

Höckner, Jonas; Voswinkel, Simon; Weber, Christoph

Working Paper

Market distortions in flexibility markets caused by renewable subsidies: The case for side payments

HEMF Working Paper, No. 05/2019

Provided in Cooperation with:

University of Duisburg-Essen, Chair for Management Science and Energy Economics

Suggested Citation: Höckner, Jonas; Voswinkel, Simon; Weber, Christoph (2019) : Market distortions in flexibility markets caused by renewable subsidies: The case for side payments, HEMF Working Paper, No. 05/2019, University of Duisburg-Essen, House of Energy Markets & Finance, Essen

This Version is available at:

<https://hdl.handle.net/10419/201588>

Standard-Nutzungsbedingungen:

Die Dokumente auf EconStor dürfen zu eigenen wissenschaftlichen Zwecken und zum Privatgebrauch gespeichert und kopiert werden.

Sie dürfen die Dokumente nicht für öffentliche oder kommerzielle Zwecke vervielfältigen, öffentlich ausstellen, öffentlich zugänglich machen, vertreiben oder anderweitig nutzen.

Sofern die Verfasser die Dokumente unter Open-Content-Lizenzen (insbesondere CC-Lizenzen) zur Verfügung gestellt haben sollten, gelten abweichend von diesen Nutzungsbedingungen die in der dort genannten Lizenz gewährten Nutzungsrechte.

Terms of use:

Documents in EconStor may be saved and copied for your personal and scholarly purposes.

You are not to copy documents for public or commercial purposes, to exhibit the documents publicly, to make them publicly available on the internet, or to distribute or otherwise use the documents in public.

If the documents have been made available under an Open Content Licence (especially Creative Commons Licences), you may exercise further usage rights as specified in the indicated licence.



House of
Energy Markets
& Finance

Market distortions in flexibility markets caused by renewable subsidies – The case for side payments

HEMF Working Paper No. 05/2019

by

Jonas Höckner,

Simon Voswinkel

and

Christoph Weber

April 2019

UNIVERSITÄT
DUISBURG
ESSEN

Open-Minded

Market distortion in flexibility markets caused by renewable subsidies – The case for side payments by Jonas Höckner, Simon Voswinkel and Christoph Weber

Abstract

Strongly increasing costs of congestion management have provoked a discussion in Europe about new approaches to solve grid congestions in a more efficient way. One approach is to design flexibility markets. In this paper we focus on the effects of subsidies for renewable energy on the market outcome of a flexibility market. We show that subsidies can cause market distortions and lead to an inefficient selection of flexibility options to solve grid congestions. We propose the implementation of side payments together with price caps and uniform pricing to achieve an efficient market design. Ultimately choosing between flexibility markets with and without side payments involves a tradeoff between minimizing system costs and maximizing renewable in-feed. Our analysis provides the framework for a conscious political choice on that subject.

Keywords: congestion management, smart markets, flexibility markets, side payments, renewables

JEL-Classification: Q41, Q48

Highlights:

- Flexibility markets decrease congestion management costs by acquiring DSM options
- RES can also offer flexibility by voluntarily curtailing power infeed
- RES consider guaranteed subsidies as opportunity costs
- RES bidding at opportunity costs can lead to inefficient and costly market outcomes
- Side payments, price caps and uniform pricing lead to an efficient market design

Jonas Höckner

(CORRESPONDING AUTHOR)

House of Energy Markets and Finance

University of Duisburg-Essen, Germany

Universitätsstr. 12, 45117 Essen

+49-(0)201 / 183-2643

jonas.hoeckner@uni-due.de

www.hemf.net

Simon Voswinkel

House of Energy Markets and Finance

University of Duisburg-Essen, Germany

simon.voswinkel@uni-due.de

Christoph Weber

House of Energy Markets and Finance

University of Duisburg-Essen, Germany

christoph.weber@uni-due.de

The authors are solely responsible for the contents which do not necessarily represent the opinion of the House of Energy Markets and Finance nor the views of the entire enera consortium.

Table of Contents

Abstract	1
1 Introduction	1
2 Regional flexibility markets.....	5
3 Bidding behavior in the regional flexibility market	6
3.1 Overview	6
3.2 Opportunity costs of demand-side flexibility	6
3.3 Opportunity costs of generation-side flexibility.....	6
3.4 Opportunity costs of wind power plants under the EEG regime.....	7
3.4.1 Feed-in tariffs and remuneration by the grid operator	7
3.4.2 Contracts between direct marketers and asset owners	7
3.4.3 Unrestricted scheduling (green light).....	8
3.4.4 Curtailment by EinsMan (red light).....	8
3.4.5 Flexibility market (yellow light).....	9
3.5 Distortions caused by EEG subsidies	10
3.6 Side payments resolve distortions.....	12
4 Application and results.....	12
4.1 Case description.....	13
4.2 Curtailment via EinsMan.....	13
4.3 Flexibility market without side payments.....	14
4.4 Flexibility market with side payments	15
5 Discussion	16
5.1 Congestion management vs overall system costs	17
5.2 Grid operator's perspective.....	17
5.3 Renewables infeed	18
5.4 Market clearing rules and bidding strategies.....	18
5.5 Coping with uncertainties	20
6 Conclusion and policy implications.....	21
7 Acknowledgements	22
8 References	23

1 Introduction

The design of electricity markets has been subject to many discussions over the last decades. Especially, different approaches how to handle grid congestions in transmission grids caused by limited line capacities provoked debates between academics (Weibelzahl, 2017). The most frequently compared concepts are nodal pricing, as it is predominant in the United States, and zonal pricing, which underlies the European market model.

Many experts refer to nodal pricing as the optimal solution, because transmission constraints are directly reflected in the market outcome by differentiated prices at the various grid nodes (Bjørndal and Jørnsten, 2001; Ehrenmann and Smeers, 2005; Hogan, 1992; Neuhoff et al., 2013; Schweppe et al., 1988). In contrast, the European electricity markets are based on a zonal market model, where there are one or at most a few price zones per country. Since May 2015, the cross-border capacity allocation in Central Western Europe is organized as flow-based market coupling and available cross border transmission capacities are auctioned implicitly based on a European load flow model (Felten et al., 2018; van den Bergh et al., 2016). In a zonal market, intrazonal congestions cannot be addressed efficiently by market splitting and grid operators need alternative congestion management methods like redispatch or countertrading to prevent congestions (Bjørndal and Jørnsten, 2007; Vries and Hakvoort, 2002). Several publications analyze the market results of zonal market models and different congestion management methods comparing it to a nodal market design (Bjørndal et al., 2003; Bjørndal and Jørnsten, 2007, 2001; Ehrenmann and Smeers, 2005; Holmberg and Lazarczyk, 2015; Oggioni and Smeers, 2013).

Due to an extensive increase of distributed renewable resources and delayed network expansions, the assumption of a copper plate within different price zones in Europe does not hold in many cases. This particularly applies to Germany, where high subsidies and a priority feed-in for renewable energy have been stipulated in the renewable energy law (EEG) which have led to a significant increase in renewable generation capacities. In combination with delayed grid expansions, the German transmission grid is not yet capable of transporting huge amounts of wind power from the North to the load centers in the South (bdew, 2018). Additionally, high shares of renewables are connected to the distribution grid, which causes critical backflows to the transmission grid in periods of high renewable infeed. Thus, the number of network congestions and the congestion management costs have increased drastically over the last years (compare Figure 1).

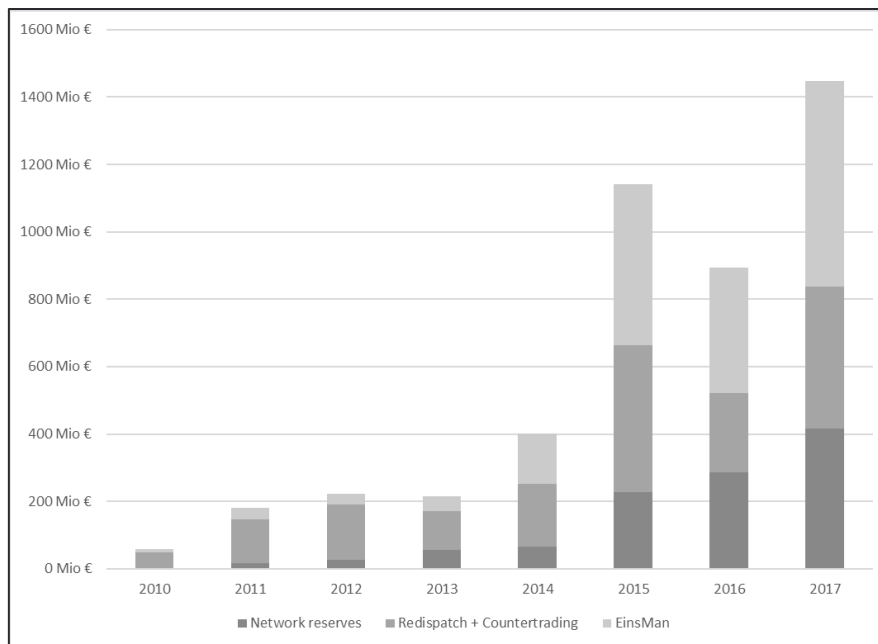


Figure 1: Congestion management costs in Germany (bdew, 2018; Bundesnetzagentur, 2018b)

Given the ambitious goals of extending renewable capacities, which will be primarily connected to the distribution grid, congestions on lower grid levels are expected to increase significantly. Thus, it is important to find new methods of congestion management that grid operators on all grid levels can apply.

To describe the complex interaction between market and grid sphere, a traffic light concept has been proposed in Germany (bdew, 2013; Bundesnetzagentur, 2011). The green phase designates situations without binding grid constraints, so that no market interventions by the grid operator are required. In contrast, the red phase indicates an actual congestion which requires direct action by the grid operator. German legislation enables the transmission grid operators to take these coercive measures and request the modification of conventional power plant schedules, that are initially based on the unrestricted market results. When these measures are exhausted and the congestion could not be averted, grid operators can curtail renewable infeed using Einspeisemanagement (EinsMan) as an ultimate measure. Compared to the set of measures that are available to transmission system operators (TSO), the distribution system operator's (DSO) options to manage congestions are limited. Besides topological measures, DSOs are basically restricted to EinsMan.¹ The idea behind the yellow traffic light is to enable new market-based approaches to efficiently prevent predicted congestions. This concept is in accordance with the strongly discussed proposal by the European Commission to use market-based mechanisms to resolve grid congestions (cf. Article 12 in European Commission, 2016; Hirth and Schlecht, 2018). The key aspect of the yellow traffic light is an intelligent interaction between grid sphere and market

¹ A new method which allows grid operators to contract controllable loads in the distribution grid has been recently introduced. Yet the formation of the statutory framework currently continues.

sphere to utilize flexibility options in the market (Aichele and Doleski, 2014; bdew, 2013). The phase explicitly addresses operators at all grid levels but has not been completely defined yet. An intensively discussed approach are smart markets which are at the heart of this paper (Bundesnetzagentur, 2011; Ecofys and Fraunhofer IWES, 2017). Smart markets serve the main purpose to acquire small-scale and decentral flexibility options, which are mainly connected to lower voltage levels, to enable secure grid operation in distribution grids (Ecofys and Fraunhofer IWES, 2017; Kornrumpf et al., 2016). These markets can in principle be utilized by transmission grid operators as well and extend existing transmission grid services.

According to Ecofys and Fraunhofer IWES (2017), two broad categories of smart markets may be distinguished (cf. Figure 2): on the one hand those, where flexibility is procured by the grid operator and on the other hand approaches where quotas of available grid capacities are allocated to grid users and possibly traded by them on a secondary market.

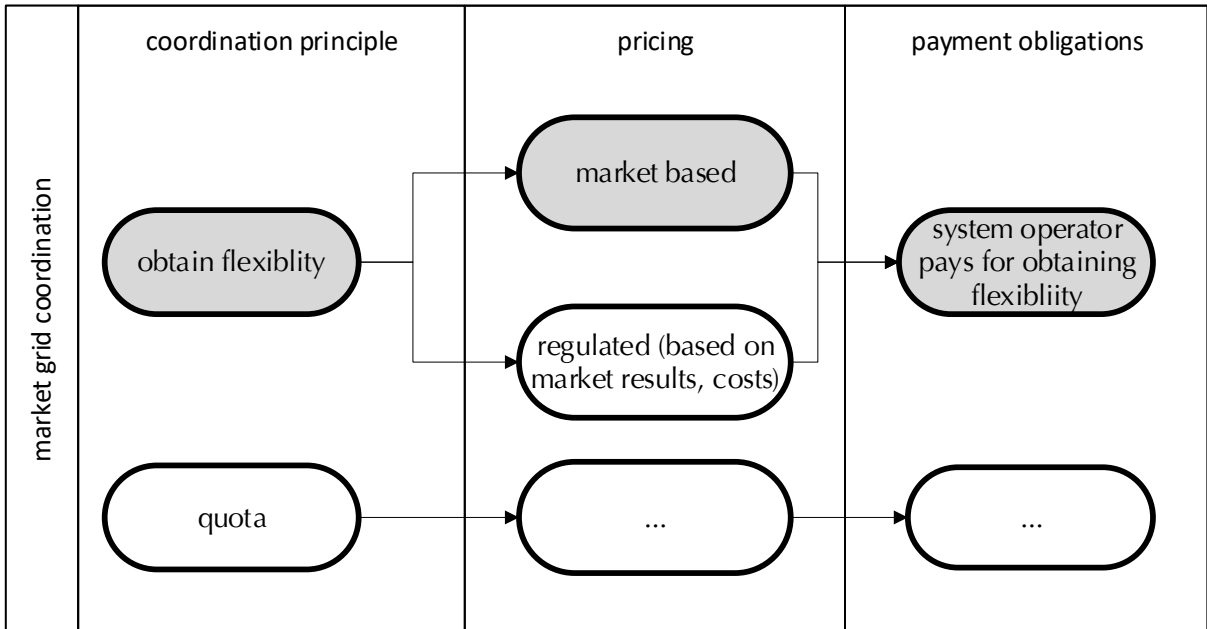


Figure 2 Key categories and potential specifications of smart markets based on Ecofys and Fraunhofer IWES, 2017, p. 24

In Germany, the project “Proaktives Verteilnetz” (proactive distribution grid) aims to demonstrate a quota based smart market (Wiedemann, 2017). Applying new approaches for distribution system state estimation, the grid operator determines an individual and non-discriminatory power range per retail company. Thereupon each retail company can decide individually how to fulfill these restrictions most efficiently. The concept of a secondary trading platform for these flexibility calls is evaluated as well.

As examples of markets where flexibility is procured explicitly, the E-Energy projects² implemented manifold market platform solutions with the intention to integrate new decentral players to an innovative market setting (Karg et al., 2014). While “eTelligence” designed regional products that could be utilized by grid operators as ancillary services, the project “E-DeMa” developed a market to acquire new demand side flexibilities (Agsten et al., 2013; Koch et al., 2012). Furthermore, “MeRegio” designed a hybrid model based on the idea of the capacity traffic light, which enables grid operators to tender the elimination of a certain grid congestion on a market platform (Karg et al., 2014).

Apel et al. (2014) conceptually designed a flexibility market “RegioFlex” that enables system operators to access flexibilities in the system to prevent congestions. Currently, several projects of the SINTEG³ program further develop and demonstrate regional flexibility platforms in order to test new approaches to ensure secure grid operation with high shares of intermittent power generation (BMW, 2016). The showcase enera, for example, implements a regional flexibility platform based on local order books in cooperation with EPEX Spot in order to set up regional ancillary services to manage grid congestions.

This article focuses on smart markets designed as regional flexibility markets. We subsequently analyze the effects of subsidies for renewable energy sources on the outcome of a regional flexibility market. We show that subsidies can cause market distortions and lead to an inefficient selection of flexibility options. We also discuss how external payments may solve this problem. The discussion is rooted in the specific German context in order to avoid lengthy discussions of the broad variety of regulations in place, yet we believe the results obtained can also be transferred to other legislations with renewable support schemes, zonal markets and congestion management issues in the distribution grid.

The paper is organized as follows: In section 2 we describe the regional flexibility markets as underlying this paper. Actors and their incentives for participating in the flexibility market as well as distortions caused by subsidies and the resolution of these distortions are discussed in section 3. An illustrative example is given in section 4, which demonstrates the problem of market distortions caused by EEG subsidies and how side payments can help with the solution. In section 5

² The E-Energy projects were funded by the Federal Ministry of Economics and Technology (BMW) and Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) and comprised six flagship initiatives (eTelligence, E-DeMa, MeRegio, moma, RegModHarz and Smart Watts), which focused on the ICT-based energy system of the future.

³ “The Smart Energy Showcases - Digital Agenda for the Energy Transition” (SINTEG) is funded by the Federal Ministry of Economics and Technology (BMW) and aims to set up large-scale showcase regions for developing and demonstrating model solutions that can deliver a secure, efficient and environmentally compatible energy supply with electricity being generated to a large extent from volatile sources such as wind or solar. The showcase projects are enera, WindNODE, C/sells, Designnetz and NEW 4.0.

we discuss the concept and implications of side payments and derive practical recommendations for future regulation. Finally, section 6 summarizes the results.

2 Regional flexibility markets

As discussed in section 1, one important category of smart markets is the regional flexibility market. In this market, grid operators buy the flexibility they need to manage congestions from market participants, who in turn adjust the dispatch of their assets to conform to the trades they made on the market platform.

In our analysis we consider a regional flexibility market structured according to this concept. Additional assumptions are that participation is open to any asset already able to participate in spot markets, but not mandatory. Further every participant can freely set bid offers as they see fit, with the system allowing free price formation as it is recommended by Ecofys and Fraunhofer IWES (2017) for wind dominated network areas. Therefore, assets are in competition with each other, the grid operator chooses the best options among the offers.

For what follows, no assumptions are necessary as to the method by which effectiveness regarding the removal of congestions is assessed or regarding the way regionality is established.

We define flexibility as the deviation of actual power infeed (or withdrawal) from a previously planned baseline. Participants sell their willingness to deviate from the previously planned baseline to the grid operator and in turn must then adjust the actual infeed or withdrawal from their assets. Additionally, participants whose bids are accepted need to buy or sell the energy on the spot market to keep the system balanced.

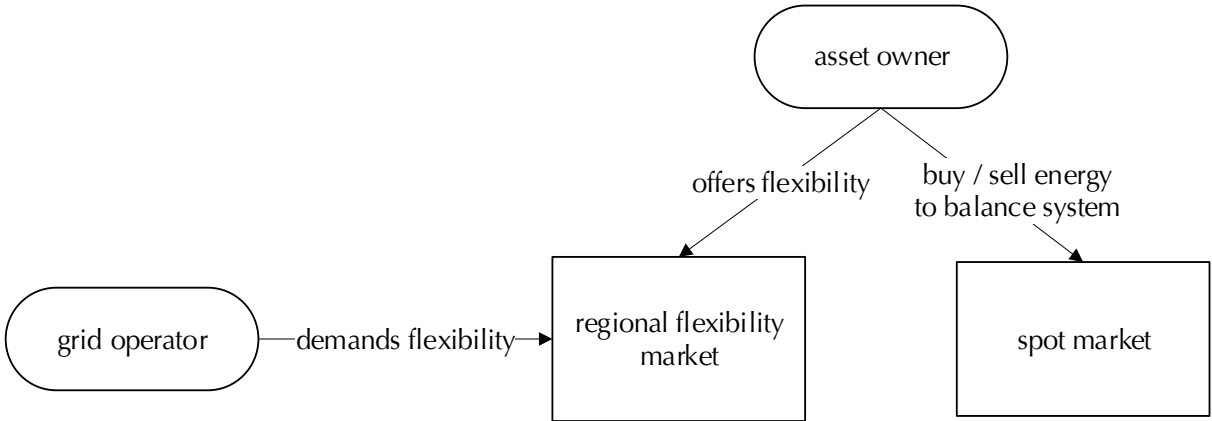


Figure 3: Interaction between grid operator, asset owner and flexibility / spot markets

3 Bidding behavior in the regional flexibility market

3.1 Overview

In any market, a market participant who has no obligation to participate will only conclude a trade if its (expected) profits exceed profits obtained under other marketing alternatives. Hence any flexibility provider in a flexibility market will base its bid into the market on opportunity costs, i.e. foregone profits from alternative operation and trading strategies. Therefore, the opportunity costs of flexibility providers must be considered in detail in order to determine their bidding behavior in the market.

Especially opportunity costs of wind power plants are essential to consider, because they represent in principle a large potential of flexibility in future power system. In periods of excess production, curtailing wind infeed is always an option – it is obviously not beneficial in terms of CO₂ emissions, but might be more cost efficient than other alternatives. Thereby, the market premium, which is an important part of the governmentally guaranteed remuneration, can induce market distortions and therefore has to be examined in more detail.

The next sections will discuss the opportunity costs of different types of assets and in detail those of wind power plants. Afterwards, market distortions caused by the EEG-subsidies will be analyzed and solutions to these distortions suggested.

3.2 Opportunity costs of demand-side flexibility

For demand-side assets participating in the regional flexibility market, one must assume that care has already been taken to optimize their dispatch on the spot market. Therefore, any action taken to assist the grid operator in solving a problem it may have (e.g. a looming congestion), will take the asset in a direction away from its optimal dispatch.

Opportunity costs of demand-side flexibility are hard to quantify. They include the costs of electricity at different times, marginal utility of dispatch and operational costs such as personnel. For the purposes of this paper we abstract from the actual opportunity costs and assume that the flexibility offered to the grid operator will have some price attached to it. Further the costs incurred by the grid operator when choosing this flexibility will correspond to the bid price of the asset, undistorted by savings elsewhere.

3.3 Opportunity costs of generation-side flexibility

Opportunity costs for generation-side flexibility are more easily determined than for demand-side flexibility. For increasing as well as decreasing dispatch they will be largely determined by fuel costs, offset by the revenue generated when selling (or buying) this additional (or now missing) energy on the spot market.

As with demand-side flexibility in section 3.2, we abstract from actual costs, and only assume that some sort of cost will be associated with a modification of their dispatch and hence demanded on the regional flexibility market. Also, as with demand-side flexibility, these costs incurred by the grid operator will be actual additional costs.

3.4 Opportunity costs of wind power plants under the EEG regime

Opportunity costs of wind power plants under the EEG regime are determined by a multitude of factors, ranging from feed-in tariffs to different scenarios for production and curtailment. In the following sections each of these factors will be examined in detail.

3.4.1 Feed-in tariffs and remuneration by the grid operator

Most wind power plants in Germany are subsidized in the EEG system. As of January 1st, 2016, all newly installed wind power plants above 100 kW nameplate capacity in the EEG system have to sell their energy directly on the spot market (§19 EEG, so-called “direct marketing”) as opposed to earlier systems, where marketing of the energy was done by the responsible transmission system operator. To market the energy on the spot market, aggregators can be employed to minimize transaction costs for the individual asset owners. As it stands, only directly marketed wind power plants with or without subsidies in the EEG system can participate in a regional flexibility market of any kind. As by far the biggest part of wind power plants in Germany are subsidized in the EEG system, we will only consider wind power plants that are in direct marketing, remotely controllable, and subsidized in the EEG system. The EEG system guarantees a feed-in tariff determined by the German Renewable Energy Act (§19 EEG in combination with §20 EEG). The guaranteed EEG tariff of a specific asset depends on several factors such as commissioning year and technical specifications.

The remuneration for these power plants consists of two parts: spot market revenues and the so-called market premium (MP), with the market premium intended to fill the gap between the guaranteed EEG remuneration and spot market revenues. The market premium is determined monthly for each asset as the difference between its specific EEG feed-in-tariff and a monthly market value (*MMV*), which is an index calculated as a (wind-energy) volume weighted average spot price that is supposed to represent the average spot revenues made by selling the wind power at the spot market. Both, the market premium and the monthly market value, are determined ex-post, as market data is necessary for the calculation.

3.4.2 Contracts between direct marketers and asset owners

We assume there is a contract between asset owner and direct marketer, where the asset owner receives remuneration in the amount of the monthly market value from the direct marketer. Together with the market premium received from the grid operator, the asset owner thus receives

the full feed-in tariff for each produced MWh of electricity. The direct marketer carries the market risk but can also keep all market income exceeding the *MMV*. We further assume that the grid operator only pays the market premium for *actually*, not *potentially* produced electricity; the same holds for the direct marketer who will not pay the asset owner if infeed is curtailed by the grid operator. However, the grid operator reimburses the asset owner for these lost revenues in case of EinsMan curtailment. If the direct marketer curtails the power plant outside EinsMan, it must reimburse the asset owner, as the grid operator will not pay the market premium for a voluntarily curtailed power plant.

For the most part in our analysis, we treat the direct marketer and the asset owner as a single entity. The terms of contract between both parties only become relevant when talking about the reimbursements by the grid operator. In this case, it is important to note that we use as working assumption that the grid operator does not have an obligation to reimburse the direct marketer, but only the asset owner.⁴ We will point out the difference in the relevant parts of this paper.

3.4.3 Unrestricted scheduling (green light)

If no congestions have been identified, the wind power plant can feed in all generated electricity without restrictions. The direct marketer will receive the revenues from the sale of electricity due to direct marketing at the wholesale market (p_{DA}) and pays the *MMV* to the asset owner. Additionally, the grid operator will pay a market premium to the asset owner for every MWh fed into the network, such that the revenues of the wind power plant sum up to the warranted EEG tariff. The opportunity costs per MWh are

$$R_{Normal} = P_{DA} + MP$$

The monthly market value does not feature in this equation, because it is paid by the direct marketer and received by the asset owner. It is therefore an internal cash flow not of direct interest in this analysis. Given the green phase, the market premium is paid out of the so-called EEG account for which cash inflows are collected through the EEG levy from the electricity customers. These details are of considerable relevance when the overall system costs of flexibility markets are to be assessed (see section 5.1)

3.4.4 Curtailment by EinsMan (red light)

In case of a grid congestion, regulation allows the grid operator to curtail wind energy infeed as an ultimate measure (EinsMan, cf. section 1). In doing so, regulation stipulates that the grid operator who is responsible for the curtailment has to compensate the asset owner for lost revenues

⁴ This assumption is not uncontroversial. For a discussion see for example Bundesnetzagentur (2018a).

(*EEG*).⁵ Under the assumption that the direct marketer sold the predicted wind power infeed on the spot market for a price P_{DA} , additional costs arise for balancing because the balancing group manager has to offset imbalances caused by the unscheduled curtailment due to EinsMan operations. This can be done by purchasing energy at the intraday market or paying for balancing energy. In practice, there is often no time to balance at the intraday market so that costs for balancing energy incur (P_{BC}). Consequently, the opportunity costs per MWh can be described as

$$\begin{aligned} R_{EinsMan} &= P_{DA} - P_{BC} + EEG \\ &= P_{DA} - P_{BC} + MP + MMV \end{aligned}$$

The MP and MMV are paid by the grid operator as compensation for lost revenues directly to the asset owner, bypassing the direct marketer. The MP is paid as compensation, because payment of the “normal” MP depends on *actually* produced energy. The MMV has to be paid because the asset owner does not get remuneration for the curtailed energy from the direct marketer, and the MMV therefore constitutes lost revenues (see section 3.4.2).

3.4.5 Flexibility market (yellow light)

The auctions of the platform are held intraday with a lead time long enough for flexibility providers to modify their mode of operation and offset imbalances at the intraday market (for a price P_{ID}). If the wind power plant already sold the power on the day ahead spot market (P_{DA}) and then successfully offers voluntary curtailment in the flexibility market (for a price P_{FM}), the revenues sum up to

$$R_{FM} = P_{FM} - P_{ID} + P_{DA}$$

To participate in the flexibility market, the direct marketer has to receive at least the opportunity costs of the marketing alternative. In case of a congestion, the alternative would be EinsMan and the opportunity costs would be determined as explained in section 3.4.4. Therefore, the minimum price that the direct marketer has to receive to participate in the flexibility market is as follows:

$$\begin{aligned} R_{FM} &= R_{EinsMan} \\ \Leftrightarrow P_{FM} - P_{ID} + P_{DA} &= P_{DA} - P_{BC} + MP + MMV \\ \Leftrightarrow P_{FM} &= P_{ID} - P_{BC} + EEG \end{aligned}$$

⁵ §15 EEG defines that the compensation shall cover 95% of lost revenues plus additional expenses minus saved expenses. If lost revenue exceeds 1 per cent of the annual revenues, the amount will be fully compensated from that date. For simplicity, we will calculate with 100% and it is assumed that wind power plants have no saved expenses in case of curtailment.

Note, that the grid operator would compensate the asset owner rather than the direct marketer for lost revenues in the EinsMan. The direct marketer “inherits” this responsibility from the grid operator when it decides to curtail the infeed voluntarily, as explained in section 3.4.2.

The formula above highlights that the direct marketer must cover the EEG remuneration that the asset owner would otherwise receive from the grid operator if the plant were curtailed through EinsMan. Additionally, it might be willing to accept less than the full EEG tariff, because compared to EinsMan the direct marketer saves part of the costs for balancing energy ($P_{ID} - P_{BC}$) by balancing on the intraday market compared to the costs of buying balancing energy, which is the normal case in EinsMan.⁶ Furthermore, the direct marketer might have some additional costs or savings when curtailing itself voluntarily as opposed to forcibly. We introduce a term C_{add} which is specific to each direct marketer and can be positive or negative to represent those additional costs or savings. In our further considerations we will simplify the equation by specifying that

$$\begin{aligned} P_{FM} &= P_{ID} - P_{BC} + EEG + C_{add} \\ &= EEG - X \\ &= MP + MMV - X. \end{aligned}$$

The bid price is therefore the plant-specific EEG tariff corrected by an additional X-term, the value of which will be determined by the direct marketer.

3.5 Distortions caused by EEG subsidies

As seen in section 3.4.5, the bid price for wind power plants in the EEG scheme with direct marketing is based on the plant-specific EEG subsidies. In the following we show that the grid operator incurs part of these costs regardless of whether the wind power plant produces normally, is curtailed by EinsMan, or voluntarily reduces output because of its commitments in the flexibility market.

While producing normally, cash flows from the grid operator to the wind power plant and direct marketer per MWh are

$$CF_{GO,normal} = MP.$$

If curtailed by EinsMan, cash flows from the grid operator to the wind power plant and direct marketer per MWh are

$$CF_{GO,EinsMan} = MP + MMV.$$

⁶ This is under the assumption that the direct marketer does not try to game the system by profiting of balancing energy.

In the flexibility market the bid price per MWh of the direct marketer (expecting EinsMan as the alternative) would be

$$P_{FM} = P_{ID} - P_{BC} + \mathbf{MP} + MMV + C_{add}$$

and this is the basis for the cash flow from the grid operator to the direct marketer if the bid is selected. It is apparent from these equations that the market premium is a fixed part of cash flows from the grid operator to the wind power plant / direct marketer. From an overall economic point of view, the grid operator should not consider the market premium for renewables when selecting flexibilities based on the merit order because it will be paid anyway: Either

1. the wind power plant is not running, and the grid operator must pay the market premium as part of congestion management (as compensation in case of curtailment, or implicitly as part of the bid price in case of voluntary shut downs) or
2. the power plant is running, and the market premium must be paid as EEG remuneration.

From an economic perspective, the market premium is paid either way and thus should not be included in the calculus when the optimal congestion management flexibilities are chosen. Consequently, an alternative flexibility option will only decrease overall costs when it is cheaper than renewable flexibilities excluding the market premium.

The merit order of flexibility options is biased if wind power plants with market premia of different amount and / or other flexibility options without market premia bid in the same market. These uncorrected merit orders are sources of bias because they are including factors which should not be relevant for the decision about which flexibility options to contract.

Three effects can be distinguished:

1. Shifts in the merit order within the group of wind power plants because of different market premia. This leads to an inefficient selection of wind power plants to contract because the market premium will be paid either way and should not play a role when choosing flexibility options.
2. Shifts in the merit order between wind power plants and other flexibility options, which make wind power plants look more expensive than they are compared to alternatives.
3. The grid operator will not be able to judge how much it should be willing to pay for flexibility in lieu of EinsMan curtailment because it does not know the real (effective) cost when choosing flexibility options.

These distortions can be avoided by paying the market premium independently of the bidding decisions of the direct marketer – then it is not part of the opportunity cost considerations of the direct marketer which consequently does not include it in its flexibility offer. Adjusting the merit

order of the flexibility market can hence ensure that the grid operator will find the overall economic optimum when selecting flexibilities based on the merit order. We suggest the implementation of side payments, which exclude market premia from the flexibility market as described in section 3.6.

3.6 Side payments resolve distortions

As detailed in section 3.4.5, the reason for direct marketers to include the market premium in the bid price on the flexibility market is that it “inherits” the responsibility to remunerate the asset owner if it voluntarily curtails the wind power plant, because the grid operator will only compensate the asset owner if the wind power plant is running or “forcibly” curtailed by EinsMan.

There are therefore two ways to enable the direct marketer to not include the market premium in the bid price:

1. Pay the asset owner regardless of whether the wind power plant is voluntarily curtailed or not.
2. Add an additional payment equaling the market premium to the direct marketer when contracting voluntary curtailment on the flexibility market.

As there are other reasons to voluntarily curtail the wind power plant (e.g., scheduled or unscheduled maintenance) for which the grid operator should not reimburse the asset owner with the market premium, payment should be coupled to a contract on the flexibility market. We will refer to such payments as *side payments*. They will be paid retroactively to qualifying EEG subsidized power plants taking part in the flexibility market for each unit of flexibility sold. Because of the introduction of guaranteed side payments, which cover parts of the opportunity costs explained in section 3.4.5, renewable flexibility providers will decrease their bids in competitive markets by the same amount. Consequently, the market premium will be externalized from the flexibility market and an undistorted flexibility merit order is obtained. All bids then represent true additional costs incurred by the grid operator.

The next section will give examples of the effect side payments (and a lack thereof) have on the merit order of flexibility options.

4 Application and results

Based on the considerations in section 3, we construct an example to illustrate how flexibility markets can contribute to congestion management. We compare the results of congestion management without a flexibility market, which is basically EinsMan, i.e. renewable curtailment, to the market results of a flexibility market with and without side payments. In this comparison we focus on overall system costs and the energy infeed of renewables.

4.1 Case description

Given that our focus is on congestion management, we disregard all cost and revenue streams related to energy spot markets, as these stay constant, and consequently system costs only include costs for congestion management plus the EEG remuneration of renewables since the latter may be affected by the congestion management. In doing so, one must be careful when adding up these different cost components, since the costs of congestion management are financed by network charges whereas the costs for supporting EEG plants are paid out of the EEG account. In this section both cost components will be treated as part of system costs, but they are analyzed more in detail from a grid operator's perspective in section 5.2.

Table 1 details a situation where the grid operator predicts a congestion at a transformer of the distribution grid that it can manage using five different flexibility providers in a market area.

Table 1 Available flexibility options. Total needed flexibility is 3 MW, available flexibility per plant is 1 MW.

Name	Type	MMV	MMV +- X	MP	Other
RES 1	Wind Onshore	35	35	30	
RES 2	Wind Onshore	35	30	45	
RES 3	Wind Onshore	35	20	60	
Other 1	non-RES				15
Other 2	non-RES				60

In the example, three different wind farms may offer to curtail power infeed voluntarily on the market at opportunity costs as well as two other plants which can adjust their load / infeed, the details of which are not important for the example.⁷ For simplicity, we assume that all actors can offer a flexibility of 1 MW and the grid operator's flexibility demand is 3 MW. For the wind farms the table shows the monthly market value, which is the same for all wind onshore plants. Another column details the monthly market value offset by a value "X" which represents any markup or a markdown from the total feed in tariff, such that

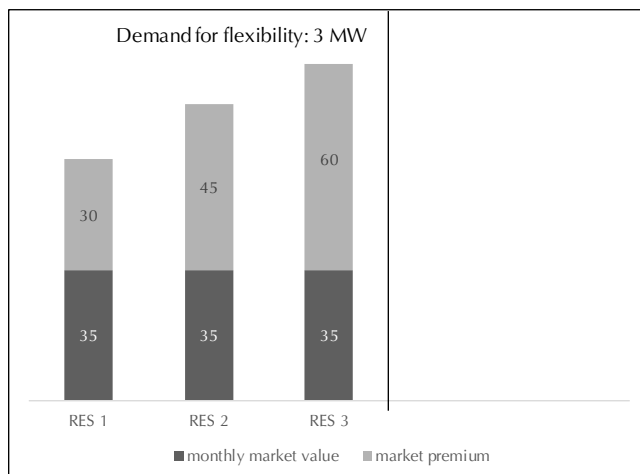
$$P_{FM} = EEG - X = MP + MMV - X.$$

The "X" sets wind power plants apart from each other in the flexibility market and may represent risk premia, expected cost savings or any other factors.

4.2 Curtailment via EinsMan

Today, no market-based instrument allows the distribution grid operator to make use of industrial loads or the storage flexibilities to manage congestions. That is why the grid operator would fall back on EinsMan and curtail the wind infeed as illustrated below.

⁷ The costs of these actors are fictitious and do not necessarily represent the true opportunity costs of comparable real assets.



Costs for flexibility

Name	Type	MMV	MP	other
RES 1	Wind Onshore	35	30	
RES 2	Wind Onshore	35	45	
RES 3	Wind Onshore	35	60	

Costs for running RES

Name	Type	MMV	MP	other

Total relevant system costs

Type	Value
Congestion management	240
Running plants	0
Total	240

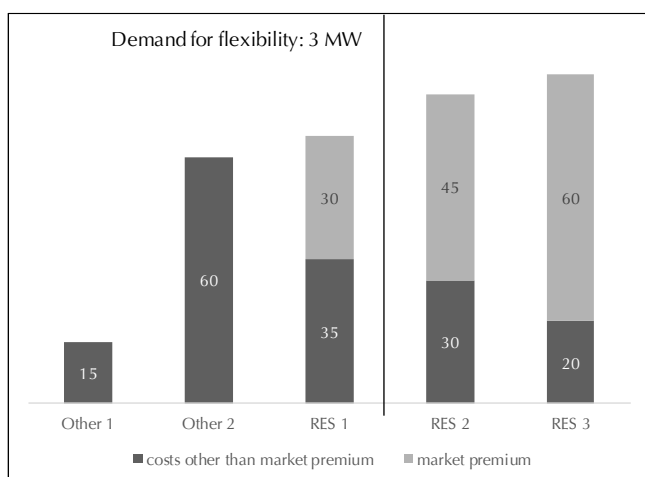
Figure 4 Merit order of flexibility options and costs in the EinsMan curtailment

On the left side of Figure 4 the merit order of the EinsMan measures is shown. Efficient EinsMan would select the power plant with the lowest EEG tariff first for congestion management, followed by the second and third cheapest flexibilities. To successfully avert the grid congestion, all wind power plants must be curtailed resulting in EinsMan costs of 240 €. This amount corresponds to the overall costs since no market premia for operating wind power plants must be paid. At the same time, it is the benchmark to assess the market result of the flexibility platform.

4.3 Flexibility market without side payments

The introduction of a flexibility market enables the grid operator to contract flexible loads and batteries for congestion management. Due to the inclusion of new and cheaper flexibility options, the merit order is changed as shown in Figure 5. In this case, revenues from the flexibility market must cover opportunity costs of renewables as described in section 3.4.5. Thus, the bids must correspond approximately to the foregone EEG remuneration. Non-renewable flexibilities in contrast are assumed to bid at marginal costs.⁸ If non-renewables can bid at lower costs than EEG remuneration, EEG-power plants move to the right in the flexibility merit order.

⁸ For a discussion of strategic bidding see section 5.4.



Costs for flexibility

Name	Type	MMV +- X	MP	other
RES 1	Wind Onshore	35	30	
Other 1	non RES			15
Other 2	non RES			60

Costs for running RES

Name	Type	MMV	MP	other
RES 1	Wind Onshore			
RES 3	Wind Onshore		60	
RES 2	Wind Onshore		45	

Total relevant system costs

Type	Value
Congestion management	140
Running plants	105
Total	245

Figure 5 Merit order of flexibility options and associated costs on a flexibility market

In the example, Other 1 as cheapest flexibility option would be selected first, followed by Other 2. To solve the congestion completely, the grid operator can limit curtailment to only the cheapest of the wind power plants (RES 1). This results in congestion management costs summing up to 140€.⁹ However, since the power plants RES 2 and RES 3 generate power and are compensated in accordance with §19 EEG in combination with §20 EEG, the market premium is paid to these units and has to be considered in a system perspective. This finally adds up to overall costs of 245 € which leads to an increase of system costs compared to the reference case of EinsMan despite decreasing congestion management costs.

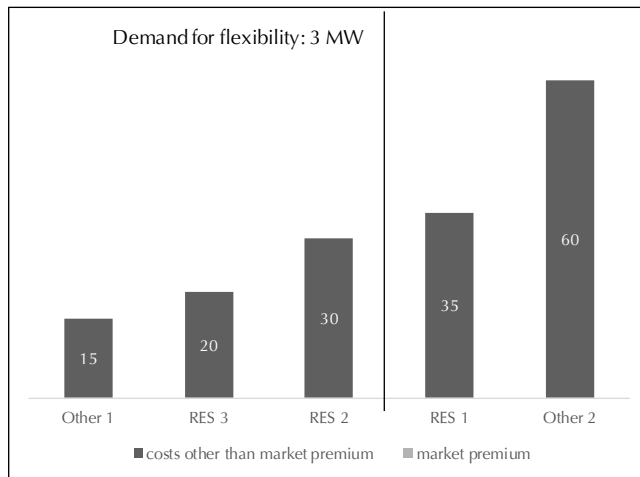
4.4 Flexibility market with side payments

Contrary to the previous example, in this example the wind power plants RES 1, RES 2 and RES 3 receive their individual market premium as a side payment if they successfully bid in the flexibility market. Thus, their bids do not have to fully cover the EEG tariff plus mark-up but only the *MMV* adjusted for *X*

$$bid_{flex}^{wind} = MMV + MP - X = MMV - X$$

Consequently, the merit order changes significantly as shown in Figure 6. Now, the wind flexibilities are cheaper compared to Other 2 and the grid operator would select Other 1, RES 2 and RES 3 to manage the congestion. This results in congestion management costs of 170€. These costs consist of the payments for accepted bids on the market (Other 1 and the two wind power flexibilities) and the side payments for RES 2 and RES 3, which the grid operator will pay out after determination of the market premium.

⁹ Note that we assume that the market clears on a pay-as-bid basis. For a discussion of market clearing rules see section 5.4.



Name	Type	MMV +- X	SP	other
Other 1	non RES			15
RES 2	Wind Onshore	30	45	
RES 3	Wind Onshore	20	60	

Name	Type	MMV	MP	other
RES 1	Wind Onshore		30	
RES 2	Wind Onshore			
RES 3	Wind Onshore			

Type	Value
Congestion management	170
Running plants	30
Total	200

Figure 6 Merit order of flexibility options and associated costs on a flexibility market utilizing side payments

Given this scenario, RES 1 feeds in power without restrictions and its market premium must be paid additionally, leading to overall system costs of 200€ - a new minimum.

Three significant changes result from the introduction of side payments compared to a flexibility market without side payments:

1. Overall system costs decrease significantly, since all arising cost components are reflected adequately in the decision of flexibility selection. It should be noted that, although overall system costs decrease, costs of congestion management increase slightly.
2. Flexibilities provided by renewables improve their position in the merit order. This leads to more curtailment of renewable power.
3. The position of the renewable plants within their "group" change. While RES 1 was the cheapest option before, it is now the most expensive because its "X" is smallest. This illustrates that once the individual market premia stop distorting the bids, individual cost factors of the plants become relevant.

5 Discussion

Table 2 provides an overview of the considered cases. Several aspects are worth noting and will serve as basis for further discussions. First, markets without side payments minimize congestion management costs while overall system costs can be even higher than in case of EinsMan. In contrast, a flexibility market with side payments can lead to an efficient selection of flexibilities from an overall system perspective, at the same time resulting in higher congestion management costs than achieved without side payments. Consequently, there is a trade-off between the minimization of congestion management and overall system costs when choosing the best market design. This problem has to be examined in more detail. Additionally, the introduction of side

payments leads to lower renewables infeed compared to a flexibility market without side payments. Lastly, the interplay between market clearing rules and bidding strategies of flexibility providers is investigated in more detail.

Table 2 Summary of associated costs in the example cases

Type	funding source	EinsMan	Market w/o SP	Market w/ SP
Congestion management	Grid tariff	240	140	170
Operating EEG plants	EEG account	0	105	30
Total Costs		240	245	200
RES infeed in MW		0	2	1

5.1 Congestion management vs overall system costs

The introduction of a flexibility market decreases congestion management costs compared to EinsMan in both cases, both with and without side payments (-70€, respectively -100€). This is logical because system operators can apply new and cheaper flexibilities to manage congestions. It is also clear that congestion management costs in a market without side payments are lowest because the grid operator can select flexibilities with the lowest absolute costs, which the grid operator must compensate itself.

However, in a market without side payments, the market premium has a great effect on the selection of flexibilities, although the market premium has to be paid anyway. Therefore, a market without side payments, even though it leads to the lowest costs of congestion management, may induce higher overall costs than curtailment via EinsMan when considering congestion management and EEG cost as shown in previous sections (EinsMan: 240€, Market without SP: 245€). In order to prevent the grid operators from making market decisions based on non-influenceable cost components, side payments are introduced. In this case, the overall costs are minimized because the cheapest flexibilities which are having an actual impact on the overall system costs are selected.

5.2 Grid operator's perspective

Since grid operators are acting for their own account, they are likely to prefer a market outcome which minimizes their own cost, namely congestion management costs, rather than overall system costs. Minimizing congestion management costs in a market without side payments would lead to lower network fees and relieve the grid operator's customers. Given that the minimization of congestion management costs can entail higher overall system costs, this comes along with a transfer of costs to all customers via a higher renewable levy. From an overall system perspective, higher EEG-levy payments for all consumers would overcompensate the lower network charges for a few customers of a certain grid operator – at least in an electricity system like the German one with multiple distribution grid operators.

Here incentives for grid operators should be aligned so that they are incentivized to choose the solution with the lowest overall cost. This is also true for the more general issue of incentives to minimize congestion management costs. If those are considered as pure pass-through item as in the current German regulation, the incentives to implement flexibility markets are very limited. Yet a detailed discussion of regulatory approaches in that field is beyond the scope of this paper.

5.3 Renewables infeed

Since flexibility providers ask for compensation of the whole feed-in tariff as opportunity costs, the bids in the market without side payments are quite high and renewable flexibilities are expensive compared to other flexibility options. That is why without side payments, the wind power flexibilities would be selected last by the grid operator which leads to the highest renewable infeed possible in our example (2 MW). With the implementation of side payments, the market prices for flexibility from renewables are lower. That is why renewable flexibilities would be selected more frequently and the infeed of renewables would decrease, in our numerical example to 1 MW.

However, compared to currently used EinsMan, the infeed of electricity generated by renewables increases in both variants of flexibility markets. This is a consequence of new demand-side flexibility options being made available for congestion management through the introduction of the flexibility markets.

In the end, it is hence a political choice, which flexibility market design is preferred. The choice then reflects a tradeoff between overall costs and the maximization of renewable infeed, which should be made consciously and not just as an unintended side effect.

5.4 Market clearing rules and bidding strategies

So far, the discussion has focused on the cost impacts of the different flexibility market designs. Thereby the pricing and other market clearing rules of the flexibility market have been disregarded. Yet one may wonder about the pricing implications of the different market designs and this requires a consideration of the market rules and related agent behavior.

Basically, two alternatives may be considered for the pricing rule: uniform pricing (also called pay-as-cleared) or pay-as-bid (or discriminatory pricing). Whereas auction-based energy spot markets typically use uniform pricing, pay-as-bid has been prevalent in the German and other reserve power markets. At first sight, pay-as-bid has the advantage that the buyer (in our case the grid operator) does not pay more than requested by the sellers. Yet this reasoning does not consider that sellers will adapt their bidding strategy to the clearing rules. Academic literature indicates that uniform pricing rules provide more incentives for cost-based bids whereas pay-as-bid

leads to “guess-the-price” type bidding behavior (e.g. Wolfram, 1999, Newberry and McDaniel, 2002, Cramton, 2017). Under perfect competition and complete information it may even be proven that the two auction formats lead to the same result (Müsgens et al., 2014). Hence bidding at marginal costs is no valid assumption in a pay-as-bid market design and independently of the auction design in flexibility markets, the grid operator as buyer will pay more than the cost of the bidders. This is visualized in Figure 7 for the case of uniform pricing – which is at identical marginal bids the upper bound for prices under pay-as-bid.

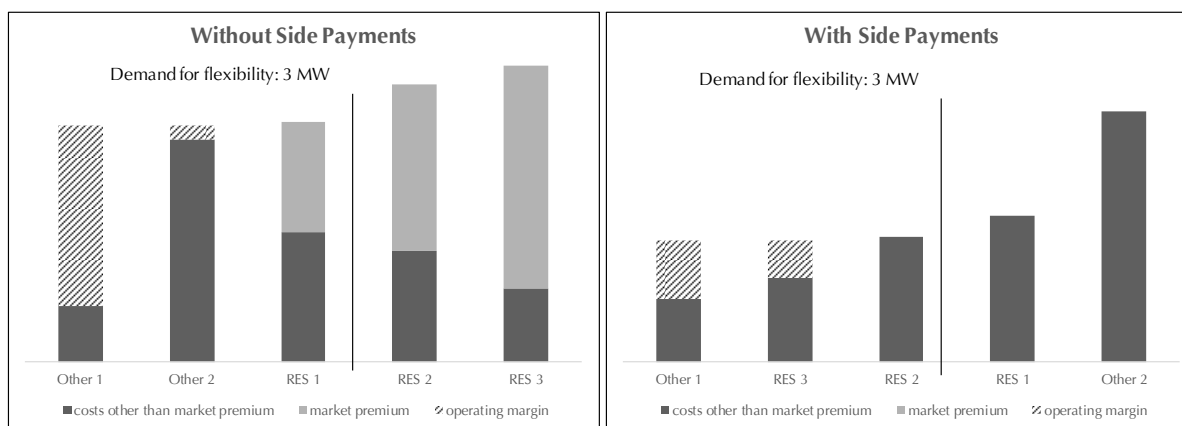


Figure 7 Uniform pricing in markets without and with side payments and resulting

If there is moreover only a limited number of bidders, those may bid strategically and exert market power. In this setting, it is important to ensure that the system costs are not higher than under the traditional command and control strategy of EinsMan and that at the same time there are sufficient incentives for market entry. This calls for a market design combining the following three elements:

- Uniform pricing,
- Clear price caps to avoid costs in excess of EinsMan,
- Side payments.

The two main arguments for uniform pricing are that bidding is simpler for small market participants since they can bid their marginal costs instead of having to guess the price and that the incentives for putting strategic bids are lower (since they only occur for marginal units). The price cap is required to ensure that the market provides economic benefits, and the side payments make setting this price cap both easier and more efficient. The discussion in section 3.5 has shown that the market premia MP must be paid independently of the market design as well as under EinsMan. Under EinsMan, the additional payment to all curtailed EEG units is the monthly market value MMV . Therefore, this is the price cap to be used in the flexibility market with side

payments.¹⁰ This ensures that the system costs in this market design do not exceed the cost of the conventional approach.¹¹ Furthermore, congestion management cost will not exceed the corresponding cost under EinsMan. For the flexibility market without side payments, setting the price cap is not as easy since it will depend on the mix of EEG units curtailed under EinsMan and the corresponding *MP*. If this is established correctly, the congestion management cost may be kept under the EinsMan cost, yet this is not true for the system cost as established previously. Figure 7 even illustrates that the operating margins earned in a market without side-payments may be substantially higher than with side payments – i.e. the distributional effects are stronger, with the flexibility providers as beneficiaries and the consumers (via grid fees and EEG levy) as the losers. On the other hand, the limited operation margins in flexibility market with side payments still provide incentives for market entry.

5.5 Coping with uncertainties

Side payments are intended to counter distortions in the market by removing the market premium from the bid price of renewable flexibilities. This is complicated by the fact that the values of the individual market premia are unknown at the point of bidding, because they are calculated as the difference between the monthly market value of the given renewable power source and the individual power plants EEG feed-in tariff.

Consequently, the direct marketers as well as the grid operators have to predict the monthly market value. The direct marketer has to predict the *MMV* because it provides the base line for its bid price. The grid operator has to predict the *MMV* to determine the price cap in order not to exceed EinsMan costs.

This raises the question, what effect uncertainties with respect to the *MMV* have on the market. If both the direct marketers as well as the grid operator are risk averse, they may place uplifts on their bids and discounts on the price cap, respectively. This reduces the leeway for market clearing since even if both the grid operator and the direct marketers predict the same *MMV* bids may be placed above the price cap.

One possible solution could be for the grid operator to announce a “benchmark *MMV*” before the flexibility auctions. Rather than calculating the side payment based on the actual (later) established *MMV*, the side payment would be calculated using the benchmark *MMV*. The direct marketers could be sure that they will be paid the complete EEG-tariff if they bid the benchmark *MMV*. Of course, this approach also informs other market participants about the price cap set by

¹⁰ This obviously implies that EinsMan is used as recourse action if the number of bids on the flexibility market below the price cap is insufficient.

¹¹ Here obviously the costs of setting up and operating the market are disregarded (as are the cost of the conventional EinsMan) and it is assumed throughout that all bids have the same effectiveness with respect to congestion relief – although a generalization is possible to bids with different sensitivities.

the grid operator and they may adjust their bids accordingly – yet under uniform pricing the inframarginal bids do not have an incentive to do so.

Further research should be done on the benefits and possible drawbacks of such signaling as well as on alternative solutions to cope with uncertainties.

6 Conclusion and policy implications

This paper analyses key design elements for flexibility markets based on theoretical considerations. Compared to conventional congestion management methods like the curtailment of renewables (e.g. EinsMan), flexibility markets can provide the opportunity to include new flexibility options and thereby reduce costs for congestion management. However, our analysis also shows that renewable flexibilities bidding at opportunity costs can lead to an inefficient and costly market outcome under the current regulatory framework. This market distortion is related to the payments made to renewable units if they are curtailed. These potential revenues are then included into the opportunity cost on which bids into the flexibility market are based.

To avoid this distortion, we recommend taking the following actions:

- A1. Implementation of side payments.** The size of the side payments should correspond to the so-called market premium paid to the renewable unit, since this payment is due anyway – either as renewable support payment if power infeed is unlimited, or as part of the compensation if the renewable unit was curtailed due to a congestion. These side payments are triggered whenever renewable units submit bids to the flexibility market, and these are selected by the grid operator. In this case, the grid operator's optimal flexibility selection on the market results in an overall system cost minimum.
- A2. Payments of market premia (and side payments) from the EEG account in case of congestion management.** To make such a market design attractive for grid operators who aim to minimize their congestion management costs, we suggest paying the market premia from the EEG account not only for operating units but also in case of congestion management. This would externalize the market premia as cost components from the grid operators' calculation and thus incentivize it to choose the solution with the lowest overall cost. Finally, the funding of market premia from the EEG account would prevent unwanted distributional effects between consumer groups that would occur if a single grid operator minimized its congestion management costs, and thus the network charges for its customers, at the expense of rising EEG levies for all consumers.
- A3. Implementation of uniform pricing and a price cap to limit strategic behavior in flexibility markets.** The flexibility market should be based on uniform pricing and include a price cap in order to limit incentives for strategic bidding. Setting the price cap to the

level of the monthly market value can ensure that the market outcomes are beneficial compared to a conventional command and control approach.

Furthermore, there are necessary political decisions to be made:

- D1. Tradeoff between system costs and renewable infeed.** The introduction of a flexibility market with and without side payments decreases the curtailment of renewables by acquiring new flexibility options. While the flexibility market without side payments decreases renewable curtailment the most, it brings along high overall costs (in some cases even higher than in case of EinsMan). The renewable infeed in case of a flexibility market with side payments may be lower than in case of no side payments, yet it achieves a market outcome at minimum overall system costs.
- D2. Regulatory treatment of flexibility costs.** How to treat flexibility costs as part of congestion management is still an open question. If – as in the current German regulation – congestion management costs such as EinsMan reimbursements are considered as pure pass-through items, the incentives to implement flexibility markets are very limited.

Flexibility markets can contribute to the efforts to implement market-based congestion management measures as demanded by the European Commission. The actions we have specified and the necessary political decisions we have identified contribute to the efficient design of such flexibility markets.

7 Acknowledgements

We drafted this paper within the scope of the research project “enera” (project code 03SIN330) as part of the SINTEG funding program of Federal Ministry for Economic Affairs and Energy of Germany.

Supported by:



Federal Ministry
for Economic Affairs
and Energy

on the basis of a decision
by the German Bundestag



SINTEG

SCHAUFENSTER INTELLIGENTE ENERGIE

8 References

- Agsten, M., Bauknecht, D., Becker, A., Brinker, W., Conrads, R., Diebels, V., Erge, T., Feuerhahn, S., Heinemann, C., Hermsmeier, J., Hollinger, R., Klose, T., Koch, M., Mayer, C., Pistor, G., Rosinger, C., Rüttinger, H., Schmedes, T., Stadler, M., 2013. Abschlussbericht eTelligence: Neue Energien brauchen neues Denken, Oldenburg. <http://www.etelligence.de/feldtest/file/eTelligence%20Projektabschlussbericht%20-%20November%202012.pdf>.
- Aichele, C., Doleski, O.D. (Eds.), 2014. Smart Market: Vom Smart Grid zum intelligenten Energiemarkt. Springer Vieweg, Wiesbaden, 868 pp.
- Apel, R., Berg, V., Fey, B., Geschermann, K., Glaunsinger, W., Scheven, A. von, Stötzer, M., Wanzek, S., 2014. Regionale Flexibilitätsmärkte: Marktbasierter Nutzung von regionalen Flexibilitätsoptionen als Baustein zur erfolgreichen Integration von erneuerbaren Energien in die Verteilnetze. Studie der Energietechnischen Gesellschaft im VDE. <https://shop.vde.com/de/vde-studie-regionale-flexibilit%C3%A4tsm%C3%A4rkte>.
- bdew, 2013. BDEW-Roadmap: Realistische Schritte zur Umsetzung von Smart Grids in Deutschland. bdew, Berlin, 71 pp. https://www.bdew.de/media/documents/Pub_20130211_Roadmap-Smart-Grids.pdf. Accessed 12 December 2018.
- bdew, 2018. Redispatch in Deutschland: Auswertung der Transparenzdaten. bdew, Berlin, 27 pp. https://www.bdew.de/media/documents/Awh_20180212_Bericht_Redispatch_Stand_Februar-2018.pdf. Accessed 16 November 2018.
- Bjørndal, M., Jørnsten, K., 2001. Zonal Pricing in a Deregulated Electricity Market. *The Energy Journal* 22 (1), 51–73.
- Bjørndal, M., Jørnsten, K., 2007. Benefits from coordinating congestion management: The Nordic power market. *Energy Policy* 35 (3), 1978–1991. 10.1016/j.enpol.2006.06.014.
- Bjørndal, M., Jørnsten, K., Pignon, V., 2003. Congestion Management in the Nordic Power Market: Counter Purchases and Zonal Pricing. *Competition and Regulation in Network Industries* 4 (3), 271–292. 10.1177/178359170300400302.
- BMWi, 2016. Information on the funding programme entitled ‘Smart Energy Showcases – Digital Agenda for the Energy Transition’ (SINTEG). https://www.bmwi.de/Redaktion/EN/Downloads/bmwi-papier-sinteg-kernbotschaften.pdf?__blob=publicationFile&v=3. Accessed 9 January 2019.
- Bundesnetzagentur, 2011. "Smart Grid" und "Smart Market": Eckpunktepapier der Bundesnetzagentur zu den Aspekten des sich verändernden Energieversorgungssystems, Bonn, 50 pp.

https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/NetzzugangUndMesswesen/SmartGridEckpunktepapier/SmartGridPapierpdf.pdf?__blob=publicationFile. Accessed 15 November 2018.

Bundesnetzagentur, 2018a. Ergänzender Hinweis zur Entschädigung bei direktvermarkteten EE-Anlagen nach dem Einspeisemanagement-Leitfaden 3.0, Bonn. https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/ErneuerbareEnergien/Einspeisemanagement/Leitfaden3_0_E/Leitfaden3.0final.pdf. Accessed 14 January 2019.

Bundesnetzagentur, 2018b. Quartalsbericht zu Netz- und Systemsicherheitsmaßnahmen: Gesamtjahr und Viertes Quartal 2017. Bundesnetzagentur, Bonn, 63 pp.

Cramton, P., 2017. Electricity market design. *Oxford Review of Economic Policy* 33 (4), 589–612. 10.1093/oxrep/grx041.

Ecofys, Fraunhofer IWES, 2017. Smart-Market-Design in deutschen Verteilnetzen: Entwicklung und Bewertung von Smart Markets und Ableitung einer Regulatory Roadmap. Studie im Auftrag von Agora Energiewende, 156 pp. https://www.agora-energiewende.de/fileadmin/Projekte/2016/Smart_Markets/Agora_Smart-Market-Design_WEB.pdf. Accessed 21 March 2017.

Ehrenmann, A., Smeers, Y., 2005. Inefficiencies in European congestion management proposals. *Utilities Policy* 13 (2), 135–152. 10.1016/j.jup.2004.12.007.

European Commission, 2016. Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity, Brussels.

Felten, B., Felling, T., Osinski, P., Weber, C., 2018. Flow-Based Market Coupling Revised - Part I: Assessing Small- and Large-Scale Systems. submitted manuscript.

Hirth, L., Schlecht, I., 2018. Market-Based Redispatch in Zonal Electricity Markets. USAEE Working Paper (18-369). 10.2139/ssrn.3286798.

Hogan, W.W., 1992. Contract networks for electric power transmission. *Journal of Regulatory Economics* 4 (3), 211–242. 10.1007/BF00133621.

Holmberg, P., Lazarczyk, E., 2015. Comparison of congestion management techniques: Nodal, zonal and discriminatory pricing. *The Energy Journal* 36 (2). 10.5547/01956574.36.2.7.

Karg, L., Kleine-Hegermann, K., Wedler, M., Jahn, C., 2014. E-Energy Abschlussbericht: Ergebnisse und Erkenntnisse aus der Evaluation der sechs Leuchtturmprojekte. <http://www.e-energie.pt-dlr.de/images/ERGEBNISBERICHT.pdf>. Accessed 21 March 2017.

- Koch, M., Schmedes, T., Stadler, M., Klose, T., Hollinger, R., Rüttinger, H., Rosinger, C., 2012. Integratives Smart Market Konzept zur Systemintegration dezentraler Erzeuger und als Handelsplattform für Netzbetreiber, in: Fechner, R. (Ed.), Smart Grid. Intelligente Energieversorgung der Zukunft ; Kongressbeiträge ; 5. - 6. November 2012, Internationales Congresscenter Stuttgart (ICS). VDE-Verl., Berlin.
- Kornrumpf, T., Meese, J., Zdrallek, M., Neusel-Lange, N., Roch, M., 2016. Economic dispatch of flexibility options for Grid services on distribution level, in: 19th Power Systems Computation Conference. PSCC 2016 Genova : June 20-24, 2016, Centro congressi Porto Antico, Magazzini del Cotone Conference Centre, Genova, Italy. 2016 Power Systems Computation Conference (PSCC), Genoa, Italy. 6/20/2016 - 6/24/2016. IEEE, Piscataway, NJ, pp. 1–7.
- Müsgens, F., Ockenfels, A., Peek, M., 2014. Economics and design of balancing power markets in Germany. *International Journal of Electrical Power & Energy Systems* 55, 392–401. 10.1016/j.ijepes.2013.09.020.
- Neuhoff, K., Barquin, J., Bialek, J.W., Boyd, R., Dent, C.J., Echavarren, F., Grau, T., Hirschhausen, C. von, Hobbs, B.F., Kunz, F., Nabe, C., Papaefthymiou, G., Weber, C., Weigt, H., 2013. Renewable electric energy integration: Quantifying the value of design of markets for international transmission capacity. *Energy Economics* 40, 760–772. 10.1016/j.eneco.2013.09.004.
- Newberry, D., McDaniel, T., 2002. Auctions and trading in energy markets: an economic analysis. Cambridge Working Papers in Economics 0233. Faculty of Economics, University of Cambridge. <https://ideas.repec.org/p/cam/camdae/0233.html>. Accessed 1 April 2019.
- Oggioni, G., Smeers, Y., 2013. Market failures of Market Coupling and counter-trading in Europe: An illustrative model based discussion. *Energy Economics* 35, 74–87. 10.1016/j.eneco.2011.11.018.
- Schweppe, F.C., Caramanis, M.C., Tabors, R.D., Bohn, R.E., 1988. Spot Pricing of Electricity. Springer US, Boston, MA.
- van den Bergh, K., Boury, J., Delarue, E., 2016. The Flow-Based Market Coupling in Central Western Europe: Concepts and definitions. *The Electricity Journal* 29 (1), 24–29. 10.1016/j.tej.2015.12.004.
- Vries, L.J. de, Hakvoort, R.A., 2002. An Economic Assessment of Congestion Management Methods for Electricity Transmission Networks. *Journal of Network Industries* os-3 (4), 425–466. 10.1177/178359170200300403.

- Weibelzahl, M., 2017. Nodal, zonal, or uniform electricity pricing: How to deal with network congestion. *Frontiers in Energy* 11 (2), 210–232. 10.1007/s11708-017-0460-z.
- Wiedemann, T., 2017. Proaktives Verteilnetz - Proactive Distribution Grid. ETIP SNET Workshop, Aachen. <https://www.etip-snet.eu/regional-workshops/central-region/aachen-workshop-presentations/>. Accessed 14 January 2019.
- Wolfram, C.D., 1999. Electricity Markets: Should the Rest of the World Adopt the United Kingdom's Reforms?: A formula for inefficient production and higher prices. *Regulation* 22 (4), 48–53.

Correspondence

Jonas Höckner

Research assistant, Chair for Management Science and Energy Economics

House of Energy Markets and Finance
University of Duisburg-Essen, Germany
Universitätsstr. 12, 45117

Tel. +49 201 183-2643

Fax +49 201 183-2703

E-Mail jonas.hoeckner@uni-due.de

Web www.hemf.net

Simon Voswinkel

Research assistant, Chair for Management Science and Energy Economics

House of Energy Markets and Finance
University of Duisburg-Essen, Germany
Universitätsstr. 12, 45117

Tel. +49 201 183-3127

Fax +49 201 183-2703

E-Mail simon.voswinkel@uni-due.de

Prof. Dr. Christoph Weber

Chair holder, Chair for Management Science and Energy Economics

House of Energy Markets and Finance
University of Duisburg-Essen, Germany
Universitätsstr. 12, 45117

Tel. +49 201 183-2966

Fax +49 201 183-2703

E-Mail christoph.weber@uni-due.de