Market-Based Congestion Management in Electric Power Systems with Exploitation of Aggregators

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Abstract

The paper addresses market-based congestion management (MBCM) in electric power systems utilizing aggregators of dispersed small-scale (residential, commercial and small industrial) electricity consumers, producers and prosumers at the distribution network. The proposed method is based on the market principle, where the system operator performs minimum-cost redispatching of generators, loads and aggregators as to relive congested lines. The power system is linearized and presented by the direct current (DC) model for power flow calculation. In this way, Power Transfer Distribution Factors (PTDFs) and Topological Generation and Load Distribution Factors (TGDFs and TLDFs) which describe the relation between generators/loads/aggregators and line-power flows are applied. The proposed solution applies two decoupled optimizations. The upper-level optimization includes bid-based redispatching for congestion relief, while low-level optimization provides the optimal bid of an aggregator for the MBCM procedure, where block offers are introduced for aggregators that have multiple connection points (MCPs) to the transmission network and inject power synchronously at different locations. Both optimization problems are solved by linear programming. Case studies show the applicability of the proposed congestion management method on a simple test model of a power system.

Keywords: Aggregator, linear programming, market-based congestion management, optimization, prosumer.

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Nomenclature

Indices:

a	Subscript index for aggregator.
b	Subscript index for bid.
ij	Subscript index for line i-j.
l	Subscript index for location.
m	Subscript index for generator or load (market participant).
max	Superscript index for maximum value.
min	Superscript index for minimum value.
p	Subscript index for prosumer.
t	Subscript index for time slot.

Variables and functions:

c	Price ($\frac{€}{\text{MWh}}$).
$GLSK$	Generation and load shift key (p.u.).
J	Objective function (€).
P	Active power (MW).
$PTDF$	Power transfer distribution factor (p.u.).
s	Cost (€).
TDF	Transmission distribution factor (p.u.).

Parameters, sets and constants:

A	Number of aggregators in set $\mathcal{A}$.
$\mathcal{A}$	Set of aggregators.
$\mathcal{B}$	Set of bids.
L	Number of connection points in set $\mathcal{L}_a$.
$\mathcal{L}$	Set of multiple connection points.
M	Number of elements in set $\mathcal{M}$.
$\mathcal{M}$	Set of market participants.
Ω	Set of decision variables.
P	Number of prosumers in set $\mathcal{M}_a$.

Abbreviations:

AC	Alternating current.
CM	Congestion management.
DC	Direct current.
DSO	Distribution system operator.
GGDF	Generalized generation distribution factor.
GLSK	Generation and load shift key.
MBCM	Market-based congestion management.
MCP	Multiple connection point.
PTDF	Power transfer distribution factor.
SCP	Single connection point.
TDF	Transmission distribution factor.
TGDF	Topological generation distribution factor.

TLDF Topological load distribution factor.

TSO Transmission system operator.

1. Introduction

Congestion management (CM) is an ancillary service which is gaining on its importance due to increasing share of renewable energy sources with unpredictable nature impacting also line loadings going beyond the limits, and slower realization of new investments into transmission paths due to environmental constraints and general unacceptance. This ancillary service is the responsibility of transmission system operators (TSOs) and distribution system operators (DSOs), if congestions occur in distribution network. They need effective tools to prevent transmission paths from overloading in order to provide reliable operation of power system. In the past, this service was provided solely by generating companies; it was only later that big industrial consumers identified within the demand-side management recognized it as a great business opportunity in this segment of energy markets and started offering their available demand flexibility to TSOs too, [1], [2], [3], [4].

It is to be expected that the future grid will be more distributed. A noticeable uptake is seen at the residential level where consumers, virtual power plants and prosumers are increasing installations of renewable energy sources (photovoltaic panels), flexible demand (heating and cooling) and storage systems (batteries and electric-drive vehicles). These behind-the-meter applications can provide different services for their owners, e.g. back-up supply, load shifting, optimization of energy procurement, maximization of self-consumption, etc. If coordinated adequately via aggregators, all these new technologies and concepts can be efficiently applied to ensure the needed dispatchable potential in power systems, also in CM. From the technical point of view, there are no barriers to reaching this goal since numerous solutions in the field of information, communication technology and control are available for application.

The idea in this paper employs prosumers with their production, flexible demand and storage capabilities as a potential way of providing support for congestion relief on critical transmission lines. In this research, "prosumer" refers to a small-scale (residential, commercial and small industrial) electricity consumer with on-site generation like rooftop photovoltaic panels and battery storage, not excluding electric-drive vehicles and virtual power plants. In [5], the projected uptake of solar and battery storage in 2050 is 80 GW and 100 GWh, which will represent between 30% and 50% of total demand; see the scenario called "Rise of the Prosumer", [6]. A similar trend has been observed in Europe as well, [7].

The CM problem is a topic that has been frequently addressed by many researchers, and numerous solutions have already been put into practice. A detailed overview of available approaches is provided in [8]. In a vertically integrated traditional power system, before its unbundling, TSOs determined the transmission line flows within the allowable range in the lowest cost, [9].

In a deregulated environment, CM is still the responsibility of TSOs. One of the earliest available solutions was the nodal pricing (locational marginal pricing) method, [10]. It provides adequate economic (price) signals to market participants preventing the network from congesting. This solution is very exact, but highly complex for application.

In the zonal (regional) pricing solution [11], critical transmission lines are identified a priori and represent potential zonal boundaries. The system is split into defined zones only in case of congestion, and each zone has an unique market clearing price so that trading between and within the zones does not cause any congestions on identified critical lines. The problem with zonal pricing is that it does not prevent internal congestions, since zonal boundaries are defined ex-ante.

[12] and [13] apply the DC optimal power flow approach, where fuel costs are minimized and social welfare is maximized while relieving transmission line congestions.

The countertrade approach is based on the market principle, where market players provide their bids for power increase or decrease while TSO performs in the next step an auction as to find an optimal bid structure that would relive a congestion. This solution is presented in [14] and utilizes Generalized Generation Distribution Factors (GGDFs) described in [15] to obtain the relation between redispatched power and change of line power flow. Linear programming is applied to obtain an optimal redispatch of power production and load.

In addition to GGDFs, frequently applied factors describing the relation between market participants' power change and line power flows are Transmission Congestion Distribution Factors, which are also available for reactive power as in [16], [17], or the frequently applied PTDFs as in [18], or generator sensitivity factors on congested lines as presented in [19]. Many other variations and different namings of these factors are available in literature.

Another efficient approach to CM similar to distribution factors is to employ power tracing techniques in combination with an optimization algorithm as presented in [20], [21]. [22] provides a review of the power flow tracing.

Many researchers have proposed CM solutions by finding the optimal position of controllable devices such as Flexible alternating current (AC) Transmission System [23], [24], [25]; in this group: Thyristor Controlled Series Compensator [26], Static VAr Compensator [27], Static Compensator, Static Series Synchronous Compensator [28], etc. by applying one of the intelligent optimization algorithms such as the Genetic Algorithm [29], [12], Differential Evolution [30], Particle Swarm Optimization [31], [32] and other evolutionary algorithms. Besides these controllable devices also transmission-line switching and operation of transformer taps can be applied to mitigate congestions. All these approaches are cost-free, [33], since they do not involve any generation and load rescheduling and curtailment.

Several MBCM approaches for congestion relief on the transmission and distribution level have been proposed recently. In general, it is a pool-based market model where s system operator collects flexibility bids (adjustment bids) of market participants, performs an auction, implements the selected bids and relieves critical lines. These approaches are non-cost-free, [33], and as such are applied in the second stage if cost-free methods do not relieve congestions entirely. For example, in [34], a distribution market operator is introduced that clears the flexibility market with help of electric-drive vehicles. Another market framework is proposed in [35] where a flexibility clearing house acts as an "independent non-profit driven entity" and carries out CM in distribution network via flexible distributed energy resources. In [36], a collaboration platform between a virtual power plant and a DSO is developed to initiate market-oriented solutions of smart distribution grid security including CM. Also EPEX SPOT proposes in [37] a flexibility marketplace where system operators can procure flexibility offered by certified flexibility providers such as aggregators, storage systems, power plants, renewable energy sources, etc. In [38], a flexible demand is exploited by aggregators for congestion relief. On the aggregator's level (lower tier), a transactive market model is used in order to formulate swap bids of consumers' flexible demand. An aggregator provides these bids to a DSO that clears a swap market (upper tier), employs the selected bids and relieves the network. With this market scheme, real-time congestions are solved.

The advantage of real-time approaches is the fact that congestion forecasts within a day or for the next hour are more reliable and actions are consequently more effective. Main drawbacks of real-time approaches are required prompt responses of market participants and timely actions of system operators. However, this issue is efficiently solved by adequate information and communication technologies. Solutions that apply day-ahead market models have to deal with forecast uncertainties. For example, [39] presents a robust optimization framework for the day-ahead scheduling of residential smart user under uncertainties of forecast parameters. Another approach is to apply chance-constrained stochastic approach as presented in [40], where the uncertainty of wind power and demand-side response are jointly considered in order to determine the optimal daily dispatch of generators and demand-responsive.

The research presented in this paper was motivated by the following facts:

- unexpected occurrence of line overloading due to unpredictable operation of renewable energy sources,

- overloading of transmission lines due to lack of new investments into transmission lines,
- unexploited potential of aggregated generation and demand flexibility at the distribution level for CM at the transmission level.

The paper proposes a new MBCM method with the integration of aggregated producers, consumers and prosumers operating at the distribution level. The proposed market model follows the latest research works, [34], [35], [36], [37], that apply a pool-based model, but with different market designs as already discussed. The main idea in the paper derives from [14] and [18] that also apply a pool-based market model for CM. The existing work is improved as GGDFs are replaced by PTDFs and TGDFs/TLDFs, [22], which present the impact of generators/loads/aggregators on line loadings. These factors allow for the simultaneous bidding of generators, loads, and also aggregators in the proposed MBCM. The actual advantage of proposed factors is that they enable a coupling of transmission and distribution networks, which, compared to [14], enables an inclusion of aggregators into the bidding procedure for CM.

More specifically, the idea presented in this work enables aggregators with MCPs to participate in the CM market. For example, a recent reference [34] proposes a conceptually similar solution where aggregators exploit electric-drive vehicles for CM via a day-ahead market framework. It is important to note that all aggregators in this research, [34], have a single connection point (SCP) to the transmission network, which easier the problem since each aggregator's flexibility impacts the grid from one point only. The existing solutions have to be improved by applying appropriate distribution factors and adequate market model that would enable also aggregators with MCPs to efficiently participate in the CM market.

The proposed MBCM procedure incorporates two optimization models. The low-level problem is applied by an aggregator in order to deliver the best possible and competitive offers to MBCM optimization performed by the TSO. The main contributions of the proposed solution are:

- inclusion of dispersed prosumers at the distribution level into the MBCM optimization model,
- modelling of location-related block offers of aggregators with MCPs,
- application of distribution factors such as PTDFs, TGDFs and TLDFs in the optimization model carrying information about the transmission and distribution network.

The remainder of the paper is organized as follows: generation and load redispatching is presented in Section 3, followed by Section 4, which presents aggregator redispatching. The proposed MBCM model is presented in Section 5 and in Section 6, results are analysed and discussed in detail, followed by the final Section 7 that concludes the paper.

2. Model of Electric Power System and Market Design

Line power flows through the system are determined by topology and injected nodal power flows as a result of market activities of generators, loads and aggregators as presented in Figure 1. Two types of aggregators are considered in this research: aggregators with a SCP as the one on the left-hand side in Figure 1, and aggregators with MCPs as the one on the right-hand side in Figure 1. Aggregators of both types merge prosumers with flexible production and/or demand including virtual power plants, electric-drive vehicles and trains, energy storage systems, smart homes, etc., as in [39] and [41]. An interesting overview of technologies appropriate for aggregation are provided in [42] and [43] pointing out microgrids with smart homes, energy hubs and energy router components. In general, aggregators are technology-agnostic meaning they comprise of all kinds of technologies operating on different voltage levels. It is only important that prosumers comprising of different technologies are flexible and adequately controllable, which is required for aggregators' exploitation in the CM procedure.

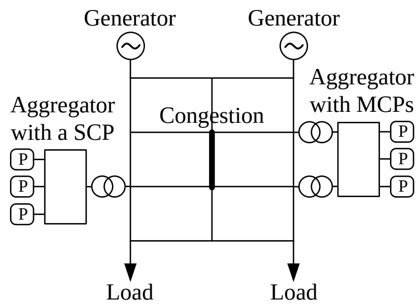

Figure 1: Structure of electric power system.

In case of transmission line congestions, the system operator performs remedial actions by generation, load and aggregator redispatching in order to eliminate line overloading. Figure 2 presents a market-based solution, where the system operator foresees a congestion problem in the next hour and calls the CM market participants to provide their adjustment (flexibility) bids through a dedicated market platform. Next, the system operator has to perform the matching procedure of bids for active-power changes at a specific price, so as to utilize the cheapest offers first and therefore achieve an optimal redispatch of production and load. Finally, all market participants are informed about the auction result and the implementation of selected bids can be performed in the following hour when line overloading is expected to occur. As presented, the proposed market-based solution is a complementary real-time market with an hourly resolution (or 15 minutes and less) running in parallel with other real-time markets such as an intra-day market or a balancing market, but with a specific purpose. This market is proposed to be a real-time market since line congestions can be predicted more accurately on a hourly basis.

The bidding curve of market participant m with the set of sections, i.e. bids, $\mathcal{B}_m$, is presented in Figure 3. The eligible bidders in general are generators and loads as proposed in [18], but in this research the idea is upgraded since also aggregators with flexible production and/or consumption dispersed throughout the distribution network are recognized as eligible bidders.

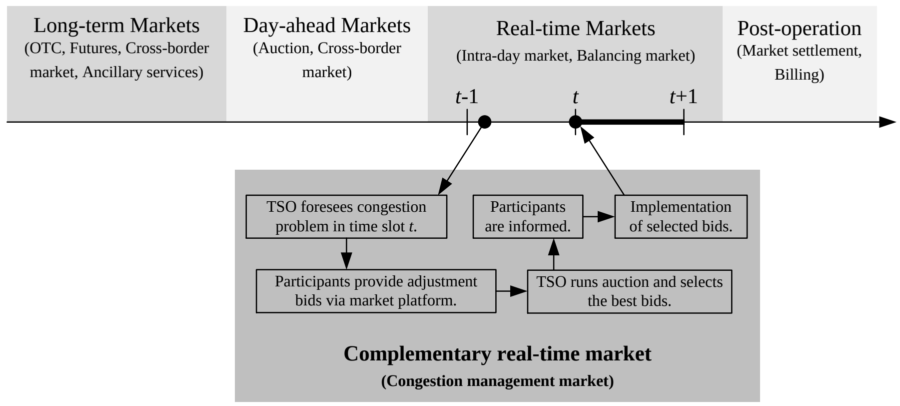

Figure 2: Market design.

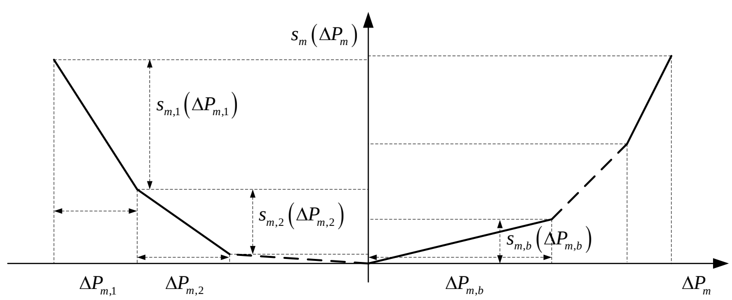

Figure 3: The bidding curve for MBCM of participant m.

The b-th bid price for power change of participant m:

$$c_{m,b} = \frac{s_{m,b}\left(\Delta P_{m,b}\right)}{\Delta P_{m,b}}, \tag{1}$$

is determined by the cost for power change $s_{m,b}$ and the power change $\Delta P_{m,b}$ itself. It is important to note that the power change $\Delta P_{m,b}$ presents a flexible response of the bitter in a positive or negative direction but always with a positive bid price giving a concave shape of the bidding curve in Figure 3.

3. Generation and Load Redispatching

The system operator has to perform the matching procedure of bids, so as to utilize the cheapest offers first and therefore achieve an optimal redispatch of production and load. The idea is already presented in [18], and summarized in this section. The objective function is formulated as:

$$J = \underset{\Omega}{\text{minimize}} \sum_{m \in \mathcal{M}} s_m, \tag{2}$$

where Ω represents the set of decision variables (continuous optimization variables):

$$\Omega = \{\Delta P_1, \ldots, \Delta P_m, \ldots, \Delta P_M\}, \tag{3}$$

where ΔP_m is the active power change of generator/load m calculated as (8), and M is the total number of bidding participants in the set $\mathcal{M}$. The total cost of participant m in (2) is expressed as:

$$s_m = \sum_{b \in \mathcal{B}_m} s_{m,b}. \tag{4}$$

The redispatching procedure is performed taking into account the following constraints of the power system, [18]:

- limited capacities of generators and loads:

$$P_m^{\min} \leq P_m + \Delta P_m \leq P_m^{\max}, \tag{5}$$

- active power balance in the system:

$$\sum_{m \in \mathcal{M}} \Delta P_m = 0, \tag{6}$$

- limited transmission capacities (lines and transformers):

$$P_{ij}^{\min} \leq P_{ij} + \Delta P_{ij} \leq P_{ij}^{\max}, \tag{7}$$

where P_m and ΔP_m in (5) and (6) represent the injected active power of generator/load m in MBCM and its total active power change, which is expressed as:

$$\Delta P_m = \sum_{b \in \mathcal{B}_m} \Delta P_{m,b}. \tag{8}$$

In (7), P_{ij} represents the active power flow on line i–j. The active power flow change on line i–j, ΔP_{ij}, is expressed with optimization variable $\Delta P_{m,b}$ by applying PTDF as:

$$PTDF_{ij,m} = \frac{\Delta P_{ij}}{\Delta P_m}. \tag{9}$$

$PTDF_{ij,m}$ represents the impact of generator/load m on the active power flow on line i–j. Consequently, ΔP_{ij} in (7) is expressed as:

$$\Delta P_{ij} = \sum_{m \in \mathcal{M}} \left(\Delta P_m PTDF_{ij,m} \right). \tag{10}$$

In (6), transmission losses and reactive-power flows are neglected, because the DC model of the electric power system is applied. An assessment of this assumption is performed in [18].

4. Aggregator Redispatching

Similar to generators and loads, aggregators can likewise provide their bids for congestion relief performed by the system operator. As presented in the model (2)-(10), the location of a provider (load, generator and aggregator) is very important, since it defines the impact of dispatched power on the loading of a congested line through the corresponding PTDFs. If it is presumed that aggregators merge producers, consumers and prosumers on the distribution network, these locations are recognized as connection points and present links (transformers) between transmission and distribution networks.

Aggregators can have a SCP, the same as conventional loads and generators in the system, as presented by aggregator b in Figure 4, or MCPs at different locations in the system as presented in Figure 4 by aggregator a with three MCPs. Aggregators with MCPs make the bidding procedure within the MBCM scheme more complex since they have to provide block orders instead of regular bids, as they inject power at multiple locations in the system.

The most common block order is a time-related block order that consists of a specified volume and price for a certain number of consecutive hours within the same day. For example, Nord Pool markets have four types of block orders: regular, profiled, curtailable and linked. Regular block orders have an "all-or-nothing" condition. They must be fully accepted or fully rejected, and if

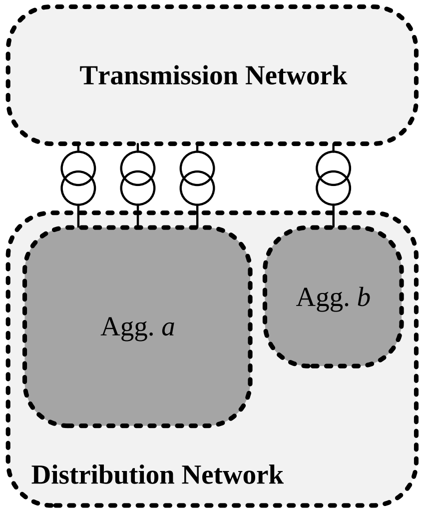

Figure 4: Aggregators with SCP and MCPs.

accepted, the contract covers all hours and the entire volume specified. In linked block orders, accepting an individual block order depends on accepting other block orders. Curtailable block orders are those which can be partially accepted according to a user-defined Minimum Acceptance Ratio. A block with the ratio of 100 % is a regular "all-or-nothing block order", so it is either fully accepted or fully rejected. A profile block is a block order where volume can differ over the entire time span of the block. Minimum order duration is three hours in Nordic and Baltic regions and two hours in the UK. The start and stop time of a profile block order is defined by the user. Profile block orders can be linked and they may be curtailable. The volume weighted average price over the duration of the order is used to determine its acceptance. The price is compared with the block volume weighted average day-ahead price for the periods for which the block is defined.

This paper proposes that location-related block orders be introduced instead ot time-related block orders when aggregators with MCPs are considered. These block orders have an "all-or-nothing" condition regarding the location, meaning bids at different CPs of a certain aggregator must be fully accepted or fully

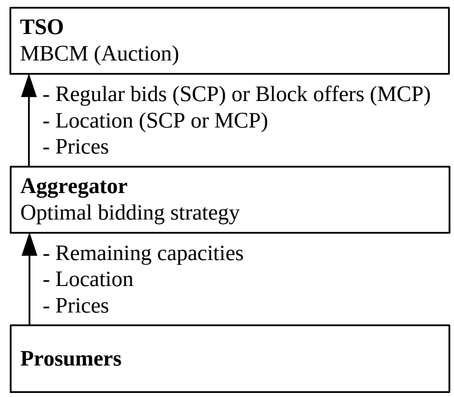

Figure 5: Aggregator's role in the MBCM.

rejected. Block orders do not apply to aggregators with a SCP. They provide regular bids at a single location in the system as generators and loads.

In this research, the members of aggregators are producers, consumers and prosumers dispersed throughout the distribution network. They are flexible in both directions so they can increase or decrease their power within the capacity limits in order to provide certain system services such as congestion relief.

Since the potential of a single prosumer (also producer and consumer) on the distribution level has a negligible effect at the transmission level where CM is applied, aggregators have to step in between the TSO and prosumers in order to merge all this dispersed potential into a sufficient amount that can be efficiently exploited in the MBCM scheme executed by the TSO. The concept of aggregators' involvement in MBCM by utilization of their prosumers' potential is presented in Figure 5. In addition to the aggregation of this potential, the role of an aggregator is also to provide the most competitive offers in MBCM, weather regular bids or block offers, when congestion occurs.

If the TSO utilizes this aggregator for congestion relief, the aggregator has to sort the remaining capacities of all (P) prosumers in ascending order according to their prices (c_p), so as to engage the cheapest prosumers first. The objective function of aggregator a is formulated as:

$$J_a = \underset{\Omega_a}{\text{minimize}} \sum_{p \in \mathcal{M}_a} (c_p \Delta P_p), \tag{11}$$

where Ω_a represents the set of decision variables (continuous optimization variables):

$$\Omega_a = \{\Delta P_1, \dots, \Delta P_p, \dots, \Delta P_P\}, \tag{12}$$

where ΔP_p represents the power change of prosumer p, which is limited by:

$$P_p^{\min} \leq P_p + \Delta P_p \leq P_p^{\max}. \tag{13}$$

The summation of power changes of all prosumers:

$$\Delta P_a = \sum_{p \in \mathcal{M}_a} \Delta P_p, \tag{14}$$

represents the bid quantity of aggregator a in MBCM and the bid price is calculated as:

$$c_a = \frac{J_a}{\Delta P_a}. \tag{15}$$

If aggregator a has MCPs as in Figure 4, the regular bid has to be reformulated into a location-related block order as:

$$\Delta P_a = \{\Delta P_{a,1}, \dots, \Delta P_{a,l}, \dots, \Delta P_{a,L}\}, \tag{16}$$

where L represents the number of connection points and $\Delta P_{a,l}$ stands for the bid of aggregator a at location l and it is calculated as:

$$\Delta P_{a,l} = \sum_{p \in \mathcal{M}_a} (\Delta P_p TDF_{l,p}), \tag{17}$$

where $TDF_{l,p}$ represents the TGDF or TLDF [22] of prosumer p on the linkage between the transmission and distribution network l, which is also recognized as the CP of aggregator a to the transmission network. The TGDF is applied when the prosumer acts as a generator and the TLDF when it consumes power. These factors represent the producers' and consumers' shares in line power flows [22].

Applying the Generation and Load Shift Key (GLSK), $GLSK_{a,l}$, which represents the share of power change at location l in the total power change of aggregator a:

$$GLSK_{a,l} = \frac{\Delta P_{a,l}}{\Delta P_a}, \tag{18}$$

the block order in (16) can be reformulated to a triple form suitable for the bidding procedure in MBCM as:

$$\left(\Delta P_a, \{GLSK_{a,1}, \ldots, GLSK_{a,l}, \ldots, GLSK_{a,L}\}, c_a\right), \tag{19}$$

where the triple consists of the bid quantity, the GLSK set and the bid price.

Finally, the impact of aggregator a on the active power flow on path i–j is calculated as:

$$\Delta P_{ij,a} = \sum_{l \in \mathcal{L}_a} \left(\Delta P_{a,l} PTDF_{ij,l}\right), \tag{20}$$

where $\mathcal{L}_a$ represents the set of MCPs of aggregator a.

Figure 6 depicts the power flows and the impact of prosumers in aggregator a on congested line i-j through PTDFs and transmission distribution factors (TDFs) TGDFs and TLDFs. It is important to notice that a successful bidding in MBCM performed by the proposed optimization procedure (11)-(20) requires information about the prosumers' individual capacities and prices, and PTDFs and TDFs (TGDFs and TLDFs) of the network if the aggregator has MCPs. In the case of a SCP, distribution factors are not required and the bidding procedure follows the standard approach performed by regular generators and loads bidding in MBCM.

5. MBCM model

Since the proposed MBCM model incorporates also aggregator redispatching, the optimization model (2)-(10) has to be extended. First, the objective function (2) has to be expanded as:

$$J = \underset{\Omega}{\text{minimize}} \left\{ \sum_{m \in \mathcal{M}} \sum_{b \in \mathcal{B}_m} \left(c_{m,b} \Delta P_{m,b}\right) + \sum_{a \in \mathcal{A}} \left(c_a \Delta P_a\right) \right\}, \tag{21}$$

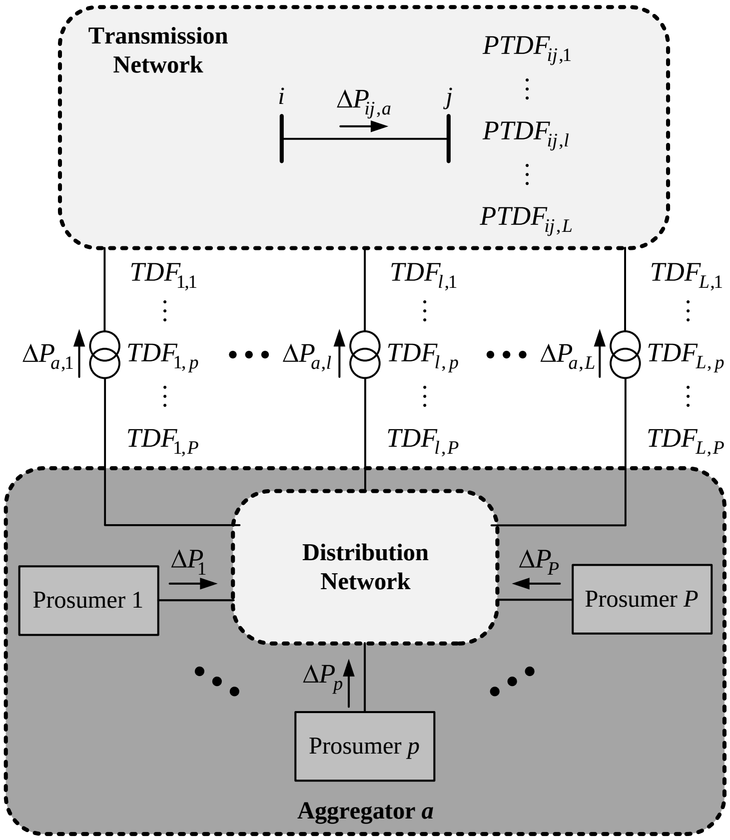

Figure 6: Concept of prosumers' aggregation.

where Ω presents the extended set of decision variables:

$$\Omega = \{\Delta P_{1,1}, \ldots, \Delta P_{m,b}, \ldots, \Delta P_a, \ldots, \Delta P_A\}, \tag{22}$$

where A is the total number of bidding aggregators in the set $\mathcal{A}$. Similar constraint as (5) for generators and loads is required for aggregators, as well:

$$P_a^{\min} \leq P_a + \Delta P_a \leq P_a^{\max}. \tag{23}$$

The active power balance constraint (6) is extended as:

$$\sum_{m \in \mathcal{M}} \Delta P_m + \sum_{a \in \mathcal{A}} \Delta P_a = 0. \tag{24}$$

Finally, the change of active power flow on the congested line in (10) is calculated as:

$$\Delta P_{ij} = \sum_{m \in \mathcal{M}} \left(\Delta P_m PTDF_{ij,m} \right) + \sum_{a \in \mathcal{A}} \sum_{l \in \mathcal{L}_a} \left(\Delta P_{a,l} PTDF_{ij,l} \right). \tag{25}$$

Additional constraint regarding the "all-or-nothing" condition for block orders has to be included in the model as:

$$\Delta P_{a,l} = \left(\Delta P_a GLSK_{a,l} \right). \tag{26}$$

The proposed MBCM procedure is depicted in Figure 7. The upper-level optimization consists of five steps (as in Figure 2) that are performed by the TSO in order to relieve congested lines. In the second step, the lower-level optimization is executed by aggregators. This optimization is completely decoupled from the upper-level optimization problem since it is independently run by aggregators and its set of inputs does not include any optimization variables from the upper-level optimization problem. Besides specification of the procedure, Figure 7 also summarizes both optimization models through their mathematical formulation.

6. Case studies

The proposed method for MBCM with bidding aggregators is tested on the IEEE standard 39-bus test system presented in Figure 8. The parameters for buses and branches required for DC power flow, PTDF and TDF (TGDF, TLDF) calculation are given in Tables 4 and 5 in the Appendix, Section 8.

Four cases are studied and compared in order to present the MBCM solution:

- case A with uncongested transmission lines - initial case,
- case B with transmission capacities of lines 5–6 and 16–17 limited to 400 MW and 170 MW, respectively, and with no aggregator included in the MBCM model,
- case C with limited transmission capacities as in the previous case and with one aggregator bidding in the MBCM procedure,

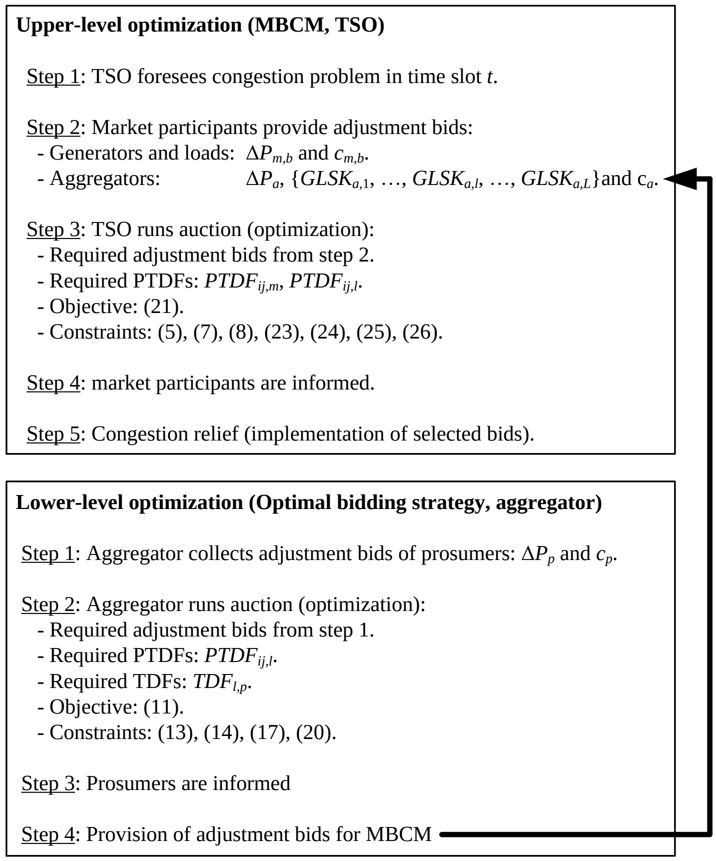

Figure 7: MBCM procedure with two optimization problems.

- case D with limited transmission capacities as in case B and with one aggregator bidding in the MBCM procedure with a 50 % price reduction.

For the sake of clarity, only generators and one aggregator with MCPs are presumed to be bidding. However, loads and aggregators with a SCP can easily be included in the bidding process. Tables 1 and 2 present the bids of generators and the aggregator participating in the MBCM scheme. In this simplified research, DC power flow is applied and a short discussion regarding AC power flows and reactive power is available in [18].

In the initial stage, the aggregator identifies prosumers' capacities available for CM, and according to their price and position in the distribution network

Table 1: Data for bidding generators in the IEEE 39-bus system.

Bus m	$\Delta P_{m,b}$ (MW)	$c_{m,b}$ ($\frac{€}{\mathrm{MWh}}$)	$PTDF_{5-6,m}$	$PTDF_{16-17,m}$
30	-50	-1	0.0457	-0.7055
30	100	50	0.0457	-0.7055
30	200	40	0.0457	-0.7055
31	-100	20	-0.5163	-0.4559
31	300	40	-0.5163	-0.4559
32	-200	10	-0.3092	-0.4159
33	400	35	0	0
34	-20	10	0	0
34	300	20	0	0
35	100	35	0	0
36	-70	11	0	0
36	50	35	0	0
36	150	30	0	0
37	-40	50	0.0426	-0.7278
37	30	25	0.0426	-0.7278
38	-100	15	0.0312	-0.8114
38	100	20	0.0312	-0.8114

Table 2: Data for bidding aggregator with MCPs.

CP l	Bus l	$GLSK_{a,l}$	$\Delta P_{a,l}$ (MW)	$PTDF_{5-6,l}$	$PTDF_{16-17,l}$
1	3	-0.3851	24.6990	0.0607	-0.6943
2	11	0.5806	-37.2367	-0.3761	-0.4289
3	12	0.4651	-29.8256	-0.3092	-0.4159
4	13	0.3395	-21.7707	-0.2423	-0.4030
Total (ΔP_a)			-64.1339		

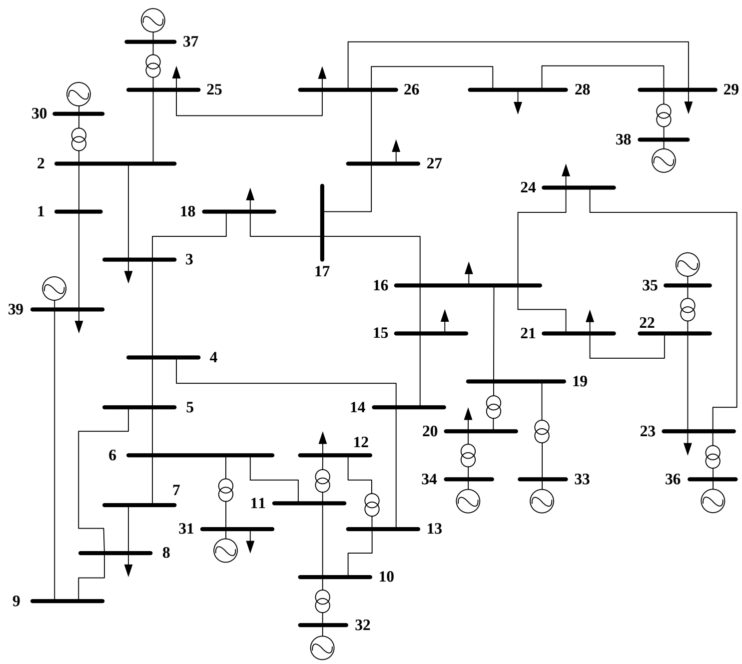

Figure 8: IEEE 39-bus model.

it performs the optimal prosumers' dispatch, which is finally reformulated into the bid for the CM scheme performed by the TSO. In this research, 150,000 prosumers are taken into account, each with the available capacity for CM needs, i.e. a randomly generated value between 9 kW and 11 kW applying uniform distribution. Half of the prosumers are able to perform a power decrease and the other half can increase power within the available capacity if required. Prosumer prices are also generated applying uniform distribution between the values 10 $\frac{€}{\text{MWh}}$ and 20 $\frac{€}{\text{MWh}}$. For each prosumer, TDFs in (17) are randomly defined considering:

$$\sum_{l \in \mathcal{L}_a} TDF_{l,p} = 1. \tag{27}$$

PTDFs required in (20) are provided for both congested lines in Table 2.

It is presumed that the strategy of aggregator a is to offer such a bid that would, if utilized, relieve the congested lines 5–6 and 16–17 by 30 MW and 20 MW, respectively, at most.

According to (19), the result of the aggregator's optimization is the adjustment bid applicable in the CM scheme with the quantity of $-64.1339\,\mathrm{MW}$ at the price of $13.93\,\frac{€}{\mathrm{MWh}}$ obtained by (15) and with the GLSK provided in Table 2. This bid, i.e. block order, is provided to the TSO for utilization, if competitive to the bids offered by other market participants. A negative value of the bid quantity means power reduction in (23), i.e. a negative power change of this aggregator.

Table 3 presents the results of MBCM optimization for all four cases. In case A with no transmission congestion, generation and aggregator redispatching is not performed and the cost of CM equals 0. In case B, both congestions are relieved by generators only and the total cost equals €4,457.9318. If the aggregator bids as in case C, the total cost of CM is reduced to €4,448.552 since the generators are less utilized due to the aggregator's redispatced power of $-9.1710\,\mathrm{MW}$. If the bidding aggregator reduce its price by $50\,\%$ as in case D, it is more competitive and fully utilized. The cost of CM reaches €4,107.4079 and cannot be further reduced since the aggregator's bid is fully deployed.

Although the proposed method is tested on simple case studies, it can be efficiently applied to large-scale problems since each aggregator performs the lower-level optimization independently applying linear programming. Also the upper-level optimization contains a linear problem (market auction) and it is solved separately from the aggregators' optimization. Additionally, paralleled and distributed computing can be used to increase scalability of the proposed solution.

7. Conclusion

This paper proposes a new method of MBCM with the utilization of aggregated prosumers operating on the distribution network. The optimization procedure consists of two levels, where the low-level optimization is performed by the aggregator in order to provide competitive offers for MBCM optimization. Aggregators with MCPs require an introduction of location-related block orders.

Table 3: Results for IEEE 39-bus system.

Results	A	B	C	D
P_{5-6} (MW)	-459.3690	-400.0000	-400.0000	-400.0000
ΔP_{5-6} (MW)	0	59.3690	59.3690	59.3690
P_{16-17} (MW)	208.2953	170.0000	170.0000	170.0000
ΔP_{16-17} (MW)	0	-38.2953	-38.2953	-38.2953
ΔP_{30} (MW)	0	0	0	0
ΔP_{31} (MW)	0	-100.0000	-100.0000	-50.7997
ΔP_{32} (MW)	0	-13.3620	0	0
ΔP_{33} (MW)	0	0	0	0
ΔP_{34} (MW)	0	1.9477	1.4635	14.4973
ΔP_{35} (MW)	0	0	0	0
ΔP_{36} (MW)	0	0	0	0
ΔP_{37} (MW)	0	11.4143	7.7075	0.4363
ΔP_{38} (MW)	0	100.0000	100.0000	100.0000
ΔP_a (MW)	0	0	-9.1710	-64.1339
Cost of CM (€)	0	4,457.9318	4,448.0552	4,107.4079

In the countertrade MBCM model, a bid-based generation/load/aggregator redispatching is performed, utilizing PTDFs, TGDFs and TLDFs in order to obtain the relation between redispatched power and a change of power flows. The effectiveness of the proposed solution is demonstrated on the case of an IEEE 39-bus system.

8. Appendix

Tables 4 and 5 present parameters of the IEEE 39-bus power system.

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Table 4: Bus parameters of IEEE 39-bus system.

Node m	Type	P_m (MW)	P_m^{min} (MW)	P_m^{max} (MW)
1	PQ	0	-	-
2	PQ	0	-	-
3	PQ	-322	-	-
4	PQ	-500	-	-
5	PQ	0	-	-
6	PQ	0	-	-
7	PQ	-233.8	-	-
8	PQ	-522	-	-
9	PQ	0	-	-
10	PQ	0	-	-
11	PQ	0	-	-
12	PQ	-8.5	-	-
13	PQ	0	-	-
14	PQ	0	-	-
15	PQ	-320	-	-
16	PQ	-329.4	-	-
17	PQ	0	-	-
18	PQ	-158	-	-
19	PQ	0	-	-
20	PQ	-680	-	-
21	PQ	-274	-	-
22	PQ	0	-	-
23	PQ	-247.5	-	-
24	SL	-308.6	-	-
25	PQ	-224	-	-
26	PQ	-139	-	-
27	PQ	-281	-	-
28	PQ	-206	-	-
29	PQ	-283.5	-	-
30	PV	250	0	350
31	PV	521.3	0	750
32	PV	650	0	750
33	PV	632	0	732
34	PV	508	0	608
35	PV	650	0	750
36	PV	560	0	660
37	PV	540	0	640
38	PV	830	0	930
39	PV	-104	0	1100

Table 5: Branch parameters of IEEE 39-bus system.

Bus i	Bus j	Type	R_{ij}	X_{ij}	R_{ij}	t_{ij}
1	2	Line	0.0035	0.0411	0.6987	0
1	39	Line	0.0010	0.0250	0.7500	0
2	3	Line	0.0013	0.0151	0.2572	0
2	25	Line	0.0070	0.0086	0.1460	0
3	4	Line	0.0013	0.0213	0.2214	0
3	18	Line	0.0011	0.0133	0.2138	0
4	5	Line	0.0008	0.0128	0.1342	0
4	14	Line	0.0008	0.0129	0.1382	0
5	6	Line	0.0002	0.0026	0.0434	0
5	8	Line	0.0008	0.0112	0.1476	0
6	7	Line	0.0006	0.0092	0.1130	0
6	11	Line	0.0007	0.0082	0.1389	0
7	8	Line	0.0004	0.0046	0.0780	0
8	9	Line	0.0023	0.0363	0.3804	0
9	39	Line	0.0010	0.0250	1.2000	0
10	11	Line	0.0004	0.0043	0.0729	0
10	13	Line	0.0004	0.0043	0.0729	0
13	14	Line	0.0009	0.0101	0.1723	0
14	15	Line	0.0018	0.0217	0.3660	0
15	16	Line	0.0009	0.0094	0.1710	0
16	17	Line	0.0007	0.0089	0.1342	0
16	19	Line	0.0016	0.0195	0.3040	0
16	21	Line	0.0008	0.0135	0.2548	0
16	24	Line	0.0003	0.0059	0.0680	0
17	18	Line	0.0007	0.0082	0.1319	0
17	27	Line	0.0013	0.0173	0.3216	0
21	22	Line	0.0008	0.0140	0.2565	0
22	23	Line	0.0006	0.0096	0.1846	0
23	24	Line	0.0022	0.0350	0.3610	0
25	26	Line	0.0032	0.0323	0.5130	0
26	27	Line	0.0014	0.0147	0.2396	0
26	28	Line	0.0043	0.0474	0.7802	0
26	29	Line	0.0057	0.0625	1.0290	0
28	29	Line	0.0014	0.0151	0.2490	0
12	11	Tran.	0.0016	0.0435	0	1.0060
12	13	Tran.	0.0016	0.0435	0	1.0060
6	31	Tran.	0	0.0250	0	1.0700
10	32	Tran.	0	0.0200	0	1.0700
19	33	Tran.	0.0007	0.0142	0	1.0700
20	34	Tran.	0.0009	0.0180	0	1.0090
22	35	Tran.	0	0.0143	0	1.0250
23	36	Tran.	0.0005	0.0272	0	1.0000
25	37	Tran.	0.0006	0.0232	0	1.0250
2	30	Tran.	0	0.0181	0	1.0250
29	38	Tran.	0.0008	0.0156	0	1.0250
19	20	Tran.	0.0007	0.0138	0	1.0600

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