MAGKS

Joint Discussion Paper
Series in Economics

by the Universities of

Aachen · Gießen · Göttingen
Kassel · Marburg · Siegen

ISSN 1867-3678

No. 39-2014

Sebastian Schäfer and Lisa Schulten

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This paper can be downloaded from
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Coordination: Bernd Hayo • Philipps-University Marburg
Faculty of Business Administration and Economics • Universitätsstraße 24, D-35032 Marburg
Tel: +49-6421-2823091, Fax: +49-6421-2823088, e-mail: hayo@wiwi.uni-marburg.de

A Capacity Market to Improve the Transition towards Sustainable Electricity Generation

Sebastian Schäfer* Lisa Schulten†

University of Siegen, Germany
June 29, 2015

Abstract

A capacity mechanism next to the energy-only market provides necessary investment incentives that spot markets lack. We suggest a capacity market which also accounts for the current transition to a higher share of renewable energy. This creates a powerful regulation to improve the transition process. We show that an increasing share of renewables leads to a comparative advantage for peak-load power plants in a capacity market. This results in higher flexibility as opposed to missing flexibility induced by the merit order effect at the spot market. Capacity mechanisms do not account for the effects caused by promoting renewable energy so far. We consider these effects via endogenous discrimination of prices paid for offered capacity. This triggers more efficient incentives to direct the capacity mix to its long-run equilibrium where discriminated prices converge to one equilibrium capacity price.

Keywords Capacity Markets, Electricity Markets, Resource Adequacy, Reliability Options, Renewable Energy, Merit Order Effect
JEL Q41, Q42, Q48, L94

*schaefer@vwl.wiwi.uni-siegen.de
†schulten@vwl.uni-siegen.de

1 Introduction

In the past, electricity sectors around the world were ruled by monopolies which were in charge of generation, retail and operating the grid. About 20 years ago advanced economies in Europe, the US and parts of South America started liberalizing the electricity sector by unbundling the monopolies and forming a market for electricity (Ranci and Cervigni, 2013). The result is a complex system which is mainly based on a wholesale market where electricity is traded on the spot, intraday and future markets. Since the wholesale market exclusively deals with the physical and financial trade of electricity it is also called energy-only market. A necessary complement to this system is the balancing market which ensures short-run security of supply.[1]

This restructured electricity market system revealed flaws in incentivizing sufficient investments in new generating capacity in the aftermath of liberalization. Nonetheless, the lack of new investments was not recognized as a problem for quite some time as most electricity systems have been characterized by significant overcapacity caused by regulatory and political intervention before the liberalization process (Ockenfels *et al.*, 2013). Today however, there is an ongoing discussion on the introduction of additional instruments to satisfy resource adequacy.[2]

A well-designed capacity mechanism can solve shortcomings of an energy-only market by providing a stable investment environment by means of continuous payments. Some authors analyze best practices of such mechanisms. In Section 2, we briefly present strengths and weaknesses of certain instruments in use with the result that a capacity market based on reliability options is the most promising mechanism.

Challenges arise from distortions caused by the incomplete internalization of CO_2 emissions and the support of renewable energy outside the market. On the one hand, intermittent renewable electricity generation induces fluctuations on the supply side that increase price volatility. On the other hand, average spot prices are affected.

Spot markets are characterized by marginal cost pricing and renewable energy sources, which do not face fuel costs, display lowest marginal costs. The more electricity is generated from these renewable sources, the less is required from fossil sources to satisfy inelastic demand. As a consequence renewables will squeeze out fossil power plants with highest marginal costs. Those power plants are peak-load power plants. Therefore the average spot price level will decrease, known as the merit order effect

[1] See Ranci and Cervigni (2013) for a detailed overview of the structure and functioning of electricity markets.

[2] Resource adequacy denotes the system's ability to satisfy demand at all times in contrast to security of supply which describes the ability to balance sudden changes in demand (CREG, 2012, 7). Resource adequacy can therefore be defined as long-term security of supply.

of renewable energy (de Miera *et al.*, 2008; Sensfuß *et al.*, 2008).

Even though these peak-load technologies are the most expensive ones in terms of marginal costs, they are a crucial component of the capacity mix. While base-load power plants usually run all the time, peak-load power plants run only when needed. They must be able to ramp up and down fairly quickly at low costs. Hence, their market exit may induce a flexibility problem. Negative spot prices are for instance a result of missing flexibility. Since flexibility is especially required to balance intermittent electricity generation from renewables, an increasing share of renewables accentuates the flexibility problem. Consequently the merit order effect creates a price signal at spot markets which exacerbates deviations from the long-run optimal capacity mix.

A capacity market creates a link between marginal and fixed costs and is thus an effective policy instrument to tackle the described problems, if designed carefully. However, so far, suggested comprehensive capacity market designs do not incorporate distortions of energy-only markets. The designs are thus not compatible with today's electricity markets in transition to low carbon electricity generation and the long-run optimal capacity mix cannot be achieved in an efficient way.

To investigate these distortions, we introduce a simple model of a comprehensive capacity market with a representative peak-load and a representative base-load power plant in Section 2. We further model a reference case to analyze the impact of power plant maturity, emission costs and an increasing share of renewable energy on the power plant mix with comparative statics. Additionally, we introduce theoretical considerations to estimate the degree of internalization of emission costs stemming from the promotion of renewable energy. This is an extension of standard environmental economics.

In Section 3, we develop a capacity market design that considers the consequences of the promotion of renewable energy on the basis of our model's results. We derive a price supplement per capacity unit depending on the power plant's individual emission factor. The transmission system operator (TSO) makes use of these price supplements to *endogenously* calculate two threshold values for the emission factor. This leads to three different groups of power plants with increasing capacity payments because of decreasing emission factors.

In the literature, there is either no price discrimination (e.g. Cramton and Ockenfels, 2012; Cramton *et al.*, 2013) or it is given exogenously (Matthes *et al.*, 2012). A capacity market without price discrimination faces significant efficiency losses in distorted energy-only markets, whereas exogenous limits must be constantly adjusted and might attract lobbying of any kind resulting in efficiency losses, too.

In contrast to these two designs, our suggested capacity market is applicable to the current transition process of energy-only markets (but also to markets in equilibrium) and displays high political feasibility. It can be implemented in countries with liberalized electricity markets and promotion of renewable energy, whenever promotion costs can be determined.

2 Theoretical considerations for capacity markets

From a theoretical point of view, spot markets should be able to provide fixed-cost coverage via a peak energy rent (PER) in scarcity events for peak-load power plants and a PER plus an infra-marginal rent (IR) for base- and medium-load power plants (CREG, 2012). Why these price signals may not be adequate in reality can essentially be explained as follows.

First, strategic behavior by power plant operators can distort the price signal. Generators with a portfolio of power plants have an incentive to hold back capacity close to the capacity constraint to induce a scarcity event which leads to a price spike and a high PER (Cramton and Ockenfels, 2012).

Second, in order to limit this strategic behavior most countries cap the spot price. If this price cap is set too low there will be missing money (MM) to cover fixed costs in the long run. This leads to underinvestment in new capacity and distorts the optimal capacity mix (Vázquez *et al.*, 2002; Cramton and Stoft, 2005; Joskow, 2008; Cramton and Ockenfels, 2012).

Third, electricity prices are stochastic and display a high hourly, weekly and monthly volatility corresponding to changes in demand. Consequently a generator's income is volatile and new investments are subject to significant risks (Vázquez *et al.*, 2002). This creates disincentives for investments (Cramton *et al.*, 2013; Ockenfels *et al.*, 2013).

Can these problems be solved by other measures than capacity mechanisms? A natural suggestion is to remove the price cap, so that missing money does no longer exist, but the absence of a price cap exacerbates strategic behavior by generators which again does not provide an adequate price signal for investment decisions. Furthermore, high electricity prices are hard to sell to the public, although occurring rarely. Lastly, even without a price cap, scarcity prices may not be high enough to attract new investments (Joskow, 2008), especially in the presence of renewables and the resulting merit order effect.

Price volatility may be alleviated by demand side measures that enable a better response to electricity prices. However, concepts like real-time pricing, smart meters or smart grids still face too high costs for implementation on the large scale. Anyway, the evolution of demand side measures does not compete with the implementation of capacity markets, as they can be combined. On account of these considerations, capacity mechanisms are a rational choice to deal with insufficient investment incentives.

2.1 Capacity markets with reliability options

Capacity instruments in use are mainly strategic reserves or capacity payments. Their design and implementation is fairly simple. Capacity payments provide additional money for generators to set sufficient investment incentives. In principle the payments are a regulator's guess for missing money and generators decide on how much capacity to offer. As a consequence it is likely that the contracted capacity will be too high or too low.

In the case of strategic reserves the regulator pays some generators for access to additional capacity when it is needed. Power plants which act as strategic reserves are usually excluded from the wholesale market and function as electricity generators of last resort. Strategic reserves are often old power plants which would have been shut down without additional payments. This approach addresses only a small fraction of power plants. Therefore it distorts the market equilibrium. Strategic reserves and capacity payments are not market-based and consequently not efficient (CREG, 2012). They are a fast, but not sustainable solution because they impede a market equilibrium.

Far better results can be obtained with market-based instruments. Capacity obligations with a secondary market for exchangeable certificates and capacity markets with so-called reliability options (ROs) are mentioned in this context. The former is used in France while the latter has been implemented in the UK and both instruments are already applied in US regions. All in all, comparative studies emphasize the superiority of capacity markets with ROs compared to other mechanisms especially regarding efficiency of capacity targeting, investment stability and compatibility with the spot market (Finon and Pignon, 2008; Joskow, 2008; Siegmeier, 2011; Flinkerbusch and Scheffer, 2013).

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

Prior to the auction the regulator defines p_{strike}, the total amount of options (amounting to required capacity $\underaccent{\tilde}{C}$), the penalty and the time horizon for the continuous payment. In the auction every bidder offers a single price-quantity pair. These bids are ordered from lowest to highest until $\underaccent{\tilde}{C}$ is satisfied. The price of the last accepted bid determines the premium all generators get per capacity unit. This premium corresponds to the equilibrium price p^*.

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

The suggested design fulfills most requirements for a successful capacity mechanism, but the issue of possible market power abuse is admittedly not addressed. The design does not control for incentives of generators to demand a higher price than required. An extension of the proposal by Cramton and Ockenfels (2012); Cramton *et al.* (2013) tackles this problem by enforcing that already existing capacity is obliged to participate in the auction with total capacity. Their bid is restricted to a price of zero, so existing capacity cannot influence the equilibrium price p^*. Imagine already existing capacity would suffice to meet required capacity $\underaccent{\tilde}{C}$. The resulting equilibrium price of the auction would be zero and a capacity market would not be necessary. Only if new capacity is contracted, the price can be greater than zero. Hence, solely new capacity determines the premium all generators receive.

The described capacity market is only suitable for an energy-only market in equilibrium, but most markets are in a transition phase to lower emissions. A so-called focused capacity market contains elements of a transition design. Hereby, critical values are defined for emission factors, flexibility and annual utilization time. These exogenously given limits favor flexible and less carbon-intensive gas power plants and thus create more suitable incentives for a transition process (Matthes *et al.*, 2012). Nevertheless, it is questionable whether the focused capacity market is robust and efficient because of market interventions by exogenously defined limits. In accordance with Vázquez *et al.* (2002); Cramton and Ockenfels (2012) we design a comprehensive capacity market, but for the transition phase based on endogenously determined limits of emission factors.

2.2 Modeling a reference case

As a first step we examine the equilibrium of an energy-only market. Although it is reasonable to assume that power plants are running as long as the spot price is higher than their operation costs this is not realistic. Unforeseen maintenance and non-linear behavior of power plants with respect to operation costs prevent a permanent availability. For instance, it does not make sense to cold start base-load power plants for solely one hour since ramping up and down is costly. Thus, there is an individual probability of failure for every power plant i that it is not running despite of a spot price above its operation costs. This leads to a certain expected share X_i of potential spot market profits which is lost. The lost share may depend on the spot market price since incentives to keep a power plant running are different for low and high spot prices. This leads to different shares $(X_{IR,i}, X_{PER,i}, X_{MM,i})$ of lost infra-marginal rent (IR), peak energy rent (PER) and missing money (MM).

At an energy-only market capital costs have to be covered by profits at the spot market (IR and PER). If profits are not sufficient there will be missing money. This yields

$$\delta_i K_i = (1 - X_{IR,i})IR_i + (1 - X_{PER,i})PER + (1 - X_{MM,i})MM. \tag{1}$$

Capital costs per capacity unit of generator i equal standard capital depreciation $\delta_i K_i$. Additionally, an individual risk premium is included in δ_i. Thus, risk is modeled proportional to the current capital stock as old power plants face lower risks because of lower remaining capital costs.

In the next step we introduce a capacity market and model its equilibrium price per capacity unit p^* which is the auction's clearing price. This serves as a reference case for the following analysis. The time horizon is one year. Every existing power plant is obliged to place a bid in the capacity auction while participation of new power plants is voluntary. Following Vázquez *et al.* (2002) generators which do not provide the contracted amount of electricity when the spot price exceeds p_{strike} have to pay a penalty.

Capacity payments equal the difference between each generator's costs and profits at the spot markets if they bid truthfully. Costs consist of capital costs $\delta_i K_i$, the penalty ϱ_i, and the PER because generators commit to pay the difference between p_{spot} and

p_{strike} as soon as the spot price rises above the strike price. This amounts exactly to the PER. Profits at the spot market are the sum of IR and PER multiplied with the respective individual availability factors. To determine the clearing price, submitted bids of all n power plants are sorted in ascending order. If $m \leq n$ power plants are necessary to provide the required capacity $\underline{C}$, the equilibrium price equals the bid of generator m

$$p^* = p(\underline{C}) = p(\sum_{i=1}^{m} C_i) = \delta_m K_m + X_{PER,m} PER + \varrho_m - (1 - X_{IR,m}) IR_i. \qquad (2)$$

Since all generators receive the equilibrium price the incentive to increase the bid above true costs is rather weak. Because of competition, overbidding significantly increases the risk to lose the auction while potential additional profits are quite low. In Section 3.1 we suggest a mechanism which provides additional incentives for truthful bidding among existing power plants.

The further analysis requires a closer look at the IR, PER, and the penalty ϱ. The potential IR per capacity unit for any generator i is given by the difference between the spot price and operation costs multiplied with the respective duration. Multiplication with the availability factor $1 - X_i$ yields the true IR_i. Fig. 1 depicts an imaginary spot price distribution over one year. The potential IR per capacity unit of generator i corresponds to the integral from his operation costs $C_i^V + C_i^{ETS}$ to p_{strike}. Operation costs are split into C_i^V as variable costs and C_i^{ETS} as emission costs.[3]

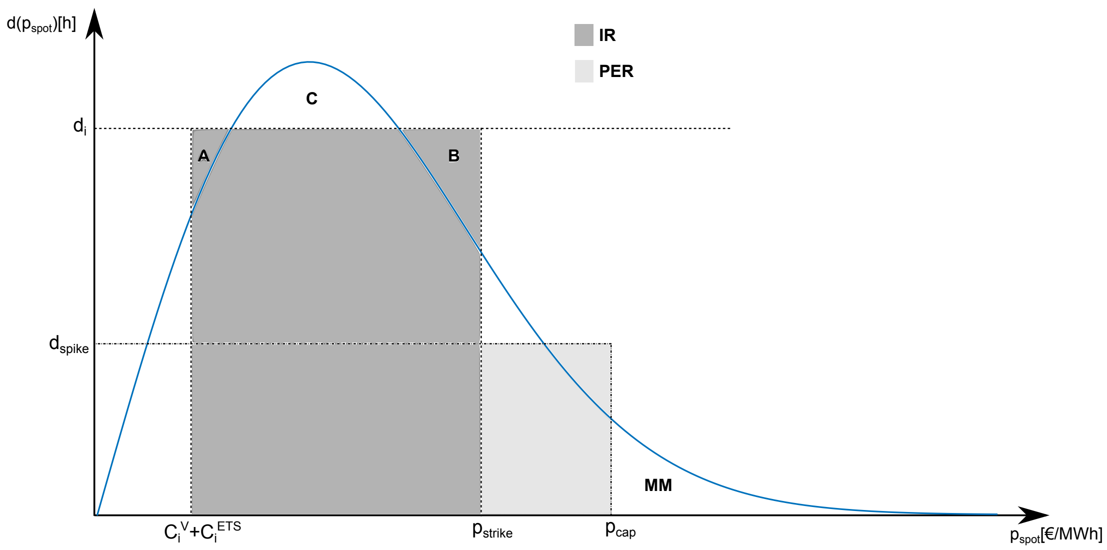

Figure 1: Schematic illustration of the distribution of spot prices for one year in €/MWh. The duration of power plant's i production in hours depends on the spot price.

[3] In the EU, emission costs arise from its Emissions Trading System (ETS).

To simplify the notation in the subsequent analysis we define the normalized duration d_i. Referring to Fig. 1 as an example, d_i is defined such that $A + B = C$. Thus, we can replace the integral by a simple product of normalized duration and the difference of the strike price and operation costs (see dark gray rectangular in Fig. 1). This yields

$$\begin{aligned} IR_i &= \int_{C_i^V + C_i^{ETS}}^{p_{strike}} d(p_{spot})\ \mathrm{d}p_{spot} \\ &= d_i \left(p_{strike} - C_i^V - C_i^{ETS}\right). \end{aligned} \tag{3}$$

An analogous procedure determines the PER (see Fig. 1)

$$\begin{aligned} PER &= \int_{p_{strike}}^{p_{cap}} d(p_{spot})\ \mathrm{d}p_{spot} \\ &= d_{spike}\left(p_{cap} - p_{strike}\right). \end{aligned} \tag{4}$$

d_{spike} is the same for each generator because the strike price exceeds the operation costs of any power plant. In contrast d_i is different for each generator.

To determine the optimal penalty ϱ_i we insert Eq. 1 into Eq. 2 leading to

$$p^* = PER + (1 - X_{MM,i})MM + \varrho_i. \tag{5}$$

According to this equation, a capacity market without MM and penalty is a transformation of volatile PER into a continuous payment at no extra cost for the regulator.

However, Eq. 5 would also reveal an incentive for generators to pretend a higher capacity than actually available if there was no penalty. In this case a "generator" without any capacity ($X_{MM,i} = 1$) is always able to underbid any of his competitors since he has no capital costs and therefore does not face MM. If the equilibrium price includes MM of competitors such a "generator" will gain profits. He gets p^* while he only has to pay the PER to load because of ROs, but MM (of other generators) is left. This problem, identified by Cramton *et al.* (2013), can be solved with an explicit penalty. It is charged additionally if no electricity is delivered when the spot price exceeds p_{strike}. Such a penalty leads to a markup of the capacity bid, since generators price in their expected penalty. Thus, the markup is higher for "generators" without capacity and they will not be successfull in a capacity auction anymore if the penalty is designed carefully. For a too low penalty, incentives to deceive remain. A too high penalty implies a higher risk for all generators caused by a higher markup. Eventually, this leads to extra costs, since it influences the equilibrium. Therefore, in the optimum, the penalty should amount exactly to MM for "generators" without capacity to discorage them to participate.

The regulator can approximate MM ex-post. According to Eq. 5 it is around the difference between the clearing price p^* and the PER per capacity unit if penalties are rather small. This allows the definition of a penalty factor as ratio of clearing price and PER per capacity unit

$$\xi = \frac{p^*}{PER}. \tag{6}$$

The penalty is effectively applied by multiplying payments resulting from ROs with the penalty factor if no electricity is delivered. This leads to an annual payment of PER$\cdot\xi$ for a "generator" without any capacity, which is equal to p^* (see Eq. 6). Consequently there is no incentive to pretend higher capacities in a capacity market.

Although the regulator can calculate ξ only after the equilibrium price p^* is known, the described penalty system can be applied if the calculation procedure is announced before the auction takes place. To avoid information asymmetry it might be useful to publish the regulator's estimation for the PER, too. This enables each generator to estimate MM as the basis for a markup of his bid to offset the penalty.

Generators calculate individual values for missing money $MM_i = MM(1-X_{MM,i})$ as it is the difference between their price bid p_i and the PER per capacity unit. Taking into account his individual probability of failure $X_{MM,i}$ generator i can calculate his markup ϱ_i. He has, however, to consider that the resulting increase of his bid will lead to a higher penalty factor (see Eq. 6) if he is the price setting generator. This can be anticipated by using the following well-known infinite series to calculate the individual markup

$$\begin{aligned} \varrho_i &= MM_i(X_{MM,i} + X_{MM,i}^2 + ... + X_{MM,i}^n) \\ &= MM_i \left(\frac{X_{MM,i}}{1 - X_{MM,i}} \right) \\ &= MM \cdot X_{MM,i}. \end{aligned} \tag{7}$$

To evaluate the equilibrium of a capacity market, we consider a representative base-load and a representative peak-load power plant for simplicity. These power plants can be seen as aggregates of total existing capacity. Accounting for Eq. 1 we obtain

$$\begin{aligned} \delta_{peak} K_{peak} &= (1 - X_{PER,peak})PER + (1 - X_{MM,peak})MM \\ \delta_{base} K_{base} &= (1 - X_{PER,base})PER + (1 - X_{MM,base})MM + (1 - X_{IR,base})IR_{base} \end{aligned} \tag{8}$$

if $p_{strike} := C_{peak}^V + C_{peak}^{ETS}$.[4]

[4] Vázquez *et al.* (2002) recommend to set the strike price at 25 % above marginal cost of the peak-load power plant though emphasizing that the level of the strike price is not critical. If the strike price is lower, required premiums must be higher and vice versa.

This simplifies the notation, since (according to Eq. 3) the IR for peak-load power plants vanishes. Therefore profits for the representative peak-load power plant at the spot market are restricted to the PER whereas the base-load power plant additionally gains an IR.

The difference between capital costs of both representative power plants using Eq. 3 and 8 yields

$$\begin{aligned}\delta_{base}K_{base} - \delta_{peak}K_{peak} = (1 - X_{IR,base})\left(C^{V}_{base} - C^{V}_{peak} + C^{ETS}_{base} - C^{ETS}_{peak}\right) d_{peak} \\ - (X_{PER,base} - X_{PER,peak})PER \\ - (X_{MM,base} - X_{MM,peak})MM\end{aligned} \tag{9}$$

In short

$$\Delta K = (1 - X_{IR,base})\Delta C d_{peak} - \Delta X_{PER}PER - \Delta X_{MM}MM \tag{10}$$

In energy-only market equilibrium, the difference of capital costs is equal to the difference of operation costs and the difference of power plants' availability multiplied with the PER and MM. Higher capital costs have to be compensated by lower operation costs or higher availability and vice versa. According to Eq. 2 the respective pricing equations for the representative peak- and base-load power plant are

$$\begin{aligned}p_{peak} &= \delta_{peak}K_{peak} + X_{PER,peak}PER + \varrho_{peak} \\ p_{base} &= \delta_{base}K_{base} + X_{PER,base}PER + \varrho_{base} - (1 - X_{IR,base})\Delta C d_{peak}.\end{aligned} \tag{11}$$

By inserting Eq. 4 and 10 into Eq. 11 we obtain the equilibrium condition for a capacity market. Considering Eq. 7 we get

$$\begin{aligned}\Delta p &= p_{base} - p_{peak} \\ &= \Delta K + \Delta X_{PER}\left(p_{cap} - p_{strike}\right) d_{spike} + \Delta\varrho - (1 - X_{IR,base})\Delta C d_{peak} \\ &= \Delta\varrho - \Delta X_{MM}MM \\ &= 0.\end{aligned} \tag{12}$$

Eq. 12 reflects the zero-arbitrage principle. It does not only hold for the discussed representative power plants, but in general. If we take for instance a peak-load power plant with lower variable costs than the representative one, this advantage will be compensated by higher capital costs. Otherwise it cannot be part of an equilibrium because investments in this superior technology would yield positive profits. Consequently price bids are equal for all power plants in equilibrium while $\Delta p \neq 0$ indicates a disequilibrium. The greater the price difference, the greater the deviation from the equilibrium.

2.3 Impact of power plant maturity

If we use the approximation

$$K_i = K_{0,i} e^{-\delta_i t_i} \tag{13}$$

with i indicating the different types of power plants and additionally define

$$\Delta t = t_{base} - t_{peak}, \tag{14}$$

we get together with Eq. 12

$$\frac{\partial \Delta p}{\partial \Delta t} = -\delta_{base}^2 K_{base} - \delta_{peak}^2 K_{peak} < 0 \qquad \forall \Delta t > 0. \tag{15}$$

A difference in the average maturity of power plants has a direct influence on the price difference. If the representative base-load power plant is older than the peaker ($\Delta t > 0$), the price bid of the base-load power plant will be lower ($\Delta p < 0$) because of lower capital costs. This leads to a comparative advantage. The dependency on age reduces the risk for existing power plants to be substituted by new more efficient ones. With respect to a transition process this yields a delayed adjustment.

A little thought experiment illustrates resulting implications. Imagine two cases. In the first case, the share of renewables has increased slowly to the final share resulting in a certain age distribution of fossil power plants. In the second case, the same share is introduced, but all fossil power plants have to be built at once. As a consequence, all power plants will be of the same age. While in the second case the capacity mix is a best response to the share of renewable energy, the first case also considers the given capacity mix with its age distribution. The equilibrium of a capacity market is different in case one. The equilibrium is path-dependent.

2.4 Impact of an increasing share of renewable energy

The merit order effect is a result of the incomplete internalization of emission costs preventing a full market integration of renewables. Therefore renewable energy is currently introduced outside the market by different support mechanisms.

This leads to an excess of fossil capacity which will be reduced only in the long-run because of the long lifespan of power plants. The adjustment to the equilibrium will take place in a sequential manner. The current market design provokes a reduction of excess capacity by shutting down some peak-load power plants first, since they face highest variable costs. The result is increasing inflexibility and an inefficient utilization of base-load power plants. Thus, in a second step old base-load power plants with a short remaining lifespan will close down. Finally, if too many peak-load power plants shut down in step one, investments in this technology will be undertaken to increase flexibility.

The question arises whether this sequential process is an intertemporally efficient solution for the transition phase. However, the energy-only market does not provide any direct link between capital costs and spot prices while the capacity market does. The reaction of capacity market prices to an increasing share of renewable energy is thus of particular interest.

Let φ be the share of renewable energy. The merit order effect can then be described by

$$\frac{\partial \bar{p}_{spot}}{\partial \varphi} < 0.$$

If the share of renewables increases, fossil electricity generation will decrease which results in decreasing average spot prices $\bar{p}_{spot}$ (explained in Section 1). Operation times for peak-load power plants and the duration of scarcity events will decrease. This is also true for the normalized duration d_{peak} and d_{spike}, since the integrals in Eq. 3, 4 become smaller leading to

$$\frac{\partial d_{peak}}{\partial \varphi} < 0, \qquad \frac{\partial d_{spike}}{\partial \varphi} < 0. \tag{16}$$

Both representative power plants are affected by decreasing PERs caused by declining d_{spike} (see Eq. 11). The representative base-load power plant additionally loses profits as a result of lower d_{peak}.

The impact on the capacity market is given by Eq. 12 considering Eq. 16

$$\begin{aligned} \frac{\partial \Delta p}{\partial \varphi} = \frac{\partial \Delta K}{\partial \varphi} + \frac{\partial \Delta X_{PER}}{\partial \varphi} \left(p_{cap} - p_{strike}\right) d_{spike} + \frac{\partial \Delta X_{MM}}{\partial \varphi} MM - \frac{\partial \Delta C}{\partial \varphi} d_{peak} \\ + \frac{\partial MM}{\partial \varphi} \Delta X_{MM} + \frac{\partial d_{spike}}{\partial \varphi} \Delta X_{PER} (p_{cap} - p_{strike}) - \Delta C \frac{\partial d_{peak}}{\partial \varphi}. \end{aligned} \tag{17a}$$

The increase of renewable energy may, on the one hand, cause the market exit of power plants. On the other hand, it reduces spot market profits for remaining power plants. Peak-load power plants with highest variable costs may exit the market if the spot price decreases to a level, which is permanently below their operation costs. These market exits are an observed consequence of the merit order effect. The first line in Eq. 17a reflects this effect keeping in mind that the representative power plants consist of several power plants of the same technology, but of different cost structures.

As a result, average spot market profits of remaining peak-load power plants will increase, but average capital costs will increase to the same extent, as for all power plants, also the remaining ones, Eq. 8 holds in the equilibrium. This yields

$$\frac{\partial \Delta K}{\partial \varphi} = \frac{\partial \Delta C}{\partial \varphi} d_{peak} - \frac{\partial \Delta X_{PER}}{\partial \varphi} \left(p_{cap} - p_{strike}\right) d_{spike} - \frac{\partial \Delta \varrho}{\partial \varphi}.$$

So that Eq. 17a simplifies to

$$\begin{aligned}\frac{\partial \Delta p}{\partial \varphi} &= \frac{\partial MM}{\partial \varphi} \Delta X_{MM} + \frac{\partial d_{spike}}{\partial \varphi} \Delta X_{PER} (p_{cap} - p_{strike}) - \Delta C \frac{\partial d_{peak}}{\partial \varphi} \\ &> 0.\end{aligned} \tag{17b}$$

Eq. 17b illustrates the effect of an increase of renewable energy on the remaining power plants which is always positive because: The first term corresponds to the increase in MM while the second term describes the reduction of the PER. Both terms also consider the respective differences of availability $\Delta X_{PER}, \Delta X_{MM}$. Since peak-load power plants are more flexible than base-load power plants it is very likely that ΔX_{PER} and ΔX_{MM} are positive. The increase of MM exceeds the decrease of the PER because MM does not only grow to the same extent as the PER is reduced but additionally increases with decreasing IR. Thus, for $\Delta X_{PER} \approx \Delta X_{MM}$ the sum of the first two terms is clearly positive while the third term is positive anyway.

Nevertheless, even if the sum was negative ($\Delta X_{MM} < 0; \Delta X_{PER} < 0$) the decrease of the IR (third term) would ensure a positive result since it does not consider the difference in respective availability. Therefore it is clearly greater than the sum of the first two terms. Thus, Eq. 17b is always positive.

Hence, an increasing share of renewable energy provides a comparative advantage for peak-load power plants. To clarify, let us consider the following example:

capital costs peak-load	$\delta_{peak} K_{peak}$	490,000 €/MW
probability of failure	X_{peak}	0.02
capital costs base-load	$\delta_{base} K_{base}$	873,000 €/MW
probability of failure	X_{base}	0.03
IR	$(p_{strike} - C^{V}_{base} - C^{ETS}_{base}) d_{peak}$	400,000 €/MW
PER	$(p_{cap} - p_{strike}) d_{spike}$	500,000 €/MW

For simplicity we assume $X_{peak} = X_{IR,peak} = X_{PER,peak} = X_{MM,peak}$ and $X_{base} = X_{IR,base} = X_{PER,base} = X_{MM,base}$. According to Eq. 11 this yields

$$
\begin{aligned}
p_{base} &= 873,000 \text{ €/MW} + 0.03 \cdot 500,000 \text{ €/MW} + \varrho_{base} - 0.97 \cdot 400,000 \text{ €/MW} \\
&= 500,000 \text{ €/MW} + \varrho_{base} \\
p_{peak} &= 490,000 \text{ €/MW} + 0.02 \cdot 500,000 \text{ €/MW} + \varrho_{peak} \\
&= 500,000 \text{ €/MW} + \varrho_{peak}.
\end{aligned}
$$

Considering Eq. 5 we find that MM equals zero leading to $\varrho_{base}=\varrho_{peak}=0$. Thus, the equilibrium price at the capacity market is $p^* = p_{base} = p_{peak} =$ 500,000 €/MW. The equilibrium price corresponds exactly to the PER per capacity unit which generators have to pay because of their commitment enforced by ROs. Without a capacity market the representative peak-load power plant would get $R_{peak} = PER(1-X_{peak}) =$ 490,000 €/MW while the base-load power plant would earn $R_{base} = (PER+IR)(1-X_{base}) =$ 873,000 €/MW. Capital costs are exactly covered. A capacity market would not be necessary in this example, but it produces the same results.[5] Total costs of electricity generation for consumers in a capacity market C^c or an energy-only market C^{eo} are

$$C^c = C^{eo} = \rho \underline{C} R_{base} + (1-\rho) \underline{C} R_{peak} \tag{18}$$

with ρ as share of contracted base-load capacity. Nevertheless, this does not value the advantage foreseeable income for generators because of continuous payments.

If this equilibrium is distorted by an increasing share of renewables, a result may be:

capital costs peak-load	$\delta_{peak} K_{peak}$	490,000 €/MW
probability of failure	X_{peak}	0.02
capital costs base-load	$\delta_{base} K_{base}$	873,000 €/MW
probability of failure	X_{base}	0.03
IR	$(p_{strike} - C^V_{base} - C^{ETS}_{base})\hat{d}_{peak}$	250,000 €/MW
PER	$(p_{cap} - p_{strike})\hat{d}_{spike}$	400,000 €/MW

The PER decreases less than the IR in this example as empirical data suggests (Nicolosi and Fürsch, 2009). Applying Eq. 11 as above, we obtain

$$
\begin{aligned}
p_{base} &= 642,500 \text{ €/MW} + \varrho_{base} \\
p_{peak} &= 498,000 \text{ €/MW} + \varrho_{peak}.
\end{aligned}
$$

5 Recall that the capacity payment to peak-load power plants is reduced by 10,000 €/MW because of their probability of failure. For base-load power plants this reduction amounts to 15,000 €/MW.

Together with Eq. 5 we can calculate MM for both generators yielding MM_{base} = 242,500 €/MW and MM_{peak} = 98,000 €/MW. Without a capacity market we find $R_{peak} = PER(1 - X_{peak})$ = 392,000 €/MW and $R_{base} = (PER + IR)(1 - X_{base})$ = 630,500 €/MW as respective profits at the wholesale market. The difference between capital costs and these profits result in the same values for MM as with a capacity market. Since MM occurs, generators have to consider a markup in a capacity market which can be calculated according to Eq. 7

$$\varrho_{base} = 0.03/(1 - 0.03) \cdot 242,500 \text{ €/MW} = 7,500 \text{ €/MW},$$
$$\varrho_{peak} = 0.02/(1 - 0.02) \cdot 98,000 \text{ €/MW} = 2,000 \text{ €/MW}.$$

If we assume constant demand for fossil capacity with an increasing share of renewables (to guarantee security of supply), the equilibrium price will be 642,500 €/MW + 7.500 €/MW = 650,000 €/MW. The regulator assigns the penalty factor ξ = 650,000 /400,000 = 1.625. The penalty for the base-load power plant will be ϱ_{base} = (1.625 · 400,000 €/MW - 400,000 €/MW) · 0.03 = 7,500 €/MW which is exactly its markup as price setting power plant. The penalty for the peak-load power plant will be ϱ_{peak} = (1.625 · 400,000 €/MW - 400,000 €/MW) · 0.02 = 5,000 €/MW which exceeds its calculated penalty. However, this has no serious consequence since the peak-load power plant is not price setting and receives sufficient payment to cover capital costs nevertheless.

On the one hand, the example illustrates that without a capacity market a massive adequacy problem occurs because missing money hampers investments. On the other hand, a capacity market seems to cause additional costs $C^c - C^{eo} = (1 - \rho)\underline{C}R_{peak}$ = $(1 - \rho)\underline{C}$ 150,000 €/MW at first glance, as consumers pay more than necessary with respect to capital cost coverage. However, this is only true in a static approach. Old power plants have a comparative advantage, but base-load power plants will be replaced progressively. In the medium term base-load power plants will exit the market and peak-load capacity will increase. The cost advantage for peakers is essential as it directs the capacity mix to its equilibrium.

If fossil capacity is reduced because of increased renewable energy, additional peakers may not be needed. The comparative disadvantage of base load-power plants leads to a disproportional reduction of base-load technology which reduces the inflexibility of the capacity mix.

Hence, the capacity market will directly lead to a more flexible fleet of power plants in contrast to the sequential adjustment of today's energy-only markets.

2.5 Impact of carbon emission costs

We define

$$\Delta C^{ETS} = C^{ETS}_{base} - C^{ETS}_{peak} \tag{19}$$

to discuss the influence of CO_2 emission costs on the equilibrium. Neglecting rather clean nuclear power plants, base-load power plants are generally dominated by emission-intensive coal while peak-load power plants mainly run with far less carbon-intensive gas. Taking into account Eq. 12 yields

$$\frac{\partial \Delta p}{\partial \Delta C^{ETS}} = d_{peak} > 0. \tag{20}$$

If the price for emission allowances increases, the difference in emission costs increases as well, leading to an increasing Δp. Rising emission costs thus yield a comparative advantage for peak-load power plants in this framework. Generally less emission-intensive power plants face a comparative advantage with respect to increasing emission costs in a capacity market. The difference in emission costs has a direct influence on profits realized at the spot market. According to Eq. 11 this cost effect is transferred to the capacity market.

Despite the fact that this provides a general consideration of CO_2 emissions within a capacity market, problems arise with respect to adequacy. The price development of allowances within the ETS has harmed reliability as there was a period of just two and a half years that was not affected by oversupply (Schäfer, 2014). Anyway, the certificate price itself does not reflect the adequate degree of internalization at the spot market, since the additional promotion of renewable energy is not taken into account.

Some theoretical considerations to explain this in more detail are depicted in Fig. 2 that shows a schematic curve for marginal damage (MD) and marginal abatement costs (MAC). The MAC curve consists of two parts MAC^{ETS} and MAC^{RES}. MAC^{RES} corresponds to marginal abatement costs caused by the decarbonization with renewable energy sources while MAC^{ETS} captures mitigation strategies incentivized by the ETS. For low emission reductions, as currently the case, the use of renewable energy is not incentivized by the ETS because MAC^{RES} is far higher than the certificate price of the ETS. The intersection point of MAC and MD results in E^* describing the optimal long-run emission level. This value is easily identified in theory, but it is an assumption in reality and eventually a political objective.

The long-run objective of the EU for instance claims 80–95% CO_2 mitigation until 2050. To achieve this goal, the EU introduced the ETS in 2005. This system proposes several intermediate objectives by setting certain emission caps while permitting the

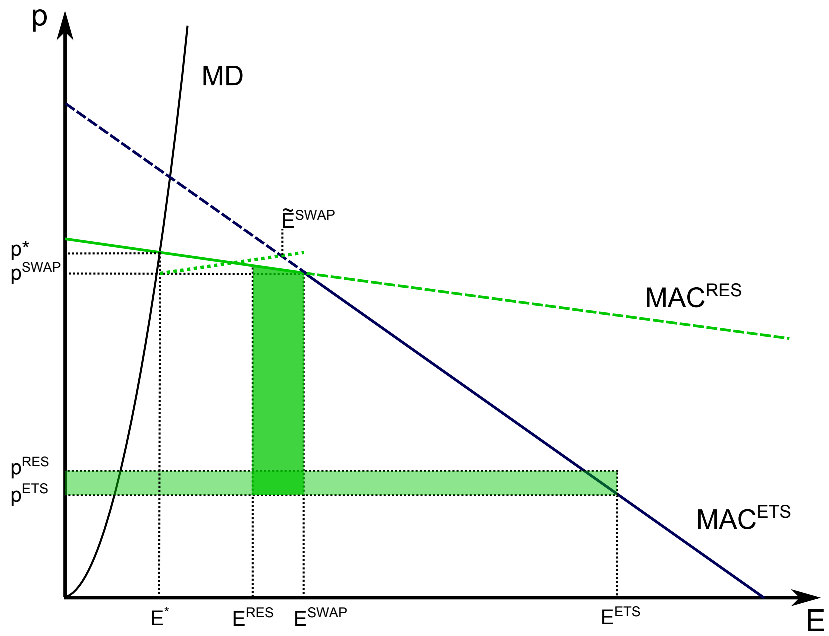

Figure 2: CO_2 mitigation with respective marginal abatement costs incentivized by the ETS (MAC^{ETS}) and the promotion of renewable energy (MAC^{RES}) with integrated price supplement ($\Delta p^{RES} = p^{RES} - p^{ETS}$).

trade of emission allowances. E^{ETS} in Fig. 2 shows such an intermediate objective with the resulting certificate price p^{ETS}. Besides the split MAC, Fig. 2 displays a standard picture used in environmental economics (see Nordhaus, 1991).

It might be possible, but far more expensive (because of physical restrictions) to reach the long-run objective without at least a partial substitution of fossil fuels (dashed part of MAC^{ETS} in Fig. 2). In the future MAC^{RES} will thus be lower than MAC^{ETS}, although currently the opposite is true. Renewable energy would therefore enter the market in the long run without any promotion as soon as the certificate price reaches p^{SWAP}. From that point on renewables will be the dominant mitigation strategy while other strategies play a minor role. Hence, today's promotion of renewable energy can be seen as shifting investments (which would have been undertaken in the future anyway) to an early stage. Fig. 2 depicts the emissions mitigated by the promotion of renewable energy ($E^{SWAP} - E^{RES}$). Respective abatement (promotion) costs are visualized by the entire dark-shaded area (see Schäfer, 2014).

The static approach of Fig. 2 suggests a higher efficiency by following solely MAC^{RES} instead of MAC^{ETS}, if the certificate price exceeds p^{SWAP}. This is not precise for increasing MAC^{RES} because $MAC^{ETS}(E^{SWAP}) < MAC^{RES}(E^{*})$. An efficient solution requires $MAC^{ETS}(E^{SWAP}) = MAC^{RES}(E^{*})$. The reason is the comparative advantage for other strategies until MAC^{ETS} equals MAC^{RES}. Thus it is a necessary condition for an equilibrium. This effect can be shown in Fig. 2, too. We need to invert MAC^{RES} between E^{SWAP} and E^{*}. The intersection point of the resulting dashed line and MAC^{ETS} yields $\tilde{E}^{SWAP}$. Thus, total emissions which are mitigated by renewables will be $\tilde{E}^{SWAP} - E^*$ instead of $E^{SWAP} - E^*$. However, this distinction is irrelevant for the following analysis because Fig. 2 is just a schematic illustration.

Although the promotion of renewables also contributes to emission reduction, the certificate price only reflects the degree of internalization of emission costs in terms of the ETS. Therefore it is too low, if the promotion of renewable energy is taken into account. Since the capacity market reacts to the certificate price, this too low degree of internalization would lead to a capacity mix that is not adequate. The capacity market would guide investments to an equilibrium which no longer exists, if it only considered p^{ETS}.

The abatement costs of renewables are well-known in reality. In countries with feed-in tariffs (FiTs) or contracts for differences (CfDs) these are mainly the difference costs between remuneration for renewables and the spot price. Furthermore the total amount of emissions $E^{ETS} - (E^{SWAP} - E^{RES}) = \sum_{i=1}^{k} E_i$ and the total amount of electricity produced with fossil $\sum_{i=1}^{k} Q_i$ and renewable energy sources $\sum_{i=k+1}^{n} Q_i$ is known because of reporting obligations of the ETS and the promotion system. Assuming (in line with Schäfer, 2014) that in the long run the emissions mitigated by renewable energy are about the average direct emissions of fossil energy sources yields

$$E^{ETS} = \sum_{i=1}^{k} E_i \frac{\sum_{i=1}^{n} Q_i}{\sum_{i=1}^{k} Q_i} \tag{21}$$

with n total power plants, k fossil power plants and $n - k$ renewable power plants. If the promotion costs of renewable energy S are divided by E^{ETS}, we obtain a price supplement Δp^{RES} for ETS allowances. The product of Δp^{RES} and E^{ETS} yields the light-shaded area between p^{ETS}, p^{RES} and E^{ETS} which is as large as the dark one because both are equal to the abatement costs of renewable energy (see Fig. 2). Since the light-shaded area is not completely below the MAC-line and some emissions will remain in the optimum, the estimation of the price supplement is de facto still slightly too low. However, the adjusted certificate price ($p^{RES} = p^{ETS} + \Delta p^{RES}$) is a good estimator for the actual degree of internalization in the electricity sector.

Introducing the adjusted certificate price at the spot market would lead to a different merit order of power plants as emission costs are more pronounced. It would have the same effect as a carbon tax and is therefore difficult to enforce politically because of huge contingent losses for existing power plants. Integrating the adjusted price into the capacity market is easier to implement, as it may imply additional payments and influences the future rather than the present capacity mix. The necessary transformation to a price supplement per capacity unit must consider the different emission intensities of the power plants. A well-known measure in this context is the emission factor which is calculated on the basis of annually averaged data for every power plant

$$e_i = \frac{E_i}{Q_i}. \tag{22}$$

The transformation factor which is needed in addition can be expressed by

$$\eta = \frac{E^{ETS}}{\underline{C} \cdot \sum_{i=1}^{k} e_i}. \tag{23}$$

The regulator can calculate the transformation factor for every year. Finally Eq. 22 and Eq. 23 yield

$$\begin{aligned} \Delta\tilde{p}_i^{ETS} &= \Delta p^{RES} \eta e_i \\ &= \frac{S}{\underline{C}} \frac{e_i}{\sum_{i=1}^{k} e_i} \end{aligned} \tag{24}$$

reflecting the price supplement per capacity unit for each power plant, if abatement costs of renewable energy S are distributed according to the individual share of total emissions $e_i / \sum_{i=1}^{k} e_i$. Capacity is treated equally, although base-load power plants will generate more electricity than peakers. With respect to reliability this is not crucial.

3 Recommendations for a capacity market

The main aim of a capacity market is to ensure reliability by continuous and sufficient investment incentives. An adequate tool for this purpose seems to be a comprehensive capacity market with a single price for any available capacity unit. In principal, distortions of the equilibrium result in short-term cost advantages which will influence investments and eventually lead to an optimal power plant mix. Since today's electricity markets are in a transition phase and will not reach an equilibrium in the next years or even decades, the mechanism faces two serious problems.

First, a permanent disequilibrium means additional costs. These are transferred from producers to consumers by a capacity market (see example in Section 2.4). A single price would lead to potentially high profits for some emission-intensive power plants which are almost completely depreciated. While consumers might accept costs stemming from capacity payments to allow a transition to less carbon-intensive electricity generation, there is no acceptance for unnecessary payments to dirty power plants. This compromises political feasibility, since consumers expect burden sharing instead of full insurance for generators.

Second, the too low degree of internalization would set incentives for an intermediate equilibrium which is no longer optimal (see Section 2.5). Additionally, the theoretical considerations in Section 2.3 show that capacity price bids depend on power plants' maturity with comparative advantages for old facilities. Both the too low degree of internalization and the advantage of old power plants will slow down the transition process and thus give rise to the question whether the transition can be fast enough in the framework of a comprehensive capacity market without any regulation.

These problems can be solved by price discrimination as discussed in Section 3.2. It increases political feasibility and enables an acceleration of the transition phase. Even more important, it is economically justifiable, as convergence to intermediate equilibria is not necessary in the current transition phase.

3.1 Capacity market design

We suggest a step-wise procedure that incorporates three different capacity payments with respective limits for emission factors. New low carbon power plants can achieve the highest payments, while existing and more emission-intensive power plants will get a lower one or no payment at all. At first, generators offer their capacity for example in a sealed bid auction. A descending clock auction as suggested by Cramton and Ockenfels (2012) is also possible, but more cumbersome.[6] This results in a merit order of capacity as depicted in the lower graph of Fig. 3 as an example.

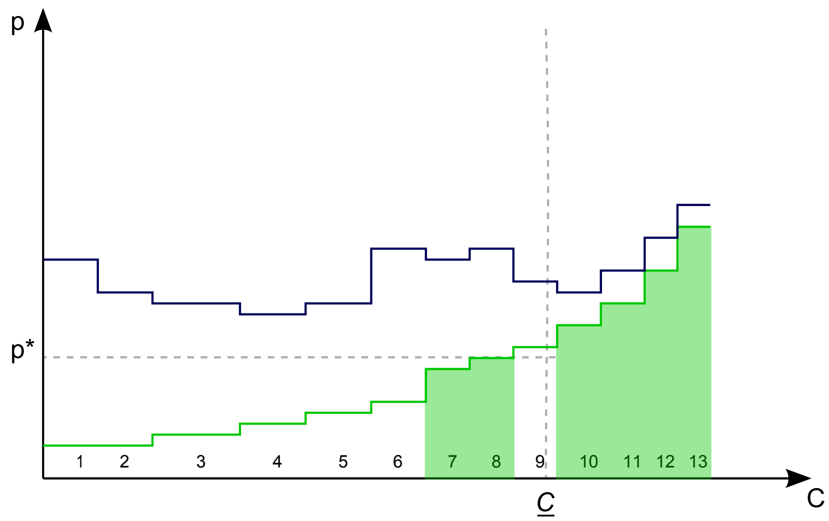

Figure 3: Example for a merit order of capacity (lower graph) with respective price supplements (upper graph) for power plants $n = 1, ..., 13$ ordered by increasing bids (step 1).

[6] See for example Harbord and Pagnozzi (2014) for a discussion of the descending clock auction in the context of capacity auctions.

To reduce market power abuse Cramton and Ockenfels (2012) suggest to force all existing power plants to take part in the auction with a bid of zero. This ensures a new power plant (the shaded bars in Fig. 3) to be price setting. If bids of old power plants exceed those of new ones, this indicates market power abuse because old power plants have a cost advantage (see Section 2.3). We also enforce all existing generators to participate in the auction or leave the market permanently, but accept positive bids for existing power plants. Nevertheless, only the last *new* power plant which is needed to meet $\underline{C}$ is considered for price determination. In so far, the resulting p^* would be in accordance with Cramton and Ockenfels (2012). In Fig. 3 power plant 8 sets the price, although number 9 is needed, too.

The bids of existing power plants are needed for step 2 and 3 of our mechanism. The regulator calculates the price supplement $\Delta\tilde{p}_i^{ETS}$ according to Eq. 24 for every power plant and adds it to the respective bid. All necessary information for doing so is usually given by the support mechanism for renewables or at least easily accessible. The result is the upper graph of Fig. 3 which reflects total costs for generators under consideration of a more realistic degree of internalization. The merit order of capacity may change and the new equilibrium price increases to $\tilde{p}^*$ because it includes the respective price supplement (see Fig. 4).

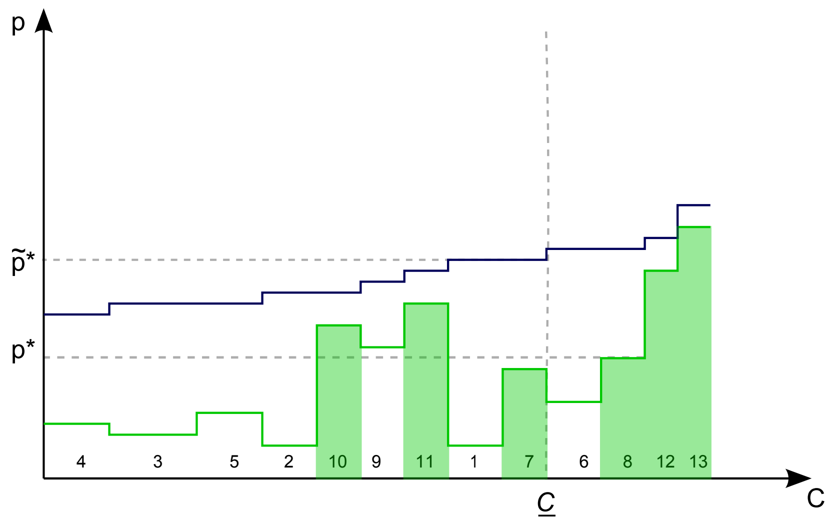

Figure 4: Merit order of capacity for the same sample power plants under consideration of capacity bids (lower graph) and respective price supplements (upper graph) for power plants $n = 1, ..., 13$ ordered by increasing total costs (step 2).

If generators with a successful bid received $\tilde{p}^*$ as a capacity payment, they would have to pay the promotion of renewable energy. While this is conceivable in principle, it would increase the degree of internalization at the spot market immediately (as today's capacity market is the future spot market) leading to great distortions. Therefore step 2 is only used to identify the proper merit order of capacity.

This step enables the regulator to classify three groups with respective price discrimination (see Fig. 5). Existing power plants with a successful bid in step 1 only, but not in step 2 (power plant 6 in our example) are so emission intensive that they would leave the market, if the proper degree of internalization was applied. They do not receive any capacity payment ($p_1^* = 0$) to induce their fade out instead of providing an incentive to further invest in such a technology.

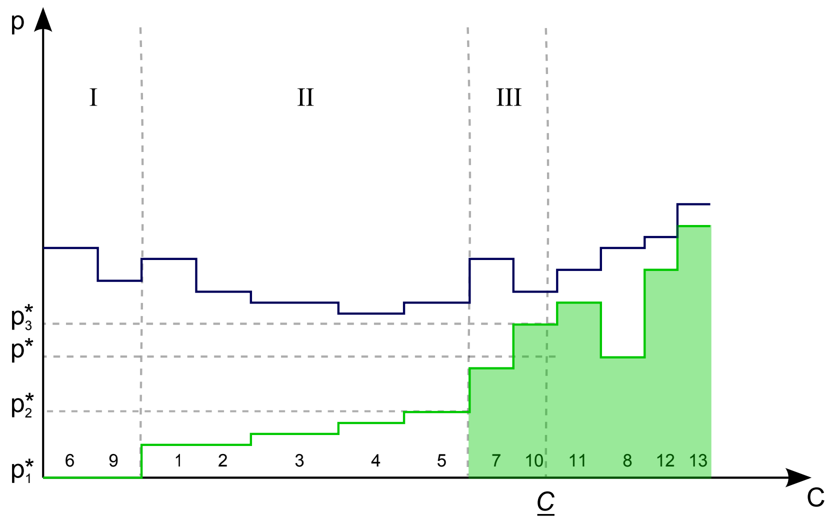

Figure 5: Merit order of capacity (lower graph) and respective price supplements (upper graph) of the successful sample power plants for power plants $n = 1, ..., 13$ ordered by increasing bids within each of the three groups (step 3).

To prevent market power abuse, existing power plants which placed a bid higher than the last necessary new power plant do not receive a payment either. To spare old, but clean power plants from this penalty, it should only apply to power plants that bid more than new power plants in step 1 and step 2 of our mechanism (plant 9 in our example). The hazard of being penalized with a price limited to p_{strike} instead of p_{cap} prevents generators from placing bids above their costs. Should this penalty seem too hard, payment obligations can be restricted to a power plant's downtime, if the spot price is above p_{strike}. In that way, losses for this power plant caused by payment obligations are limited without putting reliability at risk. All power plants which do not receive any money are grouped together and appear at the left end of the merit order of capacity (see power plants 6 and 9 in Fig. 5).

The missing capacity to satisfy $\underline{C}$ is served by power plants with increasing total costs according to step 2. Generators with successful bids in step 1 and 2 form group II. Group III consists of those which were only successful in step 2 (cleanest technologies). The highest bid in each of the two groups determines respective capacity prices p_2^* and p_3^*. Existing power plants are preferred over new ones to prevent capital erosion. Less emission-intensive power plants are preferred in group III. That is why power plant

10 is part of our optimal capacity mix instead of 8 (see Fig. 5).

3.2 Evaluation of the suggested market design

We design a comprehensive capacity market with endogenous limits of emission factors leading to discriminated prices. In this endogeneity our proposal differs from a focused capacity market (see Section 2). Direct market interventions to set the right limits are not necessary in our framework. This avoids an ongoing discussion about the limits which might attract lobbying activities of any kind. Beyond that, our mechanism is advantageous, since the limits adjust endogenously over time. In the long run, the price supplement and respective price discrimination will vanish as soon as p^{ETS} increases to p^{SWAP}. The connection between the ETS allowance price and the price supplement is beneficial as well. Increasing allowance prices lead to a decreasing price supplement and vice versa. Therefore emission costs are more predictable leading to higher investment certainty with decreasing risk premiums for generators.

Carbon-intensive power plants which could not place successful bids under consideration of the price supplement (group I) will leave the market earlier because of missing money. Clean power plants, to the contrary, get higher payments than in a standard comprehensive capacity market (group III) to enter the market earlier. Price discrimination therefore incentivizes investments in power plants with lower emission factors and hampers investments in less clean technologies. This accelerates the transition process. The comparatively lower payments to emission-intensive power plants (group I and II) will also increase acceptance of consumers for this mechanism. Both will enhance political feasibility.

In a focused capacity market, numerous power plants do not receive payments. This stimulates generators to close down existing power plants and build new ones instead. The design is criticized for this incentive, since it might cause extra cost. This critique does not hold for our framework because non-payment is only a penalty for market power abuse or directed at power plants which should leave the market in the medium run anyway. All other required power plants receive a capacity payment. Thus, our regime is less strict, but more cost-efficient. Capacity payments could even be restricted in such a way that consumers do not pay more in our mechanism than in a standard comprehensive capacity market, if this criterion is not fulfilled anyway.

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

The analysis in Section 2 shows that even a standard comprehensive capacity mechanism will introduce more flexibility without any guidance because peak-load power plants benefit from a comparative advantage in case of an increasing share of renewables. This is also true for our design. A capacity market will oppose the results of the merit order effect, observed on energy-only markets. The squeezing out of solely flexible gas power plants will terminate.

4 Conclusions

The suggested capacity market is a powerful regulation to tackle most of the currently discussed market problems of the transformation process to a low carbon electricity sector. Our capacity market model shows advantages for older power plants because of lower risks of losing remaining capital. With an increasing share of renewable energy, more peak-load power plants will be built which will lead to higher flexibility. This tackles the missing flexibility problem of today's spot markets resulting from the merit order effect of renewable energy. In principle, a capacity market creates the right answer to more intermittent electricity generation from renewable energy with respect to flexibility issues.

Based on these findings we develop a comprehensive capacity market. We utilize promotion costs of renewables in the determination of the proper degree of internalization of external CO_2 costs. The result is a price supplement per capacity unit depending on the power plant's individual emission factor. It can be calculated by the TSO with data available from established reporting obligations. The comparison of successful bids with and without a price supplement allows the TSO to endogenously calculate two threshold values for the emission factor. This leads to three different groups of power plants with increasing capacity payments as a result of decreasing emission factors. The first group receives no premium because power plants are so emission intensive that the proper degree of internalization would make them leave the market. The remaining two groups receive premiums determined by the last required power plant (highest bid) of each group. The third group with the cleanest technology gets the highest payments while power plants in the second group receive lower premiums. Moreover, an analysis of bids allows to identify power plants which intend to exercise market power. To restrict market power abuse these are penalized by receiving no payments.

This market-based mechanism regulates the necessary adjustment of residual fossil capacity with an increasing share of renewables. It introduces several advantages in comparison to other regulations which are mostly based on direct market interventions. The endogenously determined emission factors ensure that market interventions to readjust the limits are not necessary. This enhances robustness and efficiency as compared to regulations with exogenously defined threshold values for emission factors. Also price discrimination of capacity premiums evolves endogenously leading to a redistribution of money from emission-intensive to cleaner power plants. This sets sufficient incentives to direct the capacity mix to its long-run equilibrium where discriminated premiums converge to one equilibrium price. Furthermore, it accelerates the transition process and prevents capital erosion, since all power plants receive sufficient payments except for group 1, which diminishes. Redistribution will also increase consumers' acceptance because avoided payments for emission-intensive power plants do not result in full insurance for generators, but in burden sharing. These results significantly improve political feasibility.

The demand side as well as storage did not play any role in our considerations so far. Future research should address the question how these can contribute to reliability, too. Moreover it should be assessed whether renewable energy sources can participate in the capacity auction and if so, under which conditions.

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