Towards a framework for modelling market-based congestion management in distribution grids

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***Abstract* —congestion management using congestion management (CM) markets could extend the grid operators CM toolbox and can be one way to unlock small-scale flexibility potentials. The presented framework allows to study the effects of operational CM markets and simulates the operational planning of flexibility providers as well as the grid operation planning of grid operators under consideration of CM markets. Within the operational planning, small-scale flexibilities are marketed via aggregators. Consequently, the grid operators perform grid analyses and determine current-based congestions. These congestions are then relieved by determining optimal countermeasures. The application of the presented framework shows its effectiveness in relieving congestions as well as a varying flexibility usage depending on the grid structure and the costs for activation.**

Keywords—congestion management, grid operators, flexibility markets, optimisation framework, operational flexibility

I. INTRODUCTION

Using market-based mechanisms within congestion management has been defined as a key principle within the internal market for electricity within the European Union [1]. Congestion management (CM) or flexibility markets are a practical implementation of this market-based principle allowing grid users to sell their operational flexibility to grid operators on a dedicated market to relieve grid congestions. CM markets and their effects have been discussed broadly within the literature [2-5]. Additionally, different concepts for CM markets have been tested European-wide within several different demonstration projects (see different classifications in [6-8]).

Congestion management and the market-based procurement of flexibility for CM purposes gain importance, especially in distribution grids, due to the fundamental changes that are based on the desired decarbonisation. The major driver on the generation side is the increasing number of installed generation based on volatile renewable energy sources (RES), especially in the distribution grids. On the demand side, increased sector coupling and electrification can be observed, leading to the expansion of heat pumps and an increasing share of electric vehicles. These developments pose challenges to the historically grown distribution grid structures, which must be addressed in long-term grid expansion planning. In a short-term grid operation, the developments lead to an increasing number of grid congestions which manifest as violations of the allowable voltage band or current limits.

The increasing flexibilisation of the demand side ends the time of static load patterns and offers growing flexibility potentials, which could be used in a grid-serving manner. CM markets can be seen as a possibility for integrating and raising distributed, small-scale flexibility potentials. In order to assess the operational implications of CM markets, simulation-based methods can be helpful.

II. OBJECTIVE

Anticipating the effects of a CM market for its participating flexibility providers as well as the grid operator is complex due to existing dependencies and numerous influencing factors. It seems obvious that both mentioned perspectives need to be taken into account while studying CM?.

For potential market participants (e.g., aggregators), a new market might offer additional earnings by placing operational flexibility on the market. This also affects the decision making in the conventional energy markets (day-ahead as well as the intraday market) and therefore the occurrence of grid congestions. For grid operators, the CM market is an additional tool to relieve congestions during the grid operation planning, where congestions are identified and optimal countermeasures are determined.

The aim of this contribution is to present a modelling framework that can be used to evaluate the effects of congestion management markets for flexibility providers as well as for grid operators. The framework focusses on modelling the offering as well as the demand of flexibility in an operational timeframe.

III. METHODOLOGICAL APPROACH

A. Underlying Market Design and Framework Overview

The developed framework is linked to an analysis of different possible market designs of CM markets that has been done within the European project INTERRFACE. Within the analysis, different CM market design options were described, among others, based on their purpose, level of integration, or timespan. The market design linked to the developed framework is an operational CM market that can be seen in Figure 1. On the market, the grid operator reserves capacity on the day before actual operation time and activates the necessary amount close to real-time.

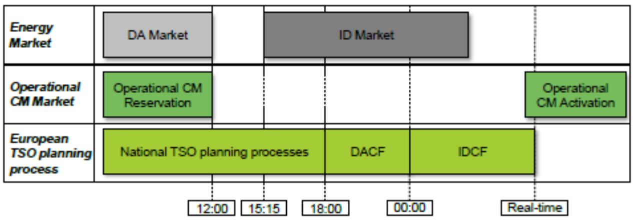

Figure 1 - Concept of an operation CM market

In order to evaluate the effects of the CM markets, it is necessary to take into account the processes that lead to the necessity of congestion management. The framework depicted in Figure 2 consists of two major parts, namely the simulation of the market participants' operational planning and the simulation of the grid operation planning.

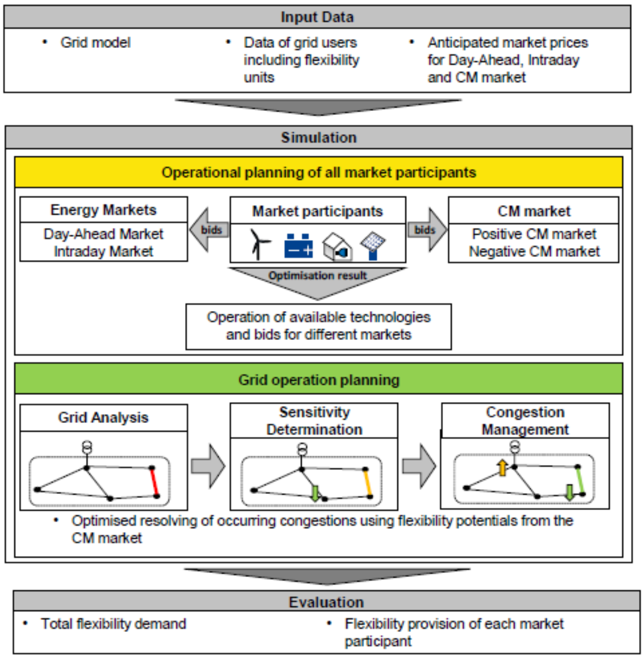

Figure 2 - Overview of the developed framework

The framework uses input data consisting of a grid model of the distribution grid excerpt, comprehensive data regarding the grid users (such as technological parameters) as well as anticipated market prices for the energy markets (day-ahead and intraday market) as well as the CM market.

As part of their operational planning, all grid users determine their optimal operational decisions as well as the optimal marketing decisions considering the anticipated prices on the markets.

Within the grid operation planning that is usually done on the day ahead, the grid operators conduct grid analyses based on the available information (e.g., weather forecast) in order to identify/predict? congestions. If necessary, they perform congestion management by using the offered flexibility from the CM market to relieve congestion.

As a result, the flexibility activated as well as unit specific schedules can be evaluated.

B. *Modelling of the Operational Planning of Market Participants*

1) *Objective Function of the Operational Planning*

As market participants can be active in multiple markets, there are different options for the operation of their controlled units and their trading decisions. It can be assumed that market participants aim to maximise their contribution margin by changing/planning ?their behaviour based on the price assumptions for the different markets. Therefore, the operational planning results in an optimisation problem. Within the framework, grid users connected to the same grid node or in the underlying grid are grouped and marketed together by a local aggregator. This aggregator manages the operation of the grid users and has access to the energy as well as the CM market.

The objective function of a single aggregator consists of two parts that are coupled by constraints:

$$max \left\{ \sum_{t=1}^{d} \mathit{operational\ decision} + \mathit{trading\ decision} \right\} \tag{1}$$

Within the operational decision, the aggregator decides for a single time step t how to operate its assets by determining their operation for the energy markets (day ahead (DA), intra day (ID)), the CM markets (CM+, CM-)[1] and the supply of the aggregator's load (Load) depending on generation costs for each asset i:[2]

$$\sum_{i=1}^{n} \left(P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,CM-} + P_{i,t}^{Gen,Load} \right) \cdot c_{i,t} \tag{2}$$

Within the trading decision, a portfolio-wide trading decision is determined for a single time step t. It contains the decision variables for selling ($Sell$) and buying (Buy) at the respective markets depending on the anticipated market prices p. Aggregators are only able to sell flexibility on the CM markets:

$$\left(P_t^{Sell,DA} - P_t^{Buy,DA}\right) \cdot p_t^{DA} + \left(P_t^{Sell,ID} - P_t^{Buy,ID}\right) \cdot p_t^{ID} + P_t^{+,CM} \cdot p_t^{+,CM} + P_t^{-,CM} \cdot p_t^{-,CM} \tag{3}$$

2) *Constraints of the Operational Planning*

A variety of different constraints apply to the operational planning of the aggregators. These can be grouped as follows

[1] Positive flexibility provision is understood as an increase of an active power injection or the decrease of consumption. Negative flexibility is defined as the decrease of active power injection or the increase of load.

[2] It should be noted that the objective function is more complex for storage technologies (electric vehicles and battery storages)

- Technological constraints for each individual asset of the aggregator (technology models)
- Constraints for trading in different markets
- Coupling constraints

In order to consider the existing operational constraints of the individual assets, specific technology models for different generations (RES plants, thermal plants, CHP) and storage technologies (battery storages, electric vehicles) as well as for load exist.

The technology models for generation technologies limit the sum of their generation for the markets to either their installed capacity (thermal plants and CHP) or their feed-in time series (RES). Additionally, offering negative flexibility in the CM market is coupled with participation in the wholesale markets. More complex constraints for thermal power plants such as minimum up- or downtimes are neglected, assuming that only flexible power plants are used. CHP plants can either operate heat-lead where an external heat demand defines a minimum generation baseband, or power-led, based only on electricity prices.

Within the framework, small-scale battery storage systems are considered. It is assumed that these systems can be accessed and used by the aggregators. For storage technologies, more complex constraints exist since the continuity of the State of Charge (SoC) needs to be ensured and time steps need to be coupled. Therefore, SoC variables for every time step exist that are affected by discharging the storage to either the energy markets or the load. The SoC is rising by charging the storage via the energy markets. Offering flexibility on the negative or positive CM market does not affect the SoC as activation is uncertain, whereas trades on the energy markets can be realised immediately for the given prices. Additionally, constraints on the power balance of the storage systems exist. These ensure that the sum of the operational decisions of the storage is within the charging and discharging power limits and are linked to the decisions for the CM market [3]. During operation only charging or discharging is allowed, which is ensured by additional binary variables.

Electric vehicles (EVs) that primarily satisfy mobility demands may also be used for the optimisation of the portfolio of the aggregator while being connected to the electrical grid. In the framework, EVs are modeled as storage systems with additional constraints. These additional constraints are the unavailability during driving times as well as the energy needed for driving. The latter affects the SoC and is modeled using minimum SoCs based on external driving profiles. The driving profiles are based on a driving profile generator which has been used to create a high number of EV profiles [9].

The constraints of trading in different markets ensure that either positive or negative flexibility is offered on the market. The coupling constraints of the operational planning couple the operational decision variables with the trading decision variables. Therewith, the power balance is kept in every time step.

C. *Modeling of the Grid Operation Planning of Grid Operators*

As part of the grid operation planning process, the grid operators anticipate congestions in its grid based on the schedules of the grid users and – if necessary - determine optimal countermeasures by using flexibility from the CM market. Within the framework, a simplified direct current (DC) load-flow is performed and current-based violations are considered as congestions if the resulting flow on the lines exceed the maximum admissible power flow.

In order to relieve detected congestions, the grid operator can use the flexibility that has been offered by the grid users on the CM market. The usage of flexibility is linked to the power flow by using linear sensitivity factors (power transfer distribution factors – PTDF) that result from the load flow analysis. The elements of the PTDF matrix can be interpreted as the effect of the activation of flexibility at unit i for the load flow of branch m:

$$PTDF_i^m = \frac{\Delta P_{Branch\,m}}{\Delta P_{Unit\,i}} \tag{4}$$

1) *Objective Function of the Grid Operation Planning*

For the planning of countermeasures for occurring congestions it can be assumed that grid operators aim for cost efficiency and the least-cost solution. Therefore, within the framework, the usage of flexibility by the grid operator is modeled as a mixed-integer optimisation problem minimizing the total costs of flexibility access in all time steps. The source of flexibility is two-fold: Firstly, the grid operator can access the local positive ($\Delta P_{i,t}^+$) and negative ($\Delta P_{i,t}^-$) flexibility that has been offered on the CM market by all grid user in its own and the underlying grid. Secondly, positive ($\Delta P_{Market,t}^+$) or negative ($\Delta P_{Market,t}^-$) flexibility from the intraday market can be used. This type of flexibility, available at the current market prices $c_{Market.t}^+$ and $c_{Market.t}^-$ does not affect local grid congestions due to the high spatial distance, but might be beneficial in grids where flexibility potentials are unbalanced. The resulting objective function is defined as:

$$min \left\{ \sum_{t=1}^{d} \left(\sum_{i=1}^{l} \Delta P_{i,t}^+ \cdot c_{i,t}^+ + \Delta P_{i,t}^- \cdot c_{i,t}^- \right) + \Delta P_{Market,t}^+ \cdot c_{Market.t}^+ + \Delta P_{Market,t}^- \cdot c_{Market.t}^- \right\} \tag{5}$$

2) *Constraints of the Grid Operation Planning*

[3] This allows that a storage system can offer full range of negative flexibility changing its mode of operation from discharging to charging (and vice versa)

For the developed optimisation problem within grid operation planning, three different types of constraints exist. These are namely

- Technological constraints for each individual asset for the provision of flexibility
- Congestion relief
- Balanced use of flexibility

In order to ensure that technological boundaries of the flexibility providing assets are considered, constraints for each individual assets exist. For generation (RES plants, thermal plants, CHP) technologies the flexibility potentials are limited to the offers within the CM market that have been determined as part of the operational planning. A more detailed consideration of technological constraints is not necessary as these have been considered already within the operational planning resulting in an optimal schedule. For storages and EV, the necessary constraints need to be more comprehensive since an activation changes the SoC [10]. This could lead to a violation of the SoC boundaries in later time steps which can be prevented by the active energetic compensation of the assets. Therefore, additional compensation and accounting variables exist. The compensation of the storage or EV is possible in all time steps of the optimisation horizon if the asset is available for compensation. The accounting variables keep track of the unbalanced energy over the optimisation horizon.

Central for the optimisation within the grid operation planning is the constraint to ensure that all occurring current-based congestions are relieved. Therefore, constraints for every line in every time step exist, linking the flexibility usage with the power flow on the line using the determined PTDF. The formulation considers the maximum admissible power flow F^m_{max} on the line in both directions, as well as the current base flow $F^m_{Base,t}$ before the activation of flexibility and is formulated as follows:

$$-F^m_{max} \le F^m_{Base,t} + \sum_{i=1}^{n} (\Delta P^+_{i,t} + C^-_{i,t}) \cdot PTDF^m_i - (\Delta P^-_{i,t} + C^+_{i,t}) \cdot PTDF^m_i \le F^m_{max} \qquad (6)$$

It should be noted that besides the activation of flexibility in positive ($\Delta P^+_{i,t}$) and negative ($\Delta P^-_{i,t}$) direction, also the necessary compensation of activated negative flexibility ($C^-_{i,t}$) as well as the compensation of positive flexibility ($C^+_{i,t}$) for storages and EV have an impact on the power flow. These need to be considered to prevent congestion induced by the compensation.

To account for a minimal impact of the congestion management on the energy system and individual grid customers, a balance-neutral flexibility activation is required. This ensures that the congestion management does not affect the system-wide power balance and stability. Therefore, a flexibility activation always needs to be balanced by an activation of flexibility in the opposite direction. The balancing can be done by using local flexibility or by flexibility from the intraday market. This existing constraint – valid for every time step – can be formulated as follows:

$$\sum_{i=1}^{n} \Delta P^+_{i,t} + \Delta P^+_{Market,t} = \sum_{i=1}^{n} \Delta P^-_{i,t} + \Delta P^-_{Market,t} \qquad (7)$$

IV. EXEMPLARY INVESTIGATIONS AND RESULTS

1) *Setup of the Test Cases*

For the exemplary investigations, the described framework has been parameterized by using two different medium voltage grids. The framework needs comprehensive data regarding the grid as well as the grid users. To ensure data consistency, the data is based on the SimBench project [11], and the installed capacities are shown in Table 1. With respect to electric vehicles, home charging stations (3.7 kW and 11 kW) as well as charging stations at work (3.7 kW, 11 kW, and 22 kW) are considered. The anticipated market prices for the energy markets as well as the CM market shown in Figure 3 are exemplary.

TABLE I. INSTALLED CAPACITIES OF THE TEST CASES INCLUDING RESOURCES WITHIN THE UNDERLYING LV GRID

Technology	**Installed Electrical Capacity / Load**	
	Rural Grid MV/LV	***Suburban Grid MV/LV***
Wind Power	13.4 / 0 MW	35.1 / 0 MW
PV	0.3 / 27.1 MW	1.7 / 24.0 MW
Storage Systems	0 / 6.3 MW	14.4 / 19.1 MW
Electric Vehicles	0 / 1.0	0 / 6.9 MW
CHP	0.9 / 0 MW	0.5 / 0 MW
Load	2.1 / 15.9 MW	1.2 / 36.4 MW

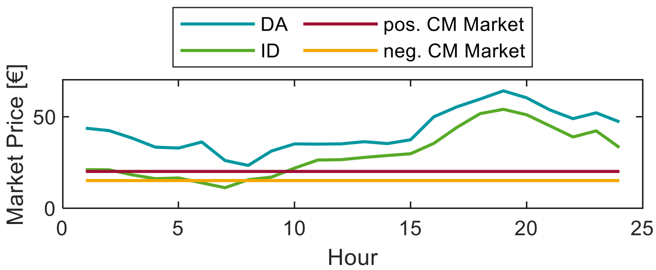

Figure 3 - Anticipated energy market and CM market prices

1) *Results of the Operational Planning*

As a result of the operational planning, the aggregators determine their optimal behaviour on the energy markets as well as the CM market. The aggregated operational schedule for all aggregators within the rural grid can be seen in Figure 4.

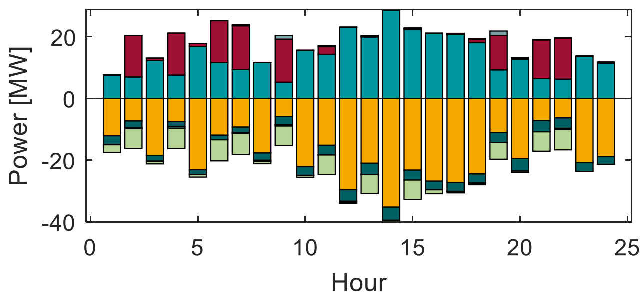

Figure 4 - Aggregated results of the operational planning within the rural grid

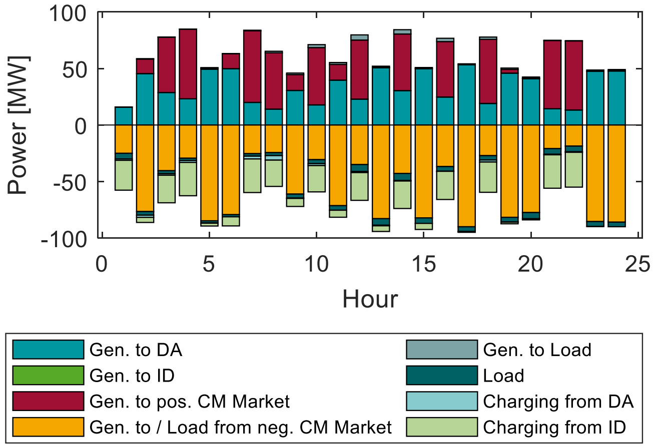

Figure 5 - Aggregated results of the operational planning within the suburban grid

It can be seen that in both cases, generation capacity is mainly marketed on the day ahead market, as it presumably offers the highest prices. Consistently, charging storages and EVs is done by buying from the cheaper intraday market. It should be noted, that the offered flexibility on the CM market is highly unbalanced especially in the rural grid due to the comparably higher RES potentials. This means that grid operators will only have limited possibilities to access local positive flexibility potential. The determined optimal schedules are transferred and serve as a basis within the operation planning

2) *Results of the Grid Operation Planning*

As part of the grid operation planning, the grid operator performs a load-flow analysis determining current-based congestions. Thereby, the branch utilisation limit has been defined as 50% of the total capacity based on the $n-1$ criterion. Branches with a higher utilisation are considered as congestions. The results of the load-flow analysis show a total of six situations with congestions with a maximum utilisation of 58% for the rural grid. Within the suburban grid, 198 situations with congestion exist with a maximum utilisation of 78%. In both test cases, the usage of flexibility by the grid operator relieves the congestions, pushing the branch utilisation below 50%.

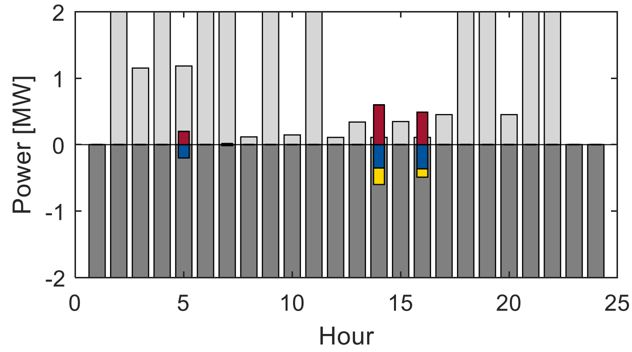

Figure 6 - Flexibility usage within the rural grid

In Figure 6, the result of the determination of the optimal flexibility usage is depicted. It shows the economic positive and negative flexibility potentials (in grey, cut off for better visibility) as well as the realised flexibility activations. It can be seen that solely negative flexibility potential from RES is used. In order to balance negative flexibility activation, flexibility from the intraday market is used.

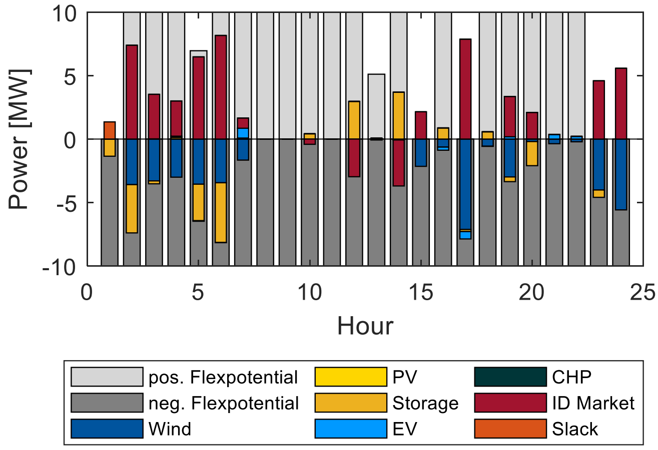

Figure 7 - Flexibility usage within the suburban grid

Since more severe congestions exist in the suburban grid, higher flexibility volumes are used as shown in Figure 7. It can be seen that storages and EV are used to a larger extent in both directions. Similarly, balancing flexibility activation is mostly done by using remote flexibility from the intraday market.

V. CONCLUSIONS

Market-based congestion management using CM markets could extend the grid operators toolbox in terms of CM and can be one way to unlock small scale flexibility potentials. The presented framework is one possible implementation to consider the effects of CM markets. Central for assessing those effects is the assumption that an additional market affects aggregators as well as grid operators. Within the exemplary investigations it could be shown that the aggregators offer positive and especially negative flexibility potentials on the CM market. Current-based congestions could be relieved using the offered flexibility. The chosen volume and technology for flexibility provision is dependent on the grid structure and therefore the nature of the congestions as well as the costs for flexibility provision.

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