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A Capacity Market for Electricity Sectors with Promotion of Renewable Energy

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Abstract

A capacity mechanism next to the energy-only market provides necessary investment incentives that spot markets lack. The adequate capacity mix can only be achieved by accounting for the current transition phase to electricity generation with a growing share of renewables. We show that an increasing share of renewable energy 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. Suggested capacity mechanisms do not account for the promotion of renewable energy so far. We consider support for renewables 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

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1 Introduction

Restructured electricity markets 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 due to 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 next to energy-only markets to satisfy resource adequacy.¹

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 electricity generation induces fluctuations on the supply side that increase price volatility. On the other hand, average electricity prices decrease due to the merit order effect (Flinkerbusch and Scheffer 2013).² This leads to market exits of flexible peak-load power plants with comparatively high variable costs, although flexible power plants are required in the long run to balance intermittent electricity generation from renewables. This is a result of focusing solely on variable costs at energy-only markets. Thus, the energy-only market exacerbates deviations from the long-run optimal capacity mix. Managing the transition process successfully is one of the most challenging tasks of today's electricity markets.

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 electricity generation with a significant share of renewable energy. The long-run optimal capacity mix cannot be achieved in an efficient way.

To investigate these distortions, in Section 2 we introduce a simple model of a comprehensive capacity market with a representative peak-load and a representative baseload power plant as a first step. These power plants can be seen as aggregates of

¹ 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.

² See for example Sensfuß, Ragwitz, and Genoese (2007) or Cludius, Hermann, and Matthes (2013) for an analysis of the merit order effect.

total existing capacity. 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 some theoretical considerations for estimating the degree of internalization of emission costs stemming from the promotion of renewable energy. This is an extension of standard environmental economics.

In a second step, 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 put special emphasis on the application of the suggested capacity market design using data which is in fact available. Based on this data 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 due to decreasing emission factors.

In the literature, there is either no price discrimination (see Cramton and Ockenfels (2012) and Cramton, Ockenfels, and Stoft (2013)) or it is given exogenously (see 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 today's energy-only markets (but also to markets in equilibrium) and displays high political feasibility. It can be implemented in basically every country with liberalized electricity markets and promotion of renewable energy.

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 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 prevent this strategic behavior most countries apply a price cap that restricts the spot price to rise above a certain level. If this price cap is set too low to generate a sufficiently high PER, there will be missing money to cover fixed costs in the long run. This leads to underinvestment in new capacity and distorts the optimal capacity mix (Vázquez, Rivier, and Pérez-Arriaga 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, Rivier, and Pérez-Arriaga 2002). This creates disincentives for new investments (Cramton, Ock-enfels, and Stoft 2013; Ockenfels et al. 2013).

2.1 Capacity Markets with Reliability Options

Some of the shortcomings of energy-only markets mentioned above may be tackled by restructuring spot markets. However, the missing money problem can arguably not be solved by such measures and requires the use of an additional capacity mechanism (Joskow 2008; Winkler and Altmann 2012). Capacity instruments in use are mainly strategic reserves or capacity payments since their design and implementation is fairly simple. A major drawback is that these mechanisms are not market-based and consequently not efficient (CREG 2012).

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 under discussion for implementation in France while the latter is planned to be implemented in 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, Rivier, and Pérez-Arriaga (2002). They suggest that the TSO, representing the regulator, buys ROs from generators of electricity 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 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 the lowest to the highest bid until C is satisfied. The price of the last accepted bid determines the premium all generators get per contracted capacity unit.

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 the spot market alone. Moreover, the RO and the explicit penalty ensure that generators do actually deliver electricity in scarcity events.

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) and Cramton, Ockenfels, and Stoft (2013) tackles this problem by enforcing that already existing capacity enters the auction with a price bid of 0. Consequently existing capacity cannot influence the equilibrium price p^* but new capacity determines the premium all generators receive.

Still this extension 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, present in the German discussion, contains elements of a transition design. Hereby, critical values are defined for the emission factor, 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 due to market interventions by exogenously defined limits. Therefore we design a comprehensive capacity market for the transition phase based on endogenously determined limits of emission factors.

2.2 Modeling a Reference Case

As a first step we model the capacity market equilibrium price p^* as a reference case for a comparative static analysis. Every existing power plant is obliged to place a bid in the capacity auction while participation of new power plants is voluntary. The bids of all n power plants are sorted in ascending order. If m power plants are necessary to provide the required capacity C, the equilibrium price equals the bid of power plant m. In contrast to Vázquez, Rivier, and Pérez-Arriaga (2002) and following Cramton and Ockenfels (2012) and Cramton, Ockenfels, and Stoft (2013) we do not apply an explicit penalty as the payment of the RO by generators acts as an implicit penalty.

This yields

$$p^* = p(\underline{C}) = p(\sum_{i=1}^{m} C_i) = (p_{cap} - p_{strike})d_{spike} + \Pi_m,$$
(1)

whereas $(p_{cap} - p_{strike})d_{spike}$ is defined as PER per capacity unit. We define d_{spike} as the normalized duration of scarcity events depending on spot market prices p_{spot}

$$d_{spike} = \frac{\int_{p_{strike}}^{p_{cap}} d(p_{spot}) \mathrm{d}p_{spot}}{p_{cap} - p_{strike}}$$
(2)

to simplify the notation. The PER represents costs for generators due to the ROs since they commit themselves to pay this amount to load as soon as p_{spot} rises above p_{strike} . If generators do not sell electricity or less than contracted at these times, they will reduce their profits.

The PER depends on the (expected) duration and intensity of scarcity events which is equal for all power plants because all of them are reasonably assumed to run. By definition a scarcity event occurs, if capacity is at its limit, thus if all generators produce electricity. If the price cap is set optimally ($p_{cap} = p_{cap}^*$), the PER is sufficient to cover capital costs leading to sufficient investment incentives. Missing money does not exist in this case.

The second part Π_m is distinct for every power plant and describes the difference between capital costs and electricity market profits per capacity unit

$$\Pi_i = \delta_i K_i - (p_{strike} - C_i^V - C_i^{ETS}) d_i.$$
(3)

Next to standard capital depreciation $\delta_i K_i$ an individual risk premium is included in

 δ_i . This risk premium is modeled proportional to the current capital stock as old power plants are able to offer capacity at a lower price since their remaining capital costs are lower. The second term in Eq. 3 displays profits generated at the spot or balancing market with C_i^V as variable costs and C_i^{ETS} as emissions costs. In the EU, emission costs arise from its Emissions Trading System (ETS). For simplicity we consider a representative base-load and a representative peak-load power plant. In the equilibrium capital costs of each type are covered by the PER, electricity market profits and, if necessary, missing money MM

$$\delta_{peak}K_{peak} = (p_{cap} - p_{strike})d_{spike} + MM$$

$$\delta_{base}K_{base} = (p_{cap} - p_{strike})d_{spike} - (p_{strike} - C_{base}^V - C_{base}^{ETS})d_{peak} + MM.$$
(4)

The strike price is normalized to $p_{strike} = C_{peak}^V + C_{peak}^{ETS}$ to simplify the notation.³ Therefore profits for the representative peak-load power plant are restricted to the PER while the base-load power plant additionally gains an IR depending on the period of use of the representative peak-load power plant (d_{peak}) which is normalized analogously to Eq. 2. The difference of the two equations yields

$$\delta_{base} K_{base} - \delta_{peak} K_{peak} = (C_{peak}^V - C_{base}^V + C_{peak}^{ETS} - C_{base}^{ETS}) d_{peak}.$$
 (5)

In short

$$\Delta K = \Delta C d_{peak}.$$

In equilibrium, the difference of capital costs is equal to the product of the difference between operation costs $(C^V + C^{ETS})$ and the normalized utilization of the representative peak-load power plant. Higher capital costs have to be compensated by lower operation costs and vice versa. According to Eq. 1 the analogous pricing equations for the representative peak- and base-load power plant are

$$p_{peak} = (p_{cap} - p_{strike})d_{spike} + \delta_{peak}K_{peak}$$

$$p_{base} = (p_{cap} - p_{strike})d_{spike} + \delta_{base}K_{base} - (p_{strike} - C_{base}^V - C_{base}^{ETS})d_{peak}.$$
(6)

Under consideration of Eq. 5 we obtain the equilibrium condition for a capacity market

$$\Delta p = p_{base} - p_{peak}$$

= $\Delta K - \Delta C d_{peak}$ (7)
= 0.

³ Vázquez, Rivier, and Pérez-Arriaga (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.

Eq. 7 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 outweighed by higher capital costs. Otherwise it cannot be part of an equilibrium because investments in this superior power plant would yield positive profits. Consequently Eq. 3 is equal for all power plants in equilibrium

$$\Pi_1 = \Pi_2 = \dots = \Pi_m. \tag{8}$$

 $\Delta p \neq 0$ 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

$$K_i = K_{0,i} e^{-\delta_i t_i} \tag{9}$$

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

$$\Delta t = t_{base} - t_{peak},\tag{10}$$

we get together with Eq. 7

$$\frac{\partial \Delta p}{\partial \Delta t} = -\delta_{base}^2 K_{base} - \delta_{peak}^2 K_{peak} < 0 \qquad \forall \Delta t > 0.$$
(11)

A difference in the average maturity of power plants has a direct influence on the price difference. Older power plants have a comparative advantage due to lower capital costs. If the representative base-load power plant is older than the peaker ($\Delta t > 0$), this will result in a lower price for the base-load power plant ($\Delta p < 0$) leading 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 power plants. In the second case, the same share is introduced but all 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 as compared to case two. The equilibrium is path-dependent.

2.4 Impact of an Increasing Share of Renewable Energy

A well-known result of the promotion of renewable energy is the so-called merit order effect which is characterized by decreasing average spot prices with an increasing share of renewables (Sensfuß, Ragwitz, and Genoese 2007; Cludius, Hermann, and Matthes 2013). This effect is explained by 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. The most common ones are feed-in tariffs or premiums. This leads to an excess of fossil capacity which will be reduced only in the long run. For small shares of renewable energy this will result in a pro rata reduction of total fossil capacity while mainly base-load power plants will be affected, if the share of renewables is large enough to serve parts of base load. In the short and medium run however, the opposite will happen as the reduced spot price level will squeeze peak load power plants out of the market due to their comparatively higher variable costs.

The current market design will provoke the closure of peak-load power plants until costs resulting from missing flexibility exceed the higher variable costs of peakers. Thereby, the adjustment to the equilibrium will take place in a sequential manner. After excess capacity is reduced by shutting down peakers, base-load capacity will decline especially as soon as power plants are almost completely depreciated. During this phase the utilization of base-load power plants cannot be efficient because of missing flexibility. Yet the question arises whether it is nevertheless an intertemporally efficient solution for the transition process.

The answer is yes, if the mitigated capital erosion caused by the reduction of excess capacity is larger than the additional cost due to increasing inflexibility. However, the energy-only market does not provide any link between capital 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

$$\frac{\partial p_{spot}}{\partial \varphi} < 0.$$

A decreasing spot price will result in a decline of residual load. 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 integral in Eq. 2 gets

smaller leading to

$$\frac{\partial d_{peak}}{\partial \varphi} < 0, \qquad \qquad \frac{\partial d_{spike}}{\partial \varphi} < 0. \tag{12}$$

According to Eq. 6, both representative power plants are affected equally by decreasing PERs due to decreasing d_{spike} . The representative base-load power plant additionally faces declining profits due to lower d_{peak} . In reality however, we observe heterogeneous plants with a certain distribution of operation costs. The spot price may thus decrease to a level which is permanently below operation costs of some power plants. Under consideration of such a distribution decreasing PERs, as modeled here, also describe the current market exit of gas power plants with high variable costs. These market exits are an observed consequence of the merit order effect. In contrast to that base-load power plants will not exit the market as long as there is any chance to gain profits from the spot market $(d_{peak} > 0)$.

While this analysis focuses on the mechanisms of an energy-only market, the impact on the capacity market is given by Eq. 7 together with Eq. 12

$$\frac{\partial \Delta p}{\partial \varphi} = \frac{\partial \Delta K}{\partial \varphi} - \frac{\partial \Delta C}{\partial \varphi} d_{peak} - \Delta C \frac{\partial d_{peak}}{\partial \varphi}
= -\Delta C \frac{\partial d_{peak}}{\partial \varphi}
> 0.$$
(13)

Those peak-load power plants with highest variable costs may exit the market, if we think of the representative peak-load power plant consisting of a whole fleet of power plants. This also makes capital costs as well as variable and emission costs depend on the share of renewable energy. As a result, variable costs of the remaining peak-load power plants will decrease but due to Eq. 8 this means an increase of average capital costs to the same extent leading to

$$\frac{\partial \Delta K}{\partial \varphi} = \frac{\partial \Delta C}{\partial \varphi} d_{peak}.$$
(14)

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

$\delta_{peak} K_{peak}$	500,000 €/MW
$\delta_{base} K_{base}$	900,000 €/MW
$(p_{strike} - C_{base}^V - C_{base}^{ETS})d_{peak}$	400,000 €/MW
$(p_{cap} - p_{strike})d_{spike}$	500,000 €/MW
	$\begin{split} &\delta_{peak} K_{peak} \\ &\delta_{base} K_{base} \\ &(p_{strike} - C_{base}^V - C_{base}^{ETS}) d_{peak} \\ &(p_{cap} - p_{strike}) d_{spike} \end{split}$

According to Eq. 6 this results in an equilibrium price $p^* = p_{base} = p_{peak} = 1,000,000$

€/MW. Without a capacity market the representative peak-load power plant would get $R_{peak} = PER = 500,000$ €/MW while the base-load power plant would earn $R_{base} = PER + IR = 900,000$ €/MW. Since capital costs are exactly covered, there is no missing money. A capacity market would not be necessary in this example, but since the PER has to be paid to load in the capacity market, it leads to the same results. The peak-load power plant will get $R_{peak} = p^* - PER = 500,000$ €/MW and the base-load power plant $R_{base} = p^* + IR - PER = 900,000$ €/MW. Total costs of electricity generation for consumers are

$$C = \rho \underline{C} R_{base} + (1 - \rho) \underline{C} R_{peak}$$
⁽¹⁵⁾

with ρ as share of contracted base-load capacity. If this equilibrium is distorted by an increasing share of renewables, a possible result may be:

capital costs peak-load	$\delta_{peak} K_{peak}$	500,000 €/MW
capital costs base-load	$\delta_{base} K_{base}$	900,000 €/MW
IR	$(p_{strike} - C_{base}^V - C_{base}^{ETS})\hat{d}_{peak}$	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). Nevertheless, this relationship is not crucial in this context. Without a capacity market we find $R_{peak} = PER = 400,000 \notin$ /MW and $R_{base} = PER + IR = 650,000 \notin$ /MW. Missing money occurs now because both power plants can no longer cover their capital costs. In a capacity market we obtain different price bids $p_{base} = 1,050,000 \notin$ /MW and $p_{peak} = 900,000 \notin$ /MW which indicate a disequilibrium. If we assume constant demand for fossil capacity with an increasing share of renewables (due to reliability), the equilibrium price will be 1,050,000 \notin /MW. We obtain $R_{peak} = p^* - PER = 650,000 \notin$ /MW and $R_{base} = p^* + IR - PER = 900,000 \notin$ /MW.

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 $\Delta C = (1 - \rho) \underline{C} = 150,000$ \in /MW at first glance, since consumers pay more than necessary with respect to capital cost coverage. However, this is only true in a static approach. The cost advantage for peakers is essential as it will incentivize investments in these kinds of power plants and direct the capacity mix to a new equilibrium. This will not happen immediately, since old power plants have a comparative advantage but base-load power plants will be progressively replaced. In the medium term the disequilibrium will vanish by market exits of base-load power plants and an increase of peak-load capacity.

The same is true, if demand for fossil capacity is reduced because of additional renewable energy. Due to intermittent renewable electricity generation the decrease of base-load capacity will be much slower than the installation of renewable capacity. Therefore additional investments in peak-load power plants may be incentivized to guarantee sufficient flexibility of the capacity mix. The capacity market will consequently lead to a more flexible fleet of power plants not in the sequential manner of today's energy-only markets.

2.5 Impact of Carbon Emission Costs

If we define

$$\Delta C^{ETS} = C^{ETS}_{base} - C^{ETS}_{peak} \tag{16}$$

to discuss the influence of CO_2 emission costs on the equilibrium, Eq. 7 yields

$$\frac{\partial \Delta p}{\partial \Delta C^{ETS}} = d_{peak} > 0. \tag{17}$$

The difference in emission costs has a direct influence on profits of base-load power plants realized at the spot market. According to Eq. 6 this cost effect is transferred to the capacity market. Neglecting rather clean nuclear power plants, base-load power plants are generally dominated by emission-intensive lignite while peak-load power plants mainly run with far less carbon-intensive gas. If the price for emission allowances increases, the difference in costs due to the ETS 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.

Despite the fact that this provides a general consideration of CO_2 emissions within a capacity market, problems arise with respect to adequacy and reliability. 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. The certificate price itself does not reflect the adequate degree of internalization at the electricity 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. 1 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} . The intersection point of both curves results in E^* describing the optimal long-run emission level. This value is easily identified in theory but it is always an assumption in reality and eventually a political objective.



Figure 1: CO₂ mitigation with respective marginal abatement costs of the ETS (MAC^{ETS}) and promotion costs of renewable energy (MAC^{RES}) with integrated price supplement $(\Delta p^{RES} = p^{RES} - p^{ETS})$.

The long-run objective of the EU for instance claims 80–95% CO₂ 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 trade of emission allowances. E^{ETS} in Fig. 1 shows such an intermediate objective with the resulting certificate price p^{ETS} . Beside the two parts of MAC Fig. 1 displays a standard picture used in environmental economics (see Nordhaus (1991)).

It might be possible, but far more expensive (due to physical restrictions) to reach the long-run objective without at least a partial substitution of fossil fuels (dashed part of MAC^{ETS} in Fig. 1). In the future MAC^{RES} will thus be lower than the marginal abatement costs of other strategies, although currently the opposite is true. Renewable energy would therefore enter the market in the long run even without any promotion as soon as the certificate price reaches p^{SWAP} . From that point on it is more efficient to follow MAC^{RES} instead of MAC^{ETS} . 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. 1 depicts the emissions mitigated by the promotion of renewable energy ($E^{SWAP} - E^{RES}$). Respective abatement (promotion) costs are visualized by the dark-shaded area below MAC^{RES} which is surrounded by E^{SWAP} and E^{RES} (Schäfer 2014).

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 directly reacts to the certificate price, this low degree of internalization would lead to a capacity mix that is not adequate with respect to the true degree. 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 these are mainly the difference costs between remuneration and the electricity spot price. Furthermore the total amount of emissions $E^{ETS} - (E^{SWAP} - E^{RES})$ 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 due to reporting obligations of the ETS and the promotion system. Assuming (in line with Schäfer (2014)) that the emissions mitigated by renewable energy are about the average direct emissions of fossil energy sources in the long run yields

$$E^{ETS} = \sum_{i=1}^{k} E_i \frac{\sum_{i=1}^{n} Q_i}{\sum_{i=1}^{k} Q_i}$$
(18)

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. 1). 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 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 implies additional payments and influences rather the future 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

$$e_i = \frac{E_i}{Q_i}.$$
(19)

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

$$\eta = \frac{E^{ETS}}{\underline{C} \cdot \sum_{i=1}^{k} e_i}.$$
(20)

The regulator can calculate the transformation factor for every year. Finally Eq. 19 and Eq. 20 yield

$$\Delta \tilde{p}_i^{ETS} = \Delta p^{RES} \eta e_i$$

$$= \frac{S}{\underline{C}} \frac{e_i}{\sum_{i=1}^k e_i}$$
(21)

reflecting the price supplement per capacity unit for each power plant, if abatement costs of renewable energy are distributed according to the individual emission factor. Each capacity unit 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 is faced with 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 a transition to less carbon-intensive electricity generation, there is no acceptance for payments to dirty power plants. This compromises political feasibility.

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 since 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.⁴ This results in a merit order of capacities as depicted in the lower graph of Fig. 2 as an example.



Figure 2: 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).

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. 2) 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

⁴ See for example Harbord and Pagnozzi (2014) for a discussion of the descending clock auction in the context of capacity auctions.

to participate in the auction or leave the market permanently, but accept positive bids for existing power plants. If only the last new power plant which is needed to meet \underline{C} is considered for price estimation, there will be no difference with respect to p^* following our framework or the suggestion of Cramton and Ockenfels (2012). In Fig. 2 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. 21 for every power plant and adds it to the respective bid. All necessary information for doing so is given by the framework of the ETS and the support mechanisms for renewables. The result is the upper graph of Fig. 2 which reflects total costs under consideration of a more realistic degree of internalization. The merit order of capacities may change and the new equilibrium price increases to \tilde{p}^* because it includes the respective price supplement (see Fig. 3). If generators with a successful bid received \tilde{p}^* as 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.



Figure 3: Merit order 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).

This step enables the regulator to classify three groups with respective price discrimination (see Fig. 4). 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 4: Merit order of capacity (lower graph) and respective price supplements (upper graph) of the successful sample power plants for power plants n = 1, ..., 14 ordered by increasing bids within each of the three groups (step 3).

To prevent market power abuse, existing power plants which placed a higher bid 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 the resulting price cap at 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 due to 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 (see power plants 6 and 9 in Fig. 4).

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 technology). The highest bid in each of the two group 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 plants 10 and 11 are part of our optimal capacity mix instead of 7 and 8 (see Fig. 4).

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 due to 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 and nearly depreciated power plants (group I and II) will also increase acceptance of consumers to pay 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.

The suggested market design with its division into groups significantly reduces market power. 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 any sense, since it results in no capacity payments. Competition of new power plants will increase because market entry barriers are reduced by lower risks due to 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

Our capacity market model shows advantages for older power plants due to lower risks of losing remaining capital. With an increasing share of renewable energy, more peakload 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 design under consideration of the promotion of renewable energy. We utilize promotion costs of renewables in the determination of the proper current 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 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 due to 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 us to identify power plants which intend to exercise market power. To restrict market power abuse these are penalized by receiving no payments, too.

The endogenously determined emission factors ensure that market interventions to readjust the limits are not necessary. This enhances robustness and efficiency as compared to instruments 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. Moreover it accelerates the transition process and prevents capital erosion since solely the fade out of the first group is provided while all other plants receive sufficient payments. Redistribution will also increase consumers' acceptance because money "is guided in the right direction". These results significantly improve political enforceability.

The suggested capacity market design tackles most of the currently discussed problems of the transformation process of the electricity sector to low carbon electricity generation. The demand side as well as storage did not play any role in our considerations so far. Future research should address the question how this 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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