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Cross-border effects of capacity mechanisms: Do uncoordinated market design policies countervail the goals of European market integration?

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Roland Meyer and Olga Gore

Cross-Border Effects of Capacity
Mechanisms:

Do Uncoordinated Market Design
Policies Countervail the Goals of
European Market Integration?

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**Cross-Border Effects of Capacity Mechanisms: Do Uncoordinated
Market Design Policies Countervail the Goals of European Market Integration?**

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June 19, 2014

Abstract

This article analyses cross-border effects of capacity mechanisms and discusses whether such mechanisms countervail the goals of European Market Integration. Using a two-country-model, the countries' policy options are analysed from a game-theoretical viewpoint. A model simulation identifies the main effects on investments, trade, and overall welfare.

We find that a strategic reserve and reliability options have both negative cross-border effects if implemented unilaterally. This exerts pressure on the neighbouring country to change its market design as well. Given that both countries chose their optimal market design, however, the Nash Equilibrium is welfare improving from an overall point of view.

Reliability options are superior to a strategic reserve as they avoid a non-market-based dispatch of generation and thus increase market trade and welfare. Furthermore, surpluses are redistributed from producers to consumers, which serves overall welfare if the focus is on consumer benefits.

Key words: Market design; Generation adequacy, capacity mechanisms, Internal European Market

JEL-classification: D47; L11; L52; L94

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1 Introduction

Europe's electricity markets are heading towards a high penetration of renewable energy sources (RES). The challenges of integrating intermittent and capital intensive RES into existing markets has led many European countries to reconsider their market design in favour of capacity mechanisms (CMs). The reason is the so-called "missing money problem" (Cramton & Stoft, 2006): due to their low marginal cost, RES suppress electricity wholesale prices and reduce the prospects of conventional generation capacity (as well as for storage and demand response) to earn sufficient revenues for electricity sold to the market. Those capacities are needed, however, to compensate for occasional shortfalls of RES-supply. The idea of CMs is to ensure generation adequacy by providing investment incentives through capacity-based payments for reserve capacity that would otherwise suffer from both lower energy prices and a decreasing utilization of capacity in RES-dominated electricity markets.

The effectiveness and efficiency of CMs have been broadly analysed, and different forms of them are applied around the world. Many EU member states currently consider to re-design their electricity markets in favour of a CM or have already done so (CREG, 2012). However, there is still a lack of understanding, whether and to what degree CMs cause cross-border effects which would conflict with the European goals of an Internal Market for Electricity. This paper picks up the discussion and analyses the cross-border effects against the background of European market integration based on a theoretical simulation model.

The Internal European Energy Market is a key part of the EU 2020 strategy, as it is considered an important tool to ensure affordable, secure and sustainable electricity supply in the future (European Commission, 2010). It aims to enhance competition by opening the national markets to foreign participants, thereby increasing supply security and cost efficiency (Booz & Company et al., 2013; Creti et al., 2010; Jamasb & Pollitt, 2005; Pellini, 2012). However, the European Commission has recently raised concerns that these goals may be undermined by the fact that market design decisions are made at the national level and are weakly harmonised across Europe (European Commission, 2013). Uncoordinated CMs may distort the cross-border trade and hinder the achievement of the Internal Electricity Market in Europe (ACER, 2013; RAP, 2013).

CMs may have several spillover effects:

- *Price effects.* Capacity mechanisms typically aim to reduce peak prices by replacing the sole energy-based remuneration of generators with two-part payments consisting of energy-based and capacity-based payments. This may affect trade with neighbouring markets relying on energy payments only.
- *Capacity effects.* Capacity mechanisms may have an indirect capacity effect by redirecting investments. Negative cross-border effects occur, if generation investments are triggered in regions that have CMs, while investments in other regions become less attractive.
- *Welfare effects.* In the case of positive externalities, the introduction of capacity markets involves a free-riding effect. Consumers in the country with a capacity market may pay for an increase in generation capacity that partly leaks to the neighbouring market. Consumers in the “passive” market may act as free-riders, since they benefit from an increase in reliability and lower energy prices without having to pay for the additional capacity. On the other hand, CMs may also incur negative externalities. A reduction in price spikes in the CM market limits the export prospects of the neighbouring market, thereby aggravating its missing money problem. In other words, a capacity market in one country may partly export the missing money problem to the neighbouring country, forcing it to change its own market design.
- *Infrastructure investment.* CMs can distort investment incentives to build new interconnectors in case of reduced trade leading to lower congestion rents for the interconnector owners (Meyer et al., 2014).

There are a few real-life examples for the interaction of energy-only and capacity markets: PJM and the Midwest ISO control areas in the US, Ireland and Great Britain, and Russia and the Nordic market. Inefficient cross-border trade has been observed in all the above cases (McInerney & Bunn, 2013; Viljainen et al., 2013). Experiences in these markets demonstrate how challenging the integration of electricity markets with different market designs can be. However, only a few recent studies focus on the impact of CMs in Europe on the cross-border trade and show that unilateral implementation of capacity mechanisms may cause cross-border effects and threaten the efficiency of the internal electricity market (see e.g. Sweco, 2014; Thema, 2013). The degree to which individual CMs may impact cross-border trade depends on the degree of interconnectivity between the markets, the correlation of prices and scarcity situations between the markets and coordination of the possible cross-border impact with the neighbouring market.

This paper investigates the cross-border effects of two forms of CMs, a strategic reserve (SR) and reliability options (RO), which represent two basic approaches to address the missing money problem. The analysis is based on a theoretical two-country model which is used to examine the strategic interaction between the individual market design policies. We use a game-theoretical approach where national policy makers act as strategic players deciding whether to implement a capacity mechanism or to remain an “energy-only” market. The Nash Equilibrium is analysed with respect to national and aggregate welfare, price effects and investment effects. The results are based on a simulation to help identify the main drivers of the cross-border effects.

The paper is structured as follows. Section 2 details the discussion on capacity mechanisms in Europe, illustrates the missing-money problem, and briefly explains the functioning of CMs. Section 3 describes the modelling approach to the analysis of CMs. The results are presented and discussed in section 4. Section 5 concludes.

2 Discussion on CMs in Europe

2.1 Missing-money problem

Electricity markets have traditionally been so-called “energy-only” (EO) markets. Electricity generators are paid for the volume of electricity (MWh) they produce and sell to the wholesale market. Energy payments have to recover both variable and fixed cost of the power plants. In absence of market distortions, these revenues should suffice to attract new investment to ensure generation adequacy in the long run (Hogan, 2005). However, ambitious targets to increase the share of renewable generation by means of support schemes and priority access to the grids pose a challenge to market functioning. Many European member states are concerned that energy-only markets alone might be not able to deliver sufficient reserve capacity required to back up shortfalls of energy from renewable energy sources (RES) during periods of low wind and sun (Eurelectric, 2011; Meulman & Merey, 2012; Nicolosi, 2012). The main problem is that RES suppresses energy wholesale prices, while at the same time the high share of RES reduces the utilisation of reserve capacity. This creates a “missing money problem” for peak generators, if electricity prices are not high enough or price spikes occur too rarely to recover the full costs of existing power plants. The lack of promising investment prospects is aggravated by uncertainties about future electricity, fuel and CO₂ prices, the number of operating hours of conventional power plants (or load factors)

and regulatory interventions in market design and rules (Joskow, 2006). In the long run, weak investment incentives in capacity needed to back up the increasing share of intermittent RES might lead to a resource adequacy problem in energy-only markets. Figure 1 illustrates the missing money problem.

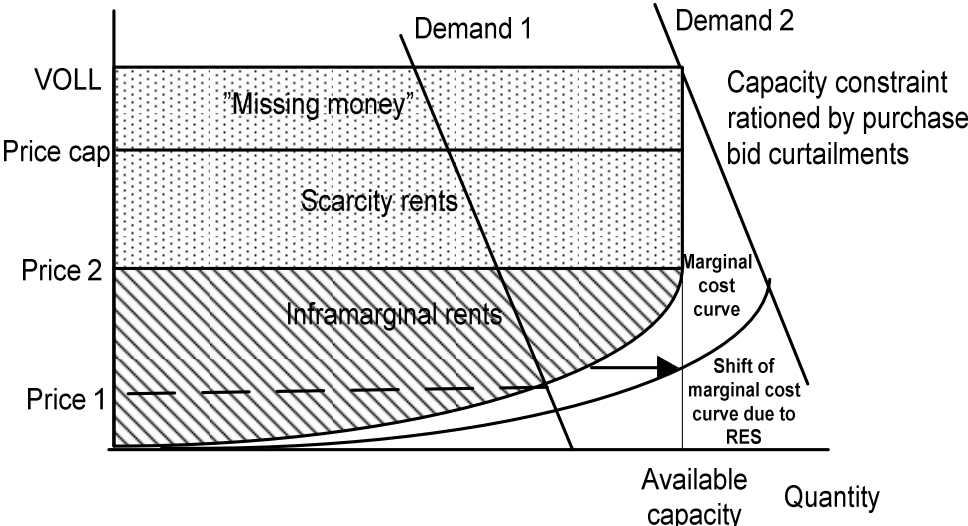


Figure 1. Missing-money problem
 Source: adapted from Joskow, 2006

In a competitive energy-only market, generators bid their short-run marginal costs, and the hourly market clearing price equals the marginal cost of the last generating capacity or the demand response resource that clears supply and demand given that demand does not exceed the available capacity (as illustrated by ‘Demand 1’ in Figure 1). The fixed costs of dispatched generators are recovered through the inframarginal rents given by the area between the market clearing price (‘Price 1’ in Figure 1) and the marginal costs of the generators. In a relatively small number of hours per year there will be scarcity situations when the demand exceeds the available capacity (‘Demand 2’ in Figure 1). In this case, demand is curtailed at the maximum price. Under competitive scarcity conditions, the maximum price at the day-ahead market should reflect the value of lost load (VOLL); the price that consumers place on reducing consumption by a significant amount. Generators then earn “scarcity rents” that amount to the area between the VOLL and Price 2 in Figure 1. For peak capacities operating mainly during scarcity conditions, scarcity rents are an important source of revenue to cover the fixed costs. However, the lack of short-term demand response provides the generators with an opportunity to exercise market power during scarcity conditions. Therefore, a threat

of market power abuse may induce regulators to set a price cap so that the electricity market is cleared at a lower price in scarcity conditions. The price cap protects customers against high prices, but at the same time reduces scarcity revenues, thereby reducing investment incentives by restricting the expected return on investment.

The current missing-money problem in the European energy-only markets is not directly based on the classical price cap argument. The recent decline in the generators' profitability is mainly due to the excess power generation caused by the rapid growth of (subsidised) RES. Low marginal cost of RES generation leads to a merit order effect by shifting the supply curve to the right (see Figure 1). The effect is that both prices and load factors of the conventional power plants are reduced. The decline in the operating hours of combined-cycle gas turbines (CCGT) in some EU countries is already observed and forecasted for the future years (Pöyry, 2011). In Spain, for instance, CCGTs were dispatched for only half as many hours in 2010 compared with 2004. The peak generators fail to recover their fixed costs as a result of the reduced number of operating hours, suppression of real scarcity prices caused by oversupply and scarcity price capping when the market is tight. An increasing number of recently built CCGTs, which are highly efficient but do not operate on a profitable basis, are in risk of being mothballed unless markets provide a higher remuneration. Ten of Europe's biggest power companies announced mothballing of a total of 21.3 GW of gas power plants in 2013 (Caldecott & McDaniels, 2014). All these factors worsen the current investment climate in peak generation.

2.2 Capacity mechanisms

The aim of CMs is to ensure the profitability of the existing power plants and to support investments in new power plants by providing stable revenues in the form of capacity payments (Cramton & Stoft, 2005; Cramton & Ockenfels, 2012; De Vries, 2007; Joskow, 2008). To prevent the continuing closure of flexible peak generators, capacity payments should ensure fixed cost recovery for reserves to backup capacity for the growing share of RES (Brunekreeft et al., 2011; Cepeda & Finon, 2013; CREG, 2012). France, for instance, is implementing a CM in the form of Capacity Obligations by 2015–2016 (Finon, 2012; RTE, 2013). Similarly, the UK plans to introduce a Forward Capacity Market by the end of 2014 (UKERG, 2010; UK government, 2013). In Germany, two forms of CMs are currently in the discussion: a strategic reserve (SR) and reliability options (RO). The German Association of Energy and Water Industries has issued a conceptual framework for implementing a strategic

reserve in Germany as a temporary measure to prevent the closure of the existing peak power plants, which struggle to recover their fixed costs caused by the reduced load factors until the operation of power plants becomes profitable again (BDEW, 2013). Figure 2 illustrates the current state of the CMs in Europe.

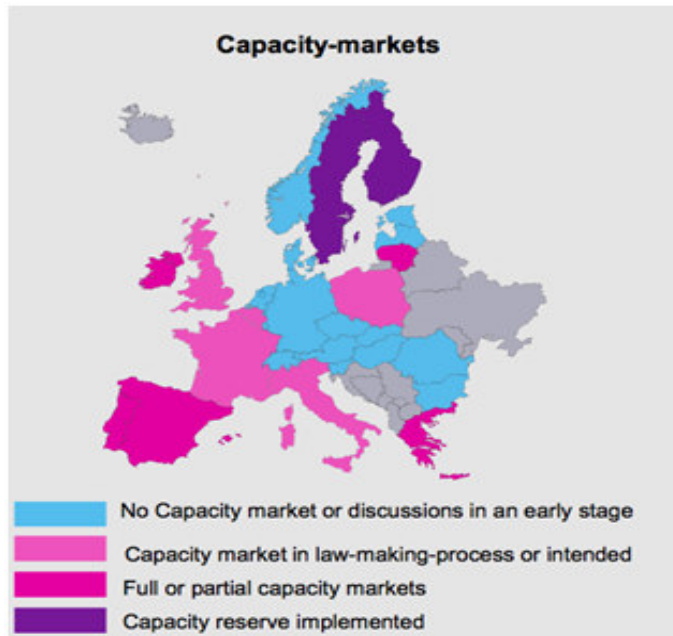


Figure 2. Capacity markets in Europe
Source: adapted from Parkinson, 2013

Capacity mechanism can be divided into price-based mechanisms (capacity payments) providing direct financial support for investments, and quantity-based mechanisms (forward capacity markets, capacity obligations, reliability options, and strategic reserve) where the regulator sets the desired amount of capacity, and the price evolves from the market clearing.

Quantity-based CMs can be based on centralised capacity auctions, where a central authority determines the level of capacity based on demand forecasts and data about the state of the power system. Examples for centralised CMS are forward capacity markets implemented in the US e.g. by PJM and ISO-NE (Benedettini, 2013). Capacity obligations are an example for a decentralised scheme consumers are obliged to contract a certain level of capacity required to cover peak demand. Consumers can meet the obligation through own

capacity or bilateral contracts with capacity providers at the price agreed between the parties.¹ Our focus is on a strategic reserve and reliability options, both of which will be characterised in the following sections.

2.3 Strategic reserve

A strategic reserve is a central approach where a certain amount of reserve capacity is auctioned to safeguard security of supply in cases when market capacity is scarce. While the main part of the market remains energy-only, a strategic reserve is contracted in addition to market capacity and is withheld from the spot market in favour of a central dispatch. The required volume of strategic reserve is tendered by a central authority, which is typically the transmission system operator (TSO). The TSO does not own the strategic reserve, but rather contracts power plants to provide availability when needed. The total cost for maintaining the strategic reserve is collected through grid charges. Strategic reserves are implemented for instance in Sweden and Finland. However, the reserve is rather small and activated a few hours per year at most.

A strategic reserve may bring inefficiencies to the short- and long-run operation of the spot market depending on how and when the reserve is activated, i.e. the dispatch rule. There are basically two possible ways to utilize the reserves.

In case of a price-based dispatch, the strategic reserve is activated as soon as a certain price in the day-ahead market is reached. If the dispatch price is set too low to allow sufficient scarcity prices, this further suppresses market revenues and, hence, investment incentives. As a result, the strategic reserve has to be relatively larger to obtain the same amount of overall capacity in the market (Brunekreeft et al., 2013). Therefore, setting the proper dispatch price is an essential element in designing the strategic reserve. As will be shown in the simulation results, a price-based dispatch of the strategic reserve can lead to a distortion of investments and trade.

Under a quantity-based dispatch rule, reserves are activate after markets have been cleared, i.e. only if load cannot be met by available market capacities. This avoids limiting the scarcity revenues on the market and the risk of setting an inefficiently low dispatch price.

¹ A detailed analysis of different types of capacity mechanisms is presented in numerous publications, see e.g. De Vries (2007) and Pfeifenberger et al. (2009).

We focus on the price-based dispatch and show that it may lead to a crowding out of available market capacities, notably imports, if reserves are activated at a price lower than the maximum market price. We note, however, that under both dispatch rules there may be distortive effects due to the non-market based activation of reserves which does not necessarily ensure a least-cost dispatch of generation units in both markets.

2.4 Reliability options

Reliability options are a quantity-based capacity mechanism, where the regulator (typically TSO) purchases call options (reliability contracts) from generators on behalf of consumers covering the forecasted peak demand plus a reserve margin. The TSO sets the strike price in the electricity market, typically at a slightly price higher than the marginal cost of the most expensive unit in the system. Whenever the market price exceeds the strike price, the auctioneer (acting in the consumers’ interest) calls the option and thereby commits the involved generators to provide electricity physically or financially at the determined strike price. In case of a financial obligation, the committed generators that have sold call options must pay the difference between the actual market price and the strike price for each MW sold in the capacity auction. Figure 3 illustrates the principle.

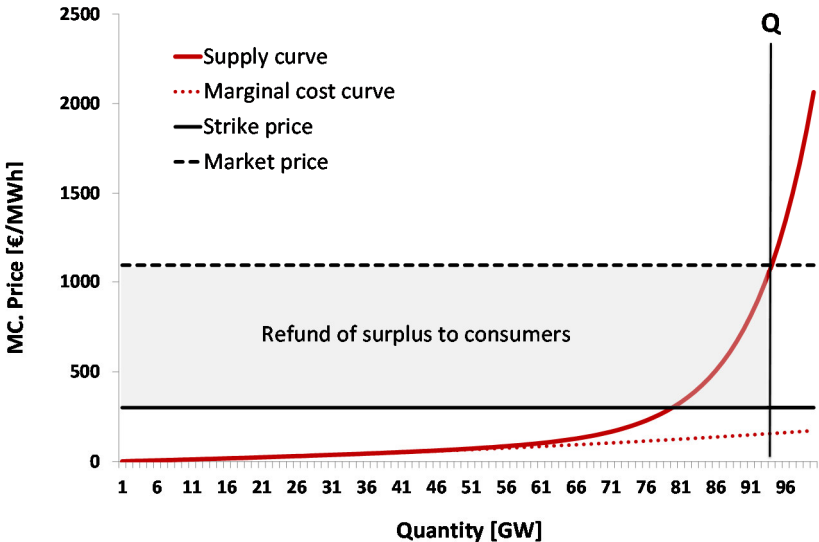


Figure 3. Mechanism of reliability options

Both producers and consumers are hedged against price spikes, though in the opposite direction. A loss of peak revenues above the strike price is now compensated through selling option premiums in capacity auctions, the size of which will depend on the generator’s loss of

revenues after setting a certain strike price in the spot market. The capacity auction represents either a uniform auction, where generators submit capacity bids expressing the volume of capacity they want to sell at a certain price, and all accepted generators receive the price of the last accepted bid; or a pay-as-bid auction where each accepted generator receives the price of its own bid. All accepted generators are obliged to keep their capacity available. Non-availability is penalised when the option is called (Bidwell, 2005; Cramton & Stoft, 2008; Vázquez et al., 2002; Vázquez et al., 2003).

Reliability options may have an impact on both the short- and long-term operation of the electricity market. As will be argued further below, it may affect the generators' bidding behaviours and thereby short-term pricing in the energy market, since the quasi-price-cap imposed by the strike price may incentivise generators to reduce their mark-ups on marginal costs. Given the strong price effects of reliability options, we find that implementation of this mechanisms in one market, may put strong pressure on the neighbouring market to implement reliability options as well.

3 Two-country market model

3.1 Modelling approach

The model assumes two energy markets that are interconnected by market coupling. Both markets 1 and 2 suffer from a missing-money problem, therefore considering the implementation of a capacity mechanism (CM) to maintain generation adequacy. The aim of the analysis is to evaluate the cross-border effects resulting from a unilateral market design change. Both markets' policy options are analysed from a game-theoretic point of view, assuming a one-shot game in which both players decide on whether or not to implement a CM. The Nash equilibrium is analysed in terms of welfare, trade and electricity prices. The two CMs analysed are a strategic reserve (SR) and reliability options (RO) as described in the previous section. The results will be based on a model simulation to help identify the main drivers of the policy effects.

In the initial situation (short-run equilibrium) we assume sufficient generation capacity to meet peak load, which appears to be a realistic setting for most European markets at the moment. However, a certain volume of peak load generators in both markets is assumed to fall short of scarcity revenues needed to cover their fixed cost. Hence, capacity would

diminish in the long run unless a capacity market is implemented. The modelling assumption for the missing-money problem is described in section 3.2.

We assume price inelastic demand, which varies over time according to a load duration curve. To simplify the model and focus on the impacts of the market design we assume that the demand level is the same for both markets in each moment. In other words, we neglect differences in stochastic variations between the two markets.² The load is supposed to vary between a minimum (20 GW) and maximum value (100 GW). The load duration curve for both markets is given by

$$L(D) = p \cdot \exp(q \cdot D) + r \quad (1)$$

Electricity supply in both markets is given by the merit order, which determines the order of dispatch of the generation units from the lowest to the highest marginal supply bids. For the analysis we assume two asymmetric markets with respect to their marginal cost; market 1 is supposed to have a strictly lower marginal cost than market 2. The initial generation capacity in both markets is assumed to be $K_1=K_2=100$ GW, that is, the peak demand in both markets can be met by total available capacities.

We distinguish between the marginal bid curves and the marginal cost curves by allowing price mark-ups depending on the scarcity of generation capacity. In doing so we follow the concept of residual supply index (RSI) developed by the California Independent System Operator (CAISO, 2004).³ The marginal cost and bid curves are described by an exponential function (see e.g. Takashima et al., 2007). Marginal bids depend on a scarcity ration defined by the ratio of the current output and the total available generation capacity.

The marginal cost curve for both markets $i=1,2$ is given by

$$MC_i = a_i \cdot [\exp(b_i \cdot Q_i) - 1] \quad (2)$$

The mark-up on marginal cost is given by:

² We are aware of the fact that by neglecting the stochastic feed-in of RES we disregard an important argument for the missing-money problem. However, the focus of this study is not on explaining or evaluating the missing-money effect, but on measuring the impact of market design options given that there is a certain degree of missing money in the energy-only market.

³ See Green and Newbery (1992) and Newbery (1998) for a theoretical foundation and application of this concept to electricity spot markets.

$$\frac{(P_i - MC_i)}{MC_i} = c_i \cdot \exp\left(d \cdot \frac{Q_i}{K_i}\right) \quad (3)$$

with $a, b, c, d > 0$,

where (Q_i/K_i) is the scarcity ration for capacity, that is, the ratio of the current output level Q_i and the total available generation capacity K_i .

Accordingly, the marginal bid curve (supply curve) $P_i(Q_i)$ is described by

$$P_i(Q_i) = MC_i(Q_i) \cdot \left[1 + c_i \cdot \exp\left(d \cdot \frac{Q_i}{K_i}\right)\right] \quad (4)$$

or

$$P_i(Q_i) = a_i \cdot \exp[\exp(b_i Q_i) - 1] \cdot \left[1 + c_i \cdot \exp\left(d \cdot \frac{Q_i}{K_i}\right)\right] \quad (5)$$

The interconnection capacity (IC) between both markets is assumed to be 5 GW. For the trade arrangement we assume market coupling, that is, there is an implicit auctioning of both electricity and interconnection capacity. The auctioneer combines the supply and demand side bids of both markets and optimises the total welfare for a given interconnection constraint. If IC is not binding, the prices in both markets will fully converge as in a single market. In the case of constrained exports, the prices will remain different, and a congestion price equal to the price difference will be charged per MWh of trade for the use of the interconnection. We assume that congestion charges will be split equally between the two markets.

Market coupling optimisation can be expressed as

$$\text{Max}\{PS_1 + CS_1 + PS_2 + CS_2\} \quad (6)$$

$$s. t. \quad Q_1 + Q_2 \leq 2 \cdot D_1 \quad (\text{no oversupply}) \quad (6a)$$

$$Q_1 \geq 0; Q_2 \geq 0 \quad (\text{non-negative outputs}) \quad (6b)$$

$$Q_1 \leq K_1; Q_2 \leq K_2 \quad (\text{generation constraints}) \quad (6c)$$

$$Q_1 \leq IC + D; Q_2 \leq IC + D \quad (\text{interconnection constraint}) \quad (6d)$$

with Q_1 : generation output in market 1

Q_2 : generation output in market 2

K_1 : generation capacity constraint (maximum output) in market 1

K_2 : generation capacity constraint (maximum output) in market 2

D: demand level (equal for both markets)

IC: interconnection constraint

Producer surplus (PS) and consumer surplus (CS) are given by

$$PS_i = a_i [\exp(b_i Q_i) - 1] \left[Q_i + c_i \exp\left(d_i \frac{Q_i}{K_i}\right) Q_i - \frac{1}{b_i} \right] + a_i Q_i \quad (7)$$

and

$$CS_i = (VOLL - P_i(Q_i)) \cdot \min(D; Q_i + X), \quad (8)$$

The value of lost load ($VOLL$) in equation (8) serves as a measure for the marginal willingness to pay for electricity consumption. Differently put, it measures the cost of electricity curtailment if demand (D) is not met by domestic production (Q) and imports. Empirical studies suggest that the average $VOLL$ is between 8,000 and 12,000 €/MWh (see e.g. de Nooij et al., 2007). We assume a $VOLL$ of 10,000 €/MWh for this study.

The simulation of market results is carried out by repeatedly solving the market coupling optimisation for the full range of demand levels. The resulting values for production, trade, prices and surpluses are summed up for one year (8760 hours), weighted by the respective number of hours per demand level given by load duration.

Table 1 summarises the load duration and supply parameters used in the simulation. Table 1 reveals that the only difference between both markets is the shape parameter a_i of the marginal cost and bid curves resulting in a stronger increase in costs and prices with increasing generation.

Table 1: Supply and load parameters

	Market 1	Market 2
Load duration		
p	2.32	2.32
q	-0.04	-0.04
r	-0.04	-0.04
Supply		
a	100	120
b	0.01	0.01
c	0.0005	0.0005
d	10	10

3.2 Energy-only market

3.2.1 Short-run equilibrium

For the initial market equilibrium we assume two energy-only markets characterised by total available generation capacities of 100 GW, which is equal to the highest peak load according to the load duration curve.

According to our assumption, market 1 has a lower marginal cost than market 2. Hence, for the initial capacity constraints, market 1 is the exporting country. Figure 4 illustrates the short-term equilibrium graphically for a given demand level in case of a full price convergence. The vertical line (D) is the demand level, which is assumed to be price inelastic and equal for both markets. The supply curve is given by S and the marginal cost curve by MC. The solid lines (Q) indicate the production values, while the total available capacity is shown by the dashed vertical lines. The prices are illustrated by the dotted horizontal lines.

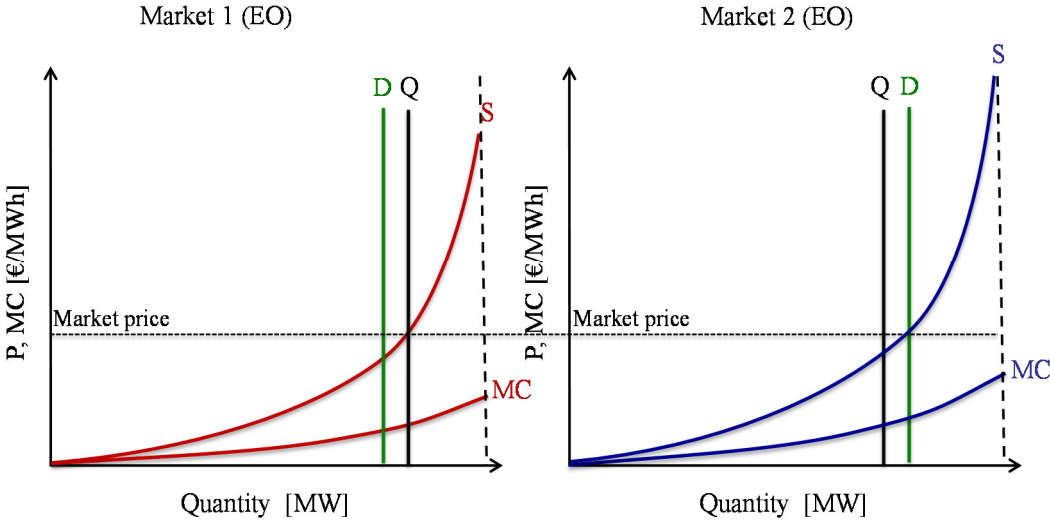


Figure 4. Short-run equilibrium for the EO-EO case for a given load

3.2.2 Missing-money problem and long-term equilibrium

Our missing-money assumption is straightforward: we define a ‘reference generator’, which is assumed to be the last generator in the merit order being able to recover its total cost in the energy-only market. This reference (zero-profit) generator in both markets is assumed to be at 95 GW in the merit order, while the remaining 5 GW of generation suffers from a

shortfall of revenues.⁴ From the zero-profit assumption for the reference generator, we can derive the fixed cost of this peak load generator, which is then equal to the inframarginal rents it receives in the market. For simplicity, we assume fixed costs to be approximately the same for all peak load units, so we can derive the long-term investment equilibrium.

The equilibrium condition is that the last generator in the new merit order will earn zero profits in both markets. The calculation of the new generation equilibrium is derived in Appendix 1.

We end up with a capacity of $K_1=96.2$ GW and $K_2=97.1$ GW. Figure 5 illustrates the long-run (investment) equilibrium for the energy-only case.

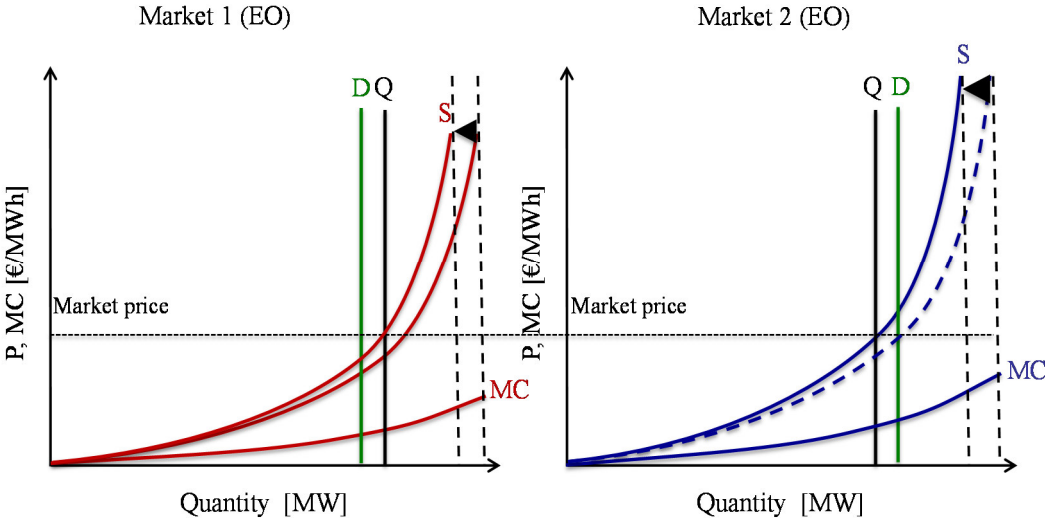


Figure 5. Long-run equilibrium for the EO-EO case for a given load

The detailed results for this long-term EO-EO market equilibrium constitute the reference case for the evaluation of capacity mechanisms.

3.3 Strategic reserve

In our model we assume a price-based dispatch of the strategic reserve (SR). As discussed in section 2.1, there is a critical relationship between the dispatch price and the size

⁴ Note that we do not specify in detail why the scarcity prices for the remaining generators would not increase accordingly in order to allow full cost recovery. Instead, we leave the question open whether this market failure is due to investment risks, regulatory risks or implicit or explicit price caps in the market (see e.g. Joskow, 2006 for a discussion).

of the reserve market. Since the reserves are dispatched when the market price is equal to the dispatch price, the latter basically functions as a price cap in the market. Defining the target capacity to be 100 GW, we assume that the dispatch price is high enough to avoid a further crowding out of the domestic market capacity. In other words, the size of the SR in both markets should be no larger than the difference between 100 GW and the amounts of capacity that would remain in the energy-only case in the long run, which is $K_1=96.2$ GW and $K_2=97.1$ GW. Hence, in the case of implementation of an SR, the optimal sizes would be $SR_1=3.8$ GW and $SR_2=2.9$ GW for market 1 and market 2, respectively.

To achieve this, the dispatch prices are to be (at least) $PD_1=1.943$ €/MWh and $PD_2=2.366$ €/MWh, which equals the highest domestic bid prices according to the supply functions given by equation (4).

Figure 6 illustrates the market equilibrium for a given load in a case where only market 1 introduces an SR while market 2 remains energy only (SR-EO). The investment incentives are basically modelled in the same way as for the energy-only markets. The difference is that in the case of an SR, the last generator always receives the dispatch price during its hours of operation.

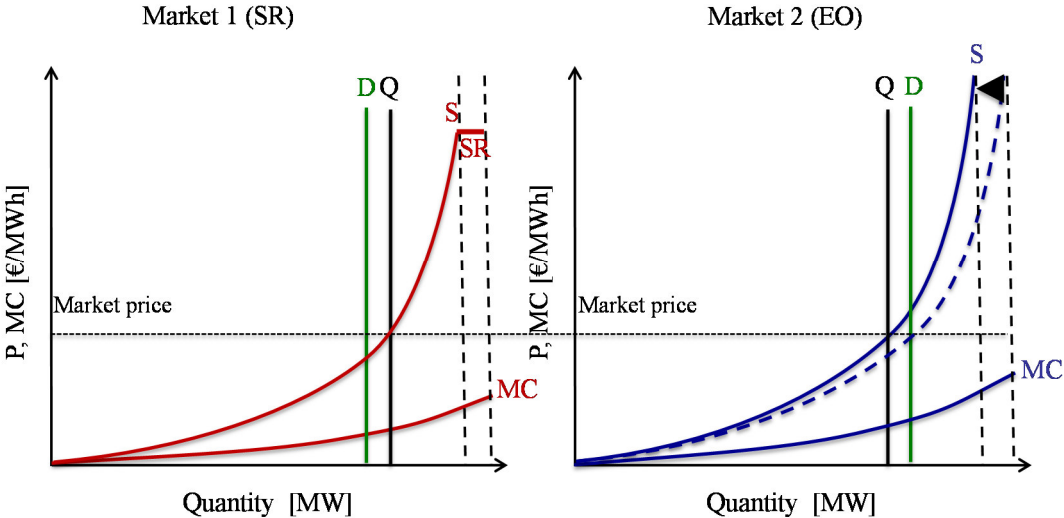


Figure 6. Long-run equilibrium for the SR-EO case for a given load

3.4 Reliability options

When modelling the reliability options (RO), we assume a strike price of 300 €/MW. The capacity payments are determined in the auction process, which we assume to rely on competitive and truthful cost bids. Our best guess for these payments is that they cover the

loss of producer surplus resulting from the implementation of reliability options, in other words, the generators would ask for an option premium that compensates them for the refund to consumers they are obliged to buy the expected call of these options.⁵

An important question is how the bidding strategy in the market will change by the implementation of the RO mechanism. Two border cases are possible. One assumption could be that the market bidding remains the same, thus following the same supply curve that applies to the energy-only market. The net revenue of generators for domestic supply would not change in cases when the reliability options are called; it remains to be the strike price multiplied by electricity sales. A second assumption could be that the generators' market bids will be lowered to the marginal cost. This would require that the option premiums gained in the RO auction are high enough to cover all of the fixed costs, and thus, the fact that the generators no longer depend on mark-ups will shift the competitive pressure fully to the electricity market. Without an explicit modelling of the strategic behaviour of firms, it is difficult to say how the new supply curve will look like. We therefore consider both mark-up-bidding and marginal-cost-bidding to compare the differences and find an indication for the most probable effect of the RO mechanism.

4 Results

4.1 Results for strategic reserve

Figure 7 shows the aggregated welfare effects for both markets and in total for all four market design strategies. The values represent the differences compared with the reference case EO-EO, which is the “do-nothing” scenario in which both markets remain energy only. Table 2 shows the welfare and investment effects for the policy combinations, also as differences compared with the reference case.

⁵ However, this estimation has to be corrected for those generation units that would leave the market in the case of energy-only markets. If the target capacity is 100 GW, we need an assumption for the capacity bids of the missing-money-generators. Given our information on marginal costs and our assumption about the peak generators' fixed cost, we make the conservative assumption that the capacity payments at least guarantee zero profits for these peakers. As a result of the fact that the target level of capacity is already available in the market, we do not have to make further assumptions about the cost of new entry (CONE) that would apply to new investments.

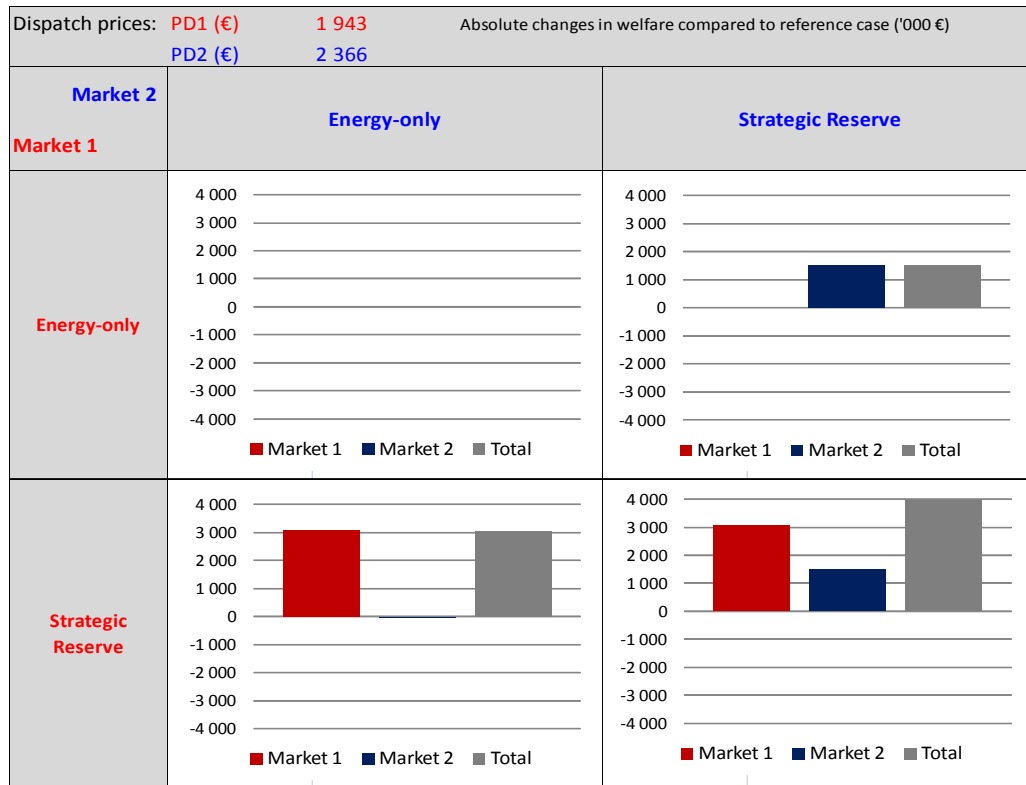


Figure 7. Strategy matrix with the welfare effects of the SR

Table 2. Welfare and investment effects of an SR

PD1 (€) 1 943		Absolute changes compared to reference case			
PD2 (€) 2 366					
	Market 1	Cases		EO	SR
	Market 2	EO	SR	EO	SR
Market 1					
Producer Surplus 1	'000 €	0	1 395	0	1 395
Consumer Surplus 1	'000 €	0	1 660	0	1 660
Capacity Payments 1	'000 €	0	1 395	0	1 395
Total Welfare 1	'000 €	0	3 055	0	3 055
Market capacity 1	GW	0,0	0,0	0,0	0,0
Strategic Reserve 1	GW	0,0	3,8	0,0	3,8
Total capacity 1	GW	0,0	3,8	0,0	3,8
Energy not supplied 1	GWh	0	-379	0	-379
Market 2					
Producer Surplus 2	'000 €	0	-239	874	635
Consumer Surplus 2	'000 €	0	218	645	863
Capacity Payments 2	'000 €	0	0	874	874
Total Welfare 2	'000 €	0	-21	1 519	1 499
Market capacity 2	GW	0,0	0,0	0,0	0,0
Strategic Reserve 2	GW	0,0	0,0	2,9	2,9
Total capacity 2	GW	0,0	0,0	2,9	2,9
Energy not supplied 2	GWh	0	0	-199	-199
Both Markets					
Total trade	GWh	0	-9	0	-9
Total Welfare	'000 €	0	3 032	1 519	4 551

Producer and consumer surpluses are corrected for the capacity and energy payments when an SR is implemented. We assume that the reserve generators receive their fixed cost as

capacity payments, and their marginal cost as energy payments. Hence, we implicitly assume a competitive and truthful bidding in the capacity auction. Note that this may not be guaranteed in practice due to asymmetric information and strategic behaviour of bidders. Accordingly, we neglect additional distortions and distributive effects that may occur in the capacity auction.⁶

All policy options appear to be welfare improving compared to the energy-only reference case. If both markets aim to maximise their total welfare, we find the Nash Equilibrium SR-SR that is welfare maximising from an aggregate point of view.

Table 2 reveals that there are negative cross-border effects on market 2 if market 1 opts for SR. As mentioned above, the dispatch prices are set equal to the highest domestic price bids in the markets in order to avoid a crowding out of domestic capacity. However, if they are lower than the import prices, they may reduce trade between the markets. In the reference EO-EO case there is a reversal of trade (i.e. market 1 start to import from market 2) when market 1 is at a full capacity, while market 2 can still export because it has a larger amount of available capacity. These exports are suppressed in the case of SR-EO, since it is cheaper for market 1 to dispatch SR than import from market 2. This crowding out of imports (which amounts to 9 GW in our simulation results) can be avoided by either setting a higher dispatch price or switching to a quantity-based dispatch of reserves, i.e. activate reserves only if there are no imports available. In this case, no cross-border effects would occur. However, the question is why consumers in market 1 should buy more expensive imports from market 2 if they can benefit from a cheaper strategic reserve instead. For national policy makers there will be no reason to take these cross-border effects into account, even if the marginal cost of the reserve units were higher than those of the imports. From an aggregate (i.e. European) point of view, the effects on efficiency solely depend on the relative marginal costs of the generation units. Hence, the non-market-based dispatch of the strategic reserve may lead to an inefficient reduction of trade, although the effects are probably moderate if the size of the reserve markets is small.

Sensitivity analysis shows that from a national perspective there is no incentive to further reduce the dispatch price, since the negative effects (crowding out domestic capacity) on consumers overcompensate the positive effects on domestic producers (suppressing imports from the neighbouring market). Hence, if the strategic reserve is adequately designed,

⁶ On the issues of auction design for a strategic reserve see e.g. Brunekreeft et al., 2013.

cross-border effects on overall efficiency are most likely moderate. However, comparing the results to those of reliability options – as provided in the next section – reveals that a strategic reserve will typically lead to an inefficient dispatch of generation.

4.2 Results for reliability options

As described in section 2.4, reliability options effectively limit scarcity prices in favour of a capacity based remuneration of generators. As a result it is unclear if generators will be able to maintain their mark-up bidding or whether they will lower their bids, in the extreme case by providing marginal cost bids. For the first part of the analysis it is assumed that generators will not adjust their bidding behaviour, that is, they stick to mark-up bidding. Figure 8 shows the respective welfare effects, while Table 4 gives the results in more detail. Again, all values are the differences compared to the reference case.

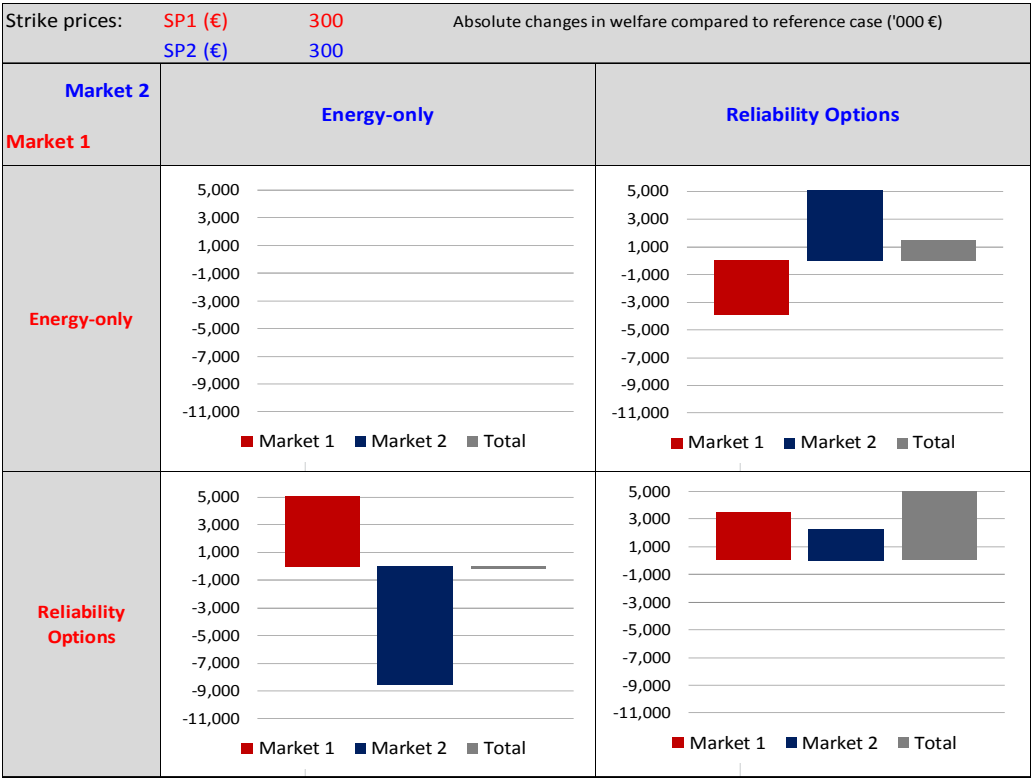


Figure 8. Strategy matrix with the welfare effects of an RO with mark-up-bidding

Table 3. Welfare and investment effects of an RO with mark-up-bidding

Strike price 1 (€)		300	Absolute changes compared to reference case			
Strike price 2 (€)		300				
	Market 1		Cases			
	Market 2		EO	RO	EO	RO
			EO	EO	RO	RO
Market 1						
Producer Surplus 1	'000 €	0	-27,527	-7,297	-27,527	
Consumer Surplus 1	'000 €	0	35,907	3,357	30,974	
Capacity Payments 1	'000 €	0	84,143	0	91,233	
Total Welfare 1	'000 €	0	8,381	-3,941	3,447	
Total capacity 1	GW	0	4	-2	4	
Energy not supplied 1	GWh	0	-379	86	-379	
Market 2						
Producer Surplus 2	'000 €	0	-8,606	-39,092	-39,092	
Consumer Surplus 2	'000 €	0	54	44,573	41,349	
Capacity Payments 2	'000 €	0	0	83,733	89,076	
Total Welfare 2	'000 €	0	-8,552	5,482	2,257	
Total capacity 2	GW	0	-4	3	3	
Energy not supplied 2	GWh	0	410	-199	-199	
Both Markets						
Total trade	GWh	0	9,286	-859	2,012	
Total Welfare	'000 €	0	-171	1,541	5,705	

Three observations are striking:

First, a unilateral implementation of RO has a strong negative effect on the neighbouring market. By holding the former missing-money-generators in the market, exports in times of peak demand from these units will increase so that the producer surplus in the other market will be significantly reduced. In other words: introducing reliability options in one market aggravates the missing-money problem in the other market so that compared with the EO-EO case, more peak generators will be pushed out of the market. This will force the neighbouring country to adjust its market design as well.

The second observation is that the overall welfare effect in the case of two RO markets is welfare improving. This is the Nash Equilibrium in our simulation. From an aggregate point of view, the reliability option mechanism is an efficient solution for the missing-money problem. Compared with a strategic reserve, this capacity mechanism avoids an out-of-market dispatch of generators and therefore favours trade. A comparison of Table 3 with Table 2 shows that the total trade between both markets increases in the RO-RO equilibrium, while it is reduced in the case of SR-SR equilibrium.

Third, implementing RO leads to a significant wealth redistribution from producers to consumers. Hence, if the policy focus is on consumers, reliability options are favourable to a strategic reserve.

An alternative model assumption for the supply curve is that generators adjust their bidding behaviour if reliability options are implemented. This may happen if the capacity payments boost competition in the spot markets. For electricity sales to the domestic market, the maximum price the generators can earn is the strike price, which is slightly above the maximum marginal cost. Thus, lowering bids may increase the volume of sales, while – in case the options are called – the net price does not change. This may incentivise generators to compete more intensively in the market by reducing their own bids.

Table 4 shows the welfare results for the case of marginal-cost-bidding in which the generators would not charge any mark-ups. Although this is an extreme assumption, it helps to identify the qualitative impacts of such strategic effects.

Table 4. Welfare and investment effects of an RO with marginal-cost-bidding

Strike price 1 (€) 300		Absolute changes compared to reference case			
Strike price 2 (€) 300					
		Cases			
	Market 1	EO	RO	EO	RO
	Market 2	EO	EO	RO	RO
Market 1					
Producer Surplus 1	'000 €	0	-27,527	-27,985	-27,527
Consumer Surplus 1	'000 €	0	33,948	14,205	30,560
Capacity Payments 1	'000 €	0	122,176	0	122,546
Total Welfare 1	'000 €	0	6,421	-13,780	3,033
Total capacity 1	GW	0	4	-6	4
Energy not supplied 1	GWh	0	-379	970	-379
Market 2					
Producer Surplus 2	'000 €	0	-17,528	-39,092	-39,092
Consumer Surplus 2	'000 €	0	8,015	44,609	41,876
Capacity Payments 2	'000 €	0	0	111,444	118,704
Total Welfare 2	'000 €	0	-9,513	5,517	2,784
Total capacity 2	GW	0	-5	3	3
Energy not supplied 2	GWh	0	710	-199	-199
Both Markets					
Total trade	GWh	0	18,630	8,558	15,075
Total Welfare	'000 €	0	-3,092	-8,263	5,817

The negative welfare effects of a unilateral implementation of an RO mechanism appear to be even stronger than in the case of usual mark-up-bidding. As long as both markets use a mark-up, the effects are mainly distributive between consumers and producers. If mark-ups are lowered in one market but not in the other one, the distortive effects on the dispatch of generation are much stronger thereby reducing the overall welfare. This distortion is only avoided if mark-ups are reduced in both markets, which is the case in the RO-RO Nash Equilibrium. In this case, the overall welfare increases significantly. Obviously, the effect of

marginal-cost-bids is that inefficiency in dispatch is fully avoided, which is not the case as long as there are different mark-ups in the electricity markets. The detailed results in Table 4 confirm this efficiency effect. It shows that the volume of total trade is highest among all analysed policy options.

To conclude, reliability options are a more efficient solution to address the missing money problem compared to a strategic reserve, notably from the consumers' points of view. However, policy makers in the connected markets should act simultaneously in changing their market design to avoid temporary negative effects of a unilateral implementation. In other words, the first mover puts strong pressure on the second player to follow.

5 Conclusions

This paper analyses the cross-border effects of two forms of capacity mechanisms; a strategic reserve and reliability options.

Our main finding is that in our simulation the Nash Equilibrium for both capacity mechanisms (CMs) is welfare improving compared to energy-only markets: both markets would opt for an implementation to address the missing-money problem.

A strategic reserve (SR) may have distortive effects on trade, if it replaces imports from the neighbouring country. This may happen in case of a price-based dispatch, i.e. if the activation of the reserve is triggered by the day-ahead price. If this trigger price is lower than the maximum import price, a SR leads to a crowding out of imports which negatively affects the neighbouring market. However, if the SR has lower cost than imports, consumers will benefit from the lower reserve price. Hence, it is questionable why a national policy maker would take these cross-border effects into account. Although these effects appear to be rather small, it might be more efficient to have a quantity-based dispatch, i.e. to activate the reserves only if demand cannot be met by domestic generation and imports. In any case, however, trade efficiency may be negatively affected by the non-market-based activation of the reserve units, as it does not guarantee a least-price dispatch of generation in both markets.

Reliability options seem to be a more efficient solution to address the missing money problem. RO increase trade between the markets and thereby favour efficiency of generation dispatch. The Nash Equilibrium increases overall welfare in both markets. Furthermore, there is a wealth redistribution from producers to consumers, as RO limit the possibility of

generators to execute market power in scarcity situations. Hence, if the focus is on consumer surplus, RO are the preferable capacity mechanisms.

It should be noted, however, that a unilateral implementation of both SR and RO have negative cross-border effects. Notably in case of RO the missing money problem is further aggravated in the passive market, which in turn will put further pressure on this country to adjust its own market design as well. Hence, market design changes should be made simultaneously to avoid temporary negative effects of unilateral market design policies.

Appendix 1: Long-run generation equilibrium

In order to calculate the available capacities in the long run, we solve the following system of equations:

$$[P_1(K_1) - MC_1(K_1)] \cdot L(K_1 - X) \cdot 8760 - FC1_{peak} = 0 \quad (\text{zero-profit 1}) \quad (9)$$

$$[P_2(K_2) - MC_2(K_2)] \cdot L(K_1 + X) \cdot 8760 - FC2_{peak} = 0 \quad (\text{zero-profit 2}) \quad (10)$$

$$P_1(K_1) = P_2(K_1 - 2 \cdot X) \quad (\text{price convergence}) \quad (11)$$

Equations (9) and (10) determine the zero-profit conditions for the last generators K_1 and K_2 in the long-run. The first term in both equations defines the revenues net of marginal cost, while the last two terms give the number of hours in which these peak generators are dispatched according to the load duration curve $L(D)$ given by equation (1). In the case of lower peak prices in market 1, its last generator produces whenever demand is equal to K_1 minus exports to market 2, and vice versa. Equation (11) requires price convergence for exports (X). This condition holds only if the interconnection constraint is not binding. Because of the slope of the supply curves at the capacity constraint, this is always the case.

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