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Cross-border effects of capacity mechanisms in interconnected power systems

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ABSTRACT

The cross-border effects of a capacity market and a strategic reserve in interconnected electricity markets are modeled using an agent-based modeling methodology. Both capacity mechanisms improve the security of supply and reduce consumer costs. Our results indicate that interconnections do not affect the effectiveness of a capacity market, while a strategic reserve is affected negatively. The neighboring zone may free ride on the security of supply provided by the zone implementing a capacity mechanism. However, a capacity market causes crowding out of generators in the energy-only zone. A strategic reserve implemented by this region could aid in mitigating this risk.

1. Overview

The growing penetration of intermittent renewable resources is leading to concerns regarding the security of supply and generation adequacy in the European Union (EU). These concerns revive and add to the existing debate about the security of supply of electricity markets (Borenstein and Bushnell, 2000; Brown, 2001; De Vries, 2007; De Vries and Hakvoort, 2003; Hesmondhalgh et al., 2010; Hreinsson, 2006; Joskow and Tirole, 2007; Pérez-Arriaga, 2001; Stoft, 2002; Woo et al., 2003). Consequently, the debate is reopened in the remaining energy-only markets in Europe whether to implement a capacity mechanism. Capacity mechanisms are policy instruments for ensuring adequate investment in generation capacity; in Europe, they are also called capacity remuneration mechanisms. The arguments for and against implementing capacity mechanisms have been described extensively in the literature (Chao and Lawrence, 2009; Cramton et al., 2013; De Vries, 2004; Hobbs et al., 2001; Joskow, 2008a; Stoft, 2002), but variable renewable energy resources add a new dimension to it.

In the EU, the decision whether to implement a capacity mechanism and its design and implementation are left to the discretion of the member states. The UK has recently implemented a capacity market (DECC, 2014) while France will do so in the near future (RTE, 2014). Belgium, Sweden, and Finland make use of strategic reserves. Germany may implement a capacity reserve but decided against a full-scale capacity market for the near future (BMWi, 2014). In a highly interconnected system, such as the continental European electricity system, an apparent risk is that the uncoordinated implementation of capacity mechanisms could reduce economic efficiency and even negatively affect the security of supply in neighboring systems (Pérez-Arriaga, 2001; Elberg, 2014; Tennbakk, 2014; Finon, 2015; Gore, 2015; Mastropietro et al., 2015; Meyer and Gore, 2015; Bhagwat et al., 2016a; Bhagwat, 2016). We utilize an agent-based model to analyze the effectiveness of capacity mechanisms in interconnected systems. We also study the cross-border effects on prices, investment and security of supply that they may cause. We expand EMLab-Generation, an existing agent-based model of electricity markets, by modeling a strategic reserve and a capacity market.

2. Model description

2.1. EMLab-generation

The EMLab-Generation agent-based model (ABM) was developed to model questions that arise from the heterogeneity of the European electricity sector and the interactions among different

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policy instruments (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014). The model provides insight into the simultaneous long-term impacts of different renewable energy, carbon emissions reduction, and resource adequacy policies, and their interactions, on the electricity market.

Power generation companies are the central agents in this model. The behavior of the agents is based on the principle of bounded rationality (as described by Simon (1986)); that is, the decisions made by the agents are limited by their current knowledge and their limited understanding of the future. The agents interact with each other and other agents via the electricity market and thereby bring about change in the state of the system. Consequently, the results from the model do not adhere to an optimal pathway and the model is typically not in a long-term equilibrium. The model thus allows us to study the evolution of the electricity market under conditions of uncertainty, imperfect information, and non-equilibrium.

In the short term, the power generation companies make decisions about bidding in the power market. Their long-term decisions concern investments in new capacity and decommissioning of power plants. The model resembles a cost-minimizing model in which investments are based on expected costs, as we did not program behavioral differences in the agents' algorithms. The only difference among the agents develops in the state of their finances during the simulation: agents that made bad investment decisions have less money to invest in later years. By having multiple agents with different financial resources, the effects of negative returns due to over investment develop more gradually than if it had been a cost-minimization model with a single investment decision.

The main external drivers for change in the model are fuel prices, electricity demand growth scenarios, and policy instruments such as capacity mechanisms. The main outputs are investment behavior and its impact on electricity prices, generator cost recovery, fuel consumption, the evolution of the supply mix, and system reliability.

The model provides the functionality for conducting an analysis of an isolated electricity market as well as an interconnected electricity system. The representation of an interconnected system is limited to two zones with an interconnector. As the objective of this paper is to understand the evolution of the electricity market over the long-term, all scenarios consist of 40-time steps, each of which represents one year.

The overview of the model activities during a time step is presented in a flowchart in Fig. 1. At the start of each time step the power generation companies make annual loan repayments (if any) for their set power plants. In the next step, power generation companies submit price-volume bids to the electricity market for all available power plants. This is followed by electricity market clearing. Once the market is cleared, the power generation companies purchase fuel for their power plants, pay for the operation and maintenance costs of all their power plants and receive payment for the energy sold on the electricity market. In the last step, power generation companies make decisions regarding investment in new capacity and dismantling of existing power plants.

A detailed description of EMLab-Generation has been presented in various reports (De Vries et al., 2013), scientific literature (Bhagwat, 2016; Bhagwat et al., 2016b; Richstein et al., 2015a, 2015b, 2014) and also in an earlier doctoral thesis (Richstein, 2015). In the next section, the structure of the model is described in detail followed by the input assumptions, model outcomes, and model limitations.

2.2. Model structure

2.2.1. Demand

In this model, a single agent procures electricity on the behalf of all consumers. Electricity demand is represented in the form of a step-wise abstraction of a load-duration curve. In this approach, empirical load data is approximated by a step function consisting of segments with variable length in hours (see Fig. 2). Thus each segment of the load duration curve has an assigned load value and a time duration, which is set as part of the initial input scenario. In each time step of the simulation, the load value for all segments is updated based on the exogenous demand growth rate. These segments have also been called "load blocks" or "load levels" in literature (Wogrin et al., 2014).

This approach for representing demand in electricity market models has been utilized for power system modeling since the 1950s, especially for medium and long-term models (Wogrin et al., 2014). The most important advantage of using this approach is that it allows for a shorter run time, enabling a larger number of simulations within a practical time frame (Richstein et al., 2014). However, due to the loss of temporal relationship between load hours, short-term dynamics such as ramping constraints and unplanned shutdowns cannot be modeled (Wogrin et al., 2014).

2.2.2. Electricity market clearing

The electricity market is modeled as an abstraction of an hourly power system (Richstein et al., 2014). Within a one-year time step, the electricity market is cleared for each segment of the load-duration curve. Therefore the segment-clearing price is considered as the electricity price for the corresponding hours of the particular segment. The load-duration curve is divided into 20 segments. When the model is run in a two-zone configuration, each zone has its own separate load-duration curve.

The power generation companies create price-volume bid pairs for their controllable (thermal) power plants for each segment of the load-duration curve. (Variable renewable energy generation is treated differently, as described in Section 2.2.5.) The power generation companies bid their power plants into the market at their marginal cost of generation, which is determined solely by the fuel costs. The volume component of the bid is based on the capacity of the available power plants. Power plant outages are not modeled, availability is assumed to be 100%. The supply curve for each segment is constructed by sorting the bids in ascending order by price (merit order). The electricity market is cleared at the point where demand and supply intersect. The highest accepted bid sets the electricity market-clearing price for that segment of the market. If demand exceeds supply, the clearing price is set at the value of lost load (*VOLL*).

In the two-zone configuration, the market clearing algorithm that is described above is run together for both zones assuming that there is no congestion between the zones. This results in a single price for both zones. If the interconnector is congested (that is, the flow over the interconnector exceeds the interconnector capacity) the two markets are cleared separately (market splitting). In the zone that exports electricity, the demand is increased up to the level where the interconnector is completely utilized. The demand in the importing zone is reduced by the same amount. As a result, the market-clearing prices for the given segment in the two zones are based on the modified demand values.

2.2.3. Investment algorithm

The investment behavior of the power generation companies is based on the assumption that investors continue to invest up to the point that it is no longer profitable. In this model, power generation companies invest only in their own electricity markets thus entry

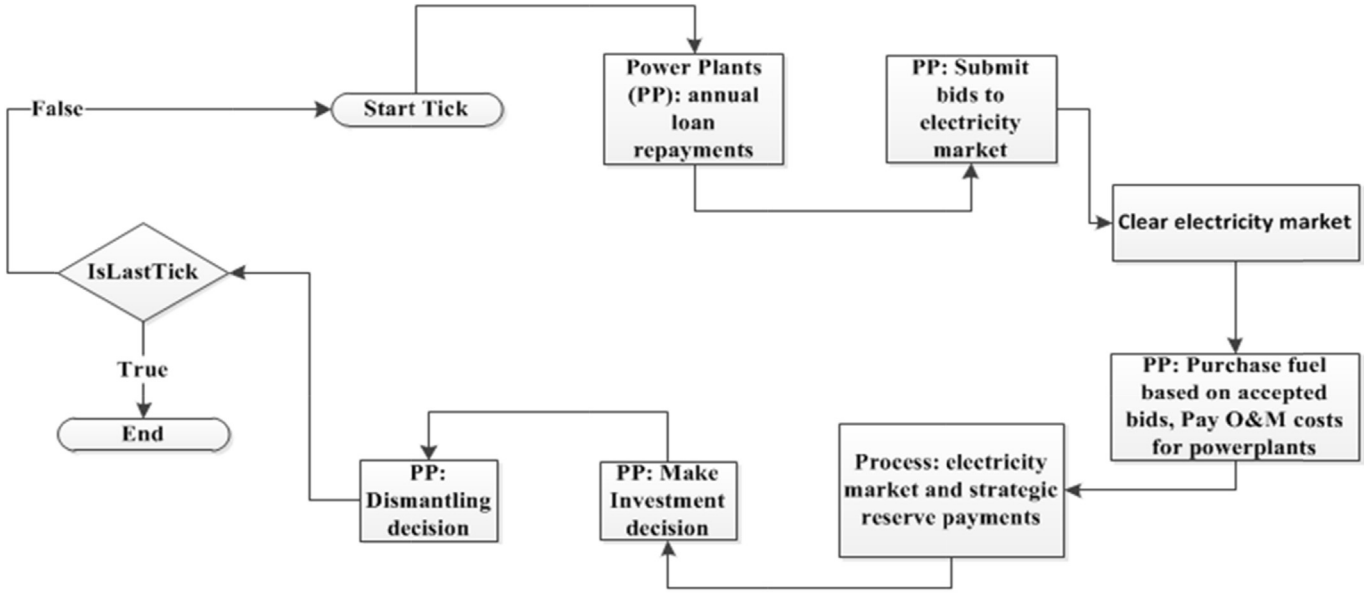

Fig. 1. Stylized flowchart of the model activities during a time step.

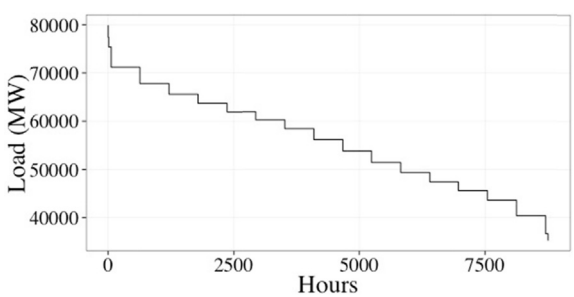

Fig. 2. Example of a load-duration curve in EMLab-Generation for one country.

into a new market is not considered.

All investments are financed using a combination of debt and equity based on user-defined values. The power generation company considers investment in a new power plant only if it has sufficient ability to finance the necessary equity. The power generation companies invest their available equity capital, based on an expected return on equity. A bank finances the debt at a user defined interest rate. The debt is repaid as equal annual installments over the term of the loan, which is matched to the depreciation period for the power plant.

Power generation companies make investment decisions sequentially in an iterative process. The investment decision of each power generation company affects the investment decision of the next power generation company by changing its forecast of available capacity; we assume that power generation companies have full information about investment decisions that have already been made by competitors. This iterative process stops when no participant is willing to invest further. In order to prevent a bias towards any particular agent, the sequence of power generation companies is determined randomly in every time step.

During each investment round, the power generation company compares the outcomes of investing in different power generation technology options available. At the start of each investment round, the power generation company forecasts demand at a point of time in the future (reference year) by extrapolating the growth rate of demand from the past. Forecasted fuel prices are used to calculate the marginal variable costs of all power plants that are expected to be available in the reference year. These may be new power plants that have been announced or existing power plants that are within their expected life span in the reference year. The future electricity price for each segment is estimated by creating a merit order of the available power plants for each segment of the load duration curve.

The investor calculates the expected cash flow in the reference year for a power plant of each power generation technology under consideration. The expected cash flow is calculated by subtracting the fixed costs of the given power plant from its expected electricity market earnings. The expected earnings from generating electricity are calculated based on the power plant's expected running hours, the variable costs (calculated based on expected fuel prices) in those hours of the reference year, and electricity market prices. The expected running hours of a power plant are calculated by comparing the expected electricity prices for each segment and the expected variable cost of the power plant under consideration. If the variable cost is lower than the electricity price, the power plant is assumed to have cleared the market in that segment and the power plant is assumed to have run for all hours of the given segment.

The expected cash-flow value for each power plant under consideration is used to calculate the specific net present value (*NPV*) per MW over the construction period and the power plant's expected service life. A weighted average cost of capital (*WACC*) is used as the interest for the *NPV* calculation. The power generation company invests in the power generation technology with the highest positive specific *NPV*. If all *NPVs* are negative then no investment is made.

2.2.4. Decommissioning of power plants

The power generation companies base the decision to decommission a power plant mainly on its operational profitability. In each time step, the power generation companies iterate through their set of power plants in order to make decommissioning decisions. For each plant, the aggregated cash flow over the previous years is calculated. The time horizon (in years) for this retroactive look is a user-defined value. If the cash flow of the plant is negative, the power generation company makes a forecast of the cash flow for the coming year. If this forecasted cash flow is also negative, the power plant is decommissioned. In order to simulate the rising costs of old power plants, the operation and maintenance costs of power plants that are active beyond their operational age are

increased year-on-year. This ensures that all old power plants are eventually dismantled depending on market conditions.

2.2.5. Intermittency of renewable energy sources

The intermittency of renewable energy sources is a short-term effect that is difficult to implement in a long-term model such as EMLab-Generation because demand is represented as a load duration curve. In this model, intermittency is approximated by varying the contribution of these technologies (availability as a percentage of installed capacity) to the different segments of the load-duration curve. The segment-dependent availability is varied linearly from a large contribution to the base segments to a very small contribution to the highest peak segment. This corresponds to the contribution of solar and wind energy to peak demand in Germany.

2.2.6. Renewable energy policy

The development of renewable electricity generation is implemented as an investment by a renewable 'target investor'. If investment in renewable energy source (RES) capacity by the competitive power generation companies is lower than the government target, the target investor will invest in additional RES capacity in order to meet the target even to the extent that the investor does not recover its costs in the market. This simulates the current subsidy-driven development of renewable energy sources.

2.3. Strategic reserve

2.3.1. Overview

When system operators implement strategic reserves, they contract and dispatch a certain volume of generation capacity, usually the generation units with the highest variable costs. This contracted capacity is then deployed when the electricity price exceeds an administratively set 'reserve price' that is higher than the power plant's marginal cost of generation but below *VOLL*.

In theory, the artificial tightening of the supply due to the presence of a strategic reserve would attract investment in generation capacity before a physical shortage occurs. Consequently, the high price spikes that occur in periods of scarcity would be replaced by more frequent but also lower price spikes, capped at the reserve dispatch price (P_{SR}) (de Vries and Heijnen, 2008). This is similar to operating reserve pricing as described by Stoft (2002). The reserve dispatch price should be calculated such that the revenues earned by the competitive generators remain same in the presence of a strategic reserve as in an energy-only market. The theory behind a strategic reserve is described in Stoft (2002); De Vries (2004); De Vries and Heijnen (2008); Rodilla and Batlle (2013). Strategic reserves can be implemented in different ways, but this design was chosen because the rules are simple and grounded in theory.

2.3.2. The strategic reserve algorithm

The main agent in the strategic reserve extension of EMLab-Generation is the strategic reserve operator, who contracts a set of power plants with a total capacity that is equivalent to the administratively established reserve size. The reserve volume is user-defined as a percentage of the expected annual peak demand. The power plants with the highest variable costs are selected because they have the lowest opportunity cost of withdrawing from the electricity market and therefore should bid the lowest in the strategic reserve capacity tender.

The companies that own contracted power plants are compensated for their annual fixed operations and maintenance costs of these power plants. The operator contracts only entire power plants, thus the complete capacity of the last required power plant is contracted. There are a variety of decision rules for how this capacity is offered to the market. In this model, contracted power plants are offered to the electricity spot market at the strategic reserve dispatch price (P_{SR}), which is calculated as explained in (Bhagwat, 2016; Bhagwat et al., 2016b). This 'reserve price' is considerably higher than its marginal cost of generation but lower than the value of lost load. This is in accordance with Stoft's (2002) theory of operating reserves pricing.

When the reserve capacity is dispatched, the strategic reserve operator pays the power plant owner(s) the variable cost of generation while keeping the additional revenue earned over and above the variable cost of generation, which is equal to the reserve dispatch price minus the variable costs of generation. The fixed payments ensure that the owners of these generating units do not make disproportionate profits but at the same time cover all their costs.

In a perfectly designed reserve, payments to the strategic reserve operator should exactly cover the cost of contracting the strategic reserve. In a case where the strategic reserve operator is unable to recover the costs of contracting the reserve, it is assumed that the system operator passes on the additional costs to consumers via network tariffs. When making an investment, and decommissioning decisions, the power generators consider the possibility of gaining additional revenues from the strategic reserve. A detailed description of the strategic reserve algorithm is available in Bhagwat et al. (2016b).

2.4. Capacity market

2.4.1. Overview

In a capacity market, consumers, or an agent on their behalf, are obligated to purchase capacity credits equivalent to the sum of their expected peak consumption plus a reserve margin that is determined by the system operator or the regulator through a process of auctions (Agency for the Cooperation of Energy Regulators (ACER), 2013; Cramton and Ockenfels, 2012; Cramton et al., 2013; Creti and Fabra, 2003; Iychettira, 2013; Stoft, 2002; Wen et al., 2004). The additional revenues from the capacity market are intended to ensure that (peaking) power plants recover their fixed costs, thus mitigating the 'missing money' problem (Joskow, 2008a, 2008b, 2006; Shanker, 2003). A capacity requirement is expected to provide an earlier and stronger investment signal than wholesale electricity prices and improve supply adequacy. A variety of capacity market designs have been implemented across the world (Agency for the Cooperation of Energy Regulators (ACER), 2013; Cramton and Stoft, 2008, 2005; Cramton et al., 2013; DECC, 2014; RTE, 2014; Spees et al., 2013).

2.4.2. The capacity market algorithm

The capacity market module in EMLab-Generation is modeled after the NYISO-ICAP model with a few simplifications. The NYISO market was chosen for its relatively simple design. Moreover, it was one of the first capacity markets to be established in the United States and considered an example of a capacity market that appears to be meeting its policy goals. Moreover, it is projected that no new resource requirements would be necessary for the NYISO region until 2018 (Newell et al., 2009).

In the NYISO-ICAP, generators offer unforced capacity[1] (UCAP) (NYISO, 2013a, 2013b) in a series of auctions. The auctions are conducted annually for the subsequent year. The ISO contracts capacity on behalf of load-serving entities (LSEs); thus, consumers participate automatically. A sloping demand curve is utilized.

[1] Unforced capacity is defined as the amount of electricity generated by a power generator after accounting for any outages (NYISO, 2013b).

Consumers are provided opportunities to correct their positions during the year via monthly spot auctions and capability period auctions. In each year there is a summer capability period (May 1st - Oct 31st) and a winter capability period (Nov 1st–April 30th) (Bhagwat, 2016; Bhagwat et al., 2016a; NYISO, 2014). The LSEs are obligated to purchase capacity credits equivalent to the minimum unforced capacity (UCAP) assigned to them (Harvey, 2005; NYISO, 2013a, 2013b). The value of unforced capacity is calculated as the product of the Installed Reserve Margin (IRM) and the forecast peak demand (NYISO, 2013b). The regulator calculates the IRM so as to achieve a loss of load expectation of once in 10 years. NYISO allows bilateral capacity contracts and imports to participate in the capacity market subject to certain rules and regulations. Detailed descriptions of the market rules are available (NYISO, 2013b; Spees et al., 2013).

In the capacity market modeled in EMLab-Generation, the capacity for the coming year is traded in a single annual auction and administered by an agent identified as the capacity market regulator. The user sets the IRM, capacity market price cap and parameters for generating the slope of the demand curve.

The regulator calculates the demand requirement (D_r) for the current year based on the IRM (r) and the expected peak demand (D_{peak}). Expected peak demand is forecast by extrapolating past values of peak demand using geometric trend regression over the past four years. The demand requirement is calculated with the following equation.

$$D_r = D_{peak} \times (1 + r) \tag{1}$$

A sloping demand curve is modeled for the capacity market like in the NYISO-ICAP and PJM-RPM capacity markets. These markets implement sloping demand curves to provide more predictable revenues to generators and to lower consumer costs by reducing price volatility (Hobbs et al., 2007). When a sloping demand curve is implemented, changes in the offered volume of capacity result in small price changes, thus stabilizing capacity market prices (Pfeifenberger et al., 2009).

As is illustrated in Fig. 3, the sloping demand curve consists of two lines: a horizontal line at the capacity market price cap (P_c) and a sloping line intersecting the horizontal line and the X-axis. The slope and position of the sloped line are dependent upon three user-defined variables, namely, the demand requirement (D_r), the lower margin (lm) and the upper margin (um). The lower and upper margins are administratively set maximum flexibility boundaries above and below the IRM. The sloping line intersects the horizontal line at Point (X = LM, Y = Pc). The slope of the line is calculated using the following equation

$$m = \frac{P_c}{LM - UM} \tag{2}$$

In which:

$$UM = D_{peak} \times (1 + r + um) \tag{3}$$

$$LM = D_{peak} \times (1 + r - lm) \tag{4}$$

The supply curve is based on the Price (€/MW) and Volume (MW) bid pairs submitted by the power generators for each of their active generation units. The agents calculate the volume component of their bids for a given year as the generation capacity of the given unit that is available in the peak segment of the load-duration curve. A marginal cost approach is used to calculate the bid price. For each plant, the power producers calculate the expected revenues from the electricity market. If the generation unit is expected to earn adequate revenues from the electricity market to cover its fixed operating and maintenance costs (that is, the total cost of staying online), the bid price is set to zero, as no additional revenue from the capacity market is required to remain operational. Units that are not expected to make adequate revenues from the energy market to cover their fixed costs bid the difference between the fixed costs and the expected electricity market revenue in order to receive the minimum revenue required to remain online.

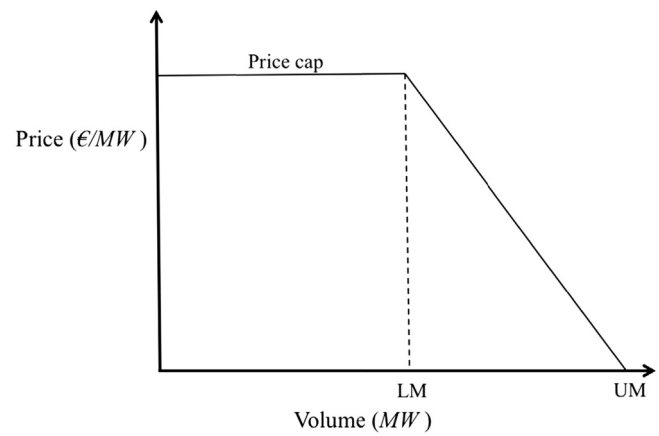

Fig. 3. Illustration of a sloping demand curve.

The capacity market-clearing algorithm is based on the concept of uniform price clearing. The bids submitted by the power producers are sorted in ascending order by price and cleared against the sloping demand curve described above. The units that clear the capacity market are paid the market-clearing price. While making the investment and decommissioning decisions, the power generators take into account the expected revenues from the capacity market.

3. Scenarios

Both markets (Zone A and Zone B) have four power producers with identical initial power plant portfolios. The shares of generation technologies in the initial supply mix are based on the portfolio of thermal generation technologies in Germany (based on Eurelectric (2012) data; see also Table 4 in the Appendix). Power plant attributes such as capital costs, operation, and maintenance (O&M) costs, and fuel efficiencies are based on the IEA World Energy Outlook 2011, New Policies Scenario (IEA, 2011). Technology development is simulated as a gradual improvement of these attributes, namely decreasing costs and improving efficiency rates. The power producers can choose from 14 different power generation technologies. The assumptions regarding the power generation technologies are presented in Table 2 of the Appendix.

The load-duration function is derived from 2010 ENTSO-E data for Germany (ENTSO-E, 2010). The peak demand at the start of the model run in both zones of all scenarios is 79,884 MW. The year-on-year fuel prices growth and demand growth trends are modeled stochastically using a triangular trend distribution, which is a mean reverting distribution. The upper and lower boundaries for the triangular distribution along with the average growth rate are user-defined values. The advantage of the triangular trend distribution is that, if the realization for a particular year is above average, then it is probable that it would remain above average in the next year as well and vice versa in a below average case (for more information on triangular distribution, see Forbes et al., 2011). Thus the distribution is able to simulate multi-year swings like those observed in reality (De Vries et al., 2013) (See Table 3 in the Appendix.). The coal and gas prices are based on scenarios of the UK Department of Energy and Climate Change (2012). The biomass prices are based

on Faaij (2006) and the lignite prices on Konstantin (2009). The development of renewable energy resources is based on the national renewable energy action plan for Germany (NREAP, 2010) up to 2020 and interpolated further.

In the case where supply does not meet demand, the electricity market price is assumed to jump up to the value of lost load (VOLL), which is set at a level of 2000 €/*MWh*. This relatively low level was chosen to reflect that some demand flexibility may occur during periods of high prices, which can only be represented in the model in the form of a lower price during the top demand segment of the load-duration curve, which represents the average of all the prices during the hours that make up this segment of the load-duration curve.

As a reference scenario, the model is run in an "energy-only" mode, with no capacity mechanisms. Three scenarios with capacity mechanism are implemented; see Table 1. In the first scenario *(SR-EO)*, a strategic reserve is implemented in one zone while the other zone maintains an energy-only market. In the second case *(CM-EO)*, a capacity market is implemented in one zone while the interconnected zone maintains an energy-only market. In the third case *(CM-SR)*, a capacity market is implemented in one zone, while a strategic reserve is implemented in the interconnected zone.

The reserve volume of the strategic reserve is set at 10% of peak demand and the reserve price is 800 €/*MW*. The dimensions of the capacity market are roughly based on the requirements of the NYISO-ICAP, the capacity market price cap is set at a 60,000 €/*MW*. The IRM value is set at 9.5% of peak demand, this value is calculated to by de-rating the 17% IRM requirement by the Equivalent Forced Outage Rate (EFORd). This size of the interconnector in all the scenarios is set at 7536 MW.

4. Results and analysis

4.1. Indicators

The following indicators are used in the analysis of the model results:

- The average electricity price (€/MWh): the average electricity price over an entire run.
- Shortage hours (hours/year): the number of hours per year with scarcity prices, averaged over the entire run.
- The supply ratio *(MW/MW)*: the ratio of available supply[2] at peak (MW) over peak demand (MW).
- The cost of the capacity mechanism (€/MWh): the cost incurred by the consumers for contracting the mandated capacity credits from the capacity market or for contracting generating units into the strategic reserve.
- The cost to consumers (€/MWh)[3]: the sum of the electricity price, the cost of the capacity market, and the cost of the renewable policy (if applicable) per unit of electricity consumed, averaged over the entire run.

The percentage change in the values of indicators in both zones for the SR-EO, CM-EO, and CM-SR scenarios, as compared to the baseline scenario (*BL*), are presented in Fig. 4. The results are also presented numerically in Table 6 of the Appendix. The average values presented in the results are calculated as annual values based on values from the 120 simulation runs over the 40-year time horizon. For the supply ratios and electricity prices over time, the median and mean trend along with the 50% and 90% confidence intervals (CI) are shown.

Table 1
List of scenarios.

Scenario	Zone A	Zone B
BL	Energy-only	Energy-only
SR-EO	Strategic Reserve	Energy-only
CM-EO	Capacity Market	Energy-only
CM-SR	Capacity Market	Strategic Reserve

4.2. Cross-border effects of a strategic reserve

In this first scenario, a strategic reserve is implemented in Zone A, while the interconnected zone (B) has an energy-only market. We compare the outcomes from this scenario with the baseline case (BL) in which both zones have energy-only markets.

The zone that implements a strategic reserve sees its supply ratio rise to 1.02, as observed in Fig. 5, an increase of 9% compared to the baseline scenario. The shortage hours decrease from 58.4 h per year to 11 h per year in this zone. As expected, the extreme price spikes in baseline scenario are replaced by more frequent, but lower price spikes in the electricity market (Fig. 6). The average electricity price drops by 8%, from 58.1 €/MWh in the baseline to 53.7 €/MWh, which is due to the reduction in shortage hours. The strategic reserve operator is almost able to recover the cost of contracting the strategic reserve, which is indicated by the capacity mechanism cost to the consumers of −0.3 €/MWh. The operator earns revenues when the strategic reserve is dispatched in the zone in which it is implemented and also from exports of the reserve capacity during hours that demand in the neighboring zone is so high that the strategic reserve is needed to avoid a shortage of power supply. An overall reduction of 6% in the cost to consumers is observed due to the presence of a strategic reserve in the system.

The supply ratio in the interconnected zone (Zone B) with an energy-only market is 0.93, which is marginally lower than in the baseline scenario (Fig. 7). However, the number of shortage hours in this zone is reduced by 74% from 58.4 h/yr to 15 h/yr due to the import of power from the neighboring zone during power shortage situations. This leads to fewer price spikes in this zone and a reduction of the electricity price from 58.1 €/MWh to 54.1 €/MWh (Fig. 8). An overall improvement in consumer benefit is observed, with the cost to consumers reduced by 5% due to the presence of a strategic reserve in the system.

We compare these results to an isolated system with a similarly sized strategic reserve. The supply ratio is the same with and without an interconnector because the agents do not consider the interconnector explicitly in their investment decision. However, in the presence of an interconnector, part of the capacity from the zone with a strategic reserve is exported to the neighboring market, as there is no restriction on exports. Consequently, there are more shortage hours in the zone with the strategic reserve than in the isolated case, while the shortage hours in the neighboring energy-only region are reduced. This spillover leads to a 2% increase in the net cost to consumers in Zone A, from 64.4 €/MWh in an isolated system to 65.7 €/MWh in the scenario with an interconnector (SR-EO Zone A). The increase is caused by an increase in the average wholesale price in Zone A from 51.4 €/MWh to 53.7 €/MWh but is offset by slightly lower payments to renewable energy generators and a lower cost of procuring the strategic reserve (both due to the higher market prices that they receive).

In this case, the consumers in Zone B are free riding on the consumers in Zone A. This effect would be smaller if the demand

[2] Available supply at peak $= \sum_{i=1}^{n}(PAC_i \times C_i)$, where n is the total number of operational power plants, PAC is the peak segment availability factor of the power plant and C is the installed capacity of the power plant.

[3] Note that this includes the cost of power outages, because in our model the electricity price rises to the VOLL when the supply is less than demand.

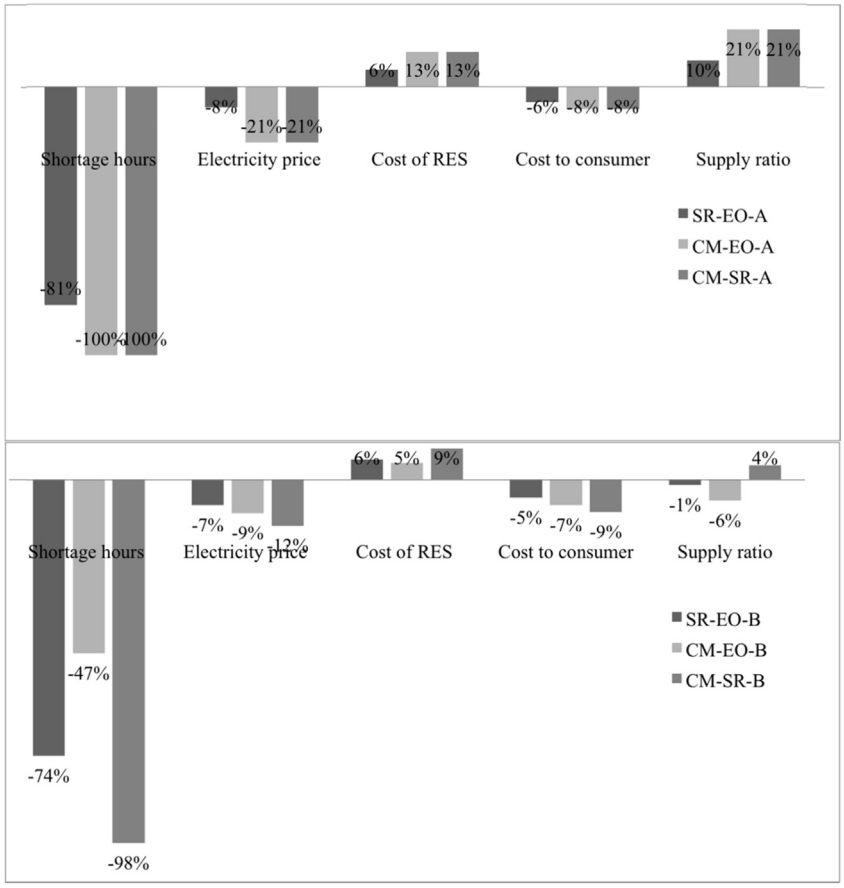

Fig. 4. The percentage change in values of various indicators in Zone A (top) and Zone B (bottom) on implementation of capacity mechanisms as compared to the baseline scenario.

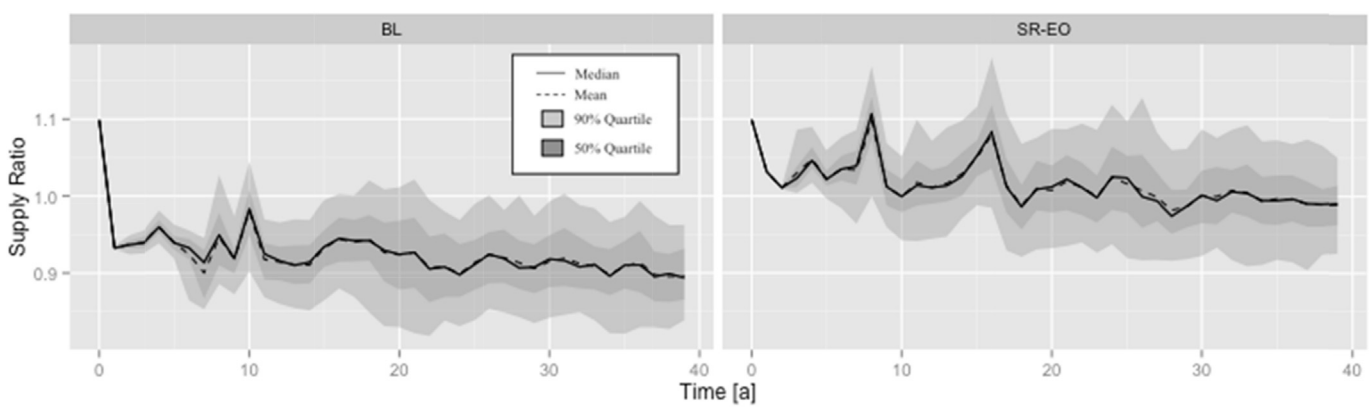

Fig. 5. Comparison of supply ratio in Zone A without (left) and with a strategic reserve implemented.

peaks in the two zones were not identical. Less interconnection would also limit the effect. TSOs would, therefore, experience an incentive to restrict exports, for example, by limiting the volume of interconnector capacity that is made available to the market, during simultaneous power shortages in both zones. However, the EU currently prohibits restriction of access to interconnections when there is no congestion (European Union, 2009a).

To summarize, implementation of a strategic reserve in one zone of an interconnected system improves the security of supply and net consumer benefits in that zone. The benefits spill over to the neighboring interconnected zone, both in terms of reduction in shortage hours and reduction in costs to consumers. In the other zone (with an energy-only market), no significant effect on investment is observed; however, this result may be caused by the fact that the investment decisions in the model did not consider imports, although lower prices lead to more plant decommissioning in the model.[4]

[4] While making investment decisions, the power producers only consider the expected power plants that participate in their own market in the future year. However, the decommissioning decisions are based on past performances of the power plants: power plants that are consistently unprofitable are decommissioned. Imports thus cause lower electricity prices as well as a lower volume of installed capacity.

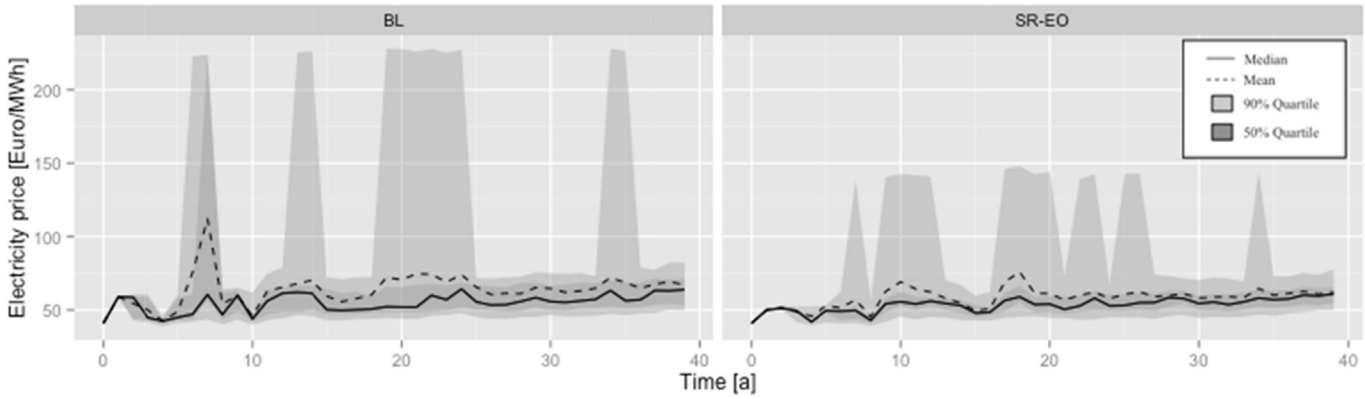

Fig. 6. Comparison of electricity price in Zone A without (left) and with a strategic reserve implemented.

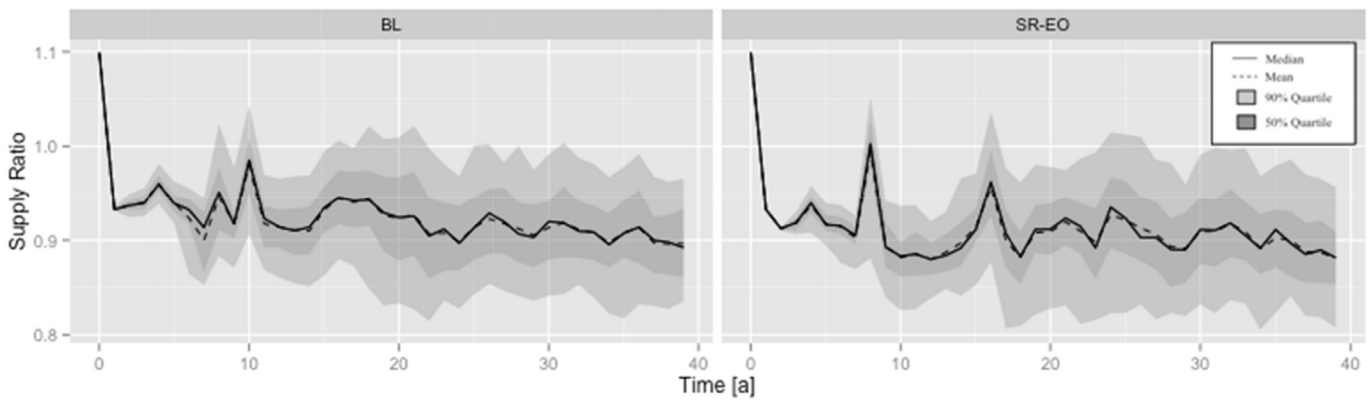

Fig. 7. Comparison of the supply ratio in Zone B without (left) and with a strategic reserve (right) implemented in the neighboring interconnected Zone A.

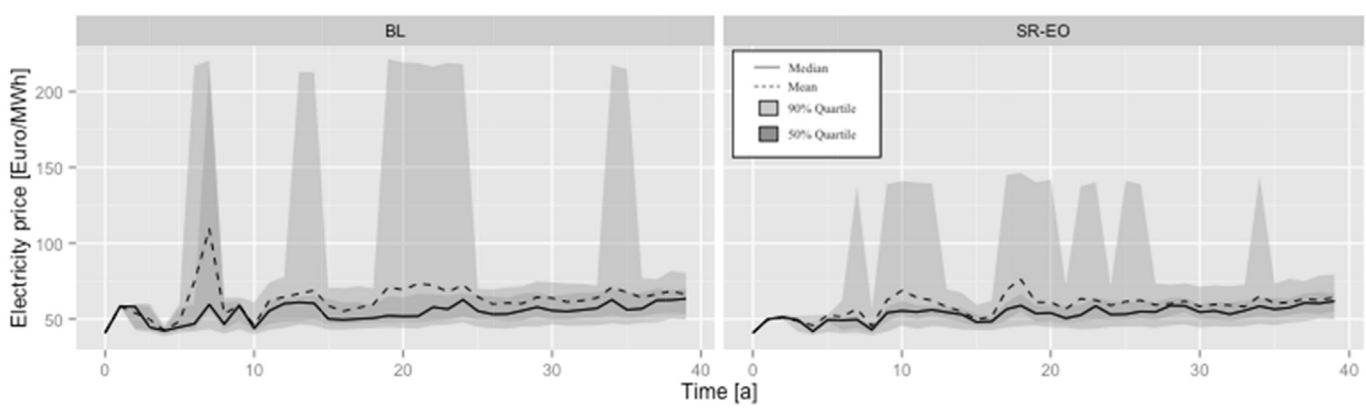

Fig. 8. Comparison of electricity price in Zone B without (left) and with a strategic reserve (right) implemented in the neighboring interconnected Zone A.

4.3. Cross-border effects of a capacity market

In this scenario, a capacity market was implemented in Zone A, while the interconnected zone (B) has an energy-only market. We compare the results from this scenario with the baseline (*BL*) scenario in which both zones have energy-only markets.

In the zone with a capacity market (A), the average supply ratio is 1.12, which is a 2.5-percentage point higher than the adequacy target (see Fig. 9). The capacity market more than meets the adequacy goals in the presence of an interconnection. The apparent overshoot in capacity can be attributed to the configuration of the capacity market demand curve (slope and price cap) and also the segmented nature of the load-duration curve. The high reserve capacity causes a steep reduction in shortage hours, from 58.4 h per year to almost zero. The average electricity price drops by 20.7%, from 58.1 €/MWh in the baseline to 46.1 €/MWh. There is also a sharp decline in electricity price volatility in this zone, as can be seen in Fig. 10. The capacity payments cost the consumer an additional 4.8 €/MWh. However, the gains from a reduction in shortage hours offset the cost of the capacity market: the total cost to consumers is reduced by 8.2%, from 69.6 €/MWh to 63.9 €/MWh.

On the other hand, a clear negative spillover effect in terms of adequacy is observed in the interconnected zone with an energy-only market (Zone B), where the supply ratio declines by 5.6%, from 0.93 in the baseline scenario to 0.87 (Fig. 11). Nevertheless, the import of electricity from the neighboring zone dampens electricity prices (Fig. 12) and reduces the number of shortage hours by 46.8% from 58.4 h/yr to 31 h/yr. The average electricity price declines from 58.1 €/MWh to 52.8 €/MWh. The net cost to consumers declines by 6.8% from 69.6 €/MWh to 64.9 €/MWh.

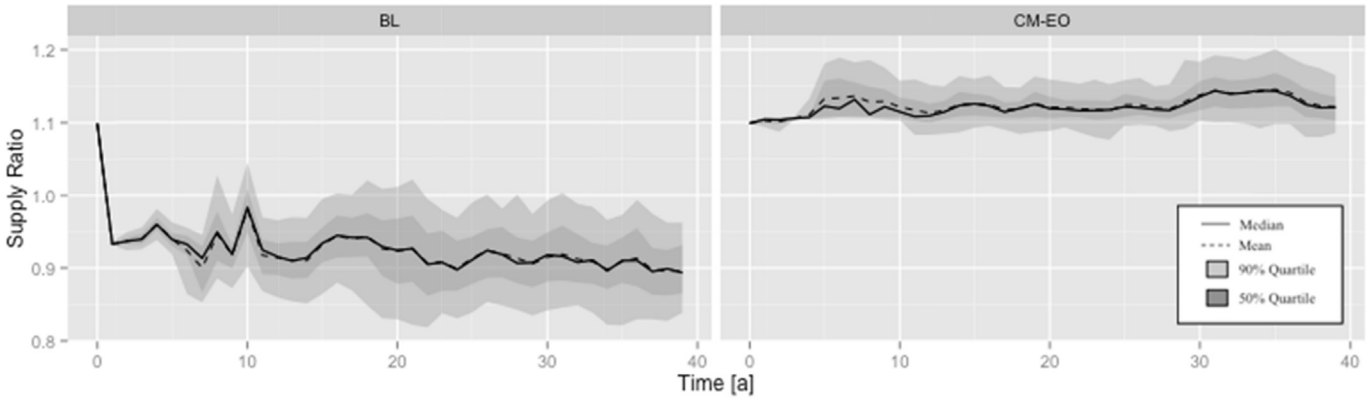

Fig. 9. Comparison of supply ratio in Zone A without (left) and with a capacity market (right).

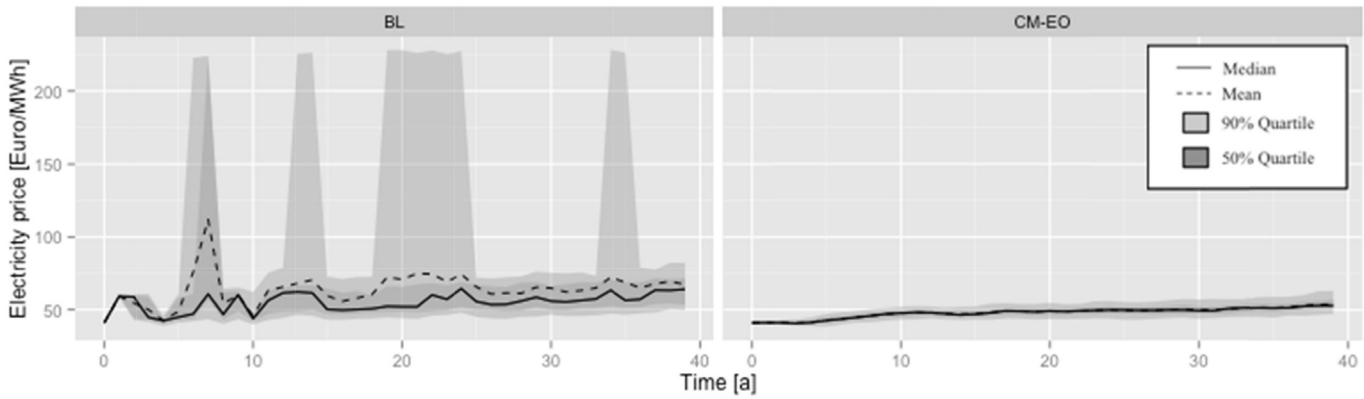

Fig. 10. Comparison of electricity price in Zone A without (left) and with a capacity market (right).

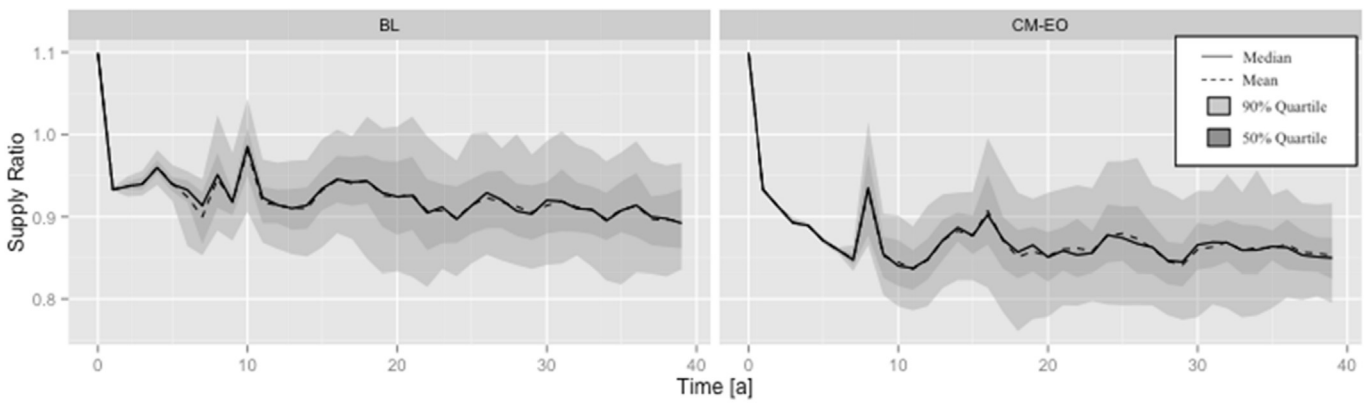

Fig. 11. Comparison of the supply ratio in Zone B without (left) and with a capacity market (right) in the neighboring interconnected Zone A.

Fig. 12 shows that the risk of an investment cycle in generation capacity in Zone B (the energy-only market) is reduced but not eliminated in the presence of a capacity market in Zone A. The generators in Zone B are crowded out to the extent that even the additional capacity due to the capacity market in A may not be able to cover all demand in the neighboring zone. In these situations, periods with substantial shortage hours in the energy-only market may occur (see Fig. 13). Thus, despite the higher supply ratio in Zone A in the CM-EO scenario, the average reduction of shortage hours in Zone B is lower in this scenario than in scenario SR-EO.

We compare the results for Zone A with the case of a capacity market in a similar but isolated system. The average electricity price in the presence of an interconnector is 5.2% higher than in an isolated system, but the cost of the capacity market is 16.4% lower in the presence of an interconnector. This finding can be attributed to lower bids in the capacity market due to the additional income for generators from exports. On average, the capacity market clearing price observed in an isolated scenario is *31,558 €/MW* as compared to *27,017* €/MW in the CM-EO scenario. On the whole, the net cost to consumers in Zone A is higher by 1.2% in the presence of an interconnector. This is the cost of free riding by consumers in the neighboring region. Note that this cost is a function of the relative sizes of the two interconnected systems and of the size of the interconnector.

We did not model the option for generators in Zone B to sell capacity in Zone A. This functionality, which is strongly preferred by the European Commission (European Union, 2016, 2009b), requires firm guarantees that the capacity that is sold across the

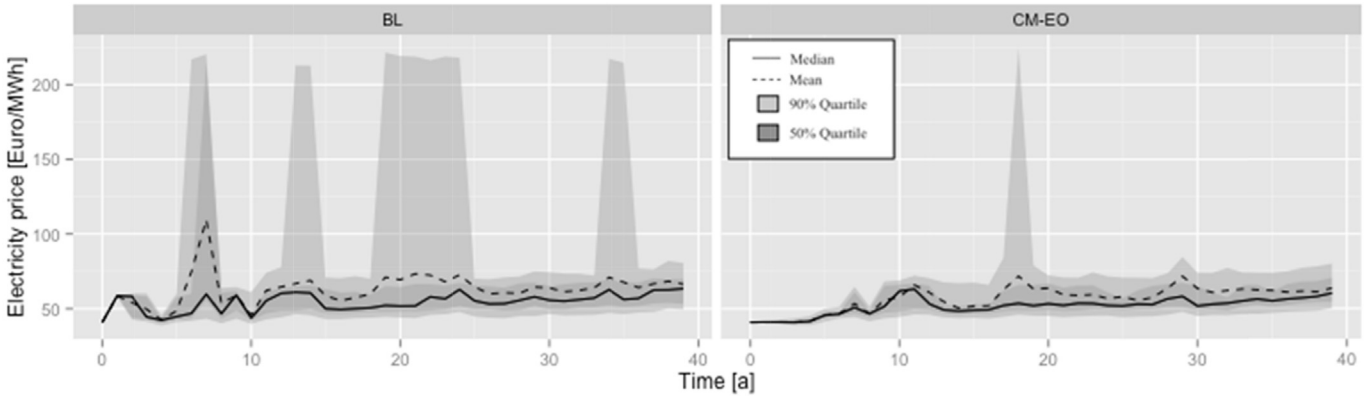

Fig. 12. Comparison of average electricity prices in Zone B without (left) and with a capacity market (right) in the neighboring interconnected Zone A.

border into the capacity market is actually available when needed. To this end, clear and firm agreements with the market operators and TSOs are needed. If implemented, this might counter-veil the free-riding effect, as it would increase the demand for generation capacity in the zone without the capacity market.

The fact that the consumers in the zone without a capacity mechanism may be free riding on the consumers in the zone with a capacity mechanism may not only create acceptability issues in the country with the capacity mechanism, where the consumers are paying more. The leadership in the zone with energy-only market may worry about the availability of electricity during power shortages and strive for sufficient domestic generation capacity to be able to meet demand without imports if necessary. This may be a reason for implementing a capacity mechanism in the energy-only market zone as well.

To summarize, the capacity market achieves the adequacy goals in the zone that implement it, even in the presence of interconnection. The supply margin remains adequate and due to the low number of shortage hours, the total cost to consumers is reduced. The connected energy-only zone free rides on the security of supply provided by the capacity market. The free riding leads to a marginal increase in the cost to consumers of the region implementing a capacity market, but the overall consumer benefit improves. However, a capacity market suppresses investment in the interconnected zone, which may make the neighboring zone import dependent and may lead to an investment cycle there. Cross-border trade of capacity credits might countervail this effect.

4.4. Cross-policy effects due to implementation of dissimilar capacity mechanisms

In this scenario (CM-SR), a capacity market is implemented in one zone (Zone A) while the interconnected zone (Zone B) implements a strategic reserve. We analyze the cross-border effects that may arise from the implementation of dissimilar capacity mechanisms in interconnected zones. The results from scenario CM-SR are compared with those from scenario CM-EO and SR-EO, which allows us to analyze the impact that capacity mechanisms have on each other's effectiveness when implemented in interconnected markets.

Based on the values of the various performance indicators presented in Fig. 4, the implementation of dissimilar capacity mechanisms in the two zones leads to a reduction of shortage hours and of the cost to consumers in both zones. The performance of the capacity market is hardly affected by the presence of a strategic reserve in the neighboring zone. There is no significant change in the indicators of the zone that implements a capacity market (Zone A), without (CM-EO) or with (CM-SR) a strategic reserve in the neighboring interconnected zone (Zone B), as is observed in Fig. 14 and Fig. 15. These results not only indicate that the capacity market is a robust policy mechanism, but also that the strategic reserve in the neighboring zone does not impact the capacity market negatively. This is not surprising, as the strategic reserve was shown to have a positive spillover effect in the SR-EO case.

In Zone B, with a strategic reserve, the import of electricity from Zone A (with a capacity market), along with the additional capacity available due to the strategic reserve, leads to a strong reduction in shortages hours (by 98% as compared to SR-EO), a reduction of the price volatility and a 9% reduction in the average electricity prices (Fig. 17). However, the exports from Zone A to Zone B reduce the need for the strategic reserve, as a result of which the strategic reserve no longer is able to recover it costs, which now are 0.2 €/MWh. In this case, it appears that a smaller strategic reserve would have sufficed.

The supply ratio in Zone B in scenario CM-SR (0.96) is lower than in the Zone A of the SR-EO scenario (1.02) that has a strategic reserve implemented, a difference of 6 percentage points, as can be seen in Fig. 16. This indicates that in the presence of the capacity market, the strategic reserve is less effective in maintaining a certain supply ratio. However, the strategic reserve also reduces the risk of investment cycles in generation capacity, as is shown in Fig. 17, and contributes to a small number of shortage hours.

With respect to the capacity market in Zone A, the difference in the capacity market clearing price is less than 1% in CM-SR *(27,231 €/MW)* as compared to CM-EO *(27,017 €/MW)*, which indicates that the presence of a strategic reserve in the interconnected zone does not impact capacity prices significantly (see Fig. 18).

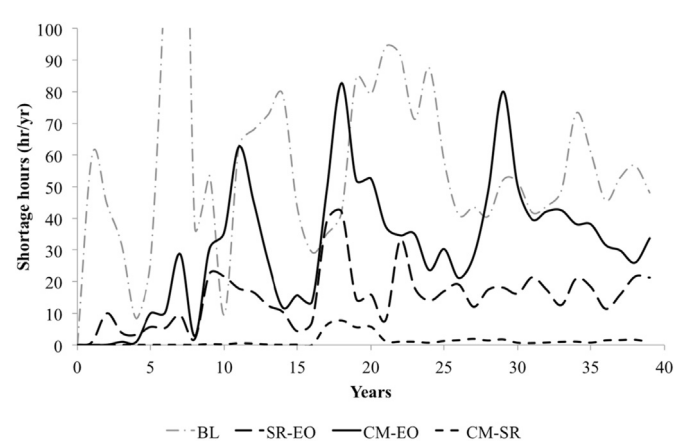

Fig. 13. Average shortage hours in the energy-only market zone (Zone B).

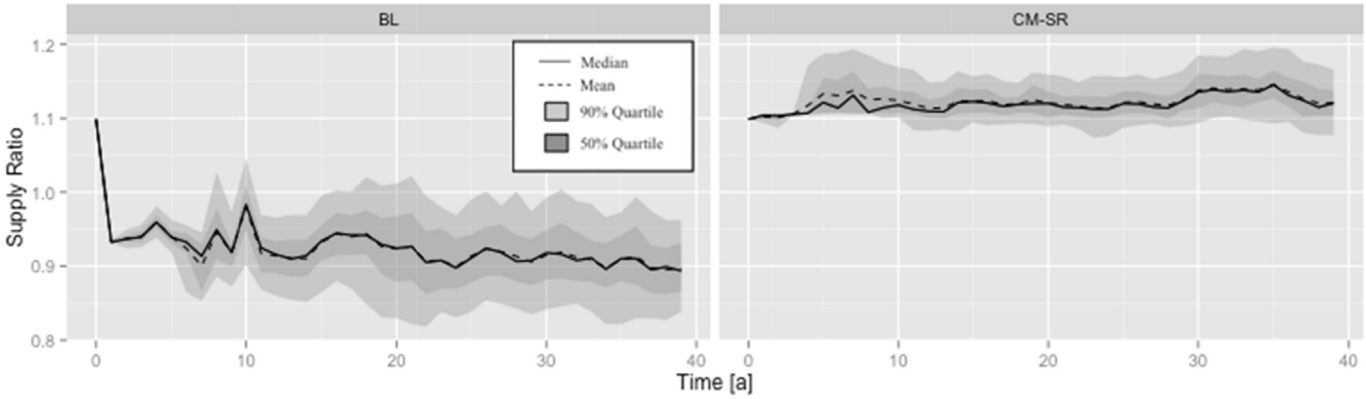

Fig. 14. Supply ratio in the baseline (left) and in CM-SR scenario (right) in Zone A.

4.5. Model limitations

In this model, the power generating companies do not exercise market power or any other kind of strategic behavior in the electricity market or the capacity market. Demand response and storage are also outside the scope of this research. As a result, price spikes are more pronounced and acute power shortages more prevalent in the model than in a market with demand response capability. This limitation may exaggerate some effects, such as the investment cycles. The capacity mechanism design was not adjusted to cross-border trade; neither cross-border trade of capacity rights or any kind of export restriction was included. Finally, as EMLab-Generation was developed to study the long-term development of electricity markets under different policy conditions, short-term operational constraints and unplanned shutdowns of power plants were not modeled. These limitations, along with the segmented nature of the load-duration curve, cause the short-term dynamics to be less precise but also leave open opportunities for future modeling research.

5. Conclusions

We present an analysis of the cross-border effects that may arise due to the implementation of capacity mechanisms in interconnected electricity markets with the use of an agent-based model. We analyze a capacity market and a strategic reserve. In

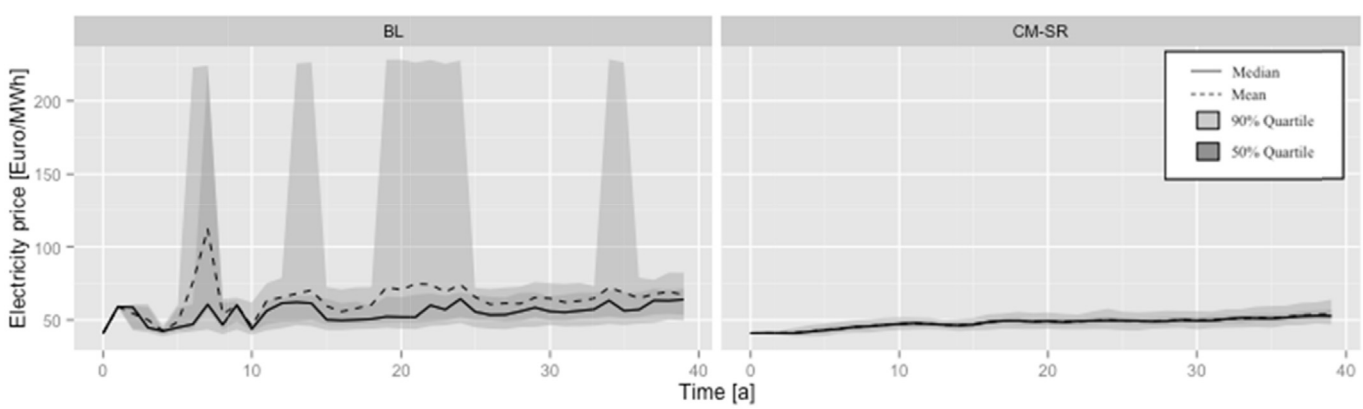

Fig. 15. Electricity prices in the baseline (left) and in CM-SR scenario (right) in Zone A.

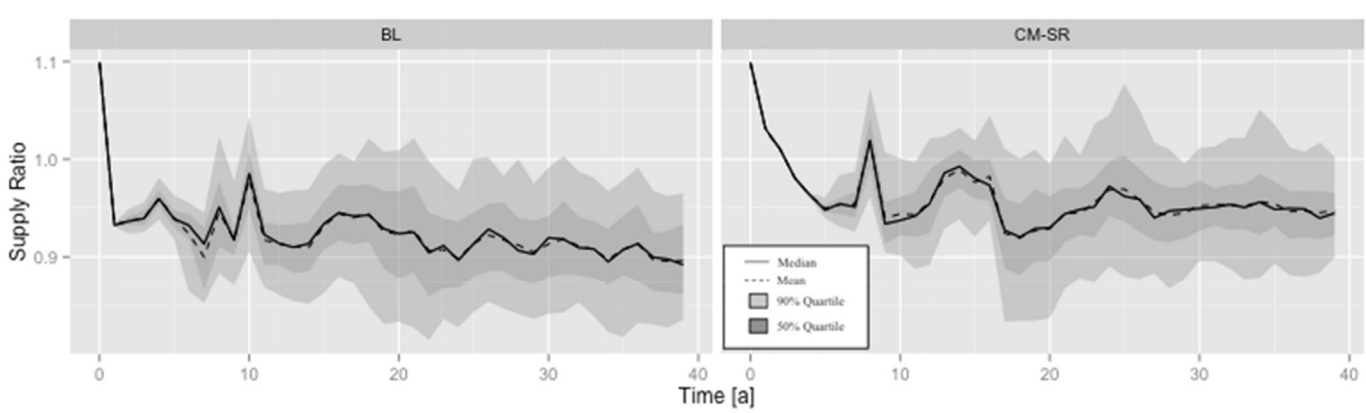

Fig. 16. Supply ratio in the baseline scenario (left) and in scenario CM-SR (right) in Zone B.

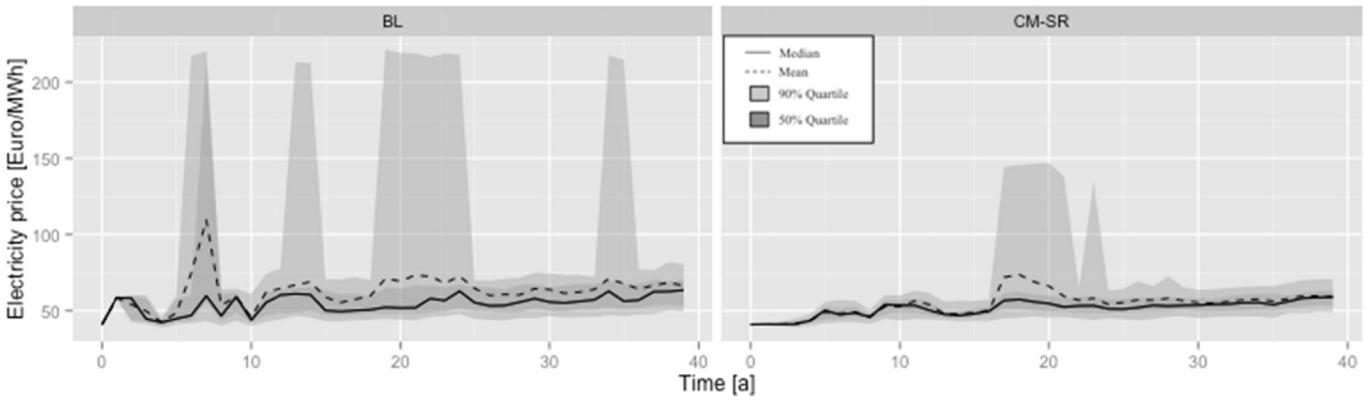

Fig. 17. Electricity prices in the baseline scenario (left) and in scenario CM-SR (right) in Zone B.

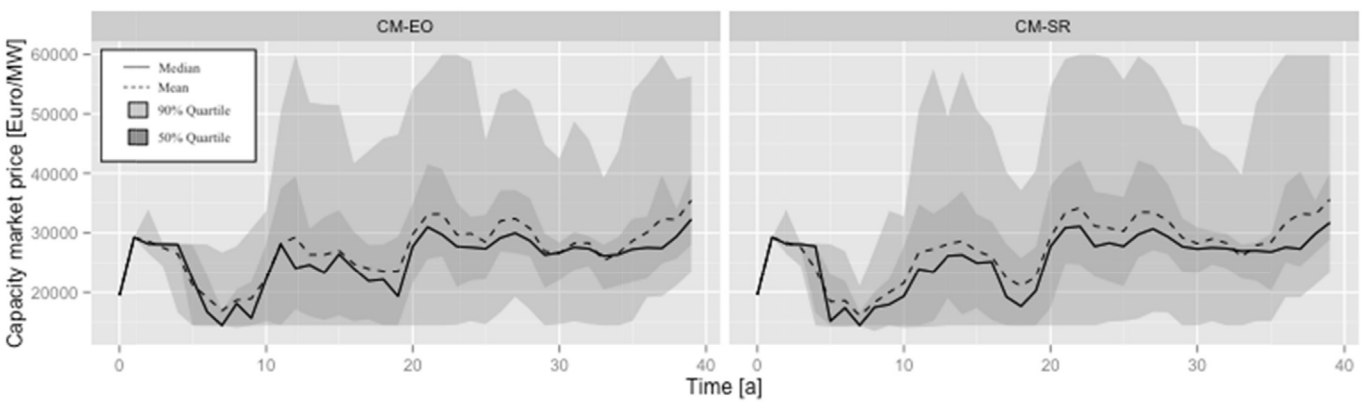

Fig. 18. Capacity market clearing prices in scenario CM-EO (left) and CM-SR (right).

the scenarios analyzed in our model, both capacity mechanisms improve the security of supply and contribute positively to consumer benefit in the two zones considered.

In our model, interconnection with a neighboring zone of a matching size does not affect the ability of a capacity market to reach its policy goals. The neighboring zone may experience a positive spillover and therefore free ride on the capacity market, but may also become import dependent. Free riding may increase costs to the consumers in the capacity market that are paying for the additional adequacy. The generators in the neighboring energy-only zone may be crowded out, in some cases to the extent that an investment cycle develops. While this does not necessarily affect generation adequacy and prices in this zone negatively, policy makers may be uncomfortable with this situation. Allowing generation companies in the zone without a capacity market to sell capacity credits in the capacity market might counter this effect, as this would increase the value of generation capacity in the non-capacity market. Another option is to implement a capacity mechanism in the neighboring zone as well. Hence, implementation of a capacity mechanism may cause pressure on neighboring markets to do the same.

A strategic reserve also has a positive spillover effect on a neighboring energy-only market, both in terms of reduction in shortage hours and cost to consumers. However, the presence of an energy-only market in a neighboring zone has a negative effect on the performance of the strategic reserve with respect to the net cost to consumers and the number of shortage hours when compared to an isolated system with a strategic reserve.

Our research suggests that a capacity market reduces the need for, but may also reduce the effectiveness of, a strategic reserve implemented in an interconnected zone. However, a strategic reserve can reduce the crowding-out effect on its electricity market caused by the capacity market and thus lower the risk of investment cycles in generation capacity.

Acknowledgments

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Appendix

Table 2
Assumptions for power generation technologies.

Technology	Capacity [MW]	Construction time [Years]	Permit time [Years]	Technical lifetime [Years]	Depreciation time [Years]	Minimum Running hours	Base Availability [%]	Peak Availability [%]	Fuels
Coal	758	4	1	50	20	5000	1	1	Coal, Biomass (10%)
CCGT	776	2	1	40	15	0	1	1	Gas
OCGT	150	0.5	0.5	30	15	0	1	1	Gas
Nuclear	1000	7	2	40	25	5000	1	1	Uranium
IGCC	758	4	1	50	20	0	1	1	Coal, Biomass (10%)
Wind Offshore	600	2	1	25	15	0	0.6	0.07	–
PV	100	2	1	25	15	0	0.2	0.04	–
Wind Onshore	600	1	1	25	15	0	0.4	0.05	–
Biomass	500	3	1	40	15	5000	1	1	Biomass
CCGTCCS	600	3	1	40	15	0	1	1	Gas
CoalCCS	600	4	1	50	20	5000	1	1	Coal, Biomass (10%)
Lignite	1000	5	1	50	20	5000	1	1	Lignite
Biogas	500	3	1	40	15	0	1	1	Biomass
IGCCCCS	600	4	1	50	20	0	1	1	Coal, Biomass (10%)

Table 3
Fuel price and demand price growth rate assumptions.

Type	Unit	Coal	Gas	Lignite	Uranium	Biomass	Demand
Start	€/GJ	3.6	9.02	1.428	1.29	4.5	–
Lower	[%]	−3	−6	−1	0	−3	2
Upper	[%]	5	8	1	2	5	2
Average	[%]	1	1.5	0	1	1	1.5

Table 4
Initial supply mix for all scenarios

Technology	Coal	CCGT	OCGT	Nuclear
% Share	50.0%	19.0%	13.0%	18.0%

Table 5
Development of installed capacity the supply mix in a scenario with growing RES.

Technology	Initial Mix	BL	BL
		Final Mix	Final capacity (GW)
Coal	50.0%	11.8%	44.8
CCGT	19.0%	10.2%	38.7
OCGT	13.0%	1.9%	7.2
Nuclear	18.0%	2.3%	8.8
IGCC	–	1.8%	6.7
Wind Offshore	–	8.8%	33.4
PV	–	43.4%	164.7
Wind	–	16.4%	62.4
Biomass	–	3.4%	12.9
CCGTCCS	–	–	0
CoalCCS	–	–	0
Lignite	–	–	0
Biogas	–	–	0
IGCCCCS	–	–	0
Total	100.0%	100.0%	379.7

Table 6
Annual average values of key indicators all scenarios.

Scenario Name	Shortage hours (h/y)	Supply ratio	Electricity price (€/MWh)	Cost of RES (€/MWh)	CCCM (€/MWh)	Cost to consumers (€/MWh)
BL-A	58.4	0.93	58.1	11.5	0.0	69.6
BL-B	58.4	0.93	58.1	11.5	0.0	69.6
CM-EO-A	0.0	1.12	46.1	13.0	4.8	63.9
CM-EO-B	31.0	0.87	52.8	12.1	0.0	64.9
SR-EO-A	11.0	1.02	53.7	12.3	−0.3	65.7
SR-EO-B	15.0	0.91	54.1	12.2	0.0	66.3
CM-SR-A	0.0	1.12	46.0	13.0	4.9	63.9
CM-SR-B	1.2	0.96	50.8	12.5	0.2	63.6
Isolated CM	0.0	1.12	43.7	13.9	5.6	63.1
Isolated SR	1.7	1.02	51.4	13.0	0.1	64.4

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