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Simulation-based estimation of the economic benefits implied by coordinated balancing capacity procurement and deployment in a day-ahead market model

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ABSTRACT

In this paper we analyze how increasing levels of cooperation in reserve procurement and activation affect the implied economic benefits and the respective network loads assuming various paradigms of coordination. To approach the question we construct a simulation model based on the portfolio-bidding day-ahead market clearing context, which takes into account the stochastic nature of reserve activation. Results show that the application of reserve demand netting is desirable in all considered aspects and benefits tend to saturate with increasing number of cooperating zones. Assuming the simultaneous application of the common merit order and reserve demand netting, in which case the benefits are the most significant, simulations show that reserve activation costs are reduced by 71% in the case of 4 zones, compared to the reference case with no coordination, while increasing the number of cooperating zones from 4 to 6, form 6 to 8 and from 8 to 10, implies only a further incremental improvement of 8, 3 and 2%. Regarding policy aspects the results point out that it may be desirable to facilitate the formation of multiple regional cooperation frameworks, which should be easier to establish compared to full-scale integration of reserve procurement and activation platforms.

1. Introduction

With the green transition and the accompanying increasing penetration of renewable intermittent and uncertain sources, new aspects have risen to the focus of energy management challenges. Unforeseen supply–demand imbalances in the power grid, arising due to demand prediction errors, weather-dependent renewable production or other factors, have to be compensated to maintain the frequency stability of the network [1,2]. Since flexibility resources may be used to compensate for the fluctuating input related to renewable sources and/or volatile demand, the value of these assets have increased significantly in the past decade. Several recent approaches have been proposed to efficiently utilize the flexibility resources of grid-connected energy hubs [3,4] , electric vehicles [5], and demand response [6].

In general, from the point of view of the respective markets, ancillary (or balancing) services [7] represent valuable tools for transmission system operators (TSOs) to support the balancing process, regardless of their physical origin. The respective products, which are shortly called 'reserves' are traded in specific platforms [8].

As reviewed also in [9], according to the response-time and length of activation, the European system classifies the reserve products as Frequency Containment Reserves (FCR), Automated and Manual Frequency Restoration Reserves (aFRR and mFRR) and Replacement Reserves (RR). Overconsumption or faults of generating units, which would imply a frequency drop are balanced using upward reserves, while under-consumption or over-production (think e.g. to non-controllable renewable sources) require the activation of downward reserves.

It has been pointed out that efficient balancing markets are a prerequisite for the integration of intermittent renewable sources [10]. Although the European Network of Transmission System Operators for Electricity (ENTSOE) has recently proposed some basic guidelines for a future framework which would allow the exchange of balancing capacities and sharing of reserves in the EU [11], as discussed in [9,12], balancing markets in Europe are practically uncoordinated. This means that regarding the sizing, procurement and activation of reserves, apart from a few exceptions (for the exceptions see [9]), there is no interaction between TSOs responsible for different control areas, neither on the level of central multi-area coordination, nor on the level of bilateral agreements and mechanisms of neighboring areas. Needless to say, this implies inefficiencies. As such inefficiencies are present not only on the level of balancing markets, but also in other forms of electricity

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trading in the case of decoupled markets, the Target Electricity Model of the European Commission aims to integrate EU electricity markets at all timescales, from long-term contracts, to day-ahead, intraday and balancing markets, in order to achieve an efficient allocation of electricity [13]. Regarding the realized results of this ambitious goal, some of its aims have been already completed: the market coupling tool EUPHEMIA [14] ensures the integration of day-ahead electricity markets, considering cross-zonal capacities, and supporting several special offer types (as e.g. block orders) which help generating units to incorporate non-convex costs (as start-up cost) in their bids. In the framework of EUPHEMIA, participants submit supply or demand bids with given minimal/maximal price parameters, which allow the representation of demand and supply elasticity. The aim of the market clearing algorithm is to maximize the total social welfare (TSW), which is interpreted as the total utility of consumption minus the total cost of production (assuming that the price of the submitted bids are corresponding to the marginal utility/production cost values) and to determine zonal clearing prices under various constraints (e.g. supply–demand balance, transmission and bid acceptance constraints) [15].

Several articles and reports discuss the experienced and potential benefits of market integration, regarding electricity markets in general [16], and in the particular case of balancing markets [17,10,18–21,12].

1.1. Coordinated operation of balancing capacity markets and coordinated activation of reserves

Efficient integration of markets requires coordinated operation. The key design elements to achieve coordinated operation in the case of cross-border balancing are described in [22]. As discussed in [9,12], in the case of balancing energy, the coordination may be implemented in three different levels, namely on the level of sizing, procurement and activation of reserves.

Historically, the sizing of reserves (the determination of the amount of reserves required) is performed by the local TSO for its own control area, according to various rules and guidelines [23]. A typical rule is that the total amount of allocated reserves must be sufficient to substitute the largest producing unit in the case of its fault. It is easy to see that in such a case, if control areas are merged, the amount of reserves, which must be allocated per area may decrease — this is not the only guideline for reserve sizing though. One aim of the article [20] is exactly to estimate the benefits, which are implied by the integration of balancing capacity markets in the aspect of reserve sizing. Sizing and the effect of balancing capacity market integration on sizing are however not the subject of this paper, in this study we focus on the procurement (i.e. allocation) and deployment (i.e. activation) of reserves.

1.1.1. Coordination of reserve procurement

Procurement of reserves takes place in advance to the possible delivery of reserve resources, typically at least 12–24 h before the potential deployment. In the procurement process, generating units (and in case other participants, e.g. controllable loads, energy storage units) may offer their flexibility in the form of up or down-reserves at a given *allocation price*. This means that if such a bid is accepted in the procurement process, the TSO pays at least the allocation price for the bidder to keep the flexibility resource (i.e. the up/down reserve) on standby for a potential case of activation in the defined time frame. In the current paper we assume that the procurement of reserves takes place via an EUPHEMIA-type day-ahead market setting, where the elementary building blocks are simple price-quantity bids both on the demand and on the supply side and the market is cleared via the pay-as-clear (i.e. uniform pricing) approach [24]. The uncoordinated setting, which will be used as reference, in the context of the current paper means that the total quantity of accepted reserve demand bids must be met by the total quantity of accepted reserve supply bids in every single (control) zone. In this case it is always possible to activate the reserves in such a way, which does not implies any network load on cross-zonal transmission lines – since every zonal TSO may activate its 'own' reserves, i.e. reserves, which have been allocated inside the respective control zone. This scenario corresponds to the case of uncoordinated activation, because in this case not necessarily the most cost efficient reserve resources are deployed to cover the reserve needs (but the ones, which are located and allocated in the actual zone).

In the proposed framework, the coordinated setting corresponds to the case when no nodal balances are required for the equality of accepted demand and supply bids, this balance applies only on the level of all zones. In the latter case, which may be also termed as 'exchange of reserves' as in [9], in the deployment phase it may happen that to cover the reserve needs of a zone, resources located in other zones must be activated, which implies network flows between the zones.

1.1.2. Coordination of reserve activation

Activation (i.e. deployment) of the allocated resources happens in real time. If the TSO senses that the actually arising supply–demand imbalance calls for intervention, it activates the reserve or, if the required reserves have been (partially) procured outside its control zone, sends request signal to the authenticated TSO partner(s) to activate the allocated reserve. As the process of reserve activation, in contrast to day-ahead energy trading, is stochastic in nature, the preliminary network capacity allocation for cross-zonal activation poses a significant challenge for network and market operators [22].

As discussed in [9] as well, the two basic paradigms of reserve activation are the (i) common merit order (CMO) and the (ii) imbalance netting or reserve demand netting (RDN). Under the merit order we mean that the reserve-providing resources may be ordered according to the activation cost of the reserve, and this ordering is used to determine the most cost-effective activation pattern for a given reserve demand. The common merit order means that this ordering is performed for the whole set of the reserve resources and not zone-wise, so reserves are activated in the most economic way — always the resources with the lowest activation cost are activated first, regardless of their location.

Reserve demand netting is based on the consideration that up and down reserve demands between different zones may be netted before the activation process of reserve resources.

1.2. Related literature

One of the first articles, which argued that coordination between TSOs is desired in the balancing market is [16], while Doorman and van der Veen [22] were among the first who compared the performance of various market design principles in the context of integrated balancing markets, using the concepts of the CMO and RDN. One of the earliest studies which aimed at assessing the benefits of coordinated reserve activation and RDN based on real data has been published by ACER, the agency for the Cooperation of Energy Regulators [19]. A similar report has been published by DG Energy [25] to predict the same benefits for a simulated scenario regarding the year of 2030 of the European power system. The benefits of coordinated activation of tertiary or replacement reserves in the case of Portugal are estimated in [26,27].

Regarding the studies which extend the analysis beyond the reduction of activation costs and also consider the benefits related to coordinated procurement, Gebrekiros et al. propose a flow-based model assuming sequential clearing of the balancing capacity and the day-ahead energy market [28] to assess the benefits of integrating the Northern European balancing markets by exchanging balancing capacity. In contrast, a simultaneous (i.e. joint) procurement of energy and reserves is assumed in the article [29], which also considers cross-zonal capacity constraints in the 2030 North-European scenario. A similar approach is used in [20] in the case of the Central Western European power system. Dominguez et al. [30] compare sequential and joint procurement models for energy and reserves and conclude

Table 1
Summary of the literure.

Reference	Coord. of reserve deployment	Coord. of reserve procurement	Coord. of reserve sizing	Model	mult top.
[29]	x	x		CSD(DCOPF)	
[28]		x		CSD[a]	
[20]	x	x	x	CSD (UC)	
[21]		x		stylized data-driven	
[9]	x	x		CSD (UC)	
[30]	x	x	x	CSD	
[12]	x	x	x	CSD	
[32]		x	x	CSD (ODIN)	
This paper	x	x		PB	x

Abbreviations: CSD: Centralized scheduling dispatch, UC: Unit Commitment, DCOPF: Direct current optimal power-flow, PB: Portfolio-bidding.

[a] Centralized dispatch model with portfolio-bidding market elements.

that coordinated procurement of reserves is beneficial in all considered models.

A few studies include the analysis of the benefits implied by the coordination of reserve sizing as well. The paper [9] is an example of such approaches, which focuses on the Central Western European power system. The stochastic model of Dominguez et al. [30] also considers coordinated reserve sizing and procurement, using a stochastic programming model approach. The paper of Viafoira et al. [31] proposes a novel two-stage stochastic bilevel reserve procurement approach, which dynamically updates the reserve zones in the process of the operation. Finally, Khodadadi [32] presents a dynamical FRR dimensioning method.

1.3. Contribution

As we can see in Table 1, unit commitment (UC) and similar models based on the assumption of centralized dispatching and scheduling are the most prevalent in the relevant literature [20,9,33,12]. These models are explicitly taking the physical production processes of generating units into account, although with different level of detail. As various generating units of different technologies like coal, gas turbines, hyrdo, nuclear, solar, wind etc. have significantly different production characteristics and constraints, it takes a huge effort to feed these models with realistic multi-area generation and transmission data and they usually result in model instances with high complexity – e.g. the model in [29] includes 300 000 variables and 400 000 constraints for a 24 h period. The diversity of UC and similar centralized dispatch models is reflected in the set of considered technical constraints and parameters (e.g. ramp-up and -down costs times, start-up costs, minimum up- and down-times etc of generating units, etc.), the assumed share of renewable generation, whether and how they consider the dedication of cross-zonal capacities for reserve procurement and the analyzed characteristic case study (typically central-western Europe or North-Europe).

However, these models do not consider the strategic market behavior of generators, like e.g. optimal bidding, capacity withholding and other economic motives, and typically consider the generating units as price takers (as explicitly stated in e.g. [30]). On the other hand, according to the general trends of European market integration, generating units are self scheduling and, alongside distributors and other demand side entities, they act as strategic actors on the market who represent themselves through their (mostly simplified) bids on the trading platforms and reserve the right of scheduling for themselves. By neglecting the economic motives of generating units the resulting dispatch may be significantly different compared to the realized dispatch.

In addition, UC and similar models are basically cost minimizing energy production models, thus the approaches summarized in Table 1 dominantly consider the operation of the balancing market strongly connected to the energy market, and analyze various (e.g. sequential or joint) market integration approaches between the energy and the reserve markets.

The main contributions of the current work may be summarized as follows.

- First, we propose a simple portfolio-bidding modeling approach, which allows to decouple the description of the phenomena related to coordinated reserve procurement and activation from the energy-production processes and the related scheduling models in the context of the implied economic benefits, and the flexibility of which allows its application on various network topologies of different sizes.
- Second, we use the proposed model to study, how the benefits of coordinated balancing capacity procurement and deployment scale up with the increase in the number of cooperating balancing zones.

We provide a model for the procurement and deployment procedures of cross-border balancing in the context of EUPHEMIA-like two-sided day ahead portfolio-bidding allocation schemes. For the aim of simplicity, only a single period is considered in the model. Allocation and activation costs of the reserve providing units, which are reflected in the bids are taken into account separately in the proposed allocation-activation procedures, i.e. activation costs are not considered in the allocation phase (and vice versa).

Regarding the second main aim, while several studies have been performed on fixed topology (thus fixed size) networks – see Table 1, there has been only a few articles which considered the question of optimal configuration of zones of cooperation in balancing [31].

2. Model

To demonstrate how the aforementioned concepts are modeled in the current study, we consider a simple example of two connected control zones, where supply and demand bids for up and down reserves are present.

Table 2 summarizes the up reserve supply bids. The first column of the Table holds the quantity of the bid (Q^{US}), which is negative in the case of supply. The second column corresponds to the allocation (or procurement) price (per unit) P^{US}, while the third column describes the zone of submission Z. The last (4th) column of Table 2 corresponds to the activation cost (CA^{US}) of the up reserve resource. This value defines the activation cost per unit, which arises if the previously allocated reserve is (later) activated. Reserve supply bids, which are at least partially accepted at the end of the procurement phase are considered as allocated reserves.

The up reserve demand bids are similarly summarized in Table 3 (for demand bids there is no activation cost).

Down reserve supply and demand bids are summarized in Tables 4 and 5 respectively.

The positive direction of the connecting line is towards zone 2, flows of this direction are considered as positive. The zonal bids and the simple two-zonal system is depicted in Fig. 1.

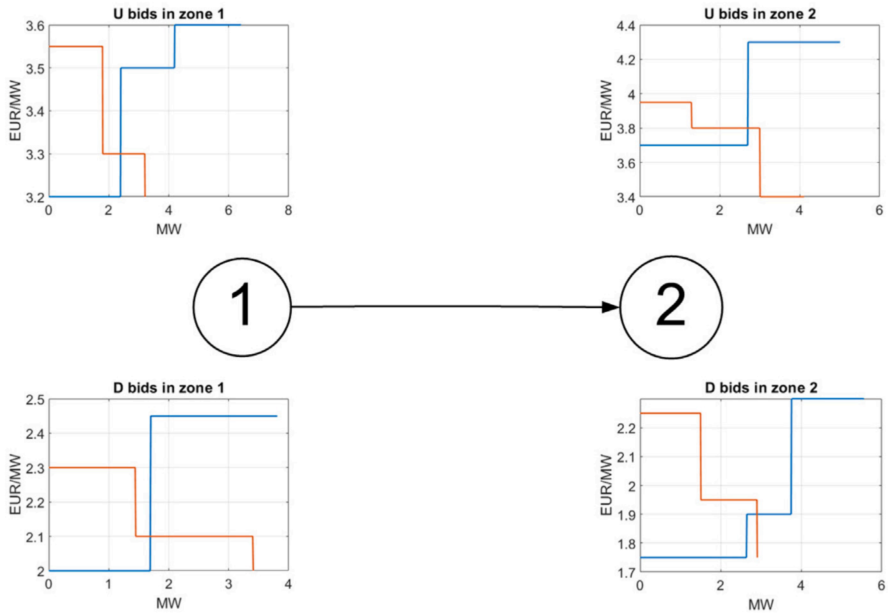

Fig. 1. Simple 2-zonal system with up and down reserve bids.

Table 2
Up reserve supply bids in the case of the simple demonstrative example.

Q^{US}	P^{US}	Z	CA^{US}
−2.4	3.2	1	6.5
−1.8	3.5	1	6.6
−2.2	3.6	1	6.9
−2.7	3.7	2	6.8
−2.3	4.3	2	6.7

Table 3
Up reserve demand bids in the case of the simple demonstrative example.

Q^{UD}	P^{UD}	Z
1.8	3.55	1
1.4	3.3	1
1.3	3.95	2
1.7	3.8	2
1.1	3.4	2

Table 4
Down reserve supply bids in the case of the simple demonstrative example.

Q^{DS}	P^{DS}	Z	CA^{DS}
−1.7	2	1	1.9
−2.1	2.45	1	1.65
−2.65	1.75	2	1.7
−1.1	1.9	2	1.35
−1.8	2.3	2	1.85

Table 5
Down reserve demand bids in the case of the simple demonstrative example.

Q^{DD}	P^{DD}	Z
1.45	2.3	1
1.95	2.1	1
1.5	2.25	2
1.4	1.95	2

2.1. Uncoordinated reserve procurement

If we assume uncoordinated reserve procurement process, the markets for up and down reserves are cleared separately for both zones, and the set of accepted/rejected bids and the market clearing prices are determined by the intersection points of the aggregated supply and demand curves as depicted in Fig. 1. The bids left of the intersection point will be fully accepted, and the price-setter bid (located in the intersection point) will be (most likely) partially accepted, while all other bids are rejected.

The formal model of the clearing problem in the case of uncoordinated procurement is described by Eqs. (1)–(7). The variables of the problem are the acceptance variables of the bids, denoted by x_i^{US}, x_i^{DS}, x_i^{DS}, x_i^{DD}, and the zonal market clearing prices for up and down reserve products, denoted by MCP_k^U and MCP_k^D respectively, where k is used for the indexing of zones. Z_k denotes the bid set corresponding to zone k.

$$\max \sum_i x_i^{US} Q_i^{US} P_i^{US} + \sum_i x_i^{UD} Q_i^{UD} P_i^{UD} + \sum_i x_i^{DS} Q_i^{SS} P_i^{SS} + \sum_i x_i^{DD} Q_i^{DD} P_i^{D} \tag{1}$$

s.t.

$$\sum_{i \in Z_k} x_i^{US} Q_i^{US} + \sum_{i \in Z_k} x_i^{DS} Q_i^{SS} = 0 \quad \forall Z_k \tag{2}$$

$$\sum_{i \in Z_k} x_i^{DS} Q_i^{DS} + \sum_{i \in Z_k} x_i^{DS} Q_i^{DS} = 0 \quad \forall Z_k \tag{3}$$

$$x_i^{US} > 0 \rightarrow MCP_k^U >= P_i^{US}, \quad x_i^{US} < 1 \rightarrow MCP_k^{US} <= P_i^{US} \quad \forall i \in Z_k \tag{4}$$

$$x_i^{UD} > 0 \rightarrow MCP_k^U <= P_i^{UD}, \quad x_i^{UD} < 1 \rightarrow MCP_k^U >= P_i^{UD} \quad \forall i \in Z_k \tag{5}$$

$$x_i^{DS} > 0 \rightarrow MCP_k^D >= P_i^{DS}, \quad x_i^{DS} < 1 \rightarrow MCP_k^{DS} <= P_i^{DS} \quad \forall i \in Z_k \tag{6}$$

$$x_i^{DD} > 0 \rightarrow MCP_k^D <= P_i^{DD}, \quad x_i^{DD} < 1 \rightarrow MCP_k^D >= P_i^{DD} \quad \forall i \in Z_k \tag{7}$$

In the case of the proposed simple example, the market clearing prices (MCPs given in EUR/MW[1]) are determined by the price setter bids as $MCP_1^U = 3.3$, $MCP_2^U = 3.8$, $MCP_1^D = 2.1$, $MCP_2^D = 1.9$. The surplus of fully accepted bids may be calculated as the absolute

[1] In the standard context of day-ahead markets, the prices are given in EUR/MWh, as the original time period was one hour — today in several applications, 15 min long periods are considered, so we assume that the prices always are given in the context of the period-length.

difference between the bid price and the respective MCP, multiplied by the bid quantity (partially accepted bids have no surplus, since the MCP is equal to the bid price — rejected bids do not have surplus either). The resulting total social welfare (TSW) of a zonal up or down reserve market is the sum of the bid surpluses, i.e. the they are equal to the are between the aggregated demand and supply curves left of the intersection point. In this particular case, $TSW^U = TSW_1^U + TSW_2^U = 0.69 + 0.465 = 1.155$ EUR, where TSW_i^U denotes the TSW value resulting from the up reserve market in node i. Similarly, $TSW^D = TSW_1^D + TSW_2^D = 0.46 + 0.9925 = 1.4525$ EUR.

The resulting acceptance indicators of various bids in the case of uncoordinated procurement (as depicted in Fig. 1) are described numerically in Eq. (8).

$$y^{UD} = \begin{pmatrix} 1 \\ 0.4286 \\ 1 \\ 0.8235 \\ 0 \end{pmatrix} \quad y^{US} = \begin{pmatrix} 1 \\ 0 \\ 0 \\ 1 \\ 0 \end{pmatrix} \quad y^{DD} = \begin{pmatrix} 1 \\ 0.1282 \\ 1 \\ 1 \end{pmatrix} \quad y^{DS} = \begin{pmatrix} 1 \\ 0 \\ 1 \\ 0.2273 \\ 0 \end{pmatrix} \tag{8}$$

The amount of procured up reserves in areas 1 and 2 are 2.4 and 2.7 units respectively, while the amount of procured down reserves in areas 1 and 2 are 1.7 and 2.9 units (the accepted supply quantity equals the accepted demand quantity for each zone).

2.1.1. Uncoordinated activation

On the day subsequent to the procurement process, depending on the actual network state (over/under-production/consumption) up or down reserve requirements may arise in the different zones. We describe a reserve demand pattern (RDP) with a vector of length $n^{UD} + n^{DD}$, where n^{UD} and n^{DD} denote the number of up demand and down demand bids respectively. $RDP(i) \in [0, 1]$ describes, how much the respective demand bid is activated. The arising up and down demand needs in the various zones may be derived by considering the sum of the appropriate elements of the RDP vector, weighted by the corresponding Q^{UD} and Q^{DD} values. Only accepted demand bids may be activated up to the level of their acceptance.

If we consider e.g. $RDP_1 = [0\ 0\ \ 1/1.3\ 0\ 0 \quad 1\ 0\ \ 0\ 0]$, we can see that the third up reserve demand bid and the first down reserve demand bid are activated. According to Tables 3 and 5, these are corresponding to zones 2 and 1 respectively, implying a total up reserve demand of 1 unit (MWs) in zone 2, and a total down reserve demand of 1.45 units in zone 1. One may check that this is a feasible RDP, since none of the elements exceeds the acceptance values of y^{UD} and y^{DD} described in Eq. (8).

In response to the up reserve need, the allocated up reserve supplies in zone 2 are activated, starting from the cheapest activation cost (in this particular case however, there is only one accepted up reserve supply bid – i.e. only one reserve providing resource with activation cost of 6.8). Similarly, in response to the down reserve need, the allocated down reserve resources in zone 1 are activated.

To describe which allocated resources are activated to match the arising reserve demand, we use the reserve activation pattern (RAP) vector of length $n^{US}+n^{DS}$, where n^{US} and n^{DS} denote the number of up demand and down supply bids respectively. $RAP(i) \in [0, 1]$ describes, how much the respective supply bid is activated. Only accepted supply bids may be activated up to the level of acceptance.

Assuming uncoordinated procurement, in the case of uncoordinated activation, the total activated reserve supply quantities resulting from the RAP must match the total activated reserve demand quantities derived from the RDP for each individual zone. In this case each TSO aims to cover the reserve demands in its own zone at minimal cost with the resources available inside the zone. In the case of our example, $RAP_1^{UC-UC} = [0\ 0\ 0\ \ 0.3704\ 0 \quad 0.8529\ 0\ \ 0\ 0\ 0]$ (the upper index refers to the uncoordinated procurement and to the uncoordinated activation), implying a total cost of 9.555 units (EUR), denoted by C_1^{UC-UC} As the activated reserves are in the same zones as the demand, this approach implies no network load on the connecting line.

2.1.2. Coordinated activation: Common merit order (CMO)

When the activation of reserves in the case of the demand described by RDP_1 is carried out according to the common merit order principle, the resulting activation pattern is described by $RAP_1^{UC-CMO} = [0.4167\ 0\ 0\ \ 0\ 0 \quad 0\ 0\ \ 0.4528\ 0.2273\ 0]$, i.e. the up reserve allocated in node 1, which has the lowest activation cost (6.5) is activated at the rate of 0.4167 (providing 1 unit of up reserve), while 2 allocated down reserve resources in zone 2 are activated to fulfill the down reserve need in zone 1 ($0.4528 \cdot 2.6500 + 0.2273 \cdot 1.1 = 1.45$).

In this case, while the cost of reserve activation is decreased to $C_1^{UC-CMO} = 8.8775$ units, a flow of 2.45 units is present on the connecting line, which shows that available transmission capacity is a prerequisite in the case of coordinated cross-zonal deployment of reserves. Let us note that if the available transmission capacity is limited, the activation pattern may be adjusted to match the bottleneck — the activation process in this case may be described by a linear programming problem, in which the aim is to minimize the activation cost, with respect to the transmission constraints on the implied flows.

2.1.3. Coordinated activation: Reserve demand netting (RDN)

The netting of reserve demands mean that the arising up reserve demand of 1 unit in zone 2 is considered as an activated down reserve supply, thus only a remaining 0.45 units of down reserve demand has to be covered by activation of reserve providing resources (according to the common merit order). The activation pattern is described by $RAP_1^{UC-RDN} = [0\ 0\ 0\ \ 0\ 0 \quad 0\ 0\ \ 0.0755\ 0.2273\ 0]$, implying $C_1^{UC-RDN} = 0.6775$, and a line flow of 0.45 units.

2.2. Coordinated reserve procurement

The formal model of the clearing problem in the case of coordinated procurement is described by Eqs. (9)–(15). The variables of the problem are the acceptance variables of the bids, denoted by x_i^{US}, x_i^{DS}, x_i^{DS}, x_i^{DD}, and the market clearing prices for up and down reserve products, denoted by MCP^U and MCP^D respectively.

$$\max \sum_i x_i^{US} Q_i^{US} P_i^{US} + \sum_i x_i^{UD} Q_i^{UD} P_i^{UD} + \sum_i x_i^{DS} Q_i^{SS} P_i^{SS} + \sum_i x_i^{DD} Q_i^{DD} P_i^{D} \tag{9}$$

s.t.

$$\sum_i x_i^{US} Q_i^{US} + \sum_i x_i^{DS} Q_i^{SS} = 0 \tag{10}$$

$$\sum_i x_i^{DS} Q_i^{DS} + \sum_i x_i^{DS} Q_i^{DS} = 0 \tag{11}$$

$$x_i^{US} > 0 \rightarrow MCP^U >= P_i^{US}, \quad x_i^{US} < 1 \rightarrow MCP^{US} <= P_i^{US} \quad \forall i \tag{12}$$

$$x_i^{UD} > 0 \rightarrow MCP^U <= P_i^{UD}, \quad x_i^{UD} < 1 \rightarrow MCP^U >= P_i^{UD} \quad \forall \tag{13}$$

$$x_i^{DS} > 0 \rightarrow MCP^D >= P_i^{DS}, \quad x_i^{DS} < 1 \rightarrow MCP^{DS} <= P_i^{DS} \quad \forall i \tag{14}$$

$$x_i^{DD} > 0 \rightarrow MCP^D <= P_i^{DD}, \quad x_i^{DD} < 1 \rightarrow MCP^D >= P_i^{DD} \quad \forall i \tag{15}$$

In the case of coordinated reserve procurement, the outcome of the allocation process may be visualized by considering the aggregated demand and supply curves implied by the merged bid set (of the bid sets of zone 1 and 2). The merged bid sets for up and down reserve are depicted in Fig. 2.

In the case of up reserve, the price-setter bid is corresponding to zone 1, here the MCP will be equal to its bid price (3.55). in zone 2, the MCP may take any value from 3.4 to 3.7. In the case of down reserve, the price setter bid also corresponds to zone 1, determining the MCP (=2). Regarding zone 2, the MCP may range from 1.95 to 2.25. The above MCP values will imply the bid acceptance indicators summarized in Eq. (16).

$$y^{UD} = \begin{pmatrix} 0.6667 \\ 0 \\ 1 \\ 1 \\ 0 \end{pmatrix} \quad y^{US} = \begin{pmatrix} 1 \\ 1 \\ 0 \\ 0 \\ 0 \end{pmatrix} \quad y^{DD} = \begin{pmatrix} 1 \\ 1 \\ 1 \\ 0 \end{pmatrix} \quad y^{DS} = \begin{pmatrix} 0.6765 \\ 0 \\ 1 \\ 1 \\ 0 \end{pmatrix} \tag{16}$$

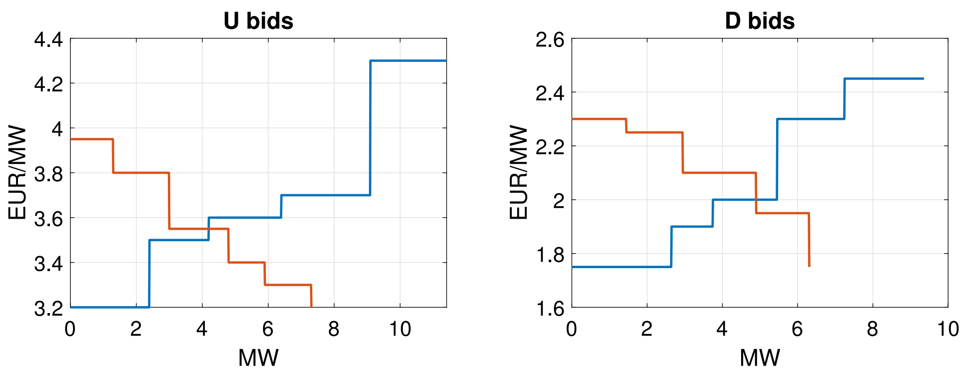

Fig. 2. Coordinated procurement of U and D bids in the 2-zonal example.

The amount of reserves procured is as follows in this case. The total amount of up reserve supply allocated in zone 1 is 4.2 units, and 0 in zone 2. The total amount of up reserve demand allocated in zone 1 is 1.2 units, and 3 units are allocated in zone 2. The total amount of down reserve supply allocated in zone 1 is 1.15 units, and 3.75 in zone 2. The total amount of down reserve demand allocated in zone 1 is 3.4 units, and 1.5 units are allocated in zone 2.

The TSW resulting from the up reserve market is equal to $TSW^U =$ 1.875, while the TSW of the down reserve market equals to $TSW^D =$ 1.7775. If we compare these values with the ones described in Section 2.1, we can see that both have been increased (not surprisingly, since the zonal balance constraints have been relaxed, and only total balance is required).

2.3. Own first activation

In the case of coordinated procurement, uncoordinated activation in general is not an option, since it is possible that the amount of reserve supply allocated in a given zone cannot cover the arising demand.

Let us still consider the reserve demand pattern RDP_1, which is a feasible activation pattern also according to the acceptance indicators described in Eq. (16). It is easy to see that since there is no up reserve providing resource allocated in zone 2, which could cover the arising demand.

However, one may assume that zonal demands are covered up to the possible level by zonal supplies (e.g. to minimize network loads and coordination when possible) – we will call this approach 'own first activation'. It is still assumed that zonal supplies are activated according to the respective zonal merit order.

In this very case, the own first activation approach is described by $RAP^{C-OF} = [0.4167\ 0\ 0 \quad 0\ 0 \quad 0.6765\ 0 \quad 0\ 0.2727\ 0]$, impling a cost of $C_1^{C-OF} = 9.09$ units, and a line flow of 1.3 units.

2.4. Common merit order

The common merit order activation method results in $RAP^{C-CMO} =$ $[0.4167\ 0\ 0 \quad 0\ 0 \quad 0\ 0 \quad 0.1321\ 1\ 0]$, $C_1^{C-CMO} = 8.58$ and a line flow of 2.45 units.

2.5. Reserve demand netting

In the case of reserve demand netting, $RAP^{C-RDN} =$ $[0\ 0\ 0 \quad 0\ 0 \quad 0\ 0 \quad 0\ 0.4091\ 0]$, $C_1^{C-RDN} = 0.6075$ and the line flow is equal to 0.45 units.

2.6. Computational formulation

The uncoordinated and coordinated procurement of reserves may be formalized directly in a day-ahead market framework [34], implying linear programming (LP) problems. The determination of reserve activation pattern (RAP) vectors may be also performed via solving various LP problems, thus the model may be considered computationally simple.

3. Simulations

To analyze the benefits implied by coordinated reserve activation and procurement, a simulation study has been conducted.

First, random planar networks of various size have been generated (n_z = 4, 6, 8 and 10, where n_z denotes the number of zones). In addition to the topology, the line admittance parameters, which determine the flows in the case of inter-zonal transfers, have also been randomized to obtain networks with different PTDF matrices [35] (a DC-load flow model has been used to obtain the PTDF from the topology and admittance values). 10 random networks of each size have been generated.

Second, for each generated network, 20 different reserve bid sets have been generated, for which the uncoordinated and coordinated procurement process has been performed. One the one hand, it may seem logical that the allocation of resources with more expensive production (i.e. activation) cost is higher, however it is also plausible to assume that generating units would rather like to use cheap resources for explicitly scheduled generation, i.e. by bidding their production in the day-ahead energy market, and keep the more expensive production sources in standby (thus bidding their capacity in the reserve market). Accordingly, the first 10 bid sets have been generated under the assumption that the allocation and activation prices of bids are positively correlated, while these values have been assumed to be independent in second 10 bid sets.

Third, for each resulting reserve allocation, 100 different random reserve demand pattern (RDP) vectors have been determined, for which the outcome of various reserve activation protocols have been determined. Reserve demand patterns have been determined as follows. For each zone, up or down reserve demand was chosen (with equal probabilities), and all accepted reserve demand bids of the chosen type have been sampled according to uniform distribution to determine the resulting reserve demand in the corresponding zone.

Additional details and parameters of the simulations may be found in Appendix A.

4. Results

In this section, the simulation results in the case of independent allocation and activation costs are summarized and discussed. In the case of correlated allocation and activation costs, the results, which are very similar, may be found in Appendix B.

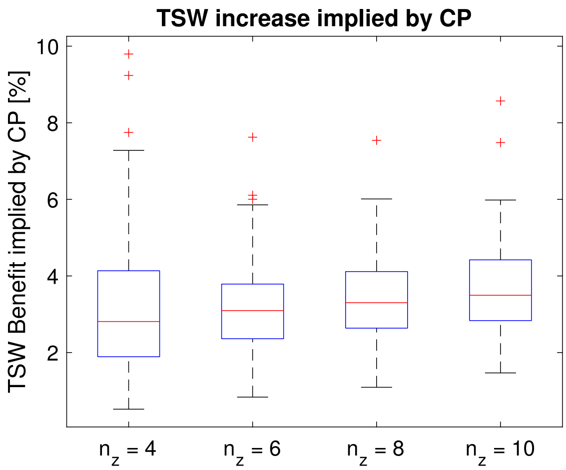

Fig. 3. TSW increase implied by coordinated procurement.

Table 6
Mean and median values of the relative TSW-increase implied by coordinated reserve procurement in the case of various network sizes [%] (n_z denotes the number of zones considered).

$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
3.25 2.81	3.17 3.1	3.41 3.3	3.66 3.5

Table 7
Mean and median values of the relative reserve activation cost decrease implied by the common merit order (CMO) in the case of various network sizes in the case of uncoordinated and coordinated reserve procurement [%], compared to uncoordinated/own-first activation.

	$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
Uncoord. proc.	17.2 17.4	19.4 19.6	20.6 20.6	21.2 21.4
Coord. proc.	19 19.3	21.5 21.7	22.9 23.1	23.3 23.4

4.1. Increase of the TSW in the case of coordinated procurement

In the case of coordinated procurement, the TSW resulting from the market clearing is increased. The values of the relative TSW-increase implied by coordinated reserve procurement in the case of various network sizes are depicted in Fig. 3, while their mean and median values are summarized in Table 6.

In the box plots, the central mark represents the median, while the edges of the box correspond to the 25th and 75th percentiles respectively. The whiskers extend to the most extreme data points which are considered not to be outliers, and the outliers are plotted individually with red crosses.

4.2. Reduction of activation cost in the case of CMO

The values of the relative reduction of the reserve activation cost, compared to uncoordinated activation implied by CMO in the case of various network sizes are depicted in Fig. 4, while their mean and median values are summarized in Table 7.

4.3. Reduction of activation cost in the case of RDN and CMO

The values of the relative reduction of the reserve activation cost, compared to uncoordinated activation implied by the simultaneous application of RDN and CMO in the case of various network sizes are depicted in Fig. 5, while their mean and median values are summarized in Table 8.

Table 8
Mean and median values of the relative reserve activation cost decrease implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of uncoordinated and coordinated reserve procurement [%], compared to uncoordinated/own-first activation.

	$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
Uncoord. proc.	65.7 70.7	73.4 79.2	77.6 82.5	80.6 85.2
Coord. proc.	66.8 73.3	74.2 80.3	78.8 83.6	81.2 85.5

Table 9
Mean and median values of the relative decrease of average flow values implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of uncoordinated and coordinated reserve procurement [%], compared to the sole application of CMO.

	$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
Uncoord. proc.	57.3 57.9	57.8 58.2	59.1 59.3	60.3 60.3
Coord. proc.	56.7 56.7	57.6 57.9	59 59.9	60.4 61.5

4.4. Reduction of implied flows due to RDN

4.4.1. Average flows

As we have seen in Section 2, in the case of uncoordinated procurement, uncoordinated activation does not implies network flows. In all other cases however, due to zonal reserve imports, exports and exchanges, network flows are typically arising. The approach of reserve demand netting (RDN), applied together with the common merit order (CMO) is though able to significantly reduce the network load compared to the sole application of CMO.

To compare the average implied flow values, for each simulated activation scenario, we calculated the network flows for each line of the actual network and averaged them. Following this, we averaged the resulting values for each RDP to obtain a single value for each bid set on each network.

The values of the relative reduction of the average flows implied by the simultaneous application of RDN and CMO in the case of various network sizes are depicted in Fig. 6, while their mean and median values are summarized in Table 9.

4.4.2. Extreme flows

If one considers the problem of capacity allocation for inter-zonal reserve trading and coordinated activation, the average implied network flows are not necessarily the most informative. As the transmission limitations of network lines are usually considered as strict constraints, which must be respected under any circumstances, the capacity allocation must be prepared for extreme flow values as well. To give a comparison of the implied extreme flows, for each simulated activation scenario, we calculated the network flows for each line of the actual network and considered their maximum. Following this, we calculated the 5% expected shortfall of the resulting values over the RDPs to obtain a single value for each bid set on each network. Expected shortfall (ES) [36,37], is a coherent measure of risk [38], the α-expected shortfall is calculated as the expected value of the worst α % of the scenarios considered.

The values of the relative reduction of the extreme flows implied by the simultaneous application of RDN and CMO in the case of various network sizes are depicted in Fig. 7, while their mean and median values are summarized in Table 10.

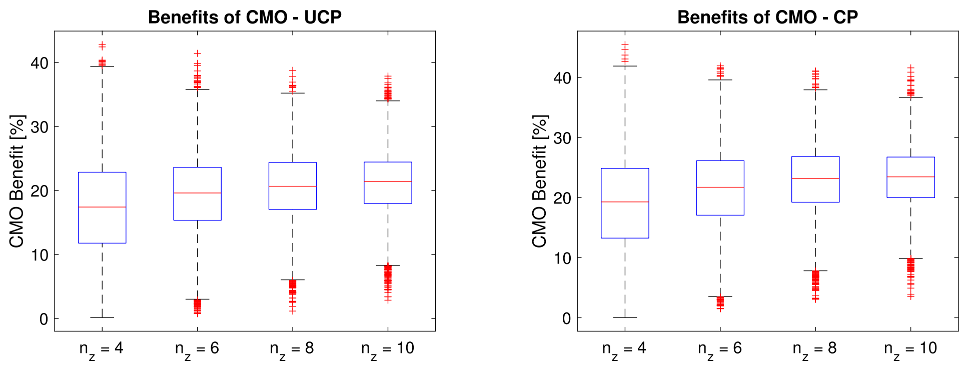

Fig. 4. Relative reserve activation cost decrease implied by the common merit order (CMO) in the case of various network sizes in the case of coordinated and uncoordinated reserve procurement [%], compared to uncoordinated/own-first activation.

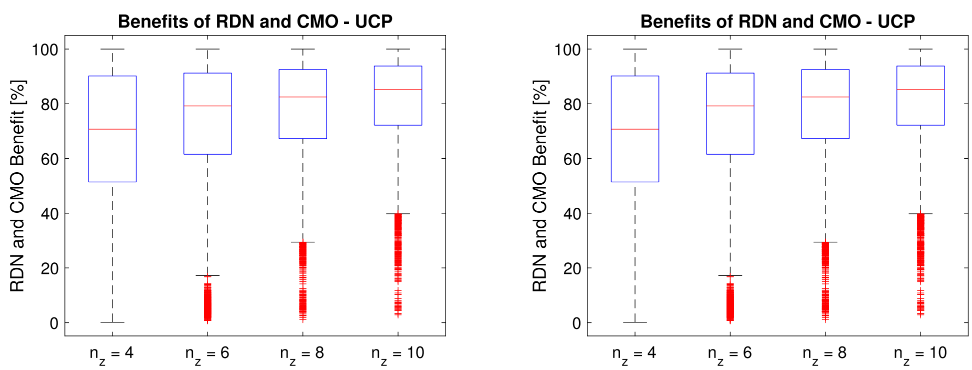

Fig. 5. Relative reserve activation cost decrease implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of coordinated and uncoordinated reserve procurement [%], compared to uncoordinated/own-first activation.

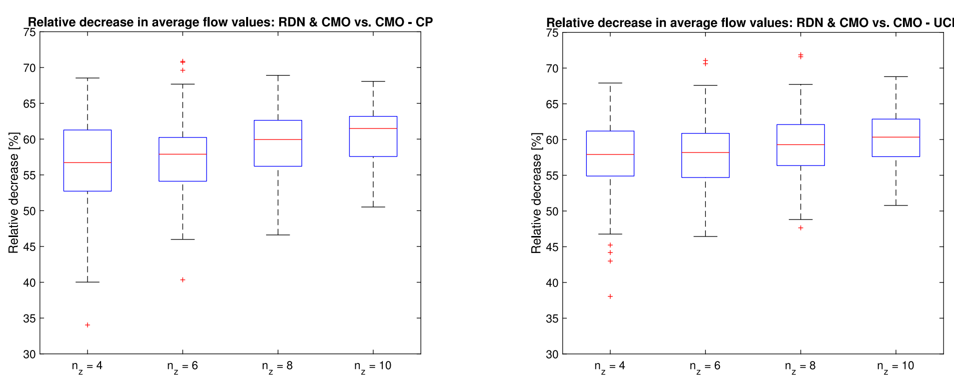

Fig. 6. Relative decrease of average network flows implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of coordinated and uncoordinated reserve procurement [%], compared to the sole application of CMO.

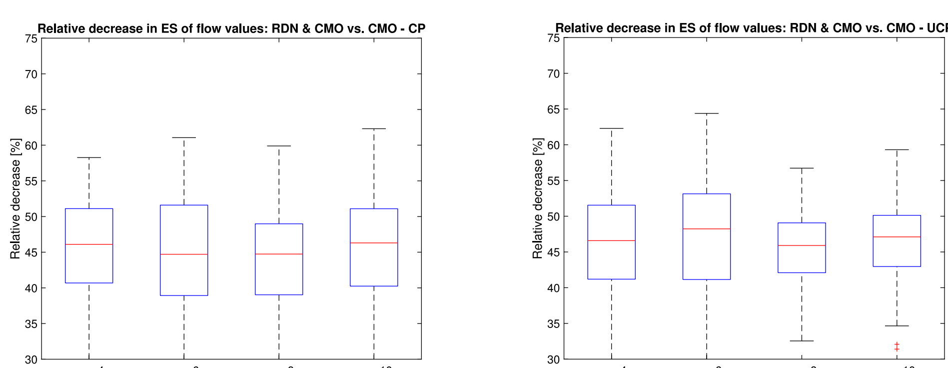

Fig. 7. Relative decrease of extreme network flows implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of coordinated and uncoordinated reserve procurement [%], compared to the sole application of CMO.

Table 10
Mean and median values of the relative decrease of extreme flow values implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of uncoordinated and coordinated reserve procurement [%], compared to the sole application of CMO.

	$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
Uncoord. proc.	46.1 46.6	47.4 48.2	45.3 45.9	46.7 47.1
Coord. proc.	45.2 46.1	44.9 44.7	43.7 44.7	45.4 46.3

5. Discussion

5.1. Direct implications of the simulation results

Observing the presented simulation results one may recognize that coordinated reserve procurement has a beneficial effect in two contexts. On the one hand, as it can be seen in Tables 6 and 12, as a direct effect it increases the resulting TSW value of the procurement clearing by 3%–4% in average, and on the other hand, if one examines Tables 7, 8, 13 and 14, it can be seen that the savings in the case of coordinated reserve activation (either COM or RDN+CMO) are also higher (by 1%–2%) in the case of coordinated procurement, which enhances the inter-zonal allocation and trading of reserves.

The benefits of coordinated procurement however are dwarfed by the benefits implied by coordinated activation of reserves. Even the sole application of the CMO brings significant relative benefits of reserve activation costs ranging from 17 to 25%, depending on the number of zones involved in the coordination. Nevertheless, the results also show that applying CMO without RDN is not a rational decision. The activation cost benefits in the case of the co-application of RDN and CMO are far more superior (from 66 to 82% in contrast to 17 to 25%), while Tables 9, 10, 15 and 16 show that the implied average and extreme network flows are also significantly lower in this case. These resulting benefit levels match the estimated benefits implied by coordinated activation described in [20].

Flows in the case of coordinated procurement and own-first activation are not presented in detail, but in general, it can be said that the average flows implied by own-first activation are about 10% of the average flows in the case of RDN+CMO, while the worst case flows in the case of own-first activation are about 30%.

In the aforementioned tables and Figs. 5 and 4 one may see that the benefits implied by coordinated activation tend to saturate as the number of cooperating zones is increased.

In addition, Appendix B shows that the results are quite robust in the context of the assumptions regarding the bid sets present. The relative benefits in the case of correlated allocation and activation costs do not differ significantly from the results described in Section 4.

5.2. Limitations of the study

We have to note that the simulation assumed a similar distribution of reserve providing resources in each zone. More precisely, the same number of bids with random quantities have been assumed for each zone, resulting in varying total quantity of reserve supply. Of course, if the simulations are adjusted to real data, and more significant differences regarding the distribution of reserve resources may be taken into account, the relevance of the results may be enhanced. This is also equally true for the demand side, where also the same number of bids with random parameters have been assumed for each zone.

Furthermore, as discussed earlier, in the current study only single-period allocation and activation scenarios have been simulated. It is natural to assume that some of the generating units participating in the reserve procurement and activation process have technical constraints like minimal up- and down-times and ramping constraints and critical economic parameters related to the generation pattern, like start-up, shut-down and/or ramping costs. In a realistic multi-period setup, where the capacity market framework also allows (multi-period) non-convex orders like block-orders or minimum-income orders, it is straightforward to assume that such units will take advantage of these opportunities to incorporate their non-convex costs in their bids, thus these parameters would affect the bidding their behavior. As pointed out in e.g. [34], if such bids are present in the market, paradox rejection (or acceptance) must be allowed in order to guarantee the existence of a clearing solution. As the phenomena of paradox rejection potentially makes such markets somewhat less efficient, it may be stated that by neglecting these aspects, the proposed model probably over-estimates the benefits related to coordinated allocation at some level. The level of this error could be guessed only, if the ratio of non-convex orders (or generating units potentially submitting such orders) would be known. However, using real data of European markets, it has been shown in [39] that the tradeoffs between opportunity costs minimization and the generated welfare are typically very small.

5.3. Further impacts

In addition to the direct economic benefits of coordinated reserve procurement and activation modeled in this study, coordination and market integration on these levels has other potential effects as well regarding the operation of the electricity sector. The first and foremost effect of balancing market integration is that controllable generating units will have access to an increasing number of buyers of balancing capacity and balancing energy, thus the relative value of the generation of such units is likely to be increased. However, if the increased resilience of the network due to more efficient reserve management [29] allows the market entry of further renewable sources which supply at near-zero marginal costs, this relative value increase of balancing-capable units possibly does not necessarily coincides with a general or even local increase in the energy market clearing prices.

On the other hand, the mechanism of reserve demand netting, which has proven to be impressively fruitful in the present study as well, has the advantage that it does not even involves the suppliers of balancing products. Reserve demands of opposite signs may be simply canceled out, if the available transmission capacity is available for the respective flow, without the practical participation of generating units.

Nevertheless, the curtailment of cross-zonal capacities for coordinated balancing capacity procurement and activation (including reserve demand netting) is probably the most critical element of the connected network management assignments, considering flows of both pre-dispatched energy and balancing energy transfers. This critical aspect has been emphasized in the recent article of [12] as well, where the author gives a thorough classification of cross-zonal capacity allocation approaches applied in integrated balancing market models.

Probably one of the most important tasks, which will require serious effort and coordination of transmission system operators is to determine, how the limited network resources may be allocated in the most efficient and desirable way considering various energy and balancing products in the same time. Although recent approaches have been proposed for the network-constrained simultaneous allocation of energy and reserves [40], this problem still represents the most important and critical open question related to the integration of balancing markets.

Furthermore, one more important policy related implication of balancing market integration has to be mentioned, to which, until recently, not much attention has been paid. Practically all of the related literature sources discussed in Section 1.2 are aiming to estimate the extent/volume of the economic benefits implied by coordinated balancing capacity procurement and deployment (this article is no exception either). However, while it is becoming increasingly clear that balancing market coordination brings significant economic benefits regarding the *total cooperation area*, the related changes in balancing service requirements in certain regions and prices may imply surplus gain or loss in the portfolio of single market participants, depending on the applied technology, spatial position, connectivity parameters and other possible factors. In other words, the market integration process also initiates a process of welfare transfer. As discussed by Wu et al. [41], "*The willingness to accept BMI (balancing market integration) depends not only on whether there is room for social welfare improvement but also on whether the distribution of any social welfare increment is reasonable and whether the market mechanism can achieve fair allocation according to the contributions created by each market member*". In other words, different participants, in the light of their expected surplus, may be not equally motivated to undertake the coordination and standardization efforts necessary for balancing market integration. This observation points out that carefully designed profit-sharing and redistribution policies and mechanisms may have high importance in supporting the acceptance of balancing market integration initiatives.

6. Conclusions and future work

6.1. Conclusions

Based on the presented results, the first conclusion, which can be made is that the results suggest that the benefits implied by coordinated activation are superior compared to the benefits implied by coordinated procurement (66%–81% vs. 2%–4%), thus this level of coordinated reserve market operation should be a priority in further research and development. Coordinated activation should include the use of the concept of RDN, since the application of this principle together with the CMO translates to very significant benefits. While the application of CMO without RDN results in a 17%–23% reduction of the deployment costs, this value is 66%–82%, if RDN is also applied.

Furthermore, as discussed in Section 5, the simulation results show that the benefits implied by coordinated procurement and activation tend to saturate with the increasing number of the involved zones. Considering the CMO + RDN case, which implies the highest benefits, simulations show that reserve activation costs are reduced by 71% in the case of 4 zones, compared to the reference case with no coordination, while further increase of the number of cooperating zones from 4 to 6, form 6 to 8 and from 8 to 10, implies only additional incremental improvements of 8, 3 and 2%. Based on this observation, which naturally needs further verification, preferably based on realistic data regarding bid and network parameters, we may conclude the following.

While the realization of a full EU-level cooperation in cross-border reserve trading is clearly challenging (still desirable), it may be worth to consider to support the facilitation of multiple regional cooperation structures involving less zones, since the benefits could be still significant. Establishing such regional cooperation frameworks is presumably less challenging, since less participants are involved in the harmonization process of reserve products and clearing and activation protocols. Naturally, even in the case of such regional cooperation structures, the usage of standards is essential to allow further integration of these coupled systems in the future.

6.2. Future work

Regarding the assumptions about the relation of allocation and activation cost, it is straightforward to assume that the sum of the allocation and activation cost must (at least) cover the production (and standby) cost of the generating unit, but the distribution between the allocation and activation bid price may differ among bidders. Although, as discussed above, the first results show that bid-related assumptions do not significantly affect the results, it may be interesting to use a more complex model for bid generation in the model. In the case of (positive) reserve supply, the bid price is determined as the result of technological factors, as e.g. fuel cost, and strategic considerations of financial nature as well. To construct an area-specific case study, not only the installed capacities of various technologies in different zones and their respective cost parameters must be considered (as e.g. in [12]), but similar to [28], also assumptions have to be made about the bid determination process on the level of each participating unit. As the bidding data of markets is confidential, even in the retrospective context, these assumptions have to be speculative at some level. Agent based models, which simulate the rule-based decision making process and interaction of participants (agents), may be used for this purpose. These models are usually assuming that the potentially heterogeneous agents have imperfect or local information, based on which they determine their bids. In the case of such an application, the proposed simple single-period portfolio-bidding model must be extended for a multi-period version. This approach may be subject of further studies.

Furthermore, according to the current practice, a generating unit must decide on which market (energy or reserve) it wishes to bid its production capacity, which phenomena clearly leads to potential inefficiencies. Joint energy and reserve markets [42] aim to handle this problem by coordinating the procurement of energy and reserves. More recent results aim to minimize lost opportunity cost in the context of joint markets [43]. However, if inter-zonal trading of balancing capacity is also allowed, such approaches analyses must be complemented by transmission capacity allocation, taking into account that while procured energy deliveries are deterministic, the activation of reserves is of stochastic nature — this challenge has been already discussed in [22].

In addition, as discussed in [41], increasing emphasis must be given to profit-sharing mechanisms to equally incentivize potential participants for the coordinated sizing, procurement and deployment of reserves in order to foster the smooth integration of renewable sources into the power mix.

CRediT authorship contribution statement

Dávid Csercsik: Conceptualization, Methodology, Software, Writing – original draft, Visualization, Writing – review & editing, Funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

No data was used for the research described in the article.

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Appendix A

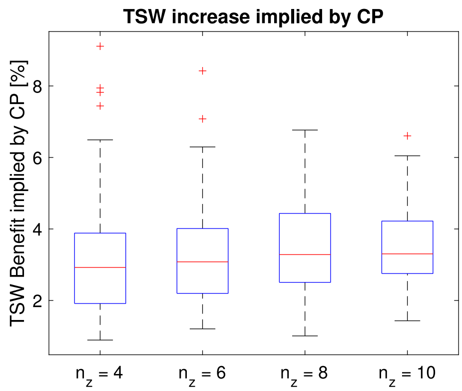

Fig. 8. TSW increase implied by coordinated procurement.

Table 11
Ranges of random bid parameters.

Parameter	Range
Q^{US}	[1 5]
P^{US}	[2 8]
CA^{US}	[2.5 3.5]
Q^{UD}	[1 5]
P^{UD}	[2 12]
Q^{DS}	[1 5]
P^{DS}	[1 7]
CA^{DS}	[2.5 3.5]
Q^{DD}	[1 5]
P^{DD}	[1 11]

Table 12
Mean and median values of the relative TSW-increase implied by coordinated reserve procurement in the case of various network sizes [%].

$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
3.12	3.22	3.46	3.52
2.92	3.08	3.28	3.3

A.1. Generation of random networks

Random networks with given number of nodes (zones) have been generated as follows.

First, the topology of the network has been generated, i.e. an undirected planar graph with node number n_z. Random planar graphs may be constructed by either starting from a line on n_z nodes and properly adding edges, or by using the Delaunay triangulation algorithm [44]. Following the determination of the network topology, the admittance values of the edges have been set, considering a random value in [0.5, 1.5] according to uniform distribution (in the following, if we refer to a random value from a given interval, we suppose uniform distribution). In the next step, the PTDF matrix of the network [35] has been determined,using a DC load-flow model.

A.2. Generation of random bid sets

For each zone, 40 bids have been generated, 10 of each type (e.g. 10 up reserve supply). Tabular 11 holds the parameter ranges, from which the bid parameters have been determined.

Appendix B

Results in the case of correlated allocation and activation cost (see Fig. 8).

Table 13
Mean and median values of the relative reserve activation cost decrease implied by the common merit order (CMO) in the case of various network sizes in the case of uncoordinated and coordinated reserve procurement [%].

	$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
Uncoord. proc.	20.2	21.9	23.4	24.4
	20.1	22	23.5	24.4
Coord. proc.	21.5	22.6	23.7	24.6
	21.6	22.9	23.8	24.7

Table 14
Mean and median values of the relative reserve activation cost decrease implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of uncoordinated and coordinated reserve procurement [%].

	$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
Uncoord. proc.	67.3	74.1	78.7	81.9
	72.8	79.7	83.7	86.4
Coord. proc.	67.8	74.8	78.9	81.8
	73.4	80.8	83.9	86.2

Table 15
Mean and median values of the relative decrease of average flow values implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of uncoordinated and coordinated reserve procurement [%].

	$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
Uncoord. proc.	56.1	58.1	57.9	59.6
	57.2	58.5	58.1	60.1
Coord. proc.	55.7	58.4	58.1	60.5
	56.1	58.6	59.3	61.2

Table 16
Mean and median values of the relative decrease of extreme flow values implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of uncoordinated and coordinated reserve procurement [%].

	$n_z = 4$	$n_z = 6$	$n_z = 8$	$n_z = 10$
Uncoord. proc.	44.6	44.1	44.2	46.4
	45.9	44.3	45.3	47
Coord. proc.	43.4	43.5	43.8	45.9
	43.8	44.6	44.4	46.2

B.1. Increase of the TSW in the case of coordinated procurement

B.2. Reduction of activation cost in the case of CMO

Table 13 and Fig. 9 hold the corresponding data.

B.3. Reduction of activation cost in the case of RDN and CMO

Table 14 and Fig. 10 hold the corresponding data.

B.4. Reduction of implied flows due to RDN

B.4.1. Average flows

Table 15 and Fig. 11 summarize the results corresponding to average flows.

B.4.2. Extreme flows

Table 16 and Fig. 12 summarize the results corresponding to extreme flows.

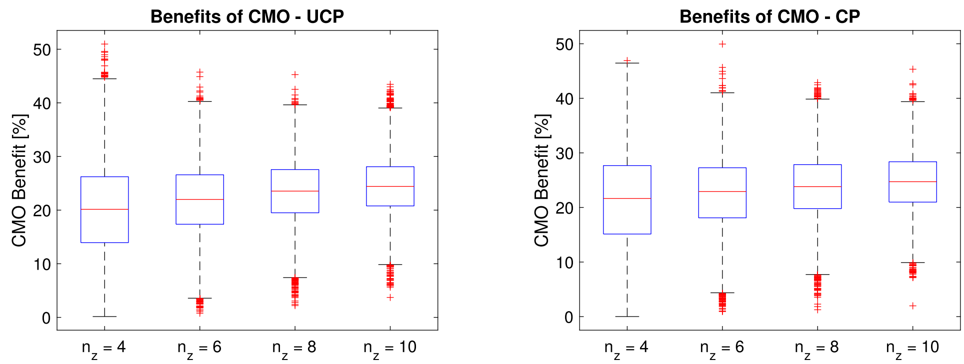

Fig. 9. Relative reserve activation cost decrease implied by the common merit order (CMO) in the case of various network sizes in the case of coordinated and uncoordinated reserve procurement [%].

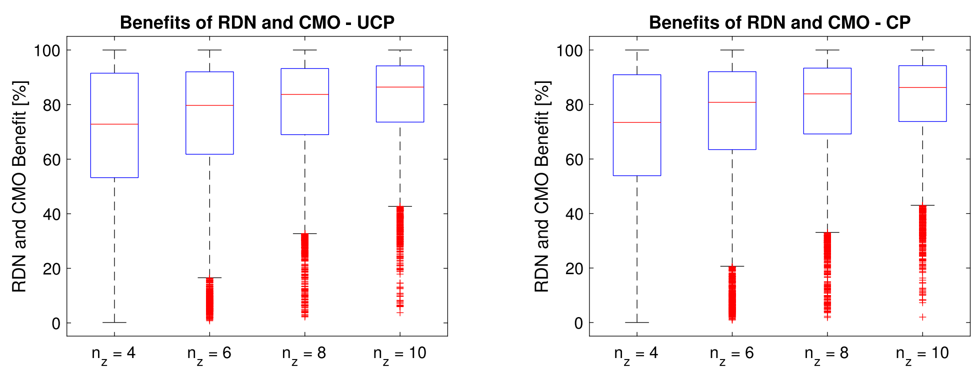

Fig. 10. Relative reserve activation cost decrease implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of coordinated and uncoordinated reserve procurement [%].

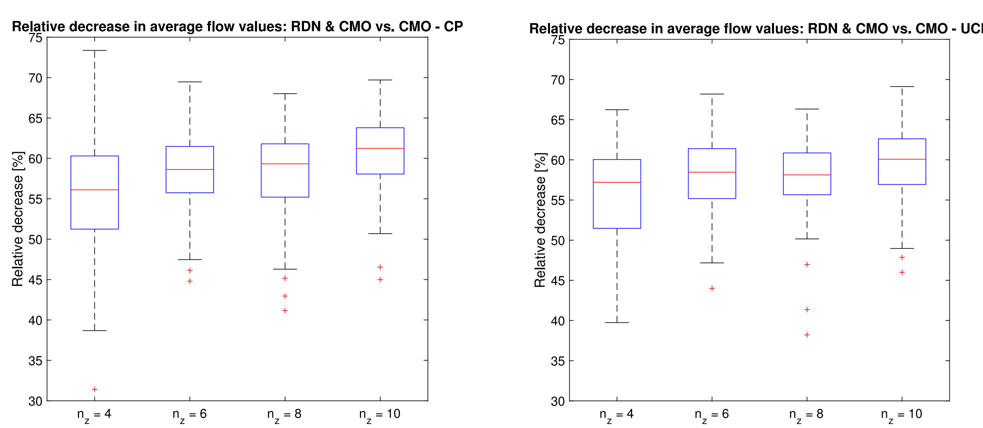

Fig. 11. Relative decrease of average network flows implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of coordinated and uncoordinated reserve procurement [%].

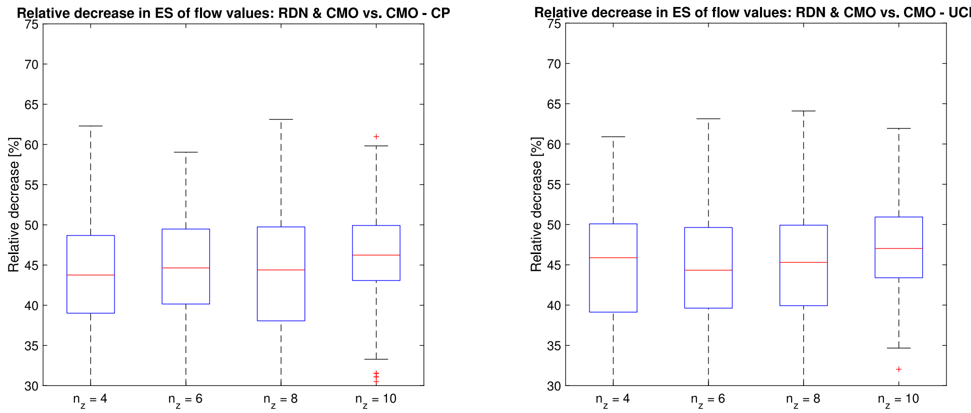

Fig. 12. Relative decrease of extreme network flows implied by reserve demand netting (RDN) and common merit order (CMO) in the case of various network sizes in the case of coordinated and uncoordinated reserve procurement [%].

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