum willingness to pay. The pay-as-bid feature avoids the low revenue outcomes of the Vickrey auction and discourages shill bidding and some kinds of collusive strategies" (Ausubel and Milgrom, 2002). An iterative mechanism can sometimes implement the same outcome as a direct-revelation mechanism but with less information revelation and agent computation required (Parkes, 2001).

To summarize this section, we can conclude that cooperation in RES-e capacity expansion creates gains and offers the potential to increase the benefit of all involved Member States. Thus far, significant barriers exist that prevent these cooperation gains from being exploited. However, in this section I have pointed out concepts rooted in economic theory and mechanism design that are capable to address these barriers in principle. In the following chapters I build on these ideas to develop an efficient mechanism for cross-border support of RES-e capacity.

Chapter 3

Concept of a mechanism for cross-border support of renewable electricity in the European Union

In chapter 2 I have shown that cooperation in RES-e expansion is beneficial, but different sources of market failure in the market for RES-e thus far have prevented the synergies of cooperation from being exploited. In this chapter I propose a new mechanism that addresses the current shortcomings, in order to increase the efficiency of RES-e expansion.

3.1 Two new ingredients: cross-border impact factor and cross-border auction

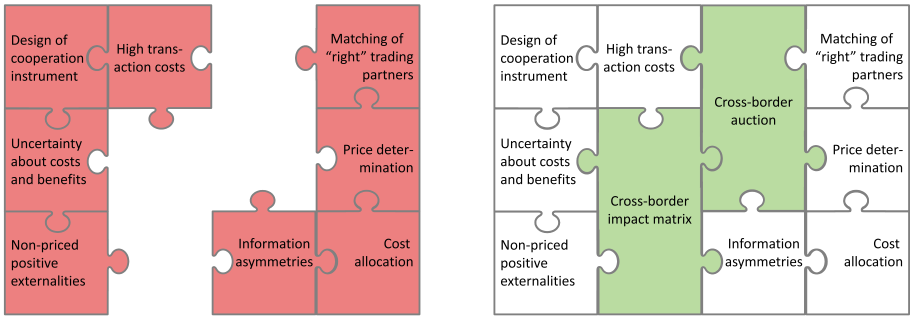
The new mechanism I propose consists of two main elements: (i) a cross-border impact factor that indicates the spill-overs of benefits between Member States induced from additional RES-e generating capacity; and (ii) an EU wide cross-border auction in which Member States and generators of RES-e bid to buy, respectively to supply additional RES-e capacity and the auctioneer offers to serve that set of bids, which maximizes net surplus. In section 2.3 I have identified the market failures, which are the cause of the barriers to the formation of a market for RES-e. Next I explain the features of the mechanism that can help overcome these barriers.

- First I have shown that RES-e expansion goes along with significant *externalities*. The new mechanism incorporates these externalities into prices for capacity in two steps ensuring that choices reflect the true costs and benefits. (i) The *cross-border* *impact factor* provides for each location a consistent measure of how the benefit from a unit of RES-e capacity is distributed across Member States, which allows Member States to determine their willingness to pay for this respective location. (ii) The c*ross-border auction* aggregates the willingness to pay of all Member States for each location so that efficient choices can be made.

- The willingness of Member States to pay for RES-e capacity and the cost of firms supplying that capacity is the *private information* of individual Member States and RES-e generators respectively. Strategic considerations cause these actors to misrepresent this private information in negotiations, leading to inefficient outcomes. The mechanism I propose seeks to minimize the incentives for actors to do so. In the mechanism a cross-border cost allocation between Member States emerges as an equilibrium of a competitive bidding process. In this way a level playing field is created with all information being transparently available, which is a necessary requirement for efficient trade to take place.

- As explained, information regarding costs and benefits of RES-e expansion is partially *missing*, *uncertain* or *complex* to assess: the cross-border impact factor provides a *standardized, systematic procedure* to tackle this shortcoming in all three dimensions: the impact metric of the cross-border impact factor is chosen in a way, that even if information is missing for some effects, the direction of the impact is the same as for the effects that are included in the metric of the factor. The uncertainty is considered by constructing the cross-border impact factor for different scenarios of plausible developments of the power system and merging these into a single representative indicator. The complexity of assessing costs and benefits in the power sector with certain accuracy requires the usage of sophisticated modeling tools and specialized competence to conduct the analysis, which both may not be readily available decentrally. In the mechanism I propose the assessment of costs and benefits is carried out centrally, so that it could be carried out by the most competent institution, but in a systemic way so that it can be applied by each project.

- The need to reevaluate costs and benefits for each individual project, as well as questions about the specific design of the cooperation agreement of a new project, including legislative approval, lead to high project specific *transaction costs.* The new mechanism solves this barrier by providing a standardized procedure for assessing costs and benefits and providing standardized design elements, so that these costs can be split among all new projects (compare section 2.2). The guiding idea



(a) barriers **(b)** solutions

Figure 3.1: Barriers and solutions for cooperation in RES-e

in this respect is that the impact factor approach allows moving away from the individual project level evaluation to the system level, which brings along several advantages: first of all, the way the distribution of benefits would be calculated becomes more transparent, reproducible and consistent, but most importantly as the analysis is conducted simultaneously for all projects, the transaction costs for assessing cooperation projects, which had posed an important barrier so far, would be significantly lowered. Moreover, abstracting away from the project level evaluation would allow that a new project could more easily be supported jointly by a larger group of Member States, by having the impact factor determining each Member State´s share in benefit from the new project and therefore also her share in costs. This implies that by joining forces, the off-taking Member State would not anymore have to take over the whole financial responsibility, but rather a new project could be divided into different shares splitting up the financial responsibility between several Member States[1]. In spite of the standardization the mechanisms still allows maximum flexibility of the Member States to express their preferences for cooperation.

- Finally, experience with the cooperation mechanisms has shown a great difficulty in *finding prices* that would determine an allocation of costs and benefits, which would be perceived as fair and would make all involved parties better off. The mechanism relieves Member States from this burden, as they now only have to know their individual willingness to pay and the mechanism finds the efficient transfer prices for them, such that the highest possible cooperation gains are realized.

[1]This corresponds to the idea of the Lindahl equilibrium discussed in chapter 2

3.2 Relating the mechanism to economic theory

In this section the new elements that constitute the mechanism are "blended" with the economic theory background that I have introduced in section 2.4.

First, I use the cross-border impact factor to account for spatial preferences in the Lindahl equilibrium; that is, I adapt the Lindahl equilibrium for the pure public goods case to the impure public good characteristics of RES-e capacity.

In the pure public good case such as in the Lindahl equilibrium it is assumed that each Member State consumes the same amount of the public good - in our case RES-e capacity - so that we have $x_i^\star - q^\star = 0$ (cf. eq. 2.12). In section 2.2 I have already concluded that RES-e capacity can be classified as impure public good that is nonexcludable and only partially rivalrous. The difference to a pure public good case is that each Member State´s benefit share from the RES-e capacity is different, due to special properties that determine how benefits spill over in electricity markets. Thus, letting α_i denote Member State $i's$ share in consumption from the unit of RES-e capacity with $\sum_i \alpha_i = 1$, we can adapt eq. 2.12 to our particular problem and now have $x_i^\star = q^\star \cdot \alpha_i$; that is, each Member State's consumption of RES-e capacity is differentiated according to her share α_i. With this we can derive the equilibrium condition for the optimal provision of RES-e capacity as shown in eq. 3.1.

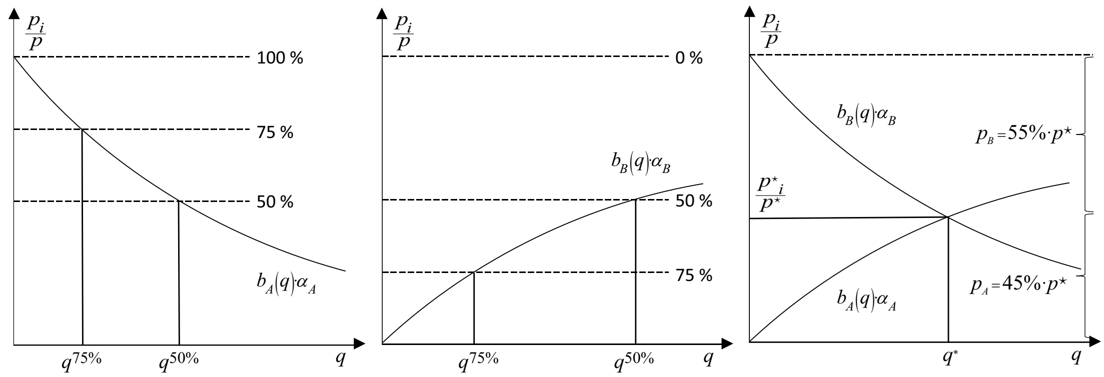
$$\sum_i b_i^{'}\left(q^\star \cdot \alpha_i\right) = c^{'}\left(q^\star\right) \tag{3.1}$$

Equation 3.1 states that for the amount of RES-e capacity q to be optimal the sum of marginal benefits each Member State derives from her share in consumption of RES-e capacity α_i has to equal the marginal cost of providing it. From this we can furthermore establish eq. 3.2, which states that the optimal price $p_i^\star$ paid by each Member State for the provision of RES-e capacity has to equal her marginal benefit she derives from a unit of RES-e capacity times her share in consumption of the benefit.[2]

$$p_i^\star \stackrel{!}{=} b_i^{'}\left(q^\star \cdot \alpha_i\right) = b_i^{'}\left(q^\star\right) \cdot \alpha_i \tag{3.2}$$

Moreover the equilibrium prices assure that all costs are allocated. Figure 3.2 illustrates this for a case of two Member States A and B. Let us first take a look at figure 3.2a: it shows for Member State A an illustrative demand curve as of type $b_i\left(q \cdot \alpha_i\right)$. The vertical axis does not show as usual the price, but since we are dealing with a public good it shows the price share $\frac{p_A}{p}$ that is allocated to Member State A; for instance if Member

[2]Placing α_i outside the bracket is possible here due to the assumed quasi-linearity of $b\left(q\right)$



(a) Lindahl A **(b)** Lindahl B **(c)** Lindahl AB

Figure 3.2: Illustration of Lindahl equilibrium prices accounting for spatial preferences

State A's price share in the new unit of RES-e capacity were 100% her demanded quantity would be zero. Figure 3.2b shows the demand curve of Member State B, who sees the vertical axis flipped the other way around. Like Member State A, Member State B demands more as her share in the full price goes down. In order to have an equilibrium, which is where the two demand curves intersect each other, both Member States have to demand the same amount of RES-e capacity and costs have to be covered exactly. By drawing a line over to the price axis from the point of intersection, we get each Member State's share in the full price $p^\star$ that needs to be paid for $q^\star$ units of RES-e capacity. In our example Member State $A's$ price share is 45% and Member State $B's$ price share is 55%.

Second, the cross-border auction I propose is in a similar spirit as some of the earlier work on the design of incentives for public goods as discussed in Green and Laffont (1978) and in particular it is inspired and guided by a mechanism proposed by Young (1998a). As the mechanism by Young it relies on strong Nash equilibrium, which is discovered in a multi-round bidding process, as solution concept. In contrast to the VCG mechanism there is typically no dominant strategy solution, so that the mechanism does not elicit the Member State´s true willingness to pay; however it elicits them partially, enough to ensure that the allocation of RES-e capacity decided by the mechanism is efficient. This slight drawback compared to the VCG mechanism is compensated for by some features of high practical relevance: the solution concept ensures that the mechanism is budget balanced and all costs can be covered. Moreover it is group-rational; that is, no coalition of Member States can simultaneously choose new strategies and increases their payoff. The mechanism I propose also differs from the contribution by Young (1998a) in some important aspects. Demand is not restricted to a single project, but is offered simultaneously to all supply options, thereby accounting for spatially explicit preferences and all supply options that can be matched with demand and result in a positive net benefit can be selected. On the supply side it does not assume the costs to be known by the auctioneer, but these are also discovered by the mechanism.

3.3 Conceptual framework and modeling approach

The objective of this section is to arrange the different actors and elements that form the cross-border mechanism in a conceptual framework as shown in figure 3.3. Thereby, the framework also serves as narrative of the prevalent regulatory framework under which the cross-border mechanism would be implemented. Hierarchically, the framework can be divided in three stages that in the following are described in reversed order.

The bottom level (stage I) is the integrated and fully coupled EU electricity market. Several actors, such as RES-e generators, conventional generators, electricity consumers or electricity traders are active in this market. They decide on investment and generation or respectively consumption levels in order to maximize their revenues from the sales of electricity or to maximize their benefit for the purchase of electricity respectively. The actors are situated at different nodes of the electricity network, which are linked by a joint transmission system operator (TSO) system. Electricity generators sell electricity to the market zone that their node is situated in and the different market zones are linked by a (flow-based) market coupler that aims to minimize price differentials between the market zones. Besides selling their generation to the electricity market RES-e generators can gain revenues by offering capacity at different auctions that are organized in the upper stages. Therefore they estimate their income from sales on the electricity market so that the cost differential to the full investment costs determines their ask price at the RES-e auctions.

In the middle level (stage II) are the EU Member States. Here I assume that in the future - in line with the state aid guidelines - auctions will be used as the default national instrument to determine the level of the support premium. Member States aim to maximize the benefit from RES-e generation and therefore for instance can choose on technologies or locations that they offer to be auctioned. Besides setting up a domestic auction a Member State can also decide to submit bids in the EU cross-border auction. In deciding her level of participation in both auction types the Member State has to determine her trade-off between the benefits she receives and the prices she has to pay in both auctions.

In the top level (stage III) is the EU cross-border auctioneer, who maximizes EU

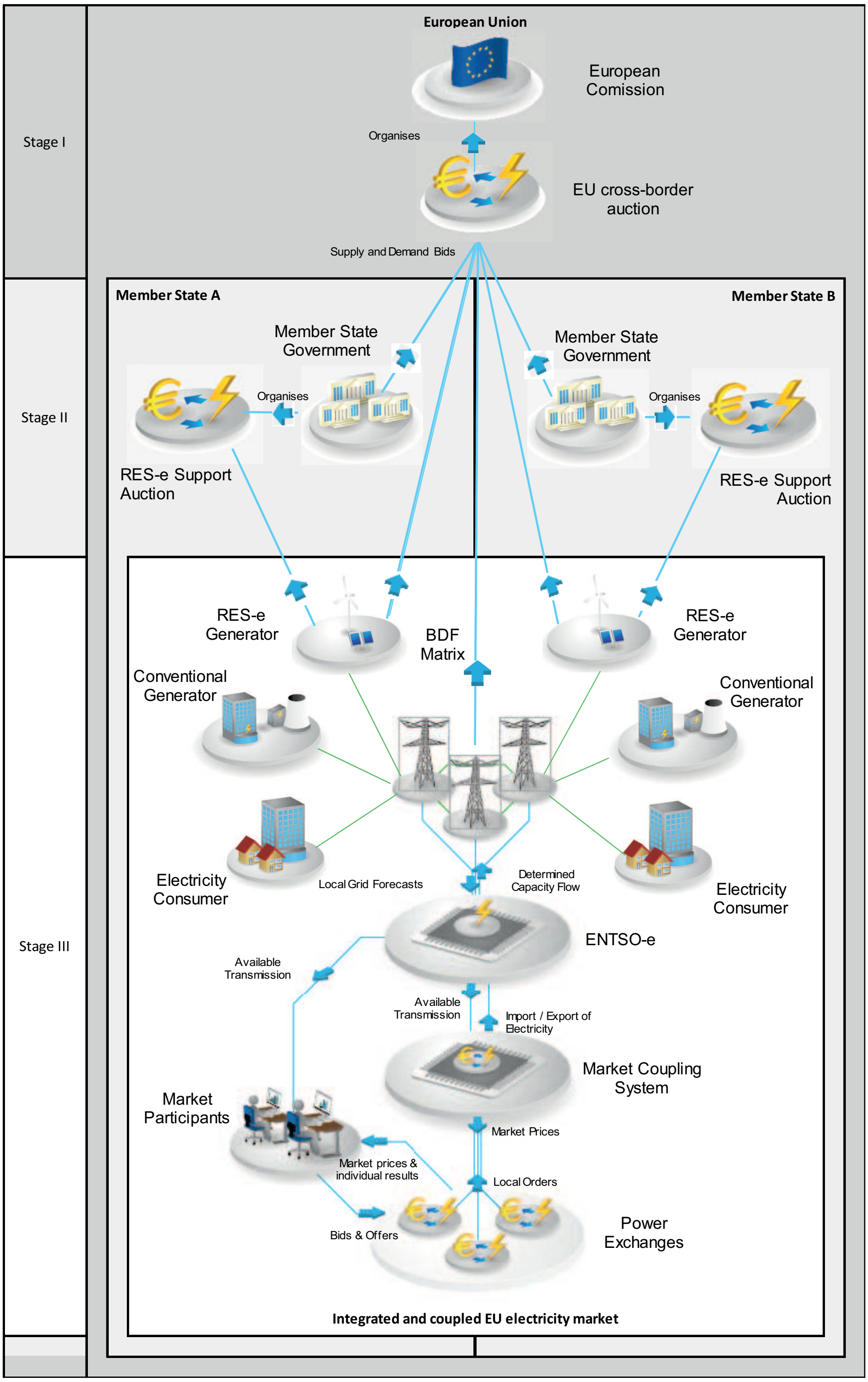


Figure 3.3: Conceptual framework for the mechanism, source: figure adapted from original figures provided by courtesy of TenneT TSO (2010)

wide surplus; she can represent for instance the EC or some party nominated by the EC to conduct the auction on her behalf. In order to determine the maximum surplus she receives information inputs from the lower levels; Member States and generators of RES-e bid prices indicating their willingness to pay for, respectively their costs of additional RES-e capacity. In addition, based on the market structure of the first level, ENTSO-e calculates the cross-border impact matrix indicating the spill-over of benefits to all Member States from a unit of RES-e capacity installed in one Member State. The cross-border auctioneer uses the cross-border impact matrix to determine the aggregate demand of all Member States at each possible location for new RES-e capacity.

Next I discuss, how numerical results can be obtained. The three-stage structure of the individual agents optimization problems gives rise to a complex equilibrium problem that is mathematically very challenging to solve and where it is not clear that a unique equilibrium can be identified (Huppmann and Egerer, 2014; Zerrahn and Huppmann, 2014). Even the bi-level sub-problems alone are very complex to solve. The Nash game between the second and the third stage, where each Member State decides how to parametrize her domestic auction, taking both as given the reaction of the electricity market and the other Member States' decisions in their domestic auctions constitutes an *Equilibrium problem with equilibrium constraints* (EPEC) (Gabriel et al., 2012). In particular, the alternative option of a domestic auction also has an influence on Member States' and RES-e generators' bidding rationales in the EU cross-border auction making it a binary choice. The calculation of the cross-border impact matrix is a two-level problem between the first and the third stage, since capacity additions that are decided in the in the EU cross-border auction could alter market outcomes in the third stage and thus the coefficients of the cross-border impact matrix.

In order to reduce the complexity of the problem, I decompose the overall problem in easier to solve sub-problems, by separating the optimization problem of the auction from the input parameters to the auction; that is, the bid prices and the cross-border impact matrix. This is possible for the bid prices, since some assumptions on the bidding rationales of both the Member States and the RES-e generators can be derived from the analytical problem statements (cf. chapter 5). For the cross-border impact matrix I discuss in chapter 4 under which assumptions the separation from the auction can be a valid procedure. This yields two mathematical models: (i) the surplus maximization problem of the auction in stage I can be modeled as *linear program*, respectively *integer program*, in case only discrete rather than continuous bid sizes would be allowed. This would however only concerns the last bid accepted and does not influence the outcome much so that I here stick to the easier to solve linear program. (ii) Instead of modeling stages I and II as an EPEC, both stages are combined in one model that is formulated as *mixed complementarity problem*, which jointly considers several electricity market actors' interrelated optimization problems (Gabriel et al., 2012). This is achieved by introducing the auction as market clearing condition to the model rather than stating it explicitly as optimization problem, so that all remaining optimization problems are on the same level.

Fortunately, most of this complexity does not arise in practice, since it is not required that all stages are in equilibrium simultaneously. Rather Member States and RES-e generators submit their supply and demand to the auction as parameter and will revise their decisions based on outcomes of previous rounds or auctions, so that convergence towards an efficient equilibrium can be reached (in the longer term).

Chapter 4

Tracing the distribution of benefits from renewable electricity generation in the internal electricity market

Over the last two decades Europe's energy policy has consistently been geared towards achieving three main objectives: energy in the EU should be affordable and competitively priced, environmentally sustainable and secure for everybody. A well-integrated internal energy market is thought to be a fundamental prerequisite to achieve these objectives in a cost-effective way (European Commission, 2014b). According to the electricity directive of 2003, the key European legislation on establishing an internal market for electricity, every consumer in Europe should be free to purchase electricity from the supplier of her choice. Suppliers, on the other hand, should have access to all European customers. The development towards the completion of the internal market has been prescribed in the so called target model (ACER, 2013). The target model for the day-ahead timeframe is a European price coupling, which simultaneously determines volumes and prices in all market zones, based on the uniform marginal pricing principle. It has however also been recognized that the target model could not be implemented top-down from scratch, but rather by a bottom-up, step-by-step approach. In a strategy paper in 2005 the EC for the first time mentioned regional markets as a step towards a pan-European market. Since then, regional initiatives have been started by the European regulators. Regional initiatives emerged from adjacent market zones that became coupled. Market coupling uses implicit auctions in which traders do not actually receive allocations of cross-border capacity themselves but bid for energy on their exchange. The exchanges then use the available cross-border transmission capacity to minimize the price difference between two or more zones. It can be expected that in the future trade across market zones can be increasingly used to balance the intermittency of RES-e supply (Epex Spot, 2015). As the transmission grid initially has not been set-up for large scale trading of electricity, currently several initiatives are underway to improve the situation. One of them is the flow-based market coupling in order to have a more accurate representation of loop flows in determining the commercial flows when electricity is traded over long distances. While under the flow based market coupling physical and commercial flows do not coincide, it is a step in this direction that (commercial) benefits are realized in the area where electricity actually physically flows to.

4.1 Proposal for a cross-border impact factor

Electricity generated from RES-e capacity is integrated into the EU wide market coupling, so that the electricity price acts as a (short term) locational signal as to how RES-e generating capacity should be dispatched and traded across borders to achieve allocative and operational efficiency. In the longer term investment perspective however such a signal is missing, since in most of the cases RES-e generating capacity investments do not only depend on the electricity price signal, which at least in theory could provide such a signal (Moreno et al., 2010), but also on the payment of a support premium that is generally decided by non-coordinated, national support systems. In order to enhance the cooperation and coordination of RES-e support across borders the EC in the 2009 RES directive (European Council and European Parliament, 2009) introduced a set of cooperation mechanisms. The idea has been that two or more Member States jointly organizing their support instruments would also improve the locational signal for the siting decision of investors in new RES-e generating capacities. So far however the cooperation mechanisms have hardly been used due to the existence of several barriers (cf. section 2.3). In a similar debate in the context of the state aid guidelines Member States considering to open their national support schemes for RES-e plants in another Member State put forward that some sort of proof of a "real" physical impact on their own power system would be needed (de Lovinfosse, 2014; Schlichting, 2014); that is, Member States were not willing to pay support for new RES-e generating capacity that is installed abroad if they do not gain a share in the benefit. Moreover Member States considering to open their national support schemes generally were in favor of approaches that would allow for reciprocity (BMWi, 2016); that is, the host Member State of a cross-border project would equally support cross-border projects in the off-taking Member State. In order to address these challenges and to develop efficient signals for the siting of new RES-e generating capacities I propose a concept for the development of a cross-border impact factor. The objective of the factor shall be to provide a reliable metric of the impact new RES-e generating capacity installed abroad has on the domestic power market of a Member State that is considering to support RES-e across borders.

As outlined above, based on the Member States' motivations for and prerequisites of supporting RES-e installations across borders I derive two preliminary indicators for measuring the impact:

1. *Physical Impact*: This indicator would measure the physical impact on a power system, which for the purpose of operationalization can be defined as the **change in national generation mixes** induced by an additional unit of RES-e capacity at one or more locations, whereby I explicitly consider the impact of altered real power flows across the transmission grid.

2. *Net Social Benefit*: This indicator would measure the accumulated benefit net of the market benefit (this is already internalized in the prices for electricity) a Member State experiences from the installation of an additional unit of RES-e generating capacity at one or more locations. The net social benefit can be regarded as a measure of societies' willingness to pay for the non-energy value of additional RES-e capacity.

These two indicators are related, but of different quality. The first indicator is contained in the second one in the way that the social benefit represents a monetary weighting across all benefit categories (cf. section 2.1) of the effects induced from the physical impacts.

System boundaries and conceptual framework for deriving the cross-border impact factor

Assessing the future impact of additional RES-e generating capacity abroad on the domestic power market requires the usage of modeling tools. The impacts from RES-e generation occur in different layers (cf. section 2.1). It is virtually impossible to model all these effects and their interactions correctly, but the inevitable need to conduct a cost-benefit analysis of the cross-border impacts requires identifying a comprehensible and practical approach. I recommend to set the system boundaries at the level of the power system and to use a systemic approach; that means an impact factor that can be used for the evaluation of all projects and not just for a single project. In the following I justify the recommendations.

The principle alternative to a system level approach of the impact factor calculation would be a project level approach. I think that a systemic approach is superior when it comes to delivering more accurate results of the impact analysis since it is only possible in this way to compare projects consistently so that the decision for a new project will not be based on a biased or deviating method of impact analysis giving wrong preference to a less efficient project.

The other aspect regards the system boundaries. Capturing all effects in a modeling framework requires coupling a power system model with a macro economy model, a local air pollution impact model and the like. I believe that not much is given up, but a lot is gained limiting the system boundaries to the power system. As will be shown below the physical and economic laws that govern the flow of electricity are quite precise. Since nearly all benefits induced from RES-e generation directly or indirectly depend on the physical impact of the power flow, it allows for a reliable metric for tracing the distribution of benefits. The effects induced from the changed power flows and generation mixes are at the same time the impulses for the macroeconomic and other models external to the power sector. The effects represented by these models are however much more difficult and less reliable to model and therefore could well distort the overall outcome. For instance, one may think of the ability of two distinct power market models to replicate the same electricity price series versus the ability of two distinct macro economy models to replicate the same employment effects. The latter is much more difficult since the system to be modeled is much less precisely known and understood compared to the power sector. Therefore a conceptual framework including models external to the power sector would be much more arbitrary.

We have seen why it would be preferable to set the system boundaries of the cross-border impact factor at the level of the power system. I have also argued before that not much information with regards to the distribution of the overall benefits would be lost. The reason is that the benefits which are external to the power sector are to some extent correlated with the benefits that accrue inside the power system; that is, the resources saved (saved capital, CO_2 and fuel costs) for the provision electricity, expressed by lowered generation costs. In this respect it advisable to distinguish between three categories of effects:

- *Physical impact*: The physical impact is directly related to the generation cost savings within the power system. The power injection from additional RES-e capacity induces a power flow that displaces (conventional) generation. The value this altered power flow has to the system depends on the change in the net generation pattern; that is, the change of power injections and withdrawals according to the least-cost dispatch rationale. Thus the benefit internal to the power sector is a direct consequence of the physical impact and when the benefit in a node increases the physical impact also increases. This will become clear from the explanations in the following sections.

- *Non-distributive effects* (avoided local air pollution, non-internalized value of CO_2 emissions savings, security of supply): Non-distributional effects directly occur at the node where generation is displaced. That means for instance when fuel costs are saved emissions are also saved and security of supply increases due to a lowered dependence on fuel imports. The more the price for CO_2 adequately reflects the social costs of emitting also the monetary weighting of the emissions savings effects improves.

- *Distributive effects* (Employment and innovation effects): From the discussion in section 2.1 we know that for employment and innovation effects two modes of action have to be distinguished: the resource savings in the economy and the direct economic impulse from the new technology innovation system.

  - The resource savings in the economy are a direct consequence of the benefits in the power sector, i.e., less resources have to be spent to produce a unit of electricity output. These savings can be transferred to the economy either as increase in consumer or generator surplus; how they are shared depends on the reaction of the electricity price to the physical impact and thus the elasticities of supply and demand. When consumer surplus increases as a result of lowered electricity prices this also has a positive impact on the economy, since electricity becomes a cheaper input factor. Moreover decreased generation costs can increase the rents of of RES-e generators if the electricity price is not impacted by the additional generation, which allows them to allocate more financial capital to R&D activities or to increase their workforce. I conclude that the resource savings for the economy can either materialize in welfare for consumers or RES-e generators, whereby the increase in consumer welfare will likely account for the major share. With exception to changes in RES-e generators surplus changes in consumer surplus and benefits from resource savings are equivalent.
  - The second mode of action are the economic impulses that are spread through positive network externalities, which generally are of a different nature as

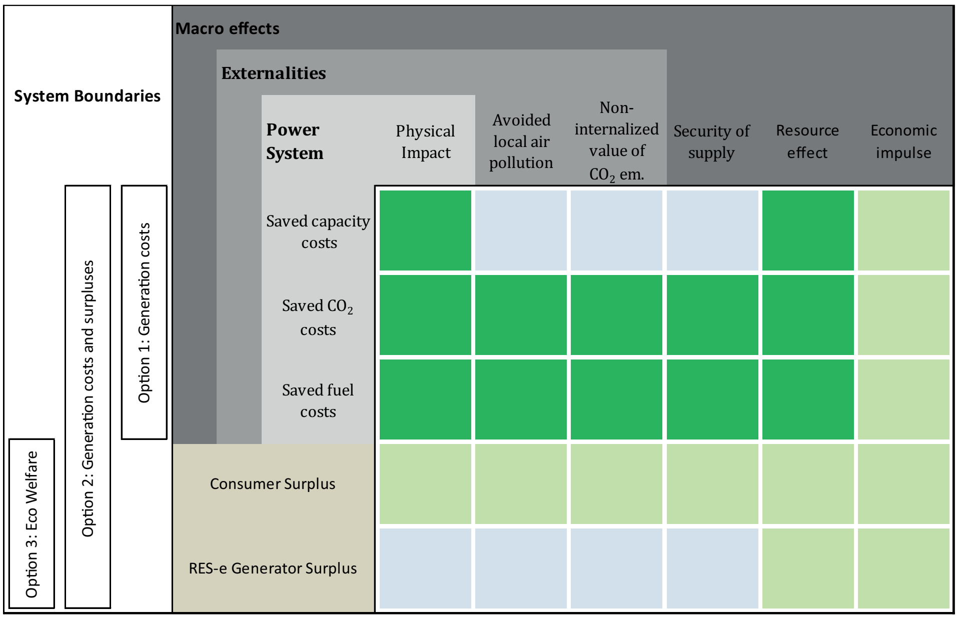


Figure 4.1: System boundaries for indicator. Colors showing high (green), low (light green) or neutral (blue) correlation between effects.

they do not spill-over based on engineering-economic characteristics of the power system, but are based on economic linkages of different actors. It may however be reasonable to assume that employment and innovation effects are more likely to spill-over the closer two Member States (nodes) are situated to each other. As also the spilling over of the generation cost savings is constrained by limitations in transmission capacity that in general increase by distance this effect can be assumed to serve as a rough proxy. However, similar as for the resource effect on employment and innovation, the node at which generation is displaced and the node at which the rent is earned need not coincide, if for instance all the generation cost savings would be exported. Therefore, the RES-e generators surplus could be again a good proxy to capture this re-distributional effect, since the surplus is earned at the node where the injection of power takes place an thus also the highest economic impulse is created by the investment.

The discussion above leaves us with three options for setting the system boundaries of the impact factor (cf. figure 4.1). Most of desired benefits are captured fairly well by the resource cost savings effect. An exception may be the employment and innovation effects since these are usually situated at the supply node and therefore can be distributed differently than the resource savings owing to the network structure of the electricity system. However all in all resources savings seem to serve as a good proxy for the benefits under consideration, therefore option 1 seems to be most viable, possibly to be complemented by RES-e generators surplus as complementary indicator.

Besides the correlation between different effects as explained above further arguments justify the approach. As can be seen from figure 5.1 under future market design effects yet (partly) external to the power system may become more internalized. This regards in particular the benefit of saved CO_2 emissions that could, through the reform of the EU ETS, more accurately be reflected in the generation costs of fossil fueled power generation.

To conclude I have provided a framework for the development a cross-border impact factor. The metric of choice to measure the impact would be the resource savings within the electricity sector serving as a good proxy for both the physical impact or the net social benefit. Thus I term the cross-border impact factor *Benefit Distribution Factor* (BDF). In the following I develop the BDF from scratch, first by explaining the underlying physical, electrical engineering and economic foundations, then deriving the different impact metrics and finally illustrating the concept in a 3-node application.

The engineering framework for deriving the Benefit Distribution Factor

For a number of economical, ecological and technical reasons it is not reasonable to meet all demand for electricity locally. Therefore, the optimal configuration of a certain power system consists of a mix of generation technologies, which are situated at different locations and connected via electricity transmission grids in a way that the generated electricity can be transmitted to the source of demand. In existing power systems, different technologies and hierarchical levels of electricity grids are used in order to ensure an efficient and reliable operation of the power system. For example, which voltage levels or transmission technologies are most reasonable depends on the distance between two transmission points, the type of surrounding grid topology in which these points are interlinked and the actual amount of electricity to be transmitted on average.

The aim of this section is to provide a purposeful description of the basic principles underlying electricity transmission instead of an elaborated mathematical derivation including proofs. Therefore, I do not depart from the most sophisticated formulation of physical laws; rather I provide simple statements, which are sufficiently correct within the boundaries of the application; that is, to allow evaluating the impacts that arise from changed generation patterns in interconnected power systems like the one in Europe.[1]

The physics of electricity transmission[2]

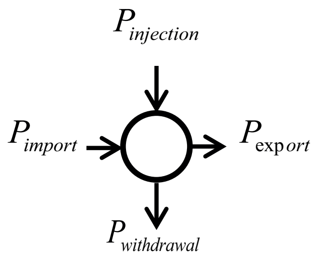
To study existing transmission grids we can abstract in many cases from the details in the small-scale infrastructure and focus only on the macrostructure of the grid. The grid model consists then of nodes and lines, which connect them.

Definition 4.1. (node) A node is a point within a transmission grid, where power can be injected or withdrawn from. A node can either be a physical grid hub or an aggregation from grid hubs ranging e.g. from zones within countries up to all grid hubs within a country. Generators, consumers and transmission grid lines can be connected to nodes. The way in which nodes are connected within a certain transmission grid is described by the grid topology. From here on for the sake of clarity and since it does not impair the general concept, I assume that a node coincides with the system boundaries of a Member State and that each player can uniquely be assigned to a node so that we have $i, n \in N \equiv I$. Therefore the terms Member States, nodes or market zones will be used interchangeably in the following depending on the most suitable terminology in the particular context.

Power is the flow of electricity that is released, absorbed or transmitted in every moment and is denoted P in the following. The average flow in one direction is called the active or real power flow and is measured and quantified in MW. Energy is the amount of electricity that is available for consumption and/or transmission and is denoted $\bar{q}$. It is the cumulative sum of power flows within a fixed period of time t. 1 MWh is the amount of electricity that a constant power flow of 1 MW over 1 hour accumulates. Thus the difference is that power does and have a time dimension and energy has; in the following I will mostly refer to "power" where I illustrate the impact of RES-e capacity

[1]The following explanations are focused on selected physical principles of meshed alternating current (AC) grids for two reasons. Firstly, AC grids are currently the dominant technology in Europe's transmission grids. Secondly, the basic functioning of direct current (DC) transmission links does not need any detailed explanation. The flow through DC lines, i.e. a simple point-to-point transmission, can be controlled independently from the remaining flows in the grid. Meshed DC grids are currently not technologically feasible Van Hertem et al. (2010). We also abstract from different voltage levels of grids and the peculiarities that arise at each level and limit the explanations to the fundamentals that govern the operation of all high-voltage AC transmission grids. The main take-away of this section shall be that power flows have two main drivers: the topology of the grid and the net generation at nodes, i.e. the distribution of injections and withdrawals of power across all nodes. Thus, in order to assess the physical impact new RES-e generating capacity is causing over its lifetime, one has to know the status of the grid topology and the economic dispatch of generation units in the network in each instance of time for the whole lifetime of the plant in question.

[2]This section has been developed jointly with André Ortner

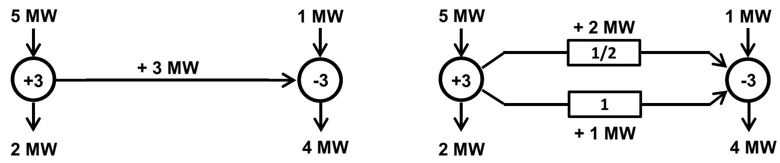


$$P_{injection} - P_{withdrawal} + P_{import} - P_{export} \stackrel{!}{=} 0$$

Figure 4.2: Principle of energy conservation

and to "energy", where I measure the impact of RES-e capacity, but it is evident that the impacts can be expressed in both dimensions that can also be converted into each other. When we say that electricity is generated from any source, we mean that energy is converted from some primary energy carrier to electricity. The maximum conversion rate is determined by the electricity generation capacity; capacities are denoted q/Q in the following. The decisive variable to explain the size and distribution of power flows in the grid is the impedance, describing the opposition against an electric current in AC transmission lines. The impedance is composed of the two parts resistance and reactance. Both parts of the impedance can be interpreted as some kind of friction against a flow. Whereas the resistance of a line causes thermal transmission losses as power flow increases, the reactance of a line determines the size of the power flow induced by a given driving force. In high-voltage transmission lines the resistance is very small compared to the reactance and can be neglected in good approximation. Both parameters are mainly depending on the materials used, the surroundings, the construction type and the length of the line or cable.

Principle (1) – Energy conservation I start with the fundamental law of energy conservation to construct the node balance within a grid. Note, that electricity storage would be connected to certain nodes. The charging or discharging of the storage is accounted as injections or withdrawals, respectively. The principle of energy conservation says that the sum of power injections in all nodes of a transmission grid has to equal the sum of power withdrawals from all nodes of the grid in every moment. The requirement that this holds for every moment also clarifies that energy cannot be stored within the grid. Against this background we are able to draw up the balance of a node (cf. figure 4.2). This principle holds for each node in a certain grid. This condition limits on the one hand the space of possible net generation patterns in the grid and on the other hand connects the node imports and exports of several nodes with each other. This relation



(a) Driver of power flows **(b)** Distribution of power flows

Figure 4.3: Driver and distribution of power flows

is expressed within principle (2).

Principle (2) – Driver of power flows Principle (2) states that the power flow through a line is driven by imbalances of generation $\bar{q}$ and demand $\bar{d}$ (net generation = $\bar{q} - \bar{d}$) at both nodes of a certain line. A positive net generation at one node flows in the direction of a negative net generation at the other node. An example of two nodes may illustrate this relation (cf. figure 4.3a). Power is simultaneously injected and withdrawn from two nodes. The power injection minus the power withdrawal (net generation) is displayed within each node. The left node has a positive net generation of 3 MW and the right one a negative net generation of same size. This causes a power flow of +3 MW from the left to the right node; a negative sign of the power flow would indicate a flow against the orientation of the line, i.e., a power flow from right to left. Note, that in the given example the node balance of physical principle (1) holds for both nodes. The power flow can now be controlled via changes in net generations. However, each additional injection has to be compensated by a reduced injection elsewhere, or by an additional withdrawal, respectively (cf. principle 1).

Principle (3) – Distribution of power flows Now that we know what causes power flows we can ask how a flow driven by a given force splits up over parallel pathways through the grid. Principle (3) states that the power flows through lines from sources to sinks split up in proportion to the reciprocal value of their reactance. To clarify this principle let us again take the example from principle (2) and split up the connecting line in between the two nodes in two lines. The reactances of the lines are ½ and 1, respectively (e.g. the line at the bottom could have twice the length of the one at the top). According to this principle the total power flow of 3 MW splits up in proportion of the inverse values of the reactances, namely 2 to 1. This example can be created from any grid for the case we inject only in one node and withdraw power from only one node. We just have to add up all the reactances from the lines in serial in between the two nodes (nodes with zero net generation are ignored) and end up with two nodes

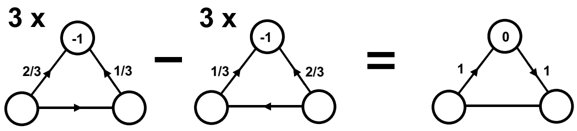


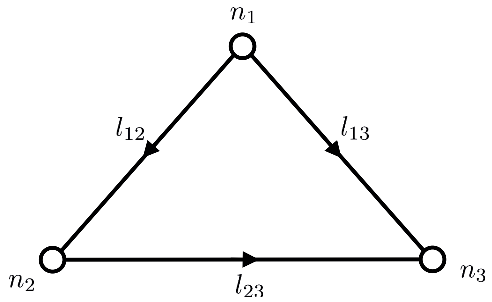
Figure 4.4: Additivity of power flows

connected by a set of parallel lines.

Principles (2) and (3) help us to understand basic power flow tendencies in transmission grids. Fortunately, most of them are intuitive. Power tends to flow from regions with surplus generation to nearest demand centers. The only difference to an ordinary transport model is that it is not restrained to a certain path; it rather takes all available paths at the same time.

Principle (4) – Additivity of power flows Principle (4) says that the sum of power flows on each line stemming from a superposition of flows caused by two distinct net-generation patterns within the grid is in good approximation the flow on each line that would result if both net-generation patterns would be at work simultaneously. This principle embodies the resulting linearity of the underlying system equations if all simplifications for high-voltage AC grids are incorporated. It is very useful in the sense that it is not necessary to calculate the resulting power flows of all possible net-generation patterns, rather we need simply calculate the flows in the grid stemming from an injection of 1 MW in one node and a withdrawal of 1 MW in another node (The node where we withdraw power from is called reference, or slack node). If we perform this for all nodes – except the slack node, which is the same in all cases – we can reproduce the outcome of any net generation pattern by simply scaling, adding and subtracting the flows from these calculations.

I illustrate this principle for the case of a three-node grid (cf. figure 4.4). The three nodes are connected via reactances of same size (i.e., they are of same construction type and length). Note, that for the distribution of flows only the proportion of reactances to each other, not their absolute size is decisive. Following the above described process, we can derive the flows of an identity injection at both bottom nodes to the slack node (top node) by applying principle (3). Since the sum of reactances over one path is twice as high as on the other path, the flows also split up in proportion 2/3 to 1/3. If we now want to calculate the flows stemming from a net generation of 3 MW at the lower left node and a net generation of -3 MW at the lower right node, we can simply multiply the flows of both “unit” cases with 3 and subtract them from each other.



(a) 3-node grid

$$TOPO_{ln^*} = \begin{array}{c} \\ l_{12} \\ l_{13} \\ l_{23} \end{array} \begin{array}{c} \begin{array}{ccc} n_1 & n_2 & n_3 \end{array} \\ \begin{bmatrix} 1 & -1 & 0 \\ 1 & 0 & -1 \\ 0 & 1 & -1 \end{bmatrix} \end{array}$$

(b) Topology Matrix

$$PTDF_{ln} = \begin{array}{c} \\ l_{12} \\ l_{13} \\ l_{23} \end{array} \begin{array}{c} \begin{array}{cc} n_2 & n_3 \end{array} \\ \begin{bmatrix} -2/3 & -1/3 \\ -1/3 & -2/3 \\ 1/3 & -1/3 \end{bmatrix} \end{array}$$

(c) PTDF matrix

Figure 4.5: Deriving the Power Transfer Distribution Factor matrix

The within physical principle (4) described process of "unit" injections is documented for each grid in the so-called Power Transfer Distribution Factor (PTDF) matrix. The PTDF matrix contains for all nodes of a certain grid (except the slack node) a column that indicates how the unit power flow (= 1MW) stemming from a unit net generation from this node (+1MW) to the slack node (-1MW) is distributed over the lines of the grid. I derive the PTDF matrix for the 3-node grid I used in principle (4). The matrix contains 3 rows (one for each line) and 2 columns (2 injection nodes (lower left and right)). The slack node is not included in the PTDF matrix, because all injections from the other nodes necessarily have to be balanced by the slack node to ensure principle (1) holds. Power flows stemming from injections in the slack-node can simply be derived by scaling any unit case with a negative number.

To construct the PTDF matrix we have to agree on the orientation of power lines in the grid (cf. figure 4.5b). I count flows from the slack node to the lower nodes positive. Also, I count a power flow from the lower left to the lower right node positive, or negative, respectively, in case it flows from the right to the left node. Having this in mind, we can build the PTDF matrix of the 3-node example by simply entering the flows from figure 4.4 into matrix form.

With this matrix the distribution of power flows over all three lines can be calculated by simply multiplying a vector of any net generation of both injection nodes with the PTDF matrix. This relationship is shown in eq. 4.1: the flow over a line l is obtained

Table 4.1: Selected notation of chapter 4

Sets	
$n, nn, m \in N \equiv M$	...nodes (of supply, demand)
$l \in L$	...transmission lines
$t \in T$	...time steps
$a \in A$	...years / periods
$s \in S$	...scenarios
Variables	
$\bar{q}_{n,t}$	...electricity generation [MWh]
$\bar{d}_{n,t}$	...electricity demand [MWh]
q_n	...generation capacity [MW]
$\bar{c}^{gen}_{t,n}$	...generation costs [Euros per MWh]
Parameters	
$PTDF_{l,n}$	...Power Transfer Distribution Factor
$TOPO_{l,n}$	...incidence matrix assigning lines l to nodes n

by multiplying the PTDF matrix with the net generation at each node $n \in N$.

$$Flow_{l,t} = \sum_n PTDF_{l,n} \cdot \left(\bar{q}_{n,t} - \bar{d}_{n,t}\right) \tag{4.1}$$

If we perform this calculation for the same generation pattern as in principle (4), i.e., $P_{injection} = [+3, -3]^T$we get $Flow_{12} = -\frac{2}{3} \cdot 3 + \left(-\frac{1}{3}\right) \cdot (-3) = -1$ and likewise $Flow_{13} = 1$ and $Flow_{23} = -2$, which are the same flows we derived in the right-hand side graph of figure 4.4. Note, that I use the convention of line orientation as indicated in the grid graph in figure 4.5a; therefore we have to count $Flow_{12}$ as negative.

Assessing the physical impact of RES-e capacity

Having established the power flow equation and the relevant terminology I can now rewrite the demand condition from principle (1) as shown in eq. 4.2.

$$\bar{q}_{t,n} + \bar{q}^{RES}_{t,n}\left(q^{RES}_n\right) - \sum_l TOPO_{l,n} \cdot Flow_{lt} = \bar{d}_{t,n} \tag{4.2}$$

Equation 4.2 again states that the sum of power injections and im-/exports at a node has to equal demand. It furthermore tells us that the generation pattern $\bar{q}_{t,n}$ can be modified by:

1. the direct injection of power $\bar{q}^{RES}_{t,n}$ from RES-e capacity at a node $n \in N$,

2. the import of power $-\sum_l TOPO_{l,n} \cdot Flow_{lt}$ from another node,
3. or a combination of both.

From eq. 4.2 it follows that any marginal increase of power at a node n induced from an direct injection or an import causes a marginal substitution of the initial generation pattern (cf. eq. 4.3) so that the node balance holds.

$$\Delta\bar{q}_{t,n} + \Delta\bar{q}_{t,n}^{RES}\left(\Delta q_n^{RES}\right) - \sum_l TOPO_{l,n} \cdot \Delta Flow_{lt} = 0 \tag{4.3}$$

By inserting eq. 4.1 into and re-arranging eq. 4.3 we can derive eq. 4.4, which provides a formal description of how the physical impact from RES-e capacity can be measured.

Definition 4.2. (Physical impact) I define the physical impact at one or more nodes $n \in N$, as the change in national generation mixes $\Delta\bar{q}_{t,n}$ caused by a power flow that stems from the injection of power from an additional unit of RES-e generating capacity installed at node $n \in N$.

$$\Delta\bar{q}_{t,n} = \frac{\Delta\bar{q}_{t,n}^{RES}\left(\Delta q_n^{RES}\right) + \sum_l TOPO_{l,n} \cdot \sum_n PTDF_{l,nn} \cdot \Delta\bar{q}_{t,nn}}{1 - \sum_l TOPO_{l,n} \cdot PTDF_{l,n}} \tag{4.4}$$

We can observe that the physical impact at a node $n \in N$ has two determinants: (i) the status of the grid topology, which is embodied in the two matrices TOPO and PTDF and (ii) the economic dispatch of generation units in the network (cf. eq. 4.4).

The economic framework for deriving the Benefit Distribution Factor

The underlying economics

The physical flows of electricity are closely related to economic rationales inherent to electricity markets and both mutually interact. The power exchange tries to clear the market with the cost minimal dispatch of generation capacities that is technically feasible. The dispatch determines the net generation pattern that in turn drives the power flow (cf. principle 2); that is, power flows - respecting constraints of transmission capacity (cf. eq. 4.5c) - from the nodes with the lowest generation costs to the sources of

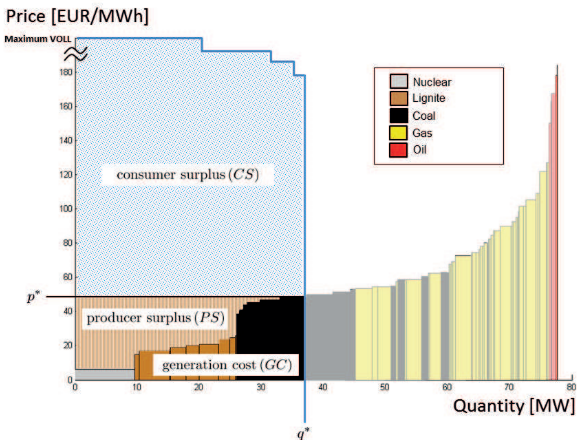


Figure 4.6: Merit order curve illustrating economic welfare metrics

demand where it is withdrawn.

$$\min_{\bar{q}_{t,n}} \bar{c}_t^{gen} = \sum_n \left(\bar{C}_n^{var} + k_n \cdot \bar{q}_{t,n}\right) \cdot \bar{q}_{t,n} \tag{4.5a}$$

$$s.t.\ \bar{q}_{t,n} \leq Q_n^{max} \tag{4.5b}$$

$$\sum_n PTDF_{l,n} \cdot \left(\bar{q}_{t,n} - \bar{d}_{t,n}\right) \leq Q_l^{atc} \tag{4.5c}$$

In the electricity market the gradients of the merit order and demand curves determine the market outcome, whereby the price of electricity acts as coordinating signal. The system marginal price is the market signal that equates supply and demand of electricity in each hour. This comprises all costs arising from marginal actions required to balance supply with demand. In hours of overcapacity, which is usually the case, the price is set by the short run marginal costs of available capacity according to the merit order curve. In hours of scarcity the price can for instance be set by the cost of providing control energy, the costs of financing investments in new generating capacity or the opportunity costs of shedding load.

The economic welfare in a single (isolated) market zone is given by the sum of consumer surplus and generator surplus. It can simply be calculated by subtracting from the area below the demand curve the area below the merit order curve up to the capacity needed to satisfy demand. This implies that the consumer surplus is given by the area lying vertically between the demand curve and the electricity price and the producer surplus is given by the area below the electricity price net off the costs of generation (cf. figure 4.6).

The impact of the changed generation pattern on generation costs and welfare metrics is illustrated further in the following. In the illustrations in figure 4.7 I only look at the case where power is imported from another node. This does however not prevent that the interpretation of the analysis can be generalized to all three cases as the injection of power at a node can be treated in the same way as an import, since both reduce the need for generation at the node (cf. eq. 4.2).

Assessing the economic impact of RES-e capacity

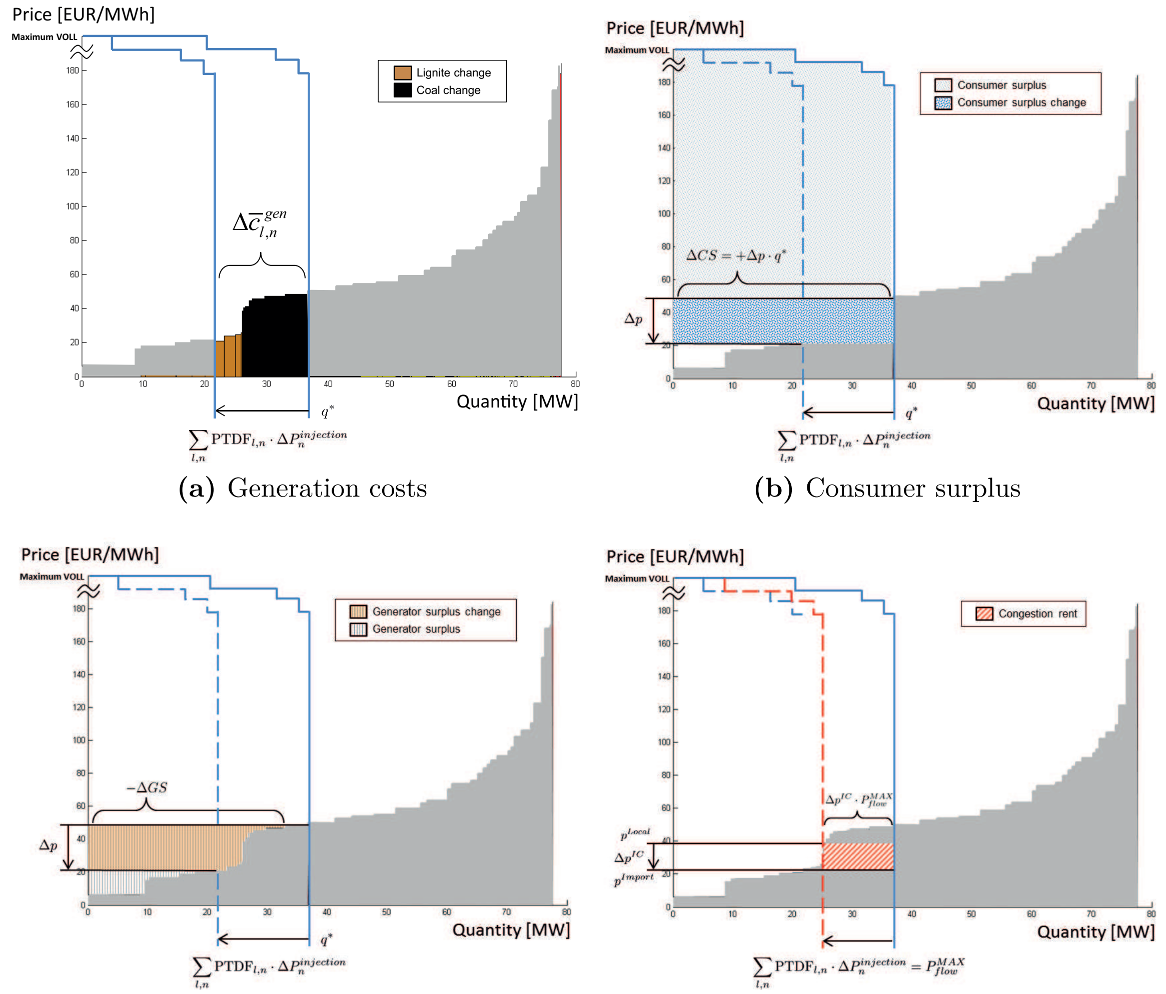
Equipped with the knowledge on the drivers of electricity trade we are now able to analyze the economic impact from additional RES-e capacity. For that purpose in the following $n \in N$ refers to a *demand node*, i.e., a node where the physical impact induced from an additional unit of RES-e capacity materializes as benefit as a consequence of the changed generation pattern. On the other hand $m \in M$ refers to a *supply node,* i.e., a node where the additional unit of RES-e capacity is installed and usually also supported financially, whereby a node can simultaneously (which will often be the case) be a supply and demand node. Since each Member State is represented by a single node, which can both be a source of supply and demand, the two sets $n, m \in N \equiv M$ are equivalents. As derived in section 4.1 the generation costs are selected as the system boundaries for measuring the economic impact.

Definition 4.3. (Benefit Distribution Factor) The Benefit Distribution Factor indicates for a given interval $[t, t']$ between points in time - usually an hour - the benefit, expressed as a node $n's$ share in generation costs savings relative to the generation costs savings of all nodes $n \in N$, which is induced by the physical impact stemming from the injection of power from an additional unit of RES-e capacity at a node $m \in M$.[3]

$$BDF_{m,n}\left(\Delta q_m^{RES}\right) = \frac{\sum_t^{t'} \Delta \bar{c}_{t,n}^{gen}}{\sum_t^{t'} \sum_n \Delta \bar{c}_{t,n}^{gen}} = \frac{\sum_t^{t'} \bar{C}_n^{var} \cdot \Delta \bar{q}_{t,n} + k_n \cdot \Delta \bar{q}_{t,n}^2}{\sum_t^{t'} \sum_n \left(\bar{C}_n^{var} \cdot \Delta \bar{q}_{t,n} + k_n \cdot \Delta \bar{q}_{t,n}^2\right)} \tag{4.6}$$

We thus see from eq. 4.6 that the benefit is a direct consequence of the changed generation patterns $\Delta \bar{q}_{t,n}$; that is, the power injection from the RES-e capacity displaces generation from other capacity which prevents that costs of generation incur. Since the BDF approach should be scalable to be applicable to projects of different size, the benefit

[3]In eq. 4.6 on the right hand side the index m is contained in the change of generation pattern $\Delta \bar{q}_{t,n}$, since this also depends on the changed generation pattern at every other node $nn \in N \setminus n$ (cf. eq. 4.4).



(a) Generation costs **(b)** Consumer surplus

(c) Generator surplus **(d)** Congestion rent

Figure 4.7: Measuring economic impacts

a demand node $n \in N$ experiences from a new unit of RES-e capacity at supply node $m \in M$ is expressed relative to the sum of benefits that all demand nodes $n \in N$ receive from the respective supply node m, rather than in absolute terms.

I further illustrate the idea with the help of figure 4.8. This figure shows a stylized network consisting of nodes that are connected by transmission lines. Nodes are assigned to the different Member States $\{A, B, C\}$ that they are situated in and can be both source of electricity supply and demand. In this example new generating capacity of photovoltaic power is installed at node $m1$ that is situated in Member State B. The installation of RES-e generating capacity at this node induces benefits in the network at the demand nodes by displacing the costs of some alternative generating option. The benefits are not split evenly due to transmission constraints in the network. In this

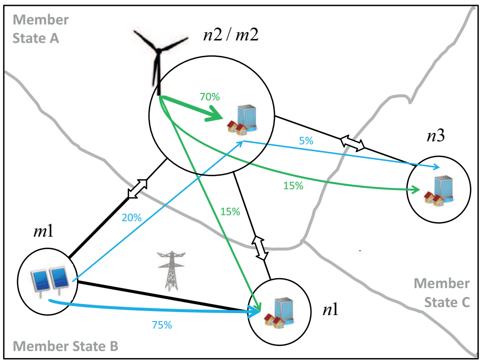


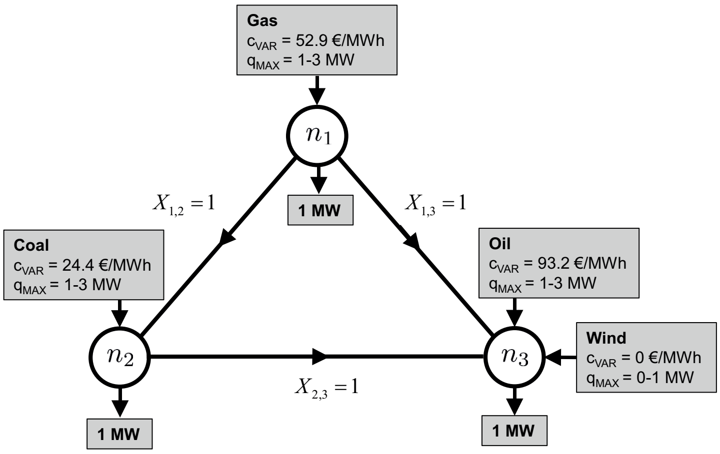
Figure 4.8: Illustration of BDF concept. Arrows indicate distribution of benefits across nodes in percentage points.

stylized example 75 percent of the aggregate benefit stays in Member State B, whereas the remaining share of the benefit is experienced in Member States A (20 percent) and C (5 percent). Besides PV electricity generation, additional RES-e generation comes from a wind power plant installed at node $m2$, which induces a benefit at demand nodes $n1, n2$ and $n3$. Also in this case the largest share of the benefit remains in the node where the wind power capacity is installed.

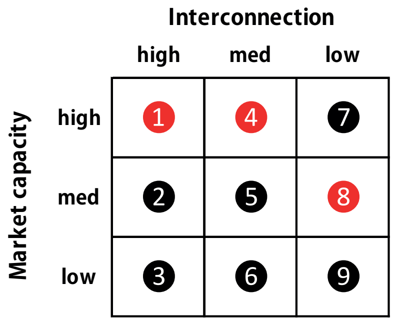
Besides giving a good indication of the distribution of benefits from a new unit of RES-e capacity further requirements for the cross-border impact factor have been defined in section 4.1: it should allow for reciprocity between Member States and it should be calculated in a systemic way. In order to achieve these desired properties I suggest to calculate the BDFs from the same model run and enter them into a *Benefit Distribution Factor Matrix* where the rows contain the BDFs for each supply node $m \in N$ and the columns indicate the benefit that is distributed to demand nodes $n \in N$ for each respective BDF.

Definition 4.4. (Benefit Distribution Factor Matrix) The Benefit Distribution Factor Matrix **BDF** contains for all demand nodes $n \in N$ of a network in each column the share of benefit this node receives from a new unit of RES-e capacity installed at a supply node $m \in N$. All supply nodes of a network are ordered by rows, whereby the the distribution of benefit from each supply node over all columns has to add up to one.

$$\mathbf{BDF} = \begin{bmatrix} BDF_{A,A} & \cdots & BDF_{A,n} \\ \vdots & \ddots & \vdots \\ BDF_{m,A} & \cdots & BDF_{m,n} \end{bmatrix}$$



(a) Set-up of study grid model



(b) Scenario table

Figure 4.9: Study set-up

4.2 Assessing physical and economic impacts of RES-e capacity in a three-node model[4]

The aim of this section is to demonstrate the above described impacts of additional RES-e generating capacity on power systems based on a 3-node model. Such a grid model constitutes the simplest form of a grid that reveals loop flows and is therefore best suited to capture all effects that might occur in the internal electricity market with flow-based market coupling. First, I describe the parameter settings and assumptions of the model. Then I provide an overview on the scenarios. Finally, I discuss the results of three selected scenarios in detail to foster the qualitative understanding of all involved interrelated impacts. In figure 4.9a a schematic overview of the simple grid model that is used to study the impacts is illustrated. The topology and orientation of the grid lines is the same as in figure 4.5. All the grid lines have a normalized reactance X of 1. Therefore, the same PTDF matrix as derived in figure 4.5, including the logic of deriving power flows, is valid for this model. I connect to each of the grid nodes certain generation technologies that differ in their marginal generation costs. All of the generators have, depending on the scenario, a maximum generation capacity of 1 or 3 MW. Each node has a demand of 1 MW in all scenarios. Thus, even without any grid connections each power node could be supplied self-sufficiently.

In all scenarios I consider only one time step. This enables us to observe the impacts of interest most clearly. This assumption is not a loss of generality, because more time steps up to period over a couple of years would then simply be the accumulated and

[4]The analysis in this section has been conducted jointly with André Ortner

averaged result of single time steps (cf. section 4.3). To study the impact of additional RES-e capacity a wind generator is connected to node 3. First, I start a model run without any wind in-feed. From that I derive the benchmark values for the variables of interest for the working point. Then an additional unit of wind power of 1 MW is injected into node 3 so that we can assess the changes of these variables as compared to the working point model run. This enables us to calculate changes in welfare and generation costs per node as a result of the additional wind in-feed. It should be noted, that this is a relatively high change in RES-e in-feed as compared to the load. However, this allows to observe the effects more clearly.

Figure 4.9b shows all of the considered scenarios which are grouped along two dimensions. The first dimension is the level of market capacity. In the case of high market capacity the maximum generation capacity of all three generators is 3 MW. Therefore, the total demand within the grid can be theoretically covered by each of the generators. However, in the absence of grid congestion the market will only require the lowest cost option, namely coal, to generate electricity. This is exactly the situation in scenario 1. One generator supplies many markets under the assumption of high interconnection and therefore no grid congestion. In case of medium and low market capacity the maximum generation output of coal and then of gas is limited to 1 MW. This leads to a situation where each node demand can only be covered by its own generator. The second dimension is the level of interconnection among the nodes. In the high scenario each line has a maximum transmission capacity of 1 MW. Therefore, theoretically each demand can be fully covered by a generator connected to another node. In case of medium and low interconnection I first limit the maximum transmission capacity of line node1-node2 to 0.5 MW and then additionally the capacity of line node2-node3 to 0.5 MW. This leads to grid congestion between the nodes. In this case loop flows play a crucial role. For example, the transmission from one node to another can be limited due to congestion within a parallel path. This impacts then not only power flows, but also the price levels that appear at each node. This leads to the situation where congestion rents on non-congested lines appear. Finally, non-intuitive flows might arise in case the welfare in the whole grid can be increased on cost of decreasing the welfare at one node. In the following the results of the scenarios 1, 4 and 8 covering some interesting impacts are discussed in detail. The interpretation of the results is split-up into impacts on generation costs, consumer rents, producer rents and congestion rents. The impacts are discussed under changed framework conditions represented by scenario 1, 4 and 8. Table 4.2 summarizes the maximum capacities of generation and transmission for the three scenarios.

In the following the results of the three scenarios, which are displayed in figure 4.10

Table 4.2: Scenario parameters

Generation capacity (MW)	Scenario 1	Scenario 4	Scenario 8
Coal (n2)	3	3	3
Gas (n1)	3	3	1
Oil (n3)	3	3	3
Transmission capacity (MW)	**Scenario 1**	**Scenario 4**	**Scenario 8**
n1-n2	1	0.5	0.5
n1-n3	1	1	0.5
n2-n3	1	1	1

and table 4.3, are interpreted in more detail. The results for all scenarios are shown in table A.1.

Physical impacts

In the working point in scenario 1 coal supplies the demand on all three nodes, since it is the cheapest option and no grid line is congested. The power flows can be interpreted by applying physical principle (4). Node 2 has a net generation of 2 MW, which must be exported from the node (cf. physical principle 1). In this case this happens via two flows, one flowing from node 2 to node 1 and one from node 2 to node 3. Flow 2-1 splits up over the parallel paths line23-line13 and line12. By applying physical principle (3) we already know that the flow over line12 will be twice as high as over line23-line13, because the sum of reactances along the path is half as large. As the net generation in node 1 is -1 we can conclude that 2/3 MW of that demand flows over line12 and 1/3 MW over line23-line13. In case of flow node2-node3 the portioning is the other way around: 2/3 MW flows over path line23 and 1/3 MW flows over path line12-line13. According to physical principle (4) we can superpose all resulting flows per line. This superposition then exactly leads to the flows in t1 of scenario 1. The flows (2/3 and 1/3) on line12 and line23 add up to 1 MW and the flows over line13 cancel each other out. In time step t2 an additional 1 MW of wind generation is fed in node 3. Due to the fact that this wind generation has a marginal generation cost of zero it replaces the imported coal and fully covers the local demand. Therefore, coal only covers demand in node2 and node1. This results in an electricity flow from node2 to node1, which flows as argued before with 2/3 MW over line12 and 1/3 MW over path line23-line13. That means in the case of no grid congestion wind simply replaces more expensive fossil fuels. This statement can be generalized; in case the grid is not congested each net generation pattern in the grid can be realized. This of course includes the least-cost net generation pattern, therefore

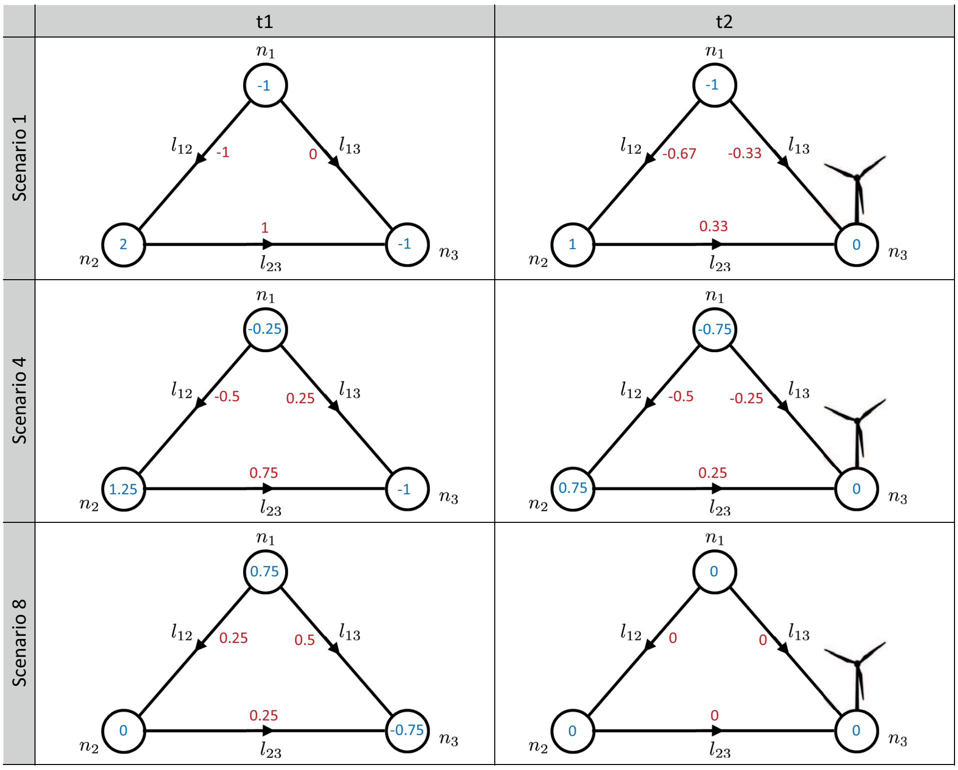


Figure 4.10: Resulting power flows and net generation patterns in selected scenarios. All scenarios consist of two time steps, one before (the working point) and one after the in-feed of one (additional) MW from wind power into node 3. The resulting power flows are marked in red. Within each node the difference between generation and demand (net generation) is displayed in blue color.

the grid acts as if it was not there.

Scenario 4 restricts line flow line12 to 0.5 MW. This leads to the situation where both, coal and gas have to run in order to avoid the operation of oil on node3. The situation changes in time step 2, where node3 is self-sufficient due to additional wind in-feed. This relieves the gas generator since 0.75 MW from coal can now flow to node1. Because of the flow limit on line12, 0.5 MW from this share can flow over line12 and 0.25 MW over line13. The remaining demand of 0.25 MW has to be covered locally by the gas generator connected to node2. The finding from this scenario is that the dispatch in a congested grid can deviate from the least-cost dispatch. It changes in a way that more expensive generators are ramped-up, which drive flows against the direction of the lines which are congested to keep the flows below their maximum limit. If additional generation from RES-e generating capacity exacerbates or relieves such a situation depends on whether the flows it drives relieve or exacerbate the congestion.

The probability of congestion rises with the level of market capacity. In case of a limited capacity of coal as illustrated in scenario 8, the coal generator is already in the working point not able to cover any additional demand besides the one on node2. The second cheapest unit, namely gas on node1, transports some share of power over line12 and line12-line23. Due to grid congestion on line13 it can only transport a maximum of 0.75 MW to node3 and the oil generator is needed to cover the remainder. When additional generation from wind is injected into node3 the oil generation as well as the (more expensive) gas imports are completely replaced so that each node is now covering its own demand and no power flows are needed any more. To sum up, I derived that in case of high transmission capacities the least-cost dispatch without considering the grid does not differ from the solution including the grid. In case of lower interconnection the probability of grid congestion rises. This may cause congested grid lines, which in turn force the actual generation dispatch to alter from the least-cost one. In this situation it is decisive for the value additional capacity from RES-e has, if it relieves or exacerbates this congestion. This especially holds in situations of high market capacity that lead to an increasing amount of cross-border flows and thus higher probability of grid congestion. For cases with lower market capacity additional RES-e generating capacity tends to replace larger shares of domestic generation. In the following sections the implications of these findings on the change in nodal generation costs and welfare are discussed.

Impacts on generation costs

The change in generation costs has already been identified beforehand as preferred indicator to measure the impact of RES-e capacity. I already discussed that the value of this change on the one hand depends on the generation dispatch in the working point and on the other hand whether RES-e generation causes flows that relieve grid congestion or not. In the three scenarios we had three different working point situations caused by grid congestion and capacity limitations of low-cost generators. The additional wind generation caused flows that always relieved the grid congestion and therefore reduced generation costs. The value of these reductions depends on the running generators in the working point. Whereas in scenario 1 only the least-cost generator coal is replaced, in scenario 4 a mix of coal and gas and in scenario 8 the more expensive mix of gas and oil has been replaced. Consequently, the benefit of cost reduction materializes where generation is displaced. Note, that in scenarios 1 and 4 the share of cost reduction in the wind node node3 is zero. Whereas in scenario 4 the amounts of replaced coal and gas were the same and only the difference in costs determined the share, in scenario 8 the share of the more expensive oil is only one third of the replaced gas, therefore the share of replaced costs in the gas node node1 is higher.

Impacts on consumer surplus

In our simple model we only considered short-run marginal costs of all generation units. Therefore, the electricity price per node is determined by the marginal generation cost increase that results from a marginal increase of demand at this node. In scenario 1 coal is price setter in both time steps and therefore the electricity price at all nodes and both time steps is 24.4 EUR/MWh; consequently, the changes in consumer rents are zero. In scenario 4 grid congestion on line12 in between coal and gas is present. This leads to different electricity prices in all nodes. In node2 coal is price setter, in node1 it is gas and in node3 a value in between the generation costs of coal and gas results as electricity price. This can be explained by the fact that an additional unit of demand at node3 would be served by a mix of additional coal and gas generation. Again this situation holds for both time steps, therefore no changes in price levels and consequently consumer rents occur. In scenario 8 the nodal prices change during the two time steps. In both time steps additional demand at node1 can be delivered by an increase in gas generation, therefore the price change and consumer rent change is zero. An additional unit of demand in node2 is supplied by a mix of gas and oil (because the flow on line13 and coal generation is already on its limit) in time step 1 and solely by coal in time step 2. In node3 oil is price setting in time step 1. After wind in-feed in time step 2 oil is replaced and the price in node3 is set by gas, the most expensive unit that is running in this moment. The consumer rent is the difference between the prices after and before the wind in-feed times 1 MW. I conclude that changes in consumer rents depend on the elasticity of generation. In case we assume an elasticity of demand greater than zero it also plays a role. However, we see that although additional RES-e in-feed might decrease generation costs, it does not necessarily mean that also electricity prices and consumer rents are influenced.

Impacts on generator rents

In contrast to welfare improvements for consumers decreasing electricity prices induced from additional RES-e generating capacity reduce generator rents. However, in the Member State that installs the wind power plant additional generator rents arise for the amount of additional RES-e generation. This happens in all scenarios. The additional 1 MW wind in-feed at node3 receives a generator rent in the height of the prevailing electricity price at this node in time step 2. The other units do not receive any generator rent most of the time since they are price setter in the node they are connected to. One exception is coal, which receives in scenario 8 and time step 1 a generator rent of 20.15

EUR, because gas is price setter and there is no line congestion in between coal and gas. In time step 2 this rent disappears and thus the corresponding generator rent as well. I conclude that generator rents are influenced by nodal prices. The severeness of the impact again depends on the elasticities of supply and demand. Furthermore, whereas the consumer surplus is influenced by the size of national demand the generator surplus is influenced by the size of national generation, i.e., also imports and exports play a role. The difference between the two appears in the congestion rents that are collected and distributed among the involved TSOs in charge.

Impacts on congestion rents

Congestion rents occur when electricity is transported through a congested line that connects two different price zones. It accounts for differences between consumer and generator rents in the whole grid. Since congestion rents are inherent to a certain line rather than to a node an allocation of the rent is not straight forward. However, typically national TSOs cooperate in the operation of a cross-border line. An often used split of congestion rents between two adjacent TSOs is 50/50. I follow this convention and allocate half of the congestion rent to each connected node. In scenario 1 no line is congested during both time steps, therefore the congestion rents are also zero. In scenario 4 an interesting situation occurs. Although the flow through line13 is not on its upper limit an additional flow is blocked by the congestion on line line12. Because there is a price difference between node1 and node3, a congestion rent arises on this line although it is not fully utilized. This is a result of a limitation caused by the system and is inherent to the procedure of flow-based market coupling. However, we are interested in a change of congestion rents before and after the wind in-feed. It can be seen that the congestion rent over line13 increases and the one over line23 decreases at the same amount. Due to the fact that price levels in each node remain constant during the two time steps these rents are the result of smaller line flows over path line23-line13 because of the additional wind in-feed. The change in congestion rents in scenario 8 is exactly the same as the size of congestion rents in time step 1 but negative, since all rents disappear in time step 2. The resulting congestion rents are influenced on the one hand by the amount of the flow through the line and on the other hand by the price differences as already discussed in the previous sections. I conclude that grid congestion might lead to shifts in rents between consumers, producers and TSOs that can occur in all directions.

Finally, table 4.3 provides a summary of the impacts discussed beforehand. We observe that additional RES-e generating capacity in all cases leads to generation cost savings in the system. The BDF indicates how these cost savings are split up between the

Table 4.3: Summary of impacts of additional RES-e on generation costs and welfare for selected scenarios. The impacts are ex-post calculated as difference of generation costs and welfare between these two time steps.

	Scenario 1			Scenario 4			Scenario 8		
System Generation Cost Savings [€]	24.38			38.64			62.98		
Benefit Distribution Factor [%]	n1	n2	n3	n1	n2	n3	n1	n2	n3
	0%	100%	0%	68%	32%	0%	63%	0%	37%
Nodal Generator Surplus [€]	n1	n2	n3	n1	n2	n3	n1	n2	n3
	0.00	0.00	24.38	0.00	0.00	38.65	0.00	-20.15	52.91
Nodal Consumer Surplus [€]	n1	n2	n3	n1	n2	n3	n1	n2	n3
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.15	40.30
Nodal Congestion Rent [€]	n1	n2	n3	n1	n2	n3	n1	n2	n3
	0.00	0.00	0.00	3.57	0.00	-3.57	-12.60	-12.60	-5.04
Changes in Nodal Welfare [€]	n1	n2	n3	n1	n2	n3	n1	n2	n3
	0.00	0.00	24.38	3.57	0.00	35.09	-12.60	-12.60	88.17
	24.38			38.65			62.98		

different nodes. Since in our stylized example the impacts have been over-pronounced intentionally, the BDF appears more one-sided than it would be the case in practice. Moreover, we observe that the generation costs savings and the surplus changes accrue at different nodes due to distributional effects in the interconnected electricity market. We also see, that generation cost savings are transformed in one or the other form of nodal rent changes and that the system generation cost savings equal the sum of changes in nodal welfare.

4.3 Calculating the BDF matrix for different system states and system development scenarios

Robustness of the BDF matrix for different system states and modeling implications

So far I have been referring to an **additional unit** of RES-e generating capacity in order to calculate the impact, but I have not further specified what the size of the additional capacity would be. Precisely the additional capacity is determined in the EU cross-border auction. Therefore I see two principal approaches (cf. figure 4.11) and one alternative option to determine the change in RES-e generating capacity in order to derive the BDF matrix:

1. *Sequential approach*: In this approach the BDF matrix is calculated ex-ante and then passed on as parameter to the cross-border auction. With this approach the assumption is made that the values of the matrix stay constant for certain ranges of additional of RES-e capacities so that the additional unit could be calculated as marginal change of RES-e capacity.

2. *Integrated approach*: If however the assumption is made that the values of the BDF matrix loose their validity with every new addition of capacity - both in time and space - this would in every case alter the outcome of the auction, which in turn would affect the values of the BDF matrix: the implication would be that both the auction outcomes and the BDF matrix would have to be determined simultaneously. This would constitute a bi-level problem between the first and the third stage in the auctioning game. The lower stage would be modeled by market and network models, which would make the problem in the first stage non-linear. In order to solve such a bi-level problem, the lower level problem would need to be linearized and inserted to the auctioneer‘s maximization problem as equilibrium constraints. This approach however also brings along several mathematical complexities.

3. *Decentralized approach*: The third approach differs from the two other ones in so far that the derivation of the BDF matrix would be decentralized instead of being conducted centrally. One could allow Member States to set their willingness to pay according to their preferences for each node in the network. Such an approach could be relevant if a Member State‘s elasticity of substitution at each node would depend on other effects than those measured directly or indirectly through the

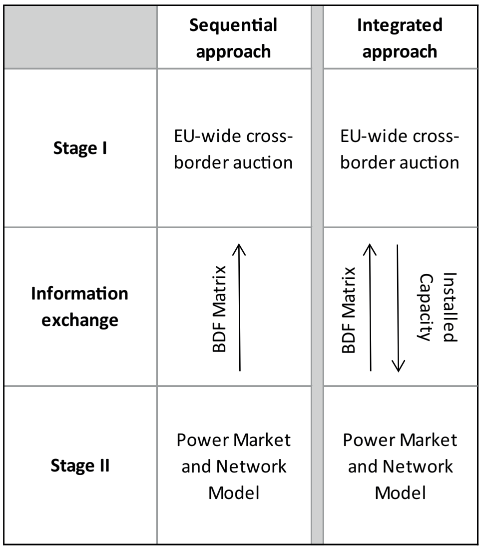


Figure 4.11: Modeling approaches for the BDF

BDF matrix, i.e., effects that do not entirely depend on the spill-over of benefits. Even though in this case the coefficients of the BDF matrix would be determined decentrally, Member States in making their decisions could be aided by a centralized matrix calculation. Returning the burden to assess all relevant information back to the Member States, would however be inconsistent with overcoming some of the barriers identified in section 2.3.

In the following I explain under which conditions I think it will be possible to apply the sequential approach: a principle that is often applied to decompose problems in engineering and physics into easier to solve sub-problems is the superposition principle.

Definition 4.5. (Superposition principle) The superposition principle states that, for all linear systems, the net reaction at a given place and time caused by two or more stimuli is the sum of the responses which would have been caused by each stimulus individually. So that if input α produces response γ and input β produces response δ then input $(\alpha + \beta)$ produces response $(\gamma + \delta)$.

$$\Delta\bar{c}_n^{gen}\left(\Delta q_{m1}^{RES} + \Delta q_{m2}^{RES}\right) = \Delta\bar{c}_n^{gen}\left(\Delta q_{m1}^{RES}\right) + \Delta\bar{c}_n^{gen}\left(\Delta q_{m2}^{RES}\right) \quad \forall \quad n, m \tag{4.7}$$

I argue that the sequential approach can be a valid representation of reality as long as the superposition principle holds. Applied to our problem at hand the superposition principle has the following implication: the change in generation costs at a node $n \in N$ induced from the injection of power from an additional unit of RES-e capacity at node $m \in N$ stays the same, whether the additional injections take place isolated or simultaneously (cf. eq. 4.7), which means that the impacts of injections at different nodes do not interact, both in space and time. This has an important implication for the BDF matrix calculation: it allows calculating the BDF matrix by only considering additional unit injections at single nodes, so that the BDF matrix can feed as parameter into the auction and does not need to be updated for each change in net injection profiles (induced by newly installed RES-e capacities). The superposition principle holds as long as the effect of an additional net injection on the change in generation costs can be assumed to be approximately linear.

Claim 4.1. The impact of power injections from an additional unit of RES-e capacity at a node $m \in N$ on the change in generation costs at a node $n \in N$ is sufficiently linear for ranges of RES-e capacity additions as those typically defined by the cross-border auction so that the superposition principle is a good approximation of reality.

I will argue next, why the necessary condition of approximate linearity can be a plausible assumption:[5] The general line of reasoning goes like this:

- I postulate that the merit order curve generally follows a convex shape (cf. figure 4.6)
- The working point of the merit order curve when RES-e feed-in takes places will often be in a flat, near linear section of the curve
- The deviation from the working point induced from the RES-e power injection is small, so that we will still be in the near linear section of the merit order curve

The general shape of the merit-order curve is non-linear and follows a convex shape by approximation. I do however claim that the in-feed of RES-e generation mostly takes place when the working point of the merit order is in the approximately linear or at least only weakly non-linear section of the curve. The argument for this is twofold. On the one hand the additional unit of RES-e generating capacity will mostly be available when other already existing RES-e generating capacity is available. The existing RES-e capacity displaces peak load generation such as gas, which is pushed out of the market, so that the working point of the merit order is moved across to an overall flatter section. On the other hand the coupling of electricity markets hampers and prevents price spikes for an average dispatch situation, real price spikes are only likely to arise - if at all - when the availability of RES-e generating capacity is about zero.

[5]Note that these are however only claims, which I do not attempt to prove within this thesis and which will have to be tested in further research elsewhere

From a practical perspective moreover the following argument applies additionally: as already mentioned above the modeling of the impact factor will most likely never fully represent the reality, but deviations will occur due to simplifications in the modeling approach or deviations in the input parameters. If there is no general bias in the methodology; that is, the methodology gives equal consideration to all effects inside the power sector, these deviations will in cases both occur upwards and downwards so that to a certain extent they will net out each other so that the aggregate impact fits fairly well again.

Obviously the BDF matrix will have to be updated in certain intervals, but how often exactly? Two crucial issues play a role here. First, if the amount of additional RES-e capacity exceeds a certain threshold the superposition principle cannot be applied anymore and the coefficients of the BDF matrix are losing their validity. Second, the more the assumed framework parameters that determine the dispatch deviate from most plausible forecasts at the time of calculation of the BDF matrix the less credible are its coefficients. The challenge therefore is to come up with thresholds, which determine at which point an update of the BDF matrix is necessary, be it because of a significantly different RES-e investments, or unforeseen developments of framework condition.

Parametrization of the BDF matrix

Next I introduce additional sets that are added to the BDF matrix in order to express different states of the system. The set $a \in A$ assigns the BDF matrix to different years, respectively periods. This is required, because a change in dynamic parameters, such as fuel costs, affects the level of spill-overs and thus the parametrization of the BDF matrix. This regards in particular changes of the grid topology and interconnection capacity, but also other parameters such as the composition of the generation mix or the shape of the demand profile. Moreover the set $s \in S$ indicates a range of possible future scenarios for the development of the power system. This is required because the future is uncertain and different scenarios refer to different plausible future developments of input parameters.

Now that the BDF matrix can be expressed for different system states, a plausible set of parameters has to be identified, which provides for a good representation of the different system states that determine the BDFs and which is readily available at the required scale. I propose to integrate the parametrization and calculation of the BDF matrix in the creation process of the Ten Year Network Development Plan (TYNDP) (ENTSO-e, 2014). For the cost benefit analyses conducted under the TYNDP the same tools and data-sets are used that would also be needed for the calculation of the BDF

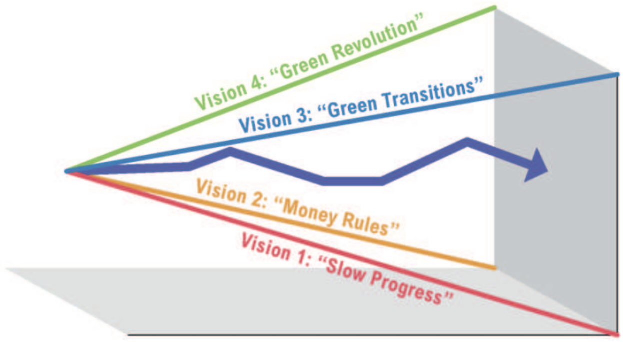


Figure 4.12: Visions under the TYNDP 2014, source: ENTSO-e (2014)

matrix. The basis for the TYNDP 2014 scenario analyses are four 2030 visions. The visions are not so much forecasts of the future, but rather plausible future states selected as wide-ranging possible alternatives. This ensures that the realized pathway actually falls within the range described by the visions with a high level of certainty (cf. figure 4.12).

The span of the four visions is large to meet the various stakeholder expectations. The visions mainly differ with respect to ENTSO-e (2014):

- "The trajectory towards the Energy Roadmap 2050: Visions 3 and 4 maintain a regular pace from now until 2050, whereas visions 1 and 2 assume a slower start then acceleration after 2030. Fuel and CO_2 prices favor coal (resp. gas) in visions 1 and 2 (resp. visions 3 and 4)".

- "Consistency of the generation mix development strategy: Visions 1 and 3 build from bottom-up, based upon each country's energy policies, but still with a harmonized approach across Europe, whilst visions 2 and 4 assume a consistent top-down pan-European approach. The most important monitored characteristic parameters, which differ through the visions, are total yearly consumption, generation mix and RES share in the total supply, CO_2 emissions, and average energy price. Differences in the high-level assumptions of the visions are manifested among others in markedly different fuel and CO_2 prices sets in visions 3 and 4 compared to visions 1 and 2, resulting in a reversed merit order for gas and coal units".

Integrating the calculation of the BDF matrix into the TYNDP process would have several advantages. First of all the required methods and data-sets are already available within this process. This would also ensure that the data-set is consistent across the EU and transparent. The latter is important, because the coefficients assigned to the BDF matrix from the calculation will have an impact on the outcome of the mechanism, thus

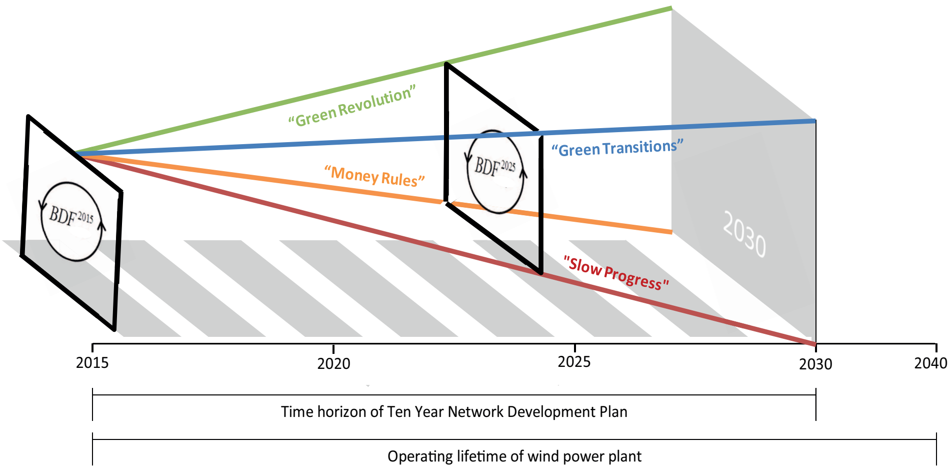


Figure 4.13: Example for wind power plant of integrating the BDF calculation into the TYNDP

the input data used for the calculation should be agreed on by all concerned Member States and deviating views could be clarified within the TYNDP consultation process. A further advantage would be that the TYNDP is updated on a regular basis so that an updated matrix could be calculated when parameters change. For instance for 2030 an increase of the interconnection target to 15 % is foreseen (European Commission, 2015a), which will likely have a significant effect on the spill-over of benefits. Finally the integration into the TYNDP would allow for a better coordination between transmission and generation investments, as current and future grid constraints are implicitly reflected in the coefficients of the BDF matrix and therefore provide locational signals for the siting of new RES-e generating capacities.

$$\begin{aligned} BDF_{m,n} &= \frac{BDF_{s0,m,n,a}}{\sum_a a} + \sum_{s \neq s0} \left[\frac{BDF_{s,m,n,a+10}}{\sum_a a \cdot \sum_{s \neq s0} s} \right] \\ &= \frac{BDF_{s0,m,n,2015}}{2} + \sum_{s \neq s0} \begin{bmatrix} \frac{BDF_{s1,m,n,2025}}{8} & \frac{BDF_{s2,m,n,2025}}{8} \\ \frac{BDF_{s3,m,n,2025}}{8} & \frac{BDF_{s4,m,n,2025}}{8} \end{bmatrix} \end{aligned} \tag{4.8}$$

Now with all the parameters available one could calculate BDFs according to eq. 4.6 for different system states. Figure 4.13 illustrates for the case of a wind power plant that is installed in the year 2015 how the TYNDP would provide the roster for the BDF calculation: in order to have a good representation of system states (and thus distribution of benefits) over the lifetime of a wind power plant and to address future uncertainty and parameter variations I propose to consider two different points in time; one in the present and one ten years in the future (this would roughly correspond to half of the lifetime of a new power plant that is installed now). Both points in time would be weighted equally with 50 percent, however the point in time in the future can unfold in four different scenarios thus each future scenario would be weighted with 12,5 percent. At first the BDF for the year $a = 2015$ would be calculated. Each yearly BDF could be composed of hourly BDFs for intervals containing each hour of a year $t = [1, 8760]$ or a representative subset thereof. Since for the year 2015 the status of the power system is known, there is no need to conduct sensitivity scenarios ($s = 0$). For the year $a = 2025$ a set of four yearly BDFs would be calculated each of them representing a scenario $s = [1, 4]$ corresponding to the four visions "Slow Progress", "Money Rules", "Green Transitions" and "Green Revolution". Equation 4.8 shows the corresponding formula that could be applied. A further illustration is given in example 4.1.

Example 4.1. (BDF calculation): For this example I use the BDFs displayed in table 4.3, which have been derived for an additional unit of wind capacity installed at node $m3$. Since in this example we have $\sum_a a = 1$, i.e., we only consider one year / period the BDFs are only weighted by the number of scenarios. Giving equal weight to all scenarios yields the $BDF_{m3,n} \approx (0.44, 0.44, 0.12)$.

$$BDF_{m3,n} = \sum_s \frac{BDF_{s,m3,n}}{\sum_a a \cdot \sum_s s} \tag{4.9a}$$

$$= \frac{1}{3} \cdot \begin{bmatrix} BDF_{s1,m3,n1} \\ BDF_{s1,m3,n2} \\ BDF_{s1,m3,n3} \end{bmatrix}^T + \frac{1}{3} \cdot \begin{bmatrix} BDF_{s4,m3,n1} \\ BDF_{s4,m3,n2} \\ BDF_{s4,m3,n3} \end{bmatrix}^T + \frac{1}{3} \cdot \begin{bmatrix} BDF_{s8,m3,n1} \\ BDF_{s8,m3,n2} \\ BDF_{s8,m3,n3} \end{bmatrix}^T \tag{4.9b}$$

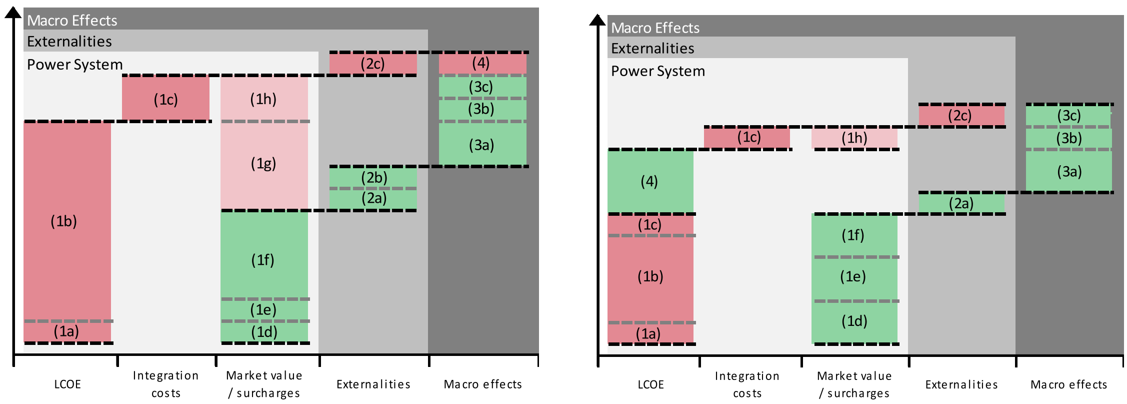
$$= \frac{1}{3} \cdot \begin{bmatrix} 0 \\ 1 \\ 0 \end{bmatrix}^T + \frac{1}{3} \cdot \begin{bmatrix} 0.68 \\ 0.32 \\ 0 \end{bmatrix}^T + \frac{1}{3} \cdot \begin{bmatrix} 0.63 \\ 0 \\ 0.37 \end{bmatrix}^T \approx \begin{bmatrix} 0.44 \\ 0.44 \\ 0.12 \end{bmatrix}^T \tag{4.9c}$$

Chapter 5

The auction bidders: Member States and renewable electricity generators

5.1 The Member States' willingness to pay for RES-e capacity expansion

In this section I discuss - from an economic perspective - the willingness to pay by Member States for additional RES-e capacity expansion. This shall be done with the help of figure 5.1 that conceptually structures and illustrates the different cost and benefit components described in section 2.1. It thereby distinguishes between two different points in time (today and future). The figure groups the effects according to the three system boundaries developed in section 2.1 (power system, externalities, macro effects), whereby a red coloring refers to "costs" and a green coloring to "benefits". I first focus on the situation in the power system today: typically the market income (1d-f) RES-e generation has in the electricity market is not (yet) high enough to cover its long term costs of generation (1a+b). Therefore, in order to incentivize the diffusion of RES-e capacities into the market, the regulator pays the RES-e generator a premium on top of the market income (1g). Moreover RES-e generation may induce additional integration costs (1c) in the residual power system, which are usually covered through grid charges (1h). Beyond that RES-e generation induces further effects (2a-3c) - mostly benefits - outside the power system. In this conceptual illustration for the situation today, costs and benefits aggregated across all system boundaries yield a net social cost as the external benefits do not cover up for the relatively higher costs of RES-e generation. Let



(a) Today **(b)** Future

(1a) Variable costs	(2a) Avoided local air pollution	(3a) Security of supply	(4) Net social benefit / net social costs
(1b) Fixed costs	(2b) Non-internalized value of avoided CO_2 emissions	(3b) Employment effects	
(1c) Integration costs	(2c) Landscape and biodiversity costs	(3c) Innovation effects	
(1d) Saved capital costs			
(1e) Saved CO_2 emissions			
(1f) Saved fuel costs			
(1g) Support premium			
(1h) Grid surcharges			

(c) Legend

Figure 5.1: Cost and benefit components in three layers

us now turn to the possible situation in the future. It is the belief that RES-e generation will be able to significantly reduce its fixed capacity costs (1b) due to not yet exploited learning curve potential. Thus in principle RES-e generation could be able to recover its full costs (maybe except integrations costs) through earnings on the electricity market. It can be expected that the contribution of different effects to the market earnings of RES-e generation is going to change in the future. Saved fuel costs (1f) are likely to decrease as less conventional generation will be displaced – in turn saved capacity costs (1d) are likely to go up, because the capacity factor for RES-e generation can be expected to increase, e.g. by means of a more flexible demand side. Changes in the design of the EU ETS may lead to a higher value of saved CO_2 emissions (2b) being internalized in the power system. Also it may be the case in the future that integration costs (1c) will to some extent be reflected in the costs of RES-e generation for example when RES-e generation becomes balancing responsible.

Next I discuss how electricity market failures relate to the context discussed above. At least two types of market failures are known with respect to RES-e generation (EFI, 2013; Mitchell et al., 2011):

- External costs of burning fossil fuels: damages from global warming and local pollution are not usually considered by private actors in the power system unless the associated external costs are purposefully internalized (2a+b). As a consequence, there is an under-investment in RES-e generating capacities.
- Imperfect appropriability of benefits from innovation: specifically, research and development, innovation, diffusion and adoption of new low-carbon technologies often create wider benefits to society than those captured by the innovator. If firms or countries underestimate the (future) benefits of investments into learning technologies (the reduction in capital costs (1b)) or if they cannot appropriate these benefits, they will invest less than is optimal from a macroeconomic perspective.

The reason that market failures exist is the economic justification for market interventions through RES-e support instruments. In these cases the positive externalities and macro effects (2a-3c) cannot be internalized by firms or even countries that act unilaterally in expanding RES-e capacity. From society‘s perspective however it is worth to – temporarily – pay a support premium so that additional RES-e generating capacity would be deployed at the efficient level. Precisely, in the long–term average, the costs of RES-e expansion (private and public support) have to be lower than the accumulative social benefits so that it pays for society to support RES-e generation. Thus from a long-term perspective, the social benefits constitute an upper boundary of what a society would be willing to pay for RES-e support.

One could argue that there would be no need to determine an individual Member State's willingness to pay, given that already an EU-wide 2030 target has been established that would already internalize the above described market failures. This argument however falls short for two reasons: firstly the EU target can be seen as the lowest common denominator the European Council could agree on and therefore is not representative for each Member States' willingness to pay (that might be higher or lower). Secondly, in case an EU-wide instrument would be established to secure the achievement on the 2030 target also this instrument would require besides information on costs information on the Member States‘ valuation of new RES-e generating capacity for making efficient siting decisions.

Willingness to pay and spatial preferences

From eq. 3.2 we already know that the spatially distributed willingness to pay of a Member State breaks down in two components:

1. The marginal benefit $b^{'}(x_n)$ she derives from a unit of RES-e capacity assuming she consumes the full unit. In section 5.1 above I identified marginal benefit with willingness to pay so that we have $b^{'}(x_n) = WTP$. Moreover, this implies that she is indifferent regarding the location of RES-e capacity, so that we have $b^{'}(x_n) = b^{'}(x_m)$; that is, the benefits from a unit of RES-e capacity are equal regardless of location given that the amount consumed is also equal. Spatial differences are incorporated in the BDF matrix.

2. Her share in the consumption of the benefit α_n. This concept has been operationalized in detail in chapter 4 through the BDF matrix.

Therefore, the willingness of a Member State $n \in N$ to pay for additional RES-e capacity needs to be differentiated by node. Precisely the willingness to pay at a node $m \in N$ has to be weighted with the BDF matrix in order to indicate Member State $n's$ willingness to pay at a node m. This relationship is shown in eq. 5.1.

$$WTP_n \cdot BDF_{m,n} = WTP_{n,m} \; \forall \; n, m \tag{5.1}$$

For instance in case the system consists of three Member States $\{A, B, C\}$ then the BDF would allocate Member State $A's$ willingness-to-pay to all nodes as follows:

$$WTP_A \cdot BDF^T_{m,A} = WTP_{A,m} = \begin{bmatrix} WTP_{A,A} \\ WTP_{A,B} \\ WTP_{A,C} \end{bmatrix} \; \forall \; m \tag{5.2}$$

The reader can observe that also the willingness to pay at node A would be weighted with the BDF, following the logic that a Member State would only be willing to pay for her share in the consumption of benefits from a unit of RES-e capacity. The demand for a unit of RES-e capacity at each supply node would then be given by the aggregated willingness to pay $D_m = \sum_n WTP_{n,m}$ of all Member States at this particular node.

The relationships described above are made more precise with the help of figure 5.2. Each cell in the table shows a three-node network connecting three Member States $\{A, B, C\}$. The four columns show the corresponding values for WTP_n, $BDF_{m,n}$, $WTP_{n,m}$ and D_m respectively. In each row only the nodes concerned are highlighted in color. I explain the procedure exemplary for Member State A in the first row: Member State A has a willingness to pay of 48 € per MWh for a new unit of RES-e capacity. The BDF of Member State A indicates 60 percent of the benefit from a unit of RES-e capacity installed in Member State A, stays in Member State A and the remaining 40 percent spill over evenly to Member States B and C. Thus to derive the willingness

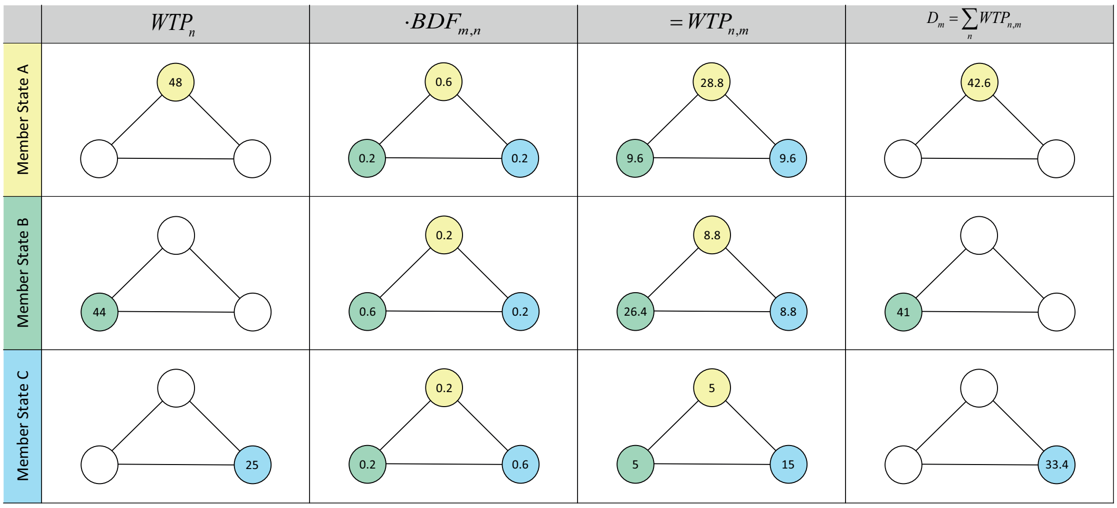


Figure 5.2: Illustration of the concept of spatially disaggregated willingness to pay

to pay from Member State A at each supply node the 48 € per MWh are multiplied with the BDF, yielding a willingness to pay of 28.8 € per MWh of Member State A for electricity generated on her own territory. The demand is then given by aggregating Member States $A's$, $B's$ and $C's$ willingness to pay for a unit of RES-e capacity installed in Member State A, yielding a value of 42.6 € per MWh.

5.2 The Member States' bidding rationale

Member states aim to maximize the net benefit b^{net} they receive from RES-e capacity. In doing so they can choose between incentivizing new RES-e capacity in a domestic auction and pay price p_n or incentivize it in the EU cross-border action and offer price $p_n^D \cdot BDF_{m,n}$. If a new unit of RES-e capacity is constructed in the domestic auction the benefit Member State n derives from it is $b\left(q_n \cdot BDF_{n,n}\right)$. On the other hand a unit of RES-e capacity selected in the EU auction leads to a benefit of $b\left(q_m^D \cdot BDF_{m,n}\right)$. Therefore, assuming perfect information on behalf of the Member State i, i.e., she can anticipate the demand vector $x_m^D = \frac{x_i^D}{BDF_{m,n}} + \frac{\sum_{j \neq i} x_j^{D\star}}{BDF_{m,n}}$ in the EU auction based on her and the other Member States' offer bids as it is the case in the Nash equilibrium, her optimization problem can be stated as follows:

$$\max_{x_n, x_m^D} b^{net} = b\left(x_n \cdot BDF_{n,n}\right) - p_n^\star \cdot x_n + \sum_m \left(b\left(x_m^D \cdot BDF_{m,n}\right) - p_n^D \cdot BDF_{m,n} \cdot x_m^D\right) \quad (5.3)$$

Equation 5.3 tells us that Member State n maximizes her net benefit from RES-e

Table 5.1: Selected notation of chapter 5

Sets	
$a, aa, aaa \in A$	...years, periods [5 years]
$p \in P$	...profile [load, feed-in, etc.]
$n, nn, m \in N \equiv M$	...nodes [of supply, demand]
$l \in L$	...transmission lines
$c \in C \in Tech$	...conventional generation technologies
$r \in R \in Tech$	...renewable generation technologies
$st \in Tech$	...electricity storage technologies
$ds \in DS$	...demand side segment
Variables	
x_m^D	...demand [MW] selected in EU auction at supply node m
x_m^S	...supply [MW] selected in EU auction at supply node m
q_n	...generation capacity [MW] installed at node n
x_n	...consumption of RES-e capacity [MW] at node n

capacity by choosing her decision variables x_n and x_m^D so as to optimally allocate her demand between both types of auctions. The KKT condition with respect to x_n writes as follows (cf. eq. 5.4):

$$\frac{\partial b^{net}}{\partial x_n} = b'\left(x_n \cdot BDF_{n,n}\right) - p_n^{\star} = 0 \tag{5.4}$$

Equation 5.5 displays the KKT condition with respect to x_m^D.

$$\frac{\partial b^{net}}{\partial x_m^D} = b'\left(x_m^D \cdot BDF_{m,n}\right) - p_n^D \cdot BDF_{m,n} = 0 \tag{5.5}$$

Dividing eq. 5.4 by eq. 5.5 and carrying out some transformations leads to eq. 5.6.

$$\frac{b'\left(x_n\right) \cdot BDF_{n,n}}{b'\left(x_m^D\right) \cdot BDF_{m,n}} = \frac{p_n^{\star}}{p_n^D \cdot BDF_{m,n}} \tag{5.6}$$

The expression on the left of eq. 5.6 shows the *marginal rate of substitution* of a unit of RES-e capacity deployed under the domestic auction for a unit of RES-e capacity deployed under the EU auction; condition 5.6 tells us that for Member State $n's$ allocation of demand between both auctions to be optimal, the marginal rate of substitution between both auction types has to equal to their price ratio. Since we have $\frac{b'(x_n)}{b'(x_m^D)} = 1$; that is, Member State n values RES-e capacity at different locations equally given that she consumes the same amount, eq. 5.6 can be re-written as $p_n^D = \frac{p_n^{\star}}{BDF_{n,n}}$, which says that at the optimum the price paid in the EU auction should equal the equilibrium price in the domestic auction divided by the share in benefit from a new unit of RES-e capacity installed in Member State n that remains in Member State n. Since $BDF_{n,n} \leq 1$, p_n^D can in principle be higher than $p_n^\star$, because in the EU auction the Member State only pays for her share in consumption of the benefits, whereas in the national auction she has to pay the full price for a new unit of RES-e capacity, regardless of how the benefits are distributed. Since however in determining $p_n^\star$ Member State n might implicitly already anticipate the spill-over of benefits induced by other Member States' deployment decisions (compare eq. 2.6), her true willingness to pay $p_n^\star \leq WTP_n \leq \frac{p_n^\star}{BDF_{n,n}}$ will likely be in between the two.

5.3 The RES-e generators' bidding rationale

The auction supply allocation problem of a RES-e generator can be stated as shown in eq. 5.7. In anticipating the clearing prices $p_n^\star$ in the domestic auction and the supply and demand curves in the EU auction he decides how to optimally allocate his supply between both types of auctions.

$$\max_{q_n, x_m^S} \Pi = p_n^\star \cdot q_n - c_n\left(q_n\right) + p_m^S \cdot x_m^S - c_m\left(x_m^S\right) \tag{5.7}$$

In analogy to the steps explained above for the Member States' optimization problem the KKT conditions of the RES-e generator's optimization problem can be converted to condition 5.8. The expression on the left is the *marginal rate of transformation*, which shows the opportunity costs of generation for different locations of RES-e capacity.

$$\frac{c_n^{'}\left(q_n\right)}{c_m^{'}\left(x_m^S\right)} = \frac{p_n^\star}{p_m^S} \tag{5.8}$$

A new RES-e project is always identified with the node at which it is situated. Since the representative RES-e generator has access to the full resource base, i.e., all nodes $m \in N$, it is essentially the same project that can either be offered in the domestic auction or the EU auction so that we have $\frac{c_n^{'}(q_n)}{c_m^{'}(x_m^S)} = 1 \; \forall \; n = m$. This leads to condition $p_m^S = p_n^\star \; \forall \; n = m$; that is, at the optimum a RES-e generator would be indifferent whether a new project situated in Member State $n = m$ would be financed through the domestic or the EU auction since he could expect the same payoff; if this were not the case his allocation of supply would not be optimal, because he could still increase profits by shifting supply.

5.4 Modeling the integrated electricity market and auctions for RES-e

This section describes the model of European electricity market that is applied in order to represent stages II and III of the conceptual framework (cf. figure 3.3).

Model description

The model is an inter-temporal, numerical dispatch and investment model of the European electricity market. Economically speaking, it is a partial equilibrium model that considers several representative electricity market actors' (conventional electricity generator, renewable electricity generator, storage operator, electricity consumer, system operator) interrelated optimization problems, that jointly constitute a Nash game between the actors. In the current set-up all actors behave fully competitive, i.e., they do not anticipate an influence of their actions on the prices and see prices as parameters – this leads to the competitive market solution being implemented. In the model all operational and investment decisions by all actors are taken simultaneously for all model periods, i.e., perfect foresight is assumed. The current time horizon of the model is up to 2035 and consists of four five year periods. The installed generating capacity for the start year of the model (currently 2015) is given as parameter, but within the forward looking time horizon of the model, changes to the capacity stock are decided endogenously. Generating capacity, generation and demand are assigned to different nodes in a network, whereby each node represents a Member State. Electricity trade between the nodes can either be NTC based and / or flow-based via the PTDF matrix. Actors in the lower stage are represented explicitly by their optimization problems. In order to reduce mathematical complexity and keep the model at one level the RES-e auction in the second stage II is represented implicitly by a market clearing constraint. The price for electricity and the RES-e premium are derived from the shadow prices (dual variables) of the market clearing constraints. The model is created by deriving the KKT conditions of each actor's optimization problem and merging them with the constraints and the market clearing conditions. The model is formulated as MCP, coded in GAMS and solved with the Path solver.

The model is in several aspects similar in formulation to other MCP models used to investigate investment incentives for RES-e expansion, which are described in the academic literature (Linares et al., 2008; Mendelevitch and Oei, 2015; Nagl, 2013; Saguan and Meeus, 2014; Schröder, 2013; Traber and Kemfert, 2011), but also contains novel formulations of particular aspects relevant in the context of this thesis.

Model notation

First, I introduce some general notation before presenting the optimization problem of each player in more detail. Table 5.1 lists the most important sets used in the model. The set $a \in A$ generally refers to a five year period, e.g. 2015-2019. For some parameters such as for instance costs or installed capacities a narrower specification of the time period is needed, in these cases I refer to the starting year of a period, e.g. 2015.

The main constituents of the model are quantities (parameters and variables), cost parameters and price variables. In general, a lowercase letter q denotes quantities that are determined endogenously in the model as part of the actors' optimization problems, whereas an uppercase letter Q denotes quantities that are given exogenously as parameter. An overbar above a parameter or variable indicates that it refers to units of electricity generation [MWh], whereas no overbar above it indicates that a parameter (except for scaling parameters) or variable refers to units of generating capacity [MW]. The parameter $Td_{p,a}$ indicates the time duration of a load profile segment p in a period a, whereby the sum of durations over all segments corresponds to the amount of hours of a five year period. The parameter Df_a discounts all future revenues to the first period. Variables in parentheses beginning with λ denote the duals of the constraints. The remaining notation is introduced in the explanation of each actors's problem.

5.5 Optimization Problems[1]

Conventional electricity generator

Equation 5.9a states the profit maximization problem of the conventional electricity generator. He can gain revenues by selling electricity generation $\bar{q}^{gen}_{p,n,c,a}$ on the market at a price $\bar{p}^{ele}_{p,n,a}$ as long as this price can at least cover his variable costs of generation $\bar{C}^{var}_{p,c,a}$. Aside from generation costs he faces fixed costs $C^{fix}_{n,c,a}$ that depend on the capacity stock which is given in each period by the sum of initial capacity $Q^{ini}_{n,c,a}$ and investments into new generating capacity $q^{inv}_{n,c,aa}$ in the prior period $aa < a$, net of capacity that is decommissioned $\left(q^{div}_{n,c,aa}\right)$ ahead of the end of its lifetime if it cannot at least recover the periodic fixed costs. Additionally investments into new generating capacity cause investment costs $C^{inv}_{n,c,a}$ that are annualized to depreciation times of ten years. In deciding

[1]In developing the model equations and coding the model I have received valuable feedback and advice from Roman Mendelevitch

the level of electricity generation the conventional generator is constrained by eq. 5.9c, which limits the maximum generation in each profile segment to the availability of the capacity stock in each profile segment.

$$\max_{\bar{q}^{gen}_{p,n,c,a}, q^{inv}_{n,c,a}, q^{div}_{n,c,a}} \Pi^C = \sum_a Df_a \cdot \Bigg[\sum_{p,n,c} Td_{p,a} \cdot \left(\bar{p}^{ele}_{p,n,a} - \bar{C}^{var}_{l,c,a}\right) \cdot \bar{q}^{gen}_{p,n,c,a}$$

$$- \sum_{n,c} \left(C^{fix}_{n,c,a} \cdot Q^{ini}_{n,c,a} - \sum_{a-lt/scale<aa<a} q^{inv}_{n,c,aa} \cdot \left(C^{inv}_{n,c,a} + C^{fix}_{n,c,a}\right) \right)$$

$$+ \sum_{n,c} \left(\sum_{a-lt/scale<aa<a} q^{div}_{n,c,aa} \cdot C^{fix}_{n,c,a} \right) \Bigg] \tag{5.9a}$$

$$s.t.$$

$$0 \geq \bar{q}^{gen}_{p,n,c,a} - Avail_{p,n,c,a} \tag{5.9b}$$

$$\cdot \left(Q^{ini}_{n,c,a} + \sum_{a-lt/scale<aa<a} \left(q^{inv}_{n,c,aa} - q^{div}_{n,c,aa} \right) \right) \; (\lambda avail_{p,n,c,a}) \tag{5.9c}$$

Renewable electricity generator

The profit maximization problem of the RES-e generator can be stated analogously to the one of the conventional generator. There is however one important distinction: the RES-e generator can gain additional revenues through a RES-e premium which can be granted either for RES-e generation (cf. eq. 5.10b) or RES-e capacity (cf. eq. 5.10c). Since only one type of support can be active at a time we have $bi_{gen}, bi_{cap} \in [0;1]$ with $bi_{gen} + bi_{cap} = 1$, i.e., the RES-e generator can only earn a RES-e premium from the support scheme in place. In eq. 5.10b where the RES-e premium is granted for generation a trick is applied in order to map the level of the premium to new installations of RES-e capacity in a given period. Therefore the premium is granted for newly installed **available** capacity, which sort of mimics the electricity generated. This assumption is plausible, as variable RES-e have short-run costs close to zero, and will therefore always be dispatched when they are available. The calculation of the generation based premium is further illustrated with the help of figure 5.3. The Investment decision takes place in period a_0, resulting capacity can be used from $a_0 + CP$ until $a_0 + CP + LT$ (active time). The level of the premium depends on the extend to which this capacity contributes to achieving political expansion target. In each period the expansion target

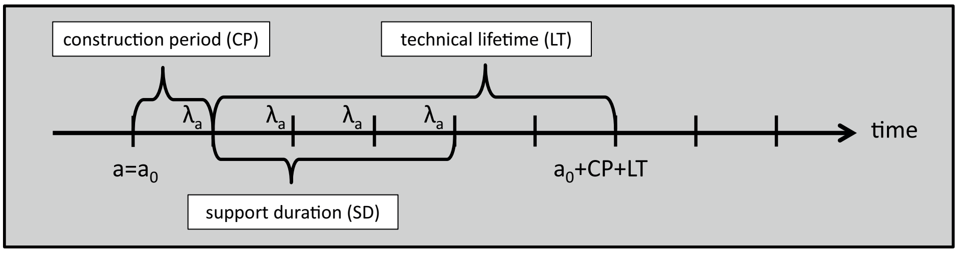


Figure 5.3: Calculation of RES-e premium

constraints have dual variables (shadow prices λ_a). In each period the premium is the sum of shadow prices over the active time $\sum_{a<a_0+CP}^{a<a_0+CP+SD} \lambda_a$.

$$\max_{\bar{q}^{gen}_{p,n,r,a}, q^{inv}_{n,r,a}} \Pi^R = \sum_a Df_a \cdot \left[\sum_{p,n,r} Td_{p,a} \cdot \left(\bar{p}^{ele}_{p,n,a} - \bar{C}^{var}_{n,r,a} \right) \cdot \bar{q}^{gen}_{p,n,r,a} \right. \tag{5.10a}$$

$$+bi_{gen} \cdot \sum_{p,n,r} \cdot \left(\sum_{a-sd/scale<aa<a} Avail_{p,n,r,a} \cdot q^{inv}_{n,r,aa} \cdot \sum_{aa<aaa<aa+sd/scale} \bar{p}^{prem}_{n,r,aaa} \right) \tag{5.10b}$$

$$+bi_{cap} \cdot \sum_{n,r} \left(\sum_{a-sd/scale<aa<a} q^{inv}_{n,q,r,aa} \cdot p^{prem}_{n,r,aa} \right) \tag{5.10c}$$

$$\left. - \sum_{n,r} \left(C^{fix}_{n,r,a} \cdot Q^{ini}_{n,r,a} - \sum_{a-lt/scale<aa<a} q^{inv}_{n,r,aa} \cdot \left(C^{inv}_{n,r,a} + C^{fix}_{n,r,a} \right) \right) \right] \tag{5.10d}$$

$$s.t.$$

$$0 \geq \bar{q}^{gen}_{p,n,r,a} - Avail_{p,n,r,a} \cdot \left(Q^{ini}_{n,r,a} + \sum_{a-lt/scale<aa<a} q^{inv}_{n,r,aa} \right) \quad (\lambda avail_{p,n,r,a}) \tag{5.10e}$$

Pumped storage operator

The pumped storage operator maximizes his profit by choosing his two decisions variables $\bar{q}^{pump}_{p,n,s,a}$ and $\bar{q}^{gen}_{p,n,s,a}$. He purchases electricity to pump water into the storage reservoir during profile segments with low electricity price levels and releases it again in situation with high prices in order to generate and sell electricity. Equation 5.11b is the usual constraint limiting the maximum generation to the available capacity. Equation 5.11c ensures that within a period a all electricity that is generated by pumped storage capacity also is pumped into the reservoir respecting round-trip efficiencies $\eta_{st,a}$. Equation 5.11d moreover limits the generation within a period to empirically observed full load hours of pumped storage reservoirs in order to implicitly reflect limitations on the reservoir´s storage capacities.

$$\max_{\bar{q}^{gen}_{p,n,st,a};\bar{q}^{pump}_{p,n,st,a}} \Pi^{St} = \sum_a Df_a \cdot \left[\sum_{p,n} Td_{p,a} \cdot \left(\bar{q}^{gen}_{p,n,st,a} - \bar{q}^{pump}_{p,n,st,a} \right) \cdot \bar{p}^{ele}_{p,n,a} \right] \tag{5.11a}$$

$$s.t.$$

$$0 \geq \bar{q}^{gen}_{p,n,st,a} - Avail_{n,st,a} \cdot Q^{ini}_{n,st,a} \quad (\lambda avail_{p,n,st,a}) \tag{5.11b}$$

$$0 \geq \sum_p \left(Td_{p,a} \cdot \bar{q}^{gen}_{p,n,st,a} \right) - \sum_p \left(Td_{p,a} \cdot \bar{q}^{pump}_{p,n,st,a} \cdot \eta_{st,a} \right) \quad (\lambda bal_{n,st,a}) \tag{5.11c}$$

$$0 \geq \sum_p \left(Td_{p,a} \cdot \bar{q}^{gen}_{p,n,st,a} \right) - Flh_{n,st,a} \cdot Q^{ini}_{n,st,a} \quad (\lambda stor_{n,st,a}) \tag{5.11d}$$

Electricity consumers

Electricity consumers maximize their surplus by deciding their level of electricity consumption. Consumption during each load profile segment is depends on the electricity comsumers' demand profile $\bar{q}^{load}_{p,n,a}$ net of their decision variable $\bar{q}^{shed}_{ds,p,n,a}$, i.e., shedding load. It pays off for consumers to shed load if the electricity price surpasses their value of lost load at a given load level, since the price of electricity would be higher than their opportunity costs of not serving demand, whereby different segments of consumer demands ds can be identified with different value of lost load levels. This is further illustrated in figure 5.4, where the dark gray area corresponds to the shedded load.

$$\max_{\bar{q}^{shed}_{ds,p,n,a}} \Pi^{CS} = \sum_a Df_a \cdot \sum_{ds,p,n} \left[\left(Voll^{up}_{ds,p,n,a} + \frac{1}{2} \cdot Slope_{ds,p,n,a} \right. \right. \tag{5.12a}$$

$$\left. \cdot \left(\bar{q}^{load}_{p,n,a} - \bar{q}^{shed}_{ds,p,n,a} \right) - \bar{p}^{ele}_{p,n,a} \right) \tag{5.12b}$$

$$\left. \cdot \left(\bar{q}^{load}_{p,n,a} - \bar{q}^{shed}_{ds,p,n,a} \right) \cdot Td_{p,a} \right] \tag{5.12c}$$

$$s.t.$$

$$0 \leq \bar{q}^{shed}_{ds,p,n,a} - q^{shed\_max}_{ds,p,n,a} \quad (\lambda shed_{ds,p,n,a}) \tag{5.12d}$$

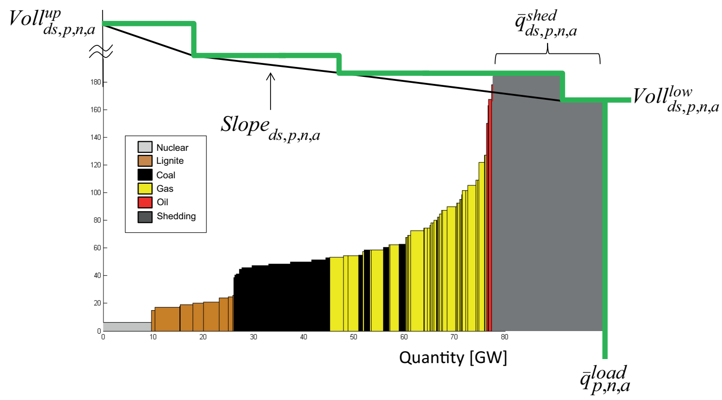


Figure 5.4: Consumer surplus and load shedding

Market coupler and system operator

The market coupler and system operator aims to maximize his profit from the trade of electricity across market zones. He does so by purchasing electricity in a low price market zone and selling it to a high price market zone, while respecting constraints of the transmission infrastructure. Since he behaves fully competitive, it is assured that transmission capacities between market zones are fully utilized in the case of price differentials between market zones so that in this way also prize differentials are minimized. Depending on the market design on transmission capacity congestion management, the trade of electricity can be organized as (i) flow-based market coupling or (ii) NTC-based market coupling. Both approaches can also be applied simultaneously, for instance for trading electricity in a combined AC and DC network.

The flow-based trade approach is shown in eq. 5.13a. The market coupler decides for each node $n \in N$ of a network the net generation $\bar{q}^{net}_{p,n,a}$[2]. If the net generation at a node is positive it can from the perspective of the market coupler be interpreted as a purchase of electricity so that the price variable has to have negative sign; on the other hand electricity is sold at node with negative net generation so that the product of price and net-generation has a positive revenue. Equation 5.13d states that at the system level imbalances have to net out, i.e., generation has to equal consumption. Equations 5.13e and 5.13f restrict the flows over each lime to the maximum line capacities in each direction and thus effectively constrain the possible imbalances at each node, i.e., the net generation of a node cannot become larger than the possible outflow, respectively

[2]We can recall from principle 4.1 that the net generation is given by the imbalance of generation and demand at a node. The market coupler however can neither control generation nor demand, both are either exogenous parameters or decided by other actors (generators, consumers). Therefore $\bar{q}^{net}_{p,n,a}$ quasi is a pseudo variable, whose value is determined by the decisions of other players in the game.

inflow over all lines to, respectively from other nodes (cf. principle 4.1).

The NTC-based approach is shown in eq. 5.13b. The market coupler buys electricity at a price $\bar{p}^{ele}_{p,n,a}$ and decides for each node n the flow to all nodes nn where he sells the electricity at a price $\bar{p}^{ele}_{p,nn,a}$. When deciding the flow $\bar{q}^{flow\_ntc}_{p,n,nn,a}$ he has to respect the net transfer capacities between each pair of nodes $q^{ntc}_{n,nn,a}$. This approach can for instance be applied when network and market studies are conducted separately, as it is also done in the TYNDP (cf. ENTSO-e (2015)), where thermal line limits and the topology of the network are implicitly reflected in the net transfer capacities that are passed over from the network to the market models.

Equation 5.13c sets a floor price $\bar{p}^{ele\_min}_{p,n,a}$. The system operator has an incentive to curtail generation if the electricity price at market clearing would become lower than the floor price. In this way it is also ensured that a market equilibrium can be found in case of very high RES-e feed-in with negative residual loads.

$$\max_{\bar{q}^{net}_{p,n,a},\bar{q}^{flow\_ntc}_{p,n,nn,a},\bar{q}^{curt}_{p,n,a}} \Pi^{ISO} = \sum_a Df_a \cdot Td_{p,a} \cdot \Bigg[\sum_{p,n} \bar{q}^{net}_{p,n,a} \cdot \left(-\bar{p}^{ele}_{p,n,a}\right) \tag{5.13a}$$

$$+ \sum_{p,n,nn} \left(\bar{p}^{ele}_{p,nn,a} - \bar{p}^{ele}_{p,n,a}\right) \cdot \bar{q}^{flow\_ntc}_{p,n,nn,a} \tag{5.13b}$$

$$+ \sum_{p,n} \left(\bar{p}^{ele\_min}_{p,n,a} - \bar{p}^{ele}_{p,n,a}\right) \cdot \bar{q}^{curt}_{p,n,a} \Bigg] \tag{5.13c}$$

$$s.t.$$

$$0 = \sum_n \left(-\bar{q}^{net}_{p,n,a}\right) \quad \left(\lambda p^{ele\_sys}_{p,a}\right) \tag{5.13d}$$

$$0 \geq \sum_n PTDF_{l,n} \cdot \left(- \sum_n \bar{q}^{net}_{p,n,a} \right) - q^{lim}_{l,a} \quad \left(\lambda linelim^{pos}_{p,l,a}\right) \tag{5.13e}$$

$$0 \geq \sum_n PTDF_{l,n} \cdot \left(\sum_n \bar{q}^{net}_{p,n,a} \right) - q^{lim}_{l,a} \quad \left(\lambda linelim^{neg}_{p,l,a}\right) \tag{5.13f}$$

$$0 \geq \bar{q}^{flow\_ntc}_{p,n,nn,a} - q^{ntc}_{n,nn,a} \quad \left(\lambda ntc_{n,nn,a}\right) \tag{5.13g}$$

$$0 \geq -\bar{q}^{curt}_{lp,n,a} \quad \left(\lambda curt_{p,n,a}\right) \tag{5.13h}$$

5.6 Market clearing conditions

Nodal energy balance

Equation 5.14 establishes the nodal energy balance (cf. principle 4.1). The dual variable of eq. 5.14 sets the price of electricity $\bar{p}^{ele}_{p,n,a}$.

$$0 = \sum_{tech} \bar{q}^{gen}_{p,n,tech,a} + \sum_{d} \bar{q}^{shed}_{d,l,n,a} + \sum_{nn} \bar{q}^{flow\_ntc}_{p,nn,n,a}$$
$$-\sum_{nn} \bar{q}^{flow\_ntc}_{p,n,nn,a} - \bar{q}^{net}_{p,n,a} - \bar{q}^{load}_{p,n,a} - \bar{q}^{curt}_{p,n,a} \quad \left(\bar{p}^{ele}_{p,n,a}\right) \tag{5.14}$$

Shared energy policy constraint

A shared energy policy constraint is introduced to the model to mimic the auction for RES-e generation (cf. eq. 5.15), respectively RES-e capacity (cf. eq. 5.16) in the second stage of the conceptual framework (cf. figure 3.3). In the MCP model the market clearing constraint can be interpreted as invisible Walrasian auctioneer that searches the price vector, which clears the market. In doing so the auctioneer anticipates the reaction of the RES-e generator based on his KKT condition, which he sees as a set of price-quantity pairs, where each price corresponds to a certain quantity of RES-e generation. He then selects $p^{prem}_{n,r,a}$ such that the RES-e generator offers sufficient generation capacity to fulfill the expansion target, but would no longer do so if the price would be reduced only marginally. As the auctioneer has complete information the price level need not be revealed in an iterative procedure, thus the clearing price corresponds to the outcome of an auction, which is incentive compatible.

$$0 \geq bi_{gen} \cdot \left(\bar{q}^{gen\_target}_{r,n,a} - \sum_{p} \bar{q}^{gen}_{p,n,r,a} \right) \tag{5.15}$$

$$+bi_{cap} \cdot \left(q^{cap\_target}_{r,n,a} - Q^{ini}_{n,q,r,a} + \sum_{a-lt/scale<aa<a} q^{inv}_{n,q,r,aa} \right) \left(\bar{p}^{prem}_{n,r,a} / p^{prem}_{n,r,a} \right) \tag{5.16}$$

The final step in developing the model is to construct the Lagrange functions $\mathcal{L}(\cdot)$ from the different actors' optimization problems and to derive from these the KKT conditions. The KKT conditions then jointly with the constraints of the optimization problems and the market clearing conditions constitute the MCP model. The Lagrangians and corresponding KKT conditions are presented in appendix B.

Chapter 6

The EU auction for cross-border support of renewable electricity

6.1 Design of the EU cross-border auction

The auction is designed as pay-as-bid auction where Member States and RES-e generators bid prices for additional RES-e capacity, indicating their willingness to pay, respectively their costs. Let each Member State $n \in N$ submit a sealed bid naming pairs $\left(p^{D}_{n,b}, x^{Dmax}_{n,b}\right)$ of prices [Euros per MW] and quantities [MW or a multiple thereof] she would be offering to pay for an additional unit of RES-e generating capacity, where D denotes that a pair refers to a demand bid for additional RES-e generating capacity and the set $b \in B$ assigns different combinations of prices and quantities do distinct bids[1]. The bids may or may not be equal to her true willingness to pay.

Let also each generator of RES-e submit bids naming pairs $\left(p^{S}_{m,b}, x^{Smax}_{m,b}\right)$ of prices [Euros per MW] and quantities [MW or a multiple thereof] he asks for an additional unit of RES-e generating capacity to be installed, whereby RES-e producers and thus their bids are assigned the index of the Member State m where their plant is connected to the grid and S denotes that the bid refers to a supply bid for additional RES-e capacity.

In order for the auction to converge to an efficient equilibrium multiple rounds of bids are allowed for the demand side, while on the supply side the auction would be conducted as “one shot”. Thus for RES-e generators the EU auction will not be much different than domestic procurement auctions for RES-e and best-practice design criteria that have been identified and which are discussed in recent literature (del Rio et al., 2015; Held et al., 2014; IRENA, 2015; Klessman et al., 2015; Ragwitz et al., 2014) can

[1] Which can be regarded as a proxy for a demand curve

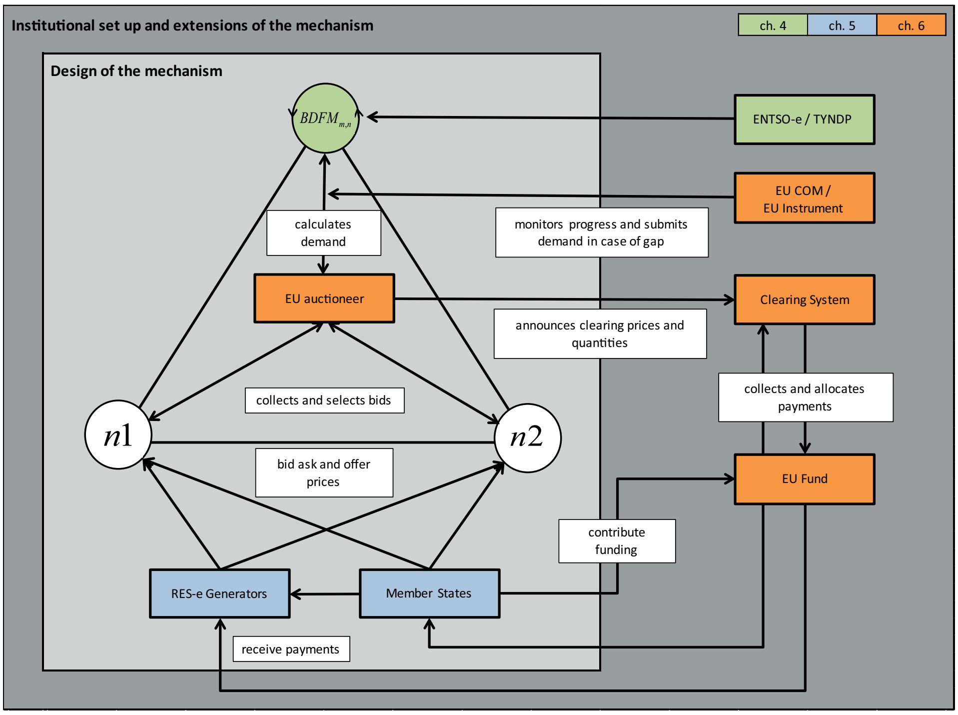


Figure 6.1: Design and possible institutional set-up of the mechanism

be applied in this context as well.

6.2 The RES-e auctioneer's optimization problem

The EU auctioneer collects all bids and calculates the demand at each supply node m by multiplying all demand bids with the BDF matrix. The decision variables of the EU auctioneer are given by $x^D_{m,b}$ and $x^S_{m,b}$. The variable $x^S_{m,b}$ determines for each bid the quantity of supply that is selected from a RES-e generator who is assigned to supply node m. In choosing $x^S_{m,b}$ the auctioneer is constrained by eq. 6.1c which ensures that the selected quantity cannot become larger than the maximum quantity $x^{Smax}_{m,b}$ offered at a certain price level. Demand bids of Member States are identified with the index n while the decision variable $x^D_{m,b}$, which allocates the demand, has the index m. The reason is that demand from Member States is offered simultaneously, though at different price levels, at all supply nodes $m \in M$. The variable $x^D_{m,b}$ determines for each bid the quantity of demand that is selected at each supply node m. In order to maximize surplus the auctioneer can split the demand bids between all supply nodes as long as it is ensured that the cumulative demand allocated to all supply nodes is smaller or equal than the maximum quantity offered for each bid (cf. eq. 6.1b). Finally, eq. 6.1d is the market clearing condition which ensures that the sum of demand bids has to be matched with the sum of supply bids at each supply node m.

$$\max_{x^D_{m,b};x^S_{m,b}} SP = \sum_m \left[\sum_{n,b} \left(p^D_{n,b} \cdot BDF_{m,n} \right) \cdot x^D_{m,b} - p^S_{m,b} \cdot x^S_{m,b} \right] \tag{6.1a}$$

$$s.t.$$

$$\sum_m x^D_{m,b} \cdot BDF_{m,n} \leq x^{Dmax}_{n,b} \;\forall\, n, b \tag{6.1b}$$

$$x^S_{m,b} \leq x^{Smax}_{m,b} \;\forall\, m, b \tag{6.1c}$$

$$\sum_b x^S_{m,b} = \sum_b x^D_{m,b} \;\forall\, m \tag{6.1d}$$

Respecting these constraints, the auctioneer then chose the set of bids that maximizes the aggregate EU-wide surplus SP and announces $x^{\star D}_{m,b}$ and $x^{\star S}_{m,b}$.

Each Member State $n's$ pay-off ϕ_n is then given by eq. 6.2.

$$\phi_n = \sum_{m,b} \left[b_n \left(x^{\star S}_{m,b} \cdot BDF_{m,n} \right) - p^{\star D}_n \cdot BDF_{m,n} \cdot x^{\star D}_{m,b} \right] \;\forall\, n \tag{6.2}$$

Based on their evaluation of the outcome of a bidding round Member States then can revise their bids. The auctioneer terminates the process after some predetermined (but undisclosed) number of rounds or by using some convergence criterion (e.g. when the change in surplus is below a certain threshold). This is called the demand revelation game.

The surplus maximizing mechanism has a unique solution, except when two or more sets have exactly the same surplus with respect to the prices bid, which could be the case in theory. In such a case some tie-breaking rule would have to be applied. In practice however this is very unlikely to arise.

Example 6.1. The functioning of the mechanism is further explained on the basis of figure 6.2, which shows in a stylized way a possible outcome of an auction, where supply and demand bids have already been merged to constitute "surplus bids". Then the vertical surplus range of each bar is given by $\sum_n \left(p^D_{n,b} \cdot BDF_{m,n} \right) - p^S_{m,b} \;\forall\, m, b$ and the horizontal size is assumed to be $x^{\star S}_{m,b}$ =1 MW $\forall\, m, b$. The surplus bids are then sorted in descending order and all bids with a positive surplus are selected – in our example this is the case up to bid 11. Some observations can be made from this figure that may be typical for such an auction: first, the reader may observe the unusual shape of the supply and demand curves, the reason being that bids are not ordered by ascending costs,

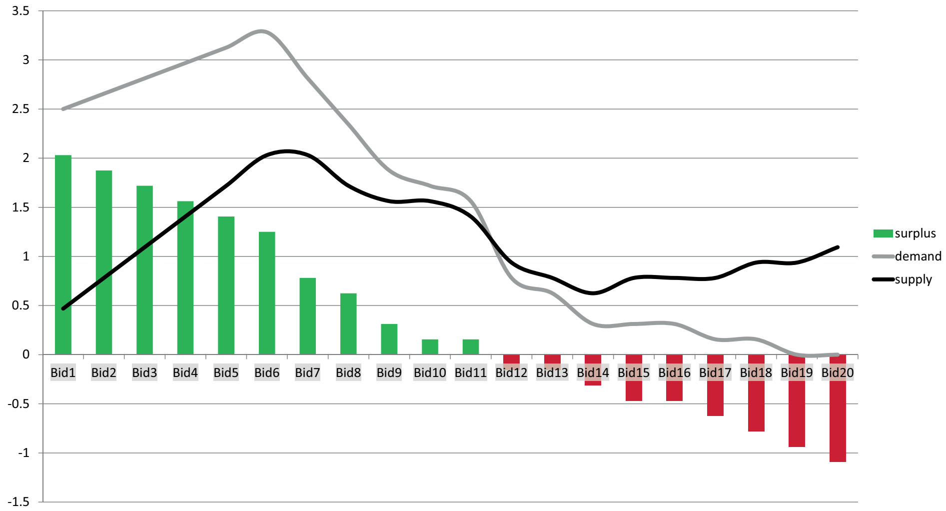


Figure 6.2: Functioning of the mechanism. Vertical axis displays surplus values in million Euros per MW. Horizontal axis displays surplus bids in descending order of surplus value.

but by descending surplus. For example bid10 (with supply price of ~1.5 million Euros per MW) has been rowed after bid6 (with supply price of ~2 million Euros per MW), because bid6 could be matched with a higher demand. Bid14 (with a very low supply price of 0.625 million Euros per MW) is not selected, because it could not be matched with sufficient demand. This may for instance be the case when a RES-e generator is situated in a Member State that does not offer demand so that demand bids from the remaining Member States alone are too low to secure a positive surplus even though the RES-e generator has asked for a low price. This shows that the mechanisms generally prefers low costs over high costs, but that low costs are only of value if they can be matched with willingness to pay. Secondly, in this example more (low-cost) supply bids are submitted than demand bids. For bid19 and bid20 the demand is actually zero. It is reasonable to assume that in practice not all supply bids can be matched by sufficient demand bids and that the level of RES-e generating capacity selected will be determined by the demand side of the market, i.e., the Member States' offer bids.

6.3 The solution concept: Nash equilibrium

In the mechanism a cross-border cost allocation between Member States emerges as an equilibrium of a competitive bidding process. Typically there is no dominant strategy solution, so the outcome may not reveal consumers true demands; nevertheless it reveals them partially - enough to ensure that that the allocation of RES-e capacity is efficient all costs are covered. It can be shown that in such type of demand revelation game, there exists a set of bids such that no Member State can deviate from these bids and each improve her gain (Aumann, 1961; Young, 1980). At such an equilibrium (called a strong equilibrium) the set of supply bids accepted will be efficient relative to the true demands, and costs will be covered (though not necessarily exactly). This result can be derived from a theorem developed by Peyton Young.

Theorem 6.1. *(Young, 1980, 1998a; Young and International Institute for Applied Systems Analysis, 1985): Let c be a subadditive cost game on I, and $b \in R^I$ a vector of benefits. The associated demand revelation game has a strong equilibrium, and for any such equilibrium the set selected is efficient and the total of accepted bids covers total costs.*

The type of demand revelation game established by the RES-e auctioneers optimization problem (cf. eq. 6.1a) however differs from the setting described by Young (1998b), since his mechanism relies on exclusion and players state their demands whether they want to be included in a joint project and enjoy the benefit or not. In our setting full exclusion is not possible due to the partial public good characteristics of RES-e capacity as described in section 2.2. Therefore in our setting the demand revelation game should be understood as capacity allocation game, because by deciding their level of demand Member States determine the allocation of RES-e capacity. While Member States cannot be excluded from the benefits from RES-e capacity, their share in benefit from a unit of RES-e capacity may significantly differ depending on the location where the new unit is installed as shown in chapter 4. The strong equilibrium is discovered in a tatonnement process. Therefore it is necessary to allow several rounds of exploratory bids on the demand side, where the Member States name their willingness to pay and the mechanisms allocates new RES-e capacities to the "apparently" efficient locations. Then Member States giving higher preference to a different allocation of RES-e capacity might try to raise their bids to achieve a more preferred outcome in terms of allocation, i.e., by increasing their price offer they could increase the likelihood the mechanism allocates new capacity at locations where they receive a higher share of the benefit. On the other hand Member States that do not prefer a significantly altered allocation will explore how far they can lower their bids so that the allocation stays unchanged. I neither attempt to formalize nor proof this process of convergence, but the point I would like to make is that a strong equilibrium can be reached by having each Member State independently determining her offer bids so as to maximize her expected benefit.

This will be illustrated in the following with the help of two simple examples. For both examples let us assume we have two Member States A and B and their willingness to pay is 50 for A and 40 for B respectively. As indicated in section 6.1 I abstract away from strategic bidding considerations for the supply side, i.e., I assume that RES-e generators report prices that represent their true costs, so that costs can be assumed known. The representative RES-e generator can install 1 MW of RES-e capacity at either Member State at a constant cost c_n of 30. The BDF matrix that is valid for both examples is displayed in table 6.1a and it tells us that that the share of benefits that spills over is 25 percent. Member states on the other hand bid pairs $\left(p^D_{n,b}, x^D_{n,b}\right)$ of prices and quantities and for this simple example let us assume that $x^D_{n,b}$ is always set to 0.75 MW. Then eq. 6.1b implies that only one unit of RES-e capacity can be financed, which can be situated either in Member State A or Member State B, so that we have $x^{\star S}_m \in [0; 1]$ and $\sum_m x^{\star S}_m = 1$. The idea behind this capacity allocation game is to elicit information on the Member States' true willingness to pay at least partially to ensure that RES-e capacity is allocated to where it is most valuable. By carrying out the calculation $b^{net} = (\sum_n WTP_n \cdot BDF_{m,n} - c_m) \cdot x^{\star S}_m$ it may be checked that $x^{\star S}_A = 1 \rightarrow b^{Net} = 17.5 > x^{\star S}_B = 1 \rightarrow b^{Net} = 12.5$ is the efficient allocation.

Example 6.2. The demand price bids and corresponding outcomes of the first example are shown in table 6.1b. In the first round the prices bid are 30,40; that is, Member State B is bidding her true WTP while Member State A is understating hers. As an outcome new RES-e capacity would be installed in Member State B and the payoffs would be 5,0. To increase her payoff Member State B might try to lower her bid to say 30. In this case the surplus for both possible allocations would be 0 and some tie-breaking rule would have to be applied; in our example in case of equal surpluses the capacity would be allocated to the Member State with the highest surplus in the previous round, namely Member State B; in practice however exact ties are very unlikely to arise. Thus from the perspective of Member State B she could have lowered her bid, by doing so increase her payoff, and still be allocated the RES-e capacity. As a consequence she could try to lower her bid even further, say to 10. In this case the prices offered by Member States would be too low to secure a positive surplus so that no RES-e capacity would be allocated and each Member State's payoff is zero. Since this would mean a welfare loss for both Member States they now could raise their bids say to 35,20. With these prices now capacity allocated to Member State A would lead to the highest surplus and both Member States would increase their payoffs. Now Member State B could probe if lowering her price offer could further increase her payoff, albeit she knows a price of 10 might be too low so 15 could be a compromise. With this price pair a strong equilibrium is reached, since no Member State can simultaneously change their price bids and each do better: if one or both Member States were to lower their price offers the surplus

Table 6.1: Illustration of solution concept

(a) BDF Matrix for examples

	MS A	MS B
MS A	0.75	0.25
MS B	0.25	0.75

(b) Example 6.2

$round$	WTP_n	c_m	p_n^D	$x_{n,b}^{Dmax}$	SP	$x_m^{\star S}$	ϕ_n
#1	50,40	30,30	30,40	0.75,0.75	2.5,7.5	0,1	5,0
#2	50,40	30,30	30,30	0.75,0.75	0,0	0,1	5,2.5
#3	50,40	30,30	30,10	0.75,0.75	-5,-15	0,0	0,0
#4	50,40	30,30	35,20	0.75,0.75	1.25, -6.25	1,0	11.25,5
#5	50,40	30,30	35,15	0.75,0.75	0,-10	1,0	11.25,6.25

(c) Example 6.3

$round$	WTP_n	c_m	p_n^D	$x_{n,b}^{Dmax}$	SP	$x_m^{\star S}$	ϕ_n
#1	50,40	30,30	30,40	0.75,0.75	2.5,7.5	0,1	5,0
#2	50,40	30,30	27,31	0.75,0.75	-2,0	0,1	5.75,6.75
#3	50,40	30,30	41,31	0.75,0.75	8.5,3.5	1,0	6.75,2.25
#4	50,40	30,30	41,40	0.75,0.75	10.75,10.25	1,0	6.75,0
#5	50,40	30,30	36,12	0.75,0.75	0,-12	1,0	10.5,7

would be negative, which would reduce their payoffs to zero. If Member State A would increase her price offer she would still be allocated the RES-e capacity, but her payoff would be reduced. If Member State B would increase her price offer, her payoff would also be reduced; if she would increase her price offer beyond 35 - the price level required to allocate RES-e capacity to Member State B, both Member States' payoffs would be reduced. Therefore no Member State would have an incentive to deviate from the prices bid in round #5. The price 35 offered by Member State A is high enough to prevent that the mechanism switches back the allocation of RES-e capacity to Member State B, which would not be the efficient allocation, even though it is not Member State $A's$ true willingness to pay. This illustrates what it means that supply bids accepted will be efficient relative to the true demands.

Example 6.3. The demand price bids and corresponding outcomes of the second example are shown in table 6.1c. We start again as in the previous example with a price pair 30,40. Let us assume now both Member States decide simultaneously to lower their prices to 27,31. With these prices the RES-e capacity would be allocated to Member State B and the surplus is zero. As we have seen above a unique maximum surplus of zero is a strong incentive for stability, since no Member State can lower her bid without loosing her payoffs. In this case however I do not think the auction would become stuck at such an outcome. Member state A could raise her bid to 41 and increase her payoff, due to the re-allocation of RES-e capacity. Member state $B's$ payoff on the other hand would be reduced due to the re-allocation of RES-e capacity, so she might want to increase her bid to reverse this. Even if she raised her bid to her maximum willingness to pay of 40 in round #4, she would not be allocated the RES-e capacity. Therefore in the next round Member State B would significantly lower her bid to say 12; Member State A on the other hand could explore if she could lower her bid to say 36 and still be allocated the RES-e capacity. The reader may convince herself that the price pair 36,12 again constitutes an equilibrium of this capacity allocation game.

Besides illustrating how individually rational bidding behavior converges the auction to an efficient equilibrium the examples reveal some more features of the solution concept. We have seen that multiple equilibria are possible that are efficient. It may be checked that they all have the same cumulative payoff of 17.5, albeit with different distributions between the Member States. An equilibrium solution is characterized by a zero surplus for the efficient allocation and negative surpluses for alternate allocations, since at these bid prices no upward or downward variation can improve payoffs. In this stylized example the equilibrium concept is surplus free. In practice surplus free outcomes may hardly ever be attainable if net benefit is to be maximized, nor may the be be required (if surplus is re-distributed): probing different prices to achieve a surplus free equilibrium is much more complex than in this binary example since multiple units of supply and demand are offered at several nodes and mutually interact. For having a stable outcome in practice it should be sufficient if surpluses are small enough to ensure that all Member States involved in the mechanism are better off than in the national case. The implication of this could be that in practice also for the demand side not multiple rounds of bidding would be required if we assume that Member States would already submit efficient bid prices in the first round, respecting condition 5.6, so that the primary application of the mechanism would less be to elicit the true willingness to pay of Member States, but rather to aggregate and allocate willingness to pay efficiently across nodes and to determine transfer prices.

For any remaining surplus several uses can be thought of:

1. It could be redistributed to the Member States

   (a) through a lump sum payment: in this case the amount redistributed to each Member State would be independent of the prices a Member State has offered

– thus there would be no opportunities for strategic gaming that could give an incentive to misreport.

(b) to be served in proportion to their final bids, which have been selected in the auction. In theory this could lead to Member States misreporting their willingness to pay by overbidding, but as a practical matter it seems very unlikely, because the Member States do not know the other supply and demand bids so that from their perspective the - most likely small - surplus is also uncertain.

2. Another possibility would be to use the surplus as compensatory payment for indirect effects that might not have been compensated appropriately (e.g. integration costs, distributional effects).

3. A further possibility would be to transfer the surplus to an EU fund. The fund could for instance be used to finance additional RES-e generating capacity expansion through a new EU instrument (cf. section 6.4).

6.4 Instrument to help ensure the EU meets her 2030 renewable energy target

Through a slight modification of the auction design the mechanism could be extended to also function as an EU instrument that not only facilitates cross-border support, but also can be used to "fill" a possible gap with respect to some given EU RES target trajectory. Such an option is explicitly listed in the EC's proposal on the governance of the Energy Union (European Commission, 2016a). This could work as described in the following.

Tracking progress towards the 2030 target

Let us assume the EU auction, where Member States can procure new RES-e generating capacity through cross-border support takes place biannually. Then it will be possible for the EC to define a (for instance linear) trajectory with biannual intermediate targets that have to be met in order to reach the 2030 target. The procedure to track the process towards the 2030 target is illustrated in figure 6.3 and described in the following.

The progress $x_{m,a}^{progress}$ of RES-e capacity expansion in Member State m in each year a can be de-composed into three parts:

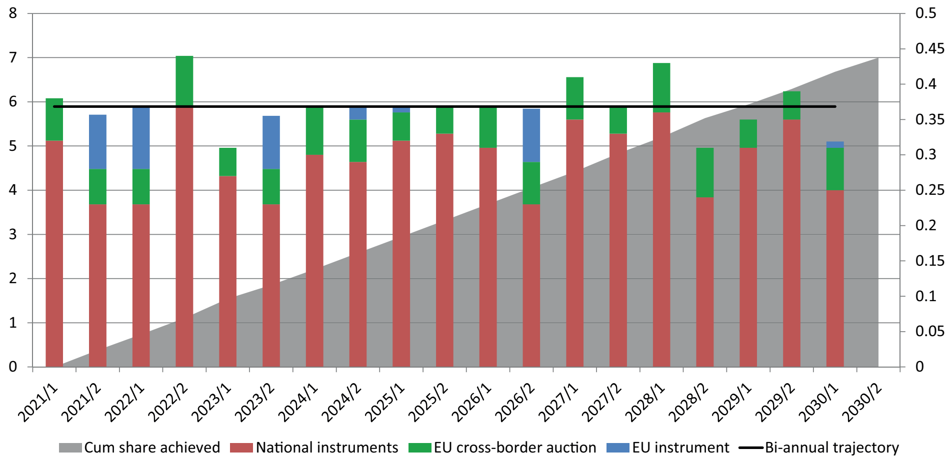


Figure 6.3: Illustrative 2030 target trajectory. Vertical axis on the left displays cumulative percentage points. Vertical axis on the right displays yearly percentage points.

1. the newly procured RES-e capacity through all national instruments $\hat{x}_{m,a} = \hat{x}_{n,a} \; \forall \; n = m$
2. the newly procured capacity in the EU cross-border auction $x^D_{m,a} = \sum_n x^D_{n,a} \cdot BDF_{m,n}$
3. and the newly procured capacity through the EU instrument $x^{EU}_{m,a} = x^{EU}_{n,a} \; \forall \; n = m$

After each cross-border auction has finished the EC would then conduct the following test: is the sum over all Member States $m \in N$ of the cumulative historic progress, newly procured generation from national instruments and newly procured capacity from the cross-border auction $\sum_m \left(\sum_{aa<a} x^{progress}_{m,aa} + \hat{x}_{m,a} + x^D_{m,a} \right)$ larger or equal or smaller than the intermediate EU generation target x^{target}_a? If

$$\sum_m \left(\sum_{aa<a} x^{progress}_{m,aa} + \hat{x}_{m,a} + x^D_{m,a} \right) \geq x^{target}_a$$

the EU instrument needs not be activated in period a; if on the other hand

$$\sum_m \left(\sum_{aa<a} x^{progress}_{m,aa} + \hat{x}_{m,a} + x^D_{m,a} \right) < x^{target}_a$$

the gap is filled through the EU instrument.

Example 6.4. The EU instrument would not need to be set up as a new auction, but could be integrated into the EU auction for cross border support. The reader is invited to take a look at figure 6.2 again. Let us assume once more that one bar corresponds to one MW[2] of quantity. The domestic auctions have already cleared and before the EU auction takes places 19 MW of additional RES-e capacity are still needed to stay on the trajectory. At the EU auction however only 11 MW of capacity could be selected that lead to a positive surplus, thus a gap of 8 MW remains. Now the intermediate target could simply be achieved by the EC demanding additional RES-e generating capacity of the amount required to reach the intermediate target, thus in this example the last bid accepted would be bid19. For bids 12 to 19 that would not be able to cover the full costs through the offer prices bid by the Member States the financing gap could be closed through the EU instrument. Such a procedure would have two advantages: firstly it would minimize the amount of financing that would need to come from an EU instrument, which may be an advantage given the difficulty to equip any such instrument with significant amounts of financial budget. Secondly, it is economically efficient: even though for bids where the surplus is negative the welfare losses are minimized in a way that new capacity is allocated to Member States where it has the highest value relative to the costs. From bid 19 on, no more willingness to pay exists for additional RES-e generating capacity expansion, from there on bids are simply ordered and selected by their level of costs as it would be the case in a cost minimizing auction or a quota scheme.

The question could come up if the fact that RES-e generating capacity expansion would partly be financed from an EU instrument, so that theoretically the possibility of “free-riding” exists, could distort bidding incentives of the Member States. There are two arguments that point against this: firstly, if Member States would understate their true willingness to pay their risk increases that their bid is not selected at all even though it would have led to a net benefit. Secondly, it is evident that also the EU instrument would be funded through Member State’s contributions according to some budget key. If all Member States would bid zero willingness to pay the whole expansion would be financed according to this key from the EU fund. This in turn gives an incentive again to increase the bids in order to benefit from the “cross-subsidization” through the fund, but not above the level of the true willingness to pay. It can thus be concluded that Member States have an incentive to reveal their true willingness to pay at least partially.

Finally, I would like to note that the combination of demand bids by the Member States and EU trajectory also has another interesting interpretation in the context of a currently ongoing policy discussion of the 2030 governance framework. Given the fact that no nationally binding RES targets have been defined a model that is currently under discussion is “pledge and review”, where Member States pledge (ex-ante) a certain

[2]Some methodology would need to be established to transform quantities of capacity into quantities of energy

amount of RES deployment and the EU reviews the actual achievement at some point on the path to 2030. In this respect the bids by the Member States and the trajectory could also be interpreted as a sort of “continuous, dynamic pledge and review” procedure. A high willingness to pay expressed by a high demand bid for a large quantity would actually correspond to a high pledging level and a demand price bid of “zero” would correspond to a pledge of “zero”[3].

The procedure described above comparing the progress achieved to the EU target could be interpreted as standardized “review” procedure. In contrast to the static ex-ante pledging model the use of the EU auction model would have the advantage of greater flexibility; that is, pledges and EU procurement could be adjusted dynamically as reaction to future (yet unknown) developments. This would give Member States a very high level of flexibility since bids at each auction are voluntary (compared to pledges that would be locked in by the beginning of the new RES governance entering into force), while still allowing for participation in an EU instrument.

Incorporating the EU instrument into the RES-e auctioneer's optimization problem

In order to incorporate the EU instrument into the RES-e auctioneer's optimization problem simply a constraint as shown in equation is added, possibly in combination with a ceiling price. The constraint forces the sum of selected supply bids at EU level to become equal to or larger than an exogenous defined EU target.

$$\sum_m \sum_b x^S_{m,b,a} = \begin{cases} x_a^{target} & \text{if } x_a^{target} \leq \sum_m \sum_b x^{Smax}_{m,b} \\ \sum_m \sum_b x^{Smax}_{m,b} & \text{otherwise} \end{cases} \quad \forall\, a. \tag{6.3}$$

When the quantity needed to satisfy the constraint is larger than the set of supply bids that would lead to the maximum surplus the effect would be that also bids are selected that negatively add to the surplus as already discussed in example 6.4. The auctioneer would however select the set of bids that leads to the lowest possible surplus losses, which is the highest level of economic efficiency that can be obtained given that an exogenous target needs to be met.

In case the EU target would not be feasible, since $x_a^{target} > \sum_m \sum_b x^{Smax}_{m,b}$ the auctioneer would instead set the constraint at the maximum amount of supply bids that can be

[3]For the latter in principle the effect can differ in that also with a bid of zero additional domestic RES-e deployment could take place (e.g. when an EU target needs to be met as described above), but in both cases the deployment would not have to be financed by the respective Member State (barring contributions to the EU fund).

served $\sum_m \sum_b x^{Smax}_{m,b}$, meaning that all supply bids would be selected. In order to prevent market power execution by the RES-e generators the EU target should therefore not be set too ambitiously, or a price cap could be introduced. This is however a problem of all auctions with fixed exogenous quantity targets; moreover it is unlikely that possible supply by the market will be below the demand needed to reach the 27 percent target, as the past has shown, where the market has reacted with supply increases in the presence of profitable support conditions (Ragwitz and Steinhilber, 2014).

In addition a slack variable $x^{EU}_{m,a}$ has to be added to the market clearing condition (cf. eq.6.4). This is necessary to keep the problem feasible when constraint 6.3 forces the supply to become larger than the maximum level of demand at each node.

$$\sum_b x^S_{m,b,a} = \sum_b x^D_{m,b,a} + x^{EU}_{m,a} \; \forall \, m, a \tag{6.4}$$

It should be noted that $x^{EU}_{m,a}$ is not included in the objective function in eq. 5.7. Therefore an increase of $x^{EU}_{m,a}$ does not contribute to surplus on the positive side, which corresponds to a demand bid with a willingness to pay of zero. This makes sense since from the EC's perspective it does not matter where in the EU new RES-e capacity is installed for the target achievement. On the other hand eq. 6.4 enforces that an increase of $x^{EU}_{m,a}$ has to be matched by an increase of $x^S_{m,b,a}$. Together this implies that the auctioneer selects supply bids $x^S_{m,b,a}$ that are needed to match EU demand $x^{EU}_{m,a}$ according to the least cost logic in order to minimize the surplus loss. The auctioneer then chooses the combination of $x^S_{m,b,a}$, $x^D_{m,b,a}$ and $x^{EU}_{m,a}$that maximizes EU wide surplus, respecting the quantity target.

EU fund and burden sharing

In this section I shortly discuss the creation of an EU fund that could be used to finance the EU contribution to the EU instrument. While the creation of a fund is not a necessary requirement it can serve as a useful vehicle for the collection and allocation of monetary contributions. The fund could be financed from the EU budget, the Member States' budget, or a combination of both. I do not speculate at this point which budgetary items could be used to fill the fund, given different legal requirements that have to be regarded in this respect.

Independent from the source of funding the question has to be answered according to which criteria the fund should be filled, not least because the allocation of contributions to the fund will have an impact on the Member States' incentives for own actions, both through national instrument or through the cross-border auction.

If contributions to the fund are coming directly from the EU budget within the multiannual financial framework this would probably be according to the EU budget key. It would however have to be determined whether this would also be appropriate in this case due the different character of the application of the fund. If the budget of the fund would directly be raised from Member States' contributions a burden sharing would have to be decided. The level of contribution could be set according to different criteria. One option would be to apply the same logic that has been applied for setting the 2020 national targets. Further options are discussed in Zehetner et al. (2015). While the 2020 targets are expressed in energy terms, they are essentially also "money raising mechanisms". Thus the energy target x_a^{target} also determines a financial contribution. Assuming national benchmark targets are in place, each Member State's contribution to the fund could then be determined as follows: let us assume again as above that an EU-wide trajectory has been defined. If $\sum_m x_{m,a}^{progress} < x_a^{target}$ additionally the following test would be conducted for each Member State: is the progress of each Member State larger or equal or smaller than her benchmark? If $x_{n,a}^{progress} \geq x_{n,a}^{benchmark}$ the respective Member State would not have to contribute financial resources to the fund. It should be noted that this kind measurement of progress explicitly also considers support by Member States for installations abroad, since we have $x_{n,a}^D = \sum_m x_{m,a}^D \cdot BDF_{m,n}$. If on the other hand $x_{n,a}^{benchmark} - x_{n,a}^{progress} = x_{n,a}^{delta} > 0$; that is, a Member State stays below her benchmark, then her contribution to the fund is determined by her share in the EU wide gap $\frac{x_{n,a}^{delta}}{\sum_n x_{n,a}^{delta}}$.

6.5 An institutional set-up for the mechanism

The mechanism would require only slightly new institutional arrangements compared to the status quo. These could be implemented under various set-ups, which offers some flexibility regarding the concrete implementation. In figure 6.1 I therefore only outline some possible elements of an institutional scheme and discuss how they are related. A new entity that would need to be created would be the EU auctioneer. This entity could directly be situated at the EC or the EC could nominate some capable agent to conduct the auction on her behalf, e.g. a power exchange. Some entity would have to be responsible to calculate the BDF matrix whereby I already proposed above to hand over this responsibility to ENTSO-e in order to integrate the calculation into the TYNDP process. The BDF matrix feeds into the auction either as parameter or as function of the quantities selected in the auction (cf. section 4.3). In the former case the relationship can be thought to be similar to what will be the case for the flow based market coupling where ENTSO-e, respectively the TSOs calculate the PTDF matrix that is used as constraining parameter in the algorithm of the market coupler. In the latter case the auction and the BDF matrix computations would have to take place simultaneously which would imply that the relevant entities (i.e. auctioneer and ENTSO-e) would have to use a joint model. An option would be to also assign ENSTO-e the responsibility to conduct the auction so that the full computational process would be embedded within a single institution, though this might contradict the "logic" of separating generation and transmission institutionally. A positive side effect of this institutional set-up is that the dialogue between actors from different, yet partly separated segments of the electricity market, such as ENTSO-e / TSOs, power exchanges, Member States, ACER or electricity generators could be facilitated with the BDF matrix calculation process serving as hub between the operational vs. investment and generation vs. transmission perspectives.

The second institutional arrangement regards the administration of the payment streams. After the auction has finished the auctioneer announces the clearing prices and clearing quantities to a clearing system that could institutionally be integrated with either the auctioneer or an EU fund, but I have displayed it as an own entity to highlight that it is a distinct task. The clearing system would net out reciprocal payment obligations and if applicable redistributable surpluses before any transactions take place. It would then announce to and collect from the Member States their net payment obligations. Then I principally foresee two options how the support payments could be directed to the RES-e generators: in one case the clearing system would transfer the determined amounts to the Member States (or another national institution nominated on their behalf) and they would pay the RES-e generators on their own territory, whose bids have been selected in the EU auction. In another case the clearing system would forward the payments to a joint EU fund that pays all RES-e generators, no matter which Member State they are situated in. Independent from the above it could be necessary that Member States provide direct payments to the EU fund if needed to finance an EU instrument for RES-e support (cf. section 6.4). Such an EU fund could institutionally for instance be attached to the European Investment Bank.

Chapter 7

An illustrative application of the mechanism to the European Union

In this chapter the theoretical and conceptual results derived in the preceding chapters of this thesis are applied to an illustrative example for the case of onshore wind energy.

7.1 Method of approach

At first, the electricity market dispatch and investment model, which is described in section 5.4 needs to be calibrated at EU level. The data set, which has been used to do so and the underlying assumptions are presented in section 7.2. The electricity market model is used to derive numerical values on (i) generation costs to calculate the BDF matrix according to definition 4.3 and on (ii) capacity premia for wind onshore to calculate supply and demand bid prices according to the relations derived in sections 5.2 and 5.3. For these purposes the model is run in two different set-ups: in order to calculate generation costs the stock of wind onshore capacity is assumed to be exogenously given. For the post 2020 period however only an overall EU target of 27 percent RES has been defined, yet it is not clear how this share will be allocated across sectors, Member States or time respectively. In order to derive a plausible allocation I derive the RES-e capacities from a RES expansion scenario conducted with the Green-X model (Resch et al., 2015), which achieves a 27 percent RES share in the EU in 2030. Then the wind onshore capacity stock is reduced gradually over several iterations starting with a value of 0.5 MW which is doubled over 10 iterations. This operation is conducted sequentially for each node. Then for the different iterations the differential costs against the base case of lowering wind onshore capacity by a certain unit size can be derived. The results of the BDF matrix calculation are presented in section 7.3.

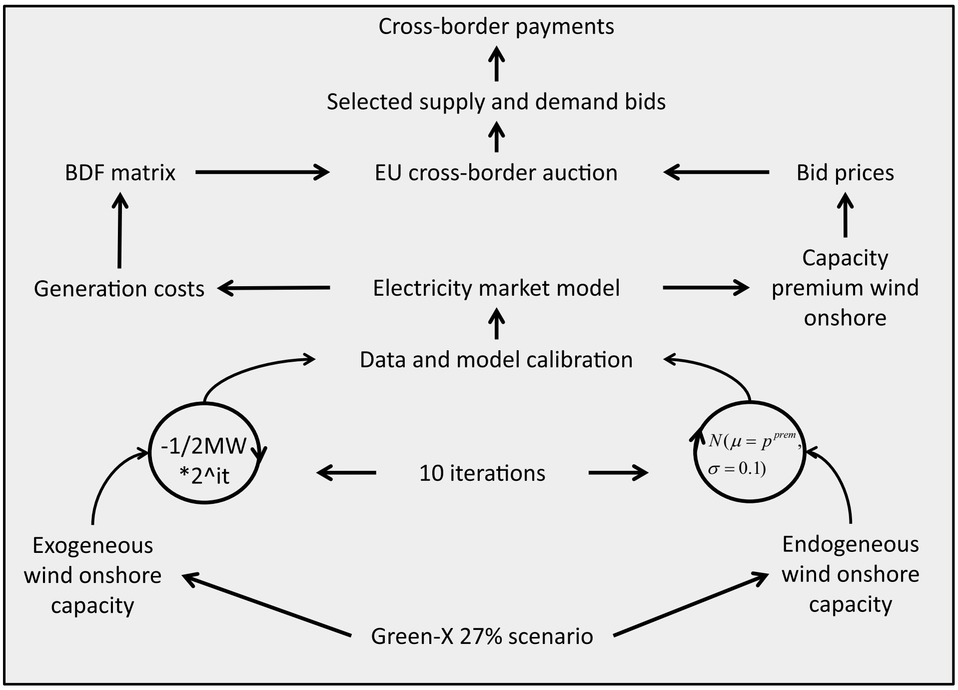


Figure 7.1: Method of approach

In order to derive capacity premia corresponding wind onshore capacity expansion is conducted endogenously in the model. Investments are required to reach exogenous capacity expansion targets, which are again based on the capacities taken from the Green-X scenario. As described in sections 5.2 and 5.3 the level of the RES-e premia can be assumed to reflect the RES-e generators' and Member States' opportunity costs. In order to construct supply and demand bidding curves from the RES-e premia I assume that bid prices follow a normal distribution with a mean value corresponding to the values of the RES-e premia. The results of the bid prices calculation are presented in section 7.3.

In the last step, both the BDF matrix and the bid prices feed as parameters into the EU cross-border auction. The auction outcomes, selected supply and demand bids as well as cross-border payments, are presented and discussed in section 7.3. An overview of the method of approach is given in figure 7.1.

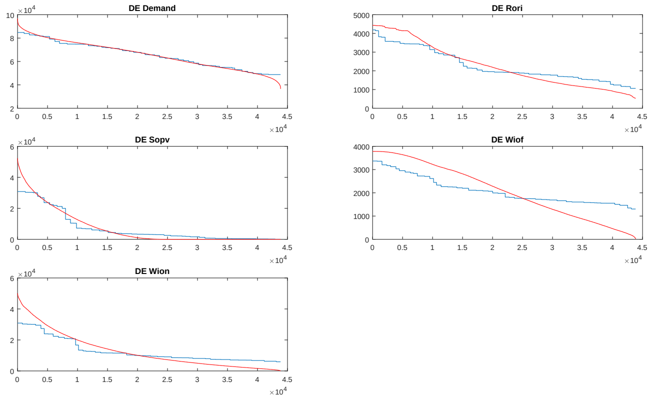
7.2 Data and model calibration

Time series data[1]

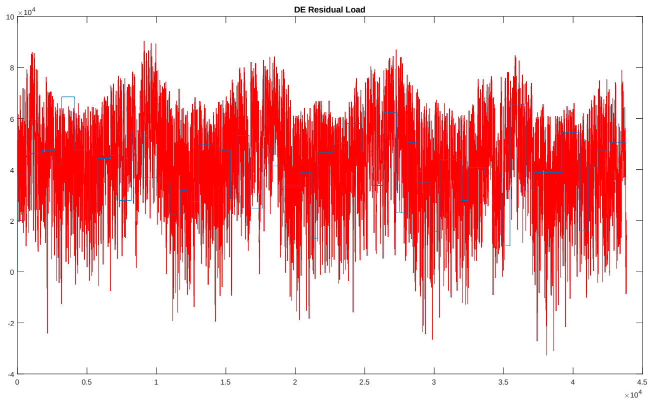
Time series data have been simulated using historical weather data for wind speeds and solar irrigation using reference technologies. Run-of-river flow rates come from a statistical database with daily resolution, which has been linearized to yield hourly resolution. Load profiles are taken from the ENTSO-e transparency platform. Altogether a consistent dataset that includes time series for each of the profile types was available for the weather years 2007 to 2011. In a next step these time series have been scaled with capacities, or to match energy volumes from the Green-X 27 percent scenario, respectively. For instance this implies that the scaled hourly load profile from ENTSO-e matches the yearly electricity demand in the Green-X scenario. The outcome of this exercise are dynamical feed-in and load profiles, which are grouped to five year periods, rather than single years, in order to account for inter- and intra-yearly variability. For the model horizon until 2035 this yields ~175,000 time series steps, which however by far exceeds the numerical capability of the computational model. Therefore in the next step of the data manipulation a clustering algorithm[2] has been applied, with the objective to reduce the number of time steps as much as possible, while maintaining the characteristics of the residual load-duration curve and respecting a pre-defined margin of error. The clustering method that has been used is *k-Means* from the Matlab package, which minimizes the squared Euclidean distance between all data observations and the one being selected by the cluster algorithm. Since the cluster algorithm had to choose system states which represent best the conditions in all Member States simultaneously the geographical correlation in the data can be maintained. In this way it has been possible to reduce the number of representative system states per period to ~50. In addition to the selection of system states the clustering algorithm also assigns the duration $Td_{p,a}$ to each system state. The results are illustrated in figure 7.2 for the example of Germany. It can be observed that the clustering algorithm can reproduce the observations fairly well, whereat average values are met better than extreme values, due to the low occurrence of the latter ones. The inferior representation of the wind offshore profile indicates the lower importance assigned to it by the clustering algorithm, due to the much lower

[1]These data have kindly been provided by Gerhard Totschnig and the approach is described in detail in Totschnig et al. (2013). Manipulation of time series data has been conducted jointly with André Ortner and Lukas Liebmann.

[2]The methodology has been developed by André Ortner and has not yet been published. A similar approach where a clustering approach is applied to a dataset for one country is for instance described in Wogrin et al. (2014).



(a) Clustered profiles. Red lines are the observed profiles ordered by descending capacities. Blue lines are the clustered profiles.



(b) Clustered residual load-duration curve. Red line is the time dependent, observed profile. Blue line is the clustered profile.

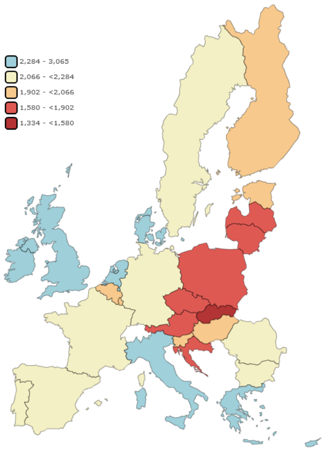
Figure 7.2: Clustered profiles and load duration curve for Germany. Horizontal axes display time steps; vertical axes display capacity [MW].

expansion level in the Green-X scenario compared to the other profile types.

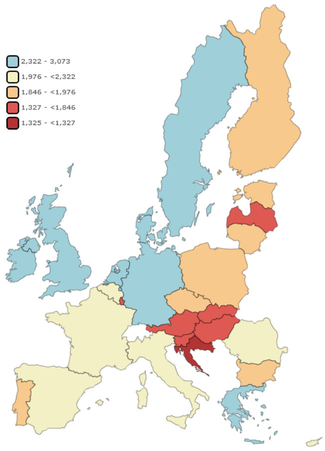
Figure 7.3 shows for the case of wind onshore the average yearly full load hours in different weather periods, which can be derived from aggregating the duration-weighted, available RES-e capacity of all system states of a period.

Installed capacities

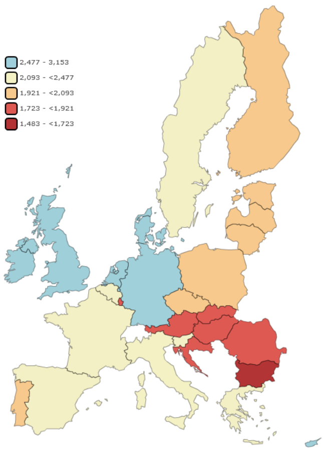
Installed generation capacities are derived from a power plant database developed at the Energy Economics Group, TU Wien. The assumed decommissioning pathway for currently installed capacities, including political moratoria for nuclear power, is displayed in figure 7.4a. Future capacity additions are either decided endogenously in the model



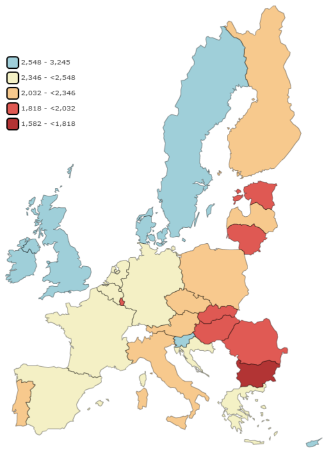
(a) 2015-2019



(b) 2020-2024



(c) 2025-2029

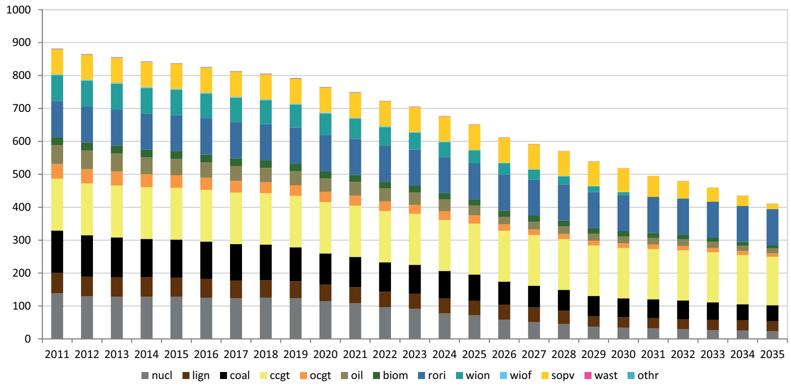


(d) 2030-2034

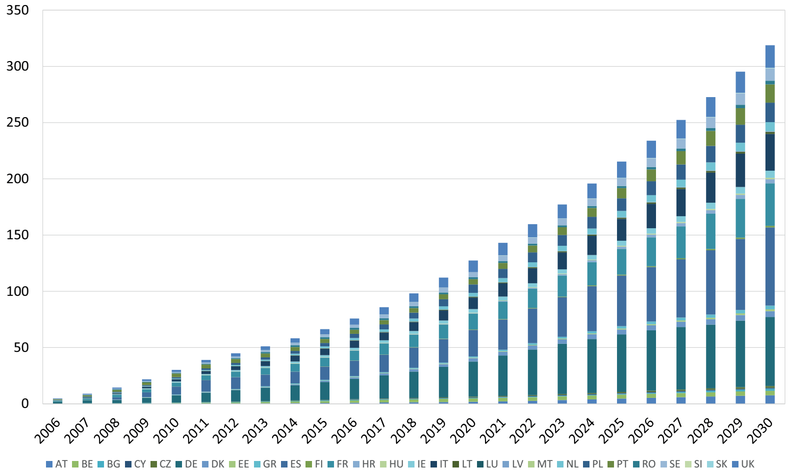
Figure 7.3: Average yearly full load hours in different weather periods

or are taken from the Green-X scenario. Figure 7.4b shows the expansion pathway for wind onshore in each of the Member States in the Green-X scenario.

Installed transmission capacities can be included in the model in either of two forms: (i) explicitly by their thermal line limits or (ii) implicitly by their corresponding NTC values (which are also based on load-flow calculations). In the former case in principle the flows over each line of the transmission network would have to be considered. This would however raise similar numerical issues with respect to computability as in the case with too many time steps. Therefore Ortner and Kruijer (2015) have developed a simplification algorithm for large-scale power system transmission grids. For large transmission grids, such as the European power grid, the required level of reduction may



(a) Installed generation capacity [GW] and decommissioning pathway in the EU, source: power plant database developed by the Energy Economics Group, TU Wien



(b) Wind onshore capacity additions [GW] for the EU, source: Resch et al. (2015)

Figure 7.4: Generation capacity development in the EU

be significant.[3] The problem with the PTDF matrix is that it quickly looses its validity and becomes inaccurate when too many transmission lines are clustered to constitute a market zone, as it is the case in this thesis where a Member State constitutes a market zone. The PTDF approach works better for market models with a high spatial resolution, but then on the other computational constraints may become an issue if the modeling is conducted at EU level.

Therefore ENTSO-e in their TYNDP cost benefit analyses uses reference transfer capacities, whose aim is to give a common ground for comparison and assessing benefits

[3] The one cluster-per-zone grid, which is the highest level of reduction possible, serves as input for the PTDF matrix calculation within this thesis (cf. appendix C). A good description of how to derive the PTDF matrix from the (clustered) grid parameters is provided in D. Shi and D. J. Tylavsky (2012).

Table 7.1: Technology parameters for selected years based on Schröder et al. (2013) and own assumptions

tech	C^{inv} [€ / kW]	C^{fix} [€ / MW.a]	$\bar{C}^{var}$ [€ / MWh]	CO_2^{EF} %	η %
n_nucl	7000	0	5	0.45	0.332
n_lign	1500	30	7	0.45	0.434
n_coal	1300	25	6	0.32	0.461
n_ccgt	800	20	4	0.27	0.602
n_ocgt	400	15	3	0.27	0.391
wion	1270	35	-	-	1
wiof	2871	80	-	-	1
sopv	1500	25	-	-	1
biom	2425	25	7	-	0.461
rori	2000	15	-	-	1

(a) 2015

tech	C^{inv} [€ / kW]	C^{fix} [€ / MW.a]	$\bar{C}^{var}$ [€ / MWh]	CO_2^{EF} %	η %
n_nucl	7000	0	5	0.45	0.335
n_lign	1500	30	7	0.45	0.443
n_coal	1300	25	5	0.32	0.463
n_ccgt	800	20	4	0.27	0.607
n_ocgt	400	15	3	0.27	0.392
wion	1211	35	-	-	1
wiof	2624	80	-	-	1
sopv	1000	25	-	-	1
biom	2280	25	7	-	0.461
rori	2000	15	-	-	1

(b) 2025

of the different projects, instead of a detailed depiction of the transmission grid. This is, because the market and network modeling are conducted in separate model runs, which allows to focus in more detail on the particular aspects of interest. The reference capacities are however informed by detailed regional network studies and therefore probably yield a more accurate representation of the transmission grid, compared to the PTDF that is calculated from a highly reduced grid. Considering the trade-offs that apply and in order to be consistent with the TYNDP, which I recommend also as platform to calculate the BDF matrix, I follow the approach from ENTSO-e here to use reference capacities from the TYNDP for the BDF matrix calculation.[4] The corresponding reference capacities are shown in tables C.1 and C.2.

Technology parameters and cost assumptions

Assumptions on technology parameters and costs for selected time periods are displayed in table 7.1. One can observe that for the future a further drop in costs for RES-e generation technologies is assumed.

Assumptions on fuel and CO_2 prices are based on the EU reference scenario 2016 (Capros et al., 2016) and are displayed in figure7.5. We can see that a gradual increase in both fossil fuel and CO_2 prices is projected.

[4]The question how to integrate or de-compose market and network modeling is a field of ongoing research activity and of high relevance for many applications and as new approaches become available they can also be used to inform the BDF matrix calculation. For a recent overview of approaches and methods compare for instance Bertsch et al. (2016).

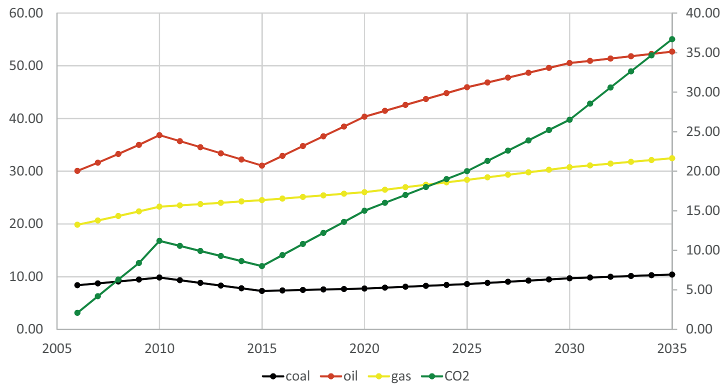


Figure 7.5: Price developments. Fuel prices in Euros per MWh_{th} are indicated on the left vertical axis, CO_2 prices in Euros per tonne CO_2 are indicated on the right vertical axis; source: Capros et al. (2016).

7.3 Results

BDF matrix

In this section I present the outcomes of the BDF matrix calculation, which has been carried out according to the methodology set out in eqs. 4.6 and 4.8 using the electricity market model described in section 5.4. The resulting BDF matrix, which is the weighted average across all ten iterations, is displayed in table 7.2. In addition the coefficients of the BDF matrix are visualized in choropleth maps shown in figure 7.6 for the example of Belgium and for all Member States in figures C.1, C.2 and C.3 in appendix C. We can observe that in many though not all cases the largest share of benefit stays in the Member State where an additional unit of wind power capacity is installed. The level of spill-overs however is significant; in 15 cases it is higher than 50 percent. High levels of spill-overs are in particular observable for Member States that are strongly enmeshed in the European electricity network, whereas Member State situated more peripheral in the network such as Italy, Portugal or Spain are characterized by higher shares of domestic benefits. The last column in table 7.2 shows the sum of the BDF coefficients of each row. As postulated by the overall concept in a closed system the benefits over the sum of demand nodes $\sum_n$ originating from a unit of capacity installed at a supply node m add up to one, or respectively 100 percent in each row. The BDF matrix is however not symmetric, thus the BDF coefficients of each column do not add up to one, as can be seen from the values displayed in the last column. Several factors play a role for this uneven distribution of benefits: of highest relevance is certainly a high interconnection rate to adjacent Member States. A striking example for this is Germany, being situated at the centerpiece of the European transmission grid, it absorbs a benefit three times a high as the virtual reference value of one, if benefits were fully evenly distributed across the EU. Further explanatory factors could be the degree of correlation between wind profiles, the level of electricity demand or the composition of the power mix and related generation cost structures of a Member State. At a smaller system scale an uneven distribution of benefits can be observed between Portugal and Spain, which due to low interconnection rates to the residual system almost operate as autarc sub-system. As can be seen from the corresponding column the high value of 168 percentage points for Spain almost solely derives from spill-overs of benefits from Portugal and therefore is mirrored by a low value of 39 percentage points for Portugal. An uneven distribution is however neither an advantage nor disadvantage if it is reflected in the design of the support mechanism. The implication of the differing values in the mechanism is that - ceteris paribus - Member States with higher values would rather act as "importers" of RES-e capacity than Member States with lower values. It does not imply that a Member States with high values pays more than other Member States, this is limited by the supply capacity bids a Member State submits to the mechanism; it only tells us that for a Member State with high values the mechanism has more options to allocate her demand, since she would benefit from RES-e capacity at several locations, and it will allocate it to the supply nodes where it is most valuable.

Figure 7.7 shows the absolute deviation in percentage points compared to the first iteration for all subsequent iterations. Each sub-bar corresponds to the deviation of the BDF coefficient in each of the nodes $n \in N$ induced by additional capacity in a node $m \in N$. Therefore a stacked bar correspond to the cumulative deviations in a $m \times n$ BDF matrix with $28 \times 28 = 784$ coefficients. We can observe that the deviations increase almost linear for each doubling of the additional wind onshore capacity at a supply node $m \in M$. The deviations are however not evenly distributed, but differ across nodes. For the 10th iteration the cumulative deviation between the 10th and the 1st BDF matrices is slightly more than 300 percentage points. Related to the sum of matrix coefficients the average change is still far less than 0.5 percentage points so that it can be concluded that in general the BDF matrix shows a high level of stability for ranges of wind onshore capacity additions between 1 MW and 1024 MW.

Bid parameters

This section describes the supply and demand bid prices and quantities. In a first step, the resulting RES-e premia, which are derived from modeling auctions for RES-e capacity (cf. section 5.6), are presented in figure 7.8a. In this example the domestic

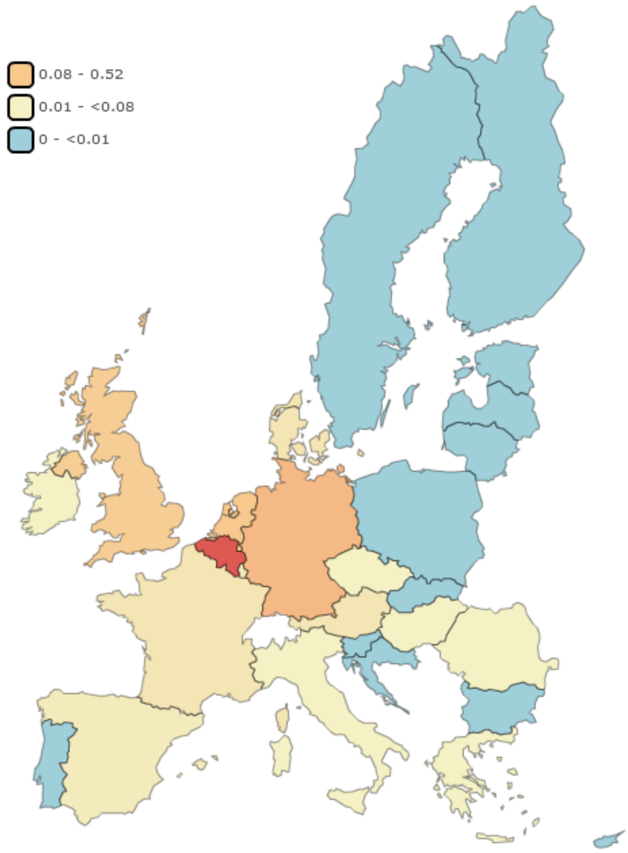


Figure 7.6: Visualized BDF for Belgium. Color code indicating 10, 50 and 90 percentiles. Legend indicating ranges for absolute values.

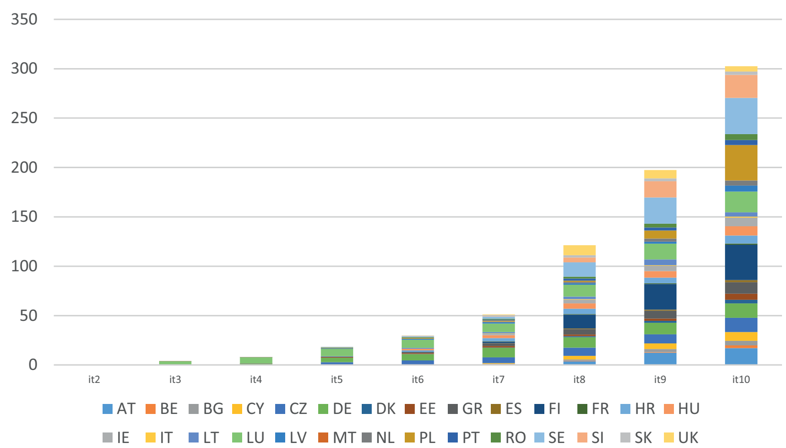
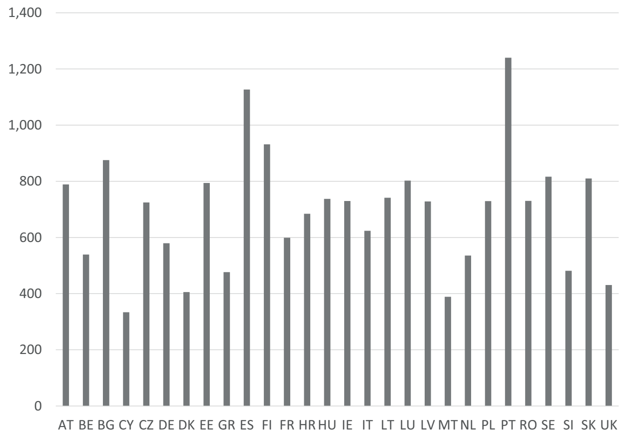


Figure 7.7: Deviation of BDF coefficients over 10 iterations. Horizontal axis displays iteration steps. Vertical axis display absolute deviations in percentage points of BDF coefficients.

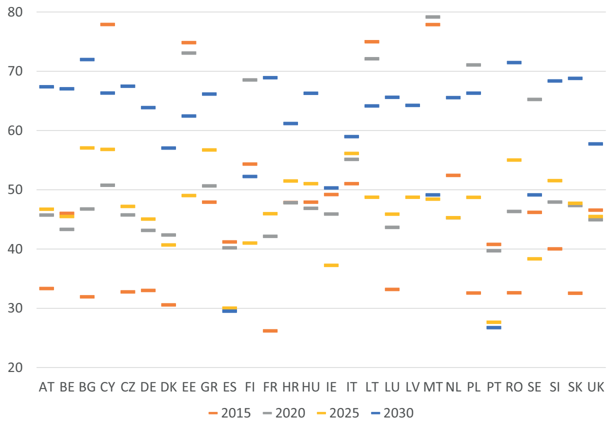
Table 7.2: BDF matrix. Rows indicate supply nodes and columns indicate demand nodes. Coefficient in each cell indicates the share of benefit that is distributed from a unit of RES-e capacity in a supply node to a demand node.

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK	$\sum$
AT	0.24	0.04	0.00	0.00	0.07	0.36	0.04	0.00	0.01	0.01	0.01	0.02	0.01	0.02	0.00	0.03	0.00	0.04	0.00	0.00	0.03	0.00	0.00	0.01	0.00	0.01	0.00	0.03	1
BE	0.03	0.52	0.00	0.00	0.01	0.14	0.03	0.00	0.01	0.02	0.00	0.03	0.00	0.01	0.01	0.01	0.00	0.02	0.00	0.00	0.08	0.00	0.00	0.01	0.00	0.00	0.00	0.07	1
BG	0.01	0.01	0.69	0.00	0.00	0.07	0.00	0.00	0.05	0.01	0.00	0.01	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.05	0.00	0.00	0.00	0.03	1
CY	0.02	0.01	0.00	0.41	0.02	0.04	0.01	0.00	0.32	0.02	0.00	0.01	0.01	0.01	0.01	0.04	0.00	0.01	0.00	0.00	0.02	0.00	0.01	0.01	0.00	0.00	0.01	0.02	1
CZ	0.08	0.02	0.00	0.00	0.40	0.16	0.02	0.00	0.01	0.01	0.01	0.02	0.00	0.02	0.00	0.03	0.00	0.01	0.00	0.00	0.02	0.04	0.00	0.01	0.00	0.00	0.10	0.03	1
DE	0.07	0.06	0.00	0.00	0.05	0.45	0.06	0.00	0.01	0.01	0.01	0.03	0.01	0.02	0.01	0.03	0.00	0.05	0.00	0.00	0.05	0.00	0.00	0.01	0.00	0.01	0.00	0.04	1
DK	0.04	0.04	0.00	0.00	0.01	0.17	0.46	0.00	0.01	0.01	0.02	0.02	0.01	0.02	0.00	0.03	0.00	0.04	0.00	0.00	0.04	0.00	0.00	0.01	0.02	0.01	0.00	0.04	1
EE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.18	0.00	0.36	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	1
GR	0.02	0.01	0.01	0.11	0.02	0.04	0.01	0.00	0.56	0.02	0.00	0.01	0.01	0.01	0.01	0.07	0.00	0.01	0.00	0.00	0.02	0.00	0.01	0.02	0.00	0.00	0.01	0.03	1
ES	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.89	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.03	1
FI	0.01	0.01	0.00	0.00	0.01	0.03	0.01	0.02	0.00	0.00	0.32	0.00	0.00	0.00	0.00	0.00	0.26	0.00	0.02	0.00	0.01	0.07	0.00	0.00	0.20	0.00	0.01	0.01	1
FR	0.02	0.03	0.00	0.00	0.00	0.15	0.01	0.00	0.00	0.04	0.00	0.62	0.00	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.01	0.00	0.00	0.00	0.08	1
HR	0.02	0.02	0.00	0.00	0.00	0.17	0.01	0.00	0.01	0.01	0.00	0.02	0.20	0.27	0.00	0.03	0.00	0.01	0.00	0.00	0.02	0.00	0.00	0.01	0.00	0.13	0.03	0.03	1
HU	0.02	0.02	0.00	0.00	0.00	0.15	0.01	0.00	0.01	0.01	0.00	0.02	0.17	0.31	0.00	0.03	0.00	0.01	0.00	0.00	0.02	0.00	0.00	0.01	0.00	0.13	0.03	0.03	1
IE	0.00	0.01	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.02	0.00	0.01	0.00	0.01	0.78	0.01	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.01	0.00	0.00	0.00	0.04	1
IT	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	1
LT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.63	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	1
LU	0.07	0.05	0.00	0.00	0.02	0.33	0.05	0.00	0.01	0.01	0.01	0.02	0.01	0.02	0.00	0.03	0.00	0.27	0.00	0.00	0.04	0.00	0.00	0.01	0.00	0.01	0.00	0.04	1
LV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.38	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	1
MT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1
NL	0.02	0.06	0.00	0.00	0.01	0.11	0.02	0.00	0.01	0.01	0.00	0.02	0.00	0.01	0.02	0.03	0.00	0.02	0.00	0.00	0.52	0.00	0.00	0.01	0.00	0.00	0.00	0.15	1
PL	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.93	0.00	0.00	0.00	0.00	0.00	0.00	1
PT	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.50	0.00	0.14	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.00	0.00	0.00	0.02	1
RO	0.01	0.01	0.22	0.00	0.00	0.07	0.00	0.00	0.04	0.01	0.00	0.01	0.00	0.01	0.00	0.03	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.53	0.00	0.00	0.00	0.02	1
SE	0.01	0.01	0.00	0.00	0.01	0.04	0.03	0.02	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00	0.26	0.00	0.02	0.00	0.01	0.07	0.00	0.00	0.23	0.00	0.01	0.01	1
SI	0.04	0.03	0.00	0.00	0.00	0.27	0.02	0.00	0.01	0.01	0.01	0.02	0.14	0.16	0.00	0.03	0.00	0.01	0.00	0.00	0.02	0.00	0.00	0.01	0.00	0.16	0.03	0.03	1
SK	0.02	0.02	0.00	0.00	0.20	0.10	0.01	0.00	0.01	0.01	0.01	0.02	0.03	0.05	0.01	0.03	0.00	0.00	0.00	0.00	0.02	0.04	0.00	0.01	0.00	0.03	0.36	0.03	1
UK	0.01	0.04	0.00	0.00	0.00	0.09	0.01	0.00	0.00	0.03	0.00	0.02	0.00	0.01	0.01	0.01	0.00	0.01	0.00	0.00	0.05	0.00	0.00	0.01	0.00	0.00	0.00	0.69	1
$\sum$	0.76	0.98	0.93	0.53	0.90	3.02	0.82	1.01	1.06	1.68	0.74	1.09	0.61	0.95	0.91	1.42	1.53	0.52	0.94	1.00	1.11	1.17	0.39	0.71	0.54	0.50	0.62	1.55	28

auctions for wind onshore are taking place in the year 2020 so that the selected capacities are available for electricity generation in the year 2025. It can be seen that the level of premia required to incentivize the investments into RES-e capacity needed to achieve the Member States' expansion targets vary significantly across Member States. They range from about 330,000 Euros per MW in Cyprus to about 1,200,000 Euros per MW in Portugal. Since the costs of new RES-e capacity are equal across the EU (cf. table 7.1) differences in premia have to be explained by differences in market income of wind onshore generation. The market revenues realized in the different Member States for the periods 2015 to 2030 are displayed in figure 7.8b. A general pattern that can be observed is that starting from the first period the market values first drop in the following period as a consequence of the higher RES-e market share and then rise again. The rise can significantly be attributed to increases in CO_2 and fuel prices (cf. figure 7.5). An exception to this pattern is the Iberian electricity market, where the average market value drops below 30 Euros per MWh in 2025-2029 and 2030-2034. Several factors cause



(a) Wind onshore premia [1000 Euros] resulting from RES-e auction in 2020



(b) Average market values in [Euros per MWh] in different model periods

Figure 7.8: Market values and wind onshore premia

the differences in market income of wind onshore generation, such as the volume of wind onshore capacity expansion (cf. figure 7.4b) relative to the level of electricity demand and available interconnection capacity or the amount of average yearly full load hours in different weather periods (cf. figure 7.3).

Some further data manipulation is required to arrive a plausible set of bid parameters. For this illustrative example I assume that Member States and generators of RES-e submit up to ten bids and that the amount of bids corresponds to size of the market for RES-e, indicated by the wind onshore expansion target x_n^{target}. In order to derive supply and demand curves the premium is multiplied with a random number R_b (cf. eqs. 7.1a and 7.1b), which follows a normal distribution with a mean of $\mu = 1$ and a standard deviation of $\sigma = 0.1$.

$$p^D_{n,b} = \prod_b p^{prem}_n \cdot R_b \tag{7.1a}$$

$$p^S_{m,b} = \prod_b p^{prem}_m \cdot R_b \tag{7.1b}$$

Values for the maximum bid size $x^{Dmax}_{n,b}$and $x^{Smax}_{m,b}$ are derived from eqs. 7.2a and 7.2b respectively. I assume that 50 MW per demand bid and 75 MW per supply bid, corresponding to a maximum aggregate demand of 500 MW respectively supply of 750 MW per Member State are typical numbers that are also observed in real world auctions for RES-e. These numbers are scaled by the expressions below the square roots, such that relatively lower demand bid prices correspond to relatively larger bid sizes and vice versa and that relatively higher supply bid prices correspond to relatively larger bid sizes and vice versa. Moreover the bid sizes are scaled to the sizes of the market for RES-e by considering the expansion target x^{target}_n.

$$x^{Dmax}_{n,b} = 50 \cdot \sqrt{\frac{\left(\frac{\sum_n p^D_{n,b}}{\sum_n}\right)}{p^D_{n,b}} \cdot \left(0.5 + \frac{x^{target}_n}{\sum_n x^{target}_n} \cdot 25\right)} \tag{7.2a}$$

$$x^{Smax}_{m,b} = 75 \cdot \sqrt{\frac{p^S_{m,b}}{\left(\frac{\sum_m p^S_{m,b}}{\sum_m}\right)} \cdot \left(0.5 + \frac{x^{target}_m}{\sum_m x^{target}_m} \cdot 25\right)} \tag{7.2b}$$

EU cross-border auction

The supply and demand bid parameters resulting from the calculations in section 7.3 are shown in tables 7.3 and 7.4 respectively. For each Member State, the first column displays in descending, respectively ascending order the level of the demand bid $p^D_{n,b}$, respectively supply bid $p^S_{m,b}$ in Euros per MW, while the adjacent column indicates the maximum quantities in MW $x^{Dmax}_{n,b}$, respectively $x^{Smax}_{m,b}$ offered by Member States, respectively generators of RES-e at a certain price level. The third columns shows the outcome of the cross-border auction; that is, the equilibrium quantities of demand bids $x^{\star D}_{n,b}$ and supply bids $x^{\star S}_{m,b}$ that have been selected in the auction, where $x^{\star D}_{n,b} = \sum_m x^{\star D}_{m,b} \cdot BDF_{m,n}$. The results of the auction are discussed in more detail in the following.

Next I discuss the functionality and the outcomes of the cross-border auction with the help of 7.9, where the demand curves (green), supply curves (red), cross-border demand

Table 7.3: Demand bid parameters and equilibrium quantities

	$p^D_{n,b}$	$x^{Dmax}_{n,b}$	$x^{\star D}_{n,b}$	$p^D_{n,b}$	$x^{Dmax}_{n,b}$	$x^{\star D}_{n,b}$	$p^D_{n,b}$	$x^{Dmax}_{n,b}$	$x^{\star D}_{n,b}$	$p^D_{n,b}$	$x^{Dmax}_{n,b}$	$x^{\star D}_{n,b}$	$p^D_{n,b}$	$x^{Dmax}_{n,b}$	$x^{\star D}_{n,b}$	$p^D_{n,b}$	$x^{Dmax}_{n,b}$	$x^{\star D}_{n,b}$	$p^D_{n,b}$	$x^{Dmax}_{n,b}$	$x^{\star D}_{n,b}$
	AT			**BE**			**BG**			**CY**			**CZ**			**DE**			**DK**		
bid1	947,412	47	41	624,157	52	52	1,069,457	34	34	345,407	57	57	752,199	40	40	628,206	137	137	429,573	66	66
bid2	848,879	48	25	615,767	51	51	987,915	34	34	322,425	57	30	740,541	39	33	609,078	135	135	401,201	66	66
bid3	841,371	48	23	517,220	54	54	975,462	34	34	313,019	57	10	708,732	39	13	607,619	132	132	395,080	66	66
bid4	819,663	47	21	511,703	53	31	850,490	35	0	295,689	57	3	658,247	40	16	603,511	129	129	393,077	64	23
bid5	771,419	47	20	496,334	52	21	753,107	36	0	282,472	56	0	641,822	39	13	575,312	128	128	376,503	63	17
bid6	758,567	34	1	482,396	38	3			0			0			0	573,182	93	9	325,507	49	1
bid7	757,211	31														571,475	84				
bid8																545,029	73				
bid9																523,788	54				
bid10																503,287	39				
	EE			**GR**			**ES**			**FI**			**FR**			**HR**			**HU**		
bid1	838,741	38	38	496,060	55	55	1,235,370	95	95	1,116,338	32	28	654,289	100	100	785,437	44	25	837,186	37	37
bid2	780,956	38	37	451,421	55	55	1,224,522	92	92	877,483	35	11	648,553	97	97	778,925	43	30	754,561	38	38
bid3	773,297	37	36	444,247	55	55	1,183,063	92	92	852,127	35	7	625,374	97	97	776,308	42	25	751,316	37	37
bid4	750,438	37	11	436,992	54	16	1,111,895	92	92	842,088	35	4	612,002	95	31	753,293	42	3	682,175	38	7
bid5	674,057	38	10	434,472	52	2	1,099,610	90	90	737,462	36	4	591,081	94	11	621,600	44	3	580,259	40	6
bid6			0			0	1,099,368	65	65			0	574,054	69	2	593,790	33	0			1
bid7							1,013,549	61					538,072	64							
bid8							1,010,008	52					523,872	55							
bid9							980,749	38					462,612	43							
bid10							911,817	28													
	IE			**IT**			**LT**			**LU**			**LV**			**MT**			**NL**		
bid1	784,936	50	50	698,520	90	90	851,987	38	38	935,384	33	14	881,127	35	35	434,768	48	48	644,069	59	59
bid2	730,894	50	50	692,611	88	88	823,506	37	37	792,742	35	11	787,988	35	35	414,920	47	36	570,361	61	61
bid3	708,566	50	6	638,107	90	90	804,039	37	37	786,740	34	14	786,467	35	35	385,069	48	0	565,546	60	60
bid4	670,053	50	5	617,437	89	89	782,739	37	37	687,560	36	15	724,279	35	10	383,611	47	0	551,211	59	59
bid5	619,597	51	4	610,892	86	60	754,223	36	36	685,484	34	15	602,227	37	10	316,854	50	0	544,869	57	31
bid6	606,937	37	1	592,009	63	2			0			1			0			0	538,982	42	5
bid7	577,270	34		585,399	57														495,702	39	
bid8				579,117	49																
bid9				561,634	36																
bid10																					
	PL			**PT**			**RO**			**SE**			**SI**			**SK**			**UK**		
bid1	849651	65	65	1440477	48	48	862288	41	41	956355	52	24	565237	42	20	871804	35	35	497759	92	92
bid2	849,651	65	65	1,440,477	48	48	862,288	41	41	956,355	52	24	565,237	42	20	871,804	35	35	497,759	92	92
bid3	766,371	66	66	1,397,313	47	31	763,178	42	42	913,690	52	9	528,286	42	32	866,353	34	29	477,904	91	91
bid4	757,568	65	65	1,395,882	46	6	630,783	45	13	821,873	54	6	495,994	43	17	830,698	34	6	433,220	93	93
bid5	755,675	64	64	1,245,871	48	6	608,963	45	4	796,197	53	2	430,178	45	3	797,404	34	1	431,260	91	91
bid6	734,762	63	1	1,146,339	48	6	602,907	44	3	780,093	52	2	404,655	45	3	744,153	34	1	415,264	90	90
bid7	712,613	46	0	1,146,123	35	4			0	778,048	37	0			0			0	406,101	66	66
bid8	689,974	42		1,119,344	32					721,642	35								396,128	60	
bid9	642,341	37		1,047,999	28					714,453	30								386,988	52	
bid10																			353,383	39	

curves (gray) and equilibrium quantities (dashed black line) are displayed for selected Member States. The horizontal size of the cross-border demand curve x_m^D cannot be stated explicitly, due to the many possibilities how cross-border demand can be allocated, since is a decision variable in the optimisation problem of the RES-e auctioneer, rather than an input parameter. So what is shown here is the maximum quantity x_m^D can take at each node m, such that eq. 6.1b still holds. The bidding curves for all Member States are displayed in figures C.4 to C.7.

Let us first take a look at figure 7.9a, which shows the bidding curves for Denmark. In this figure we already can observe several interesting features of the cross-border mechanism: first of all, the cross-border demand curve, which is a joint weighting of all Member States' demand, is significantly higher compared to the domestic demand curve. The reason is that the level of the RES-e premium required to incentivize wind onshore capacity expansion is in average lower in Denmark compared to other Member States. Therefore the opportunity costs of paying a higher support elsewhere appear in Denmark as higher demand. The effect is that the quantity $\sum_b x_{m,b}^{\star D}$ (dashed black line) that is selected by the mechanism for Denmark is much further to the right than the position on the horizontal axis where the supply and the domestic demand curves cross, indicating the quantity of supply that would have been selected if only domestic demand would have been considered. In effect the cross-border mechanism makes available the low-costs potentials in Denmark to demand from other Member States. Moreover we can observe that the cross-border demand curve steeply declines towards the end. The reason is that at higher quantities only fewer Member States offer positive demand bids that can be considered in the cross-border demand curve.

Let us next take a look at figure 7.9b, which shows the bidding curves for Spain. Here we can see that the cross-border demand curve is lower than the domestic demand curve. As a consequence less supply is selected than if only domestic demand would have been considered; however a significant portion of supply remains in Spain also with the cross-border mechanism.

Figure 7.9c is an example, where the mechanism selects more supply in Croatia than what would have been selected in the sole national case, even though the price level of cross-border demand is lower compared to the domestic demand curve; the aggregated cross-border demand curves however spans wider horizontally so that more Member States can benefit from the supply offered in Croatia. The equilibrium quantity $\sum_b x_{m,b}^{\star D}$ for Croatia is however lower than the position on the horizontal axis, where the supply curve and the cross-border demand curve cross. The explanation for this is that even though additional supply in Croatia would have led to a positive surplus, the mechanism has chosen to allocate this segment of cross-border demand to other supply nodes where it would lead to a higher surplus.

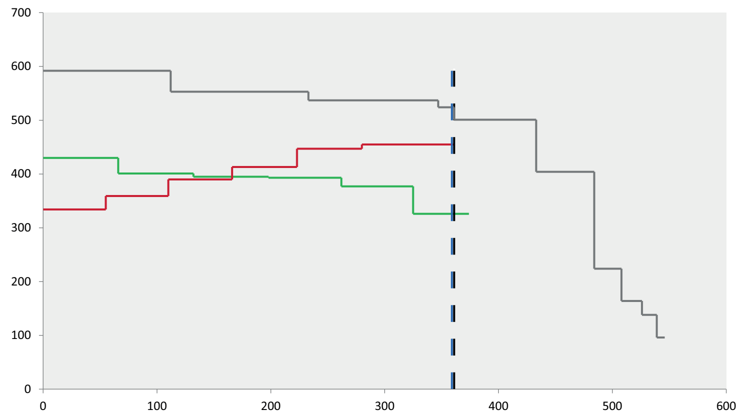
Finally, a comparison of the bidding curves for Spain and Croatia reveals the constraining nature of the BDF matrix on the possibilities of the mechanism to allocate cross-border demand. A visual inspection of the area laying vertically between the suppy and cross-border demand curves in the two Member States suggests that additional supply selected in Croatia would have led to higher surplus in comparison to additional supply in Spain. The reason why this "trade" has not taken place is that supply in Croatia and Spain are not "competing" for the same demand, at least only to a very limited amount, since almost the entire demand of Spain can only be allocated to either Spain or Portugal, whereas the demand in Croatia is competing with several other nodes due to the structure of the BDF matrix (cf. table 7.2).

Payment streams

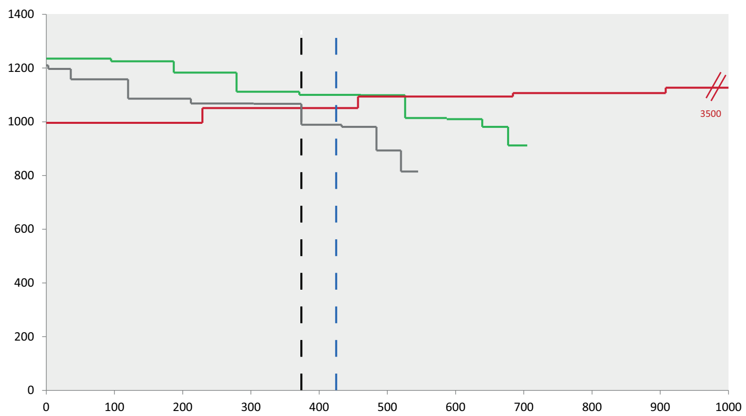
After the auction has finished the auctioneer announces the clearing quantities $x^{\star}$. The clearing of the cross-border auction induces payments streams as shown in tables C.8 to C.11. For the administration of the payments two options come into consideration: (i) bilateral payments and (ii) an EU fund, both are described showing subsequent calculation steps (just for the sake of clarity, in practice only a single step would be required) in the following. In case of bilateral payments the clearing system calculates the gross payments between all combinations of Member States by applying the following formula (cf. eq. 7.3):

$$p^{pay}_{n,m} = \sum_{b} p^{D}_{n,b} \cdot BDF_{m,n} \cdot x^{\star D}_{m,b} \tag{7.3}$$

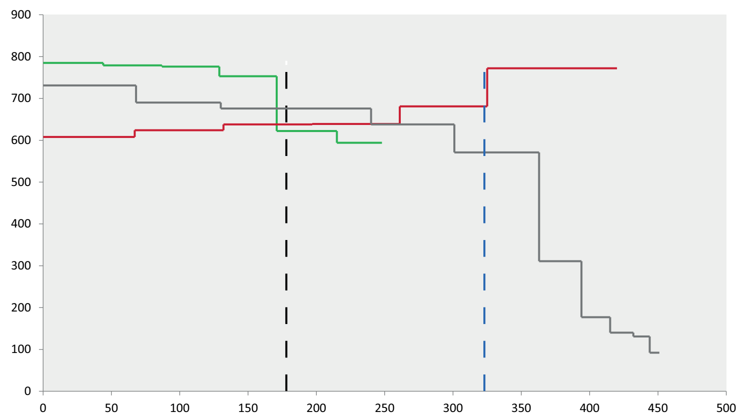
The resulting payment streams, including the payments a Member State makes to herselves, are shown in table C.8, whereby again the index m here indicates a host Member State for supply of wind onshore capacity who is therefore recipient of the payment in order to pay the RES-e generator on her territory. Consequently Member States where no supply bids have been selected do not receive payments, since they do not have to pay RES-e generators. In a next step the clearing system calculates the nodal surpluses; that is, the difference between the Member States' gross payments based on the demand bid prices and the payments to the RES-e generators based on the supply bid prices and surpluses are distributed according to each Member State's share in aggregate payments at a node (cf. eq. 7.4). Subtracting the surpluses from the gross payment obligations results in the surplus adjusted payment streams shown in



(a) DK



(b) ES



(c) HR

Figure 7.9: Bidding curves and equilibrium quantities for selected Member States. Each figure displays demand curves (green), supply curves (red), cross-border demand curves (gray) and equilibrium quantities (dashed black line), EU instrument equilibrium quantities (dashed blue line; these are discussed further below in 7.3). Vertical axis displays prices in thousands of Euros; horizontal axis displays quantities in MW.

table C.9.

$$SP^{re}_{m,n} = \frac{p^{pay}_{n,m}}{\sum_n p^{pay}_{n,m}} \cdot \left(\sum_n p^{pay}_{n,m} - \sum p^S_{m,b} \cdot x^{\star S}_{m,b} \right) \tag{7.4}$$

After correction for the surpluses reciprocal payables would still exist between the Member States so that the clearing system would calculate the net positions from these, which include only the net payables to other Member States, but not the "internal" payables from a Member State to herselves, as displayed in table C.10, The sum of each column indicates the net payments a Member State receives from all other Member States and the sum of each row indicates the aggregate payments a Member State pays all other Member States.

The principal alternative to bilateral payments would be to use an EU fund for the administration of payment streams. The resulting payment streams are shown in table C.11. In this case each Member State's gross contribution to the fund would be $\sum_m p^{pay}_{n,m}$, which reduced by the redistributable surplus $\sum_m SP^{re}_{m,n}$ yields the net contribution of each Member State to the EU fund. The reader is invited to convince herself that the sum Member States' net contributions to the fund of ~3.24 billion Euros equals the sum of surplus adjusted payments between all combinations of Member States.

Efficiency gains realized through the mechanism

In order to evaluate the potential of the *cross-border mechanism* (cbm) to increase economic efficiency, I compare the outcome of the mechanism against the following two reference cases:

1. *National support* (nat): in this case I modify in the BDF matrix in a way such that $BDF^{(nat)}_{m,n} = 1 \;\forall\; n = m$ and $BDF^{(nat)}_{m,n} = 0 \;\forall\; n \neq m$; that is, the demand bids of a Member State can only be used to support supply from RES-e generators on her own territory.

2. *Minimum support* (min): in this case the objective function from the original optimization problem (cf. eq. 6.1a) is transformed to $\min_{x^S_{m,b}} c^{support} = \sum_{m,b} p^S_{m,b} \cdot x^S_{m,b}$ and constraint 6.3 is set to $x^{target(min)} = \sum_{m,b} x^{\star S(cbm)}_{m,b}$; that is, the auctioneer tries to procure the equilibrium supply quantity from the cross-border auction now at the lowest possible cost. Subsequently, the cost minimal set of equilibrium supply quantities $x^{\star S(min)}$ is fixed and passed back to the initial surplus maximization problem so that the mechanism chooses the surplus maximizing set of demand bids for a given set of supply bids.

Next table 7.5 shows how the selected supply quantities would change compared to the benchmark case (cbm), where a negative sign means that the capacity is reduced compared to the benchmark case. From table 7.5a we can see for instance that the capacity of Denmark would be reduced in the national case since the cross-border demand from other Member States would not be available anymore. On the other hand Member States where in the benchmark case no or only little supply bids had been selected, such as Austria, Finland, Croatia or Luxembourg, now would have (more) wind onshore capacity installed on their own territory. In the aggregate the cumulative equilibrium supply quantity $\sum_{m,b} x^{\star S}_{m,b}$ would be slightly higher in the national case (5,851 MW) compared to the benchmark case (5,463 MW). The reason can be seen in constraint 6.1b, which can become a bottleneck more easily in the benchmark case due to the “inflows” from multiple nodes. Table 7.5b shows the difference in selected supply bids between benchmark case and the minimum support cost case. We can see that in this case the new supply would be more concentrated in a smaller number of Member States with the lowest price supply bid prices. For instance in Belgium, Greece, the Netherlands or the United Kingdom all supply bids would be selected in this case, while for instance Austria, the Czech Republic, Spain, Poland and several others would supply nothing.

$$\frac{c^{support}}{MW} = \frac{\sum_{m,b} p^S_{m,b} \cdot x^{\star S}_{m,b}}{\sum_{m,b} x^{\star S}_{m,b}} \tag{7.5a}$$

$$\frac{b}{MW} = \frac{\sum_{m,n,b} p^D_{n,b} \cdot BDF_{m,n} \cdot x^{\star D}_{m,b}}{\sum_{m,b} x^{\star S}_{m,b}} \tag{7.5b}$$

$$\frac{b^{net}}{MW} = \frac{b}{MW} - \frac{c^{support}}{MW} \tag{7.5c}$$

Next I compare the economic performance of the three cases with the help of three indicators which are displayed in eqs. 7.5a to 7.5c, which measure the resulting support costs, benefits and net benefits for each set of selected bids. All three indicator are expressed in relative terms, i.e., per unit (MW) of additional RES-e capacity selected by the mechanism, in order to be comparable.

The results for the indicators of the three cases are displayed in figure 7.10. It can be seen that as could be expected the (min) case performs best in terms of support costs with an average value of ~503,000 Euros per MW compared to ~592,000 Euros per MW in the (cbm) benchmark case and ~637,000 Euros per MW in the (nat) case. This tells us that the efficiency gains of cross-border support compared to the pure national case are in the magnitude of ~45,000 Euros per MW, but lower than in the pure cost minimization case. Looking at the benefits we see a different picture. Here the benefit is

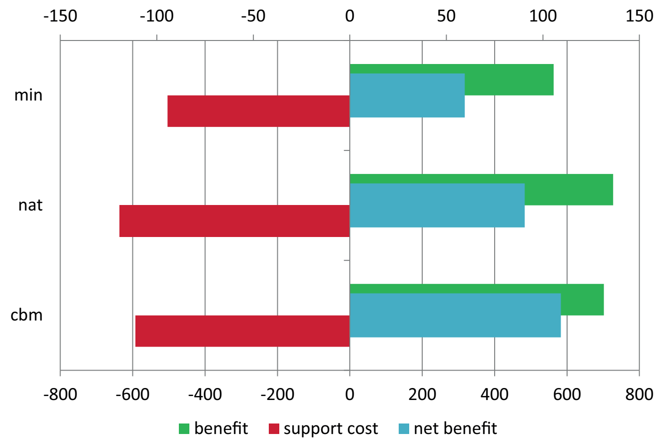


Figure 7.10: Indicators comparing economic performance of the three cases. Values are averages in thousands of Euros per MW. Benefit and support costs are displayed on primary horizontal axis; net benefit is shown on secondary horizontal axis.

the highest in the (nat) case with ~727,000 Euros per MW, compared to 702,000 Euros per MW in the (cbm) case. The reason for the slightly lower benefit is that cross-border demand is selected more likely at Member States with low-priced supply and demand bid curves as can be seen in the examples above so that lower price demand bids factor in more strongly. The reduction in benefit in the (cbm) case compared with the (nat) case is however more than compensated by a reduction in support cost so that the net benefit of ~109,000 Euros per MW in the (cbm) case exceeds the net benefit in the (nat) case of ~91,000 Euros per MW by ~18,000 Euros per MW or ~20 percent. The (min) case leads by far to the lowest benefit of ~563,000 Euros per MW, since benefits have not been considered in the initial optimization problem in this case, yielding a net benefit of ~60,000 Euros per MW.

There are two important take-aways from these findings: on the one hand the mechanism would significantly lower the support costs compared to sole national support of new wind onshore capacity, by making accesible low-cost potentials across the EU to all Member States. On the other hand the mechanism does not allocate RES-e capacity merely for the sake of minimal support costs, rather it trades-off costs and benefits in such a way that new RES-e capacity gets installed at locations with both low support costs and high impacts in terms of benefits, respectively avoided opportunity costs of alternative allocations.

EU instrument for 2030 target achievement

I conclude the results discussion in this section with an illustration of how the mechanism's functionality could be extended to also serve as EU instrument (eui) for the 2030 target achievement. The underlying approach has already been described in section 6.4. We already know that in the (cbm) benchmark case 5,463 MW of new capacity would be selected in the cross-border auction. Let us now assume that 10,157 MW, corresponding to half of the total supply bids $\sum_m \sum_b x_{m,b}^{Smax}$, of new capacity additions would be needed from the cross-border auction to stay on the target trajectory, so that we have a gap of 4,694 MW. Then constraint 6.3 would be activated with the trajectory target of 10,157 MW inserted on the right hand side. As a consequence the cross-border mechanism is forced to select sufficient supply bids so that the trajectory target is achieved. Also as EU instrument the mechanism would maximize the EU wide surplus. However, given the fact that the expansion constraint needs to be fullfilled this could imply that also bids with a negative surplus, i.e., segments on the horizontal axis where the cross-border demand curve lies below the supply curve need to be selected.

Table 7.6 shows how the selected supply quantities would change compared to the benchmark case (cbm) so that the gap can be filled. Unlike in the case of the support cost minimal supply (min) the gap would not be filled exclusively with the lowest priced bids. The reason is again that the mechanism trades-off costs again benefits, where benefits expressed as demand bids by Member States lower the required support from the EU so that the mechanism chooses the bids with highest surplus, i.e. the lowest surplus losses in this case. In this way for instance Austria, Finland or Hungary are selected by the mechanism, which would not have been the case in the pure cost minimization (min) set up.

The effect of the additional EU demand is also illustrated in figure 7.9, where the dashed-blue line indicates the quantity of supply that would be selected in each Member State with the EU instrument being activated. We can see that in Denmark no more supply compared to the benchmark case would be selected, the reason for this simply being that all supply bids have already been selected in the benchmark case. In Spain and Croatia the mechanism would in case of the EU instrument also select bids with a negative surplus, where the cross-border demand curve lies horizontally below the supply curve. The cross-border mechanism chooses these bids in a way, such that area laying below the cross-border demand curves for all Member States is EU wide minimized, while the EU wide expansion target is achieved. Achieving the EU wide expansion target would results in support costs of ~6.4 billion Euros which is roughly a doubling compared to the benchmark case with ~3.2 billion Euros. Of the 6.4 billion Euros 5.2

billion Euros would be paid for by the Member States demand bids and 1.2 billion Euros would have to be contributed from the EU fund, which is only a little more than a third of the additional financing requirement compared to a cased where the EU instrument would fully have to pay for the differential capacity expansion needed to reach the EU trajectory.

Table 7.4: Supply bid parameters and equilibrium quantities

	$p^S_{m,b}$	$x^{Smax}_{m,b}$	$x^{\star S}_{m,b}$	$p^S_{m,b}$	$x^{Smax}_{m,b}$	$x^{\star S}_{m,b}$	$p^S_{m,b}$	$x^{Smax}_{m,b}$	$x^{\star S}_{m,b}$	$p^S_{m,b}$	$x^{Smax}_{m,b}$	$x^{\star S}_{m,b}$	$p^S_{m,b}$	$x^{Smax}_{m,b}$	$x^{\star S}_{m,b}$	$p^S_{m,b}$	$x^{Smax}_{m,b}$	$x^{\star S}_{m,b}$	$p^S_{m,b}$	$x^{Smax}_{m,b}$	$x^{\star S}_{m,b}$
		AT			**BE**			**BG**			**CY**			**CZ**			**DE**			**DK**	
bid1	638,210	80	80	489,017	63	63	764,744	67	67	272,781	38	38	671,531	62	62	502,831	168	168	334,165	55	55
bid2	718,449	83		513,139	62	62	842,288	68	33	310,057	40	40	725,722	63		523,239	166	166	359,067	55	55
bid3	739,679	82		537,678	62	62	895,014	68		324,577	39	39	729,679	61		557,434	167	167	389,589	56	56
bid4	746,194	81		556,353	62		916,238	68		358,299	41	41	740,209	61		572,431	167	80	413,043	57	57
bid5	764,351	79		557,091	60		959,461	67		389,150	41	41	826,174	62		580,652	163		446,722	57	57
bid6	799,024	114		608,611	89											628,166	238		455,346	81	81
bid7	862,269	128														638,266	260				
bid8																653,905	301				
bid9																654,440	401				
bid10																680,301	566				
		EE			**GR**			**ES**			**FI**			**FR**			**HR**			**HU**	
bid1	734,261	65	65	431,503	55	55	995,554	229	229	826,155	68	525,708	127	127	607,531	67	67	646,828	60	60	
bid2	777,014	65		440,333	54	54	1,050,936	228	146	846,995	67	545,820	126	126	624,200	65	65	701,805	61	61	
bid3	794,062	64		461,488	54	54	1,093,651	227		974,179	70	563,185	125	125	638,250	65	46	736,008	61	61	
bid4	821,735	64		527,188	57		1,106,914	224		976,269	69	619,658	129		639,201	64		748,499	60	60	
bid5	868,371	64		549,173	56		1,126,897	219		1,051,776	69	628,338	126		680,684	64		852,535	62	62	
bid6							1,147,061	312				667,399	182		772,196	95					
bid7							1,192,372	343				677,024	198								
bid8							1,246,432	402				708,384	232								
bid9							1,281,786	544				724,931	313								
bid10							1,332,748	766													
		IE			**IT**			**LT**			**LU**			**LV**			**MT**			**NL**	
bid1	603,027	75	75	483,493	114	114	645,171	61	61	691,978	58	686,961	58	58	367,620	42	42	474,026	71	71	71
bid2	685,631	78	36	548,274	118	118	673,237	61	61	716,895	57	742,334	59	59	402,385	42	42	492,194	70	70	70
bid3	710,369	77		578,706	118	118	692,370	60	55	754,628	57	751,529	58	58	421,368	42		494,849	69	69	69
bid4	753,768	78		620,354	120		727,072	61		843,035	59	752,188	57	6	434,887	42		501,926	68	68	68
bid5	784,294	78		631,014	118		750,041	60		864,721	58	798,416	57		495,032	44		532,760	68		
bid6	808,049	111		645,463	168													559,262	98		
bid7	867,222	124		646,991	181													597,177	110		
bid8				651,323	208																
bid9				704,363	289																
bid10																					
		PL			**PT**			**RO**			**SE**			**SI**			**SK**			**UK**	
bid1	719,131	111	111	932,364	121	121	672,663	68	68	734,766	96	96	419,723	45	45	657,813	57	57	365,019	85	85
bid2	729,864	109	109	950,523	118	118	677,540	66	66	771,509	95		455,054	45	45	716,253	58	58	376,941	84	84
bid3	737,282	106	40	1,146,588	127		704,449	66		794,854	94		481,682	45	45	729,397	57		391,596	84	84
bid4	739,683	105		1,182,197	127		766,913	67		797,979	93		482,524	45	45	752,707	57		403,176	83	83
bid5	760,857	103		1,295,434	128		962,872	73		812,172	91		558,273	47	47	806,427	57		408,406	81	81
bid6	781,151	147		1,299,904	181					865,493	132								425,234	117	62
bid7	799,174	161		1,349,611	199					882,825	144								448,898	130	
bid8	834,960	188		1,366,263	230					905,707	167								474,158	153	
bid9																			480,194	205	
bid10																					

Table 7.5: Differences in selected supply bids in MW between reference cases and benchmark case

(a) Difference in selected supply bids between reference case (nat) and benchmark case (cbm)

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	HR	HU	IE	LT	LU	LV	NL	PL	RO	SE	SI	SK	UK
bid1											68		60			58								
bid2	83		35		17			11		82	35		53	39		44	-13			-51	95			
bid3	82	-62		-39					-54	68		-6			5		-58		1		20	-8	54	
bid4	58			-41		87	-57								3		-6					-45		
bid5				-41			-57											59				-47		
bid6							-81																	-62

(b) Difference in selected supply bids between reference case (min) and benchmark case (cbm)

	AT	BE	BG	CZ	DE	EE	GR	ES	FR	HR	IE	IT	LT	LV	MT	NL	PL	PT	RO	SE	SK	UK
bid1	-80		-67	-62		-65		-229					-61	-58			-111	-121	-68	-96	-57	
bid2			-33					-146			-36		-61	-59			-109	-118	-66		-58	
bid3										-46			-55	-58	42		-40					
bid4		62			87		57		129			120		-6	42							
bid5		60			163		56								44	68						
bid6		89			196											98						55
bid7																110						130
bid8																						153
bid9																						205

Tabelle 7.6: Difference in selected supply bids in MW between reference case (eui) and benchmark case (cbm)

	AT	BE	BG	CZ	DE	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SK	UK
bid1									68			60				58									
bid2	83		35	63		65		49	67			61	42			57							95		
bid3	82		37	61		59			39		19	61	77		-31	57		42		67	127	66	72	57	
bid4	81	62		61	87		57			129	64	60	78	120			-5	42		91		17		57	
bid5	79	60			163		56			126	64	52	14	118				44	68						
bid6		89								81				168					98						55
bid7														71					110						130
bid8																									153
bid9																									205

Chapter 8

Conclusions and further research

8.1 Discussion of findings

In this paper I propose a new mechanism for cross-border support of renewable electricity in the EU. The main motivation for the mechanism has been to overcome the barriers of supporting RES-e across borders that are associated with the currently implemented cooperation mechanisms. The main barriers hampering the use of the cooperation mechanisms that have been detected are the presence of externalities, information asymmetries, missing, uncertain or complex to assess information on costs and benefits of RES-e, high transaction costs and the lack of the formation of an efficient price signal. Due to these barriers it has been a preferred strategy for Member States to support new RES-e capacities unilaterally at national level rather than taking the risk to "trade-off" domestic benefits by engaging in cooperation. I have identified several features of the mechanism that can help overcome these barriers and thus reverse Member States' incentives for cooperation:

- *Standardization*: An important feature of the mechanism is that it moves away from a project level approach of cooperation between Member States to a systems level approach, which not only allows to avoid cost benefit analyses that would otherwise be replicated in every single project, but that is also more consistent across projects and transparent than a project level specific cost benefit analysis. This is achieved through the introduction of the BDF matrix approach. Moreover the bidirectional matrix structure implies reciprocity between Member States with regards to cross-border RES-e support.

- *Information requirements*: An important barrier so far for the negotiations between Member States about a new cross-border supported project have been the high information requirement regarding costs, benefits and distributional effects. The BDF matrix provides Member States' a reliable metric of the share in benefit they can expect to receive from RES-e capacity installed at different locations in the EU. It thus takes away a lot of the information acquisition burden from the Member States. All they have to know now is their willingness to pay for an additional unit of RES-e capacity. This has the further advantage that it allows to abstract away a Member State´s willingness to pay from the specific size of a project. Rather the mechanism "forms" a new project by summing up the willingness to pay of all Member States at each node and then comparing the aggregate to the prices bid by the RES-e generators at this node.

- *Price determination*: The price determination procedure is an inherent and precious property of the mechanism. In comparison to the cooperation mechanisms where at first projects are identified and then (fair) prices need to be found it reverses the procedure: At first the mechanism collects the price bids from the auction participants and then selects suitable new projects that maximize the EU wide surplus based on the bids submitted. The selection of all projects then simultaneously allocates new RES-e capacities efficiently across the EU and solves the cross-border cost allocation problem. Compared to the "bilateral" trading approach it is secured that the "right" trading partners are matched, i.e., the trading partners that jointly achieve the highest synergies. As such, the mechanism is a bottom-up, decentralized approach to EU wide coordination and efficiency maximization.

The are two important take-aways from these findings: on the one hand the mechanism would significantly lower the support costs compared to sole national support of new wind onshore capacity. On the other hand the mechanism does not allocate RES-e capacity merely for the sake of minimal support costs, rather it trades-off costs and benefits in such a way that new RES-e capacity gets installed at locations with both low support costs and high impacts in terms of benefits, respectively avoided opportunity costs of alternative allocations.

Besides the efficiency enhancing properties with regards to cross-border support of RES-e the scope of the mechanism also fits well into current policy priorities at EU level. In particular the mechanism is capable to address three elements that are priorities of 2030 RES governance framework that is currently under discussion:

- To enable cooperation in the development of renewables, in particular at the regional level: While designed as EU wide instrument the mechanism would be effective mostly at the regional level as the findings in this thesis suggest (cf. chapter 7). This is due to the regional approach to market coupling and limitations in EU wide trade of electricity. As the internal market for electricity matures also the mechanism will grow to a more European scope.

- To assure that the EU as a whole meets the 2030 target of at least 27 percent for the share of renewable energy consumed: I have shown how the mechanism can be extended to also serve as an EU instrument that can assure an effective and efficient EU wide target achievement, whilst still offering the Member States sufficient flexibility to define their national priorities, as requested by the European Council (2014).

- To be suitable for an interconnected EU-wide electricity market providing clear price signals for new investments and facilitating the further development of renewables Council of the European Union (2015): By considering either implicitly or explicitly short term and long term costs as well as the full social benefit (sum of private and non-market benefit) the mechanism provides price signals for siting new RES-e capacities efficiently across the EU. Moreover, as the value of the transmission grid infrastructure is implicitly reflected in the BDF matrix the mechanism leads to a better coordination between new RES-e capacity investments and existing and future planned (TYNDP) transmission grid infrastructure, thus facilitating the completion of the internal market.

8.2 Further research

BDF matrix concept

While the BDF matrix concept has a lot of merits as explained above, I understand that at the same time it is the most "fragile" element of the concept. This diagnosis follows from two perceptions:

1. The first regards the methodological aspects of the BDF matrix.

   (a) In this thesis I have developed the BDF matrix concept from the scratch, provided thorough descriptions and have demonstrated its applicability, a full proof of concept is however still outstanding and has also not been the intention of this thesis. This regards in particular aspects with regards to the validity of the superposition principle and and the additivity of power flows.

These issues should be further tested both analytically and numerically by experts in power transmission network modeling. I claim that the sequential approach can be a valid representation of reality as long as the superposition principle holds.

(b) In case further tests would reveal that the values of the BDF matrix loose their validity with every new addition of capacity, both in time and space, this would directly have an impact on the outcome of the auction, which in turn would affect the coefficients of the BDF matrix due to the altered capacity allocation: the implication would be that both the auction outcomes and the BDF matrix would have to be determined simultaneously. This would constitute a bi-level problem between the first and the third stage in the auctioning game. The lower stage would be modeled by market and network models, which would make the problem in the first stage become non-linear. In order to solve such a bi-level problem, the lower level problem would need to be linearized and inserted to the auctioneer‘s maximization problem as equilibrium constraints. This avenue of further research could be explored best by experts in operations research.

(c) For the sake of clarity within this thesis I have assumed that a node coincides with the territory of a Member State, thus implying that the distribution of benefits from one Member State to another is uniform, no matter where in a Member State the new RES-e capacity is installed. In reality it will likely make a difference where in a Member State the new RES-e capacity is installed so that it might be warranted to calculate a BDF matrix of higher granularity, such that it would indicate the spill-overs from individual nodes to Member States rather than between Member States.

(d) Finally, it will be important to find out how sensitive the coefficients of the BDF matrix are towards input parameter variations or the underlying modeling framework. More clarity in this respect could be reached if the BDF matrix calculation would also be replicated by other models and the outcomes compared in a modeling comparison fashion.

2. The second regards the political acceptability of the BDF matrix concept. Even though is meant to provide a bet possible approximation of reality, Member States might be reluctant to accept a matrix where they would primarily support RES-e installations abroad, as it would for instance be the case for Austria. As a compromise between political acceptability and efficiency Member States could decide

to agree on a minimum threshold, e.g. 50 percent, for the share of demand that is reserved for domestic installations and the residual demand would be allocated proportionally according to the weights of the BDF matrix coefficients.

Design of the mechanism

An important requirement for the mechanism to implement the efficient solution is incentive compatibility; that is, for the auction participants it is a dominant strategy to report their true costs, respectively willingness to pay. The qualitative analysis so far indicates that the mechanism could have this property, at least partially enough in order to converge to an efficient equilibrium. It should however be further be investigated by experts in the fields of mechanism design and auction theory, which specific design aspects - including surplus distribution rules - can facilitate matters on this ground. Several methodologies can be thought of in this respect:

1. The mechanism could be tested experimentally in a lab environment, where study participants submit bids in the auction. The outcome could then be compared to the modeled optimal solution, in order to evaluate the efficiency.

2. Design specifications could in a first step be defined based on empirical and qualitative analyses of best practices. Then the performance of these design elements could be tested for a large variety of plausible combinations of input parameters that could for instance be generated from a Monte Carlo analysis. This could be done in combination with iterative model coupling. For practical reason this might be the most desirable option to test the mechanism in a large scale application.

3. Another possibility would be to show analytically through mathematical proofs that the mechanism has the desired properties as it is often done in the theoretical mechanism design literature. This might however limit the test environment to a very stylized model of reality.

4. One further possibility would be to include the auctioning participants (RES-e generators, Member States) optimization problems explicitly in the numerical model, in order to endogenously model their bidding strategies. This however yields a three-stage optimization problem that is mathematically challenging. How such a problem can be solved in principle for instance see in Huppmann and Egerer (2014); Zerrahn and Huppmann (2014). If Member States and RES-e generator can choose between auction types (domestic and cross-border) the problem also becomes binary. A solution method is presented in Huppmann and Siddiqui (2015).

A design element that has not yet been considered thoroughly yet is burden sharing. The mechanism in its current form aims to implement the economically efficient solution disregarding income effects. In case some burden sharing element would be desirable (assuming it is not addressed elsewhere outside the system boundaries of the mechanism) two general options that would require further investigations could be the following:

1. It might not be perceived fair that the same bid price levels across Member States are “treated” equally in the auction if they account for a different share of a Member State´s overall budget, i.e., in order to deploy additional RES-e capacity a relatively poorer Member State has to withdraw a relatively higher fraction of resources from other uses than a relatively more wealthy Member State. In order to account for this the willingness to pay, i.e., the price levels bid by the Member States could be adapted for the respective Member State‘s purchasing power parity. It should however be investigated in how far this could distort Member State‘s incentives for truthful reporting.

2. The second option to consider burden sharing criteria could be to adjust the budget key of the EU fund that would finance the demand of the EU instrument. Several effort sharing options are for instance discussed in Zehetner et al. (2015). Also in this case the effect on the Member States’ bidding strategies would have to be investigated. As the budget key is a variable that could in principle be controlled by the EC, an interesting research question in this respect would be, which configuration of the key could incentivize and induce an desirable outcome from the EU wide perspective, i.e., an altering of the budget key could be interpreted as compensatory payment (cf. Huppmann and Egerer (2014); Huppmann and Siddiqui (2015)).

Besides economic design criteria also institutional design criteria need to be decided and further specified. In this context also legal analysis will have to play an important role.

References

ACER. *Regional Initiatives Status Review Report 2013. Final Steps Towards The 2014 Deadline*. 2013.

Cristina L. Archer and Mark Z. Jacobson. Supplying Baseload Power and Reducing Transmission Requirements by Interconnecting Wind Farms. *Journal of Applied Meteorology and Climatology*, 46(11):1701–1717, November 2007. ISSN 1558-8424, 1558-8432. doi: 10.1175/2007JAMC1538.1.

Robert J. Aumann. The core of a cooperative game without side payments. *Transactions of the American Mathematical Society*, 98(3):539–552, 1961.

Lawrence M Ausubel and Paul R Milgrom. Ascending Auctions with Package Bidding. *Advances in Theoretical Economics*, 1(1), 2002. ISSN 1534-5963. doi: 10.2202/1534-5963.1019.

Lawrence M. Ausubel, Paul Milgrom, and others. The lovely but lonely Vickrey auction. *Combinatorial auctions*, 17:22–26, 2006.

Elizabeth E. Bailey and Ann F. Friedlaender. Market Structure and Multiproduct Industries. *Journal of Economic Literature*, 20(3):1024–1048, 1982. ISSN 00220515.

Joachim Bertsch, Simeon Hagspiel, and Lisa Just. Congestion management in power systems. *Journal of Regulatory Economics*, pages 1–38, 2016. ISSN 1573-0468. doi: 10.1007/s11149-016-9310-x.

BMWi. Pilot Opening Auction For Ground-Mounted PV To Bidders From Other EU Member States, 2016.

Severin Borenstein. The Private and Public Economics of Renewable Electricity Generation. *Journal of Economic Perspectives*, 26(1):67–92, February 2012. ISSN 0895-3309. doi: 10.1257/jep.26.1.67.

Adam Brandenburger. Cooperative game theory. *Teaching Materials at New York University*, 2007.

Barbara Breitschopf and Anne Held. Guidelines for assessing costs and benefits of RET deployment. 2014.

Robert Brückmann. Smart policies to reduce renewable energy cost of capital Status Quo in the EU Member States, November 2015.

Sebastian Busch, André Ortner, and Gustav Resch. An efficient mechanism for cross-border support of renewable electricity in the European Union. Technical report, Wien, 2016.

Pantelis Capros et al. EU Reference Scenario 2016 Energy, transport and GHG emissions Trends to 2050. Technical report, 2016.

EdwardH. Clarke. Multipart pricing of public goods. *Public Choice*, 11(1):17–33, September 1971. ISSN 0048-5829. doi: http://dx.doi.org/10.1007/BF01726210.

Council of the European Union. Council conclusions on the governance system of the Energy Union, November 2015.

Antoine Augustin Cournot. Recherches sur les principes mathématiques de la théorie des richesses. 1938.

D. Shi and D. J. Tylavsky. An improved bus aggregation technique for generating network equivalents. *2012 IEEE Power and Energy Society General Meeting*, pages 1–8, July 2012. ISSN 1932-5517. doi: 10.1109/PESGM.2012.6344668.

ATC Jérôme Dangerman and Hans Joachim Schellnhuber. Energy systems transformation. *Proceedings of the National Academy of Sciences*, 110(7):E549–E558, 2013.

Isabelle de Lovinfosse. *Opening the CfD support scheme to non-UK renewables projects.* Brussels, November 2014.

Pablo del Rio, Marie-Christin Haufe, Fabian Wigand, and Simone Steinhilber. Overview of Design Elements for RES-E Auctions. AURES Report D2.2 (a), October 2015, 2015.

Wilfried Ver Eecke. The Concepts of Private, Public and Merit Goods. In Wilfried Ver Eecke, editor, *Ethical Reflections on the Financial Crisis 2007/2008: Making Use of Smith, Musgrave and Rajan*, pages 23–44. Springer Berlin Heidelberg, Berlin, Heidelberg, 2013. ISBN 978-3-642-35091-7.

EFI. Gutachten zu Forschung, Innovation und Technologischer Leistungsfähigkeit Deutschlands. Technical report, Berlin, 2013.

ENTSO-e. 10-Year Network Development Plan 2014. Technical report, 2014.

ENTSO-e. Regional Investment Plan 2015 Continental South West region. Technical report, Brussels, Belgium, 2015.

Epex Spot. Market Coupling A Major Step Towards Market Integration, August 2015.

European Commission. Energy for the Future: Renewable Sources of Energy. White Paper for a Community Strategy and Action Plan. Brussels., 1997.

European Commission. Guidance on the use of renewable energy cooperation mechanism. SWD(2013) 440 final. Technical report, 2013.

European Commission. *Guidelines on State aid for environmental protection and energy 2014-2020 (2014/C 200/01).* 2014a.

European Commission. *Progress towards completing the Internal Energy Market, COM(2014) 634 final.* October 2014b.

European Commission. Energy Union Package Communication From The Commission To The European Parliament And The Council Achieving the 10% electricity interconnection target Making Europe's electricity grid fit for 2020. Technical Report COM(2015) 82 final, Brussels, 2015a.

European Commission. Launching the public consultation process on a new energy market design, COM(2015) 340 final., 2015b.

European Commission. Proposal for a Regulation Of The European Parliament And Of The Council on the Governance of the Energy Union. Technical report, Brussels, 2016a.

European Commission. Proposal for a Directive Of The European Parliament And Of The Council on the promotion of the use of energy from renewable sources (recast). Technical report, Brussels, 2016b.

European Council. Conclusions on 2030 Climate and Energy Policy Frame work, 2014.

European Council and European Parliament. *Directive2009/28/EC on the promotion of the use of energy from renewable sources.* April 2009.

Bastian Fromen. *Faire Aufteilung in Unternehmensnetzwerken: Lösungsvorschläge auf der Basis der kooperativen Spieltheorie*. Springer-Verlag, 2013. ISBN 3-322-81803-9.

Steven A. Gabriel, Antonio J. Conejo, J. David Fuller, Benjamin F. Hobbs, and Carlos Ruiz. *Complementarity Modeling in Energy Markets*. Springer Science & Business Media, July 2012. ISBN 978-1-4419-6123-5.

Kelly Sims Gallagher, Arnulf Grübler, Laura Kuhl, Gregory Nemet, and Charlie Wilson. The Energy Technology Innovation System. *Annual Review of Environment and Resources*, 37(1):137–162, October 2012. ISSN 1543-5938. doi: http://dx.doi.org/10.1146/annurev-environ-060311-133915.

Jacob K. Goeree and Luke Lindsay. Stabilizing the economy: Market design and general equilibrium. ECON - Working Papers 092, Department of Economics - University of Zurich, September 2012.

Jerry Green and Jean-Jacques Laffont. An incentive compatible planning procedure for public good production. *The Scandinavian Journal of Economics*, pages 20–33, 1978.

Timothy Gronberg. Theory of Public Goods . Lecture notes.

Oliver Grothe and Julius Schnieders. Spatial dependence in wind and optimal wind power allocation: A copula-based analysis. *Energy Policy*, 39(9):4742–4754, 2011.

Theodore Groves. Incentives in Teams. *Econometrica*, 41(4):617, July 1973. ISSN 00129682. doi: 10.2307/1914085.

Theodore Groves and John Ledyard. Optimal allocation of public goods: A solution to the" free rider" problem. *Econometrica: Journal of the Econometric Society*, pages 783–809, 1977.

Arnulf Grübler, Nebojša Nakićenović, and David G Victor. Dynamics of energy technologies and global change. *Energy Policy*, 27(5):247–280, May 1999. ISSN 0301-4215. doi: 10.1016/S0301-4215(98)00067-6.

Paul J. Healy. Comment on “Thirteen Reasons Why the Vickrey-Clarke-Groves Process is Not Practical” by Michael Rothkopf. In *Operations Research (Online Forum Commentary)*, volume 55, page 2, 2007.

Anne Held, Mario Ragwitz, Malte Gephart, Erika De Visser, and Corinna Klessmann. Design features of support schemes for renewable electricity. Technical report, A report compiled within the European project “Cooperation between EU MS under the Renewable Energy Directive and interaction with support schemes”, 2014.

Constance E. Helfat and Kathleen M Eisenhardt. Inter-Temporal Economies Of Scope, Organizational Modularity, And The Dynamics Of Diversication, 2003.

Lion Hirth, Falko Ueckerdt, and Ottmar Edenhofer. Integration costs revisited – An economic framework for wind and solar variability. *Renewable Energy*, 74:925–939, February 2015. ISSN 09601481. doi: 10.1016/j.renene.2014.08.065.

Thomas E. Hoff and Richard Perez. Modeling PV fleet output variability. *Solar Energy*, 86(8):2177–2189, August 2012. ISSN 0038092X. doi: 10.1016/j.solener.2011.11.005.

Daniel Huppmann. *Strategic behaviour in energy markets*. Doctoral thesis, 2014.

Daniel Huppmann and Jonas Egerer. National-Strategic Investment in European Power Transmission Capacity. SSRN Scholarly Paper ID 2435891, Social Science Research Network, Rochester, NY, May 2014.

Daniel Huppmann and Sauleh Siddiqui. An Exact Solution Method for Binary Equilibrium Problems with Compensation and the Power Market Uplift Problem. DIW Berlin Discussion Paper, 2015.

IRENA. Renewable Energy Auctions – A Guide to Design. Technical report, 2015.

Warren Katzenstein, Emily Fertig, and Jay Apt. The variability of interconnected wind plants. *Energy Policy*, 38(8):4400–4410, August 2010. ISSN 03014215. doi: 10.1016/j.enpol.2010.03.069.

Corinna Klessman, Fabian Wigand, Silvana Tiedemann, Malte Gephart, Christoph Maurer, Bernd Tersteegen, Mario Ragwitz, Holger Höfling, Jenny Winkler, Tobias Kelm, Henning Jachmann, Karl-Martin Ehrhart, Marie-Christin Haufe, Malte Kohls, Malte Linnemeyer, Christoph Meitz, Christoph Riese, and Julian Asmus Nebel. Designing renewable energy tenders for Germany. Executive Summary of Recommendations, 2015.

Corinna Klessmann, Patrick Lamers, Mario Ragwitz, and Gustav Resch. Design options for cooperation mechanisms under the new European renewable energy directive. *Energy Policy*, 38(8):4679–4691, August 2010. ISSN 0301-4215. doi: 10.1016/j.enpol.2010.04.027.

Corinna Klessmann, Erica de Visser, Fabian Wigand, Malte Gephart, Gustav Resch, and Sebastian Busch. Cooperation between EU Member States under the RES Directive, 2014.

Klessmann, C.B. *Increasing the effectiveness and efficiency of renewable energy support policies in the European Union.* PhD thesis, Utrecht University, January 2012.

Henrik Klinge Jacobsen, Lise Lotte Pade, Sascha Thorsten Schröder, and Lena Kitzing. Cooperation mechanisms to achieve EU renewable targets. *Renewable Energy*, 63: 345–352, March 2014. ISSN 0960-1481. doi: 10.1016/j.renene.2013.09.035.

John Leyard. Comment on "Thirteen Reasons Why the Vickrey-Clarke-Groves Process is Not Practical" by Michael Rothkopf. *OPERATIONS RESEARCH (ONLINE FORUM COMMENTARY)*, Vol. 55, No. 2, March–April 2007, online commentary, 2007. ISSN issn 0030-364X| eissn 1526-5463 | 07.

Pedro Linares, Francisco Javier Santos, Mariano Ventosa, and Luis Lapiedra. Incorporating oligopoly, CO2 emissions trading and green certificates into a power generation expansion model. *Automatica*, 44(6):1608–1620, 2008. ISSN 00051098.

Andreu Mas-Colell, Michael Dennis Whinston, and Jerry R. Green. *Microeconomic theory.* Oxford University Press, New York, 1995. ISBN 0-19-507340-1 0-19-510268-1.

Leonardo Meeus, Nils-Henrik von der Fehr, Isabel Azevedo, Xian He, Luis Olmos, and Jean-Michel Glachant. *Cost benefit analysis in the context of the energy infrastructure package.* 2013.

Roman Mendelevitch and Pao-Yu Oei. The Impact of Policy Measures on Future Power Generation Portfolio and Infrastructure: A Combined Electricity and CCTS Investment and Dispatch Model (ELCO). 2015.

Catherine Mitchell, Janet Sawin, Govind R. Pokharel, DM Kammen, Zhongying Wang, S. Fifita, M. Jaccard, O. Langniss, H. Lucas, A. Nadai, and others. Policy, Financing and Implementation. In *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation.* Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 2011.

R. Moreno, L.A. Barroso, H. Rudnick, S. Mocarquer, and B. Bezerra. Auction approaches of long-term contracts to ensure generation investment in electricity markets: Lessons from the Brazilian and Chilean experiences. *Energy Policy*, 38(10):5758–5769, October 2010. ISSN 03014215. doi: 10.1016/j.enpol.2010.05.026.

Stephan Nikolaus Nagl. *Four Essays on the Economics of Renewable Power Markets.* Doctoral thesis, Universität zu Köln, 2013.

John F. Nash and others. Equilibrium points in n-person games. *Proc. Nat. Acad. Sci. USA*, 36(1):48–49, 1950.

Karsten Neuhoff, Julian Barquin, Janusz W. Bialek, Rodney Boyd, Chris J. Dent, Francisco Echavarren, Thilo Grau, Christian Von Hirschhausen, Benjamin F. Hobbs, Friedrich Kunz, and others. Renewable electric energy integration: quantifying the value of design of markets for international transmission capacity. *Energy Economics*, 40:760–772, 2013.

David Newbery, Goran Strbac, and Danny Pudjianto. Directorate-General Energy European Commission. 2013.

Marco Nicolosi. *The economics of renewable electricity market integration. An empirical and model-based analysis of regulatory frameworks and their impacts on the power market.* PhD thesis, Universität zu Köln, 2012.

André Ortner and Tomas Kruijer. Simplification algorithms for large-scale power system transmission grids, 2015.

Lise-Lotte Pade Pade, Henrik Klinge Jacobsen, and Lise Skovsgaard Nielsen. Assessment of Cooperation Mechanism options: Cost-Efficient and Sustainable Deployment of Renewable Energy Sources towards the 20% Target by 2020, and beyond. D3. 2. Technical report, 2012.

John C. Panzar and Robert D. Willig. Economies of Scale in Multi-Output Production. *The Quarterly Journal of Economics*, 91(3):481, August 1977. ISSN 00335533. doi: 10.2307/1885979.

John C. Panzar and Robert D. Willig. Economies of scope. *The American Economic Review*, 71(2):268–272, 1981.

David Christopher Parkes. *Iterative combinatorial auctions: Achieving economic and computational efficiency.* PhD thesis, University of Pennsylvania, 2001.

Anthony Patt, Nadejda Komendantova, Antonella Battaglini, and Johan Lilliestam. Regional integration to support full renewable power deployment for Europe by 2050. *Environmental Politics*, 20(5):727–742, September 2011. ISSN 0964-4016, 1743-8934. doi: 10.1080/09644016.2011.608537.

Mario Ragwitz and Simone Steinhilber. Effectiveness and efficiency of support schemes for electricity from renewable energy sources: Support schemes for renewable electricity. *Wiley Interdisciplinary Reviews: Energy and Environment*, 3(2):213–229, March 2014. ISSN 20418396. doi: 10.1002/wene.85.

Mario Ragwitz, Anne. Held, Jenny Winkler, Christoph Maurer, Gustav Resch, Marijke Welisch, and Sebastian Busch. Auctions for Renewable Energy in the European Union: Questions Requiring further Clarification. Study on behalf of Agora Energiewende., 2014.

REN 21. Renewables 2016 Global Status Report. Paris. Technical report, 2016.

Gustav Resch, Lukas Liebmann, Sebastian Busch, and Christoph Zehetner. Scenarios on meeting 27% Renewable Energies by 2030, December 2015.

Michael H. Rothkopf. Thirteen Reasons Why the Vickrey-Clarke-Groves Process Is Not Practical. *Operations Research*, 55(2):191–197, January 2007. ISSN 0030-364X. doi: 10.1287/opre.1070.0384.

Marcelo Saguan and Leonardo Meeus. Impact of the regulatory framework for transmission investments on the cost of renewable energy in the EU. *Energy Economics*, 43:185–194, 2014. ISSN 01409883.

Paul A. Samuelson. The Pure Theory of Public Expenditure. *The Review of Economics and Statistics*, 36(4):387–389, 1954. ISSN 00346535, 15309142. doi: 10.2307/1925895.

Julia Schlichting. *Regional Cooperation under the EEG 2014*. Brussels, November 2014.

Andreas Schröder. *Analysis of Investments in Electricity Markets*. Doctoral thesis, TU Berlin, 2013.

Andreas Schröder, Friedrich Kunz, Jan Meiss, Roman Mendelevitch, and Christian von Hirschhausen. Current and Prospective Costs of Electricity Generation until 2050. DIW Data Documentation 68, German Institute for Economic Research (DIW Berlin), 2013.

TenneT TSO. Market integration - Coupling of the European electricity markets. Technical report, 2010.

Gerhard Totschnig, Alexander Kann, Heimo Truhetz, Markus Pfleger, and Gerd Schauer. AutRES100 – Hochauflösende Modellierung des Stromsystems bei hohem erneuerbaren Anteil – Richtung 100% Erneuerbare in österreich. Technical report, 2013.

Thure Traber and Claudia Kemfert. Gone with the wind? — Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply. *Energy Economics*, 33(2):249–256, 2011. ISSN 01409883.

Michaela Unteutsch and others. Who Benefits from Cooperation?–A Numerical Analysis of Redistribution Effects Resulting from Cooperation in European RES-E Support. Technical report, Energiewirtschaftliches Institut an der Universitaet zu Koeln (EWI), 2014.

Dirk Van Hertem, Mehrdad Ghandhari, and Marko Delimar. Technical limitations towards a SuperGrid—A European prospective. In *Energy Conference and Exhibition (EnergyCon), 2010 IEEE International*, pages 302–309. IEEE, 2010.

William Vickrey. Counterspeculation, auctions and competitive sealed tenders. *Journal of Finance*, Volume 16(Issue 1):8–37, 1961.

Sonja Wogrin, Pablo Duenas, Andres Delgadillo, and Javier Reneses. A new approach to model load levels in electric power systems with high renewable penetration. *Power Systems, IEEE Transactions on*, 29(5):2210–2218, 2014.

H. P. Young. *Cost allocation and demand revelation in public enterprises*. International Institute for Applied Systems Analysis, 1980.

H. P. Young. Cost Allocation,'Chap. 34 in Robert Aumann and Segiu Hart. *The Handbook of Game Theory*, 2, 1994a.

H. Peyton Young. *Equity: in theory and practice*. A Russell Sage Foundation book. 1. princeton paperback printing edition, 1994b. ISBN 978-0-691-04464-4 0-691-04464-3 0-691-04319-1.

H. Peyton Young. Cost allocation, demand revelation, and core implementation. *Mathematical Social Sciences*, 36(3):213–228, December 1998a. ISSN 0165-4896. doi: 10.1016/S0165-4896(98)00039-0.

H. Peyton Young. Cost allocation, demand revelation, and core implementation. *Mathematical Social Sciences*, 36(3):213–228, December 1998b. ISSN 0165-4896. doi: 10.1016/S0165-4896(98)00039-0.

H. Peyton Young and International Institute for Applied Systems Analysis, editors. *Cost allocation: methods, principles, applications*. North-Holland ; Sole distributors for the

U.S.A. and Canada, Elsevier Science Pub. Co, Amsterdam ; New York : New York, N.Y, 1985. ISBN 978-0-444-87863-2.

Christoph Zehetner, Lukas Liebmann, Gustav Resch, Fabio Genoese, and Mario Ragwitz. The EU 2030 Framework for renewables – effective effort sharing through public benchmarks. Towards2030 Issue Paper., 2015.

Alexander Zerrahn and Daniel Huppmann. Network Expansion to Mitigate Market Power: How Increased Integration Fosters Welfare. Discussion Papers of DIW Berlin 1380, DIW Berlin, German Institute for Economic Research, 2014.

Appendix A

Appendix to chapter 4

Table A.1: All results for illustrative 3-node example in section 4.2

Scenario 1			Scenario 2			Scenario 3		
Generation Capacity [MW]								
Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil
3.00	3.00	3.00	3.00	1.00	3.00	1.00	1.00	3.00
Line Capacity [MW]								
line1_2	line1_3	line2_3	line1_2	line1_3	line2_3	line1_2	line1_3	line2_3
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
System Generation Cost Savings [€]								
24.38			52.91			93.21		
Benefit Distribution Factor [%]								
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	1.00	0.00	1.00	0.00	0.00	0.00	0.00	1.00
Nodal Producer Surplus [€]								
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	0.00	24.38	0.00	0.00	52.91	-40.30	-40.30	52.91
Nodal Consumer Surplus [€]								
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	0.00	0.00	0.00	0.00	0.00	40.30	40.30	40.30
Nodal Congestion Rent [€]								
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nodal Welfare [€]								
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	0.00	24.38	0.00	0.00	52.91	0.00	0.00	93.21

Scenario 4			Scenario 5			Scenario 6		
Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil
3.00	3.00	3.00	3.00	1.00	3.00	1.00	1.00	3.00
line1_2	line1_3	line2_3	line1_2	line1_3	line2_3	line1_2	line1_3	line2_3
0.50	1.00	1.00	0.00	0.50	0.00	0.50	1.00	1.00
38.64			52.91			93.21		
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.68	0.32	0.00	1.00	0.00	0.00	0.00	0.00	1.00
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	0.00	38.65	0.00	0.00	52.91	-40.30	-40.30	52.90
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	0.00	0.00	0.00	0.00	0.00	40.30	40.30	40.30
node1	node2	node3	node1	node2	node3	node1	node2	node3
3.57	0.00	-3.57	0.00	0.00	0.00	0.00	0.00	0.00
node1	node2	node3	node1	node2	node3	node1	node2	node3
3.57	0.00	35.09	0.00	0.00	52.91	0.00	0.00	93.20

Scenario 7			Scenario 8			Scenario 9		
Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil
3.00	3.00	3.00	3.00	1.00	3.00	1.00	1.00	3.00
line1_2	line1_3	line2_3	line1_2	line1_3	line2_3	line1_2	line1_3	line2_3
0.50	0.50	1.00	0.50	0.50	1.00	0.50	0.50	1.00
38.64			62.98			93.21		
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.68	0.32	0.00	0.63	0.00	0.37	0.00	0.00	1.00
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	0.00	38.65	0.00	-20.15	52.91	-40.30	-40.30	52.90
node1	node2	node3	node1	node2	node3	node1	node2	node3
0.00	0.00	0.00	0.00	20.15	40.30	40.30	40.30	40.30
node1	node2	node3	node1	node2	node3	node1	node2	node3
3.57	0.00	-3.57	-12.60	-12.60	-5.04	0.00	0.00	0.00
node1	node2	node3	node1	node2	node3	node1	node2	node3
3.57	0.00	35.09	-12.60	-12.60	88.17	0.00	0.00	93.20

Appendix B

Appendix to chapter 5: The Karush-Kuhn-Tucker conditions

B.1 Conventional electricity generator

$$\mathcal{L}^C = \sum_a Df_a \cdot \Bigg[\sum_{p,n,c} Td_{p,a} \cdot \left(\bar{C}^{var}_{l,c,a} - \bar{p}^{ele}_{p,n,a} \right) \cdot \bar{q}^{gen}_{p,n,c,a}$$
$$+ \sum_{n,c} \left(C^{fix}_{n,c,a} \cdot Q^{ini}_{n,c,a} + \sum_{a-lt/scale<aa<a} q^{inv}_{n,c,aa} \cdot \left(C^{inv}_{n,c,a} + C^{fix}_{n,c,a} \right) \right)$$
$$- \sum_{n,c} \left(\sum_{a-lt<aa<a} q^{div}_{n,c,aa} \cdot diasgregateC^{fix}_{n,c,a} \right) \Bigg]$$
$$+ \lambda avail_{p,n,c,a} \cdot \Bigg(\bar{q}^{gen}_{p,n,c,a} - Avail_{p,n,c,a}$$
$$\cdot \left(Q^{ini}_{n,c,a} + \sum_{a-lt/scale<aa<a} \left(q^{inv}_{n,c,aa} - q^{div}_{n,c,aa} \right) \right) \Bigg) \tag{B.1}$$

$$\frac{\partial \mathcal{L}}{\partial \bar{q}^{gen}_{p,n,c,a}}:\ 0 \leq Df_a \cdot Td_{p,a} \cdot \left(C^{var}_{l,c,a} - p^{ele}_{p,n,a}\right) + \lambda avail_{p,n,c,a} \perp q^{gen}_{p,n,c,a} \geq 0 \tag{B.2}$$

$$\frac{\partial \mathcal{L}}{\partial q^{inv}_{n,c,a}}:\ 0 \leq Df_a \cdot \sum_{a<aa<a+lt/scale} \left(C^{inv}_{n,c,a} + C^{fix}_{n,c,a}\right) - \sum_{a<aa<a+lt/scale} \sum_{p} Avail_{p,n,c,aa} \cdot \lambda avail_{p,n,c,aa} \perp q^{inv}_{n,c,a} \geq 0 \tag{B.3}$$

$$\frac{\partial \mathcal{L}}{\partial q^{div}_{n,c,a}}:\ 0 \leq Df_a \cdot \sum_{a<aa<a+lt/scale} -C^{fix}_{n,c,a} + \sum_{a<aa<a+lt/scale} \sum_{p} Avail_{p,n,c,aa} \cdot \lambda avail_{p,n,c,aa} \perp q^{div}_{n,c,a} \geq 0 \tag{B.4}$$

B.2 Renewable electricity generator

$$\begin{aligned}
\mathcal{L}^R = \sum_a Df_a \cdot \Bigg[& \sum_{p,n,r} Td_{p,a} \cdot \left(\bar{C}^{var}_{n,r,a} - \bar{p}^{ele}_{p,n,a}\right) \cdot \bar{q}^{gen}_{p,n,r,a} \\
& - bi_{gen} \cdot \sum_{p,n,r} \Bigg(\sum_{a-sd/scale<aa<a} Avail_{p,n,r,a} \cdot q^{inv}_{n,r,aa} \cdot \sum_{aa<aaa<aa+sd} \bar{p}^{prem}_{n,r,aaa} \Bigg) \\
& - bi_{cap} \cdot \sum_{n,r} \Bigg(\sum_{a-sd/scale<aa<a} q^{inv}_{n,q,r,aa} \cdot p^{prem}_{n,r,aa} \Bigg) \\
& + \sum_{n,r} \Bigg(C^{fix}_{n,r,a} \cdot Q^{ini}_{n,r,a} + \sum_{a-lt/scale<aa<a} q^{inv}_{n,r,aa} \cdot \left(C^{inv}_{n,r,a} + C^{fix}_{n,r,a}\right) \Bigg) \Bigg] \\
& + \lambda avail_{p,n,r,a} \cdot \Bigg(\bar{q}^{gen}_{p,n,r,a} - Avail_{p,n,r,a} \cdot \Bigg(Q^{ini}_{n,r,a} + \sum_{a-lt/scale<aa<a} q^{inv}_{n,r,aa} \Bigg) \Bigg)
\end{aligned} \tag{B.5}$$

$$\frac{\partial \mathcal{L}}{\partial \bar{q}^{gen}_{p,n,r,a}} : \ 0 \leq Df_a \cdot Td_{p,a} \cdot \left(C^{var}_{l,r,a} - p^{ele}_{p,n,a} \right)$$

$$+ \lambda avail_{p,n,r,a} \perp q^{gen}_{p,n,r,a} \geq 0 \qquad \text{(B.6)}$$

$$\frac{\partial \mathcal{L}}{\partial q^{inv}_{n,r,a}} : \ Df_a$$

$$\cdot \Bigg(- bi_{gen} \cdot \sum_{a<aa<a+sd/scale} \sum_p \Bigg(avail_{p,n,r,aa} \cdot \sum_{a<aaa<a+sd/scale} \bar{p}^{prem}_{n,r,aaa} \Bigg)$$

$$- bi_{cap} \cdot \sum_{a<aa<a+sd/scale} p^{prem}_{n,r,aa}$$

$$+ \sum_{a<aa<a+lt/scale} \left(C^{inv}_{n,r,a} + C^{fix}_{n,r,a} \right) \Bigg)$$

$$- \sum_{a<aa<a+lt/scale} \sum_p Avail_{p,r,c,aa} \cdot \lambda avail_{p,n,r,aa} \perp q^{inv}_{n,r,a} \geq 0 \qquad \text{(B.7)}$$

B.3 Storage operator

$$\mathcal{L}^{Stor} = \sum_a Df_a \cdot \left[\sum_{p,n} Td_{p,a} \cdot \left(\bar{q}^{pump}_{p,n,st,a} - \bar{q}^{gen}_{p,n,st,a} \right) \cdot \bar{p}^{ele}_{p,n,a} \right]$$

$$+ \lambda avail_{p,n,st,a} \cdot \left(\bar{q}^{gen}_{p,n,st,a} - Avail_{n,st,a} \cdot Q^{ini}_{n,st,a} \right)$$

$$+ \lambda bal_{n,st,a} \cdot \left(\sum_p \left(Td_{p,a} \cdot \bar{q}^{gen}_{p,n,st,a} \right) - \sum_p \left(Td_{p,a} \cdot \bar{q}^{pump}_{p,n,st,a} \cdot \eta_{st,a} \right) \ (\lambda bal_{n,st,a}) \right)$$

$$+ \lambda stor_{n,st,a} \cdot \left(\sum_p \left(Td_{p,a} \cdot \bar{q}^{gen}_{p,n,st,a} \right) - Flh_{n,st,a} \cdot Q^{ini}_{n,st,a} \right) \qquad \text{(B.8)}$$

$$\frac{\partial \mathcal{L}}{\partial \bar{q}^{pump}_{p,n,st,a}} : \ 0 \leq p^{ele}_{p,n,a} \cdot Td_{p,a} \cdot Df_a + Td_{p,a} \cdot \lambda bal_{n,st,a} \perp \bar{q}^{pump}_{p,n,st,a} \geq 0 \qquad \text{(B.9)}$$

$$\frac{\partial \mathcal{L}}{\partial \bar{q}^{gen}_{p,n,st,a}} : \ 0 \leq -p^{ele}_{p,n,a} \cdot Td_{p,a} \cdot Df_a + \lambda avail_{p,n,s,a}$$

$$+ \lambda bal_{n,st,a} \cdot Td_{p,a} + \lambda stor_{n,st,a} \cdot Td_{p,a} \perp \bar{q}^{gen}_{p,n,st,a} \geq 0 \qquad \text{(B.10)}$$

B.4 Electricity consumer

$$\mathcal{L}^{CS} = \sum_a Df_a \cdot \sum_{ds,p,n} \Bigg[\Big(Voll^{up}_{ds,p,n,a} + \frac{1}{2} \cdot Slope_{ds,p,n,a} \\ \cdot \left(\bar{q}^{load}_{p,n,a} - \bar{q}^{shed}_{ds,p,n,a} \right) - \bar{p}^{ele}_{p,n,a} \Big) \\ \cdot \left(\bar{q}^{shed}_{ds,p,n,a} - \bar{q}^{load}_{p,n,a} \right) \cdot Td_{p,a} \\ + \lambda shed_{ds,p,n,a} \cdot \left(\bar{q}^{shed}_{ds,p,n,a} - q^{shed\_max}_{ds,p,n,a} \right) \tag{B.11}$$

$$\frac{\partial \mathcal{L}}{\partial \bar{q}^{shed}_{ds,p,n,a}} : \; 0 \leq Df_a \cdot Td_{p,a} \cdot \Bigg(Voll^{up}_{ds,p,n,a} - \bar{q}^{shed}_{ds,p,n,a} \cdot \frac{1}{2} \cdot Slope_{ds,p,n,a} \\ + \bar{q}^{load}_{p,n,a} \cdot \frac{1}{2} \cdot Slope_{ds,p,n,a} - \bar{p}^{ele}_{p,n,a} \Bigg) \\ + \lambda shed_{ds,p,n,a} \perp \bar{q}^{shed}_{ds,p,n,a} \geq 0 \tag{B.12}$$

B.5 System operator and market coupler

$$\mathcal{L}^{ISO} = \sum_a Df_a \cdot Td_{p,a} \cdot \Bigg[\sum_{p,n} \bar{q}^{net}_{p,n,a} \cdot \bar{p}^{ele}_{p,n,a} \\ + \sum_{p,n,nn} \left(\bar{p}^{ele}_{p,n,a} - \bar{p}^{ele}_{p,nn,a} \right) \cdot \bar{q}^{flow\_ntc}_{p,n,nn,a} \\ + \sum_{p,n} \left(\bar{p}^{ele}_{p,n,a} - \bar{p}^{ele\_min}_{p,n,a} \right) \cdot \bar{q}^{curt}_{p,n,a} \Bigg] \\ + \lambda p^{ele\_sys}_{p,a} \cdot \sum_n \left(-\bar{q}^{net}_{p,n,a} \right) \\ + \lambda linelim^{pos}_{p,l,a} \cdot \left(\sum_n PTDF_{l,n} \cdot \left(- \sum_n \bar{q}^{net}_{p,n,a} \right) - q^{lim}_{l,a} \right) \\ \lambda linelim^{neg}_{p,l,a} \cdot \left(\sum_n PTDF_{l,n} \cdot \left(\sum_n \bar{q}^{net}_{p,n,a} \right) - q^{lim}_{l,a} \right) \\ \lambda ntc_{n,nn,a} \cdot \left(\bar{q}^{flow\_ntc}_{p,n,nn,a} - q^{ntc}_{n,nn,a} \right) \\ \lambda curt_{p,n,a} \cdot \left(-\bar{q}^{curt}_{lp,n,a} \right) \tag{B.13}$$

$$\frac{\partial \mathcal{L}}{\partial \bar{q}^{net}_{p,n,a}} : \ 0 \leq Td_{p,a} \cdot Df_a \cdot \bar{p}^{ele}_{p,n,a} - \lambda p^{ele\_sys}_{p,a}$$

$$-PTDF_{l,n} \cdot \left(\lambda linelim^{pos}_{p,l,a} - \lambda linelim^{neg}_{p,l,a} \right) \perp \bar{q}^{net}_{p,n,a} \geq 0 \quad \text{(B.14)}$$

$$\frac{\partial \mathcal{L}}{\partial \bar{q}^{flow\_ntc}_{p,n,nn,a}} : \ 0 \leq Td_{p,a} \cdot Df_a \cdot \left(\bar{p}^{ele}_{p,n,a} - \bar{p}^{ele}_{p,nn,a} \right)$$

$$+\lambda ntc_{n,nn,a} \perp \bar{q}^{flow\_ntc}_{p,n,nn,a} \geq 0 \quad \text{(B.15)}$$

$$\frac{\partial \mathcal{L}}{\partial \bar{q}^{curt}_{p,n,a}} : \ 0 \leq Td_{p,a} \cdot Df_a \cdot \left(\bar{p}^{ele}_{p,n,a} - \bar{p}^{ele\_min}_{p,n,a} \right)$$

$$-\lambda curt_{p,n,a} \perp \bar{q}^{curt}_{p,n,a} \geq 0 \quad \text{(B.16)}$$

Appendix C

Appendix to chapter 7: Further input data and results

Table C.1: Reference capacities [MW] 2015, 2020, source: ENTSO-e TYNDP 2016 Market Modeling Data

(a) Reference capacities 2015

	AT	BE	BG	CZ	DE	CY	DK	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK
AT				1000	5000									300		75										950		
BE												600									950							
BG									150															100				
CZ					2100																	500					1500	
CY																												
DE	5000			1400			600					1200						2300			1468				615			
DK					600																				2440			
EE											1016								650									
GR			150													100												
ES												1000											2000					
FI								1000																	2300			
FR		1850			1300					1000																		2000
HR														600												800		
HU					300								700											300			500	
IE																												
IT					100				100																			
LT																			534			500			700			
LU		700			2300																							
LV								429									834											
MT																												
NL		950			400																							1000
PL				400																							500	
PT										2200																		
RO			100											300														
SE					615		1300				2200						700					500						
SI					950								800															
SK				1100										350								400						
UK												2000									1000							

(b) Reference capacities 2020

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK
AT					1000	5000								1200		555										1200		
BE					1000							2800						1080			2400							1000
BG									1728															1400				
CY									2000																			
CZ	1200					2100																500					2100	
DE	5000	1000			1500		4000					3000		300		75		2300			4450	2000			615	950	615	
DK						4000															700				2440			1400
EE											1016								1600									
GR			1032	2000												500												
ES												5000											4200					
FI								1000																	2300			
FR		4300				3000				5000						4350		380										5400
HR														2000												2000		
HU	800					300							2000											1300		1700	2000	
IE																					1100							500
IT	385					100			500			2160														1380		
LT																			1500			1000			700			
LU		700				2300																						
LV								1600									1200											
MT																												
NL		2400				4450	700																					1000
PL					600	3000											1000								600		990	
PT										3500																		
RO			1500											1400														
SE						615	1980				2400						700					600						
SI	1200					950							2000	2000		1530												
SK					1100									2000								990						
UK		1000					1400					5400			500						1000							

Table C.2: Reference capacities [MW] 2025, 2030, source: ENTSO-e TYNDP 2016 Market Modeling Data

(a) Reference capacities 2025

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK
AT					1000	6250								1200		1105										1200		
BE					1000							2800						1080			2400							1000
BG									1728															1400				
CY									2000																			
CZ	1200					2350																500					2100	
DE	6250	1000			1750		4000					3900		300		75		2300			4725	2000			965	950	615	
DK						4000															700				2440			1400
EE											1016								1600									
GR			1032	2000												500												
ES												6500											4200					
FI								1000																	2550			
FR		4300				3900				6500					350	4350		380										5400
HR														2000												2000		
HU	800					300							2000											1300		1700	2000	
IE												350									1100							500
IT	885					100			500			2160														1380		
LT																			1800			1000			700			
LU		700				2300																						
LV								1600									1500											
MT																												
NL		2400				4725	700																					1000
PL					600	3000											1000								600		990	
PT										3500																		
RO			1500											1400														
SE						965	1980				2800						700					600						
SI	1200					950							2000	2000		1530												
SK					1100									2000								990						
UK		1000					1400					5400			500						1000							

(b) Reference capacities 2030

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK
AT					1000	7500								1200		1655										1200		
BE					1000							2800						1080			2400							1000
BG									1728															1400				
CY									2000																			
CZ	1200					2600																500					2100	
DE	7500	1000			2000		4000					4800		300		75		2300			5000	2000			1315	950	615	
DK						4000															700				2440			1400
EE											1016								1600									
GR			1032	2000												500												
ES												8000											4200					
FI								1000																	2800			
FR		4300				4800				8000					700	4350		380										5400
HR														2000												2000		
HU	800					300							2000											1300		1700	2000	
IE												700									1100							500
IT	1385					100			500			2160														1380		
LT																			2100			1000			700			
LU		700				2300																						
LV								1600									1800											
MT																												
NL		2400				5000	700																					1000
PL					600	3000											1000								600		990	
PT										3500																		
RO			1500											1400														
SE						1315	1980				3200						700					600						
SI	1200					950							2000	2000		1530												
SK					1100									2000								990						
UK		1000					1400					5400			500						1000							

Table C.3: PTDF 2015

	AT	BG	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IT	LT	LU	LV	NL	PL	PT	RO	SE	SI	SK	UK
line1	0.06																					-0.29		
line2				0.25						-0.10														
line3				0.13											-0.14									
line4	-0.71			0.06																				
line5			-0.68	0.01																				
line6				0.01														-0.44						
line7					0.47																-0.09			
line8				0.00	0.53																			
line9						0.66										-0.06								
line10		-0.54					0.15																	
line11	0.04											-0.11												
line12								1.00		0.00														
line13						-0.34			0.12															
line14				-0.09						0.04														
line15										0.55														
line16										0.03			-0.57											
line17	0.01		-0.01																					
line18											0.68	-0.05												
line19											-0.10	0.01												
line20												0.14								-0.53				
line21							-0.85						0.07											
line22													0.03									-0.08		
line23	-0.15												0.15											
line24										-0.01			0.18											
line25														0.92				-0.01						
line26	0.02			0.00																				
line27															0.63									
line28				-0.23											0.23									
line29														-0.02		0.94								
line30																	0.22							
line31				-0.20													0.19							
line32																			1.00					
line33		-0.24																		0.25				
line34				0.00																	0.23			
line35									-0.88												0.03			
line36														-0.06							0.12			
line37										-0.23														
line38																		-0.05			0.53			
line39											-0.22											0.17		
line40												-0.53											0.13	
line41																		-0.20					0.69	
line42																	-0.08							0.77
line43										-0.04														0.23
line44																	-0.51							
line45		0.22																		-0.22				
line46			0.09																				-0.18	
line47			0.22															-0.30						
line48												-0.15										0.46		

Table C.4: PTDF 2020

	AT	BG	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IT	LT	LU	LV	NL	PL	PT	RO	SE	SI	SK	UK
line1	0.08																					-0.20		
line2				0.24						-0.10														
line3				0.13											-0.14									
line4	-0.70			0.06																				
line5			-0.61	0.02																				
line6				0.02														-0.29						
line7					0.48																-0.09			
line8				0.00	0.52																			
line9						0.66										-0.06								
line10		-0.51					0.16																	
line11	0.05											-0.06												
line12								1.00		0.00														
line13						-0.34			0.12															
line14				-0.09						0.04														
line15										0.55														
line16										0.03			-0.54											
line17	0.01		-0.01																					
line18											0.69	-0.04												
line19											-0.10	0.01												
line20												0.08								-0.57				
line21							-0.84						0.06											
line22													0.02									-0.05		
line23	-0.14												0.13											
line24										-0.01			0.17											
line25														0.93				-0.01						
line26	0.02			0.00																				
line27															0.63									
line28				-0.22											0.23									
line29														-0.01		0.94								
line30																	0.22							
line31				-0.20													0.19							
line32								0.00											1.00					
line33		-0.26																		0.23				
line34				0.00																	0.22			
line35									-0.88												0.03			
line36														-0.06							0.12			
line37										-0.23														
line38																		-0.03			0.55			
line39											-0.21											0.16		
line40												-0.20											0.05	
line41																		-0.18					0.69	
line42																	-0.08							0.77
line43										-0.04														0.23
line44																	-0.51							
line45		0.23																		-0.20				
line46			0.11																				-0.14	
line47			0.27															-0.20						
line48												-0.13										0.43		
line49				0.02														-0.29						
line50													-0.07									0.16		
line51												-0.49											0.12	

Table C.5: PTDF 2025

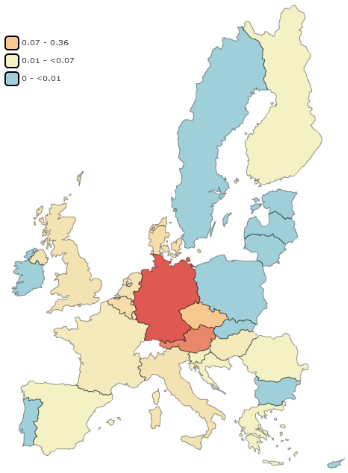
	AT	BG	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IT	LT	LU	LV	NL	PL	PT	RO	SE	SI	SK	UK
line1	0.08																					-0.20		
line2				0.18						-0.07														
line3				0.12											-0.15									
line4	-0.71			0.04																				
line5			-0.62	0.01																				
line6				0.01														-0.29						
line7					0.48																-0.09			
line8				0.00	0.52																			
line9						0.27										-0.03								
line10		-0.51					0.16																	
line11	0.05											-0.06												
line12								1.00																
line13						-0.19			0.15															
line14				-0.07						0.03														
line15										0.53														
line16										0.03			-0.54											
line17	0.01		-0.01																					
line18											0.69	-0.04												
line19											-0.10	0.01												
line20												0.08								-0.57				
line21							-0.84						0.06											
line22													0.02									-0.05		
line23	-0.13												0.13											
line24										-0.01			0.17											
line25														0.92				-0.01						
line26	0.02			0.00																				
line27															0.60									
line28				-0.20											0.25									
line29														-0.02		0.92								
line30																	0.22							
line31				-0.17													0.20							
line32																			1.00					
line33		-0.26																		0.23				
line34				0.00																	0.22			
line35									-0.85												0.04			
line36														-0.06							0.12			
line37										-0.22														
line38																		-0.03			0.54			
line39											-0.21											0.16		
line40												-0.20											0.05	
line41																		-0.17					0.70	
line42																	-0.08							0.77
line43										-0.04														0.23
line44																	-0.51							
line45		0.23																		-0.20				
line46			0.11																				-0.15	
line47			0.27															-0.20						
line48												-0.12										0.43		
line49				0.01														-0.29						
line50													-0.07									0.16		
line51												-0.49											0.11	
line52						0.54										-0.05								
line53				-0.18						0.07														

Table C.6: PTDF 2030

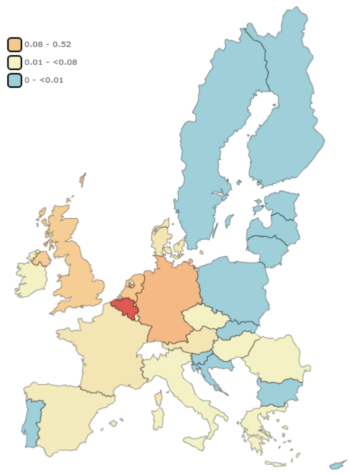
	AT	BG	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IT	LT	LU	LV	NL	PL	PT	RO	SE	SI	SK	UK
line1	0.08																					-0.20		
line2				0.18						-0.07														
line3				0.12											-0.15									
line4	-0.71			0.04																				
line5			-0.62	0.01																				
line6				0.01														-0.29						
line7					0.48																-0.09			
line8				0.00	0.52																			
line9						0.03										0.00								
line10		-0.51					0.16																	
line11	0.05											-0.06												
line12								1.00		0.00														
line13						-0.10			0.17															
line14				-0.07						0.03														
line15										0.53														
line16										0.03			-0.54											
line17	0.01		-0.01																					
line18											0.69	-0.04												
line19											-0.10	0.01												
line20												0.08								-0.57				
line21							-0.84						0.06											
line22													0.02									-0.05		
line23	-0.13												0.13											
line24										-0.01			0.17											
line25														0.92				-0.01						
line26	0.02			0.00																				
line27															0.60									
line28				-0.20											0.25									
line29														-0.02		0.91								
line30																	0.22							
line31				-0.17													0.20							
line32								0.00											1.00					
line33		-0.26																		0.23				
line34				0.00																	0.22			
line35									-0.83												0.04			
line36														-0.06							0.12			
line37										-0.22														
line38																		-0.03			0.54			
line39											-0.21											0.16		
line40												-0.20											0.05	
line41																		-0.17					0.70	
line42																	-0.08							0.77
line43										-0.04														0.23
line44																	-0.51							
line45		0.23																		-0.20				
line46			0.11																				-0.15	
line47			0.27															-0.20						
line48												-0.12										0.43		
line49				0.01														-0.29						
line50													-0.07									0.16		
line51												-0.49											0.11	
line52						0.05										-0.01								
line53				-0.18						0.07														
line54						0.23										-0.02								
line55						-0.59										0.06								

Table C.7: Incidence matrix

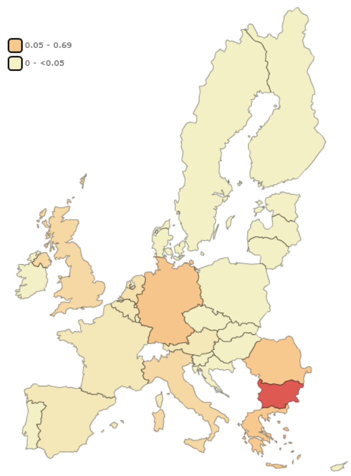
	AT	BE	BG	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IT	LT	LU	LV	NL	PL	PT	RO	SE	SI	SK	UK
line1	1																						-1		
line2					1						-1														
line3					1											-1									
line4	-1				1																				
line5				-1	1																				
line6					1														-1						
line7						1																-1			
line8					-1	1																			
line9							1										-1								
line10			-1					1																	
line11	1												-1												
line12									1		-1														
line13							-1			1															
line14					-1						1														
line15		-1									1														
line16											1			-1											
line17	1			-1																					
line18												1	-1												
line19												-1	1												
line20													1								-1				
line21								-1						1											
line22														1									-1		
line23	-1													1											
line24											-1			1											
line25															1				-1						
line26	1				-1																				
line27		-1														1									
line28					-1											1									
line29															-1		1								
line30		-1																1							
line31					-1													1							
line32									-1											1					
line33			-1																		1				
line34					-1																	1			
line35										-1												1			
line36															-1							1			
line37		1									-1														
line38																			-1			1			
line39												-1											1		
line40													-1											1	
line41																			-1					1	
line42																		-1							1
line43											-1														1
line44		1																-1							
line45			1																		-1				
line46				1																				-1	
line47				1															-1						
line48													-1										1		
line49					1														-1						
line50														-1									1		
line51													-1											1	
line52							1										-1								
line53					-1						1														
line54							1										-1								
line55							-1										1								



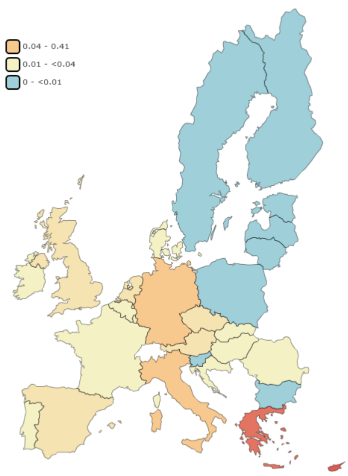
(a) AT



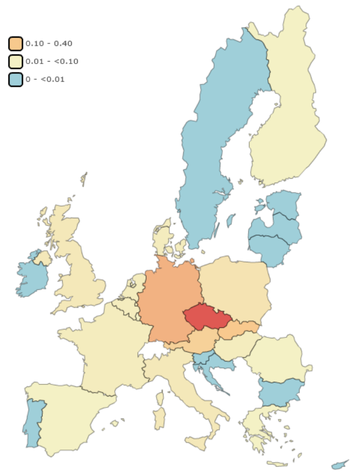
(b) BE



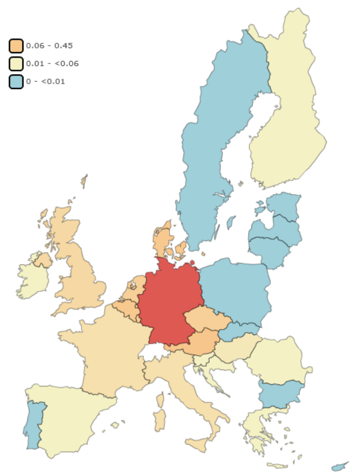
(c) BG



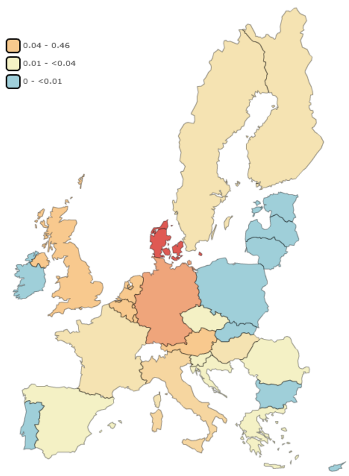
(d) CY



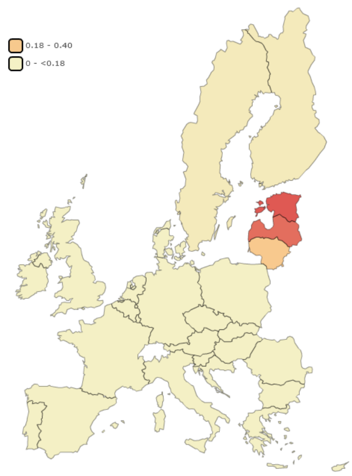
(e) CZ



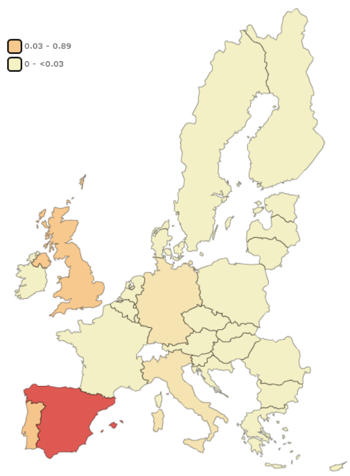
(f) DE



(g) DK

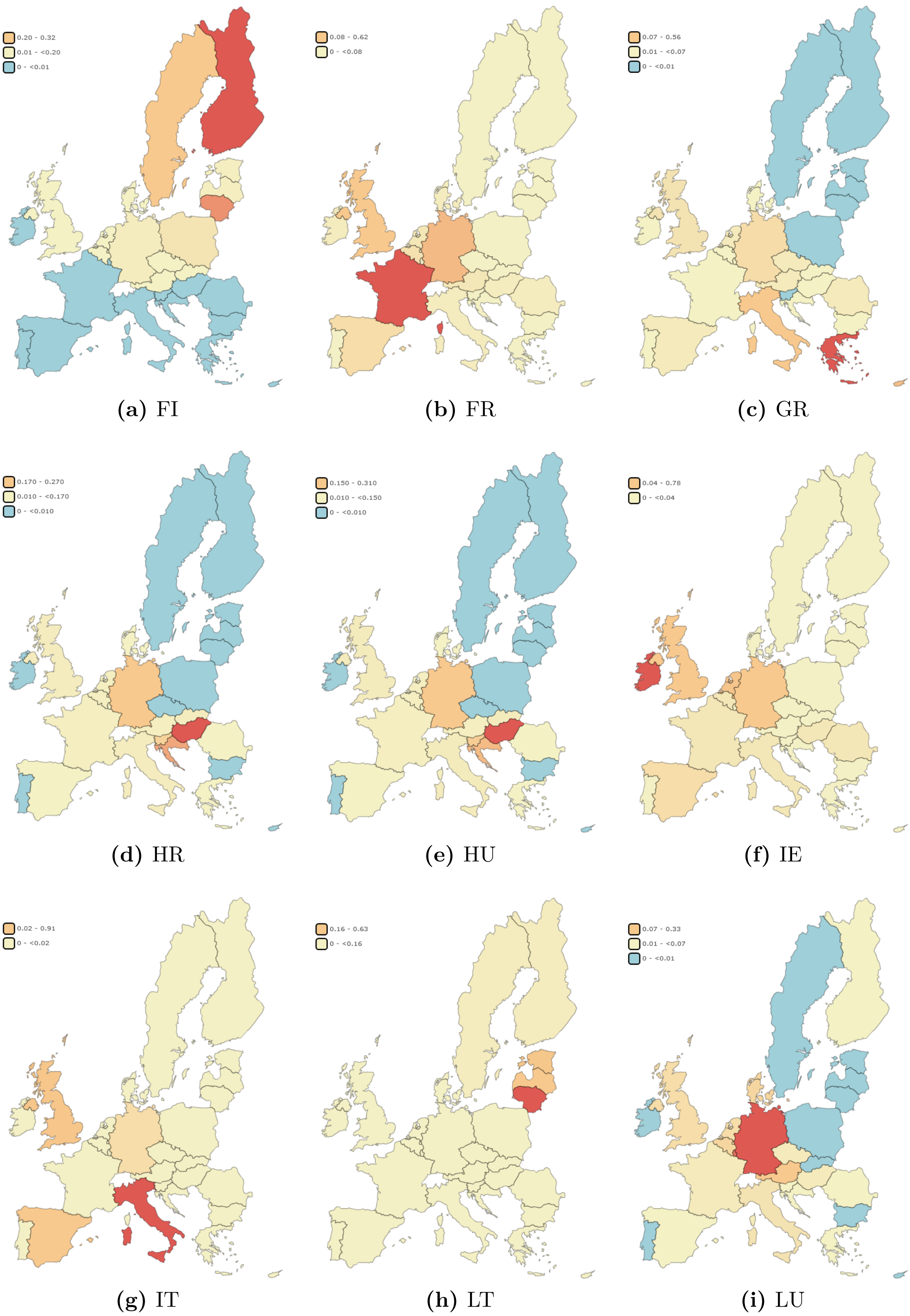


(h) EE



(i) ES

Figure C.1: Visualized BDF matrices AT-ES. Color code indicating 10, 50 and 90 percentiles. Legend indicating ranges for absolute values.

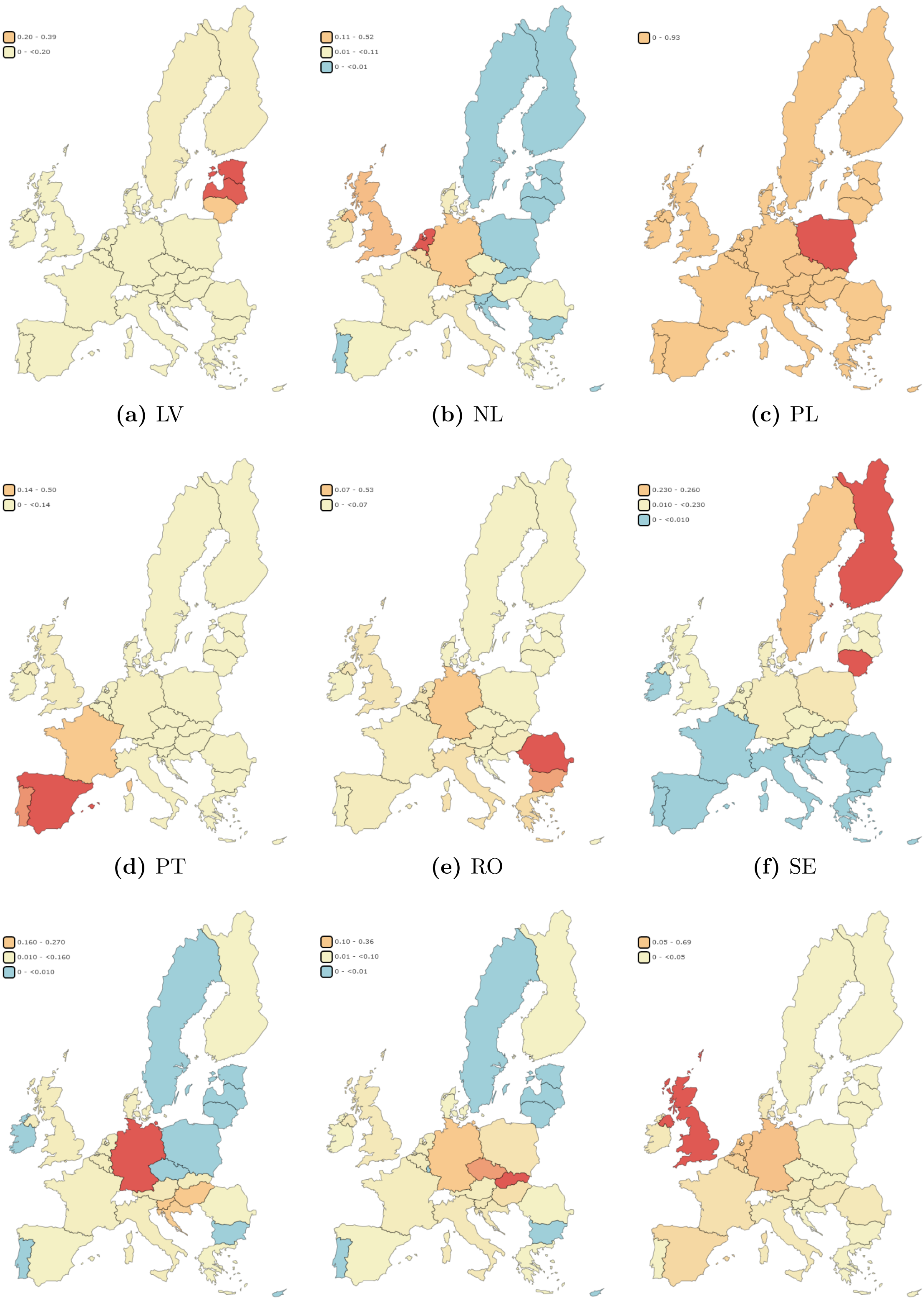


(a) FI **(b)** FR **(c)** GR

(d) HR **(e)** HU **(f)** IE

(g) IT **(h)** LT **(i)** LU

Figure C.2: Visualized BDF matrices FI-LU. Color code indicating 10, 50 and 90 percentiles. Legend indicating ranges for absolute values.

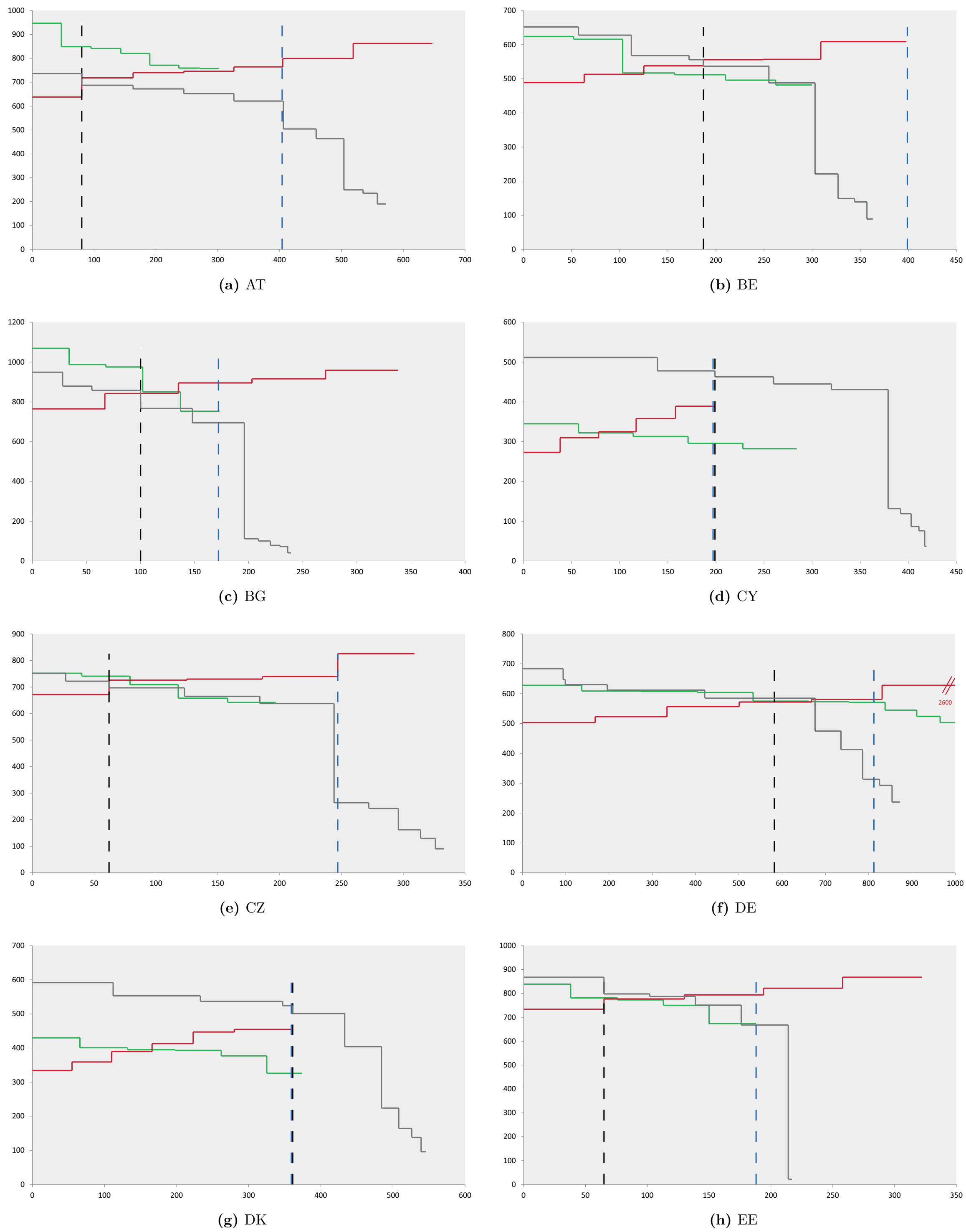


(a) LV **(b)** NL **(c)** PL

(d) PT **(e)** RO **(f)** SE

(g) SI **(h)** SK **(i)** UK

Figure C.3: Visualized BDF matrices LV-UK. Color code indicating 10, 50 and 90 percentiles. Legend indicating ranges for absolute values.



(a) AT (b) BE

(c) BG (d) CY

(e) CZ (f) DE

(g) DK (h) EE

Figure C.4: Bidding curves and equilibrium quantities AT-EE. Each figure displays demand curves (green), supply curves (red), cross-border demand curves (gray) and equilibrium quantities (dashed black line), EU instrument equilibrium quantities (dashed blue line).

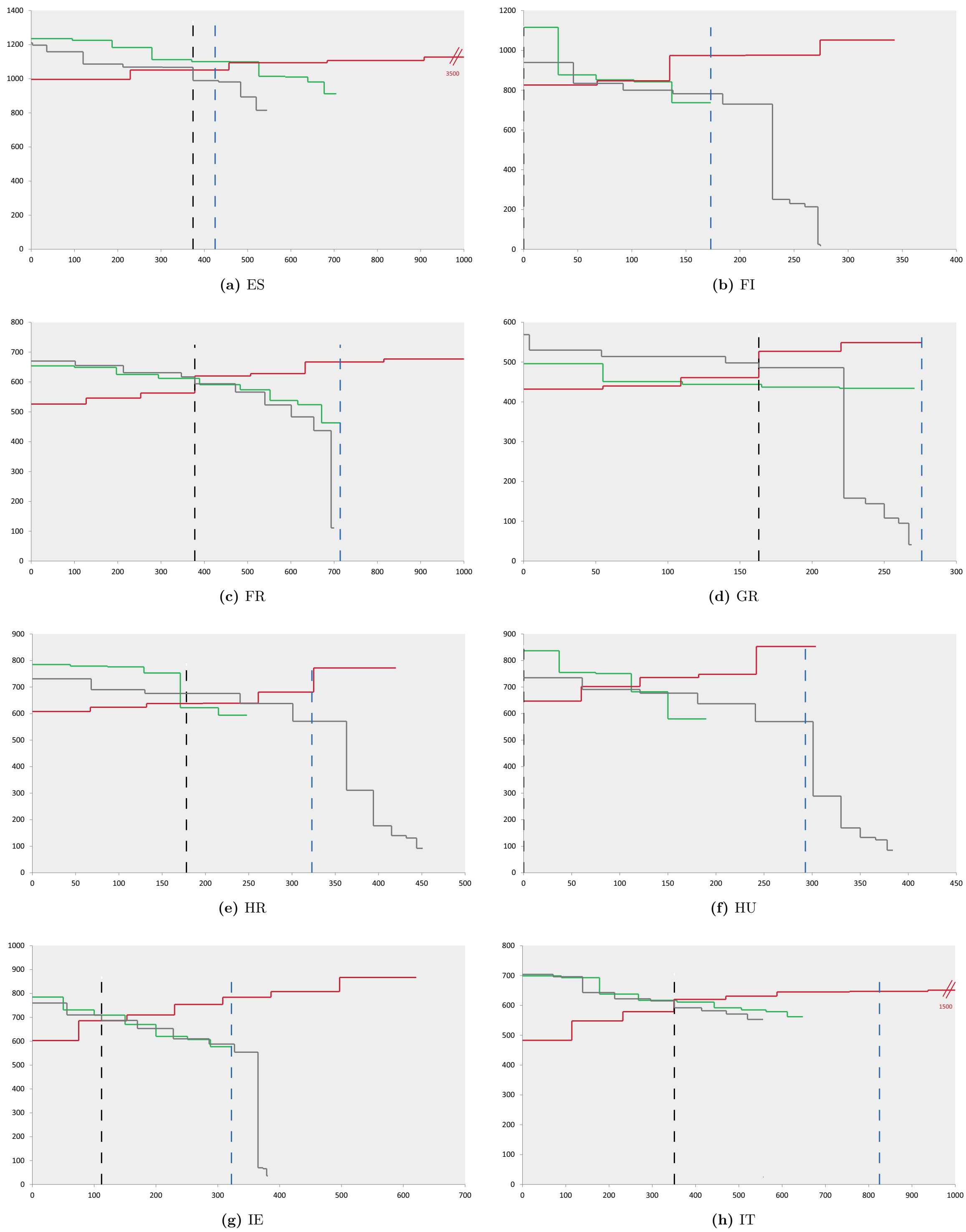
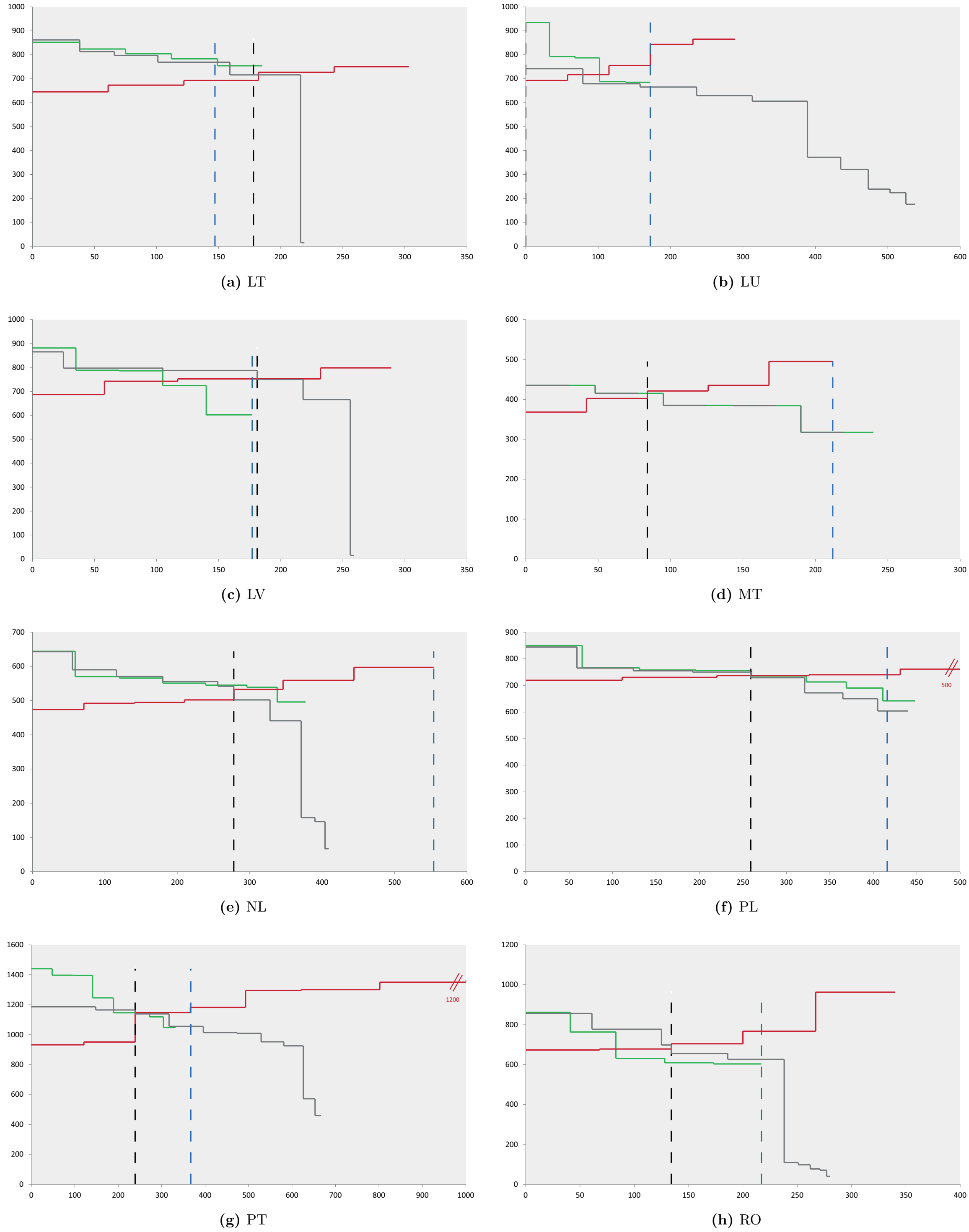
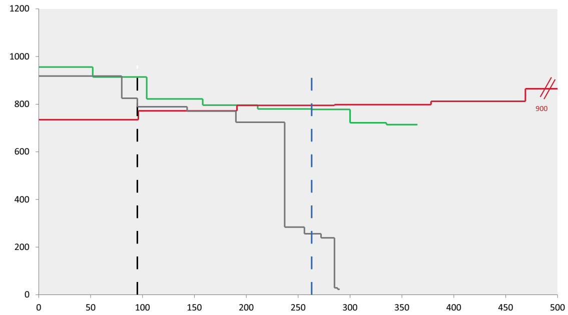


Figure C.5: Bidding curves and equilibrium quantities ES-IT. Each figure displays demand curves (green), supply curves (red), cross-border demand curves (gray) and equilibrium quantities (dashed black line), EU instrument equilibrium quantities (dashed blue line).

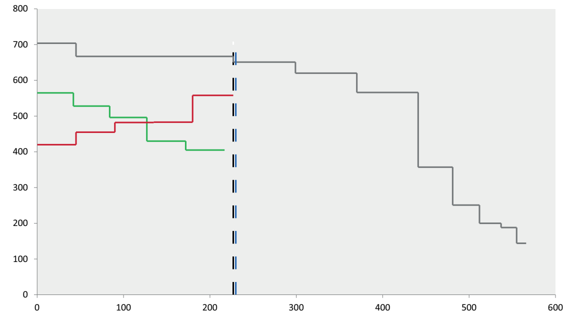


(a) LT (b) LU (c) LV (d) MT (e) NL (f) PL (g) PT (h) RO

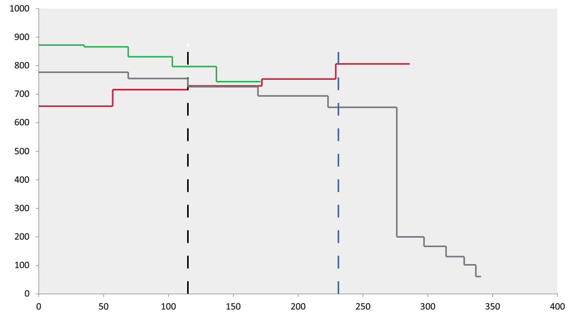
Figure C.6: Bidding curves and equilibrium quantities LT-RO. Each figure displays demand curves (green), supply curves (red), cross-border demand curves (gray) and equilibrium quantities (dashed black line), EU instrument equilibrium quantities (dashed blue line).



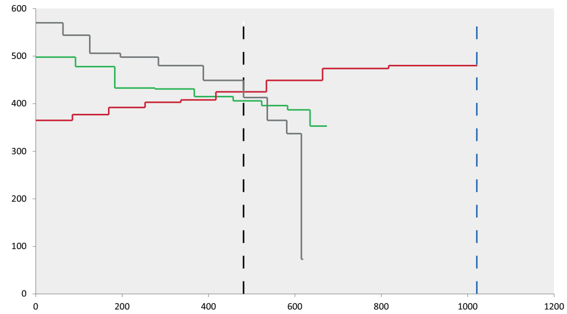
(a) SI



(b) SI



(c) SK



(d) UK

Figure C.7: Bidding curves and equilibrium quantities SI-UK. Each figure displays demand curves (green), supply curves (red), cross-border demand curves (gray) and equilibrium quantities (dashed black line), EU instrument equilibrium quantities (dashed blue line).

Table C.8: Payment streams in thousands of Euros

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK	∑
AT	18,586	4,339	801	3,632	4,345	34,506	13,826	0	3,060	6	0	5,092	3,677	0	427	491	0	0	0	0	3,904	65	4	1,055	769	7,450	2,008	3,665	111,708
BE	1,778	56,336	698	781	746	17,884	8,151	0	633	25	0	5,481	1,800	0	567	637	0	0	0	0	8,745	125	17	990	324	3,623	1,222	8,974	119,540
BG	96	202	69,266	1,015	70	551	397	0	859	0	0	0	195	0	34	0	0	0	0	0	285	0	0	30,019	0	258	135	0	103,382
CY	129	0	0	27,296	27	0	0	0	5,697	0	0	0	50	0	0	2	0	0	0	0	0	0	0	1	0	67	0	0	33,270
CZ	3,925	923	253	2,967	18,724	18,572	2,712	0	2,590	0	0	223	379	0	25	911	0	0	0	0	1,058	8,190	175	342	1,067	518	17,575	878	82,007
DE	18,146	16,121	4,213	4,661	6,134	154,829	38,505	0	4,178	3,300	0	34,538	18,066	0	3,011	1,739	0	0	0	0	18,545	438	1,876	5,437	2,343	37,489	7,124	24,762	405,456
DK	1,438	1,932	148	625	440	12,860	67,888	0	542	18	0	1,072	996	0	183	0	0	0	0	0	2,409	110	91	193	1,221	1,425	412	2,748	96,751
EE	0	61	0	70	0	625	178	21,468	60	0	0	0	0	0	0	0	22,354	0	54,979	0	83	660	0	0	1,940	0	126	81	102,684
GR	475	456	2,263	30,490	231	1,767	1,075	0	40,823	0	0	865	530	0	202	72	0	0	0	0	661	34	0	2,559	74	701	300	746	84,325
ES	944	4,590	905	4,782	816	7,601	4,091	0	4,226	375,913	0	18,241	1,982	0	2,144	9,403	0	0	0	0	4,227	413	146,430	1,203	380	2,691	1,610	17,807	610,398
FI	475	710	169	383	503	3,777	6,200	2,136	291	0	0	1,686	679	0	183	219	2,883	0	3,258	0	588	0	0	231	26,812	1,087	719	814	53,805
FR	1,080	3,737	843	1,233	712	11,378	4,505	0	1,095	30	0	148,938	2,246	0	811	1,016	0	0	0	0	2,769	150	22,060	1,101	219	3,080	1,719	6,939	215,659
HR	542	257	162	848	87	4,932	2,848	0	769	0	0	239	27,242	0	26	3	0	0	0	0	373	0	0	213	10	25,075	2,672	237	66,537
HU	1,529	1,442	358	1,254	1,093	8,107	5,194	0	1,054	27	0	2,619	37,440	0	491	182	0	0	0	0	1,424	28	22	617	68	27,558	4,459	1,650	96,618
IE	305	1,810	335	1,300	225	3,015	1,270	0	1,105	0	0	1,434	618	0	65,969	638	0	0	0	0	3,195	76	0	441	128	828	761	3,515	86,967
IT	1,522	1,681	1,804	5,973	1,164	10,263	6,501	0	7,001	2,503	0	3,404	3,107	0	1,138	208,138	0	0	0	0	5,054	51	1,209	2,381	161	4,342	2,243	3,533	273,174
LT	0	0	0	0	8	380	0	10,111	0	0	0	0	0	0	0	0	87,063	0	29,383	0	0	764	0	0	21,185	0	4	0	148,898
LU	3,219	2,979	104	1,230	707	20,624	11,629	0	984	0	0	0	1,024	0	29	255	0	0	0	0	4,001	7	206	141	416	1,953	112	3,358	52,976
LV	0	0	0	0	0	335	0	20,697	0	0	0	0	0	0	0	0	20,430	0	54,755	0	0	667	0	0	1,466	0	0	0	98,351
MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35,775	0	0	0	0	0	0	0	0	35,775
NL	1,654	8,845	1,148	2,486	899	17,185	7,791	0	2,079	0	0	5,384	2,416	0	3,897	624	0	0	0	0	82,832	234	0	1,552	478	3,176	1,572	14,294	158,547
PL	183	101	186	300	1,842	1,226	777	0	253	0	0	241	324	0	33	3	179	0	0	0	483	189,081	0	245	5,425	425	3,294	255	204,858
PT	67	282	0	1,666	16	1,281	380	0	1,473	27,256	0	17	32	0	0	0	0	0	0	0	397	107	106,721	42	100	43	5	17	139,901
RO	820	855	3,686	2,265	459	3,309	1,672	0	1,680	0	0	1,671	901	0	496	5	0	0	0	0	1,193	0	0	56,939	0	1,307	605	1,368	79,231
SE	139	114	71	211	183	1,375	7,206	1,830	174	0	0	272	106	0	0	0	2,878	0	3,190	0	162	0	0	95	20,828	357	204	279	39,674
SI	232	429	67	93	37	2,482	1,148	0	77	0	0	0	12,312	0	18	0	0	0	0	0	570	0	105	89	0	19,224	2,007	404	39,295
SK	344	489	303	2,005	5,159	1,460	952	0	1,772	0	0	261	4,930	0	29	75	0	0	0	0	408	38	0	426	540	6,728	35,677	221	61,817
UK	1,336	5,848	1,165	2,283	1,047	10,508	6,664	0	1,908	4,856	0	13,163	2,650	0	2,300	5,673	0	0	0	0	18,955	125	2,802	1,568	322	3,714	1,918	144,180	232,985
∑	58,964	114,539	88,950	99,851	45,676	350,833	201,559	56,243	84,382	413,933	0	244,843	123,705	0	82,015	230,085	135,787	0	145,566	35,775	162,322	201,361	281,717	107,879	86,274	153,117	88,485	240,725	3,834,587

Table C.9: Payment streams adjusted for surplus redistribution in thousands of Euros

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK	∑
AT	16,117	3,648	712	2,404	3,968	30,545	9,992	0	2,627	5	0	4,285	3,281	0	366	402	0	0	0	0	3,285	61	3	881	625	5,301	1,796	2,878	93,182
BE	1,542	47,365	621	517	682	15,831	5,891	0	544	23	0	4,612	1,606	0	486	521	0	0	0	0	7,359	117	13	828	264	2,578	1,093	7,047	99,540
BG	83	170	61,573	672	64	488	287	0	737	0	0	0	174	0	29	0	0	0	0	0	240	0	0	25,088	0	183	120	0	89,908
CY	112	0	0	18,065	25	0	0	0	4,891	0	0	0	45	0	0	2	0	0	0	0	0	0	0	1	0	48	0	0	23,189
CZ	3,403	776	225	1,964	17,102	16,440	1,960	0	2,223	0	0	188	339	0	21	746	0	0	0	0	890	7,665	140	286	868	368	15,720	690	72,014
DE	15,736	13,554	3,745	3,085	5,602	137,055	27,827	0	3,587	3,038	0	29,064	16,119	0	2,580	1,424	0	0	0	0	15,605	410	1,499	4,544	1,906	26,675	6,372	19,446	338,873
DK	1,247	1,624	131	414	402	11,384	49,061	0	465	17	0	902	889	0	157	0	0	0	0	0	2,027	103	73	161	994	1,014	368	2,158	73,591
EE	0	51	0	46	0	553	129	18,155	52	0	0	0	0	0	0	0	19,583	0	49,891	0	70	618	0	0	1,578	0	113	63	90,902
GR	412	383	2,012	20,179	211	1,564	777	0	35,051	0	0	728	473	0	174	59	0	0	0	0	556	32	0	2,139	60	499	269	586	66,164
ES	818	3,859	805	3,165	745	6,728	2,956	0	3,628	346,010	0	15,350	1,768	0	1,837	7,699	0	0	0	0	3,557	387	116,992	1,006	309	1,915	1,440	13,984	534,958
FI	412	597	150	254	460	3,343	4,481	1,807	250	0	0	1,419	606	0	157	179	2,526	0	2,957	0	495	0	0	193	21,819	774	643	639	44,161
FR	937	3,142	750	816	650	10,072	3,255	0	940	27	0	125,335	2,004	0	695	832	0	0	0	0	2,330	140	17,625	920	178	2,191	1,538	5,449	179,826
HR	470	216	144	562	80	4,366	2,058	0	660	0	0	201	24,306	0	22	2	0	0	0	0	314	0	0	178	8	17,842	2,390	186	54,005
HU	1,326	1,212	318	830	999	7,177	3,753	0	905	25	0	2,204	33,404	0	421	149	0	0	0	0	1,199	26	17	515	56	19,609	3,989	1,296	79,430
IE	264	1,522	298	861	205	2,669	918	0	949	0	0	1,207	552	0	56,535	522	0	0	0	0	2,688	71	0	368	104	589	680	2,760	73,762
IT	1,320	1,413	1,603	3,953	1,063	9,085	4,698	0	6,011	2,304	0	2,865	2,772	0	975	170,428	0	0	0	0	4,253	47	966	1,990	131	3,090	2,007	2,774	223,748
LT	0	0	0	0	7	337	0	8,551	0	0	0	0	0	0	0	0	76,270	0	26,664	0	0	715	0	0	17,240	0	3	0	129,787
LU	2,791	2,504	93	814	646	18,256	8,404	0	845	0	0	0	914	0	24	209	0	0	0	0	3,366	7	164	118	338	1,390	100	2,637	43,620
LV	0	0	0	0	0	296	0	17,504	0	0	0	0	0	0	0	0	17,898	0	49,688	0	0	624	0	0	1,193	0	0	0	87,203
MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32,326	0	0	0	0	0	0	0	0	32,326
NL	1,434	7,437	1,021	1,645	821	15,212	5,630	0	1,785	0	0	4,531	2,156	0	3,340	511	0	0	0	0	69,699	219	0	1,297	389	2,260	1,406	11,225	132,018
PL	159	85	166	199	1,683	1,085	561	0	218	0	0	203	289	0	28	2	157	0	0	0	407	176,976	0	205	4,415	302	2,946	200	190,286
PT	59	237	0	1,103	15	1,134	275	0	1,265	25,087	0	14	29	0	0	0	0	0	0	0	334	100	85,266	35	81	30	4	13	115,081
RO	711	719	3,276	1,499	419	2,929	1,209	0	1,442	0	0	1,407	804	0	425	4	0	0	0	0	1,003	0	0	47,586	0	930	542	1,074	65,979
SE	121	96	63	139	168	1,217	5,208	1,548	149	0	0	229	94	0	0	0	2,521	0	2,895	0	137	0	0	80	16,949	254	182	219	32,269
SI	201	361	60	62	34	2,198	829	0	66	0	0	0	10,985	0	16	0	0	0	0	0	480	0	84	74	0	13,679	1,795	317	31,241
SK	298	411	269	1,327	4,712	1,293	688	0	1,521	0	0	220	4,398	0	25	62	0	0	0	0	343	36	0	356	439	4,788	31,910	173	53,269
UK	1,159	4,917	1,036	1,511	956	9,302	4,816	0	1,638	4,469	0	11,077	2,364	0	1,971	4,645	0	0	0	0	15,950	117	2,239	1,311	262	2,642	1,715	113,224	187,321
∑	51,132	96,299	79,071	66,086	41,719	310,559	145,663	47,565	72,449	381,005	0	206,041	110,371	0	70,284	188,398	118,955	0	132,095	32,326	136,587	188,471	225,081	90,160	70,206	108,951	79,141	189,038	3,237,653

Table C.10: Net payment streams adjusted for surplus redistribution in thousands of Euros

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK	∑
AT		2,106	629	2,291	565	14,809	8,745	0	2,215	-813	-412	3,348	2,811	-1,326	102	-919	0	-2,791	0	0	1,851	-98	-56	170	505	5,101	1,497	1,720	42,050
BE	-2,106		451	517	-95	2,277	4,266	-51	161	-3,836	-597	1,470	1,390	-1,212	-1,035	-892	0	-2,504	0	0	-78	32	-224	109	168	2,217	682	2,130	3,240
BG	-629	-451		672	-161	-3,257	156	0	-1,275	-805	-150	-750	30	-318	-269	-1,603	0	-93	0	0	-781	-166	0	21,812	-63	124	-149	-1,036	10,838
CY	-2,291	-517	-672		-1,939	-3,085	-414	-46	-15,288	-3,165	-254	-816	-517	-830	-861	-3,951	0	-814	0	0	-1,645	-199	-1,103	-1,498	-139	-14	-1,327	-1,511	-42,896
CZ	-565	95	161	1,939		10,838	1,558	0	2,013	-745	-460	-462	259	-999	-184	-317	-7	-646	0	0	69	5,983	125	-133	701	334	11,008	-267	30,298
DE	-14,809	-2,277	3,257	3,085	-10,838		16,443	-553	2,023	-3,690	-3,343	18,993	11,753	-7,177	-88	-7,661	-337	-18,256	-296	0	393	-675	365	1,615	690	24,478	5,079	10,144	28,318
DK	-8,745	-4,266	-156	414	-1,558	-16,443		-129	-312	-2,939	-4,481	-2,353	-1,169	-3,753	-761	-4,698	0	-8,404	0	0	-3,603	-459	-202	-1,047	-4,214	185	-320	-2,657	-72,070
EE	0	51	0	46	0	553	129		52	0	-1,807	0	0	0	0	0	11,032	0	32,387	0	70	618	0	0	31	0	113	63	43,338
GR	-2,215	-161	1,275	15,288	-2,013	-2,023	312	-52		-3,628	-250	-212	-187	-905	-775	-5,952	0	-845	0	0	-1,229	-186	-1,265	697	-89	433	-1,253	-1,052	-6,287
ES	813	3,836	805	3,165	745	3,690	2,939	0	3,628		0	15,323	1,768	-25	1,837	5,395	0	0	0	0	3,557	387	91,905	1,006	309	1,915	1,440	9,515	153,953
FI	412	597	150	254	460	3,343	4,481	1,807	250	0		1,419	606	0	157	179	2,526	0	2,957	0	495	0	0	193	21,819	774	643	639	44,161
FR	-3,348	-1,470	750	816	462	-18,993	2,353	0	212	-15,323	-1,419		1,803	-2,204	-511	-2,033	0	0	0	0	-2,201	-63	17,611	-487	-50	2,191	1,318	-5,628	-26,214
HR	-2,811	-1,390	-30	517	-259	-11,753	1,169	0	187	-1,768	-606	-1,803		-33,404	-529	-2,770	0	-914	0	0	-1,842	-289	-29	-627	-86	6,858	-2,008	-2,178	-56,365
HU	1,326	1,212	318	830	999	7,177	3,753	0	905	25	0	2,204	33,404		421	149	0	0	0	0	1,199	26	17	515	56	19,609	3,989	1,296	79,430
IE	-102	1,035	269	861	184	88	761	0	775	-1,837	-157	511	529	-421		-453	0	-24	0	0	-651	43	0	-57	104	573	656	789	3,476
IT	919	892	1,603	3,951	317	7,661	4,698	0	5,952	-5,395	-179	2,033	2,770	-149	453		0	-209	0	0	3,742	45	966	1,986	131	3,090	1,945	-1,871	35,351
LT	0	0	0	0	7	337	0	-11,032	0	0	-2,526	0	0	0	0	0		0	8,766	0	0	558	0	0	14,719	0	3	0	10,832
LU	2,791	2,504	93	814	646	18,256	8,404	0	845	0	0	0	914	0	24	209	0		0	0	3,366	7	164	118	338	1,390	100	2,637	43,620
LV	0	0	0	0	0	296	0	-32,387	0	0	-2,957	0	0	0	0	0	-8,766	0		0	0	624	0	0	-1,702	0	0	0	-44,892
MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0
NL	-1,851	78	781	1,645	-69	-393	3,603	-70	1,229	-3,557	-495	2,201	1,842	-1,199	651	-3,742	0	-3,366	0	0		-188	-334	293	252	1,780	1,063	-4,725	-4,571
PL	98	-32	166	199	-5,983	675	459	-618	186	-387	0	63	289	-26	-43	-45	-558	-7	-624	0	188		-100	205	4,415	302	2,911	83	1,816
PT	56	224	0	1,103	-125	-365	202	0	1,265	-91,905	0	-17,611	29	-17	0	-966	0	-164	0	0	334	100		35	81	-54	4	-2,226	-110,000
RO	-170	-109	-21,812	1,498	133	-1,615	1,047	0	-697	-1,006	-193	487	627	-515	57	-1,986	0	-118	0	0	-293	-205	-35		-80	855	186	-236	-24,180
SE	-505	-168	63	139	-701	-690	4,214	-31	89	-309	-21,819	50	86	-56	-104	-131	-14,719	-338	1,702	0	-252	-4,415	-81	80		254	-257	-43	-37,942
SI	-5,101	-2,217	-124	14	-334	-24,478	-185	0	-433	-1,915	-774	-2,191	-6,858	-19,609	-573	-3,090	0	-1,390	0	0	-1,780	-302	54	-855	-254		-2,992	-2,325	-77,712
SK	-1,497	-682	149	1,327	-11,008	-5,079	320	-113	1,253	-1,440	-643	-1,318	2,008	-3,989	-656	-1,945	-3	-100	0	0	-1,063	-2,911	-4	-186	257	2,992		-1,542	-25,873
UK	-1,720	-2,130	1,036	1,511	267	-10,144	2,657	-63	1,052	-9,515	-639	5,628	2,178	-1,296	-789	1,871	0	-2,637	0	0	4,725	-83	2,226	236	43	2,325	1,542		-1,719
∑	-42,050	-3,240	-10,838	42,896	-30,298	-28,318	72,070	-43,338	6,287	-153,953	0	26,214	56,365	0	-3,476	-35,351	-10,832	0	44,892	0	4,571	-1,816	110,000	24,180	37,942	77,712	25,873	1,719	0

Table C.11: Payments to EU fund in thousands of Euros

	AT	BE	BG	CY	CZ	DE	DK	EE	GR	ES	FI	FR	HR	HU	
gross contribution	111,708	119,540	103,382	33,270	82,007	405,456	96,751	102,684	84,325	610,398	53,805	215,659	66,537	96,618	
surplus distribution	18,523	20,000	13,473	10,081	9,993	66,582	23,160	11,781	18,163	75,439	9,646	35,834	12,531	17,188	
net contribution	93,184	99,540	89,909	23,189	72,014	338,874	73,591	90,902	66,162	534,959	44,159	179,826	54,006	79,430	
	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK	∑
gross contribution	86,967	273,174	148,898	52,976	98,351	35,775	158,547	204,858	139,901	79,231	39,674	39,295	61,817	232,985	3,834,589
surplus distribution	13,205	49,425	19,110	9,356	11,147	3,449	26,529	14,573	24,820	13,252	7,406	8,055	8,548	45,664	596,932
net contribution	73,762	223,749	129,787	43,621	87,204	32,326	132,018	190,285	115,081	65,979	32,268	31,240	53,269	187,321	3,237,655