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

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About the project

The aim of **towards2030-*dialogue*** is to facilitate and guide the RES policy dialogue for the period towards 2030. This strategic initiative aims for an intense stakeholder dialogue that establishes a European vision of a joint future RES policy framework.

The dialogue process will be coupled with in-depth and continuous analysis of relevant topics that include RES in all energy sectors but with more detailed analyses for renewable electricity. The work will be based on results from the IEE project beyond 2020 (www.res-policy-beyond2020.eu), where policy pathways with different degrees of harmonisation have been analysed for the post 2020 period. **towards2030-*dialogue*** will directly build on these outcomes: complement, adapt and extend the assessment to the evolving policy process in Europe. The added value of **towards2030-*dialogue*** includes the analysis of alternative policy pathways for 2030, such as the (partial) opening of national support schemes, the clustering of regional support schemes as well as options to coordinate and align national schemes. Additionally, this project offers also an impact assessment of different target setting options for 2030, discussing advanced concepts for related effort sharing.

Who we are?

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Executive Summary

In this paper we propose and put forward to discussion a new mechanism for cross-border support of renewable electricity in the European Union (EU). The mechanism can be characterized as "hybrid" in the spectrum of approaches to facilitate cross-border support of renewable electricty (RES-e); combining the flexibility for Member States to choose freely their desired level of cooperation of "bottom-up" approaches with the coordinative ability of "top-down" approaches that is lacking in the current framework of the cooperation mechanisms. We believe that the mechanism can boost cooperation between EU Member States in supporting new RES-e generating capacities at significant scale.

This proposal is timely. In its November Council on Energy (Council of the European Union, 2015) the European Council concluded inter alia on the new governance system of the energy union that "*…enhanced regional cooperation will become a cross-cutting and important aspect of the future governance system of the Energy Union and needs to be facilitated or incentivised".* Moreover the Council's conclusions referred to the possibiliy of an EU "back-up-instrument" in case the Member States' contributions would not be sufficient to reach the EU wide 2030 target for renewable energy sources. The mechanism we propose is capable of integrating both these functionalities.

The current framework for cross-border cooperation in RES-e generating capacity expansion is given by the cooperation mechanimsm under the renewable energy sources directive (European Parliament and Council, 2009). The existing mechanisms however appear, unfortunately, to be insufficient to facilitate the efficient level of trade in RES-e generating capacity across the EU due to the existence of several barriers. The mechanism we propose in this paper is capable of overcoming these barriers. It consists of two main elements: (i) 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; (ii) a cross-border impact matrix that indicates the spill-overs of benefits between Member States induced from additional RES-e generating capacity.

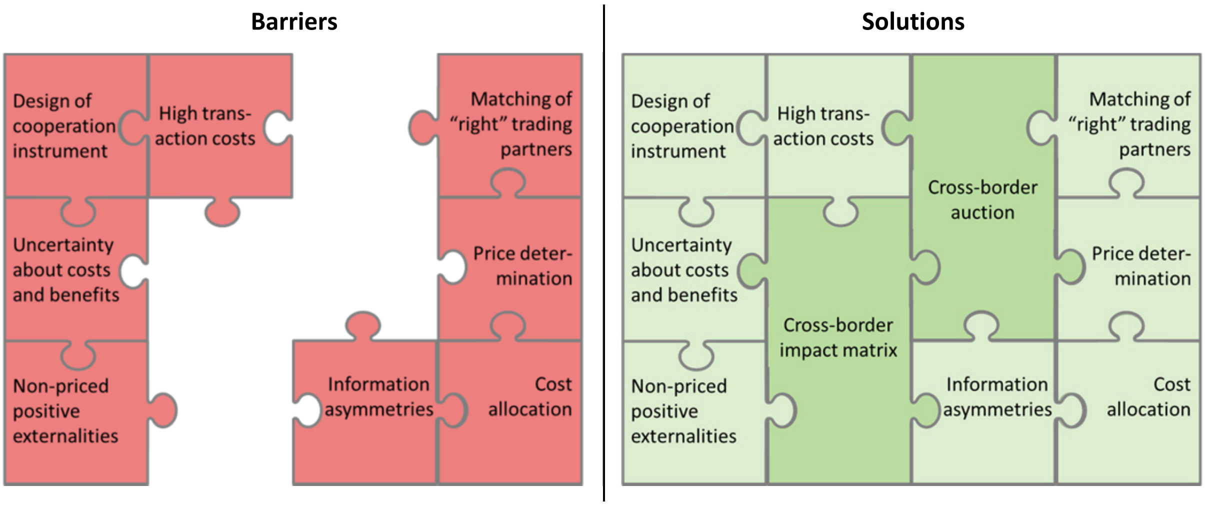


Figure E-1: Barriers and solutions to cooperating in RES-e capacity expansion.

The following barriers have been found to be most severe in preventing cooperation and are adressed by the design of the mechanism:

- Due to the maginutude of interrelated effects induced by a new project costs and benefits are often highly uncertain. Moreover effects are not exclusively experienced by the Member State making the investment decision which leads to inefficient investment. The cross-border impact matrix overcomes these weaknessess by providing a standardised, systematic procedure to indicate both the level and the relative distribution of benefits from a new RES-e project. In combination with the cross-border auction this creates an a system of mutual compensatory payments between Member States for cross-border effects.

- 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, making it much more difficult to realise a net benefit that makes all involved Member States better off than without cooperation. Our mechanism solves this barrier by providing a standardised procedure for assessing costs and benefits and providing standardised design elements, so that these costs can be split among all new projects. In spite of the standardisation the mechanisms still allows maximum flexibility of the Member States to express their preferences for cooperation.
- Information asymetries between RES-e generators and Member States and inbetween Member States regarding costs and benefits pose a significatnt barrier to cooperation. Having this in mind the auction can be designed in a way such that all actors have an incentive to reveal their true preferences; that is, their willingness to pay and their costs. 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.
- Due to the presence of multilateral externalities, effiecient trade can only take place multilaterally: Our mechanism has been designed to enable multilateral trade; it would become very complex to replicate the same outcome on a bilateral basis; however as will be shown only multilateral trade can implement the efficient level of 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 percieved as fair and would make all involved parties better off. The mechanism relieves Member States of this burden, as they now only have to know their individual willingness to pay and the mechanism finds the efficient transfer prices for them, which makes each Member State participating in the mechanism better off.

Next in Figure E-2 a basic illustration of the mechanism is given: The main actors involved in executing, and participating in the mechanism according to our proposal would be generators of RES-e, the EU Member States, the European Commission and ENTSO-e. Both RES-e generators and Member States aim to maximise their benefit from RES-e generating capacity expansion. In this respect both have to solve a geographical capacity allocation problem: generators of RES-e choose the Member State[1] for investments into new RES-e generating capacity where they can expect the highest revenues from sales of electricity plus earnings from participation in a support instrument net of long term costs of generation. Member States have to trade-off different energy policy objectives when deciding about new sites respectively generating technologies. Based on the opportunity costs of their choises both Member States and RES-e generators can then derive maximum bid respectively ask prices for the cross-border auction that would make them better off if selected; that is, both generators of RES-e and Member States would try to improve their benefit by participating in the cross-border mechanism compared to their national alternative.

The European Commission and ENTSO-e have the goal to coordinate the EU-wide expansion of new RES-e generating capacity in order to enhance EU-wide efficiency and balance. According to our proposal the Europoean Commission would be in charge of organising and conducting the cross-border auction, or nominating some party on her behalf to conduct the auction. She would also be involved alongside Member States in assissting ENTSO-e with the calculation of the cross-border impact matrix. We propose that the calculation of the matrix be integrated into the preparation of the Ten Year Network Development planning process, since it already contains all the methods and data that would be required. The matrix would indicate

[1] Which determines a market area for their sales of electricity.

how the benefit from new RES-e generating capacity in one Member State would be distributed across all EU Member States.

Both the prices bid by the Member States and the RES-e generators and the cross-border impact matrix would be used as input parameters by the auctioneer. Based on these parameters, she calculates the supply and the cross-border demand curves for each Member State; that is, each Member States constitutes a bidding zone. The auctioneer then selects the set of bids that maximizes EU-wide surplus, which implies that cross-border trade in RES-e generating capacity takes places as long as it is welfare enhancing. The outcome of the auction is payment obligations from Member States to RES-e generators and between Member States. It should however be noted that the principle of reciprocity is inherent to the design of the mechanism. That means each Member State participating in the mechanism would both make and receive payments so that these would likely net out to a larger extent[2]; thereby the design of the mechanism ensures an efficient outcome so that all Member States are better off than without cooperation.

Finally it should be emphasized that the cross-border mechanism could smoothly co-exist with national support instruments, so that participation would be voluntary, which would provide Member States the maximum degree of flexibility in achieving their RES-e expansion objectives.

[2] Assuming all Member States submit demand bids that are selected.

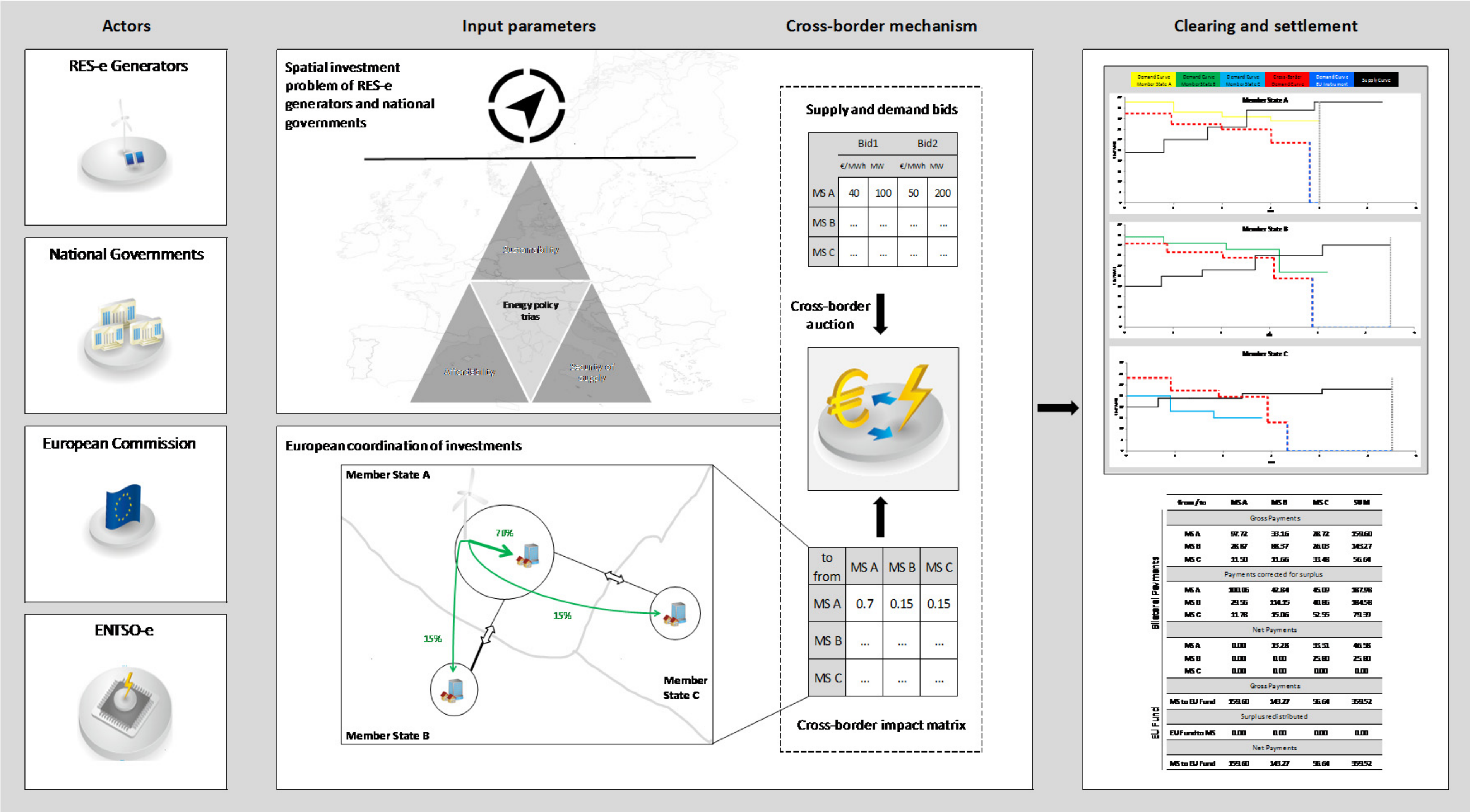


Figure E-2: Overview of the mechanism for cross-border support for RES-e in the EU. Figure adapted from and provided by courtesy of TenneT TSO, 2010.

Questions informed by the findings of this paper

How can a physical impact of new RES-e generating capacity on the power system of a Member State be measured?

We define physical impacts as the change in national generation mixes induced by new RES-e generating capacity at one or more locations, whereby we explicitly consider the impact of altered real power flows across the transmission grid.

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.

The best suited institution would be ENTSO-e, having best access to the data needed and competence to perform the calculations required. The grid topology, including all relevant parameters such as reactances and thermal line limits is assessed and updated within the context of the Ten Year Network Development plan so that this data can be assumed to be available for the needed time horizon. Also, the calculation of the economic dispatch is a standard methodology in the common cost-benefit analyses of ENTSO-e, which are performed within the context of the Ten Year Network Development Plan.

To assess the physical impact of any arbitrary combination of additional RES-e investments in Europe on national generation mixes, ENTSO-e would simply have to add a view more evaluations to their ongoing modeling activities. The additional calculations are based on the same methodology already applied and are elaborated within this paper.

How can a transfer price be found, such that all Member States benefit from cooperation in RES-e capacity expansion?

The price determination procedure is an inherent and precious property of the mechanism. In comparison to the cooperation mechanism 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 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. The outcome of the auction is payment obligations from Member States to RES-e generators and between Member States. 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, decentralised approach to EU wide coordination and efficiency maximisation.

How does the mechanism contribute to the objectives and completion of the internal market?

The single most important indicator for the progress towards the completion of the internal market is price convergence. The cross-border mechanism is a facilitator of price convergence by internalising the value towards price convergence in the cross-border impact matrix leading to a coordinated allocation of new RES-e generating capacity investments. This effect may become clearer by illustrating how the mechanism would induce a very uncoordinated allocation of RES-e investments -thwarting the completion of the internal market - to swing back to a more balanced allocation of RES-e investments facilitating the completion of the of the internal market. In a hypothetical, extreme case all the new RES-e investments would take place in only in one Member State. This would likely lead to a divergence of prices between the concerned Member State and all other Member States and as a consequence also to a divergence of market values of RES-e generation. This divergence of market values would be reflected in the values of the cross-border impact matrix: The more unbalanced the distribution of RES-e generating capacities is, the higher the difference in market values of RES-e generation becomes and, ceteris paribus, the more benefits spill over from the Member State with a high concentration of RES-e generation to the other Member States. In effect this would lead to a cross-border impact matrix that becomes more and more skewed, i.e. the relative benefit that remains in the Member State with already a high concentration of RES-e generation would decline compared to the other Member States. This would provide a signal in the auction to allocate, ceteris paribus, new RES-e generation to Member States with a relatively lower concentration of RES-e generation. It has to be noted that this would not prevent the deployment of very high shares of RES-e; it would however give incentives to deploy RES-e in a way that prices and market values reach a higher degree of convergence.

How can a European instrument be designed that incentivises additional investments into renewable electricity generating capacities to ensure the EU meets its 2030 target of a 27% renewables share?

Besides facilitating cross-border cooperation the mechanism can also be used as an EU instrument to finance additional RES-e capacity expansion if needed to reach the EU wide target of 27% renewable energy in 2030. This need could arise as the 2030 target - contrary to the 2020 target - has not been broken down into national targets and therefore it is not provided that the Member States' post 2020 efforts alone will be sufficient to reach the 2030 target.

As explained above, in the cross-border auction all bids that lead to a positive surplus are selected; i.e. for a given set of prices (bids) the auction selects a quantity of new investments into RES-e generating capacity. In order to also function as an EU instrument the total quantity of new investments would now be determined ex-ante - just like it is the case in most national auctions for RES-e support - rather than being a decision variable in the auction. The auctioneer would select bids up to the desired level of quantity whereby bids would be selected by order of their surplus contributions beginning with the largest. It might however be required that also bids with a negative surplus - indicating the financing gap for these bids - would have to be selected in order to reach to reach the EU wide expansion target. The financing gap could be paid from an EU fund. Combining an EU wide auction with the mechanism for cross-border support offers two significant advantages compared to the case of a separate EU instrument: (i) The amount of financing that would need to come from an EU fund can be expected to be significantly lower which can be a huge advantage given the probable legal and political difficulties to equip such a fund with financial resources. (ii) The EU instrument could make use of the locational siting signals derived from the cross-border mechanism so that potentially a higher level of economic efficiency could be achieved than under a separate EU auction.

Introduction

In this paper we propose a new mechanism for cross-border support of RES-e in the EU. The guiding idea is that the cross-border mechanism allocates new RES-e generating capacity across EU Member States to where it is most valuable[3].

The mechanism would be designed as an EU wide cross-border auction in that Member States and generators of RES-e bid prices indicating their willingness to pay for, respectively their costs of additional RES-e generating capacity. In addition to prices the auctioneer uses a cross-border impact matrix that indicates the spill-over of benefits between Member States induced from additional RES-e generating capacity to select the set of bids that maximizes EU-wide surplus.

The idea for the mechanism emerged from two formerly separated trains of thought. In the context of the discussion on the cooperation mechanisms under the EU renewables directive (European Parliament and Council, 2009) the idea to use a cross-border auctioning mechanism in order to facilitate price determination and cost allocation, efficient matching of "trading partners" as well as lower transaction costs has been developed by the authors. In the context of the discussion on the opening of support schemes for RES-e the idea for a cross-border impact matrix that indicates the (physical) impact in one Member State induced from the siting decision for new RES-e generating capacity in another Member State has been devised. The here proposed mechanism seeks to combine both these approaches.

The ability to exchange RES-e capacity between EU member states improves the welfare of all Member States since potentials and demands for RES-e capacity vary across the EU. This notion is reflected in the promotion of so called cooperation mechanisms by the EC. The existing mechanisms appear, unfortunately, to be insufficient to facilitate the efficient level of trade in capacity across the EU; only a small quantity of energy is expected to be subject to cooperation mechanisms (Klessmann et al., 2010). We identify three characteristics of the market for RES-e capacity that contribute to the failure of the market as is. First, 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. The mechanism we propose seeks to minimize the incentives for actors to do so. Second, the costs and benefits of adding a unit of RES-e capacity are not entirely born by actors making the expansion decision; that is, RES-e capacity generates **externalities** in the market. Bi- or multi-lateral negotiations alone are therefore unlikely to result in efficient RES-e capacity. Our mechanism incorporates these externalities into prices for capacity ensuring that choices reflect the true costs and benefits. Finally, the **transaction costs** of bi- or multi-lateral negotiations are very high since they require parliamentary approval in several Member States. In particular, establishing the share of costs and benefits seems to have derailed cooperation between Sweden and Norway (Klessmann et al., 2010). In our mechanism these costs would only accrue once for setting-up the mechanism, but then cease to exist for each individual project, which offers significant economies of scale.

1.1 Policy Context

The mechanism is in line with currently ongoing energy policy developments at EU level: In 2014 the European Council (2014) decided an EU target of at least 27% for the share of renewable energy consumed in the EU in 2030. The new governance system that will be developed to help ensure that the EU meets its energy policy

[3] We define value as the sum of market and non-market value of RES-e generating capacity net of its long-term costs of generation (variable+capital). This can, but need not coincide with the most cost efficient allocation. Compare section Appendix D for more on this.

goals will "facilitate coordination of national energy policies and foster regional cooperation between Member States." The need for cooperation between Member States and coordination between different policy fields is highlighted by the creation of a vice presidency for the Energy Union in the new EU commission. 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 (European Council, 2015).

In this respect our mechanism also fits well to the incentive issues raised in a recent proposal by Portugal for a governance system of the 2030 Climate and Energy framework (Tesniere et al., 2015).

In our view the proposed mechanism would have advantages over other models that have been in the discussion in order to facilitate EU wide cooperation and enhance the efficiency of RES-e support. In contrast to top-down approaches, such as an EU wide harmonisation of support conditions, the mechanism would allow for a decentralised optimisation of RES-e support, which would provide the Member States greater flexibility in adapting to future developments and national policy needs. Moreover, the mechanism would consider benefits, respectively opportunity costs ("alternatives") available to the Member States and may thus outperform top-down approaches that merely minimize costs when it comes to economic efficiency.

With regards to bottom-up approaches, such as the cooperation mechanisms under the renewables directive, the proposed mechanism would offer the potential to overcome several of the (technical) barriers related to the use of the cooperation mechanisms. 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. The interviews with Member States show 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 fulfilments. 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.

Regarding technical barriers, for the cooperation mechanisms to be applicable in practice one important requirement is that all the costs and benefits associated to a particular project have to be known and a cost allocation needs to be decided. Under the mechanism we propose, neither the costs nor benefits of each project are assumed known. Rather they are "discovered" by the use of the bidding mechanism and the outcome of the auction simultaneously allocates new RES-e generating capacities efficiently and solves the cross-border cost allocation problem.

In 2014 the EC published Guidelines on State aid for environmental protection and energy (European Commission, 2014). While these guidelines apply to the period up to 2020, they should prepare the ground for achieving the objectives set in the 2030 Framework. The guidelines state that

- Aid for electricity from renewable energy sources is granted as a premium in addition to the market price, whereby the generators sell its electricity directly in the market,
- And from 1 January 2017, aid is granted in a competitive bidding process on the basis of clear, transparent and non-discriminatory criteria,

- And if such competitive bidding processes are open to all generators producing electricity from renewable energy sources on a non-discriminatory basis, the Commission will presume that the aid is proportionate and does not distort competition to an extent contrary to the internal market.

We can conclude that our mechanism is fully compatible with the requirements laid out by the state aid guidelines.

1.2 Outline of this paper and how to read it

This paper is structured as follows: Chapters 2 and 3 introduce and develop concepts that form important inputs to, respectively elements of the mechanism. Chapter 2 first revisits costs and benefits associated with RES-e expansion. The reader familiar with this discussion can skip this part of the chapter and unabatedly continue with section 2.4 that discusses the determinants of willingness to pay for RES-e expansion. Chapter 3 then discusses the distribution of costs and benefits in the internal market for electricity. Of highlight this chapter will propose a procedure to derive a cross border impact matrix that indicates the distribution of benefits from additional RES-e generating capacity in the internal market.

Next Chapter 4 describes how the impact matrix concept could be implemented and applied in practice. Chapter 5 then describes the cross-border auction. At first the basic set-up will be explained and then its functioning will be illustrated and possible further variants and applications are discussed in chapter 6. Chapter 7 outlines where the need for further research emerged based on the analyses conducted in this paper. Finally chapter 8 discusses the contributions and insights from this paper.

As this paper addresses different audiences and not all chapters of this paper are equally important to all readers we have arranged the content of this paper in different formats:

Each of the main content related chapters 2-6 is preceded by a blue box that provides a short summary of the subsequent chapter. This shall serve two purposes: It shall enable the selective reader to skip individual chapters without losing the whole context. For the other readers that wish to read the full paper it can help prestructure the context and ideas of the subsequent chapter, so that she already can anticipate what to expect and which main message shall be transported.

Furthermore, in particular with regards to chapter 3 that lays out the engineering and economic foundations of the mechanism, we use boxes to highlight basic definitions (green) and principles (red) that are exploited in designing the mechanism. The idea to arrange this text in boxes is to reduce the length of background information to an extent that is still comprehensible and reproducible and to present this information in rather easy to read language. These boxes are then referred to in different sections of the paper.

2 Costs and benefits of RES-e expansion revisited

Costs and benefits of RES-e generating capacity expansion take place in layers with different system boundaries. Most of the effects take place within the power system. There RES-e generating capacity causes benefits if it displaces generation and / or capacity of an alternative (conventional) generating technology. It also causes – yet in many cases yet relatively higher – costs that incur for its own capacity and generation. The gross benefit RES-e generating capacity has within the power system is expressed by its market value and the net benefit is given by its market value net of its long term costs of generation. Currently the net benefit in the power system is often still negative, but dynamics are likely to change this in the future.

In addition RES-e generating capacity causes distributional effects inside the power system and externalities outside the power system. As regards the benefits side such as technological learning or mitigated air pollution, these benefits are not (exclusively) experienced by the RES-e investor so that she does not (fully) internalize them in her investment decision. This leads to the market failing to invest into new RES-e generating capacities at a level that would be socially efficient. Therefore society is willing to temporarily pay RES-e investors additional support for RES-e generating capacity in order to gain the long term social benefit from electricity system transformation.

As renewable energies have experienced a strong diffusion in the last two decades globally, the literature that analyses 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 in order to provide background information needed to develop the concept of the mechanism later on. 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 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 external effects and the latter macro effects.

2.1 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; 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 "policy" perspective, 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. 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)). Thus disregarding these effects would lead to "externalities" within the power system, which does not correspond to the definitions from above. 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 the latter one, are caused by the variability, limited predictability and location specifity (this effect might also apply for dispatchable RES-e generating capacities that are sited in remote areas) are termed profile costs, balancing costs and grid-related costs. 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 / 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 of a system 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 / price effect (Breitschopf and Held, 2014; Pade et al., 2012) and the “sell out of low cost potentials”. 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.

2.2 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 plants 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 plants. 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 is comparatively low, a large area of land is required for electricity generation, which generally goes along with impacts on biodiversity and landscape / visual impacts in the surrounding area where the plants are installed (Borenstein, 2012; Meeus et al., 2013). However, the overall relative 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 process of permit granting.

2.3 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 fluctuating 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 of 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 intra-nationally 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 summary of the effects described above.

Table 2-1: Categorisation of costs and benefits of RES-e expansion listed in the literature.

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

2.4 Electricity market failures and willingness to pay for RES-e generating capacity expansion

This section discusses - from an economic perspective - the willingness to pay by Member States for additional RES-e generating capacity expansion. This shall be done with the help of Figure 2-1 that conceptually structures and illustrates the different cost and benefit components described above. It thereby distinguishes between two different points in time (today and future). The figure groups the effects according to the three system boundaries developed above (power system, externalities, and macro effects), whereby a red colouring refers to “costs” and a green colouring to “benefits”.

We 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 incentivise the diffusion of RES-e generating 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 is 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 costs as the external benefits do not (yet) cover up for the relatively higher costs of generation of RES-e. In the following we refer to the benefits that arise in the power system as “**private benefits**” as they are reflected in the market income of actors in the power system and to the sum of benefits across all system boundaries as “**social benefits**” as these are the benefits experienced by society.

Let us now turn to the possible situation in the future. It is the belief / hope that RES-e generation will be able to significantly reduce its fixed capacity investment costs (1b)[4] due to not yet exploited learning curve potential. Thus in principle RES-e generation could be able to recover its full costs (maybe besides integrations costs) through earnings on the electricity market.[5] 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 the full or higher value of saved CO_2 emissions (2b) being internalised 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.[6]

Next we discuss how electricity market failures relate to the concept 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 macro-economic perspective.

[4] Relatively more strongly than – if at all – conventional generation could, due to its smaller remaining learning potential.

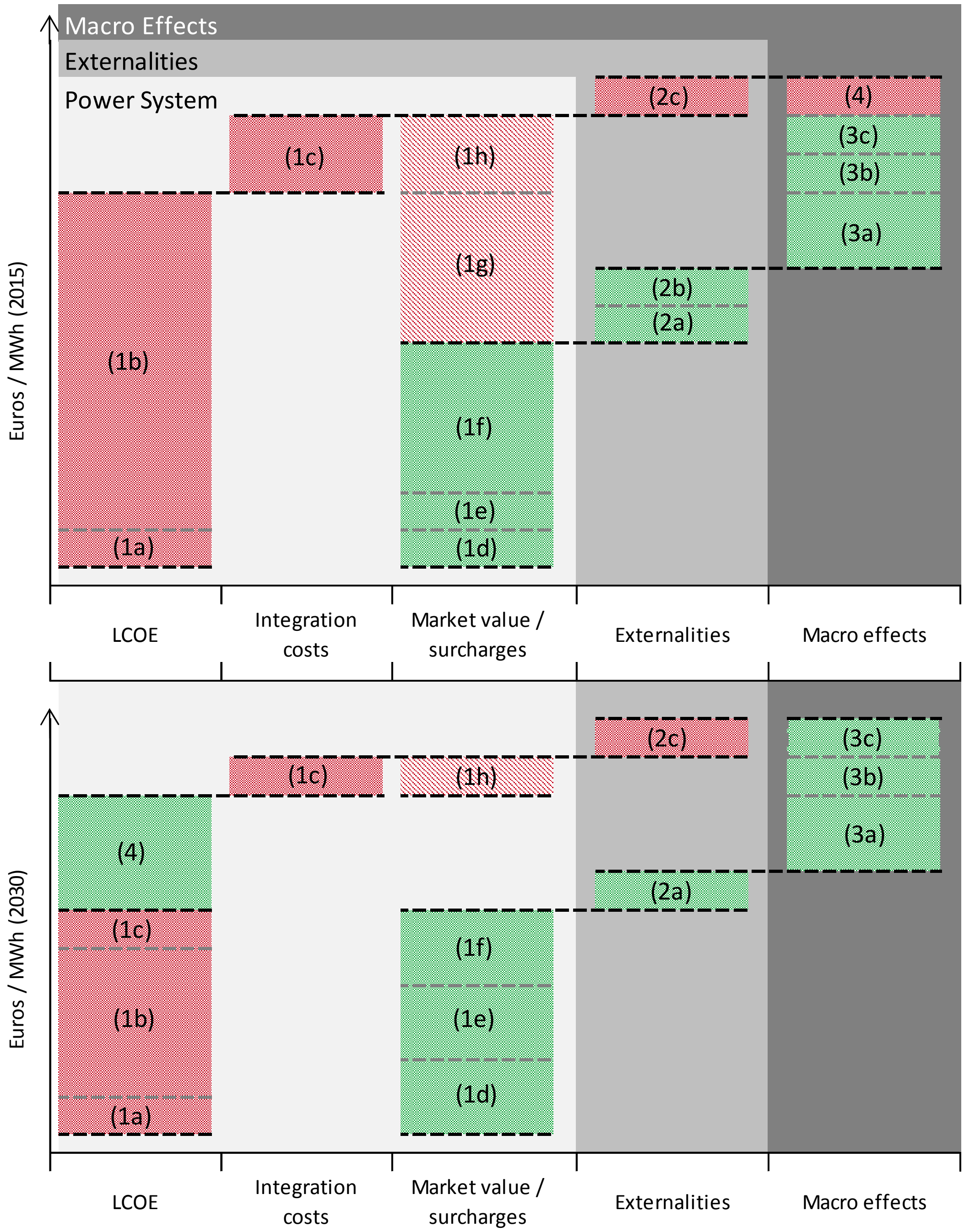
[5] Which exact market design can provide for this is still an ongoing debate

[6] State aid guidelines: beneficiaries are subject to standard balancing responsibilities, unless no liquid intra-day markets exist (European Commission, 2014).

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 generating 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 have to be lower than the sum of social benefits so that it pays for society to support RES-e generation. Thus from a dynamic, partial equilibrium perspective[7], 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 the individual Member State's willingness to pay, given that already a 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 (cf. Appendix D).

[7] This implies that at the beginning the support costs could also be higher than the non-market based benefits as long as the net benefit is non-negative in the aggregate.



Legend

(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			

Figure 2-1: Conceptual overview of costs, benefits and externalities of RES-e expansion.

Next we further elaborate on the willingness to pay for RES-e expansion. We introduce some basic notation that will be used throughout the paper.

Figure 2-2 in the left column shows the aggregate (of Figure 2-1), social benefit SB induced from additional RES-e generating capacity. It can be expected that this benefit determines an upper boundary for the maximum level of support society is willing to pay for additional RES-e generating capacity. Another view is to look at the costs and benefits from the perspective of different actors. An actor in the power system the RES-e generator bears the long-term costs of generation (1a+b) that allow her to realise private benefits PB of RES-e generation (1d-f). As the private benefit stays with the RES-e generator, society that pays the support for new RES-e generating capacity is willing to pay support at the level of the (long-term) non-market benefits $SB-PB$ at the most. From the income perspective of the RES-e generator she will make the investment into new RES-e generating capacity when it is profitable, i.e. the expected cumulative income has to be at least as high as the long term costs of generation GC . Therefore society has to pay a support premium in order to cover the RES-e investor`s cost gap. If the support premium is lower than the aggregate non-market benefits, a net benefit remains for society (compare Figure 2-2). The level of the support premium can later on in the paper be used as benchmark for the Member States' bidding rationale in the auction.

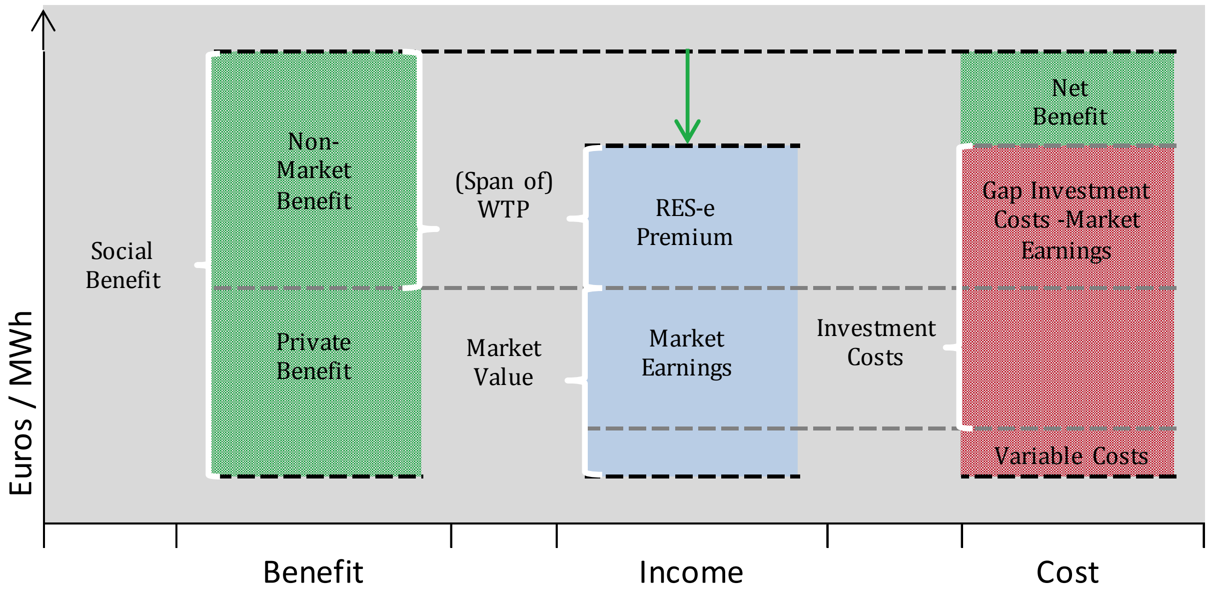


Figure 2-2: Willingness to pay for RES-e generating capacity expansion.

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

The implementation of the internal market for electricity increases the efficiency of electricity generation in the EU. While the market is capable to deliver price signals for an efficient dispatch of generating capacities (incl. curtailment of volatile RES-e) this is not the case for the longer term investment perspective of RES-e generating capacities, since their cost coverage partly still depends on additional support premium payments outside the electricity market that are not aligned across Member States. Initiatives so far to change this, such as proposals for a top-down harmonisation of support instruments or the introduction of a set of cooperation mechanism under the RES directive, however have shown little success due to various barriers and drawbacks.

In order to address these challenges and to develop efficient signals for the siting of new RES-e generating capacities we 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, considering supporting installations abroad. One metric, which in the relevant discussions at EU level mostly has been referred to as minimal requirement, is the "physical impact" RES-e generating capacity abroad has on the power system of a Member State.

In this chapter we identify two suitable metrics to measure the impact: economic benefit and economic welfare. We show that these metrics both are an accurate indicator of the physical impact and moreover are a good proxy for a range of further impacts (such as air pollution or security of supply) that are often referred to as being important in the context of RES-e generation.

Based on these metrics we propose to calculate a Benefit Distribution Factor Matrix. The matrix indicates for each Member State the impact an additional unit of RES-e generating capacity in one Member State has in all Member States. The guiding idea in this respect is that this approach allows moving away from the individual project level evaluation to the system level evaluation of additional RES-e generating capacities, 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, which had posed an important barrier so far, would be significantly lowered.

It is clear that it is not possible to perfectly predict the future development of Europe´s power systems. Thus the question arises how sensitive the results of the BDF approach react on potential deviations of assumed framework parameters. Obviously the BDF matrix will have to be updated on a frequent basis; But how often exactly? Two crucial issues play a role here. First, if the amount of additional investments in RES-e 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 deviate from forecasts being taken 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 what point an update of the BDF matrix is necessary, be it because of a significantly different RES-e investments, or unforeseen developments of framework conditions.

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 pre-requisite 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 in ERGEG (a European body of independent regulators acting as an advisory group to the Commission). 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.

3.1 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 Parliament and Council, 2009) introduced a set of cooperation mechanisms. The idea has been that two or more Member States jointly organising 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 the main reasons being high transaction costs and uncertainties about the cooperation gains. In the political negotiations about the cooperation mechanisms the uncertainty about the costs and benefits has also complicated matching the “right” trading partners, so that often national political priorities stood in the foreground, making it questionable if cooperation would lead to any efficiency gains at all.

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 (compare e.g. 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 opening their national support schemes generally were in favour of approaches that would allow for reciprocity; 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 we 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 supporting RES-e across borders. As outlined above, based on the Member States' motivations for and prerequisites of supporting RES-e installations across borders we derive two preliminary indicators for measuring the impact:

1. ***Physical Impact***: This indicator would measure the physical impact on a power system, measured as the change of the power flow and as a consequence of that in generation mixes stemming from the injection of power from an additional unit of RES-e generating capacity installed abroad.
2. ***Social Benefit***: This indicator would measure the cumulated additional net market and non-market benefits a Member State experiences from the installation of an additional unit of RES-e generating capacity installed abroad. If we recall from section 2.4 the social benefit experienced from new RES-e generating capacity determines societies' willingness to pay for it.

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

Furthermore, the impact factor shall be designed in a way to overcome the current barriers to the use of the cooperation mechanisms. The guiding idea 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, 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 its 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 project could be divided into different shares splitting up the financial responsibility between several Member States.

3.2 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 modelling tools. From Figure 2-1 we know that the impacts from RES-e generation occur in different layers. 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. We 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 we justify our recommendation.

The principle alternative to a system level approach of the impact factor calculation would be a project level approach. As already mentioned above a project level approach would not be desirable with respect to addressing the barrier of high transaction costs. Moreover we think that a systemic approach is superior when it comes to delivering more accurate results of the impact analysis. Only with a systemic approach is it possible 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 shown in Figure 2-1 in a modelling framework requires coupling a power system model with a macro economy model, a local air pollution impact model and the like. We 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 changes in capacities and power flows 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 modelled 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 discussed why it would be preferable to set the system boundaries of the cross-border impact factor at the level of the power system. We 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 generating capacity induces a power flow that displaces (conventional) generation. The value this altered power flow has to the system depends on the induced change in the net generation pattern; i.e. the change of power injections and withdrawals according to the least-cost dispatch rationale. Thus the private benefit internal to the power sector is a direct consequence of the physical impact and when the private benefit in a node increases the physical impact also increases. This will become clear from the explanations in the following sections.
- ***Non-distributional 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.
- ***Distributional effects (Employment and innovation effects)***: From the discussion in section 2.3 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 benefits from saving resources for the provision of electricity stay within the power sector and are transformed into producer and consumer surpluses; how they are shared depends on the characteristics of the specific market structure. If the node at which generation costs are lowered, were an isolated power market all the benefit would stay at this node and be split up between producers and consumers. Since the European electricity market is coupled it may however appear that benefits do not exclusively remain at the node where generation costs are lowered, but spill over up to the point where prices are equalized or transmission capacities are congested. Therefore we think that the change in producer and consumer surpluses is a plausible indicator to trace this effect as in this way also distributional effects between nodes are revealed. When consumer surplus increases as a result of lowered electricity prices this has a positive impact on the economy. When producer rents increase as result of lowered generation costs companies can allocate more financial capital to R&D activities or to increasing their workforce. Thus consumer and producer surpluses are a good

proxy for the resource effect and at the same time reveal distributional effects between nodes (economies).

- The second mode of action are the economic impulses that are spread through positive network externalities which generally are of a different nature as 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. Therefore, again the producer rent might be a good proxy to capture this re-distributional effect, since the producer surplus serves as good proxy for new economic impulses (compare above) and at the same time reveals distributional effects.

The discussion above leaves us with three options for setting the system boundaries of the impact factor (cf. Figure 3-1). From a pure cost benefit perspective option 1 is the most plausible. Given that from the perspective of Member States changes in distributional effects may be perceived as changes in costs and benefits, option 3 might turn out to be a viable one. In the further discussion we make use both of options 1 and 3 to highlight the spectrum of possible impacts.

Besides the correlation between different effects as explained above further arguments justify our approach. As can be seen from Figure 2-1 under future market design effects (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 production costs of fossil fuelled power generation. From a practical perspective moreover the following arguments apply additionally: as already mentioned above the modelling of the impact factor will most likely never fully represent the reality, but deviations will occur due to simplifications in the modelling 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 (cf. section 4.3).

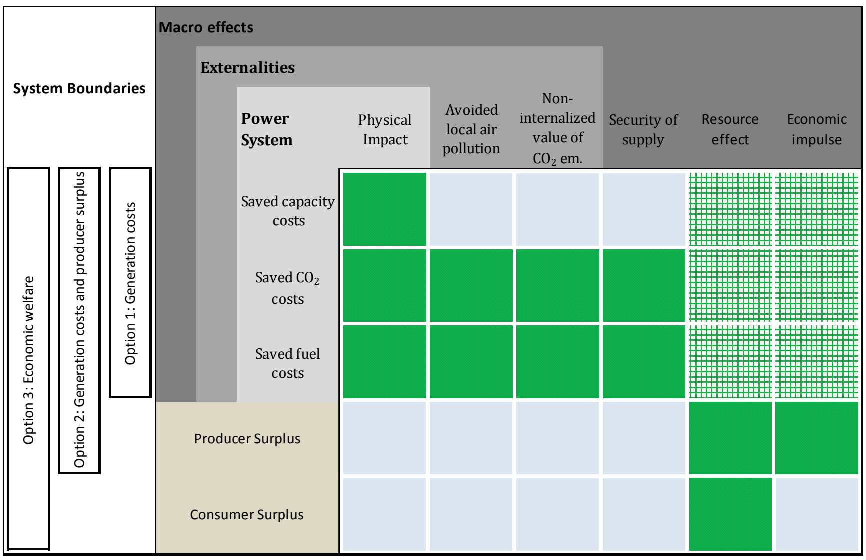


Figure 3-1: correlation between effects inside and outside the power system; solid green stands for good correlation, squared green for slight correlation, light blue is neutral, respectively not considered.

To conclude we have provided a framework for the development a cross-border impact factor. In the following we develop the impact factor 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.

3.3 The physics of electricity transmission

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 enable non-expert readers to obtain a purposeful understanding of the basic principles of electricity transmission to the extent necessary for participating in the debate of whether – and if yes, in which way – investments in RES-e generating capacity lead to "physical impacts" in Europe's power systems. Therefore, 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. Finally, we exclude all effects that do not directly impact electricity wholesale markets, i.e. we only consider active power flows, neglect transmission losses and assume that the transmission grids are operated in steady-state.

In order to get familiar with the relevant terminology we introduce the most important terms with concise definitions that are easy to understand and tailored to our application. Building on this, we will introduce four principles that govern the way electricity can be transmitted via AC grids. The consideration of these principles will help the reader to better understand the physical implications that arise from changed generation patterns in interconnected power systems like the one in Europe. The fundamental variable in power systems is power itself.

Definition – Power *is the <u>flow</u> of electricity that is released, absorbed or transmitted in every moment.*

In power systems electricity is transported through transmission grid lines or cables as directed power flows from sources to sinks. The average flow in one direction is called the active or real power flow and is measured and quantified in MW (Mega-Watts). Typical values for the maximum transmission capacity of power lines and cables in high-voltage transmission grids range from 1000 to 2500 MW.

The variable that enables power flows and which is the driver of anything is energy.

Definition – Energy *is the <u>amount</u> of electricity that is available for consumption and/or transmission.*

Energy is always positive and is typically measured and quantified in MWh (Mega-Watt-hours) in large-scale power systems. It is the cumulative sum of power flows within a period of time. When we say that electricity is generated from any source (i.e. a negative consumption) we mean that energy is converted from some primary energy carrier to electricity. 1 MWh is the amount of electricity that a constant power flow of 1 MW over 1 hour accumulates. To put this into perspective, the consumed (residential) electricity per capita ranges from 1 to 5 MWh per year in developed countries.

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 – *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.

The decisive variable to explain the size and distribution of power flows in the grid is the impedance.

Definition – Resistance and Reactance *are two parts of a measure called impedance describing the opposition against an electric current in AC transmission lines.*

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. Therefore, typical values of both parameters are specified per unit of line length.

Finally, it is important to understand the mechanism that drives a power flow through the grid. Due to the fact that we have alternating (sinusoidal) variables in AC power systems the forces that are of interest for our analysis can be traced back to phase shifts in between the time series of these variables.

Definition – *The* **Power Angle** *or transmission angle of a line is a measure proportional to the driving force of a power flow through that line.*

In high-voltage transmission grids the power flow through a line, the reactance of the line and the voltage angle are in good approximation linearly related as

$$\text{Power Flow} = 1/\text{Reactance} \times \text{Power Angle}.$$

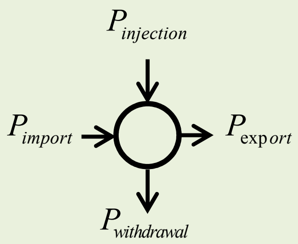
The power flow through a line is driven by imbalances of generation and demand (net generation = generation - demand) at both nodes of a certain line. A positive net generation at one node flows in the direction of a negative net generation at the other node. The power angle adjusts its sign and size according to this difference in net generations. For a constant power angle the power flow increases with decreasing reactance and vice versa.

Having clarified the relevant terms we can now formulate the four decisive principles of electricity transmission via meshed high-voltage AC transmission grids. Again, it should be stressed that the aim of describing this principles is simplicity and not an elaborated mathematical derivation including proofs. Therefore, we do not depart from the most sophisticated formulation of physical laws; rather we provide simple statements, which are sufficiently correct within the boundaries of our application.

We start with the fundamental law of energy conservation to construct the node balance within a grid. Note, that electricity storages would be *connected* to certain nodes. The charging or discharging of the storages is accounted as injections or withdrawals, respectively.

Physical principle (1) – Energy conservation: *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.*

This principle simply says that energy cannot appear and disappear from nowhere in the grid; it can only be transported through the grid from sources to sinks. 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.

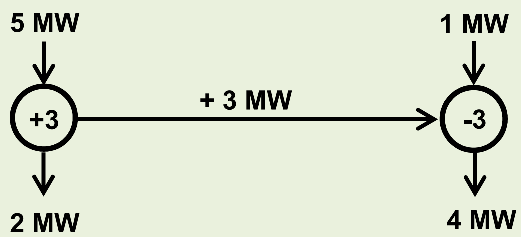


$$P_{injection} - P_{withdrawal} + P_{import} - P_{export} \overset{!}{=} 0$$

Physical principle (1) 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 is expressed within physical principle (2).

Physical principle (2) – Driver of power flows: *The power flow through a line is driven by imbalances of generation and demand (net generation = generation - demand) at both nodes of a certain line.*

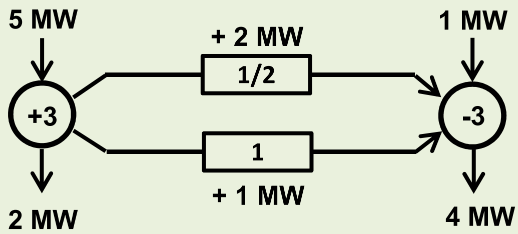
A positive net generation at one node flows in the direction of a negative net generation at the other node. An example of two nodes may illustrate this relation. Power is simultaneously injected and withdrawn from two nodes. The power injection minus the power withdrawal (net generation) is written 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. physical principle 1).



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.

Physical principle (3) – Distribution of power flows: *The power flows through lines from sources to sinks split up in proportion of the reciprocal value of their reactance.*

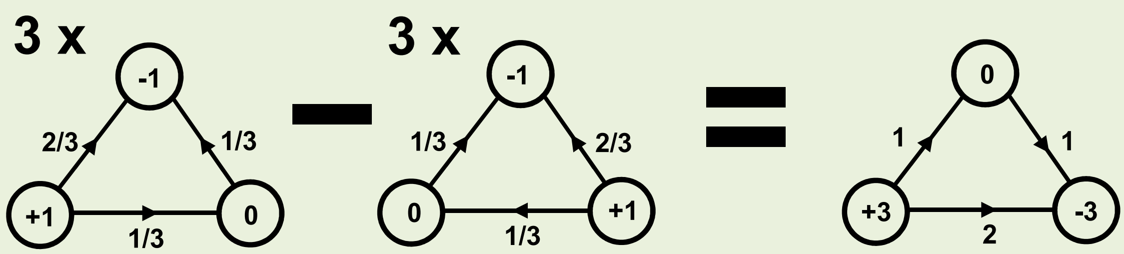
To clarify this principle we again take the example from physical principle (2) and split up the connecting line in between the two nodes in two lines. The reactances of the lines are ½ and 1, respectively (e.g. the line at the bottom could have twice the length of the one at the top). According to this 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 connected by a set of parallel lines.



The physical 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 centres. 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. In case we assume comparable technology and construction types in all parts of the grid, we see that it tends to take shorter paths more. This holds if no maximum line capacity is reached. In case a limit is reached on a certain path, power flows around the congested path over all free paths in the same logic as without congestion. However, the flow over a congested line can only be operationally limited to its upper flow limit, if an opposing power flows through the line, which is in the same size as the flow that would otherwise exceed the upper limit. This so-called congestion management in turn causes not only a flow against the congested line, but over all other lines as well. We can understand such operations as the superposition of power flows, which forms the centerpiece of all re-dispatch measures.

Physical principle (4) – Additivity of power flows: *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.*

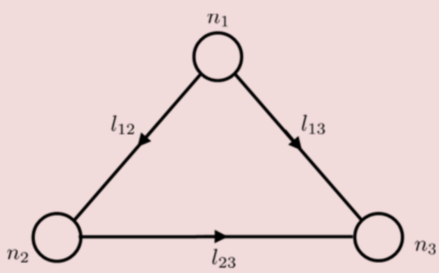
This principle embodies the resulting linearity of the underlying system equations if all simplifications for high-voltage AC grids are incorporated. It is very useful in the sense that we do not need to calculate the resulting power flows of all possible net-generation patterns, rather we need simply 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 (we call the node where we withdraw from the 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. To illustrate this principle we use a simple 3-node grid. 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 physical principle 3 (left and middle grid picture). Because 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 at the lower left node and a net generation of -3 at the lower right node, we can simply multiply the flows of both "unit" cases with 3 and subtract them from each other (cf. grid graph on the right-hand side of the equation).



The within physical principle (4) described process of "unit" injections is documented for each grid in the so-called *PTDF-matrix.* Within the framework of flow-based market coupling a simplified and frequently updated PTDF-matrix of the CWE transmission grid is currently used to determine the physical cross-zonal power flows within the market clearing algorithm.

Definition – *The* **Power Transfer Distribution Factor (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.*

We derive the PTDF matrix for the 3-node grid we used in physical 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 PDTF matrix, because all injections from the other nodes necessarily have to be balanced by the slack node to ensure physical principle (1). 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 PDTF matrix we have to agree on the orientation of power lines in the grid.



We count flows from the slack node to the lower nodes positive. Also, we 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 the left and middle grid picture in physical principle (4) into matrix form.

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

With this matrix the distribution of power flows over all 3 lines can be calculated by simply multiplying a vector of any net generation of both injection nodes with the PTDF matrix. If we perform this task for the same generation pattern as in physical 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 as we derived in the right-hand side graph of physical principle (4). Note, that we use the convention of line orientation as indicated in the grid graph in this definition; therefore we have to count $Flow_{12}$ as negative.

3.4 Welfare economics of electricity markets

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 at the cost minimal dispatch of generators that is technically feasible. The dispatch determines the changes in injections that in turn are the drivers of power flow (cf. physical principle 2); that is, power flows from the nodes with the lowest generating costs to the sources of demand where it is withdrawn. Next we first introduce some basic definitions in order to derive important principles of electricity markets.

Definition - The Merit Order Curve is a way of ranking available capacity for electricity generation, based on ascending order of price, which is determined by the short-run marginal costs of generation in a competitive environment.

Traditionally, the merit-order curve has been apportioned into three sections: base-load, mid-load and peak-load according to the capacity factor of the respective generating technologies. For instance gas power plants have a relatively low capacity utilisation as they are mostly only required to serve peak demand. In each hour the price for electricity is then determined by the intersection of the merit order and the demand curve, except for hours in which the demand surpasses the available generating capacity. The increasing penetration of RES-e generation has altered the traditional shape of the merit order curve: RES-e generation with close to zero marginal costs is ranked first in the merit order curve and displaces conventional generation capacity in particular in hours with a high availability of RES-e generating capacity.

Regarding the shape of the illustrative merit order curve shown in Figure 3-2 it should be noted that it does not include storage options and it is assumed that all forward price bids are included in the curve. Moreover the electricity demand is assumed to be static and it is only elastic for very high price levels that represent different electricity consumers' value of lost load.

Definition - The Value of Lost Load (VoLL) is a measure of the cost of unserved electricity (the electricity that would have been supplied if there had been or outage) for consumers. It is generally normalised in €/MWh. It reflects the mean value of an outage per MWh (long interruptions) or MW (voltage dips, short interruptions), appropriately weighted to yield a composite value for the overall sector or country considered. It is an externality, since there is no market for security of supply (ENTSO-e, 2015). In contrast to the economy as a whole, electricity consumers knowing their VoLL can allow the system operator to shed their loads if the price would otherwise surpass their VoLL, the difference being that the outage takes place on a voluntary basis.

The forms of the merit order and demand curves can be described by their elasticities that vary over the course of the curves.

Definition - Elasticity is an important concept in energy economics. It is used to measure how responsive demand or supply is in response to changes in another variable most commonly the price.

Therefore the elasticity depends on the steepness of the demand and supply (merit order) curves. In electricity markets the merit order curve is typically rather flat in the area of base load generation and gradually increases towards peak load generation, i.e. the elasticity is determined by the available generating alternatives in each particular segment of the supply side. Demand, in the short term, is mostly static unless for very high price that surpass the Value of Lost Load of electricity consumers. In the longer term demand is expected to become much more elastic due to new flexibility options on the demand side or real time pricing for instance.

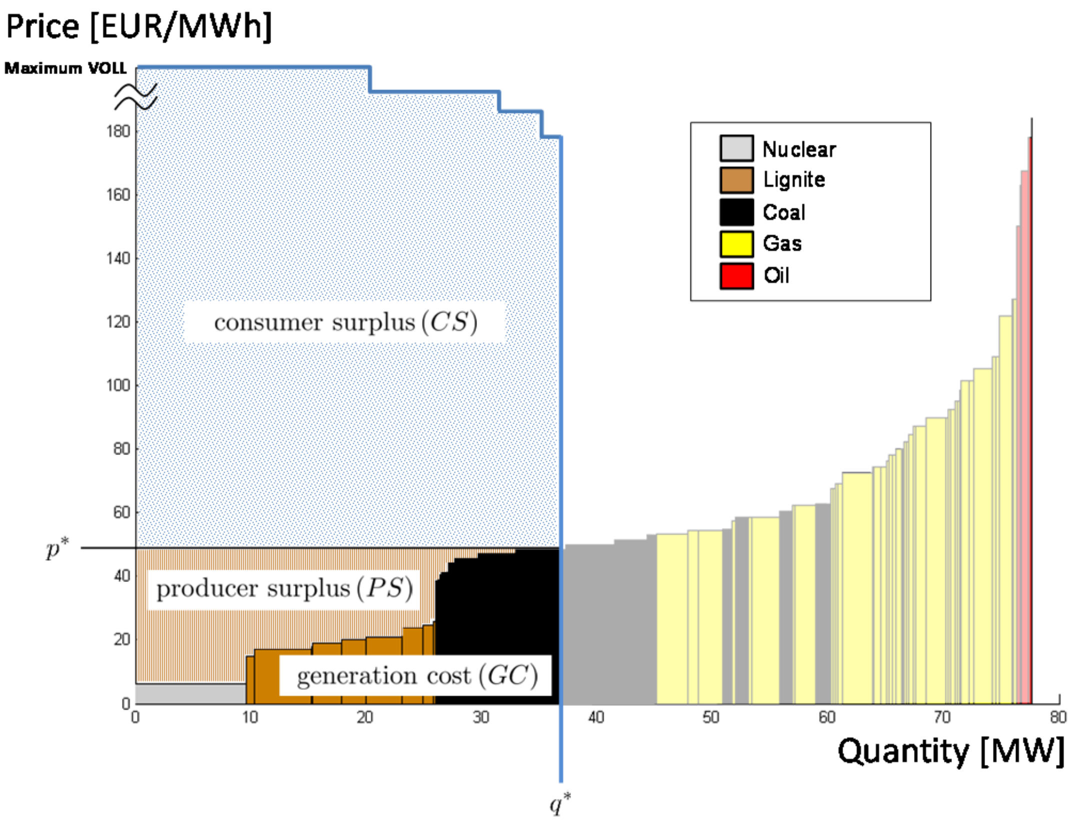


Figure 3-2: Merit order curve illustrating economic welfare metrics.

Definition – Allocative Pareto efficiency: An economic allocation is a specification of a consumption vector for each consumer and a production vector for each firm. Any economic allocation is feasible for that the total amount of each good consumed does not exceed the total amount available from both the initial endowment and production. 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 the electricity market the forms of the merit order and demand curves determine the market outcome, whereby the price of electricity acts as coordinating signal. In competitive markets Pareto efficiency is achieved in market equilibrium.

Economical Principle (1) - Market equilibrium: The system marginal price is the market signal that equates supply and demand of electricity in each hour. This comprises all cost 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.

In principle, the analysis of Pareto efficient outcomes and competitive market 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 utility generated from the consumption of the good under consideration less its cost of production and corresponds to the area lying vertically between the aggregate demand and supply curves (Mas-Colell et al., 1995). This has an important implication: **It tells us that Pareto efficiency is achieved when RES-e generating capacity is allocated in a way that the aggregate surplus is maximized.**

Definition - Economic welfare measures: The Marshallian aggregate surplus is a measure of economic welfare. The **economic welfare** in a single (isolated) market zone is given by the sum of consumer surplus and producer 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-of the costs of generation.

3.5 Economic impacts of additional RES-e generating capacity

In section 3.3 we have described the physics behind the flows of electricity. In this section we are interested in analyzing the economic impacts that are induced from these physical flows. It should be noted that the effects, which are illustrated below, have been over-pronounced by purpose for the matter of better visibility, i.e. they are not proportional to a realistic case in practice.

Precisely in this section we want to study the effect the injection of power from an additional unit of RES-e generating capacity in one node has on the change in benefit in each node. With this definition we assume that the power is provided "for free" and only the benefits induced from the additional unit of RES-e generating capacity are accounted for. Costs are neglected at this point and are factored in again at a later point by means of the cross-border auction. We measure the economic impact as the change in generation costs at each node, which corresponds to the change in private benefit.

Definition:

$$\Delta PB_n = GC_n \textit{ without additional RES-e gen. cap.} - GC_n \textit{ with additional RES-e gen. cap.}$$

From the physical principle (1) we know that the additional generating capacity`s impact on the welfare at a node can materialize through…

…the direct injection of power at a node,

…the import of power from another node,

…or a combination of both.

In the illustrations in the following we only look at the case where power is imported from another node. This does however not prevent that the interpretation of our 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 residual load at a node.

The first component we look at in Figure 3-3 are the generation cost savings. On the horizontal axis the demand curve is moved across by the volume of the import. The direction a flow induced from the injection of power at a node n takes is indicated by the PTDF matrix. The volume of the import corresponds to the sum of power flows over all lines l to a node n induced from the injection of power at a node n. Thus the change in quantity [MW] of the net import corresponds to the **physical impact**.

The benefit this physical impact has in terms of generation costs saved depends on which alternative generating capacity is displaced and thus, which resources (e.g. fuel costs, atmosphere as sink for emissions, costs of capital) are saved for the economy. In our example the net additional import of power displaces coal and lignite generating capacities, which leads to generation costs corresponding to the area highlighted below the merit-order curve being saved. In the integrated and coupled European electricity market the algorithm of the market coupler ensures that power can flow to where the (in the short term) most expensive generation options can be displaced unless limitations in transmission capacity prevent these flows (compare Appendix C), so that the overall generation costs are minimized under given constraints.

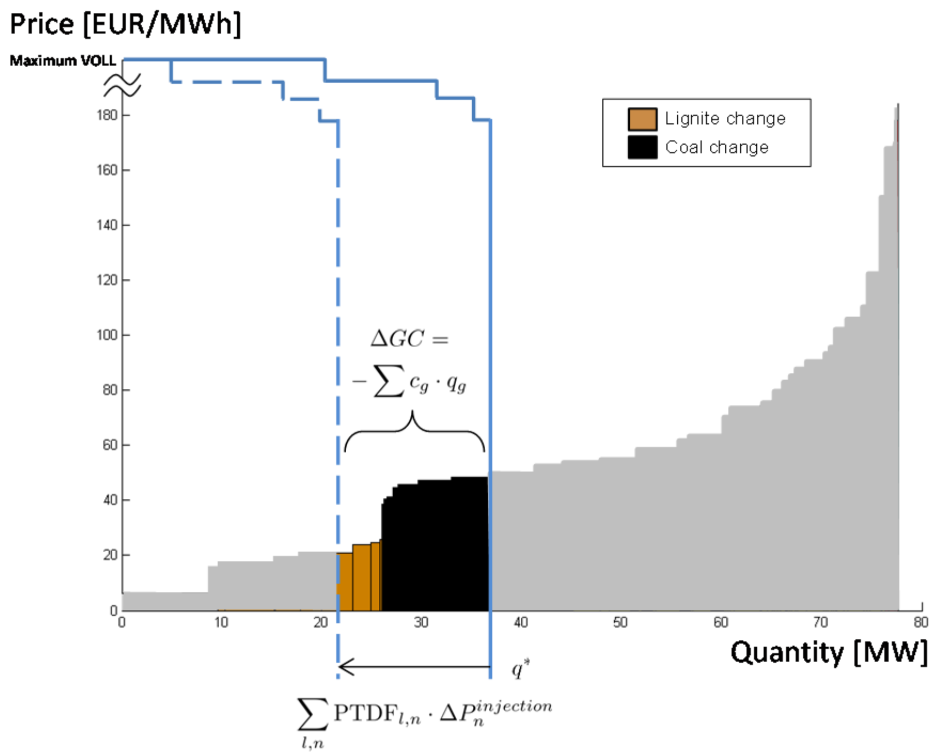


Figure 3-3: Impact from the injection of power at node n on generation cost savings at node n.

The change in generation costs answers the question of "how large is the benefit induced from the injection of power from an additional unit of RES-e generating capacity at a node n?" The follow up question then is of "who benefits from the injection of power from an additional unit of RES-e generating capacity at a node n?"

The answer is provided by economical principle (3): it says that the aggregate benefit the injection of power from an additional unit of RES-e generating capacity induces is "consumed" as changes in the rents of different actors in the power system. How the rents are shared between different actors depends on the elasticities of the supply and demand curves as can be recalled from Figure 3-2 and the extent to which generation cost savings can be passed on between market zones which depends on the available transmission capacities.

Economical Principle (3) - "Rent conservation": *The sum of generation cost savings in all nodes of the electricity market has to equal sum of surplus changes of in all nodes.*

This principle simply says that benefits generated within the power system stay within the power system and are shared by different actors, where CR refers to Congestion Rent that arises when diverging prices between market zones cannot be equalized due to a congestion in transmission capacity.

$$\sum_n \Delta PB_n = \sum_n (\Delta CS_n + \Delta PS_n + \Delta CR_n) = \sum_n \Delta Welfare_n$$

The following figures show how the injection of power at a node n has an impact on the welfare components at a node n. Figure 3-4 displays the change in consumer surplus. The import of power displaces conventional generation decreasing the marginal generation costs and thus the price for electricity from 50 € per MWh to slightly above 20 € per MWh, so that consumers can purchase the same quantity of energy at less than half the price.

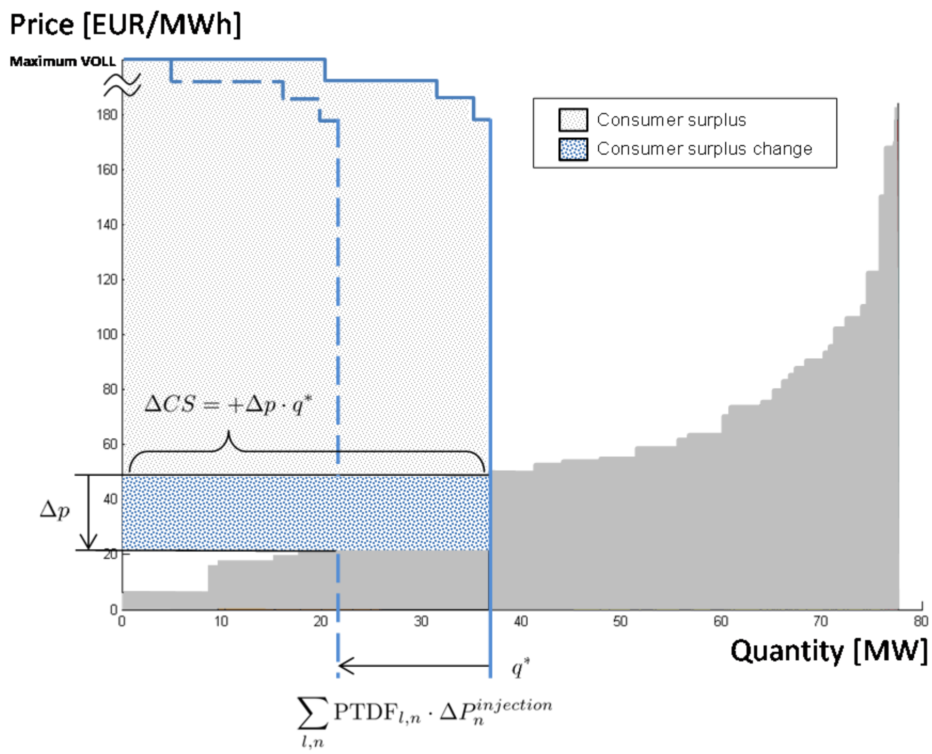


Figure 3-4: Impact from the injection of power at node n on consumer surplus at node n.

Figure 3-5 displays the change in producer surplus. Producers lose surplus not only through the reduction in price, but also through a reduction in quantity that they can generate induced by the import of electricity. It has to be noted that at node n where the additional power is injected producer surplus raises by $p_n \cdot \Delta P_n^{injection}$.

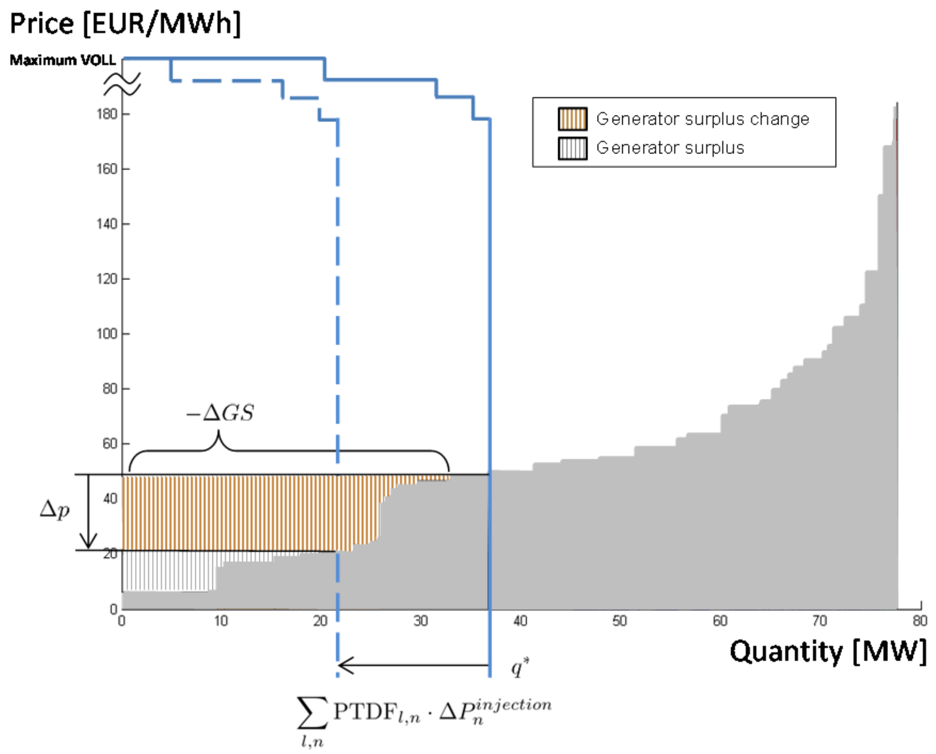


Figure 3-5: Impact from the injection of power at node n on producer surplus at node n.

Figure 3-6 displays the change in congestion rent. In the illustrations above implicitly the assumption is made that imports are not constrained by grid bottlenecks so that the quantity imported would be just high enough for prices to equalize across nodes. In this case now imports are limited to the available transmission capacity P_{flow}^{MAX} . The electricity imported only displaces marginal generation up to a price slightly below 40 € per MWh, but not to the level of price convergence slightly above 20 € per MWh. The rent from the differences between domestic and import prices stays with the operator of the interconnector reflecting the scarcity of transmission capacity. In the following examples it is assumed that congestion rents are shared in equally between nodes connected to an interconnector.

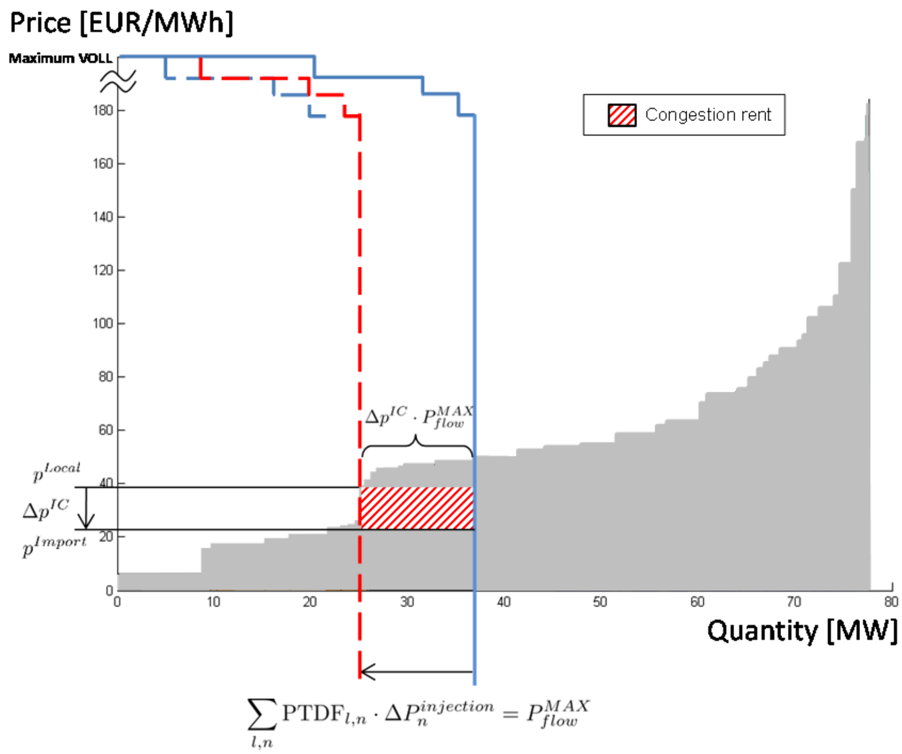


Figure 3-6: Impact from the injection of power at node n on congestion rent at node n.

3.6 The Benefit Distribution Factor Matrix

In this section we synthesize the findings so far from chapter 3 and transform them in a usable format regarding our overall objective; that is, to enable the auction for cross-border support for RES-e.

- In section 3.1 we have explained the need and rationale for a cross-border impact factor.
- In section 3.2 we have argued that the system boundaries of such a factor should be set at the level of the power system and we have identified three metrics that would serve as good proxies for the effects we are interested in to capture.
- Sections 3.3 and 3.4 provide us with the physics, engineering and economic background to derive the impact factor concept in a comprehensible way.
- Section 3.5 discusses and illustrates the impact the injection of power from additional RES-e generating capacity has on the different welfare metrics.

From section 3.2 generation costs and economic welfare emerged as two favoured metrics that plausibly unify the different components of the social benefit in a single indicator. Integrating the further findings from chapter 3 we define in the following two impact indicators. For that purpose in the following $m \in M$ refers to a "demand node", i.e. a node where a change in benefit / welfare induced from an additional unit of RES-e generating capacity materializes as change in benefit respectively welfare and that is willing to pay a certain amount of money for that. On the other hand $n \in N$ refers to a "supply node" i.e. the node where the additional unit of RES-e generating capacity that induces the changes in benefit / welfare is installed, whereby a node can simultaneously (which will often be the case) be a supply and demand node.

Definition – the **Benefit Distribution Factor (BDF)** *indicates the change in private benefit, i.e. generation costs, in a node* $m \in M$ *induced by the injection of power from an additional unit of RES-e generating capacity in a node* $n \in N$.

Definition – the **Welfare Distribution Factor (WDF)** *indicates the change in welfare, in a node* $m \in M$ *induced by the injection of power from an additional unit of RES-e generating capacity in a node* $n \in N$.

We further illustrate the idea with the help of Figure 3-7. 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 generation and consumption. In this example new generating capacity of photovoltaic power is installed at node $n1$ 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 $m1, m2, m3$ by displacing the costs of some alternative generating option (compare section 2.4). The benefits are not split evenly due to transmission constraints in the network. In this stylized example 75% of the aggregate benefit stays in Member State B , whereas the remaining share of the benefit is experienced at nodes $m2$ (20%) and $m4$ (5%). Besides PV electricity generation, additional RES-e generation comes from a windmill installed at node $n2$, which induces a benefit at demand nodes $m2$, $m3$ and $m4$. Also in this case the largest share of the benefit remains in the node $m2$ where the RES-e generating capacity is installed.

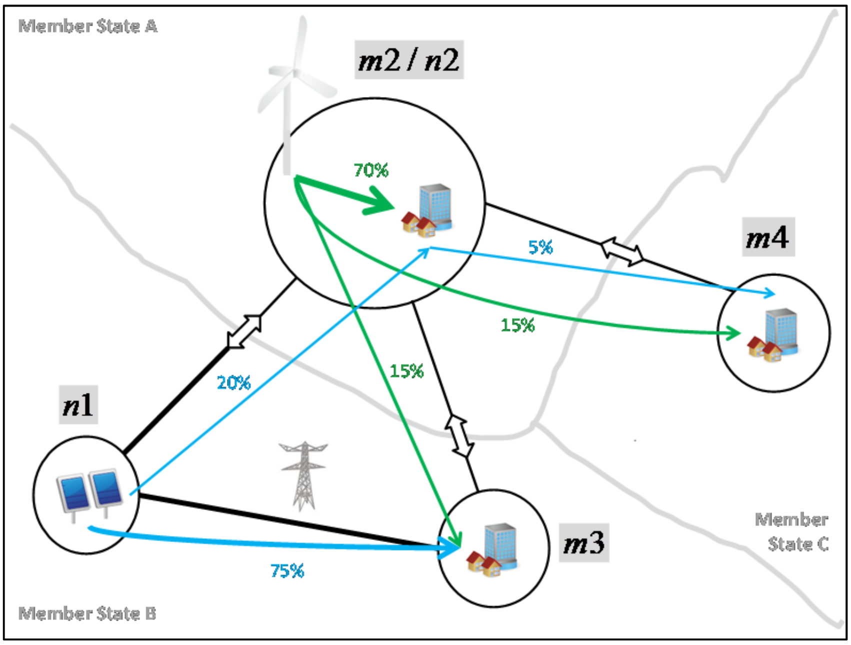


Figure 3-7: Illustration of BDF / WDF concept; Parts of figure adapted from and provided by courtesy of TenneT TSO, 2010.

From here on for the sake of clarity and since it does not impair the general concept, we assume that **nodes coincide with the territory of Member States**. Therefore each Member State represents one node, which can both be a source of supply and demand. That means m can be seen as alias of n yielding $n, m \in N = M$. 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 (cf. definition of a "node").

To recall, BDFs respectively WDFs indicate the change in benefit respectively welfare in all nodes $m \in M$ induced from the injection of power from an additional unit of RES-e generating capacity in a node n . Two further requirements for the impact factor concept have been that it should allow for reciprocity between Member States and that it should be calculated in a systemic way for each project. Therefore we propose to calculate a **Benefit Distribution Factor Matrix** (BDFM) respectively **Welfare Distribution Factor Matrix** (WDFM). Moreover as we need information on the relative distribution of benefits / welfare rather than absolute values (absolute values are generated in the auction in combination with the bid prices) the change in benefit respectively welfare in node m is expressed relative to the change in the sum of all nodes $m \in M$ and normalized to the range $[0,1]$. Equations (1) and (2) display the corresponding matrices.

$$BDFM_{n,m} = \begin{pmatrix} \frac{BDF_{A,A}}{\sum_m BDF_{A,m}} & \cdots & \frac{BDF_{A,m}}{\sum_m BDF_{A,m}} \\ \vdots & \ddots & \vdots \\ \frac{BDF_{n,A}}{\sum_m BDF_{n,m}} & \cdots & \frac{BDF_{n,m}}{\sum_m BDF_{n,m}} \end{pmatrix} \quad (1)$$

$$WDFM_{n,m} = \begin{pmatrix} \frac{WDF_{A,A}}{\sum_m WDF_{A,m}} & \cdots & \frac{WDF_{A,m}}{\sum_m WDF_{A,m}} \\ \vdots & \ddots & \vdots \\ \frac{WDF_{n,A}}{\sum_m WDF_{n,m}} & \cdots & \frac{WDF_{n,m}}{\sum_m WDF_{n,m}} \end{pmatrix} \quad (2)$$

In the following chapters we use the BDF matrix concept for further illustration; however it has become clear from this chapter that the WDF matrix concept could be used interchangeably. An alternative would be to use a composite indicator constructed from both the BDF and WDF matrices. In this case Member States in addition to their bid prices also could submit weights in order to split up the shares between both types of matrices. This is however subject to further research.

3.7 Example: assessing physical and monetary impacts of RES-e in a 3-node model

The aim of this section is to demonstrate the above described impacts of additional RES-e generating capacity on power systems (cf. section 3.4) 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, we describe the parameter settings and assumptions of the model. Then we provide an overview on the scenarios we model. Finally, we discuss the results of three selected scenarios in detail to foster the qualitative understanding of all involved interrelated impacts. A detailed overview of the results from all scenarios can be found in the Appendix B.

In Figure 3-8 a schematic overview of the simple grid model we use to study the impacts is illustrated. The topology and orientation of the grid lines is the same as in Definition – The PTDF matrix. All the grid lines have a normalized reactance of 1. Therefore, the same PTDF matrix as derived in the definition, including the logic of deriving power flows, is valid for this model. We 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.

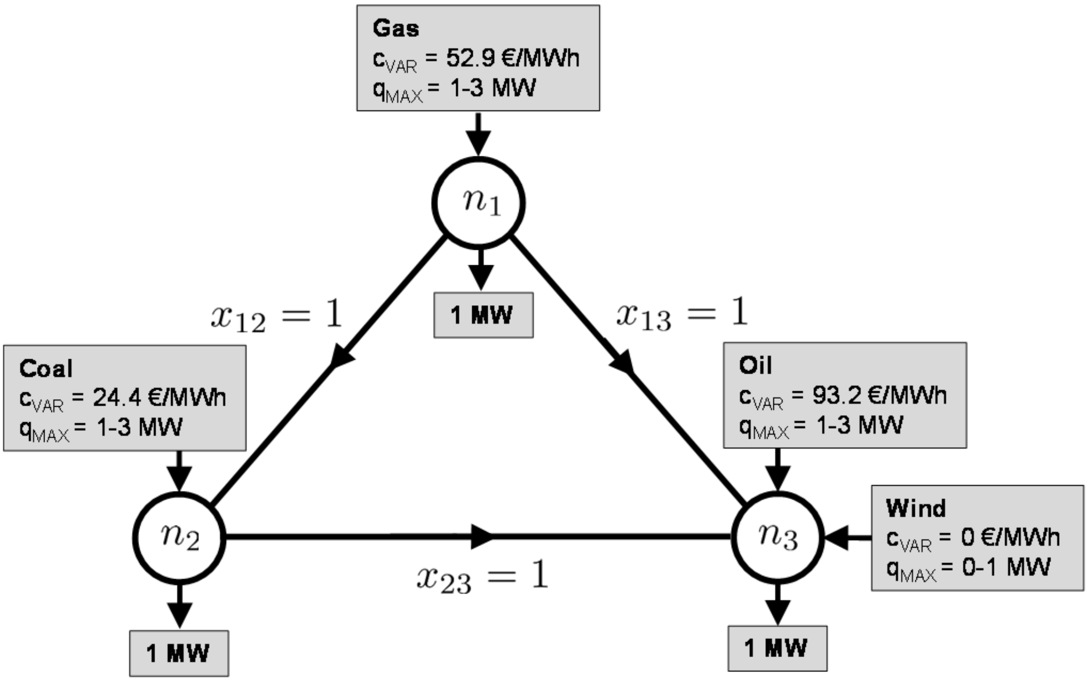


Figure 3-8: Simple grid model to study impacts of additional wind generation.

In all scenarios we 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 averaged result of single time steps (see more details in section 4.3). To study the impact of additional infeed from RES-e generating capacity we connect a wind generator at node 3. First, we start a model run without any wind infeed. From that we derive the benchmark values for our variables of interest for the working point. Then we inject an additional wind power of 1 MW into node 3 and 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 infeed. Note, that this is a relatively high change in RES-e infeed as compared to the load. However, this enables us to see the effects more clearly. In the subsequent sections the amount of additional RES-e generating capacity will be defined more clearly.

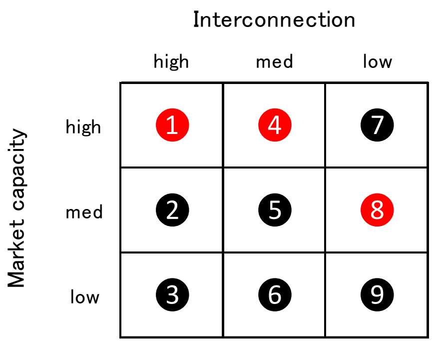


Figure 3-9: Modelled scenarios in the impact assessment. The scenarios marked in red are described in detail.

Figure 3-9 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 we first limit the maximum transmission capacity of line n1-n2 to 0.5 MW and then additionally the capacity of line n2-n3 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 grouped 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 2-1 summarizes the maximum capacity of generations and lines for the three scenarios.

Table 3-1: Parameter setting in selected scenarios.

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

All scenarios consist of two time steps, one before (the working point) and one after the infeed of one (additional) MW (additional) from wind power into node 3. The impacts are ex-post calculated as difference of generation costs and welfare between these two time steps. The resulting power flows are marked in red. Within each node the difference between generation and demand (net generation) is displayed in blue colour. In the following the results of the three scenarios are interpreted in more detail.

3.7.1 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. This net generation must be exported from the node (cf. physical principle 1). In our 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 l23-l13 and l12. By applying physical principle (3) we already know that the flow over l12 will be twice as high as over l23-l13 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 l12 and 1/3 MW over l23-l13. In case of flow n2-n3 the portioning is the other way around: 2/3 MW flows over path l23 and 1/3 MW flows over path l12-l13. 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 l12 and l23 add up to 1 MW and the flows over l13 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 n2 and n1. This results in an electricity flow from n2 to n1, which flows as argued before with 2/3 MW over l12 and 1/3 MW over path l23-l13. That means in the case of no grid congestions 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 the grid acts as if it was not there.

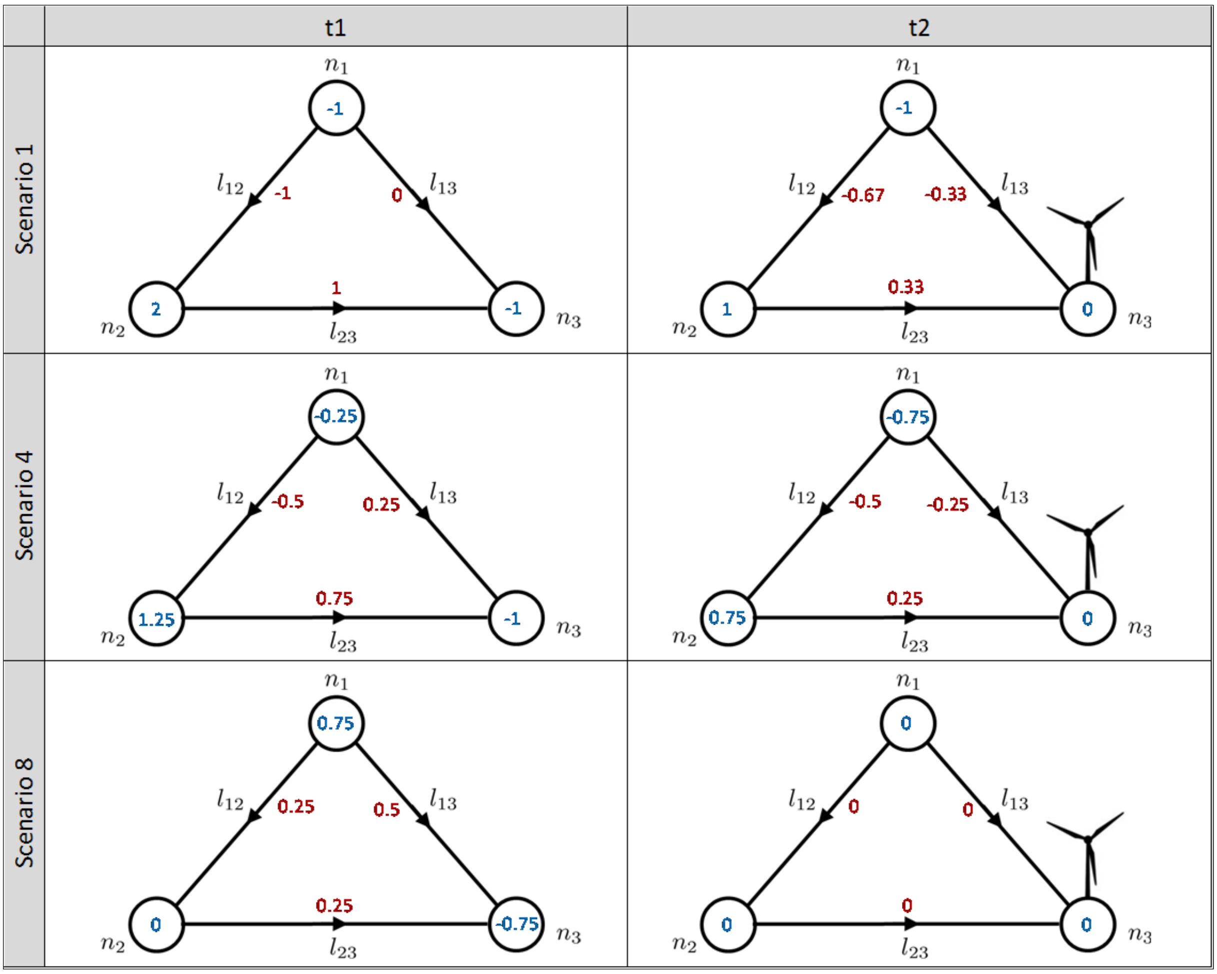


Figure 3-10: Resulting power flows and net generation in selected scenarios for two time steps (one without and one with 1 MW additional wind infeed in node 3).

Scenario 4 restricts line flow l12 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 n3. The situation changes in time step 2, where n3 is self-sufficient due to additional wind infeed. This relieves the gas generator since 0.75 MW from coal can now flow to n1. Because of the flow limit on l12, 0.5 MW from this share can flow over l12 and 0.25 MW over l13. The remaining demand of 0.25 MW has to be covered locally by the gas generator connected to n2. 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 n2. The second cheapest unit, namely gas on n1, transports some share of power over l12 and l12-l23. Due to grid congestion on l13 it can only transport a maximum of 0.75 MW to n3 and the oil generator is needed to cover the remainder. When additional generation from wind is injected into n3 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, we 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 of additional generating capacity from RES-e 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.

3.7.2 Economic impacts

3.7.2.1 Impacts on generation costs

The value of additional generating capacity from RES-e can be quantified through different measures. One decisive variable is the change in generation costs. We 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[8]. 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 happens where generation is replaced. Note, that in scenarios 1 and 4 the share of cost reduction in the “wind node” n3 is zero. The share of costs depends on the amount and cost of generation, which has been replaced (cf. economic principle - elasticities). 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” n1 is higher.

[8] Note, that an additional wind infeed at n1 or n2 in scenario 4 and 8 would actually exacerbate the prevailing congestion and thus would lead to increasing generation costs and thus negative BDFs.

Table 3-2: Impact of additional RES-e infeed on generation cost savings and its distribution.

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%

3.7.2.2 Impacts on consumer rents

An economic value of additional RES-e generating capacity exists for consumers in case electricity prices decrease and thus the consumer surplus increases. Due to the fact that we assumed a constant electricity demand of 1 MW at each node the change in consumer surplus corresponds to the change in electricity prices at each node. 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 l12 in between coal and gas is present. This leads to different electricity prices in all nodes. In n2 coal is price setter, in n1 it is gas and in n3 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 n3 would be served as 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 n1 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 n2 is supplied by a mix of gas and oil (because the flow on l13 and coal generation is already on its limit) in time step 1 and solely by coal in time step 2. In n3 oil is price setting in time step 1. After wind infeed in time step 2 oil is replaced and the price in n3 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 infeed times 1 MW. We 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 infeed might decrease generation costs, it does not necessarily mean that also electricity prices and consumer rents are influenced.

Table 3-3: Impact of additional RES-e infeed on consumer rents.

Scenario 1			Scenario 4			Scenario 8		
Change in 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

3.7.2.3 Impacts on generator rents

In contrast to welfare improvements for consumers decreasing electricity prices induced from additional RES-e generating capacity might 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 infeed at n3 receives a generator rent in the height of the prevailing electricity price at this node in time step 2.

Table 3-4: Impact of additional RES-e infeed on generator rents.

Scenario 1			Scenario 4			Scenario 8		
Change in 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

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. We conclude that generator rents are influenced by national 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 appears in the congestion rents that are collected and distributed among the involved transmission system operators in charge.

3.7.2.4 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 adjacent TSOs is 50/50. We follow this convention and allocate half of the congestion rent to each connected node.

Table 3-5: Impact of additional RES-e infeed on congestion rents per node (congestion rents per line have been evenly allocated to the connected nodes).

Scenario 1			Scenario 4			Scenario 8		
Change in 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

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 l13 is not on its upper limit an additional flow is blocked by the congestion between l12. Because there is a price difference between n1 and n3, 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[9]. However, we are interested in a change of congestion rents before and after the wind infeed. For a better interpretation of the results in Table 3-6 we additionally provide the change of congestion rents per line. It can be seen that the congestion rent over l13 increases and the one over line23 decreases at the same amount. Due to the fact that price levels in each node remain

[9] Note that this does not lead to distorted incentives for grid expansion. The marginal investment costs are not counterbalanced by a marginal benefit (increase in the congestion rent of the line), as additional line capacity do not relieve the grid congestion elsewhere in the grid. However, the switch from NTC-based to flow-based market coupling might lead to additional revenues for the involved TSOs.

constant during the two time steps these rents are the result of smaller line flows over path l23-l13 because of the additional wind infeed. 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.

Table 3-6: Impact of additional RES-e infeed on congestion rents.

Scenario 1			Scenario 4			Scenario 8		
Change in Line Congestion Rent [€]								
l12	l13	l23	l12	l13	l23	l12	l13	l23
0.00	0.00	0.00	0.00	7.13	-7.13	-5.04	-20.15	-5.04

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. We conclude that grid congestion might lead to shifts in rents between consumers, producers and TSOs that can occur in all directions. The core of the proposed methodology in this paper is to explicitly quantify these effects.

3.7.2.5 Summary of impacts from additional RES-e generating capacity

Finally, Table 3-7 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 different nodes.

Table 3-7: Summary of impacts of additional RES-e on generation costs and welfare

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		

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 (cf. section 3.2). This suggests that besides generation cost savings also surplus changes should be incorporated in the cross-border impact factor if employment and innovation effects were given a high political priority. Lastly we 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 (cf. Economical Principle (3) - “Rent conservation”).

3.8 Robustness of the BDF matrix for different system states and modelling implications

So far we have been referring to **an additional unit** of RES-e generating capacity in order to calculate the delta, but we haven´t further specified what the size of the additional capacity would be. Precisely the additional capacity is determined in the EU cross-border auction.

Therefore we see two principal approaches and one alternative option to determine the change in RES-e generating capacity in order to derive the BDF matrix:

1. ***Sequential approach***: One could argue that the additional capacities are implicitly already included in scenarios of the future development of the power system (cf. section 4.2), as scenarios in a way reflect future changes in RES-e policy design. In this case we would calibrate the power market and network model according these scenarios and calculate the change in benefits for a marginal change in RES-e generating capacity. The BDF matrix that would then be passed on to the auction would be a constant parameter.
2. ***Integrated approach***: Endogenous BDF matrix calculation by including it in the optimisation problem of the auctioneer. This would constitute a bi-level problem between the first and the third stage in the auctioning game (cf. section 5.4). The lower stage would be modelled by market- and network models as used in the TYNDP, 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, which would write as shown in Appendix D[10].
3. ***Decentralized approach***: The third approach differs from the remaining ones in so far that the derivation of the BDF matrix would be decentralized instead of being integrated into the centralized TYNDP cost benefit analyses. One could allow Member States to set bid prices for capacity from every node, instead of a single bid price and submit this parameter to the auctioneer. 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 BDF matrix, i.e. effects that do not entirely depend on the spill-over of benefits.

The third approach would not require a centralised modelling approach, but would instead put the burden on the Member States again to determine their costs and benefits from new RES-e generating capacity at different nodes. It would therefore lack methodological foundation and consistency as well as the property of reciprocity and is therefore not recommended within the framework of this paper by the authors. The first approach would be less complex from the modelling perspective, whereas the second approach could be more exact[11].

[10] It is envisaged by the authors to provide a thorough description of and solution to the 2-stage problem elsewhere.

[11] A more comprehensive assessment comparing the suitability and pros and cons of both modelling approached is planned to be provided by the authors in forthcoming work.

Table 3-8: Modelling approaches for calculating the BDF matrix.

	Sequential approach	**Integrated approach**
Stage I	EU-wide cross-border auction	EU-wide cross-border auction
Information exchange	BDF Matrix ↑	BDF Matrix ↑ Installed Capacity ↓
Stage II	Power Market and Network Model	Power Market and Network Model

3.9 Sequential modelling approach

In this section we describe the procedure to derive the BDF matrix in the sequential approach. We argue that this can be a valid representation of reality as long as the superposition principle holds.

Definition: 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 A produces response X and input B produces response Y then input (A + B) produces response (X + Y).

For the calculation of the BDF matrix this means the following:

$$\Delta PB_{n,m}\left(\Delta P_{n1}^{injection}+\Delta P_{n2}^{injection}\right)=\Delta PB_{n,m}\left(\Delta P_{n1}^{injection}\right)+\Delta PB_{n,m}\left(\Delta P_{n2}^{injection}\right)\quad \forall \quad n,m. \tag{3}$$

The change in benefit at a node m induced from the injection of an additional unit of power at node n stays the same, whether additional injections take place isolated or simultaneously, which means that the effects 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 net injections at single nodes, so that the BDF matrix can feed as parameter into the auction. This approach would be justified as long as the superposition principle holds. The superposition principle holds if the effect of additional net injection on the change in benefit can be assumed to be approximately linear.

Hypothesis (1) – The effects from net additional injections in nodes n on the change in benefit in node m are sufficiently linear - for intervals defined by quantities relevant for the auction - in order to assume additivity.

We will argue next, why the necessary condition of (approximate) linearity could be a plausible assumption: The general line of reasoning goes like this:

- We postulate that the merit order curve generally follows a convex shape
- The working point of the merit order curve when RES-e feed-in takes places will usually be in the flat, near linear section of the curve.

- The deviation from the working point induced from the RES-e power injection is low, 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 (compare Figure 3-2). We do however raise the hypothesis that the infeed 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 has a high availability. The existing RES-e generating capacity displaces peak load generation such as gas, which is pushed out of the market, which leads to an overall lower supply elasticity of the merit order curve.

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. One aspect that warrants further consideration in this respect is the question how the future shape of the merit-order curve will develop given the changes in the mix of the generating portfolio.

Furthermore we argue that the deviations from the working point induced from the injection of power from the additional RES-e capacity are likely to be small, since the newly installed RES-e capacities through the auction would account only for a rather small fraction compared to the already existing and yet to be installed generating capacities outside the auction.

We also assume that Member States will deploy new RES-e capacities somehow in proportion to their overall electricity demand and the additions of new RES-e capacities will be allocated to a timespan of several years (2021-2030).

Therefore we propose to determine the impact a power injection from additional RES-e generating capacity as marginal change, as shown in eq. (4).

$$\frac{\partial PB_{n,m}\left(P_n^{Injection}\right)}{\partial P_n^{Injection}} \tag{4}$$

4 Practical implementation of the BDF matrix

The calculation of the BDF matrix requires a large dataset of the European electricity system and competence in costs benefits analyses and electricity network and market modelling.

We propose to hand over this responsibility to ENTSO-e and to integrate the calculation into the TYNDP creation process which would bring along several advantages: First of all the required methods and datasets are already available within this process. This would also ensure that the dataset is consistent across the EU and transparent. This is important because 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, 2015), which would likely have a significant effect on the spill-over of benefits. The BDF matrix would then be calculated for a range of varying conditions reflecting plausible future system states and these values would be merged into a single matrix that gives a good indication of the average spill-overs.

The Brazilian auction for generating capacity, is an example for an existing mechanism that combines an auction format with benefit measures in order to compare projects with different cost structures (Bezerra et al., 2011). In this case the calculations of the cost-benefit-index are carried out by the government's company for planning studies, EPE.

Next we ask the question what the BDF matrix means for the willingness to pay for new RES-e generating capacity of a Member State. As we already know the benefit a Member State enjoys from an additional unit of RES-e generating capacity strongly depends on at which node in the network the additional RES-e generating capacity is connected to the grid and offered to the market. This in turn means that the willingness of a Member State to pay for additional RES-e generating capacity needs to be differentiated by node. Precisely the willingness to pay at a supply node of RES-e generating capacity is weighted with the BDF matrix in order to indicate a Member State´s willingness to pay at this node.

As described above the BDF matrix indicates the change in private benefit, i.e. generation costs, in a node $m \in M$ induced by the injection of power from an additional unit of RES-e generating capacity in all nodes $n \in N$ at any one time for a given system state. It is evident that the values the different matrix elements of the BDF matrix take are sensitive to the input parameters used to calculate the BDF matrix. The challenge therefore is to come up with a parameterization of the BDF matrix that is representative for a range of future systems states and system development scenarios. Next we introduce additional indices that allow calculating the BDF matrix for different system states and explain the rationale behind them. We then explain which dataset could be used to calculate the BDF matrices and how a representative BDF matrix could be calculated as weighted average of the different system states. Finally we present an illustrative example of a BDF matrix calculation and discuss the meaning of the BDF matrix for the willingness to pay, which is the link to the cross-border auction.

4.1 Operationalizing the BDF matrix for different states of the system

Table 4-1: New indices added to the BDF matrix

$r \in R$	RES-e generating technologies
$h \in H$	Hours of a year
$y \in Y$	Years
$s \in S$	Scenarios

Table 4-1 contains the additional indices that are added to the BDF matrix in order to express different states of the system. The indices will next be introduced in sequential order.

First of all we argue that the BDF matrix should be calculated as a technology specific factor. We therefore introduce an index set that specifies the BDF matrix for each RES-e generation technology $r \in R$. This is plausible, because different RES-e generating technologies in different nodes of a network have diverging generation profiles and calculating an average BDF value would disregard and average out these differences.

Moreover we introduce a set $h \in H$ so that the BDF matrix can be calculated for each hour of a year. This is required, because the state of the system (shape of demand profile, availability of generation technologies) differs across hours, which is reflected in a differing private market value (private benefit) and thus considering only one single hour would be arbitrary.

Next we introduce the set $y \in Y$ that assigns the BDF matrix to different years. This is required, because a change in dynamic parameters, such as fuel costs, affects the level of spill-overs and thus the parameterization 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.

Finally we introduce an index $s \in S$ that indicates a range of possible scenarios for the development of the electricity system. This is required because the future is uncertain and different scenarios refer to different plausible future developments of input parameters.

4.2 Parameterization of the BDF matrix

We propose to integrate the calculation of the BDF matrix in the creation process of the TYNDP (ENTSO-e, 2014). For the cost benefit analyses conducted under the TYNDP the same tools and datasets are used that would also be needed for the calculation of the BDF matrix as described above. In the TYNDP a combination of market and network studies is used that could also be integrated into one model. The basis for the TYNDP 2014 analyses have 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 (compare Figure 4-1).

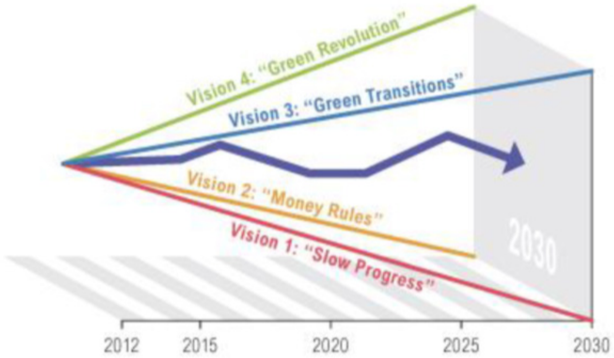


Figure 4-1: Visions under the TYNDP 2014, source ENTSO-e 2014.

The span of the four visions is large to meet the various stakeholder expectations. The visions mainly differ with respect to:

- 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 datasets are already available within this process. This would also ensure that the dataset is consistent across the EU and transparent. The latter is important, because the values assigned to the BDF matrix from the calculation will have an impact on the outcome of the mechanism as will be shown below, thus 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, 2015), which would 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 values of the BDF matrix and therefore provide locational signals for the siting of new RES-e generating capacities.

4.3 Deriving a representative BDF matrix

How the TYNDP could be used to calculate a representative BDF is illustrated in Figure 4-2 for the example of a wind power plant. Though the approach explained here may not be the most suitable statistical method for our problem at hand, it is however simple and serves to illustrate how the system dynamics could be represented in a single BDF.

A BDF would be calculated for each hour in two different years 2015 and 2025 so that each BDF would indicate the changing conditions within the operating lifetime of a wind power plant that is installed today. Thus for the year 2015 the indices of the $BDF_{s,y,h,r,n,m}$ would take the following attributes: $s = 0,\ y = 2015,\ h = [1,8760],\ r = windpower$. For the year 2025 the following attributes would change: $s = [1,4]$ (corresponding to the four visions “Slow Progress”, “Money Rules”, “Green Transitions” and “Green Revolution”), $y = 2025$.

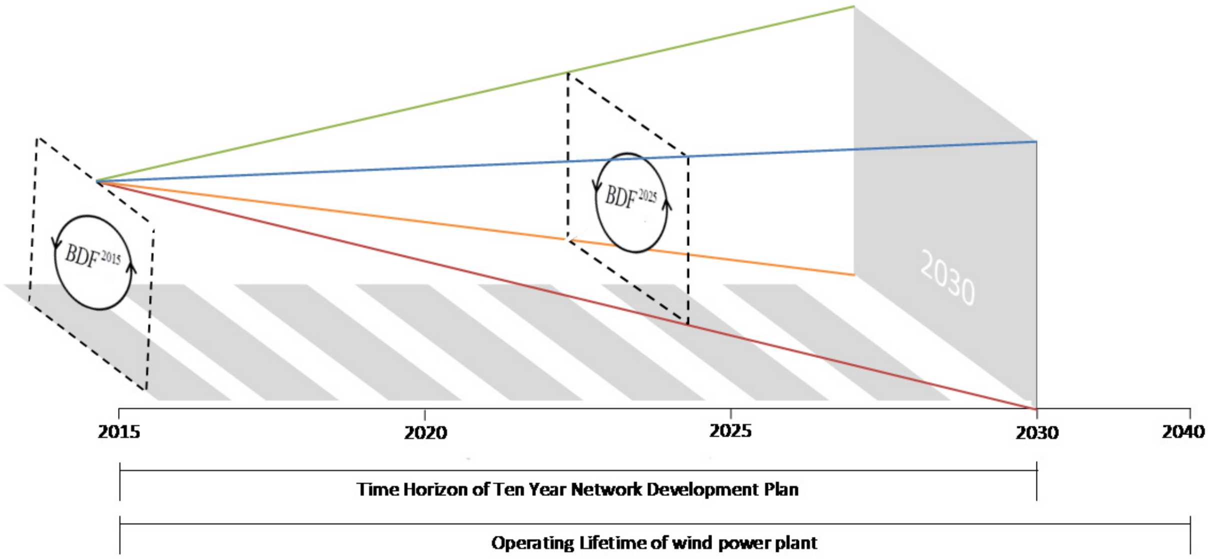


Figure 4-2: Example of Integrating the BDF calculation into the TYNDP process for wind power.

Once the different BDFs have been calculated the next step is to consolidate them into one representative BDF. This single BDF should give a good indication of the distribution of benefits over the lifetime of a plant. The calculation could be conducted as shown in eq. (5). For a given year the BDF would be calculated for each of the 8760 hours (or some plausible subset) and from these values the average would be taken as a representative value for the respective year. With respect to yearly dynamics we would 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 %. In sum these operations would yield a technology-specific BDF that indicates the average change in benefit in all nodes $m \in N$ induced from the injection of power from an additional unit of RES-e generating capacity installed in zone n and that is representative with respect to different states of the system in the present and in the future.

$$BDF_{r,n,m} = \frac{\sum_{h\in H} BDF_{s0,y,h,r,n,m}}{8760}\cdot 0,5 + \sum_{s\neq s0}\begin{pmatrix} \frac{\sum_{h\in H} BDF_{s1,y,h,r,n,m}}{8760} & \frac{\sum_{h\in H} BDF_{s2,y,h,r,n,m}}{8760} \\ \frac{\sum_{h\in H} BDF_{s3,y,h,r,n,m}}{8760} & \frac{\sum_{h\in H} BDF_{s4,y,h,r,n,m}}{8760} \end{pmatrix}\cdot\begin{pmatrix} \frac{1}{8} & \frac{1}{8} \\ \frac{1}{8} & \frac{1}{8} \end{pmatrix} \qquad (5)$$

4.4 An illustrative example

In this section we illustrate the calculation of the BDF in a practical example. Thereby we apply the "Take Out One at the Time" (TOOT) method (ENTSO-e, 2015) for project assessment. "The TOOT method provides an estimation of benefits for each project, as if it was the last to be commissioned. In fact, the TOOT method evaluates each new development investment/project into the whole forecasted network. The advantage of this analysis is that it immediately appreciates every benefit brought by each investment, without considering the order of investments. All benefits are considered in a precautionary way, in fact each evaluated project is considered into an "already developed" environment, in which are present all programmed development projects and are reported conditions in which the new investment shall operate. Hence, this method allows analyses and assessments at TYNDP level, considering the whole future system environment and every future network evolution".

The benchmark values for the allocation of RES-e generating capacities are derived from a Green-X scenario (Resch et al., 2015) that reaches the EU wide target of 27% renewable energy production with a corresponding RES-e share of about 47%

Next we calculate scenario runs and a baseline run against which the scenario runs are evaluated. In the baseline run the model is calibrated according to the Green-X capacities that achieve the EU 2030 target. In the scenario runs – in sequential order – at each node generation from wind onshore is reduced by a certain fraction of hourly electricity demand. The reduction at each node is iterated in a range of [1,3] % of electricity demand in steps 0.2 percentage points. The iteration of reductions is performed in order to get some first insights whether the validity of the superposition principle (cf. Definition: The Superposition Principle**)** for certain ranges of RES-e expansion corridors can be assumed.

The outcomes of this exemplary calculation[12] are presented in Figure 4-3 and Figure 4-4. From Figure 4-3 it can be observed that the largest share in benefit from additional wind onshore generation in Belgium is also consumed in Belgium. This share is however significantly below 50% and more than 50% of the benefit is consumed in other European Member States, whereby the data reveals that spill-overs generally increase towards the end of the lifetime of a wind power plant due to (i) an increase in interconnection capacities and (ii) the fact that new wind onshore capacity is added to an already increased socket of wind onshore capacities with a similar feed-in profile, which increases the likelihood for electricity exports. This also demonstrates also the increasing European dimension of RES-e support, which demands for a better coordination of RES-e support across Member States.

[12] These outcomes have not yet been reviewed in depth and should therefore be interpreted with caution. A description of the applied modelling approach will be presented in Busch et al. (forthcoming). A possible approach to consider flow-based market coupling in market models for the purpose of cost-benefit analyses in presented in Appendix C.

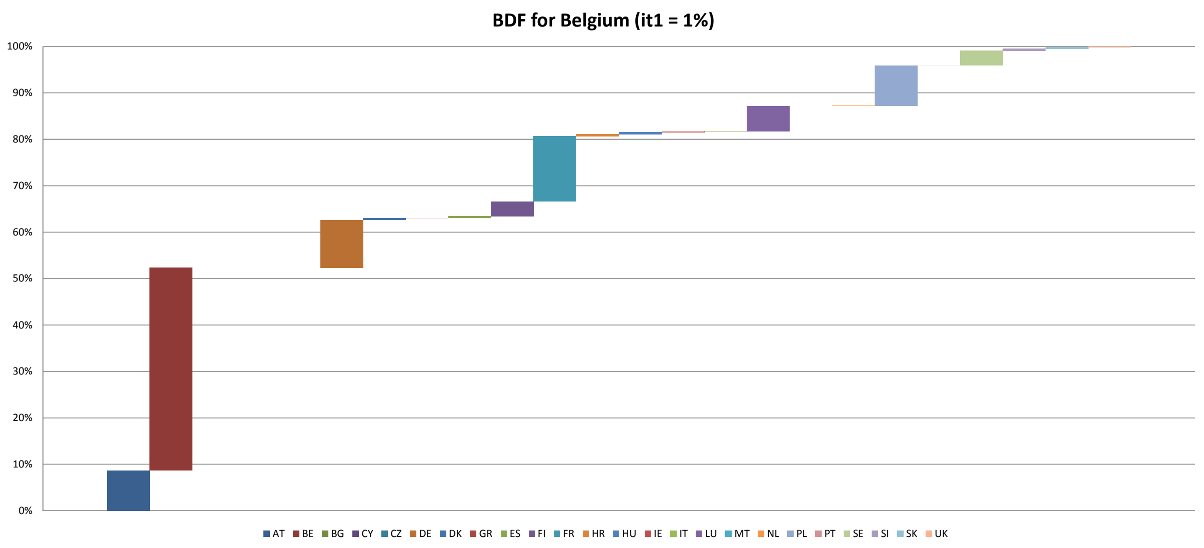


Figure 4-3: BDF for Belgium: generation from wind onshore is reduced at a rate of 1% demand compare to baseline case.

Next Figure 4-4 displays the change in the BDF for a variation in the reduction of wind onshore generation in a range between 1% and 3%. It can be observed that the BDF does not change a lot. Besides small variations in benefit shares of different Member States another trend is a gradual, albeit small, increase in benefit share for Ireland and United Kingdom for increasing levels of generation reduction. Overall this figure gives a first indication that the BDF could stay stable for at least small ranges of RES-e generation increases at one node.

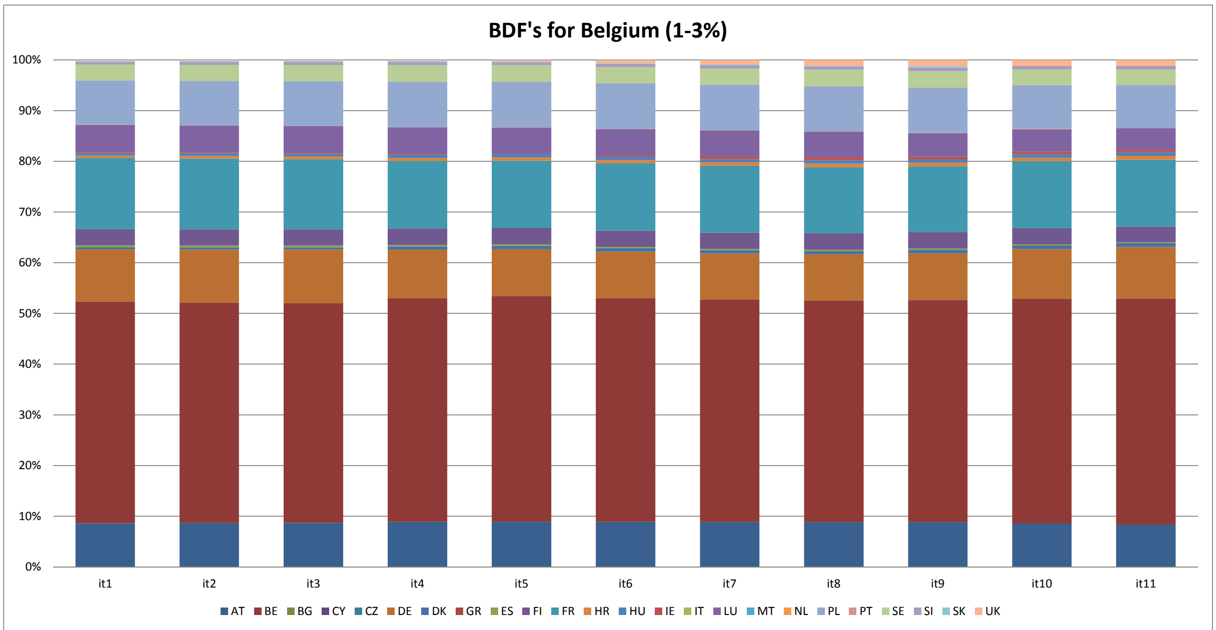


Figure 4-4: BDFs for Belgium: generation from wind onshore is reduced at rates of 1-3% demand compare to baseline case in intervals of 0.2 percentage points.

4.5 Implications for willingness to pay

The objective of this section is to bring together the findings of section 2.4 and chapters 3 and 4. So far we have discussed the willingness to pay from a "national" perspective; that is, a situation where a Member State supports additional RES-e generating capacity domestically. Now equipped with the background from chapter 3 we can generalize the concept of willingness to pay to a system of multiple nodes in an interconnected system. From Figure 2-2 above we know that the premium [€ per MWh] of supporting RES-e domestically can be seen as an upper limit that Member State $m \in N$ would be willing to pay for an additional unit of RES-e generating capacity in the EU cross-border auction. However as we also know from chapter 3 the benefit Member State $m \in N$ enjoys from an additional unit of RES-e generating capacity strongly depends on at which node in the network the additional RES-e generating capacity is connected to the grid and offered to the market. This in turn means that the willingness of Member State $m \in N$ to pay for additional RES-e generating capacity needs to be differentiated by node. Precisely the willingness to pay at node $n \in N$ is weighted with the BDF matrix in order to indicate Member State $m`s$ willingness to pay at a node n .This relationship is shown in eq. (6).

$$WTP_m \cdot BDFM_{n,m} = WTP_{m,n} \qquad \forall \qquad m,n \in N \tag{6}$$

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

$$WTP_A \cdot BDF_{A,m} = WTP_{A,n} = \begin{pmatrix} WTP_{A,A} \\ WTP_{A,B} \\ WTP_{A,C} \end{pmatrix} \tag{7}$$

The reader can observe that also the willingness to pay at node $n = A$ would be weighted by the BDF meaning that Member State A would only be willing to pay for the benefits from domestic RES-e generation that stay in its own system (and do not spill-over). One may compare this to the “national perspective” that has been described in Figure 2-2 where support is also paid for benefits that spill-over – in this respect it could be argued that the level of the per unit premium [€ per MWh] Member States are willing to pay would increase under the BDF approach as Member States would only pay for benefits that they actually receive. The demand D at each supply node $n \in N$ would then be given by the aggregated willingness to pay of all Member States $m \in N$ at this particular node as shown in eq. (8).

$$D_n = \sum_m WTP_{m,n} \qquad \forall \qquad m,n \in N \tag{8}$$

The essence from above is that Member States are actually not interested in procuring additional RES-e generating capacity at lowest possible costs, but rather in receiving the highest benefit induced from additional RES-e generating capacity per Euro spent [€ spent per € of benefit received].

The relationships described above are made more precise with the help of Figure 4-5. Each field in the table shows a three-node network connecting three Member States $\{A, B, C\}$. The four columns show the corresponding values for WTP_m, $BDFM_{n,m}$, $WTP_{m,n}$ and D_n respectively. In each row only the nodes concerned are highlighted in colour. We explain the procedure exemplarily for Member State A in the first row:

Member State A has a willingness to pay of 48 € per MWh for new RES-e generating capacity that is installed on its own territory. The BDF of Member State A indicates that of the benefit from a unit of RES-e generated in Member State A 60 percent stay in Member State A and the remaining 40 percent spill over evenly to Member States B and C. Thus to derive the willingness to pay from Member State A at each supply node $n \in N$ 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 its own territory. The demand is then given by aggregating Member States A’s, B’s and C’s willingness to pay for electricity generated in Member State A, yielding a value of 42.6 € per MWh.

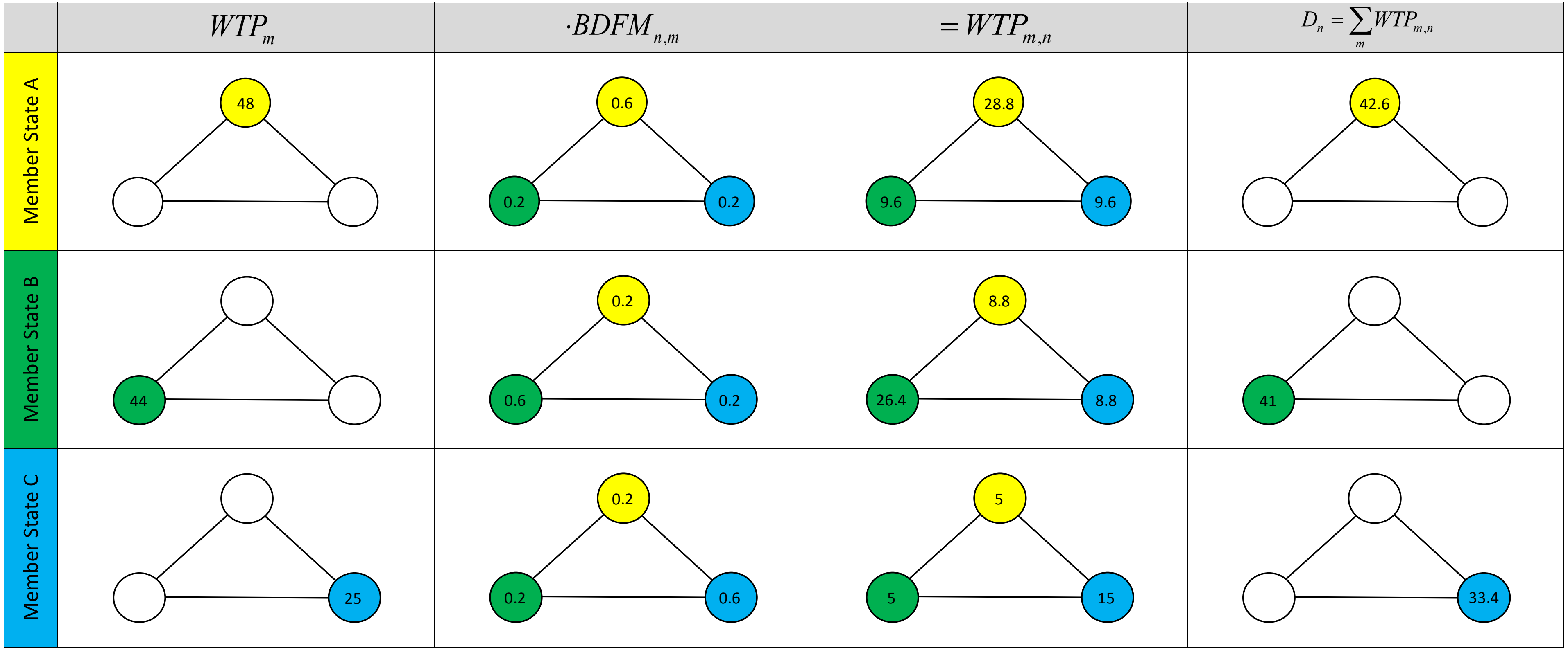


Figure 4-5: Illustration of how each Member State`s willingness-to-pay is allocated to each supply node.

5 The cross-border auction

The proposed cross-border auction would be designed as an EU wide instrument in that both Member States and generators of RES-e bid prices for additional RES-e generating capacity, indicating their willingness to pay, respectively their costs. Therefore, let each Member State submit a sealed bid naming the price that she would be offering to pay for an additional MW (or a multiple thereof) of RES-e generating capacity installed on her own territory. The price may or may not be equal to her true willingness to pay. Let also each generator of RES-e bid a price that she asks for an additional MW of RES-e generating capacity to be installed, whereby RES-e producers and thus their bids are assigned to the Member State where their plant is connected to the grid. Next the auctioneer collects all bids and calculates the demand at each node by weighting all demand bids with the BDF matrix. She then chooses the set of bids that maximizes EU-wide surplus, by subtracting the prices bid by the RES-e generators from the demand for each supply node and announces the outcome. **This demonstrates 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**.

The auction could be conducted as “one shot” or in an iterative process. In the latter case the RES-e generators and Member States may then revise their bids, e.g. increase the price in case they have not been included in the announced set of successful bids in the previous round. The auctioneer then 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). When both parties have an incentive to reveal their true costs respectively willingness to pay in order to be included, the auction converges to an efficient equilibrium. 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.

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 we already proposed above to hand over this responsibility to ENTSO-e in order to integrate the calculation into the TYNDP process.

In this chapter we describe the functioning of the mechanism. In developing our mechanism we partly draw on a concept developed by Peyton Young (1998) who has proposed an efficient mechanism for setting access charges to public facilities or publicly regulated monopolies.

5.1 Description of the auction

The proposed cross-border auction would be designed as an EU wide instrument in that both Member States and generators of RES-e bid prices for additional RES-e generating capacity. An illustration of the design of the mechanism for an example of two nodes is given in Figure 5-1. Let each Member State $m \in N$ submit a sealed bid naming the price p_m^D that she would be offering to pay for an additional MW (or a multiple thereof) of RES-e generating capacity installed **on her own territory**, whereby D denotes that the price refers to a demand bid for additional RES-e generating capacity. The price may or may not be equal to her true willingness to pay. Let also each generator of RES-e bid a price p_n^S that she asks for an additional MW of RES-e generating capacity to be installed, whereby RES-e producers and thus their bids are assigned the index n of the Member State where their plant is connected to the grid and S denotes that the price refers to a supply bid for additional RES-e generating capacity.

Next the auctioneer collects all bids and calculates the demand at each node as described in section 4.5 by weighting all demand bids with the BDF matrix.

$$D_n = \sum_m \left(p_m^D \cdot BDFM_{n,m} \right) \quad (9)$$

She then chooses the set of bids that maximizes EU-wide surplus, by subtracting the prices bid by the RES-e generators from the demand for each supply node and announces the outcome.

$$\max \sum_n \left(D_n - p_n^S \right) \quad (10)$$

The auction could be conducted as "one shot" or in an iterative process. In the latter case the RES-e generators and Member States may then revise their bids, e.g. increase the price in case they have not been included in the announced set of successful bids in the previous round. The auctioneer then 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). When both parties have an incentive to reveal their true costs respectively willingness to pay in order to be included, the auction converges to an efficient equilibrium. 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.

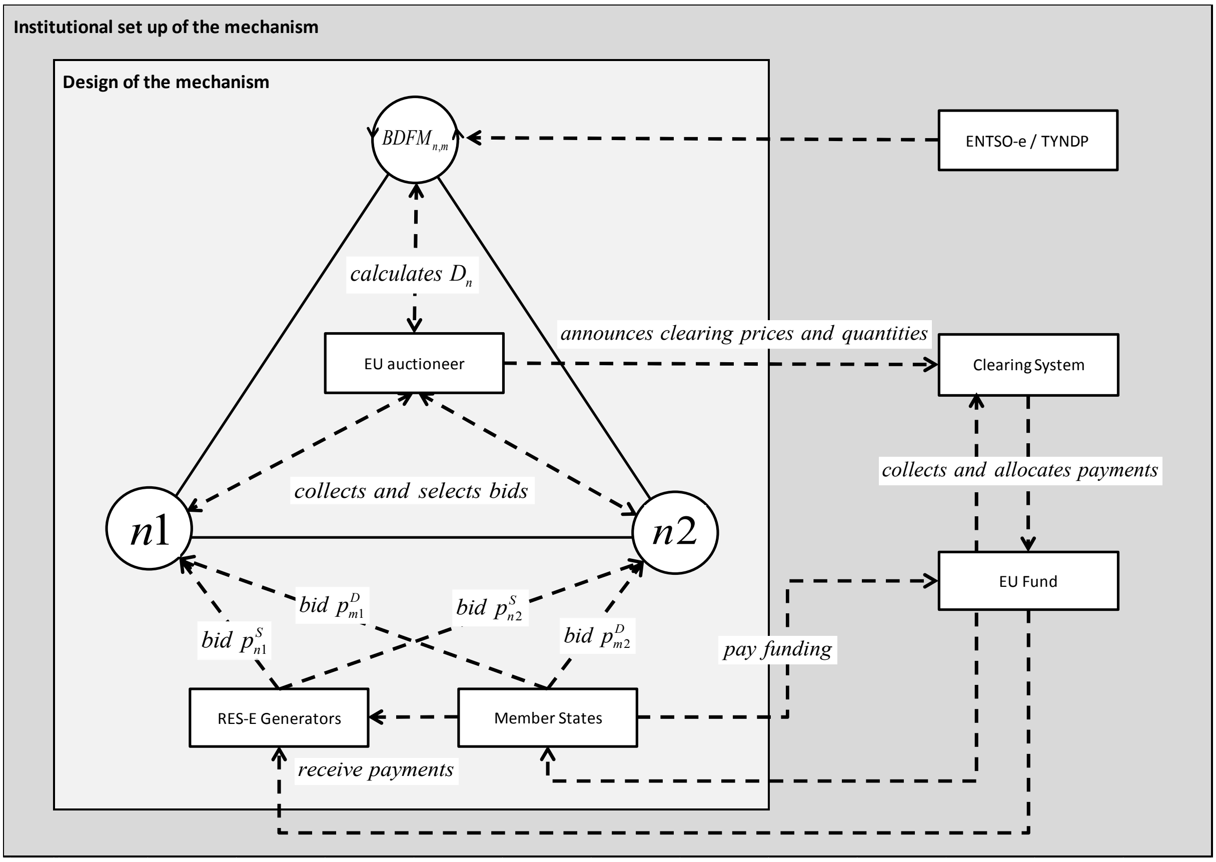


Figure 5-1: Design and possible institutional set-up of the mechanism.

The functioning of the mechanism is further explained on the basis of Figure 5-2, which shows in a stylized way a possible outcome of an auction. Let us assume for this example that supply and demand bids are fixed to a certain size (e.g. one MW) so that they can exactly be matched to a "surplus bid" Then each surplus bar is given by $D_n - p_n^S$ and is of one MW size. 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:

Firstly, the reader may observe the unusual shape of the supply and demand curves – the reason being that bids are not ordered by ascending costs, but by descending surplus. For example bid10 (with supply price of 50 € per MWh) has been rowed after bid6 (with supply price of 65 € per MWh), because bid6 could be matched with a higher demand. Bid14 (with a very low supply price of 20 € per MWh) 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 submit a demand bid 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,

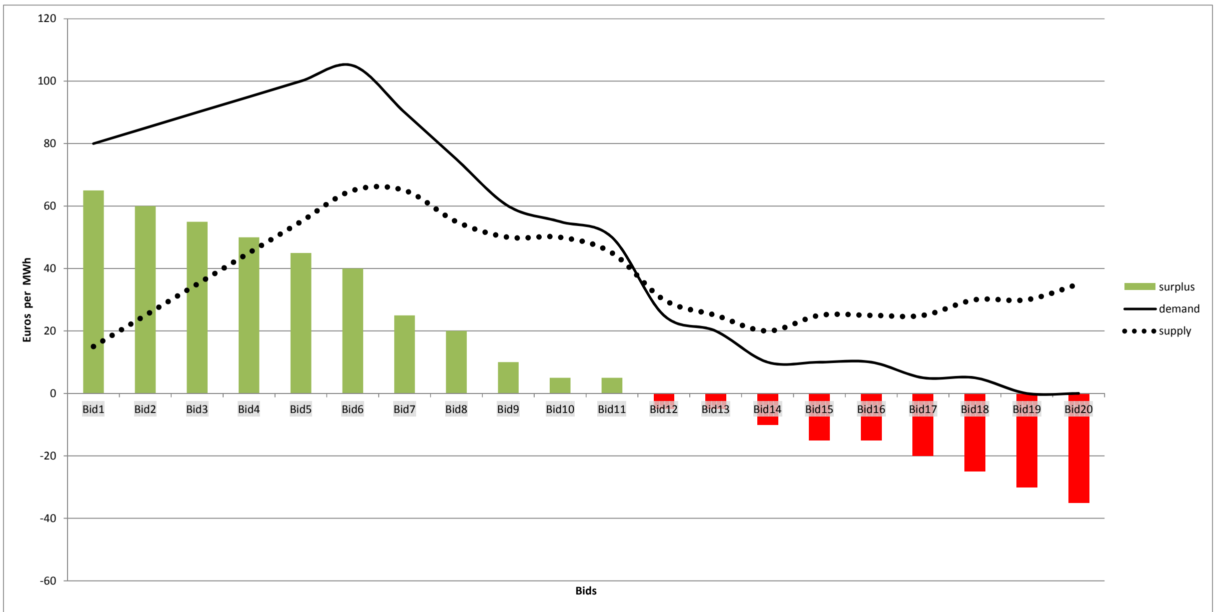


Figure 5-2: Illustration of the functioning of the mechanism.

5.2 How to distribute the surplus?

As $\sum_n D_n - p_n^S \geq 0$; i.e. the mechanism only choses bids with positive surplus, it is ensured that all costs can be covered. It is most likely that $\sum_n D_n - p_n^S > 0$ and a surplus will remain. The surplus can however be expected to be small in practice, i.e. the demand and supply curve will be nearer than in the stylized example shown above. The explanation is that while (long term) costs of RES-e generation differ across the EU they are still in a comparable order of magnitude. Moreover if the alternative "opportunity" of a national support instrument exists, both generators and Member States would try "improve" their outcome; Member States might bid less than the level of the support premium in the domestic case, generators would potentially bid more though that need not be the case (see also the relevant discussion in section 5.4). For the remaining surplus several uses can be thought of:

- It could be redistributed to the Member States
  - Through a lump sum payment: In this case the amount redistributed to each Member State would be independent of the prices bid – thus there would be no opportunities for strategic gaming that could give an incentive to misreport.
  - 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.
- 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).
- 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. (We refer to the relevant discussion in sections 5.3 and 6.1.2.

5.3 A possible institutional set-up[13]

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 5-1 we 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 we 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 x_n selected in the auction (cf. section 3.8). 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 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 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[14] 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 p^* and clearing quantities x^* to a clearing system that could institutionally be integrated with either the auctioneer or an EU fund, but we have displayed it as its 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

[13] This mechanism could be implemented under various institutional set-ups. The one described here seems straightforward with respect to the different elements forming the mechanism. There might however be other e.g. legal requirements that would make a different set-up more desirable.

[14] With respect to planning processes or market design issues.

collect from the Member States their net payment obligations. Then we 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 (e.g. according to EU budget key or some other burden sharing rule) to the EU fund if needed to finance an EU instrument for RES-e support (cf. section 6.1.2).

5.4 A three-stage framework: auction participants and their incentives

We develop a three-stage framework to further describe the structure of the problem and the relationships between the different actors involved. In the following three sections we describe the different stages in reversed order. A visual illustration of the structure is given in Figure 5-3.

5.4.1 Stage III: Integrated and coupled EU electricity market

The bottom level 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 minimize their costs for the purchase of electricity respectively. The actors are situated at different nodes of the electricity network that are linked by a joint 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 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 or respectively generation at different auctions that are organised 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 (minimum) ask price at the RES-e auctions.

Why don´t RES-e generators see the efficient investment signal?

In the internal electricity market the (short term) value generation from RES-e capacity has in the system is reflected by the domestic market value. However with regards to the long-term market value[15] and non-market benefits externalities exist that distort the investment signal RES-e generators receive from electricity prices:

- In a way a domestic auction for RES-e can be said to reflect the “capacity value” of RES-e generating capacity. It asks “what alternative costs, that is, capacity costs net of market value from RES-e generation, can be displaced by preferring one supply bid over another?” This leads to the supply bids with the lowest ask prices being selected, since this generates the highest benefit in terms alternative capacity costs of RES-e generation being displaced. The shortcoming in a domestic auction is that it does not consider the long-term market benefit new RES-e generating capacity has in adjacent market zones, since it only compares alternatives availably domestically, which leads to a distorted signal for the RES-e investor.

[15] Referring to the capacity value of RES-e generating capacity. In “energy-only” markets RES-e generators see their value of displacing conventional generating capacity which can however be assumed to be small compared to the value of displacing alternative RES-e generating capacity. Since this value is reflected in the prices of the support instrument RES-e generators only “see” their national value in case of a domestic support instrument.

- In the same manner the prices in a domestic auction also do not reflect the non-market benefits a new unit of RES-e generating capacity has abroad. While we argue above that the short term market value of RES-e also is a good proxy for its non-market benefits, it is however not internalized in the RES-e generators' investment decision since the investor does not see the higher willingness to pay in the adjacent Member State reflected in the auction price.

For these two reasons the RES-e generators do not "see" their full value and investments do not take place even though they would lead to a positive net benefit. Thus from the perspective of the RES-e generators the new framework for allocating Member States' willingness to pay offered by the BDF matrix approach provides new opportunities for cross-border financing of RES-e generating capacities. Then the RES-e generators have to select one auction - domestic or EU – at which they offer their capacity.

We will assume in the following that the domestic auction is the default case. What could then be an incentive for the RES-e generator to switch to the EU auction instead? An intuitive answer would be if she could expect higher revenues by doing so. This could be the case for several reasons: let us assume that the RES-e generator is situated in a Member State with low-cost generation potential so that the domestic RES-e support auction can be expected to clear at low price levels. In contrast the price level in the EU auction could be overall higher due to the demand from other Member States with only more expensive domestic cost alternatives available. Moreover it could be the case that the domestic auctions are limited to very tight quantities (so that only a small fraction of the domestic supply potential can be deployed under these) or that for a certain generation technology no domestic auctions are held at all. In these cases the respective RES-e generator would increase her revenues, because under the domestic scheme she might not have any earnings at all.

In all these cases the price level the RES-e generator would ask for would be in the range between the minimum price she would require to cover the investment cost gap and her opportunity costs of not offering capacity in the domestic auction, i.e. she would try to maximise her revenue by receiving the highest price per unit of capacity offered. This "searching for arbitrage" of the RES-e generators provides the Member States price signals to adjust their purchasing strategies between both auction types so that the system as a whole converges to an efficient equilibrium as will be shown below.

One further reason why RES-e generators could potentially be able to ask lower prices at the EU auction could be that investors would perceive the financing risk to be lower under the EU mechanism compared to a national auction, which in turn 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).

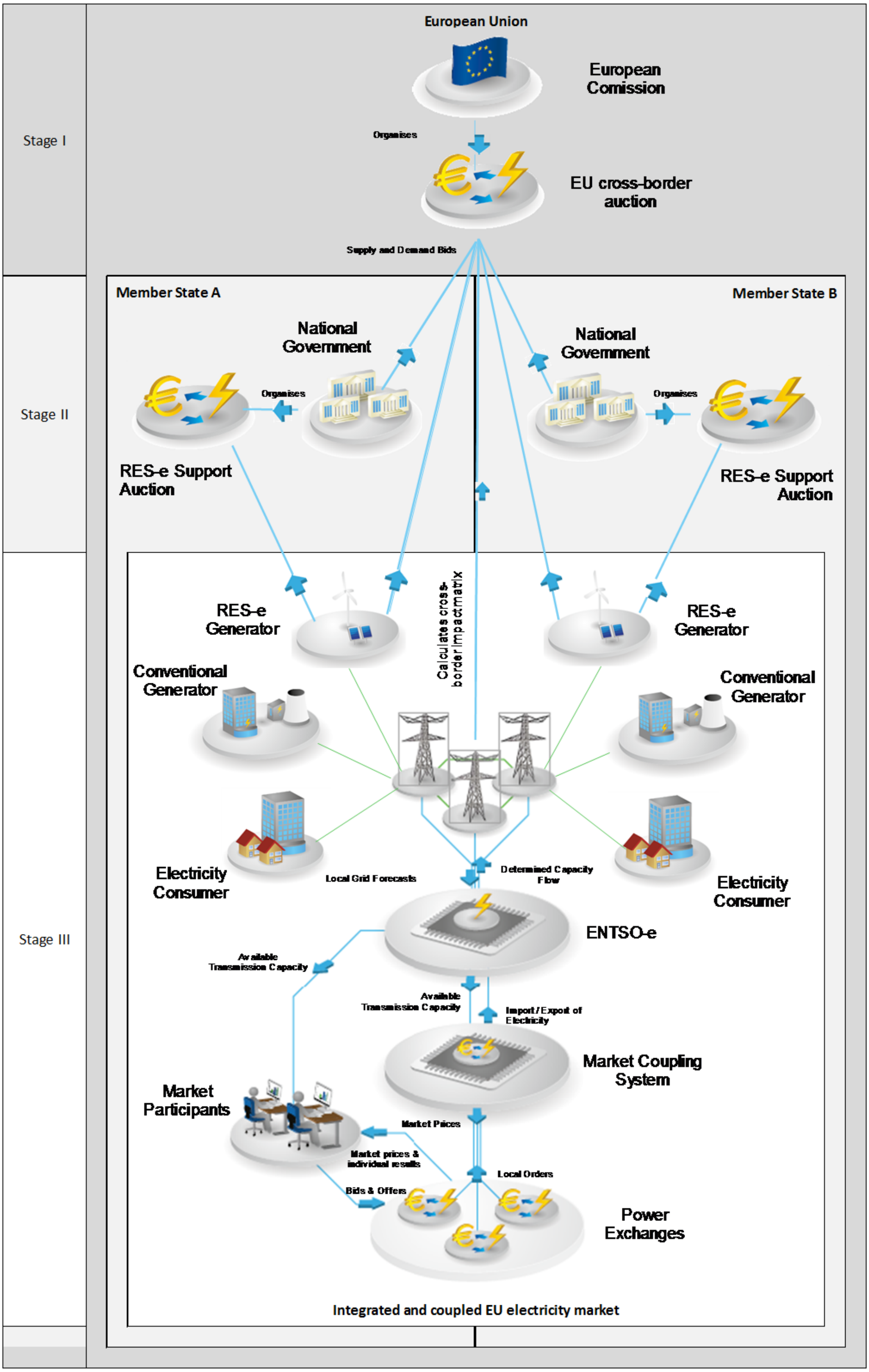


Figure 5-3: A three-stage framework to the structure of the problem. Figure adapted from original figures provided by courtesy of TenneT TSO (2010).

5.4.2 Stage II: Member States

In the middle level are the EU Member States. Here we 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 have the possibility to minimize their support costs (and / or maximize their benefit) by incentivising additional RES-e expansion either by setting-up a domestic RES-e auction or by offering demand bids in the EU auction. From the perspective of a Member State the domestic auction may offer the advantages that RES-e expansion corridors can possibly be realised with higher certainty[16] and that all the generating capacity which is supported is installed domestically. The EU auction on the other hand may have the advantages that additional RES-e generating capacity can be procured at lower support costs than it would be possible domestically and that only generation is supported that actually induces a benefit domestically (compare section 4.5). Therefore the per-unit willingness to pay at the EU auction may actually be higher compared to the opportunity cost of paying the premium that would emerge in a domestic auction as explained above. The counterargument against this would be that Member States implicitly already consider these spill overs when determining the domestic premiums. This will also be assumed in the following, that is, the benchmark price for the EU auction will be the premium that a Member State would otherwise have to pay per unit of capacity that is supported domestically.

Next we explain with the help of Figure 5-4 how a Member State can optimise her support of RES-e generating capacity, by shifting demand between the domestic and the EU auction. Therefore the bars at the bottom of the figure indicate the quantity that is procured in each type of auction and the convex curves indicate the supply curves in the two auctions based on the bids of the RES-e generators as "seen" by the Member State. We can observe that the supply curve in the EU auction is overall flatter, due to the access to lower cost and larger potential (including the potential on the Member State's own territory).

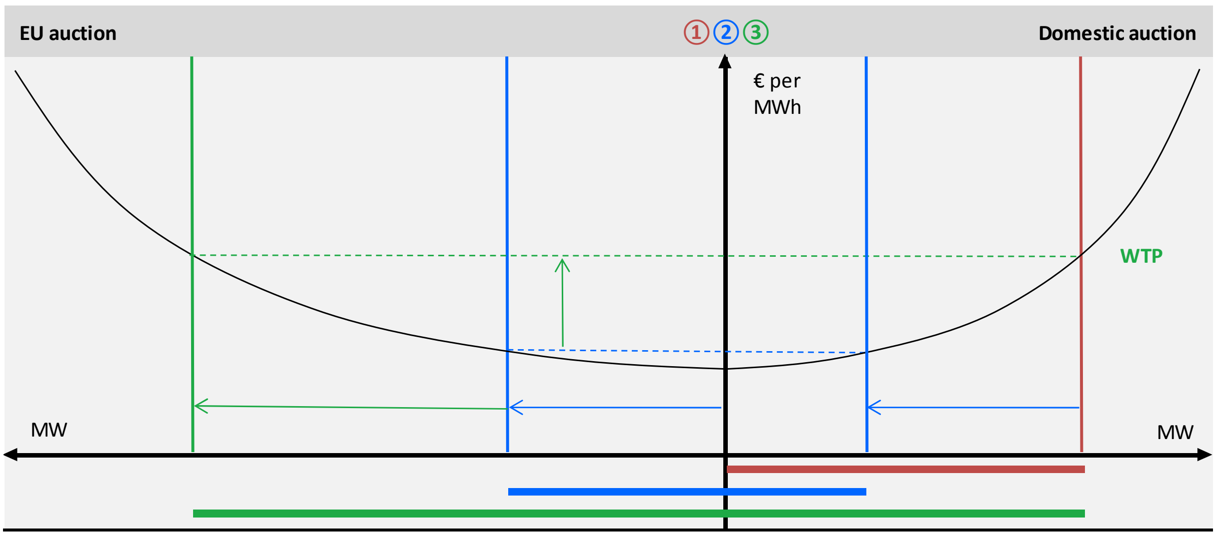


Figure 5-4: Demand allocation problem of Member States choosing between domestic and EU auction.

Let us first assume a case where no EU auction exists and Member States can incentivise new RES-e generating capacities only through domestic auctions. Then the Member State would try to set the demand in the auction such that supply bids are selected up to a premium level that equals her maximum willingness to pay for an additional unit of Res-e generating capacity (①), that is, in equilibrium the marginal costs of support and willingness to pay are equalized. Now we assume that for the cases two and three the EU auction is available for Member States as alternative to the domestic auctions. The Member State could follow two principal strategies in using the EU auction in addition to the domestic auction. One strategy (②) could be to lower the costs of

[16] In the EU auction the demand bid may not be selected whereas in the domestic auction the demand is usually a fixed quantity – which in turn implies the risk of unexpectedly high clearing prices in the domestic auction.

supporting the same quantity of RES-e generating capacity that would otherwise be procured in the domestic auction in case 1, that is, the Member State would not be willing to pay a higher premium in the domestic auction if a more cost efficient alternative would exist in the EU auction. Thus she would try shift the demand between auctions in a way that the marginal support costs in both auctions would be equalized. The other strategy (③) would be that the Member State would be willing in general to support more new RES-e generating capacity than the quantity procured in case 1 in the domestic auction, as long as the support premium is not higher than her maximum willingness to pay (implying that each additional unit adds to the net benefit). She would thus offer prices and quantities in a way that in both the domestic and the EU auction the marginal support costs equal her willingness to pay for an additional unit of RES-e generating capacity in order to maximise her benefit.

5.4.3 Stage I: European Union

In the upper level is the EU. At this level the EU wide coordination takes place through the cross-border auction. The EC as operational organ of the EU seeks to minimize the EU-wide costs of achieving the 2030 target while keeping the impacts balanced across Member States. The EC oversees the whole implementation of the mechanism and could also conduct the auction herself or assign some other party on her behalf (see paragraph 5.3). The EU auctioneer receives the demand and supply bids from the lower levels and chooses the set of bids that maximizes surplus. Next the optimisation problem of the auctioneer which is stated in equations (11)-(14) will be explained in more detail.

In comparison to the description of the mechanism under paragraph 5.1 an additional set $b \in B$ is introduced. This allows Member States and RES-e generators to submit bids as different combinations of quantities and prices. Thus the auctioneer receives from the participants bids indicating the price in **€ per MWh** and the maximum quantity in **MW** that they would pay this price level for. The decision variables of the auctioneer are given by $x^D_{n,b}$ and $x^S_{n,b}$. The variable $x^D_{n,b}$ determines for each bid the quantity of demand that is selected at each supply node n. The variable $x^S_{n,b}$ determines for each bid the quantity of supply that is selected from a RES-e generator that is assigned to supply node n. Equations (12) and (13) ensure that these quantities cannot become larger than the maximum aggregate quantity $xmax$ offered at a certain price level. Demand bids of Member States are simultaneously offered at all supply nodes $n \in N$, though at different price levels (cf. section 4.5). While it is possible to divide a bid between all supply nodes $n \in N$ the cumulative quantity selected for a certain price level $p^D_{m,b}$ cannot become larger than $xmax^D_{m,b}$. Equation (14) ensures that the sum of accepted demand bids at each supply node has to be matched with supply in order to ensure that the benefit induced from RES-e generation is allocated to where it is demanded and paid for. Respecting these constraints, the auctioneer then choses the set of bids that maximizes the aggregate EU-wide surplus and announces $x^D_{n,b}$ and $x^S_{n,b}$.

$$\max_{x^D_{n,b},x^S_{n,b}} surplus = \sum_n \sum_b \left(\sum_m \left(p^D_{m,b} \cdot BDFM_{n,m} \right) \cdot x^D_{n,b} - p^S_{n,b} \cdot x^S_{n,b} \right) \quad (11)$$

$s.t.$

$$\sum_n \left(x^D_{n,b} \cdot BDFM_{n,m} \right) \leq xmax^D_{m,b} \qquad \forall n,m,b. \quad (12)$$

$$x^S_{n,b} \leq x\max^S_{n,b} \qquad \forall n,b. \quad (13)$$

$$\sum_b x^D_{n,b} = \sum_b x^S_{n,b} \qquad \forall n.. \quad (14)$$

6 Applications and design variants of the cross-border mechanism

The mechanism can be configured to serve different applications. The main application is to facilitate cooperation and cross-border support of RES-e expansion. In addition the functionality of the mechanism can be extended to also serve as an EU instrument for the achievement of the 2030 RES target.

As regards cross-border support the mechanism is capable to overcome significant market failures caused by the lack of efficient price signals that have strongly hampered cross-border support thus far. The cross-border auction overcomes this failure by jointly considering the willingness of all Member States to pay for RES-e generating capacity expansion in each Member State. This altered allocation of demand and thus allocation of new RES-e generating capacities under the EU auction makes all Member States better off compared to the national case.

The mechanism can be easily extended to also function as EU instrument that meets demand in case a gap on the path to the 2030 target arises. This could function in the way that in addition to the Member States the European Commission would also submit demand bids at the cross- border auction. In contrary to the Member States the European Commission would not have preferences with regards to the geographical allocation of new RES-e generating capacity, it would rather seek to realise an EU wide cost-efficient allocation of new capacities in order to meet the EU 2030 target at low costs. Therefore the demand bids from the EU would not be spatially weighted with the BDF matrix, but they would rather be assumed to be homogeneous across the EU, i.e. supply bids would be selected in ascending order beginning with the lowest. The EU instrument would now combine the European Commissions 'demand bids with the demand bids of the Member States that have not been selected having the following effects: demand bids submitted by Member States that have not been selected in the sole cross-border auction could now be selected by the additional EU demand covering the negative surplus gap. In any case again low costs would be traded-off against remaining willingness to pay by Member States, by having the EU instrument pick the bids with the smallest negative surplus gaps.

In this chapter we discuss possible applications and different variants, that is, modifications of the mechanism, whereby generally the applications imply certain design variants of the mechanism.

6.1 Applications of the mechanism

The mechanism can be configured to serve different applications. Chief applications can be thought to be situations where it is used to facilitate cooperation and cross-border support of RES-e expansion and / or where it is used as EU instrument for the achievement of the 2030 RES target.

6.1.1 Cross-border support of RES-e generating capacity: an illustrative example

The standard application of the mechanism that is inherent to its design is to enable cross-border support of RES-e. In this section an illustration of the cross-border mechanism is given for some fictive parameters. An overview of the parameters is provided in Table 6-1. For each Member State, the first column indicates the level of the price bid in Euros per MWh, while the adjacent column indicates the maximum quantity Member States, respectively RES-e generators offer at a certain price level in MW. The third column indicates the size of the bid that has been selected after the surplus maximizing auction has cleared. In this example it is assumed that Member States and RES-e generators can submit up to five bids. The bids are then ordered in descending (demand bids) respectively ascending (supply bids) order by the auctioneer. From the demand bids the auctioneer calculates the curve for the cross-border demand according to the methodology described in paragraph 4.5. The maximum bid size of the cross-border bids cannot be stated explicitly as there are several degrees of freedom, but it is rather an outcome from the optimisation routine. The value that is displayed here is the maximum quantity $x_{n,b}^{D}$ could take for one node n , so that eq. (12) still holds.

Furthermore the values of the bidding parameters provide some insights on the costs and benefits of RES-e in the three fictive Member States. Member State A has the highest willingness to pay of all Member States, Member State B`s willingness-to-pay is a bit lower, but in similar order of magnitude. Member State C has offered by far lower price levels and only is willing-to-pay for up to 2.8 MW of new RES-e generating capacity. In contrary Member State C possesses the lowest cost RES-e generation potentials so that RES-e generators situated in this Member State in their bids have asked for the lowest prices. It can furthermore be observed that the aggregate supply bids (16.3 MW) exceed the aggregate demand bids (11 MW) by 5.3 MW, whereby demand bids that have not been executed by Member States translate into bids at price level zero[17].

Table 6-1: Overview of bidding parameters.

Bid#	Member State A			Member State B			Member State C		
	bid price	max size	selected size	bid price	max size	selected size	bid price	max size	selected size
	€ per MWh	MW		€ per MWh	MW		€ per MWh	MW	
					Demand Bids				
bid1	48.00	1.00	1.00	44.00	0.80	0.80	25.00	0.90	0.90
bid2	43.00	1.00	1.00	41.00	1.30	1.30	18.00	0.90	0.90
bid3	41.00	1.00	0.25	38.00	1.10	0.41	15.00	1.00	0.59
bid4	39.00	1.00	0.00	27.00	1.00	0.00	0.00	0.00	0.00
bid5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					Crossborder Demand Bids				
bid1	42.60	1.67	0.94	41.00	1.33	0.86	33.40	1.50	0.90
bid2	37.60	1.67	1.04	36.80	2.17	1.16	27.60	1.50	1.00
bid3	35.20	1.67	0.00	34.00	1.83	0.68	24.80	1.67	0.50
bid4	28.80	0.00	0.00	24.00	0.00	0.00	13.20	0.00	0.00
bid5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					Supply Bids				
bid1	24.00	0.80	0.80	20.00	0.75	0.75	20.00	0.65	0.65
bid2	30.00	0.90	0.90	25.00	0.85	0.85	24.00	0.65	0.65
bid3	36.00	0.80	0.35	28.00	1.10	1.10	24.00	1.10	1.10
bid4	44.00	1.40	0.00	35.00	1.40	0.00	26.00	1.65	0.00
bid5	48.00	1.40	0.00	40.00	1.40	0.00	28.00	1.45	0.00

Besides price bids the auctioneer requires as input parameter the BDF matrix, which means that we follow the sequential modelling approach in this example (cf. section 3.9). To keep things simple for this example we assume a BDF matrix that is symmetric. This also implies that differences in nodal surpluses and thus selected bids can only be explained by divergence in bid price levels.

[17] This would imply that additional RES-e generating capacity could still be installed if the remaining Member States` demand would be high enough to ensure a positive surplus, which is however unlikely, i.e. a bid price level of zero would effectively limit the financial support of additional RES-e generating capacity, but not its installation on the own territory. The alternative option would be that also the additional installation would be prevented, even though if it would be entirely financed by other Member States. Finally it would be possible that both types of limitations, that is financial and / or physical would be allowed.

Table 6-2: BDF matrix for the illustrative example.

to from	MS A	MS B	MS C
MS A	0,6	0,2	0,2
MS B	0,2	0,6	0,2
MS C	0,2	0,2	0,6

Next the results of the auction will be discussed. Figure 6-1 shows for each of the Member State the demand and supply curves resulting from the bids submitted by the Member States and the RES-e generators. Furthermore the dashed red line shows the cross-border demand curve, and the grey dotted line indicates the level of generating capacity that has been selected at each node. It can be observed that both in Member State A and Member State B the selected capacity is lower than it would have been in the national case, whereas in Member State C the selected capacity is higher. In effect the cross-border auction shifts some of the willingness to pay from Member States A and B to the lower cost potentials in Member State C. However still significant capacities remain in Member States A and B as the cost savings have to be traded against a reduced willingness to pay, due to the weighting factors of the BDF matrix. This example demonstrates how the cross-border mechanism facilitates EU-wide cooperation. In Member State C a high share of the selected capacity under the EU cross-border auction would otherwise not have been selected in the national auction, since Member State C`s willingness to pay alone would have been too low. As argued before the national support instruments are not suited to adequately reflect the value RES-e generating capacity abroad has on the domestic power market (cf. section 5.4.1). The cross-border auction overcomes this failure by jointly considering the willingness of all Member States A, B and C to pay for RES-e generating capacity expansion in Member State C. The altered allocation of demand and thus allocation of new RES-e generating capacities under the EU auction makes all Member States better off compared to the national case.

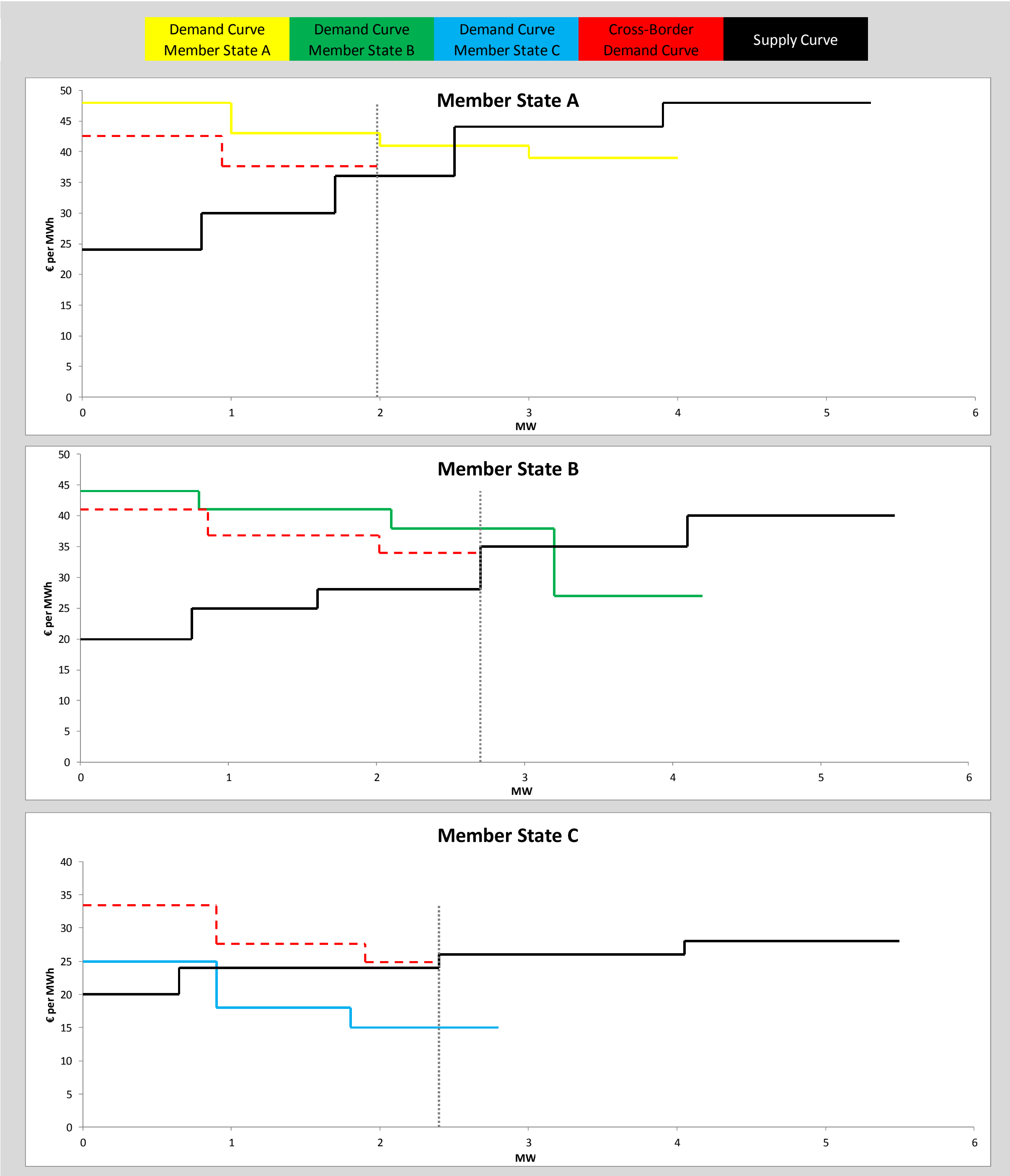


Figure 6-1: Demand and supply bid curves and equilibrium quantities.

After the auction has finished the auctioneer announces the clearing prices p^* and the clearing quantities x^*. The clearing of the cross-border auction induces some payments streams as shown in Table 6-3. For the institutional set-up of the administration of the payments two options can be thought of as described in section 5.3: bilateral payments and an EU fund; both are described in the following.

In case of bilateral payments the clearing system calculates the resulting gross payments $pay_{m,n}$ between all combinations of Member States as shown in equation (15), whereby Member States that act as hosts for new RES-e generating capacity, that is, the ones who bear the direct costs of supply are in such a case assigned the index n.

$$pay_{m,n} = \sum_b p^{*D}_{m,b} \cdot BDM_{m,n} \cdot x^{*D}_{n,b} \tag{15}$$

The reader may convince herself that the sum of payments between all combinations of Member States equals the sum of payments of € 252.88 that Member States would provide to the EU fund in the case of the alternative institutional set-up. In case that a surplus remains and that it is decided to redistribute it to the Member States the surplus would be calculated for each supply node n and it would be redistributed to the Member States m according to their share in total payments at a respective node as shown in eq. (16).

$$redist^{nodal}_{n,m} = \frac{pay_{m,n}}{\sum_m pay_{m,n}} \cdot \left(\sum_m pay_{m,n} - \sum_b p^{*S}_{n,b} \cdot x^{*S}_{n,b} \right) \tag{16}$$

This amount would then be subtracted from the gross payments between the Member States (either ex ante or ex post through redistribution by clearing system).

Table 6-3: Payments [Euros] resulting from the outcome of the cross-border auction.

	from / to	MS A	MS B	MS C	SUM
Bilateral Payments	Gross Payments				
	MS A	56.34	23.71	21.20	101.25
	MS B	17.50	66.87	19.71	104.08
	MS C	8.99	10.39	28.17	47.55
	Payments corrected for surplus				
	MS A	40.00	15.74	16.88	72.62
	MS B	12.42	44.41	15.69	72.52
	MS C	6.38	6.90	22.43	35.71
	Net Payments				
	MS A	0.00	3.32	10.50	13.82
	MS B	0.00	0.00	8.79	8.79
	MS C	0.00	0.00	0.00	0.00
EU Fund	Gross Payments				
	MS to EU Fund	101.25	104.08	47.55	252.88
	Surplus redistributed				
	EU Fund to MS	28.63	31.56	11.84	72.03
	Net Payments				
	MS to EU Fund	72.62	72.52	35.71	180.85

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. In this illustrative example Member State A would pay € 3.32 to Member State B and € 10.5 to Member State C; Member State B would pay € 8.79 to Member State C. In case an EU Fund would be used for the administration of the payments each Member State m would pay the gross amount $\sum_n pay_{m,n}^{fund}$ to the fund (through the clearing system), equalling the payments to the sum of supply nodes (including its own). In case the surplus is redistributed to the Member States, this reduces their payments by the sum of surpluses redistributed from all supply nodes $\sum_n redist_{n,m}^{fund}$. Again the reader may convince herself that the sum of payments from the Member States to the EU Fund equals the sum of surplus corrected payments in the bilateral case of 180.85. The difference to the net payments in the bilateral case is that these also contain the “internal” payments from a Member State to herself, since the EU fund would also provide the financing of new RES-e installations on her own territory.

6.1.2 Cross-border mechanism including optional EU instrument

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 up” a possible gap with respect to some given EU RES target trajectory.[18] This could work as follows: Let us assume the EU auction, where Member States can procure new RES-e generating capacity through cross-border support takes place biannually. Let us furthermore assume that it will be envisaged that from the seven percentage points that will be needed to reach the 2030 target four percentage points are allocated to the electricity sector[19]. 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. At each cross-border auction the EC would then conduct the following test: Is the sum of the historic share achieved and newly procured generating capacities from domestic auctions and the cross-border auction ($EU\_progress$) larger or equal or smaller than the intermediate EU target (EU_target)? If $EU\_progress \geq EU\_target$ no additional generation needs to be procured through the EU instrument; if $EU\_progress < EU\_target$, the gap could be filled through the EU instrument. This procedure is illustrated and summarised in Figure 6-2.

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 5-2 again. Let us assume once more that one bar corresponds to one MW[20] of quantity. The domestic auctions have already cleared and before the EU auction takes places 19 MW of additional RES-e generation are still needed to stay on the trajectory. At the EU auction however only 11 MW of generation 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 fund. Such a procedure would have two advantages: Firstly it would minimize the amount of financing that would need to come from an EU fund, which may be an advantage given the difficulty to equip any such fund with significant amounts of financial budget. Secondly, it is economically efficient: Even though for Bids12-18 the surplus is negative the welfare losses are minimized in a way that new generation is allocated to Member States where new genera-

[18] A market intervention of the EU could be justified, when Member States have biased estimates of the costs and benefits of RES-E expansion in the long term due to uncertainties or externalities: Similar as explained for companies above knowledge spill-overs are also relevant for industrial policies of states; furthermore ´benefits of RES-E are often only realized far in the future and diffuse from today’s perspective and might be discounted too high; also some synergies as economies of scale or security of supply can meaningfully only be realized at EU level an d therefore could not be considered sufficiently by individual Member States.

[19] E.g. in indicative planning of the EC; obviously there will be no fixed allocation.

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

tion 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 fund, 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 fund 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-subsidisation” 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 enough in order to be efficient (compare also the similar discussions regarding redistribution of the surplus in section 5.1 and on pricing rules in section 6.2.3).

Finally, we 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 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 “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”). 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[21] (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 (disregarding contributions to the EU fund). The procedure described above comparing the progress achieved to the EU target could be interpreted as standardised “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.

How would the EU fund be financed?

The fund could be financed from the EU budget, the Member States’ budget, or a combination of both. We do not speculate at this point which budgetary items could be used to fill the fund.

From the perspective of the Member States and for their incentives for own actions ($progress$) – be it through domestic support mechanism or the use of the cross-border mechanism – it will be decisive how their contribution to the fund is determined. For contributions directly coming from the EU budget this would likely be the EU 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. In any case, if the fund distributions were to come directly from the Member States 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. Other 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 (

[21] In such a case it could be further differentiated as to whether Member States bidding a price level of zero allow for new installations on their territory (without having to pay for them) or do not allow for new installations on their territory (subject to legal compliance). Compare also remarks in footnote 13.

$benchmark$) also determines a financial contribution. Each Member State's contribution to the fund could then be determined as follows: Let as assume again as above that an EU-wide trajectory has been defined. If $EU\_progress < EU\_target$ additionally the following test would be conducted for each Member State: Is the progress of each Member State larger or equal or smaller than its benchmark? If $progress \geq benchmark$ the respective Member State would not have to contribute financial resources to the fund. If on the other hand $progress < benchmark \rightarrow delta = benchmark - progress$, that is, a Member State stays below its benchmark, then its contribution to the fund is determined by its share in the EU wide gap $\frac{delta}{EU\_delta}$.

At this point it should be noted that the procedure described in this paragraph is similar in notion to the Portuguese proposal for a 2030 governance scheme (Tesniere et al., 2015) in that it also includes a burden sharing between under- and over-performing Member States relative to their (pledged) benchmark trajectory.

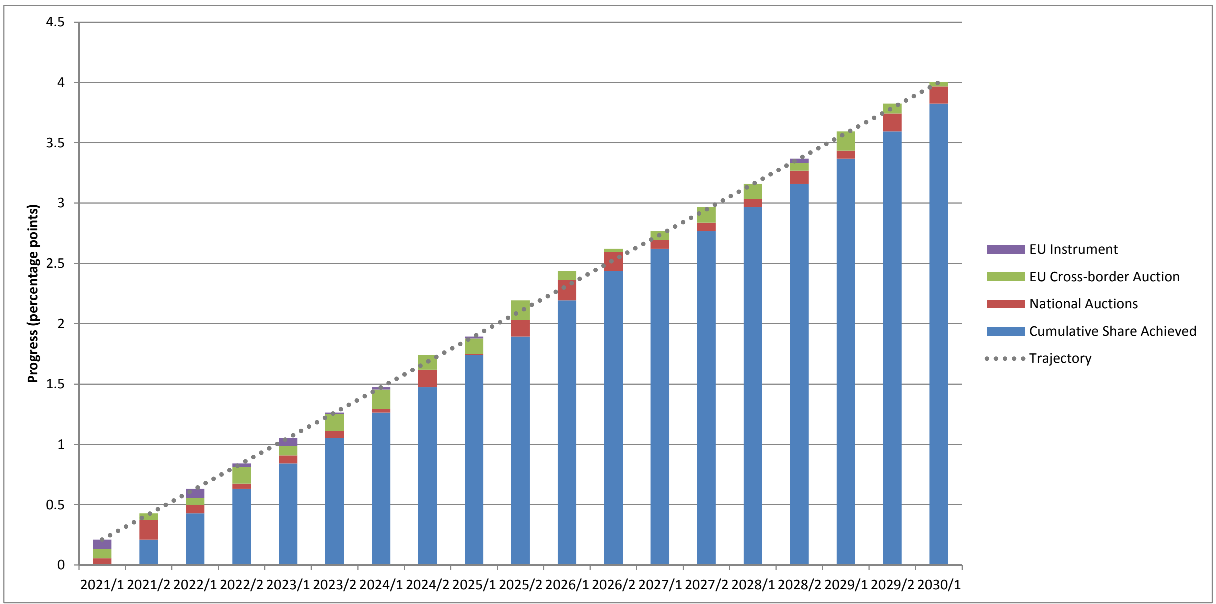


Figure 6-2: Progress and trajectory towards (intermediate) EU RES-E expansion targets.

6.1.3 Modification of the standard case: regional / national mechanism

Another application could be to use the mechanism not at EU level, but at regional, respectively national level, for instance for the opening of a domestic support instrument for installations in other Member States. In principle the same mechanism could be applied – the problem might however be that the aggregate willingness to pay might then be too low in many cases to finance additional RES-e deployment (as the system considered in such a case is smaller than the system boundaries for the spilling-over of benefits). One possible way around that could be to adjust the calculation of the BDF matrix to the "narrower" system boundaries. For instance for the case of a national application the coefficient in the BDF matrix that refers to the domestic Member State could be normalized to "one" and all other coefficients could be adjusted proportionally as show in Table 6-4.

Table 6-4: Adjustment of the BDF to national perspective of MS A.

to / from	MS A	MS B	MS C
MS A	$0,6 \cdot \frac{1}{0,6} = 1$	$0,2 \cdot \frac{1}{0,6} \approx 0,33$	$0,2 \cdot \frac{1}{0,6} \approx 0,33$

6.2 Design variants of the mechanism

This paragraph discusses some slightly differing possible design variants of the mechanism. Some relate directly to the applications discussed above, some are rather generic design question that are also discussed elsewhere in the literature, but may be evaluated differently with regards to the proposed mechanism. In this paper we do not attempt to answer general design aspects that need to be decided with respect to auctions for RES-e and refer to respective literature (del Rio et al., 2015; IRENA and CEM, 2015; Klemperer, 2004; Klessman et al., 2015; Worldbank, 2011).

6.2.1 Fixed quantity target

This design variant relates to the application of the mechanism where an EU target of generation expansion needs to be met, for instance in order to stay on a 2030 target trajectory as discussed above under section 6.1.2, or to fulfil some EU quota for cooperation (i.e. share of new RES-e installations that are supported cross-border). Therefore simply a constraint as shown in equation (17) is added to the auctioneer's optimisation problem. It forces the sum of selected supply bids at EU level to become equal to or larger than an exogenously defined EU target.

$$\sum_n \sum_b x_{n,b}^S = \begin{cases} EU\_target & \text{if } EU\_target \le \sum_n \sum_b x\max_{n,b}^S \\ \sum_n \sum_b x\max_{n,b}^S & \text{otherwise} \end{cases} \qquad (17)$$

When the minimum quantity that satisfies 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 in section 6.1.2. 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 achieved given that an exogenous target needs to be met.

In case the EU target would not be feasible since $EU\_target \le \sum_n \sum_b x\max_{n,b}^S$ the auctioneer would instead set the constraint at the maximum amount of supply bids that can be served $\sum_n \sum_b x\max_{n,b}^S$, 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. 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% target, as the past has shown, where the market has reacted with steep supply increases in the presence of profitable support conditions (Ragwitz and Steinhilber, 2014)

In addition a slack variable x_n^{EU} is added to eq. (14) as shown in eq. (18). This is necessary to keep the problem feasible when constraint (17) forces the supply to become larger than the maximum level of at each node.

$$\sum_{b} x_{n,b}^{D} + x_{n}^{EU} = \sum_{b} x_{n,b}^{S} \qquad \forall n \in N. \tag{18}$$

While x_n^{EU} is not represented in the objective function – thus it can be interpreted as the EC submitting a demand bid with a willingness-to pay of zero - eq. (18) enforces that an increase of x_n^{EU} has to be matched by an increase of $x_{n,b}^{S}$ the effect being that only the lowest costs bids are selected in order to minimize the surplus loss. The auctioneer then chooses the combination of $x_{n,b}^{D}$ and x_n^{EU} that maximizes surplus.

To illustrate this further, we repeat the example from section 6.1.1, now with an exogenous EU capacity target of 15 MW. As can be seen from Figure 6-3 the missing quantities are procured at the lowest possible costs through the EU instrument (dashed blue line).

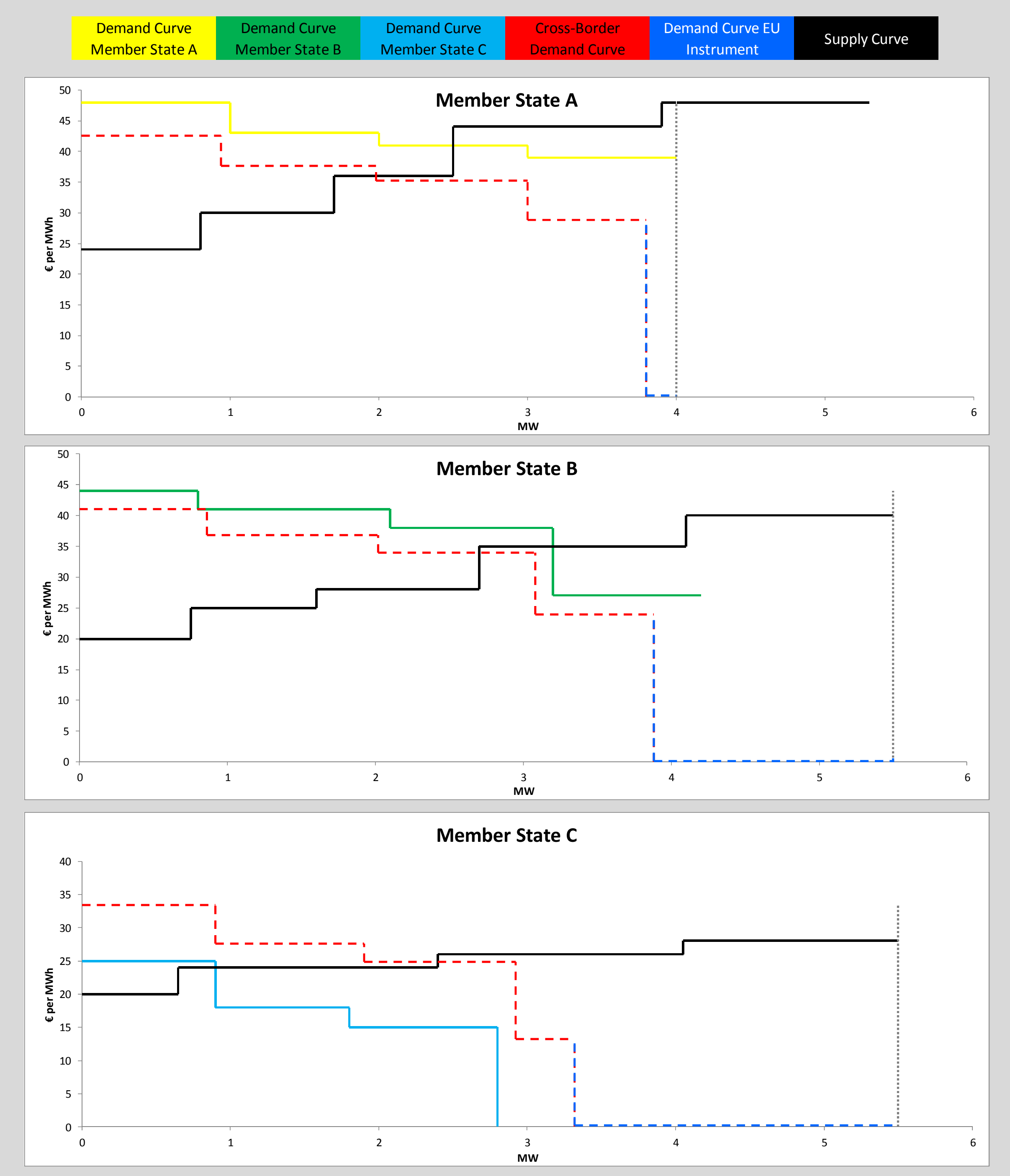


Figure 6-3: Demand and supply bid curves and equilibrium quantities with optional EU instrument.

6.2.2 Auctioning product: generation or capacity

With respect to the auctioning product, several design details need to be decided (Fraunhofer ISI et al., 2014).- An essential one regards the question if energy [€ per MWh] or capacity [€ per MW] shall be auctioned and or remunerated. While in principle both variants can lead to the same outcomes this is not the case under imperfect information or information asymmetries. Therefore the choice also determines who (RES-e generator, regulator, policy maker, auctioneer etc.) bears the risk of estimating the energy output of the generating capacity.

A payment on capacity would have the advantage that at the time the auction has cleared, all costs would be known and could be fully allocated. Whereas in the case that the support would be paid for electricity generation, costs related to an auction would still arise long time into the future depending on the duration of support. While in principle it would be possible to organise the cross-border cost allocation as described in sections 5.3 and remunerating electricity generation, it would at least become more complex than to share all costs directly.

Support that is paid for electricity generation is often seen as advantageous in the respect that it provides incentives for a high availability of the plants. If however the support is paid as premium investors receiving capacity payments also have an incentive for a high plant availability in order to maximize their revenues from the sales of electricity

6.2.3 Pricing rule: pay-as-bid vs. uniform

The mechanism differs from other RES-e auctions in the electricity sector in two important ways: Firstly, not only are costs, but also demand is determined through an auctioning procedure. Secondly, equation (12) provides that demand can flexibly be allocated to the supply node where it leads to the highest surplus. This strongly hampers the acceptance of supply bids with (very) high price levels.

We thereby focus on the two – for practical reasons - most commonly applied pricing rules in the context of electricity markets “uniform pricing” and “pay-as-bid pricing” and disregard other concepts (e.g. Vickrey pricing (Vickrey, 1961)). The pricing rules are evaluated separately for the supply side and the demand side.

6.2.3.1 Evaluation of pricing rules for the supply side

For the time being let us assume that the electricity market environment we operate in is fully competitive. The prevalent view is that uniform pricing under these assumptions is incentive compatible, that is, generators have an incentive to reveal their true costs, which is required for an efficient allocation to take place. For the wholesale electricity market the argument basically goes like this (Cramton et al., 2001; Kahn et al., 2001): *“Under the present uniform- pricing rules, suppliers in an effectively competitive market have every reason to bid approximately their marginal opportunity costs for energy in each of the blocks of power that they offer. They know that if any of those bids is rejected, because there are lower bids sufficient to satisfy the demand, they will be better off, because they will not have committed themselves to sales at prices that fail to cover their avoidable costs. More important, they know also that on their accepted bids they will receive the full benefit of whatever price above that level is necessary to equate demand and supply in the market, regardless of the level of their own bids, permitting them to pocket the difference between their avoidable costs and the market clearing price as a necessary contribution toward recovery of their fixed charges and profits. Just as with the economic dispatch of power practiced by power pools—dispatching power, that is to say, in merit order of generators from lowest to the highest marginal cost output necessary to meet demand—the consequence is that power is supplied at the minimum cost at each point in time.”*

On the other hand an established view is that pay-as-bid pricing would introduce some inevitable reduction in efficiency as generators find themselves forced to depart from bidding their marginal costs if they are to receive any compensation for their fixed costs or contribution to profits (Kahn et al., 2001). The underlying argument is that if generators would not change their bidding behavior they would receive only their avoidable costs on all their successful bids—yielding them no contribution to their fixed or common costs, let alone profits—they obviously will universally change their practice immediately, bidding instead at what they expect will turn out to be the market-clearing price.

The logic presented above is valid for the electricity wholesale market where short term operational decisions are taken. Two reasons however suggest that for our case the incentive to misreport costs is less pronounced: Firstly, in our mechanism RES-e generators ask the marginal price needed to recover their full fixed costs. Secondly, it is much more difficult to estimate the auction clearing price since the demand is not static at a given node, but is flexibly allocated to where it leads to the highest surplus. Even with a strategic bid price level below their estimation of the clearing price RES-e generators would increase the likelihood that their bids would not be selected, since they "compete" with suppliers at all other nodes.

The next aspect regards the incentive under both pricing rules to exert market power, by withholding generation capacity. In multi-object auctions bidders have an incentive to raise the price level for the clearing bid in order to increase the rents of all other accepted bids in their portfolio (inframarginal capacity). This incentive exists only under uniform pricing (Klessman et al., 2015).

Kahn et al. (2001) see another distortion for competition in the disproportionally higher specific costs of small generators in forecasting the clearing prices under a pay-as-bid pricing scheme. As already outlined above this seems less relevant for the case of the here proposed mechanism. In general for both types of pricing rules it can be assumed that the incentive to exert market power is strongly reduced compared to the case of a "national procurement auction" due to the price-node-elasticity of demand that "punishes" high cost bids.

A next issue regards producer rents, which is a classical argument by proponents of pay-as-bid pricing to give preference over uniform pricing. Under the incentive to bid the expected market-clearing price in the pay-as-bid scheme, both schemes would perform about equally in this respect, but again as explained above this incentive is less pronounced so that lower producer rents can be expected to arise under pay-as-bid pricing.

The last issue regards cost coverage under the assumption that constraint (17) is not binding. Under a uniform pricing scheme implemented both for the supply and demand side, costs would exactly be covered, as the market would be cleared at the intersection of the aggregated supply and demand curves (as it is for instance the case for electricity auctions in Europe). This would however most likely not be feasible since either the nodal balance constraint from eq. (14) would have to be violated or the case could occur that not all costs can be covered. Thus if a uniform pricing scheme is to be implemented this would have to be at the nodal level. In this case full cost coverage would be assured.

6.2.3.2 Evaluation of pricing rules for the demand side

Let us start again by discussing how the pricing rule affects the Member States incentives to reveal their true willingness-to-pay. Under pay-as-bid pricing it is an optimal strategy for Member States to bid their opportunity costs + x for, respectively marginal benefit (if no domestic alternative is available) of an additional MW of RES-e generating capacity (compare section 2.4). If they would bid less than these value they would risk not being selected even though they would still having received a net benefit if they had bid more. If they bid more than these values they would risk being selected and having to pay more than the net benefit they experience from an additional MW of RES-e generating capacity. An exceptional case is the variant of the mechanism, when it is combined with an EU Gap Filler. In this case Member States might guess to estimate the expected clearing price (that might be below the costs bid), as also "negative surpluses" could be accepted. The incentive is however weakened compared to electricity auctions since in the end payments would only be swapped from one pocket to the other – assuming that Member States also provide the funding for the EU Gap Filler. In this case a "trade-off" would exist between paying the higher price and "procuring" the domestic RES-E generation and paying the lower, more broadly split contribution to the Joint Fund. Thus in general, Member States with high cost potentials would rather tend to report their true willingness-to-pay, while Member States with low cost potentials would tend to have new RES-e generating capacities installed through (partial) financing by the joint fund.

On the other hand with a uniform pricing scheme in place all Member States would pay the marginal price of the lowest (last) demand bid accepted. This may provide an incentive to overstate their willingness-to-pay in order to increase the probability to be selected, while only paying the lower clearing price. This in turn would most likely distort efficiency. We can see that the effects are in a way "reversed" in comparison to the bidding incentives on the supply side.

In principle theoretically there would be an opportunity for Member States to conduct market power under a uniform pricing scheme by withholding capacity so that a demand bid with a very low price level would be accepted. The potential and therefore the incentive however is rather low since the margin is limited to the surplus (compare section 5.2). An exception would again be the variant of the mechanism, when it is combined with an EU gap filler, here the same logic as above applies.

Pricing schemes do not have an impact on producer rents on the demand side as the surplus is not passed on to producers. In general uniform pricing would lead to a lower surplus than pay-as-bid pricing, respectively to a zero surplus in case on the supply side also uniform pricing is implemented. The resulting incentives for the Member States depend on how the surplus is distributed (compare section 5.2). A similar logic as for the joint fund applies.

Regarding cost coverage the same argumentation as for the supply side holds.

Table 6-5: Comparison of pricing rules for different criteria; size of circle indicating the degree of criteria fulfilment.

Pricing rules	Supply Side		Demand Side	
	pay-as-bid pricing	**uniform pricing**	**pay-as-bid pricing**	**uniform pricing**
Evaluation criteria				
Incentive Compability	◕	●	◕	◖
Market Power	●	◕	◕	◖
Producer rents / Surplus	◕	◖	◕	●
Cost coverage	●	◕	●	◕

7 Further Research

This paper provides a complete description including an illustrative application of a new mechanism for cross-border support of renewable electricity in the European Union. In order to make the mechanism fit for real world applications further research on the BDF matrix concept and the design of the cross-border auction can help guide the way.

7.1 BDF matrix / WDF matrix concept

A first aspect regards the system boundaries for the BDF matrix calculation. We have chosen the private benefits as a proxy for the social benefits induced from new RES-e capacity, as we argue that non-market based benefits are to some extent correlated with private market based benefits and are likely to be further internalized in the private benefit in the future. Furthermore such a procedure has the merits that it is transparent and better reproducible by all actors than models that also cover non-market benefits such as macro effects, since electricity market follow clearly specified rules. However, larger system boundaries could be plausible for other reasons and should also be considered in future research. This would require going beyond models of the electricity sector and also including models of the economy or spatial models of land use or health impacts. Computational improvements could allow in the future looking at these sectors jointly while maintaining a high level of granularity.

One area of research regards merging the BDF and WDF matrices into a single composite, in order to better reflect each Member State’s preferences with respect to distributional effects. It would have to be decided how the weights of both components could be determined consistently.

Within the system boundaries of the electricity sector, different model types can be distinguished. Network models provide insights on the physical grid impact of new RES-e capacity, whereas market models calculate the commercial benefits of new RES-e capacities. The existing electricity market design determines the distribution of the benefits, disregarding partly the actual flows of the electricity. For the future an adaption of the market design towards a more realistic representation of the physical flows is foreseen. The effect of loop flows induced from new RES-e capacity may cause the BDF to become negative for some nodes, which will require further analysis in the context of the internal market and interpretation regarding willingness to pay and compensatory issues.

In section 3.6 we assumed that the system boundaries of one node would coincide with a Member State. However, in particular for larger Member States the effects from additional RES-e generating capacity need not be homogeneous. Therefore it would be possible to introduce a finer granularity by dividing a Member State into several nodes, which could be done by a clustering approach. A related problem would be if the cross-border mechanism were to be used at regional / national level. A problem with a system smaller than the whole EU could be that the aggregated willingness to pay would become too low to finance additional RES-e generating capacity expansion. The inconsideration of the “real” physical system boundaries of the effects causes externalities again, which prevent efficient price signals; a barrier that the EU-wide mechanism seeks to circumvent.

Moreover, our mechanism only addresses additional RES generating capacities in the electricity sector. While this sector can be assumed to play a key role in the transformation of the energy system also significant investments in the heating and transport sectors will be needed. While these sectors are mostly lacking the network properties, it is the question whether other indicators than the BDF matrix / WDF matrix approach could be meaningfully devised that allow for an integration of these sectors into the cross-border auction. This picture might also change in the future as the electricity becomes more integrated in the future with the heating and cooling and the transport sectors.

An important aspect regards the determination of the additional RES-e capacities in order to calculate the BDF matrix. As discussed in section 3.8 including the BDF matrix calculation in the EU auctioneers optimization problem causes the problem to become non-linear. Economically speaking this constitutes a Stackelberg game for a network-constrained electricity market. In order to solve this problem the BDF matrix calculation needs to be reformulated to become linear and tested for feasibility. A possible approach could be the one described in (Gabriel and Leuthold, 2010).

A related aspect from the technical point of view is the question if the auction could also be conducted technology neutral. If the BDF matrix were to be included as a parameter as described in section 3.9 a BDF matrix would have to be calculated for each technology. This again raises the question whether additivity can be assumed, which needs to be shown in further research.

Finally the weighting of the different system states proposed in section 4.3 is not based on any sound methodology. There are probably more sophisticated statistical measures available that would allow for a better and more robust selection of the different system states.

7.2 Design of the mechanism

An important requirement for the mechanism to implement the efficient solution is incentive compatibility, i.e. 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, which specific design aspects can facilitate matters on this ground. Several methodologies can be thought of in this respect:

- 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 optimal solution, in order to evaluate the efficiency and derived therefrom the incentive compatibility. This is planned in forthcoming work by the authors.
- 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 possible 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.
- Another possibility would be to try to show analytically that the mechanism has the desired properties as it is often done in the theoretical mechanism design literature.
- 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) or 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 is burden sharing. The mechanism in its current form implements the economically efficient solution disregarding income effects. In case some burden sharing element would be desirable (as it is not addressed elsewhere outside the system boundaries of the mechanism) two general options that would require further investigations could be the following:

- It might not be perceived fair that the same bid price level between Member States are “treated” equally in the auction if they account for a different share of the 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.

- 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 parameter that could in principle be set 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 (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.

8 Discussion

In this paper we propose a new mechanism for cross-border support of renewable electricity in the European Union. 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 high uncertainty about the costs and benefits involved and high information requirements resulting in high transaction costs as well as difficulties in determining trading prices that would be perceived as fair by all parties involved. 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.

Next we highlight how the proposed mechanism can overcome these barriers through several measures and thus reverse Member States` incentives in order to facilitate cooperation between them:

- ***Standardisation***: 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. The concept of the BDF matrix has two positive "side-effects": On the one hand Member States only support the share of generation from new RES-e capacity that actually induces benefits in their own market zone, which might raise the incentive to cooperate compared to the status quo. On the other hand 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 approach takes away a lot of this 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 mechanism 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 new project 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, decentralised approach to EU wide coordination and efficiency maximisation.

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 on 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 illustrations from above suggest. 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% for the share of renewable energy consumed: We 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 (European Council, 2015): By considering 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.

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Appendix A Nomenclature

Sets	
$b \in B$	Bids
$n, nn, m \in N$	Nodes
Parameters	
B	Social Benefit of RES-e generation [€]
$BDF_{n,m}$	Benefit distribution factor [%]
CR	Congestion Rent [€]
CS	Consumer Surplus [€]
D_n	Demand for additional RES-e generating capacity at a supply node n [€(MW)]
GC	Generation costs [€ per MWh]
$l_{n,nn}$	Line connecting nodes [MW]
p_m^D	Demand price offered by Member State situated in demand node m
p_n^S	Supply price bid by RES-e generator situated in supply node n
p^*	Clearing prices in the auction [€]
P	Power [MW]
PB	Private Benefit [€]
PS	Producer Surplus / Generator Rent [€]
$PTDF$	Power Transfer Distribution Factor
$P_{flow_{n,nn}}^{MAX}$	Maximal power flow between market zones n,nn respecting available transmission capacities [MW]
SB	Social Benefit [€]
$WDF_{n,m}$	Welfare distribution factor
WTP	Willingness to pay for an additional unit of RES-e generating capacity [€ per MWh / MW]
$x\max_{n,b}^D$	Maximum size for demand bid [MWh]
$x\max_{nn,b}^S$	Maximum size for supply bid [MWh]
x^*	Clearing quantities in the auction [MW]
Decision variables of the auctioneer	
$x_{n,nn,b}^D$	Accepted bid size of the demand offered by node n at node nn [MWh]
$x_{nn,b}^S$	Accepted bid size of the supply offered by node nn [MWh]

Appendix B Full results for 3-node example

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		
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
0.50	1.00	1.00	0.00	0.50	0.00	0.50	1.00	1.00
System Generation Cost Savings [€]								
38.64			52.91			93.21		
Benefit Distribution Factor [%]								
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
Nodal Producer Surplus [€]								
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
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
3.57	0.00	-3.57	0.00	0.00	0.00	0.00	0.00	0.00
Nodal Welfare [€]								
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		
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
0.50	0.50	1.00	0.50	0.50	1.00	0.50	0.50	1.00
System Generation Cost Savings [€]								
38.64			62.98			93.21		
Benefit Distribution Factor [%]								
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
Nodal Producer Surplus [€]								
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
Nodal Consumer Surplus [€]								
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
Nodal Congestion Rent [€]								
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
Nodal Welfare [€]								
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 C Congestion management of transmission capacity

In the past, the planning of power systems across Europe has been performed on national scale and interconnections to neighbouring countries have been mainly considered with regard to their contribution to security of supply. The size and amount of cross-border flows and correspondingly the level of interconnection between countries were therefore comparatively small. This perception changed with the vision of realizing the internal electricity market. In this perspective, cross-border transmission lines mainly serve as trading corridors rather than a way to ensure a more reliable operation of the grids. It is therefore of interest to optimally utilize the available transmission capacity to guarantee an efficient market outcome. An element of crucial importance is the procedure that is used to inform the market clearing algorithm of the exchange about transmission bottlenecks. These bottlenecks feed-back into the market clearing in form of trade restrictions. Different approaches for such procedures have been developed and applied in the market coupling process within Europe. These approaches can be evaluated with regard to their ability to correctly reflect the actual physical realities of power flows as well as their limits on the one hand and on the other hand by their practical feasibility in terms of data requirements and computational tractability. Besides that a fundamental differentiation criteria is whether the market participants or an independent system operator decides over the unit-dispatch and what incentives for market participants arise from each approach.

The two extremes spanning the whole bandwidth of possible approaches are the *NTC approach* (simple transport model) and the so-called *Nodal Pricing approach.* Both differ with respect to the way trade limits are determined and how they are considered in the market clearing algorithm. Within the NTC approach maximum trade limits between each two countries are calculated by the corresponding transmission system operators (TSOs) and are implemented in the algorithm as independent point-to-point flow limits. In the Nodal Pricing approach an independent system operator (ISO) uses a sophisticated power system model including a detailed grid representation. Such a model reflects real power flows and their limitations with sufficient accuracy. In between these two approaches many intermediate solutions are possible. The Central West East (CWE) region has agreed to introduce *flow-based market coupling*. Since 2012, it has been tested in parallel to the implicit NTC market coupling approach. In May 2015 it has gone online within the CWE region. If this approach delivers good results it is planned to extend it to the other regional grids within ENTSO-e.

The whole transmission grid in the CWE region is aggregated to four nodes. The responsible TSO in each node (represents a country in two cases) calculates based on a detailed grid model two day-ahead congestion forecasts (D2CF), which aim to provide a best-estimate of the expected power flows. The results of these grid simulations are then considered in the model runs of the common grid model (CGM) of the whole region. The TSOs define the grid elements that they would like to monitor and that are significantly impacted by cross-border trades. They also provide so-called *Generation Shift Keys* (GSKs). These parameters indicate, based on the working point they calculated within their D2CF scenarios, on which generation units a net position change of the hub takes place. With the selected power lines and the generation shift keys for each hub a PTDF matrix for the four hubs within CWE is calculated. The market clearing algorithm calculates power flows between hubs within CWE by using this PTDF matrix (cf. Definition – The PTDF matrix).

The aim of flow-based market coupling is to calculate good estimates of the real physical cross-border flows (and selected critical internal lines) that result from market outcome. In that sense the above described method currently applied within CWE has some flaws. First, all of the calculated parameters considerably depend on the previously calculated working point as results of the D2CF scenarios. Their usability in estimating the real power flows therefore depends on the quality of the TSO forecasts. This means the results get significantly worse the more the actual market results deviates from the forecast (e.g. in case of unplanned outages etc…) Second, besides the fact that generation shift keys depend on the forecasted working point, they are the same for a positive as well as negative variation of the net generation of a certain hub. Obviously, this is not correct for situations where demand is close to the maximum or minimum limit of the generation capacity of the marginal unit that is needed to cover demand.

To overcome these flaws we use another approach to calculate cross-border flows resulting from different market outcomes. This approach is closer to the Nodal Pricing concept in the sense that it does not rely on forecasts of the working point, but rather considers the full high voltage transmission grid without aggregated power nodes within the grid. However, the generators are aggregated per country and per technology – or even per sub-technology group in case the plants of a certain technology considerably differ in their conversion efficiency. The link between grid nodes and generators is done by so-called *Technology Generation Shift Keys (TGSKs).* These parameters indicate for a certain country how the national generation capacity of a certain technology is distributed over the nodes of the grid, i.e. it contains the share of capacity per node and (sub-) technology which sum up to 1 for the whole country. This approach does not allow to model country-internal redispatch measures. However, in the spot market clearing such redispatch is not considered anyway, since only one price per country is delivered. Basically, only on cross-border lines a maximum flow limit is imposed. This enables the algorithm to correctly deliver price differences between market zones. In case country-internal lines are also critical for cross-border transactions these lines can also be restricted. The remaining lines are only used to correctly reflect how the power flows on cross-border lines are summed up from national generation, which is a result from the market outcome.

Appendix D Auction participants, their incentives and economic efficiency

This section summarizes the incentives of the different actors assuming that we operate in a competitive setting: We do this with the help of Figure D-1, which is a refined version of Figure 2-2. Let us first focus on Member State A. Member State A´s marginal willingness to pay at the EU auction is determined by the level of the RES-e premium she would have to pay at her domestic auction for a MW of RES-e generating capacity (since for any price level below this value she would be better off in the EU auction; for any price level above this value she would be better off in the domestic auction). In a uniform price auction the level of the premium exactly covers the investment cost gap of the last supply bid selected in the domestic auction. In case the alternative of a domestic auction does not exist, for instance because a certain technology option is not available domestically, Member State A's willingness-to-pay could rise up to the level of the social benefit net of private benefits. The social benefit induced from RES-e generation differs by the location of the sites in the network where the new generating capacity is installed.

Now we also include Member State B in our consideration. In Member State B RES-e generators have more favourable conditions than in Member State A in two ways: Firstly, they can realise a higher market revenue by selling their electricity generation on the electricity market. Secondly, Member State B has better resource conditions, which leads to lower specific investment costs. In sum this leads to the RES-e generators based in Member State B asking a lower price in the EU auction than the RES-e generators based in Member State A due to the comparatively lower investment cost gap.

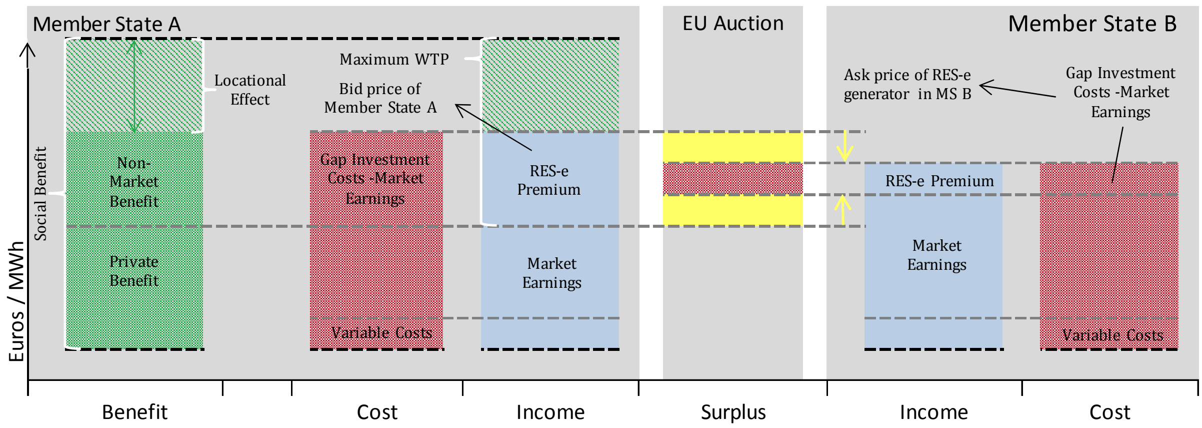

Figure D-1: Actors and their incentives for price bids in a competitive environment.

The EC has the role of the coordinating entity between the Member States. Her incentive is to coordinate the EU wide RES-e capacity expansion in order to achieve allocative efficiency. This is done by matching at each supply node the lowest ask prices of RES-e generators with the highest offered bid prices of Member States. RES-e generators generally can ask low prices if their investment costs are low and / or they can achieve high market revenues with their generation. This would lead the mechanism to choosing the system minimal cost (investment + variable + integration) portfolio of new RES-e generating capacities. Member States bid the level of the RES-e premium that they would otherwise have to pay domestically; this would lead to the marginal long-term generation costs being equalized across the EU, if the benefits from new RES-e capacities would be homogeneous for each Member State. Since this is not the case the level of the RES-e premium is weighted spatially with the BDF matrix so that long term generation costs are traded-off against locational non-market benefits. This leads the mechanism to maximising the EU-wide net benefit (= private + social benefit - costs (investment + variable + integration)) of new RES-e generating capacity.

Appendix E 2-stage formulation

For the BDF matrix calculation in the lower level a combined electricity market and network model would be used, which can typically be formulated as cost minimization problem.

$$\begin{aligned}
&\min_{q,v} \sum_n \sum_t \left(GC_{n,t} \cdot q_{n,t} \right) \\
&s.t. \\
&q_{n,t} - \overline{q}_{n,t} \le 0 \\
&\qquad \vdots \\
&h(q) = 0 \\
&g(q) \le 0 \\
&g(v) \le 0
\end{aligned} \quad (19)$$

The lower level problem is inserted to the auctioneer`s maximization problem as equilibrium constraints, which would write as follows:

$$\max_{x^D_{n,b}, x^S_{n,b}} surplus = \sum_n \sum_b \left(\sum_m \left(p^D_{m,b} \cdot BDFM_{n,m}\left(x_n\right)\right) \cdot x^D_{n,b} - p^S_{n,b} \cdot x^S_{n,b} \right) \quad (20a)$$

$s.t.$

$$q_{n,t} - \overline{q}_{n,t} + \sum_b x^S_{n,b} \le 0 \quad (20b)$$

$$\begin{aligned}
&\vdots \\
\nabla_q c(q) + \lambda^T \nabla_q h(q) + \mu^T \nabla_q g(q) &= 0 \\
\nabla_v c(q) + \alpha^T \nabla_v h(q) + \beta^T \nabla_v g(\mathrm{v}) &= 0 \\
h(q) &= 0 \\
g(q) &\le 0 \\
g(\mathrm{v}) &\le 0 \\
\mu^T g(q) &= 0 \\
\beta^T g(\mathrm{v}) &= 0 \\
\mu^T &\ge 0 \\
\beta^T &\ge 0
\end{aligned} \quad (20c)$$