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COORDINATION OF TIMING OF RESERVE CAPACITY AND DAY-AHEAD ELECTRICITY MARKETS

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I. Introduction

The typical wholesale electricity markets, mainly Day-Ahead (DA) and Intra-day (ID), are not the only marketplaces within the broad context of restructured market-based power systems. Due to the unique technical characteristics of electricity as a product, several services are needed for secure and reliable operation of the grid, mainly known as Ancillary Services. One critical category of these services consists of different types of reserves that need to be available in order to balance supply and demand in real-time; also known as Balancing Services. Providers of these services are generators (and in some cases, willing consumers) who offer some part of their available capacity as reserves to the system operator, who is responsible for system security. Thus, Reserve Capacity (RC) markets are created.

The complicating factor in design of reserve capacity markets is that generators have the opportunity to offer their free capacity in DA and ID markets *or* in reserve capacity markets. In other words, these different markets compete with each other for attracting bids. Therefore, design of reserve capacity markets can not be done in isolation from other electricity markets. This paper focuses on coordination of timing of reserve capacity markets and DA markets and it studies the effect of alternative clearance sequences of DA and RC markets.

Using an intuitive argument, the authors in [1] mention that in order to avoid low liquidity and higher prices, the RC market must be closed before the DA market, and it is confirmed by [2] that in order to ensure that the system operator has the reserves to maintain system security, the RC market should be the first. However, the issue of the sequence of these two markets is still an open question and there are examples in various systems in which the RC market is cleared after the closure of the DA market, e.g. the regulation market in PJM is closed one hour before the hour of operation while the DA market is obviously cleared on a day-ahead basis, [3]-[4]. In our analysis, three cases are defined: Case A represents simultaneous clearance, in Case B the first market is the RC market and then the DA market is cleared, and in Case C the DA market is first and the RC market is cleared afterwards. The objective of this study is to see how these different possible designs can influence the behaviour of bidders in the two markets, using market clearing prices and volumes of the offered capacity in each market as the main indicators. A simulation model is developed in MATLAB, which focuses on behaviour of the generators as “sellers” in both the DA and RC market. Each generating unit decides on its offered capacities in the two markets (bid capacities) and the corresponding bid prices in each round of the simulation. Units revise their bid capacities and prices in each round using the market outcome of the previous rounds.

The paper is structured as follows: The detailed description of the simulation model is presented in section II, the three cases and their differences are discussed in the third section, the numerical results are presented in section IV and the last section discusses the conclusions of this study.

II. Model description

As mentioned in the introduction, a simulation model is built in MATLAB using the agent-based modeling concept. Each agent is a generator who has to decide on its bids in the RC and DA markets, and the bids consist of a volume (in MW) and a price (in €/MWh for the DA market and in €/MW/hour for the RC market). We have defined two types of agents: Risk-averse agents who do not try to influence the market clearing price, and Risk-prone agents who do try to increase the market price by increasing their bid prices. In each round of the simulation, each agent decides on its bid prices for the next round by adapting its current bids, using the market information of the last round. In addition to the bid price, each agent adapts its offered capacities in the two markets (for the next round) by comparing its individual relative profits in the two markets and shifting some capacity (depending on the size of the difference in profit) from the less profitable to the more profitable market.

Bid Price Adaptation Strategy

a) *Risk-averse units*: If their bid is selected in a market (in a specific round), they keep their current bid price in the corresponding market for the next round. If their bid is not selected, they reduce their bid price in order to be among the selected bids in the next round. The price step size for a generating unit, by which the bid price of that unit is reduced for the next round, is assumed to be a percentage of the unit's total operating costs and fixed throughout the simulation.

b) *Risk-prone units*: The same strategy, as for risk-averse units, for reducing their bid prices in case of not being selected in a market is used. The difference is that risk-prone units do not necessarily keep their current bid price if they are selected. They try to influence (increase) the market clearing price by increasing their bid price if their bid is selected. So they take the risk of not being selected in order to increase the market clearing price. The price step size for a unit, by which the bid price of that unit is decreased or increased for the next round, is assumed to be a percentage of the unit's total operating costs, but it might be decreased throughout the simulation. Assume that the bid of unit *i* (a risk-prone unit) is not selected at round *n-1* but is selected in round *n*. It means that the bid price of the unit has been reduced by $Pss_{i,n-1}$ (the price step size of unit *i* at round *n-1*) for round *n* and the new bid price is low enough to get selected in the market. Since the unit is risk-prone, it tries to increase its bid price for round *n+1*. Using the same price step size will put the unit in the same situation as round *n-1*. Therefore, using the same high step size will put the generator in a cycle of not being selected in one round and being selected in the next, constantly increasing and decreasing its bid price in subsequent rounds. Thus, the unit should use a lower step size for increasing its bid for round *n+1*; competition among bidders limits the opportunity of influencing the market price by risk-prone units. The mechanism we use for decreasing the price step size is, in case a (risk-prone) unit's bid is not selected in one round and gets selected in the next round, the price step size of the unit is reduced to half for the coming round ($Pss_{i,n+1} = Pss_{i,n} / 2$). Therefore, adaptation of the price step size is performed as follows:

$$Pss_{i,n+1} = \begin{cases} Pss_{i,n} / 2 \ ; & \text{if } bid_{i,n-1} \text{ is not selected AND } bid_{i,n} \text{ is selected} \\ Pss_{i,n} \ ; & \text{Otherwise} \end{cases} \tag{1}$$

Bid Volume Adaptation Strategy

In each round, all units adapt their offered volumes in the DA and RC markets for the next round, based on market outcomes of the current round. They calculate their average profits per MW of their capacity (in €/MW/hour) in the two markets and withdraw some of their capacity from the less profitable market and add it to their offered capacity in the other market. The volume step size of a unit, by which the offered volume is shifted between the two markets for the next round, depends on the unit's profit difference in the two markets. The higher the difference in profit, the more capacity is shifted between the markets. A simple linear relationship is used in this simulation:

$$Vss_{i,n} = Vss_i^{\max}(1 - profratio_{i,n-1}) \qquad (2)$$

where $Vss_{i,n}$ is the volume step size of unit *i* at round *n*, $Vss_i^{\max}$ is the maximum volume step size for unit *i*, and $profratio_{i,n-1}$ is the profit ratio (average profits per MW of capacity) in the two markets for unit *i* at round *n-1*. Thus, in case a unit's profit in one of the two markets is zero at one round, the maximum volume is shifted to the other market for the next round. And in case a unit's profits in the two markets are equal, no volume is shifted between the two markets for the next round (the current level of offered volumes is used for the next round).

The fixed costs of generating units are neglected in this study, so the cost of producing power for each unit is equal to its operating costs. Thus, a unit's profits in the RC and DA markets are calculated as follows (if its bids are selected in the markets):

$$prof_{i,n}^{DA} = MCP_n^{DA} - OC_i \qquad (3)$$

$$prof_{i,n}^{RC} = MCP_n^{RC} \qquad (4)$$

where $prof_{i,n}^{DA}$ and $prof_{i,n}^{RC}$ are unit *i*'s profits in the DA and RC markets at round *n*, respectively, MCP_n^{DA} and MCP_n^{RC} are the market clearing prices of the DA and RC markets at round *n*, and OC_i is the operating cost of unit *i*. If a unit's bid is not selected in a market, its profit in the corresponding market in zero.

III. The Three cases

As mentioned above, three cases are defined, representing alternative designs regarding coordination of timing of the DA and RC markets.

Case A

The first case represents simultaneous closure of the two markets. Every unit decides on its bid prices and bid volumes in the two markets, based on market outcomes of each round. The only constraint for units in case A is the total offered volumes:

$$V_{i,n}^{DA} + V_{i,n}^{RC} = V_i^{Avai.} \qquad (5)$$

where $V_{i,n}^{DA}$ and $V_{i,n}^{RC}$ are unit *i*'s offered volumes in the DA and RC markets for round *n*, respectively, and $V_i^{Avai.}$ is the total available capacity of unit *i*. In addition, the lower boundary of a unit's bid price in the DA market, for all rounds, is unit's operating costs:

$$P_i^{DA} \geq OC_i \qquad (6)$$

where P_i^{DA} is the bid price of unit i in the DA market.

The equality and inequality constraints in (5) and (6) apply to all the three cases.

Case B

In the second case, first the RC market is closed and cleared and the DA market is the second. Because of sequential clearance of the markets, bid prices in the RC market will include a lost opportunity cost (LOC) component. Using the following inequality constraint, units try to make sure that no potential profit in the DA market (for round n+1) is lost by offering part of their capacity in the RC market.

$$P_{i,n+1}^{RC} \geq MCP_n^{DA} - OC_i \qquad (7)$$

where $P_{i,n+1}^{RC}$ is the bid price of unit i in the RC market for round $n+1$. The right hand side of the inequality constraint represents the unit's profit (per MW) in the DA market for round n. Therefore, the RC bid price of a unit for the next round is higher than the unit's profit in the DA market at the current round.

Case C

The third case represents the design in which the DA market is closed and cleared first and the RC market is the second. Since the LOC component in bids of generators originate from the sequential clearance of the markets, and not from the nature of the products traded in the two markets, the DA bid prices of units in case C include the LOC component because the DA market is first and units should make sure that no potential profit is lost in the RC market by offering part of their capacity in the DA market. Thus, the following inequality constraint is applied to bid prices in the DA market for case C:

$$P_{i,n+1}^{DA} \geq MCP_n^{RC} + OC_i \qquad (8)$$

where $P_{i,n+1}^{DA}$ is the bid price of unit i in the DA market for round $n+1$.

IV. Results

The data list of the thermal generating units in Germany is used in this model: 262 units (different types) with different operating costs [5]. The list includes the oil, gas, coal, nuclear and hydro power plants. It is assumed that each generator bids separately. In the following results, the demand of the DA market is 74,000 MW (rough estimation of the peak load in Germany) and the demand in the RC market is 6,000 MW which is the sum of the demand for secondary and tertiary control in Germany (the average value in 2009) [6]. The total generation capacity is 108,855 MW. It should be emphasized that the goal of this study is not to simulate the German market, but to use the available real data in order to be able to have a realistic picture (to avoid making conclusions based on a non-real test system). The initial values of the step sizes and initial bid prices used in this simulation are summarized in Table 1.

Table 1- The initial price and volume step sizes and the initial bid prices (at round 1)

Variable	$P_{i,1}^{RC}$	$P_{i,1}^{DA}$	$Vss_i^{\max}$	$Pss_{i,1}^{RC}$	$Pss_{i,1}^{DA}$
Initial Values	$0.1 \times OC_i$	$1.1 \times OC_i$	$0.1 \times V_i^{Avai.}$	$0.1 \times OC_i$	$0.3 \times OC_i$

The initial bid prices (at round 1) in the RC and DA markets are 10% and 110% of unit's operating costs (a profit of 10% of the operating cost in both markets is considered in the initial bids). The initial price step sizes for each unit are 10% and 30% of unit's operating costs, for the RC and DA market bids respectively. The volume step size (the maximum volume shift of a unit in each round) is 10% of unit's available capacity. At round 1, each unit divides its capacity between the RC and DA markets proportional to the total demand in the corresponding markets.

Distinguishing between risk-averse and risk-prone units is also a critical input to the simulation. The desirability of taking a risk-prone approach highly depends on the level of operating costs of a unit; Low-cost units can add a decent profit margin to their operating costs and expect to be selected in the market with a high probability, simply because of their low level of operating costs. Thus, trying to increase the market clearing price (taking a risk-prone approach) for low-cost units endangers their otherwise-secure and continuous profit. Therefore, we define the risk attitude of units based on their operating costs: units with costs lower than a certain level are considered risk-averse and the ones with higher costs are considered as risk-prone units. Setting this critical cost level, obviously, has profound impact on the simulation results. Figure 1 shows the cumulative distribution of operating costs of the units used in this study (thermal power plants in Germany). As can be seen, 50% of the total available capacity comes from units with an operating cost of less than 41.07 €/MWh. Using this value as the critical cost level means that half of the capacity will belong to risk-averse units and the other half to risk-prone units.

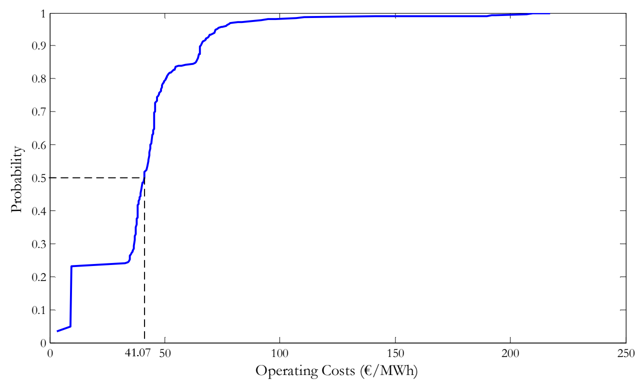


Figure 1- Cumulative distribution of units' operating costs

Figure 2 shows how the DA market clearing price in case A depends on the critical cost level used for distinguishing between risk-averse and risk-prone units. As the critical cost level increases, the number of risk-prone units decreases which results in reduction of the market clearing price. Risk-prone units have to compete with others in order to be selected in the market and by reduction of the number of risk-prone units, their influence on the market clearing price would be more and more limited. However, it should be noted that the objective in this study is to *compare* the three cases so the key factor is to apply the same critical cost level to all the cases.

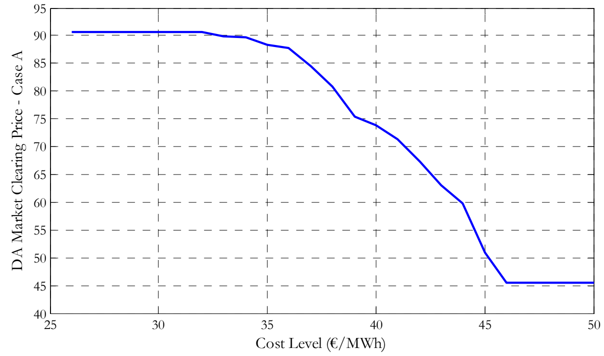
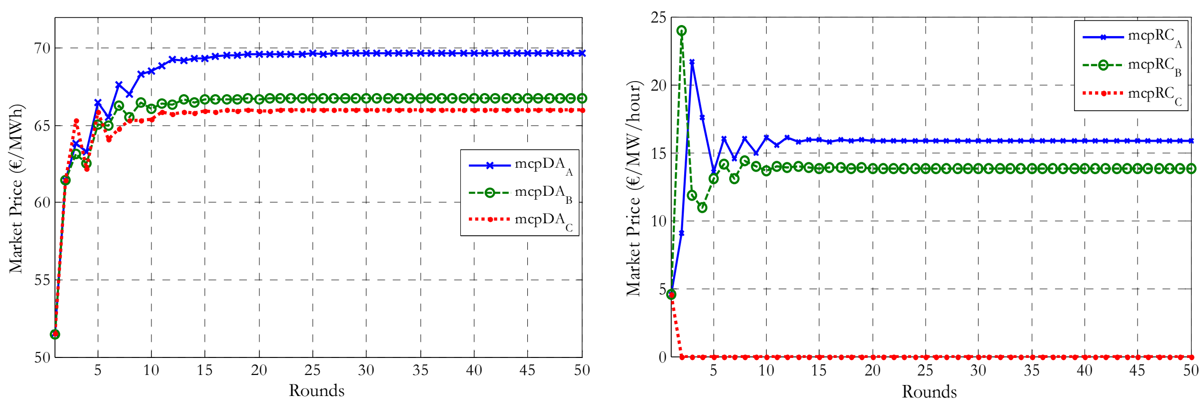


Figure 2- Final market clearing price of the DA market for Case A, as a function of the critical cost level used for distinguishing between risk-averse and risk-prone units

Figure 3 shows the market clearance prices (for each round) of the DA market and the RC market for the three cases, assuming the critical cost level to be 41.07 €/MWh. As can be seen, regarding the DA market, case A results in the highest market price, 70 €/MWh, which originates from lack of the possibility of capacity substitution between the two markets in case A; non-selected bids in one market can not be transferred to the other market so the corresponding non-selected capacity is lost (not used). Case B and case C result in almost the same DA market prices, 67 €/MWh and 66 €/MWh, respectively. Regarding these two cases, it seems that, although capacity substitution can be performed by units in those two cases which leads to lower bid prices and consequently lower DA market clearing prices, because of the significant difference in the size of the DA and RC markets (the DA market aims at meeting the electricity demand of the system, but the RC market aims at reserving sufficient capacity to compensate for deviations in real time), the sequence order of market clearances has an insignificant effect on the DA market prices. Thus, even though in case C, a lost opportunity cost component is added to the bid prices in the DA market (the first market in case C), this case leads to the lowest DA market clearing price.



(a) (b)

Figure 3- Market clearing prices (MCPs) of (a) the DA market and (b) the RC market for the three cases- assuming the critical cost level to be 41.07 €/MWh

However regarding the RC market, both case A and case B result in high market prices, 16 €/MW/hour and 14 €/MW/hour, respectively. In case B, a considerable lost opportunity cost (LOC) component will be added to the bid prices of generators in the RC market because of the sequence of markets clearance; the capacity offered in the first market (RC in case B) comes with a price high enough for the bidder to insure that no possible profit is missed in the second market (by offering that capacity in the first market). Another interesting outcome is that in case C the RC market price goes down to zero. In case C, the RC market is the second so there is no LOC component in the bids of generators and in the RC market there is no operating cost either (in contrast to the DA market). Presence of a sufficiently high level of competition will push the bid prices down to zero (actually to the level of fixed costs which have been neglected here). This is the reason why, even in case of an LOC component in the DA bid prices for case C, the DA market price is the lowest: The LOC component depends on the RC market price which becomes zero after the few first rounds.

Figure 4 illustrates the DA and RC bid prices of an individual unit in case A. The 43rd unit is a combined cycle gas-fired plant with an operating cost of 64.26 €/MWh and a net capacity of 162 MW [5]. Figure 5 shows the DA and RC bid volumes of the same unit in case A. Comparing the unit's operating costs to the market DA market clearing price in Figure 3, it can be seen that after the first few rounds the DA market price is higher than the unit's operating costs, but according to Figure 5 the unit constantly reduces its offered capacity in the DA market and shifts it to the RC market. The key is the unit's profits in the two markets. As noted earlier, since the fixed costs of the units are neglected in this study, the average-per-MW profit of the unit in the DA market is the difference between the market price and the unit's operating costs, 5.34 €/MW/hour, while the unit's profit in the RC market is the RC market clearing price, 16 €/MW/hour. Thus, in order to maximize its total profit, the unit constantly shifts its offered capacity from the DA to the RC market until all of its 162 MW capacity is offered in the RC market and it has no capacity offered in the DA market.

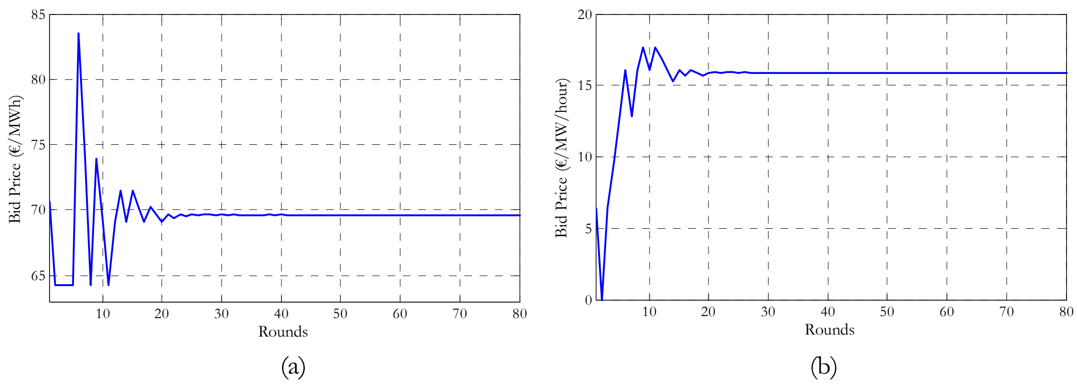


Figure 4- Individual bid prices of unit #43 in Case A- (a) DA bid price (b) RC bid price

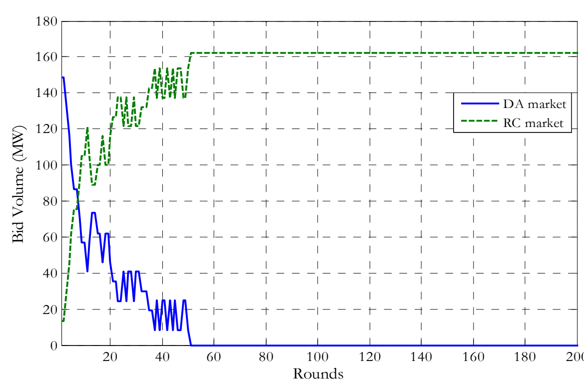
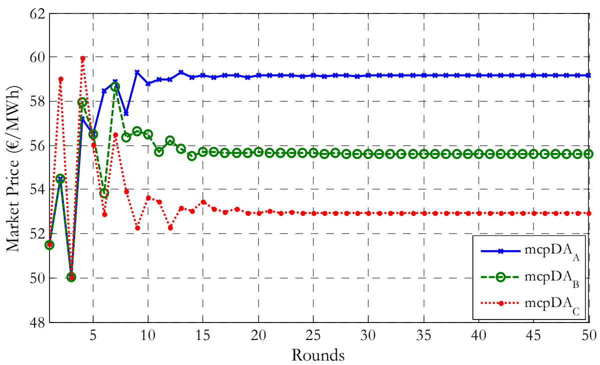


Figure 5- Individual bid volumes of unit #43 in Case A

In order to demonstrate the effect of the critical cost level (used for distinguishing between the risk-averse and risk-prone units), Figure 6 shows the DA and RC market clearing prices for the three cases using a critical cost level of 44 €/MWh. As the figure suggests, all the market prices decrease compared to Figure 3, for which a critical cost level of 41.07 €/MWh was used. Nonetheless, comparing the three different cases, case A still leads to the highest market prices, followed by case B, and the differences in market prices in case A and case B are even more distinct. Case C, again, results in the lowest market prices, with a zero RC market price, in particular.



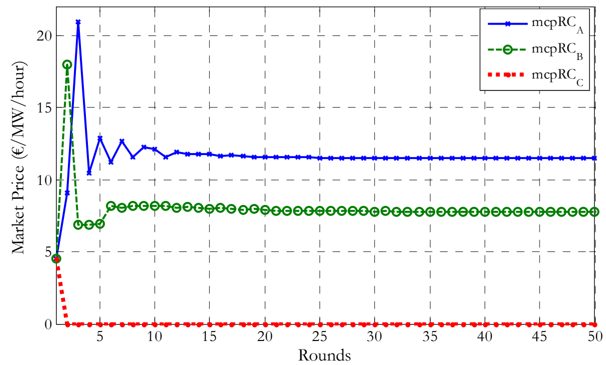


Figure 6- Market clearing prices (MCPs) of the DA market (left) and the RC market (right) for the three cases- assuming the critical cost level to be 44 €/MWh

As another crucial indicator, Table 2 shows the total volumes offered in the RC and DA markets for the three cases, in MW. It should be noted that the sum of the offered volumes in the two markets for cases B and C is higher than the total available capacity in the system (108,855 MW) which originates from the fact that in those two cases, capacity substitution between the two markets is possible, so non-selected capacity of a unit in the first market can be offered in the second market (offering of the same capacity in two markets). However, in case A, a unit has to divide up its total available capacity between the two markets.

Table 2- Total offered volumes (in MW) in the DA and RC markets for the three cases- For a critical cost level of 41.07 €/MWh

	Case A	Case B	Case C
Day Ahead Market (DA)	91,697	102,855	108,046
Reserve Capacity Market (RC)	17,158	16,373	34,855

Regarding the RC market, the lowest volume is offered in case B and the highest volume is offered in case C, in which the units learn to offer all of their capacity that is not selected in the DA market (the first market in case C) in the RC market, resulting in a final offered volume of 34,855 MW in the RC market (the difference between the total available capacity and the demand in the DA market). In case B, because of the uncertainties in whether or not offering the capacity in the RC market (first market) will lead to loss of profit in the DA market (second market), the offered volume in the RC market is limited. One might expect the same phenomenon to happen in case C for the DA market (the first market in case C). However, the offered volume in the DA market for case C is the highest. The main difference is that there is basically no minimum bid price in the RC market while in the DA market, the bid price of a unit can not go below the operating costs of the unit. Therefore, while in case B the DA market price can not go down to zero, in case C, the RC market price reaches zero after a few rounds, which in turn leads to elimination of uncertainties for bidding in the first market (DA in case C). Thus, although the uncertainties in offering capacities in the first market lead to the lowest offered volume in the RC market for case B, these uncertainties can not limit the offered volume in the DA market for case C.

The results of this study so far, show that having the DA market closed first and then closing and clearing the RC market (case C) will lead to highest offered volumes in both markets and lowest market clearing prices. The objective of the reserve capacity market is to insure that enough reserves will be available in real-time to compensate for deviations in power generation and consumption. Thus, the entire RC market is aimed at guaranteeing system security. The results of this study simply suggest that making such a guarantee before closure of the day-ahead market is much more expensive than making the guarantee after the closure of the DA market.

Nonetheless, the crucial issue is the availability of capacity from *proper resources* in the reserve capacity market. Reserves are categorized based on their technical characteristics and the system operator needs to make sure that sufficient reserves are available for every category. As mentioned above, the demand in the RC market in this simulation is the sum of the demand for secondary control (SC) and tertiary control (TC) in Germany. To utilize the output of a generator for secondary control, its rate of change must meet specific required values. The offered capacity in the reserve market for SC must be capable of being fully activated within 15 minutes; a minimum rate of change of 7% of the nominal output per minute. However the bids for TC can take hours to be fully activated; even offline units can offer TC reserves. Therefore, the crucial question is, if the DA market is closed and cleared first, will sufficient capacity from the proper resources, capable of providing SC reserves, be available in the RC market which will be closed and cleared afterwards. In order to answer this question, we make a distinction between SC and TC reserves in the RC market. The demand for SC is assumed to be 2800 MW (average of the SC demand in Germany over 2009) and the demand for TC is 3200 MW (average of the TC demand in Germany over 2009), summing up to 6000 MW demand in the RC market [6]. According to [1] and [7], the rate of change for oil- or gas- fired units is in the range of 8% per minute. Reservoir power stations, such as pumped storage plants, have rates between 1.5 and 2.5% per second (more than 90% per minute) whereas for hard coal- and lignite-fired plants, rates from 2 to 4% per minute and 1 to 2% per minute respectively are typical. The maximum rate of change for nuclear plants is approximately 1 to 5% per minute. Therefore, we assume that only the gas, oil and hydro units are capable of providing the SC reserve. The simulation is run again, assuming that in clearance of the RC market, the demand for SC reserves has to be met only using gas, oil and hydro units, whose net capacity sums up to 33,655 MW (30% of the total available capacity in the system). All units can provide TC reserves.

Figure 7 shows the market clearing prices of the DA and RC markets, for the three different cases (using the same critical cost level as in Figure 3 to Figure 5), making the aforementioned distinction between SC and TC reserves. A small increase in the DA market prices for all the three cases (compared to Figure 3) can be seen. The RC market prices suffer a larger change for cases B and C (almost 5 €/MW/hour), while the RC market price in case C remains at zero.

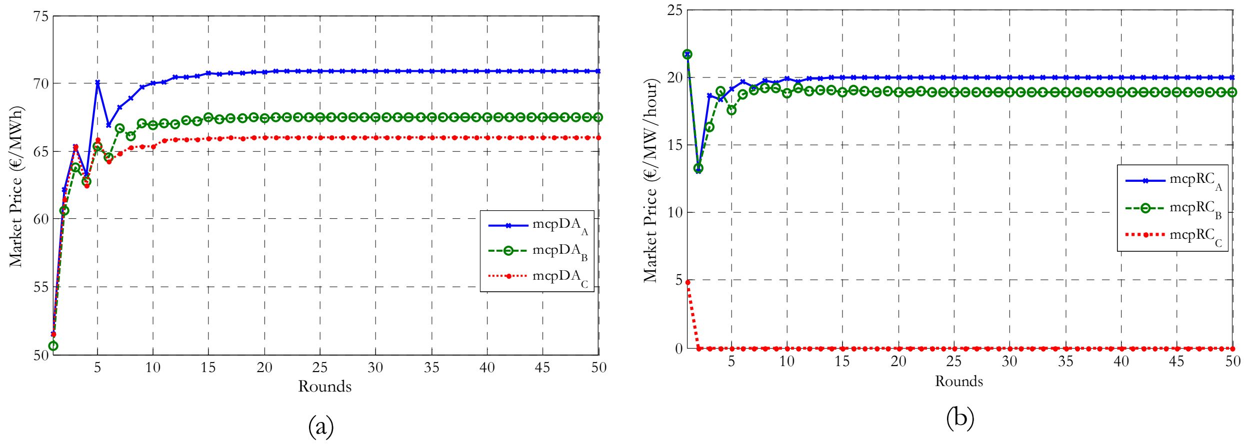


Figure 7- Market clearing prices of (a) the DA market and (b) the RC market for the three cases (Critical cost level of 41.07 €/MWh)- Distinction between SC and TC reserves

Figure 8 shows the SC and TC market prices for cases A and B. The simulation starts with a much higher price for SC reserves than TC reserves, but after some time, they both converge to the final market clearing price for the RC market.

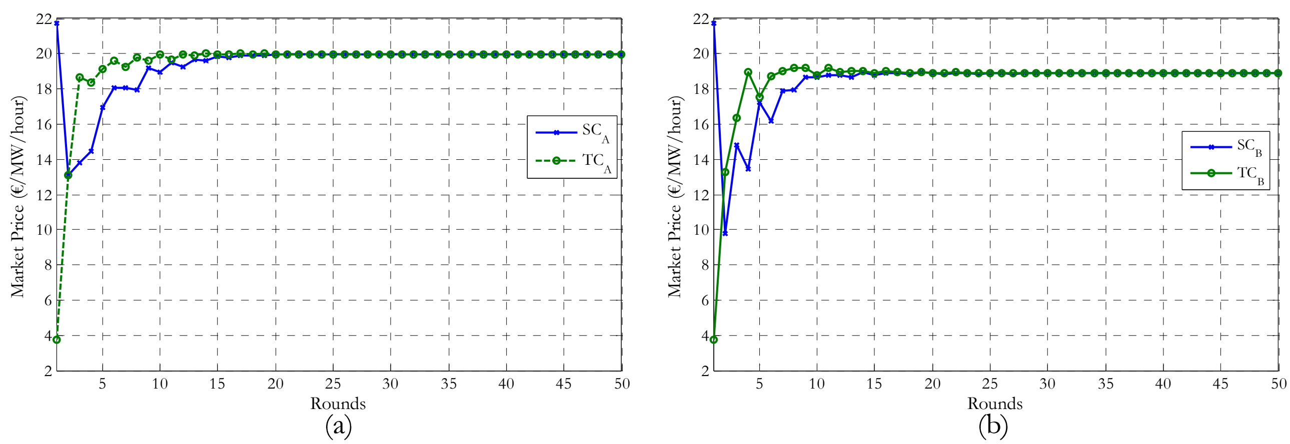


Figure 8- Market prices for the SC and TC reserves (Critical cost level of 41.07 €/MWh)- (a) Case A (b) Case B

Therefore, even in case C, where the RC market is the second market, still sufficient capacity from eligible SC reserve resources is available. Clearing the RC market after the DA market does not lead to lack of enough SC capacity in the RC market, and the SC reserve requirement (the demand for SC reserves) can be met using units that are technically capable of providing SC reserves.

Nonetheless, the question of whether or not sufficient capacity from eligible SC resources will be available in the RC market in case the RC market is cleared after clearance of the DA market needs to be answered on a case-specific basis. It highly depends on the generation portfolio of the system, so the system operator is the only entity which can answer this question. Thus, our objective is not to make generic conclusions about the sequence of clearance of the RC and DA markets. However, since the requirements on TC reserves are much looser and a high percentage of the units can provide this type of reserve, based on the results of this study, we recommend that at least the market for TC reserves be cleared after the closure of the DA market, which will lead to higher offered volumes in the market, lower prices, and higher liquidity.

V. Conclusions

Coordination of timing of the reserve capacity (RC) and day-ahead (DA) markets plays a decisive role in the offered capacities and the market clearing prices, by changing the behavior of generators who bid in the two markets. In contrast to the intuitively expected outcome, the results of the analysis show that case C (the DA market be first, and the RC market the second) leads to the lowest market prices, especially the RC market price, and highest offered capacity in the RC market, which is highly desirable from a system security perspective. The concern of availability of sufficient capacity from proper resources, e.g. secondary control (SC) which imposes strict requirements on suppliers of this reserve, holds valid if the RC market is cleared after the clearance of the DA market. Thus, although we believe one should be very cautious about making a change in design of these markets (which implicitly limits the possibilities of making general conclusions), the results of this study show that at least the TC reserve market should be cleared after the clearance of the DA market, leading to much lower costs of guaranteeing the security of supply.

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