Deliverable 3.5 - Final results of Market Design evaluation

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1 Executive Summary

Within the INTERRFACE project and based on the analysis in Deliverable D3.2, congestion management markets in addition to the existing ancillary service markets have been identified as a possible key instrument for grid operators to handle occurring congestions in their grids. Subsequently, different designs for these markets have been proposed and tested within the different demonstrators of the project.

In order to complement the view on congestion management (CM) markets and overcome some of the limitations associated with a practical application of the market designs, simulation-based approaches seem to be beneficial. Within work package 3, two different simulation-based frameworks have been developed to elaborate on the implications of congestion management markets. In this report, the foundations of both frameworks as well as some exemplary results are explained in detail.

The framework developed by RWTH aims for the realistic anticipation of the outcome of the congestion management processes including the market-based procurement of flexibility and is based on the conceptual design of a market for operational flexibility. Within the approach, both the operational planning of the market participants and the grid operation planning process of the grid operator are modelled in detail. Within the operational planning, individual aggregators optimise their generation and trading decisions of their unit portfolio to maximise their contribution margin taking into account several restrictions such as the technical constraints of their units. The resulting schedules (consisting of operating and decisions for the different markets) are considered by the grid operator during the grid operation planning, where a load-flow analysis identifies potential congestions. Based on these congestions, the grid operator optimises its flexibility usage during congestion management. Thereby, the grid operator can access the market participants' bids on the congestion management market. The framework is validated using a 6-bus validation case. More comprehensive investigations are performed on a 97-bus medium-voltage test case. The investigations show that the congestion management market offer an additional, price-sensitive marketing opportunity for market participants. Results of the test case considering a high penetration with renewable energy sources show a higher potential for negative / downward flexibility. The flexibility potential of storages systems and electric vehicles is limited due to higher costs as well as more complex operational constraints. Flexibility activation has also been shown to be highly dependent on the underlying activation costs.

At Tampere university a simulation environment has been designed and implemented to study complex energy systems while considering interactions between several involved parties. Within the environment, distribution system operator (DSO), Energy communities (ECs), local flexibility market (LFM), customers (e.g., storage resources) interact with each other to simulate a scenario as close as possible to the reality. The LFM operates one day, ahead of actual operation time from noon to 5 pm, linking DSO to the ECs. The DSO using its predictive grid optimization (PGO) application system, performs a analysis of the network forecast state (e.g., forecasted voltage values) for its 359 real-world distribution network. The analysis will indicate whether flexibility is needed. If needed, a detailed calculations by using sensitivity analysis is done to create a flexibility request containing flexibility duration, time, volume and congestion area. PGO sends the flexibility request to LFM and LFM forward the needs to ECs. ECs using their economic dispatch (ED) application system then optimize their schedules and may participate in LFM. Then the DSO, using its PGO selects the cheapest offers (if any offer exist) from the market and informs the LFM about the decision. Finally, the responsible ECs are informed by LFM. Once ED updates the flexibility resource's schedules according to the sold flexibility, in real time operation, the flexibilities are activated. DSO can confirm activation of flexibility using its state monitoring (SM) application system. The results show that the simulation environment can simulate multi-stakeholder decision-making problems without making assumptions of stakeholders' interactions (interactions might be both synergy benefits or conflict-of-interests). In addition, the case study shows some complexities of DSO level market-based congestion management, including liquidity issues when flexibility needs are local. Furthermore, it is shown that the rebound effect impacts the ability of flexibility providers in market participation significantly under certain circumstances such as when flexibility volume is limited and diversity of ECs portfolio is limited to one kind of technology.

It has been shown that simulation-based approaches can complement the practical application of CM markets. In order to accurately assess the available flexibility potential, it is important to consider the operational decisions of market participants on different markets. With respect to grid operators it has been shown that within the distribution grid very local flexibility is needed and that the usable flexibility potential is highly dependent on the grid structure.

2 Introduction and Structure of the Report

Within T3.2 of the INTERRFACE project, different market designs for congestion management (CM) markets have been introduced and described. During the project, all demonstrators implemented and tested some of the market designs and gained valuable insight into the practical application of these market designs. Based on these experiences, possible amendments and revisions with respect to the CM markets have been analysed and aggregated in D3.4.

This approach to gain insights into CM markets is complemented by simulation-based approaches. These approaches, which aim to model the processes and participants of the system under investigation in detail, add another perspective and can overcome certain limitations of the practical demonstration. With their implementation, simulation-based approaches can abstract to a certain degree from the regulatory specifics. In addition, they offer a higher degree of freedom as well as a more universal approach regarding the object of investigation.

In the context of this deliverable D3.5, the project partners RWTH and TUT have developed simulation-based frameworks that aim towards a deeper understanding of CM markets and its processes. Both approaches focus on modelling the congestion management processes of distribution grid operators taking into account a congestion management market. The developed approaches can be used for a variety of research questions such as the impact of higher penetrations of flexible units on the results within the congestion management process.

In this report, the developed frameworks are described and exemplary simulation results are presented. In chapter 3, the developed framework by RWTH, which aims to deepen the understanding of an operational congestion management market, is presented. A detailed presentation of the mathematical models for the operational planning of single market participants as well as the resulting congestion management problem of the grid operator are provided. The developed model is validated within a small validation case. Subsequently, a synthetic 97-node test case will be used for the investigations.

In chapter 4, the simulation environment developed by TUT is presented. The environment could be used to study complex energy systems while considering interactions between several involved parties. Within the environment, distribution system operator (DSO), Energy communities (ECs), local flexibility market (LFM), customers (e.g., storage resources) interact with each other to simulate a scenario as close as possible to the reality. Sequence diagrams are used to show the workflow of components in day ahead and operational time frame. Flexibility product attributes are explained and a method to calculate the flexibility volume and flexibility area is proposed. The distribution network used for studies is a real grid in Finland consists of 359 buses. Finally, some initial results of simulations are presented.

At the end of the report, the consolidated results valid for both frameworks are presented.

3 Simulation-based Approach for Evaluating Congestion Management Markets by RWTH Aachen University

3.1 Motivation and Purpose

Within the INTERRFACE project, the market designs that have been presented and analysed in T3.2 have partly been applied by the demonstrators within their individual demonstration projects. Therewith, the feedback of the demos concerning the market design is limited to the regulatory specifics and the scope of the demonstrators. For that reason, general conclusions can hardly be drawn.

As an extension, simulation-based approaches can overcome those limitations and are used to further evaluate CM markets and the effect on the congestion management of grid operators on a more analytical basis. Therewith, the simulation methods help to investigate the impact of some general conditions regarding the market results and the efficiency of a market-based procurement of flexibility.

Within this task a simulation framework has been developed, which aims for the realistic anticipation of the outcome of the congestion management processes including the market based procurement of flexibility. Conceptually, as shown in Figure 1 the framework is linked to the concept of an operational CM market, where capacity is reserved beforehand and activated within real-time. No integration with other markets and/or other CM markets on other voltage levels is considered.

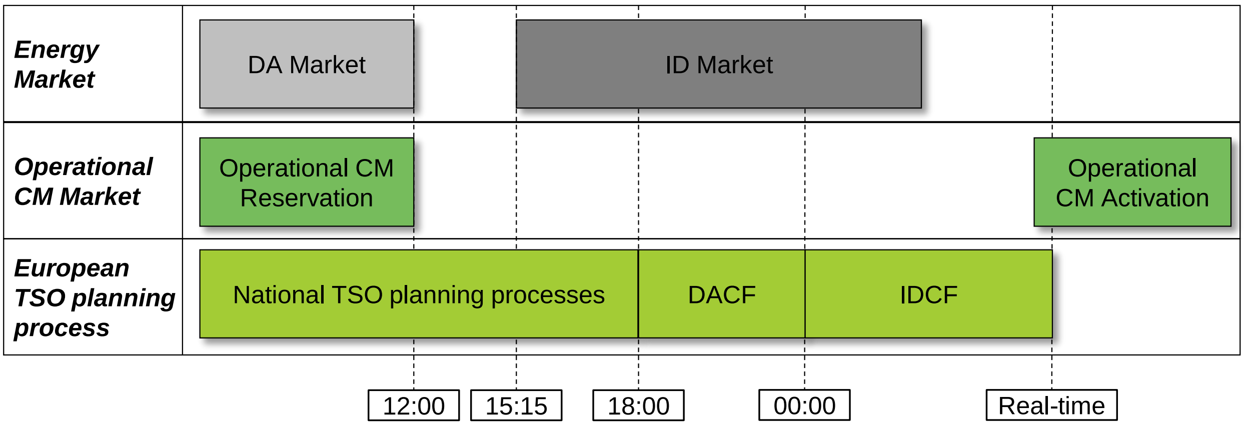


Figure 1 - Concept of an operational CM market according to D3.2 of the INTERRFACE project[1]

For potential market participants, a novel market offers additional earnings since they are able to place their operational flexibility potential. For grid operators, the CM market could extend the usable flexibility potential. Thereby, the impact of the available flexibility potentials as well as varying activation costs for different technologies will be exemplarily investigated. This helps to understand the major influencing factors for congestion management. It may also be used to qualitatively draw conclusions regarding the market design of the congestion management market.

[1] DACF: Day-Ahead Congestion Forecast, IDCF: Intraday Congestion Forecast

3.2 Methodological Approach of the Developed Framework

In order to evaluate concepts for congestion management it is necessary to take into account the processes that lead to the necessity of congestion management. Therefore, the developed framework that is depicted in Figure 2 follows a two-step approach:

- Operational planning to determine the optimal operation and marketing of units for all market participants
- Grid operation planning to identify occurring congestions within the grid and determine the optimal countermeasures

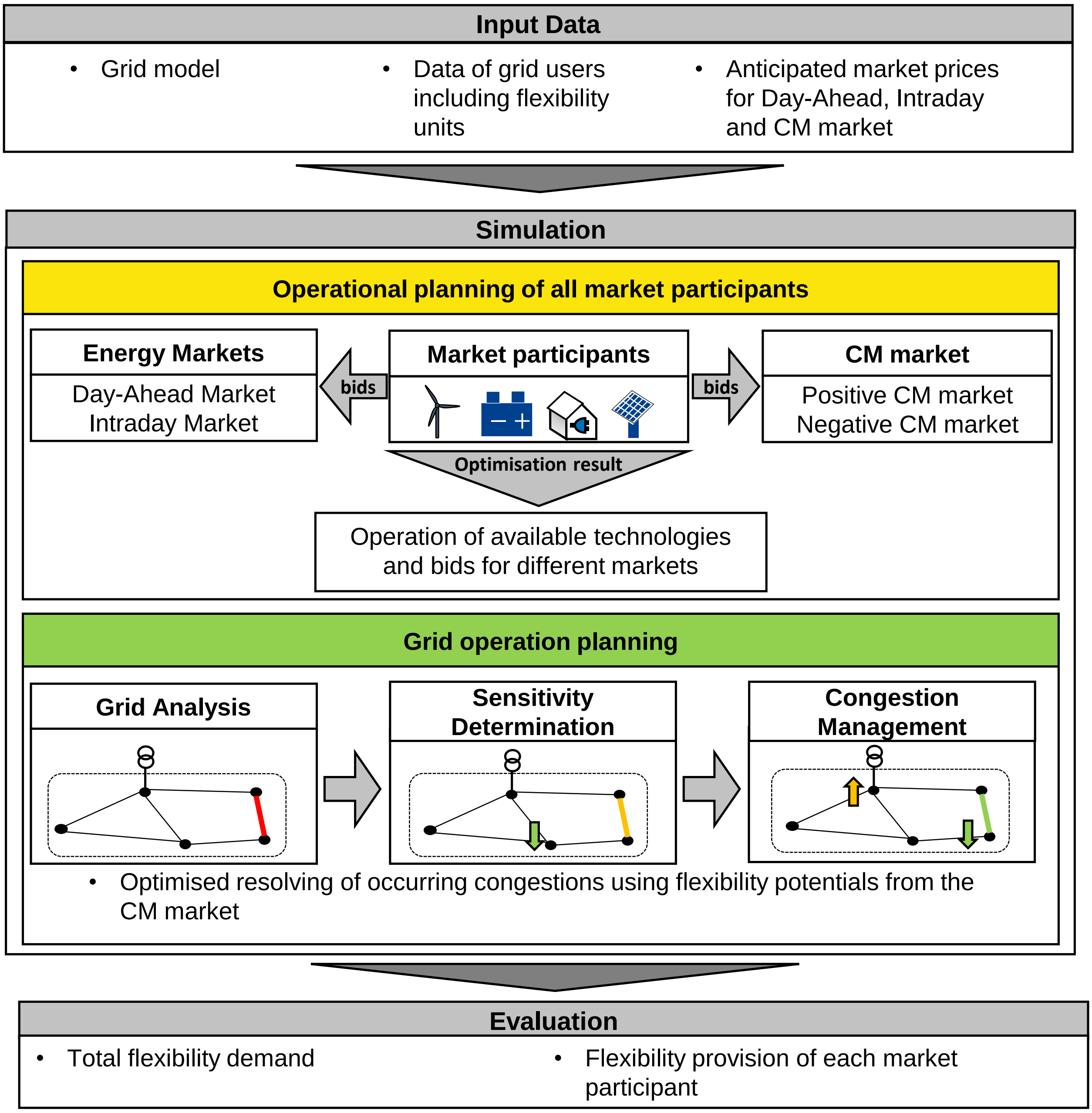


Figure 2 - Overview of the methodological approach of the developed framework

The framework uses comprehensive input data regarding the grid excerpt that is under investigation, the grid users (including technological parameters) as well as anticipated market prices for all potential markets.

Within their operational planning, market participants can decide to offer their flexibility on the positive or negative congestion management (CM) market. However, offering flexibility to these CM markets does not necessarily mean that the units are chosen within the congestion management process by the grid operator later. This is in contrast to the energy markets where bids are physically definite[2].

Within the framework positive flexibility provision is understood as the increase of an active power injection or the decrease of consumption of a unit. Negative flexibility can be provided by decreasing the active power injection or increasing the load.

Regarding the subsequent mathematical formulation of the developed framework, the following sets are used:

Set	Element of set	Total elements	Description
N	i	n	Set of different units for a single EMS
T	t	d	Set of time steps
B	m	b	Set of branches within the grid

3.2.1 Mathematical Formulation of the Operational Planning of Market Participants

The operational planning of the market participants aims towards a realistic modelling of the operational marketing of units (generation, storages and consumption) at different markets. Thereby, units that are connected to the grid in the same low voltage link are marketed together by an aggregator resulting in individual energy management systems (EMS) located at every medium voltage grid node. The EMS manage the operation of the associated units, have access to the Day-Ahead and Intraday wholesale markets and are able to provide flexibility on the congestion management market due to their spatial proximity. The objective of the individual EMS systems is to maximize their contribution margin by operating at the different existing markets based on deterministic price predictions. This results in an objective function for every EMS that consists of two parts (operation decision and trading decision) that are coupled and enable a wide range of different EMS configurations to be covered (EMS with and w/o physical assets).

$$max\ \{operation\ decision + trading\ decision\}$$

Within the operation decision, the EMS decides which asset is in operation. The distinction of different markets allows an easier allocation of the marketed quantities compared to a summarised decision variable. Within the trading decision, the EMS decides about buying or selling electricity on the wholesale markets depending on the price as well as selling positive or negative flexibility on the CM market. A simplified version[3] of the objective function can be formulated as:

$$max \left\{ \sum_{t=1}^{d} \left(\sum_{i=1}^{n} \left(P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,CM-} + P_{i,t}^{Gen,Load} \right) \cdot c_{i,t} \right) + \left(P_t^{Sell,DA} - P_t^{Buy,DA} \right) \right.$$
$$\left. \cdot\, p_t^{DA} + \left(P_t^{Sell,ID} - P_t^{Buy,ID} \right) \cdot p_t^{ID} + P_t^{+,CM} \cdot p_t^{+,CM} + P_t^{-,CM} \cdot p_t^{-,CM} \right\} \qquad 1.1$$

$$where$$

Parameter	Description
$P_{i,t}^{Gen,DA}$	Generation of unit i at time step t for the DA market
$P_{i,t}^{Gen,ID}$	Generation of unit i at time step t for the ID market

[2] This is based on the assumption that the individual units are small within the energy markets and won't affect the prices there (price-takers).
[3] It should be noted that for storage technologies (Storages and EVs) the objective function can be more complex.

$P_{i,t}^{Gen,CM+}$	Generation of unit i at time step t for the positive CM market
$P_{i,t}^{Gen,CM-}$	Generation of unit i at time step t for the negative CM market
$P_{i,t}^{Gen,Load}$	Generation of unit i at time step t for covering the load of the EMS
$c_{i,t}$	Costs for generation of unit i at time step t
$P_t^{Sell,DA}$	Quantity sold on the DA market by the EMS at time step t
$P_t^{Buy,DA}$	Quantity bought on the DA market by the EMS at time step t
p_t^{DA}	Predicted market price of the DA market at time step t
$P_t^{Sell,ID}$	Quantity sold on the ID market by the EMS at time step t
$P_t^{Buy,ID}$	Quantity bought on the ID market by the EMS at time step t
p_t^{ID}	Predicted market price of the ID market at time step t
$P_t^{+,CM}$	Quantity of positive flexibility reserved for the CM market at time step t
$p_t^{+,CM}$	Predicted market price for positive flexibility at time step t
$P_t^{-,CM}$	Quantity of negative flexibility reserved for the CM market at time step t
$p_t^{-,CM}$	Predicted market price for negative flexibility at time step t

For the optimisation of the operational planning, various constraints – especially regarding the used assets – apply. The constraints can be grouped as follows and will be described in detail in the following paragraphs:

- Technical constraints of the assets of the EMS / Technology models
- Constraints for trading at the different markets / Sub models for markets
- Coupling constraints

Technology Models – Renewable Energy Sources

As part of the optimisation, wind power plants as well as photovoltaic plants are considered. All RES units are associated with a deterministic feed-in time series. The value of the generation time series serves as an upper bound for the sum of the individually sold generation shares of the unit for the individual markets (including the positive CM market where generation capacity needs to be reserved). Additionally, a possible participation of the unit at the negative CM market is coupled with the participation at the wholesale markets. Therefore, the technical constraints for photovoltaic and wind power plants can be formulated as follows:

$$0 \le P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} \le P_{i,t}^{Feedin} \quad \forall t \in T, i \in N \tag{1.2}$$

$$0 \le P_{i,t}^{Gen,CM-} - P_{i,t}^{Gen,DA} - P_{i,t}^{Gen,ID} \le 0 \quad \forall t \in T, i \in N \tag{1.3}$$

$$0 \le P_{i,t}^{Gen,DA}, P_{i,t}^{Gen,CM+}, P_{i,t}^{Gen,CM-}, P_{i,t}^{Gen,ID}, P_{i,t}^{Gen,Load} \le P_{i,t}^{Feedin} \quad \forall t \in T, i \in N \tag{1.4}$$

$$where$$

Parameter	Description
$P_{i,t}^{Feedin}$	Deterministic feed-in of unit i at time step t

The individual generation shares do not have a contribution to the objective function, since the variables costs of the operation of RES can be neglected.

TECHNOLOGY MODELS – THERMAL PLANTS

It is assumed that a majority of plants within the distribution grid are gas power plants that can be operated flexibly. Therefore, more complex constraints such as minimum up- and downtimes or ramps are neglected. The installed capacity of the plant naturally limits the sum of the individual shares of the unit for individual markets. Analogously to RES, the constraints for thermal plants can be defined as follows:

$$0 \leq P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} \leq P_i^{Max} \quad \forall t \in T, i \in N \tag{1.5}$$

$$0 \leq P_{i,t}^{Gen,CM-} - P_{i,t}^{Gen,DA} - P_{i,t}^{Gen,ID} \leq 0 \quad \forall t \in T, i \in N \tag{1.6}$$

$$0 \leq P_{i,t}^{Gen,DA}, P_{i,t}^{Gen,CM+}, P_{i,t}^{Gen,CM-}, P_{i,t}^{Gen,ID}, P_{i,t}^{Gen,Load} \leq P_i^{Max} \quad \forall t \in T, i \in N \tag{1.7}$$

$$where$$

Parameter	Description
$P_{i,t}^{Max}$	Maximum power output of unit i

Since the operation of the plant is associated with variable costs, all decision variables (except for the negative congestion management market) contribute to the objective function with variable costs.

TECHNOLOGY MODELS – COMBINED HEAT AND POWER PLANTS (CHP)

Combined Heat and Power plants convert chemical energy from gas into thermal and electrical energy. Depending on the size of the plant, different types of CHP plants exist. Within the model, small back-pressure cogeneration plants with a constant power to heat ratio are considered. The plant can be operated either heat-lead or power-lead. The heat-lead operation is based on the time series of the heat demand whereas within power-lead operation the plant is operated more flexible based on electricity prices. The latter mode of operation is similar to thermal plants which leads to similar constraints within the model:

Power-lead operation:

$$0 \leq P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} \leq P_i^{Max} \quad \forall t \in T, i \in N \tag{1.8}$$

Heat-lead operation:

$$Q_{i,t}^{Demand} \cdot \eta_i^{CHP} \leq P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} \leq P_i^{Max} \quad \forall t \in T, i \in N \tag{1.9}$$

Power- / Heat-lead operation:

$$0 \leq P_{i,t}^{Gen,CM-} - P_{i,t}^{Gen,DA} - P_{i,t}^{Gen,ID} \leq 0 \quad \forall t \in T, i \in N \tag{1.10}$$

$$0 \leq P_{i,t}^{Gen,DA}, P_{i,t}^{Gen,CM+}, P_{i,t}^{Gen,CM-}, P_{i,t}^{Gen,ID}, P_{i,t}^{Gen,Load} \leq P_i^{Max} \quad \forall t \in T, i \in N \tag{1.11}$$

$$where$$

Parameter	Description
P_i^{Max}	Maximum electrical power output of CHP plant i
$Q_{i,t}^{Demand}$	Heat demand for CHP plant i at time step t
η_i^{CHP}	Power to heat ratio of CHP plant i

Similar to thermal power plants, all decisions variables (except for the negative congestion management market) contribute to the objective function with the variable costs of the plant.

TECHNOLOGY MODELS – BATTERY STORAGES

With battery storages, electrical energy can be stored over time. The storages considered in the model are small-scale storage systems. The characterizing parameters are the input/output power, the efficiency during charging/discharging as well as the storage capacity of the asset. In addition to the generation for different markets (discharging), additional continuous decision variables exist for the demand of the storage at different markets (by charging the storage). During operation, only either charging or discharging is possible during a single time-step. Therefore, two additional binary variables that indicate whether the storage is charging or discharging are added. These variables are coupled with the continuous decision indicating the operation of the storage for the different markets. Additionally, charging or discharging affects the state-of-charge (SOC) of the storage, which is implemented as an additional continuous variable. With respect to the SOC, the efficiency of charging and discharging needs to be considered. Furthermore, a physical balance ensures that all physically-effective trading decisions[4] are within the physical limits and also linked to the decisions regarding the CM market. This leads to the following constraints for battery storages:

SOC:

$$0 \leq -\frac{1}{\eta_{Discharge}} \cdot \left(P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load}\right) + \eta_{Discharge} \cdot \left(P_{i,t}^{LoadStorage,DA} + P_{i,t}^{LoadStorage,ID}\right) - SOC_{i,t-1} + SOC_{i,t} \leq 0 \quad \forall t \in T, i \in N \tag{1.12}$$

$$0 \leq P_{i,t}^{Gen,DA}, P_{i,t}^{Gen,ID}, P_{i,t}^{Gen,Load} \leq P_{i}^{Discharge,Max} \quad \forall t \in T, i \in N \tag{1.13}$$

$$0 \leq P_{i,t}^{LoadStorage,DA}, P_{i,t}^{LoadStorage,ID} \leq P_{i}^{Charge,Max} \quad \forall t \in T, i \in N \tag{1.14}$$

$$W_i^{Min} \leq SOC_{i,t} \leq W_i^{Max} \quad \forall t \in T, i \in N \tag{1.15}$$

Charging / Discharging Balance Physically:

$$-P_i^{Charge,Max} \leq P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} - P_{i,t}^{LoadStorage,DA} - P_{i,t}^{LoadStorage,ID} \leq P_i^{Discharge,Max} \quad \forall t \in T, i \in N \tag{1.16}$$

Charging / Discharging Balance Virtually:

$$-P_i^{Charge,Max} \leq P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} - P_{i,t}^{LoadStorage,DA} - P_{i,t}^{LoadStorage,CM-} - P_{i,t}^{LoadStorage,ID} \leq P_i^{Discharge,Max} \quad \forall t \in T, i \in N \tag{1.17}$$

Status Charge:

$$0 \leq -P_{i,t}^{LoadStorage,DA} - P_{i,t}^{LoadStorage,ID} + M \cdot y_{i,t}^{Charge} \leq M \quad \forall t \in T, i \in N \tag{1.18}$$

$$0 \leq y_{i,t}^{Charge} \leq 1 \quad \forall t \in T, i \in N \tag{1.19}$$

Status Discharge:

$$0 \leq -P_{i,t}^{Gen,DA} - P_{i,t}^{Gen,ID} - P_{i,t}^{Gen,Load} + M \cdot y_{i,t}^{Discharge} \leq M \quad \forall t \in T, i \in N \tag{1.20}$$

$$0 \leq y_{i,t}^{Discharge} \leq 1 \quad \forall t \in T, i \in N \tag{1.21}$$

Exclusivity of charge or discharge operation:

$$0 \leq y_{i,t}^{Charge} + y_{i,t}^{Discharge} \leq 1 \quad \forall t \in T, i \in N \tag{1.22}$$

$where$

Parameter	Description
$P_{i,t}^{LoadStorage,DA}$	Demand of storage i at time step t for the DA market
$P_{i,t}^{LoadStorage,ID}$	Demand of storage i at time step t for the ID market
$\eta_{Discharge} = \eta_{Charge}$	Efficiency of (dis)charging the storage
$SOC_{i,t-1}$	State of charge of storage i at time step t-1

[4] This does not include the activity on the CM market, since the activation is unknown to the EMS beforehand.

$SOC_{i,t}$	State of charge of storage i at time step t
W_i^{Min}	Minimum storage level of storage i
W_i^{Max}	Maximum storage level of storage i
$P_i^{Charge,Max}$	Maximum charging power of storage i
$P_i^{Discharge,Max}$	Maximum discharging power of storage i
M	Disjunctive parameter
$y_{i,t}^{Charge}$	Charging status
$y_{i,t}^{Discharge}$	Discharging status

As the variable costs of a storage can be neglected, the individual decision variables do not affect the objective function.

Technology Models – Electric Vehicles

Electric vehicles (EVs) primarily satisfy mobility demands. The necessary energy demand for driving is charged before departure. Since EVs are connected to the grid while being parked for a significant amount of time during the day, they can be used for other purposes (such as the optimisation of the portfolio of an aggregator) as well. Within the model they are modelled similar to battery storages, which are unavailable during driving times and have certain constraints regarding the minimum SOC. Thus, decision variables exist for discharging the EV and providing electricity for different markets and the loads[5] as well as charging the EV via the different markets. A fixed variable directly affecting the SOC of the EV can be interpreted as the energy used for driving. Similarly to the storage binary variables ensure that only charging or discharging is done during a single time step. Additionally, binary variables ensure that either positive or negative flexibility is placed on the respective congestion management markets.

SOC:

$$0 \leq -\frac{1}{\eta_{Discharge}} \cdot \left(P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load}\right) + \eta_{Discharge} \cdot \left(P_{i,t}^{LoadEV,DA} + P_{i,t}^{LoadEV,ID}\right) - W_{i,t}^{Driving} - SOC_{i,t-1} + SOC_{i,t} \leq 0 \quad \forall t \in T, i \in N \qquad 1.23$$

$$0 \leq P_{i,t}^{Gen,DA}, P_{i,t}^{Gen,ID}, P_{i,t}^{Gen,Load} \leq P_i^{Discharge,Max} \quad \forall t \in T, i \in N \qquad 1.24$$

$$0 \leq P_{i,t}^{LoadEV,DA}, P_{i,t}^{LoadEV,ID} \leq P_i^{Charge,Max} \quad \forall t \in T, i \in N \qquad 1.25$$

$$W_i^{Min} \leq SOC_{i,t} \leq W_i^{Max} \quad \forall t \in T, i \in N \qquad 1.26$$

$$w_{i,t}^{Driving} \leq W_{i,t}^{Driving} \leq w_{i,t}^{Driving} \quad \forall t \in T, i \in N \qquad 1.27$$

Charging / Discharging Balance Physically:

$$-P_i^{Charge,Max} \leq P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} - P_{i,t}^{LoadEV,DA} - P_{i,t}^{LoadEV,ID} \leq P_i^{Discharge,Max} \quad \forall t \in T, i \in N \qquad 1.28$$

Charging / Discharging Balance Virtually:

$$-P_i^{Charge,Max} \leq P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} - P_{i,t}^{LoadEV,DA} - P_{i,t}^{LoadEV,CM-} - P_{i,t}^{LoadEV,ID} \leq P_i^{Discharge,Max} \quad \forall t \in T, i \in N \qquad 1.29$$

Status Charge:

$$0 \leq -P_{i,t}^{LoadEV,DA} - P_{i,t}^{LoadEV,ID} + M \cdot y_{i,t}^{Charge} \leq M \quad \forall t \in T, i \in N \qquad 1.30$$

$$0 \leq y_{i,t}^{Charge} \leq 1 \quad \forall t \in T, i \in N \qquad 1.31$$

[5] Theoretically, the EMS could cover its connected loads by discharging the existing electric vehicles.

Status Discharge:

$$0 \leq -P_{i,t}^{Gen,DA} - P_{i,t}^{Gen,ID} - P_{i,t}^{Gen,Load} + M \cdot y_{i,t}^{Discharge} \leq M \quad \forall t \in T, i \in N \tag{1.32}$$

$$0 \leq y_{i,t}^{Discharge} \leq 1 \quad \forall t \in T, i \in N \tag{1.33}$$

Exclusivity of charge or discharge operation:

$$0 \leq y_{i,t}^{Charge} + y_{i,t}^{Discharge} \leq 1 \quad \forall t \in T, i \in N \tag{1.34}$$

Status Positive flexibility provision:

$$0 \leq -P_{i,t}^{Gen,CM+} + M \cdot y_{i,t}^{PosFlexProvision} \leq M \quad \forall t \in T, i \in N \tag{1.35}$$

$$0 \leq y_{i,t}^{PosFlexProvision} \leq 1 \quad \forall t \in T, i \in N \tag{1.36}$$

Status Negative flexibility provision:

$$0 \leq -P_{i,t}^{Gen,CM-} + M \cdot y_{i,t}^{NegFlexProvision} \leq M \quad \forall t \in T, i \in N \tag{1.37}$$

$$0 \leq y_{i,t}^{NegFlexProvision} \leq 1 \quad \forall t \in T, i \in N \tag{1.38}$$

Exclusivity of positive or negative flexibility provision:

$$0 \leq y_{i,t}^{PosFlexProvision} + y_{i,t}^{NegFlexProvision} \leq 1 \quad \forall t \in T, i \in N \tag{1.39}$$

$$where$$

Parameter	Description
$P_{i,t}^{LoadEV,DA}$	Demand of EV i at time step t for the DA market
$P_{i,t}^{LoadEV,ID}$	Demand of EV i at time step t for the ID market
$\eta_{Discharge} = \eta_{Charge}$	Efficiency of (dis)charging the EV
$W_{i,t}^{Driving}$	Change of SOC of the EV i at time step t due to driving
$w_{i,t}^{Driving}$	Energy used for driving of the EV i at time step t
$SOC_{i,t-1}$	State of charge of EV i at time step t-1
$SOC_{i,t}$	State of charge of EV i at time step t
W_i^{Min}	Minimum storage level of EV i
W_i^{Max}	Maximum storage level of EV i
$P_i^{Charge,Max}$	Maximum charging power of EV i
$P_i^{Discharge,Max}$	Maximum discharging power of EV i
M	Disjunctive parameter
$y_{i,t}^{Charge}$	Charging status
$y_{i,t}^{Discharge}$	Discharging status
$y_{i,t}^{PosFlexProvision}$	Status of positive flexibility provision
$y_{i,t}^{NegFlexProvision}$	Status of negative flexibility provision

TECHNOLOGY MODELS – LOAD SUPPLY

From the perspective of the EMS, the static electrical load at the node that needs to be supplied can either be covered by the generation units at the node or by buying electricity at the different markets. Therefore, the decision variable for the load at every time step is fixed to the actual load and will be coupled with the operation decisions as well as the trading decisions.

$$0 \leq P_t^{Load} \leq \; P_t^{Load,Forecast} \qquad \forall t \;\in\; T \tag{1.40}$$

$$where$$

Parameter	Description
P_t^{Load}	Load of EMS at time step t
$P_t^{Load,Forecast}$	Forecasted load of EMS at time step t

SUB MODELS FOR MARKETS – DA/ID MARKET

With respect to their trading decision, the EMS can buy or sell electricity at the Day-Ahead as well as the Intraday market. The trading variables at each time step are weighted inside the objective function with the anticipated market price in the respective market. This ensures that the energy which is procured for charging storages/EVs or covering the load is bought at market price. No price gap between buying and selling at the energy markets is assumed. The variables are defined as follows:

DA Market:

$$0 \leq P_t^{Sell,DA}, P_t^{Buy,DA} \leq M \qquad \forall t \;\in\; T \tag{1.41}$$

ID Market:

$$0 \leq P_t^{Sell,ID}, P_t^{Buy,ID} \leq M \qquad \forall t \;\in\; T \tag{1.42}$$

$$where$$

Parameter	Description
$P_t^{Sell,DA}$	Amount of sold energy of EMS at time step t at DA market
$P_t^{Buy,DA}$	Amount of bought energy of EMS at time step t at DA market
M	Disjunctive parameter
$P_t^{Sell,ID}$	Amount of sold energy of EMS at time step t at ID market
$P_t^{Buy,ID}$	Amount of bought energy of EMS at time step t at ID market

SUB MODELS FOR MARKETS – CONGESTION MANAGEMENT MARKET

In addition to marketing and procuring energy at the Day-Ahead- and Intraday-Market, the EMS can place bids on the congestion management markets for offering flexibility at the respective time step. Similar to the energy markets, the two decision variables are weighted within the objective function with the anticipated prices on the positive or negative congestion management market. For simplification the EMS cannot be active on the positive and the negative congestion management market at the same time step, which is ensured by binary status variables. The constraints for congestion management markets are as follows:

Status Positive flexibility selling:

$$0 \leq -P_t^{Sell,CM+} + M \cdot y_t^{PosFlexSell} \leq M \qquad \forall t \;\in\; T \tag{1.43}$$

$$0 \leq P_t^{Sell,CM+} \leq \; M \qquad \forall t \;\in\; T \tag{1.44}$$

$$0 \leq y_t^{PosFlexSell} \leq \; 1 \qquad \forall t \;\in\; T \tag{1.45}$$

Status Negative flexibility selling:

$$0 \leq -P_t^{Sell,CM-} + M \cdot y_t^{NegFlexSell} \leq M \qquad \forall t \;\in\; T \tag{1.46}$$

$$0 \leq P_t^{Sell,CM-} \leq M \qquad \forall t \in T \tag{1.47}$$

$$0 \leq y_t^{NegFlexSell} \leq 1 \qquad \forall t \in T \tag{1.48}$$

Exclusivity of positive or negative flexibility marketing:

$$0 \leq y_t^{PosFlexSell} + y_t^{NegFlexSell} \leq 1 \qquad \forall t \in T \tag{1.49}$$

$$where$$

Parameter	Description
$P_t^{Sell,CM+}$	Amount of flexibility of EMS at time step t for the positive CM market
$P_t^{Sell,CM-}$	Amount of flexibility of EMS at time step t for the negative CM market
$y_t^{PosFlexSell}$	Status of positive flexibility selling
$y_t^{NegFlexSell}$	Status of negative flexibility selling
M	Disjunctive parameter

COUPLING CONSTRAINTS FOR THE OPERATION AND TRADING DECISION – SALE COUPLING

In order to consistently model the generation and trading decisions of the EMS, the existing decision variables for generation are coupled with the decision variables for trading. This ensures that every EMS complies with the power balance and no energy is created or used unaccounted for. Please note that the operation decisions of all units of the EMS are considered here. The constraint for the overall power balance can be formulated as:

$$\begin{aligned} 0 \leq \sum_{i=1}^{n} (P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,CM+} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} - P_{i,t}^{Gen,CM-}) - P_t^{Sell,DA} + P_t^{Buy,DA} \\ - P_t^{Sell,CM+} - P_{i,t}^{Sell,CM-} - P_t^{Sell,ID} + P_t^{Buy,ID} + P_t^{Load} \leq 0 \qquad \forall t \in T \end{aligned} \tag{1.50}$$

$$where$$

Parameter	Description
$P_{i,t}^{Gen,DA}$	Generation of unit i at time step t for the DA market
$P_{i,t}^{Gen,CM+}$	Generation of unit i at time step t for the positive CM market
$P_{i,t}^{Gen,ID}$	Generation of unit i at time step t for the ID market
$P_{i,t}^{Gen,Load}$	Generation of unit i at time step t for covering the load of the EMS
$P_{i,t}^{Gen,CM-}$	Generation of unit i at time step t for the negative CM market

COUPLING CONSTRAINTS FOR THE OPERATION AND TRADING DECISION – LOAD COUPLING

To ensure that the covering of the load is modelled adequately an additional coupling constraint exists. It ensures that the energy for the load of the EMS is either generated by the assets of the EMS or purchased on the Intraday- or Day-Ahead market. The constraint can be formulated as follows:

$$0 \leq \sum_{i=1}^{n} (P_{i,t}^{Gen,Load}) + P_t^{Buy,DA} + P_t^{Buy,ID} - P_t^{Load} \leq 0 \qquad \forall t \in T \tag{1.51}$$

COUPLING CONSTRAINTS FOR THE OPERATION AND TRADING DECISION – COUPLING DA/ID/CM MARKET

For an accurate accounting of the amount of energy generated, the generation variables for individual markets are directly coupled with the selling variables. The constraints for the Day-ahead, the Intraday as well as the CM Market can be formulated as follows:

DA market:

$$0 \leq \sum_{i=1}^{n} (P_{i,t}^{Gen,DA}) - P_t^{Sell,DA} \leq 0 \qquad \forall t \in T \tag{1.52}$$

ID market:

$$0 \leq \sum_{i=1}^{n} (P_{i,t}^{Gen,ID}) - P_t^{Sell,ID} \leq 0 \qquad \forall t \in T \tag{1.53}$$

Positive CM market:

$$0 \leq \sum_{i=1}^{n} (P_{i,t}^{Gen,CM+}) - P_t^{Sell,CM+} \leq 0 \qquad \forall t \in T \tag{1.54}$$

Negative CM market:

$$0 \leq \sum_{i=1}^{n} (P_{i,t}^{Gen,CM-}) - P_t^{Sell,CM-} \leq 0 \qquad \forall t \in T \tag{1.55}$$

3.2.2 Mathematical Formulation of the Grid Operation Planning

In order to determine the grid operator's flexibility need for congestion management it is necessary to model the process of grid operation planning, which is done before real-time (typically done on the day before). During that process, grid operators conduct grid analyses based on the best available information and perform the steps of congestion management in order to relieve congestions if necessary. The two steps and their implementation within the developed framework are described in the following subsections.

Grid Analysis and Sensitivity Determination

Within the developed model, the schedules of the individual units are created based on their operational planning decisions (described in chapter 3.2.1). The schedules are then considered within a simplified DC load-flow analysis which is performed for the part of the grid that is under investigation[6]. For simplification and consistence to the performed load-flow analysis, only current-based violations are considered as congestions. Therewith, a congestion is detected if the load flow on a branch exceeds the maximum admissible power flow on the branch (that equals thermal limit) multiplied with a congestion threshold allowing the consideration of the n-1 criterion:

$$F_{max}^{m} \cdot c_T \leq F_{Base,t}^{m} \qquad \forall m \in B \tag{2.1}$$

$$where$$

Parameter	Description
$F_{Base,t}^{m}$	Base load flow on branch m before the activation of flexibility at time step t
F_{max}^{m}	Maximum admissible power flow on branch m
c_T	Congestion threshold to incorporate the n-1 criterion

To relieve occurring congestions the grid operator can use flexibility of the assets within his grid or in one of the underlying grids. The effect of the activation of flexibility at the nodes of the grid on the congested branches can be approximated by using linear sensitivity factors (PTDF – power transfer distribution factors). These factors can be obtained from the load flow calculations and are defined as:

[6] This relates to the extracted part of the grid where potential grid congestions are detected and resolved (e.g. medium voltage level), but not necessarily where a flexibility asset is connected to the grid (e.g. low voltage level).

$$PTDF_i^m = \frac{\Delta P_{Branch\ m}}{\Delta P_{Unit\ i}} \qquad \forall \mathrm{m} \in \mathrm{B}, \mathrm{i} \in \mathrm{N} \tag{2.2}$$

$$where$$

Parameter	Description
$\Delta P_{Branch\ m}$	Change of active load flow on Branch m
$\Delta P_{Unit\ i}$	Change of active load injection of unit i

The obtained PTDF matrix links all active power injections and withdraws with the power flow on all branches. With these factors, the occurring congestions can be relieved in a sense that the actual flow is lower than the maximum admissible power flow on the branches after the optimisation (see the formulation of the constraint congestion relief in Formula 2.25).

CONGESTION MANAGEMENT PROCESS AND USAGE OF MARKET-BASED FLEXIBILITY

Within the congestion management process, the network operators aim towards a flexibility usage that relieves occurring congestions while having the least costs. For that purpose, the grid operator can use positive or negative flexibility of the assets that are connected directly to its grid or aggregated flexibility potentials in the underlying grid.

Additionally, grid operators can procure flexibility on the energy markets to balance the local flexibility provision. This flexibility usage, however, has no sensitivity on local grid congestions and only serves balancing purposes[7].

In order to derive a flexibility usage associated with the least costs, the congestion management process is modelled as a mixed-integer linear optimisation problem within the developed framework. The decision variables are the usage of positive and negative flexibility from the local flexibility assets as well as the usage of positive or negative flexibility from the energy markets[8]. The objective function is defined as follows:

$$min \left\{ \sum_{t=1}^{d} \left(\sum_{i=1}^{n} \Delta P_{i,t}^{+} \cdot c_{i,t}^{+} + \Delta P_{i,t}^{-} \cdot c_{i,t}^{-} \right) + \Delta P_{Market,t}^{+} . c_{Market.t}^{+} + \Delta P_{Market,t}^{-} . c_{Market.t}^{-} \right\} \tag{2.3}$$

$$where$$

Parameter	Description
$\Delta P_{i,t}^{+}$	Amount of positive, local flexibility usage of unit i at time step t
$c_{i,t}^{+}$	Costs for the provision of positive, local flexibility usage of unit i at time step t
$\Delta P_{i,t}^{-}$	Amount of negative, local flexibility usage of unit i at time step t
$c_{i,t}^{-}$	Costs for the provision of negative, local flexibility usage of unit i at time step t
$\Delta P_{Market,t}^{+}$	Amount of positive, market-based flexibility usage at time step t
$c_{Market.t}^{+}$	Costs for positive, market-based flexibility usage at time step t (= ID market price)
$\Delta P_{Market,t}^{-}$	Amount of negative, market-based flexibility usage at time step t
$c_{Market.t}^{-}$	Costs for negative, market-based flexibility usage at time step t (= ID market price)

The developed optimisation framework has a number of constraints, which will be described in the next paragraphs:

- Technical constraints of the flexibility assets

[7] This might be beneficial in grids where flexibility potentials are highly unbalanced (only negative or positive potential exists).

[8] It is assumed here that this short-term balancing is done on the Intraday-Market.

- Congestion relief
- Node balance

TECHNICAL CONSTRAINTS OF THE FLEXIBILITY ASSETS – RENEWABLE ENERGY SOURCES / THERMAL PLANTS / CHP

Wind power and photovoltaic plants as well thermal and CHP plants can offer operational flexibility depending on their point of operation. Within the exemplary investigations, the flexibility potentials of the individual units are limited to their bids within the congestion management market that have been determined within the operational planning. A detailed consideration of the technical constraints of the individual units is not necessary, since this has already been done within the operational planning and resulted in the optimal operational decisions. Therefore, regarding their flexibility potential, the following constraints exist:

Renewable Energy Sources:

$$0 \leq \Delta P_{i,t}^{RES,+} \leq 0 \qquad \forall t \in T, i \in N \tag{2.4}$$

$$0 \leq \Delta P_{i,t}^{RES,-} \leq P_{i,t}^{Gen,CM-} \qquad \forall t \in T, i \in N \tag{2.5}$$

$$where$$

Parameter	Description
$\Delta P_{i,t}^{RES,+}$	Positive flexibility potential of RES unit i (Wind and PV) at time step t
$\Delta P_{i,t}^{RES,-}$	Negative flexibility potential of RES unit i (Wind and PV) at time step t
$P_{i,t}^{Gen,CM-}$	Offered flexibility potential of unit i at time step t for the negative CM market

Thermal Plants:

$$0 \leq \Delta P_{i,t}^{Plant,+} \leq P_{i,t}^{Gen,CM+} \qquad \forall t \in T, i \in N \tag{2.6}$$

$$0 \leq \Delta P_{i,t}^{Plant,-} \leq P_{i,t}^{Gen,CM-} \qquad \forall t \in T, i \in N \tag{2.7}$$

$$where$$

Parameter	Description
$\Delta P_{i,t}^{Plant,+}$	Positive flexibility potential of Plant unit i at time step t
$\Delta P_{i,t}^{Plant,-}$	Negative flexibility potential of Plant unit i at time step t
$P_{i,t}^{Gen,CM+}$	Offered flexibility potential of unit i at time step t for the positive CM market

CHP:

$$0 \leq \Delta P_{i,t}^{CHP,+} \leq P_{i,t}^{Gen,CM+} \qquad \forall t \in T, i \in N \tag{2.8}$$

$$0 \leq \Delta P_{i,t}^{CHP,-} \leq P_{i,t}^{Gen,CM-} \qquad \forall t \in T, i \in N \tag{2.9}$$

$$where$$

Parameter	Description
$\Delta P_{i,t}^{CHP,+}$	Positive flexibility potential of CHP unit i at time step t
$\Delta P_{i,t}^{CHP,-}$	Negative flexibility potential of CHP unit i at time step t

TECHNICAL CONSTRAINTS OF THE FLEXIBILITY ASSETS – STORAGES / ELECTRIC VEHICLES

The operational flexibility of storages as well as electric vehicles are valuable potentials for grid operators to resolve occurring congestions. However, the usage of these potentials comes with various challenges and restrictions. As storage/EV operators offered their flexibility potentials on the congestion management market, grid operators can access them. With using the offered flexibility, the grid operator changes the state-of-charge (SOC) of the asset[9]. Based on the design of the CM market, the bids within the CM market do not directly affect the SOC, but their possible activation (based on the grid operator's decision) does. Considering the optimal operational decisions of the asset in later time steps that have been determined without the knowledge of flexibility activation, this could result in invalid SOCs. Therefore, it is necessary to consider SOC derivations due to the flexibility usage and SOC limits within the optimisation problem. This is done by using additional variables: compensation and accounting variables. The energetic compensation of a flexibility usage, which is necessary to return to the original path of the SOC (based on the operation at the energy markets), can principally be done in all other hours of the optimisation horizon, if the asset is available for compensation. In order to keep track of all unbalanced energy over the optimisation horizon, additional accounting variables are added. Therefore, the constraints for the flexibility provision of storages and electric vehicles can be defined as follows:

Accounting of positive flexibility provision:

$$0 \leq -\frac{1}{\eta_{Discharge}} \cdot \Delta P_{i,t}^{Storage/EV,+} + \eta_{Charge} \cdot C_{i,t}^{Storage/EV,+} - W_{i,t-1}^{+} + W_{i,t}^{+} \leq 0 \qquad \forall t \in T, i \in N \tag{2.10}$$

$$0 \leq \Delta P_{i,t}^{Storage/EV,+} \leq P_{i,t}^{Gen,CM+} \qquad \forall t \in T, i \in N \tag{2.11}$$

$$0 \leq C_{i,t}^{Storage/EV,+} \leq P_{i}^{Charge,Max} + (P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} - P_{i,t}^{LoadEV/Storage,DA} - P_{i,t}^{LoadEV/Storage,ID}) \qquad \forall t \in T, i \in N \tag{2.12}$$

$$0 \leq W_{i,t}^{+} \leq SOC_{i,t} \qquad \forall t \in T, i \in N \tag{2.13}$$

$$W_{i,d}^{+} = 0 \tag{2.14}$$

Accounting of negative flexibility provision:

$$0 \leq \frac{1}{\eta_{Charge}} \cdot \Delta P_{i,t}^{Storage/EV,-} - \eta_{Discharge} \cdot C_{i,t}^{Storage/EV,-} - W_{i,t-1}^{-} + W_{i,t}^{-} \leq 0 \tag{2.15}$$

$$0 \leq \Delta P_{i,t}^{Storage/EV,-} \leq P_{i,t}^{Gen,CM-} \qquad \forall t \in T, i \in N \tag{2.16}$$

$$0 \leq C_{i,t}^{Storage/EV,-} \leq P_{i}^{Discharge,Max} - (P_{i,t}^{Gen,DA} + P_{i,t}^{Gen,ID} + P_{i,t}^{Gen,Load} - P_{i,t}^{LoadEV/Storage,DA} - P_{i,t}^{LoadEV/Storage,ID}) \qquad \forall t \in T, i \in N \tag{2.17}$$

$$0 \leq W_{i,t}^{-} \leq W_{i}^{Max} - SOC_{i,t} \qquad \forall t \in T, i \in N \tag{2.18}$$

$$W_{i,d}^{-} = 0 \tag{2.19}$$

Status Discharge:

$$0 \leq -\Delta P_{i,t}^{Storage/EV,+} - C_{i,t}^{Storage/EV,-} + M \cdot y_{i,t}^{Discharge} \leq M \qquad \forall t \in T, i \in N \tag{2.20}$$

$$0 \leq y_{i,t}^{Discharge} \leq 1 \qquad \forall t \in T, i \in N \tag{2.21}$$

Status Charge:

$$0 \leq -\Delta P_{i,t}^{Storage/EV,-} - C_{i,t}^{Storage/EV,+} + M \cdot y_{i,t}^{Charge} \leq M \qquad \forall t \in T, i \in N \tag{2.22}$$

$$0 \leq y_{i,t}^{Charge} \leq 1 \qquad \forall t \in T, i \in N \tag{2.23}$$

Exclusivity of charge or discharge operation:

$$0 \leq y_{i,t}^{Charge} + y_{i,t}^{Discharge} \leq 1 \qquad \forall t \in T, i \in N \tag{2.24}$$

[9] When offering flexibility potentials on the CM market, the asset operator does not anticipate whether the flexibility will be used.

$$where$$

Parameter	Description
$\Delta P_{i,t}^{Storage/EV,+}$	Positive flexibility potential of Storage/EV unit i at time step t
$C_{i,t}^{Storage/EV,+}$	Compensation of positive flexibility provision of Storage/EV unit i at time step t
$W_{i,t-1}^{+}$	Amount of positive flexibility in t-1 that still needs to be compensated
$W_{i,t}^{+}$	Amount of positive flexibility in t that still needs to be compensated
$\Delta P_{i,t}^{Storage/EV,-}$	Negative flexibility potential of Storage/EV unit i at time step t
$C_{i,t}^{Storage/EV,+}$	Compensation of negative flexibility provision of Storage/EV unit i at time step t
$W_{i,t-1}^{-}$	Amount of negative flexibility in t-1 that still needs to be compensated
$W_{i,t}^{-}$	Amount of negative flexibility in t that still needs to be compensated
$y_{i,t}^{Discharge}$	Discharging status
$y_{i,t}^{Charge}$	Charging status
M	Disjunctive parameter

CONGESTION RELIEF

As it has been described before, the aim of the congestion management is to relieve occurring congestions by using the flexibility of assets located in the grid. To ensure that congestions are relieved within the optimisation problem the following constraint needs to be considered using the linear sensitivity factors. Within the formulation also power flows in the negative direction are considered.

$$-F_{max}^{m} \leq F_{Base,t}^{m} + \sum_{i=1}^{n} \Delta P_{i,t}^{+} \cdot PTDF_{i}^{m} - \Delta P_{i,t}^{-} \cdot PTDF_{i}^{m} \leq F_{max}^{m} \qquad \forall \mathrm{t} \in \mathrm{T}, \mathrm{m} \in \mathrm{B} \qquad 2.25$$

$$where$$

Parameter	Description
F_{max}^{m}	Maximum admissible power flow on branch m
$F_{Base,t}^{m}$	Base load flow on branch m before the activation of flexibility at time step t
$\Delta P_{i,t}^{+}$	Amount of positive, local flexibility usage of unit i at time step t
$\Delta P_{i,t}^{-}$	Amount of negative, local flexibility usage of unit i at time step t
$PTDF_{i}^{m}$	Linear sensitivity of unit i on branch m

NODE BALANCE

Using flexibility for relieving congestions within the grid should have minimal impacts on the grid customers. Depending on the volume, a singular flexibility activation (positive or negative activation) affects the power balance and the system stability. Therefore it is reasonable to assume that congestion management measures are always balance neutral. This can be done by an opposing activation of flexibility which is located either locally within the same grid are or centrally at the energy markets. The necessary constraint can be formulated as follows:

$$\sum_{i=1}^{n} \Delta P_{i,t}^{+} + \Delta P_{Market,t}^{+} = \sum_{i=1}^{n} \Delta P_{i,t}^{-} + \Delta P_{Market,t}^{-} \qquad 2.26$$

$$0 \leq \Delta P^{+}_{Market,t}, \Delta P^{-}_{Market,t} \tag{2.27}$$

$$where$$

Parameter	Description
$\Delta P^{+}_{i,t}$	Amount of positive, local flexibility usage of unit i at time step t
$\Delta P^{-}_{i,t}$	Amount of negative, local flexibility usage of unit i at time step t
$\Delta P^{+}_{Market,t}$	Amount of positive, market-based flexibility usage of unit i at time step t
$\Delta P^{-}_{Market,t}$	Amount of negative, market-based flexibility usage of unit i at time step t

3.3 Validation and Exemplary Results

The developed framework has been tested and validated using a small, stylised and a bigger, more realistic test case. The structure of the following validation contains an introduction into the used input data as well as the results for the performed operational planning and the grid operation planning. Both test cases are using data from the SimBench project[10] which serves as a benchmark data set for all types of different use cases. Thereby, a synthetic medium voltage grid is used which contains all assets that are connected directly as well as all units in the underlying low-voltage grid.

3.3.1 Small 6-Node Validation Case

INPUT DATA AND CASE SETUP

The validation case consists of a grid extract with 6 nodes/buses that are connected via 7 branches and is based on a rural medium voltage grid from the SimBench dataset and can be seen in Figure 3. At the individual nodes, independent energy management systems (EMS) operate all assets that are connected directly to the nodes as well as all assets within the underlying low voltage grid. In order to limit calculation times, the assets have been aggregated to single technologies[11]. Node 1 serves as a slack node without any grid users / technologies and connects the grid to the overlaying high voltage grid.

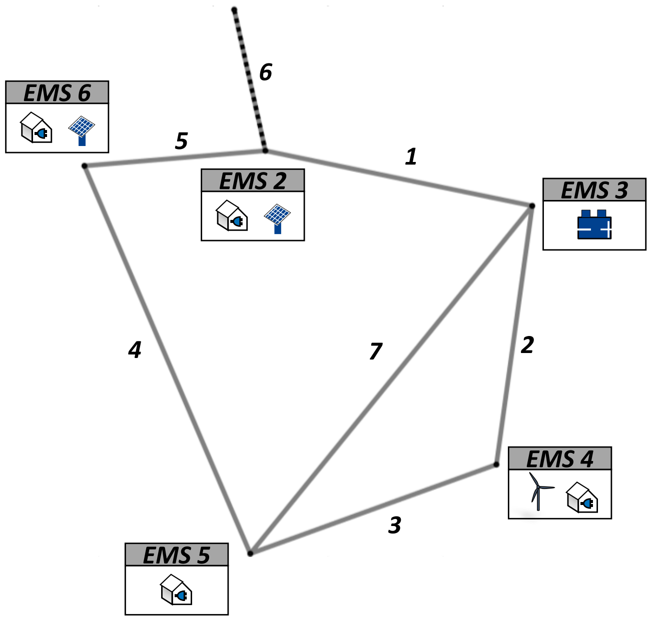


Figure 3 - Illustration and structure of the 6-node validation case

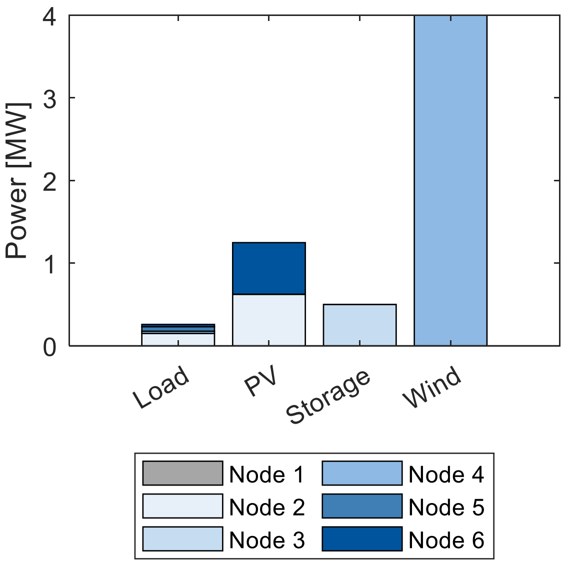


Figure 4 - Installed capacities of technologies at each node within the validation case

The installed capacities of the technologies that are connected are shown in Figure 4. It can be seen that the system is dominated by the large wind turbine at node 4, while smaller PV systems, a storage system and some electrical loads exist as well. The time series of the total load as well as the summarised generation from PV and Wind is shown in Figure 5. It can be seen that the grid has a high generation surplus that is fed into the overlaying high voltage grid via the slack node / node 1.

[10] Source: Meinecke, S.; Sarajlić, D.; Drauz, S.R.; Klettke, A.; Lauven, L.-P.; Rehtanz, C.; Moser, A.; Braun, M. SimBench — A Benchmark Dataset of Electric Power Systems to Compare Innovative Solutions Based on Power Flow Analysis. Energies 2020, 13, 3290. See also: https://simbench.de/en/

[11] Example: If multiple storages exist at the node and within the low-voltage grid they are aggregated to a single storage.

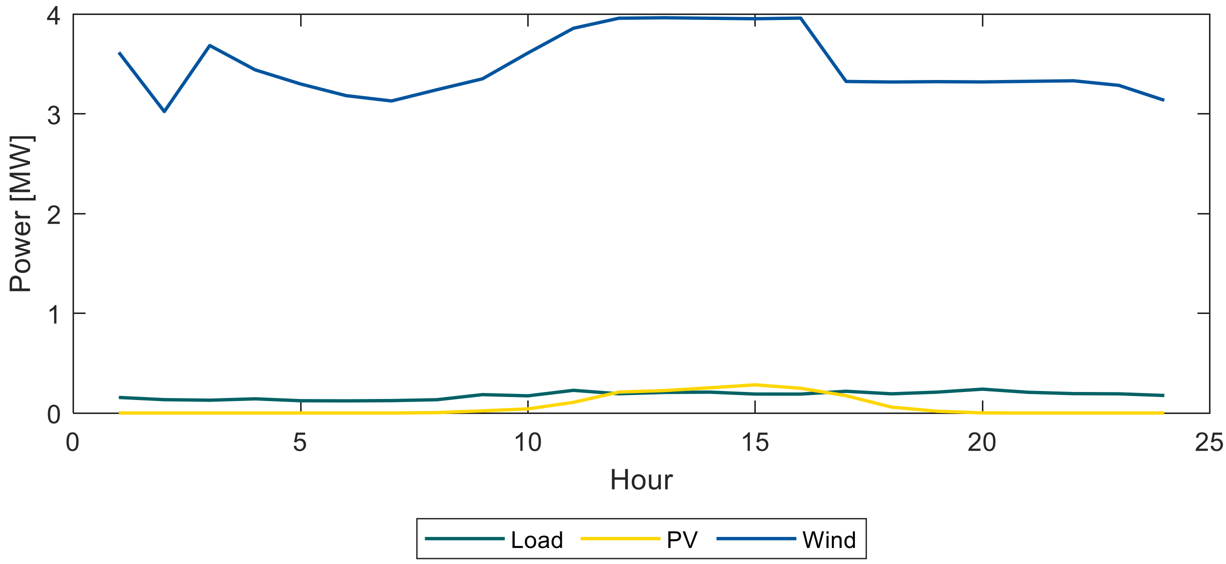


Figure 5 - Time series of RES generation and total demand within the 6-node validation case

The anticipated market prices which serve as a basis for the operational planning of the market participants are highly stylised for simplification. The price for the negative and positive congestion management market is exogenous and can be chosen freely. It is assumed that the remuneration for a positive flexibility provision (and therefore the market price) is higher than the price on the market for negative flexibility.

The optimisation horizon covers 24 hours using hourly time steps. This setup is chosen as a trade-off since a longer timeframe questions the accuracy of the generation forecasts and the anticipated prices.

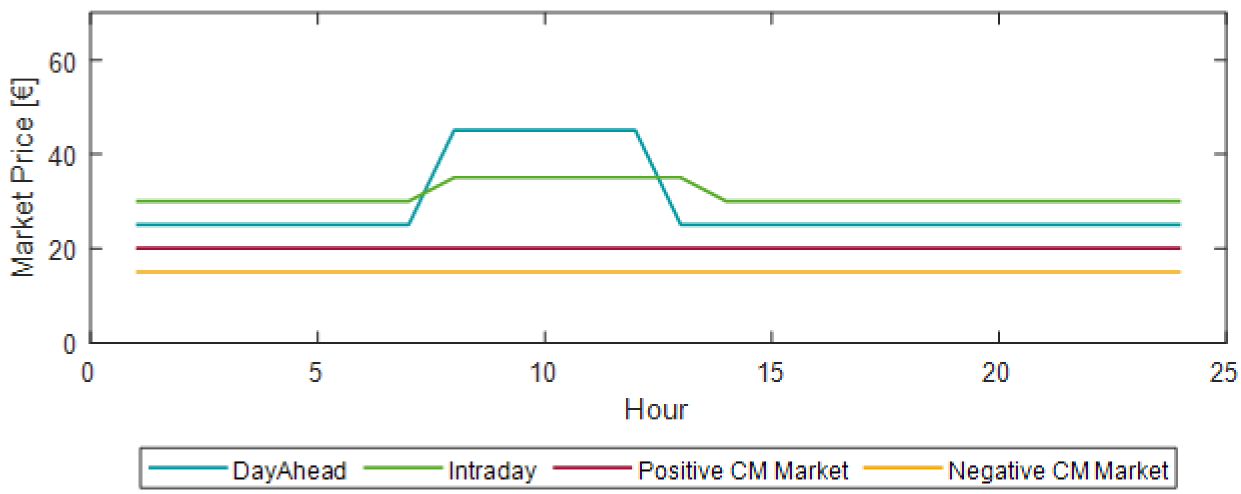


Figure 6 – Assumed market prices within the 6-node validation case

OPERATIONAL PLANNING RESULTS

Within the operational planning, the individual energy management systems at the individual nodes optimise their trading decisions and the operation of their assets in order to maximise their contribution margin. Exemplary results for the EMS at node 4 that operates the large wind power plant can be found in Figure 7. The results show that the EMS markets the WPP generation on the energy market that offer the highest price. Additionally, in all hours negative flexibility is offered to the grid operator.

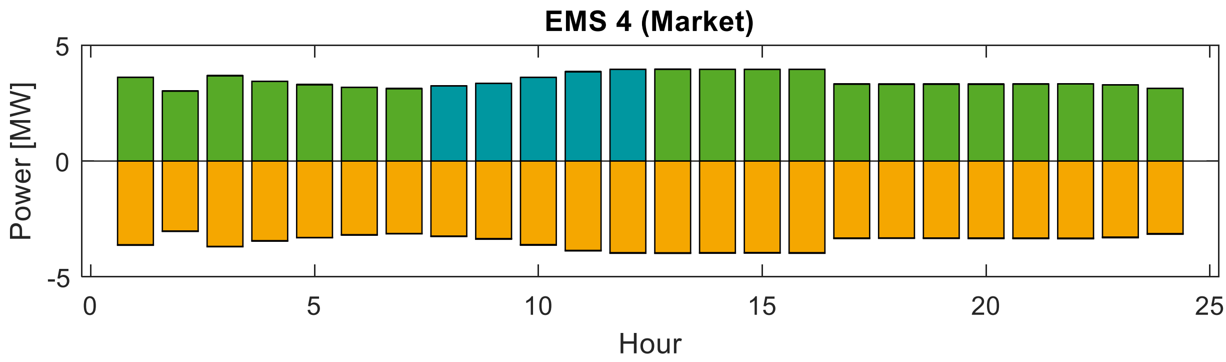


Figure 7 - Market Results of EMS 4 within the 6-node validation case

At node 3, a storage system is connected to the grid that has more complex constraints within the optimisation. It can be seen that the EMS sells energy to the energy market with the highest prices (e.g. on the DA market during hour 9, 10 and 12). This energy was bought on the lowest priced market before and has been charged into the storage earlier. Additionally flexibility is offered to the grid operator that includes reversing the point of operation (e.g. going from charging from the DA market in hour 5 to full discharge). Due to the low volatility of prices, the EMS is indifferent when considering two hours with same prices.

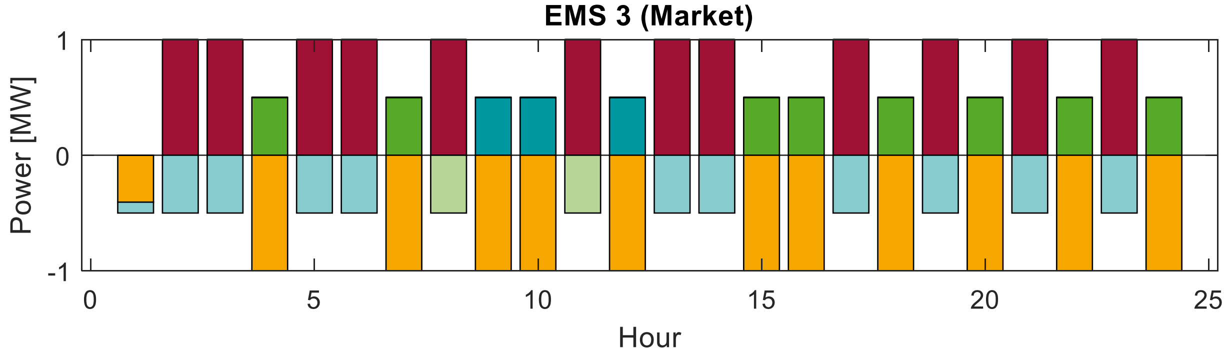


Figure 8 - Market Results of EMS 3 within the 6-node validation case

GRID OPERATION PLANNING RESULTS

The results of the operational planning for each EMS are transferred into actual power injections or demand at the grid nodes. The subsequent load flow analysis detects grid congestions that exist if the thermal utilisation of a branch exceeds the threshold of 50%[12]. Within the validation test case, congestions mainly[13] occur on branch 1 in 4 time steps. The optimisation problem within the congestion management problem aims to solve the occurring congestions using the market-based flexibility that has been offered by the grid customers. As a result, all congestions have

[12] With a branch utilisation limit of 50%, in case of the failure of grid component, a fast resupply can be enabled.
[13] A single other minor congestion (~50.11%) occurs on branch 2 in hour 13.

been resolved. It can be seen in Figure 9 that the congestions on branch 1 have been resolved by reducing the utilisation to the branch utilisation limit.

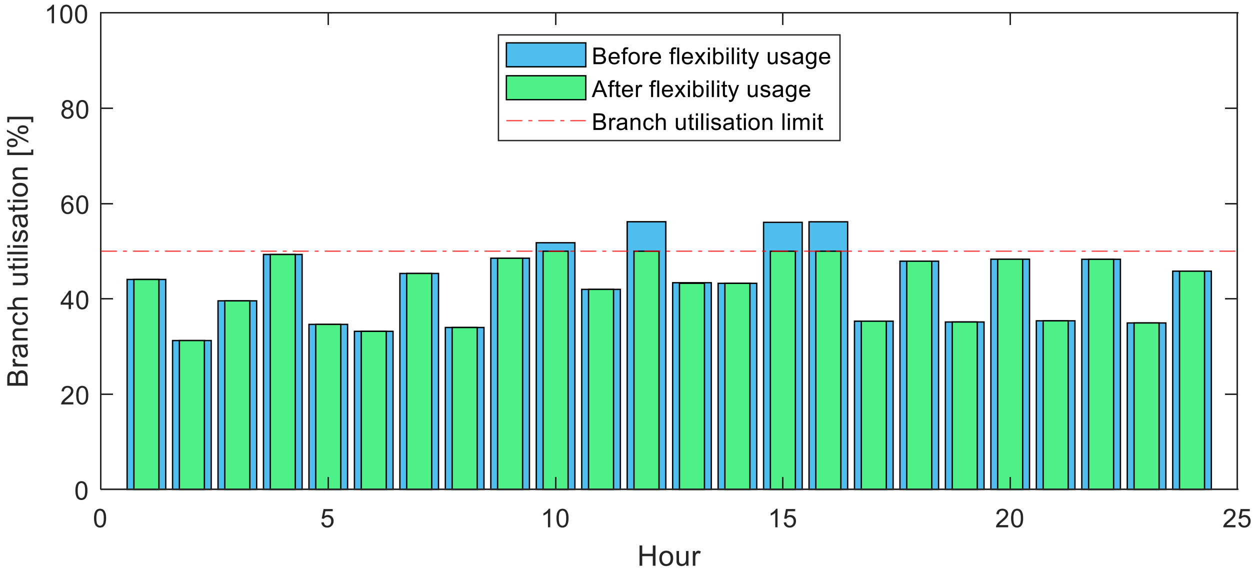


Figure 9 - Effect of the flexibility usage on the utilisation of Branch 1 within the 6-node validation case

In Figure 10, the technologies that have been used to resolve the occurring congestions are shown. It can be seen that the Wind Power Plant at node 4 provides negative flexibility whereas positive flexibility is bought on the Intraday market for balancing purposes. The decision, which technology is activated is based on its activation price, the availability for flexibility provision as well as the sensitivity factor on the respective congestion. Even though the storage is considered with a low activation price, it is not used since it needs to be compensated by the grid operator via the Intraday market resulting in higher costs.

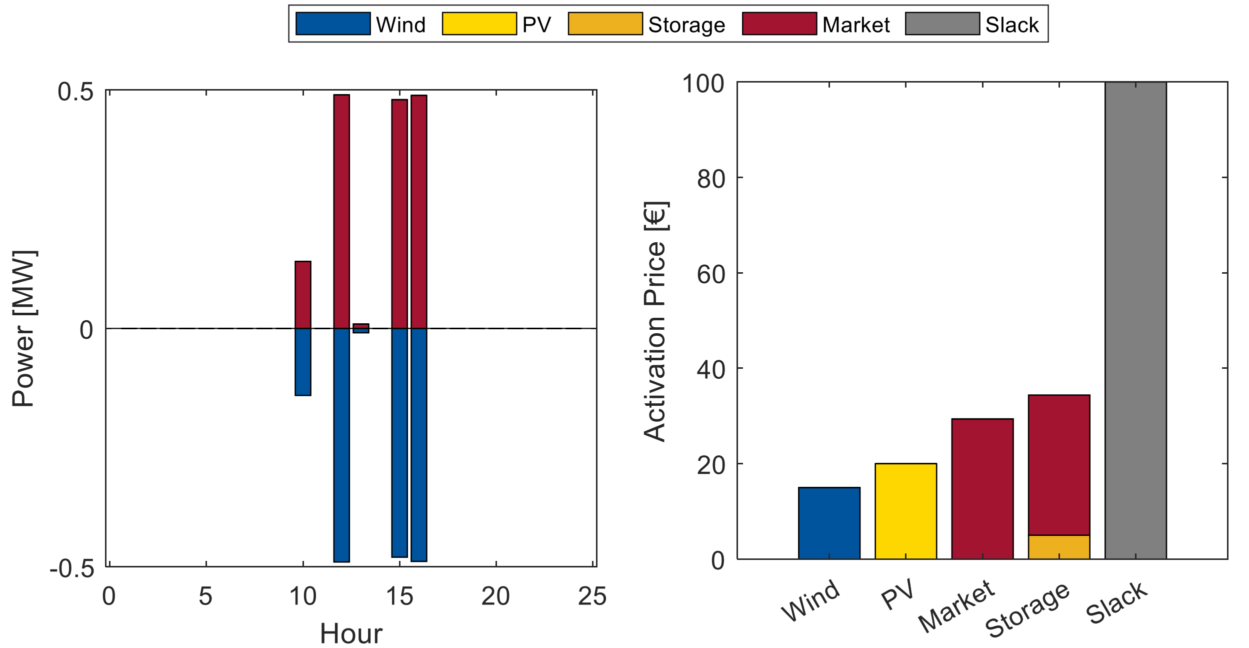


Figure 10 - Flexibility activation within the grid within the 6-node validation case

Figure 11 - Activation prices for flexibility per technology within the 6-node validation case

3.3.2 Large 97-Node Test Case

Input Data and Case Setup

The larger test case that is under investigation helps to evaluate effects on a bigger scale. The data is based on a rural medium voltage grid from the SimBench project[14] that is depicted in Figure 12. The grid has a radial structure with a connection to the overlaying high voltage grid in the centre. It is dominated by large installed capacities of photovoltaics. The assets within the underlying low voltage grid have been aggregated to the medium voltage nodes implicitly assuming that the LV grid is not congested. Regarding the existing loads, only residential loads have been considered[15], hydro power plants as well as CHPs have been excluded. It is assumed that the existing storages can freely operate as flexible assets of the EMS not being used for optimising self-consumption nor having a fixed time series. Electric vehicles can also be operated as flexible asset without a fixed charging time series while guaranteeing that mobility demands are always met. The mobility demands are derived from a synthetic set of driving profiles. The summed, installed capacities of the units connected to the grid can be found in Figure 13.

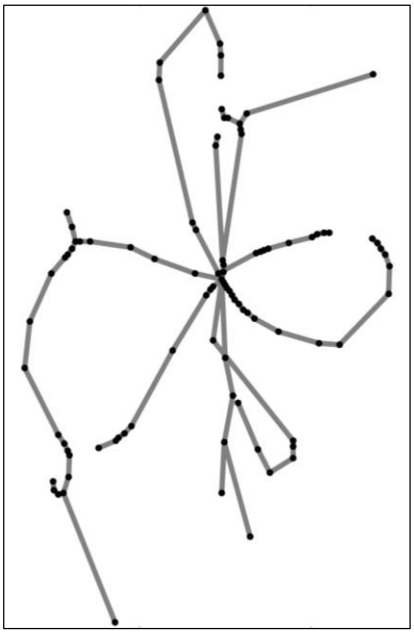


Figure 12 - Structure of the medium voltage grid under investigation within the 97-node test case

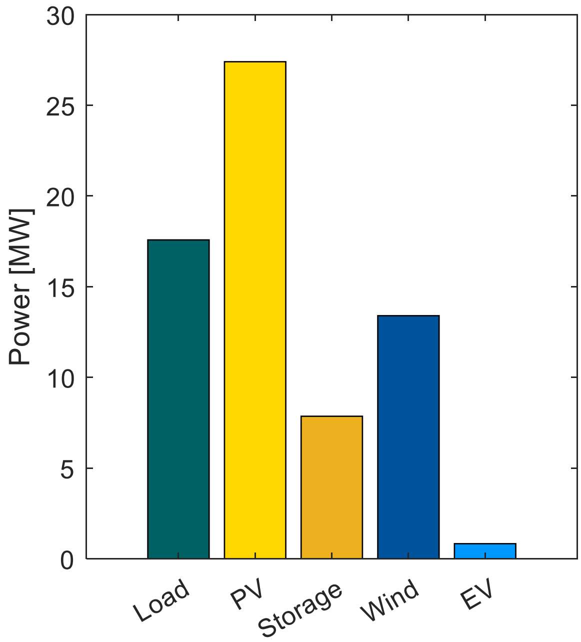


Figure 13 - Summed, installed capacities of different technologies within the 97-node test case

As within the validation case, each medium voltage grid node represents an individual energy management system and therefore will be optimised separately. A potential generation lack or surplus will be balanced by the slack node which is also the connection point to the higher grid level. For the investigations, an exemplary day (24 time steps) in spring will be showcased. The associated time series for Load, PV and Wind feed-in are shown in Figure 14. With respect to the anticipated market prices shown in Figure 15, exemplary price time series have been used. It is assumed that the prices for negative and positive flexibility are steady within the observed time horizon.

[14] The grid abbreviation codes is: '1-MVLV-rural-all-1-no_sw'

[15] Agricultural loads, commercial loads and heat pumps have not been considered.

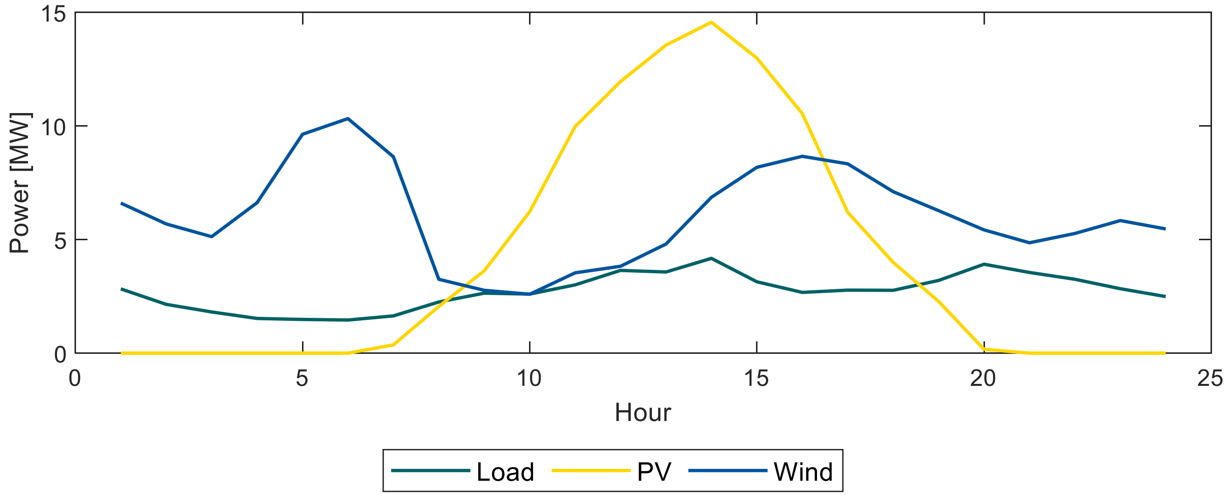


Figure 14 - Time series of RES generation and total demand within the 97-node test case

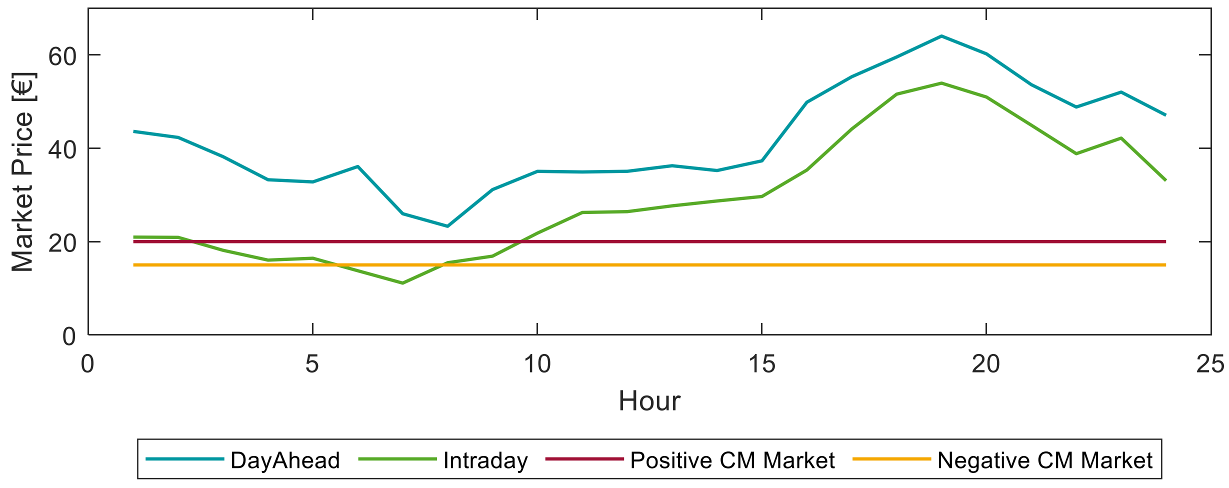


Figure 15 - Assumed market prices within the 97-node test case

Operational Planning Results

Within the operational planning, all nodes are optimised individually, considering the anticipated prices on the markets as well as the technical constraints of the assets. In Figure 16, the summarized operational planning decisions of all EMS systems at the different nodes are displayed. It can be seen that the Intraday market - due to its lower prices - is not used for selling electricity but is used for purchasing. In contrast, generation capacities are predominantly marketed on the Day-Ahead market due to perfect foresight regarding the market prices. Based on the existing spread between the two markets, serving the loads directly by the EMS' own generation capacities is unattractive.

In addition, the positive CM market seems to be attractive within the earlier hours of the day when prices are higher compared to other markets. High potential seems to exist on the negative CM markets, as the marketed generation from RES is complemented with bids for negative flexibility provision.

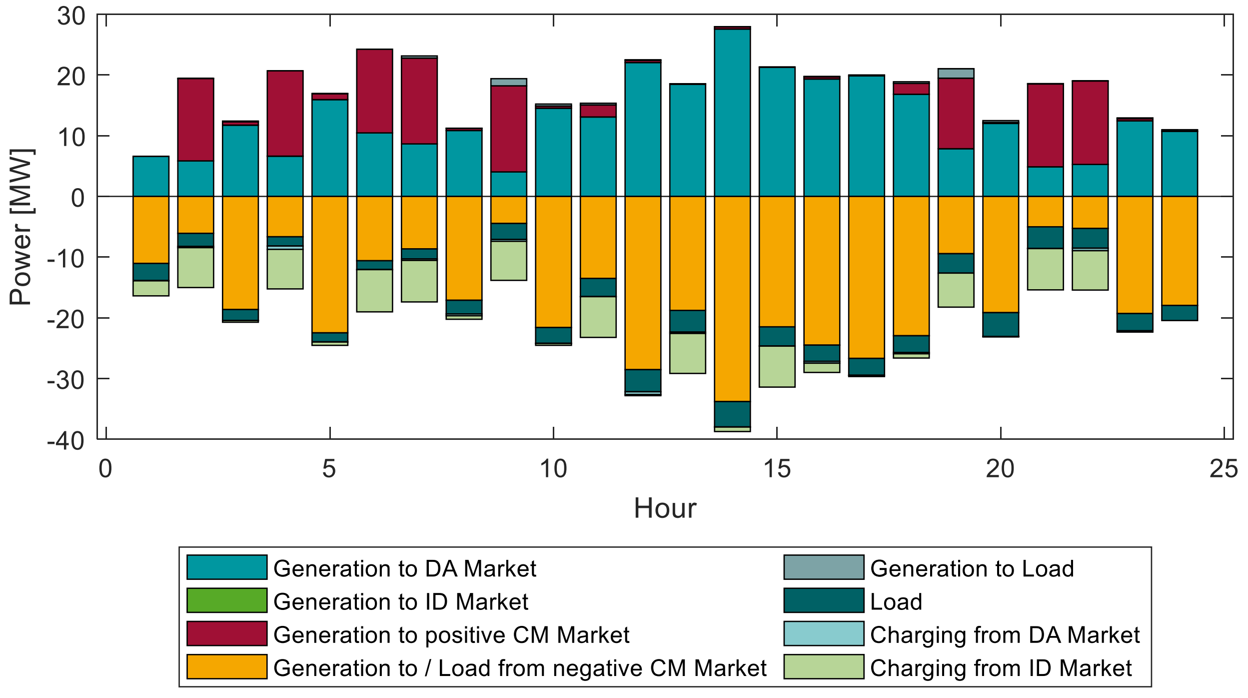


Figure 16 - Summarized operational planning decisions of all EMS within the 97-node test case

GRID OPERATION PLANNING RESULTS

When the obtained results of the operational planning are transferred into the grid, the branch utilisation limit (allowing for a maximum utilisation of 50%) is exceeded in 38 situations with a maximum utilisation of *73%* at time step 14 shown in Figure 17.

Time step 14

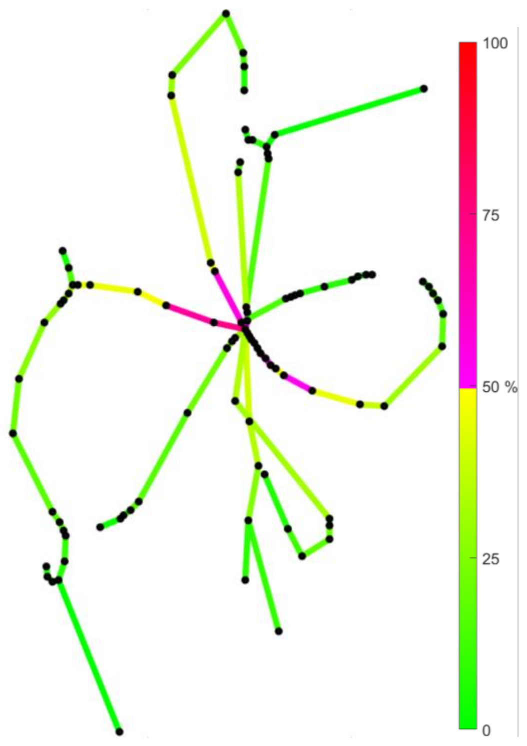


Figure 17 - Utilisation of branches at time step 14 within the 97-node test case

In Figure 18, the branch utilisations sorted based on their utilisation before the flexibility usage are shown. It can be seen that all congestions have been resolved within the optimisation and no branch exceeds the thermal limit any longer.

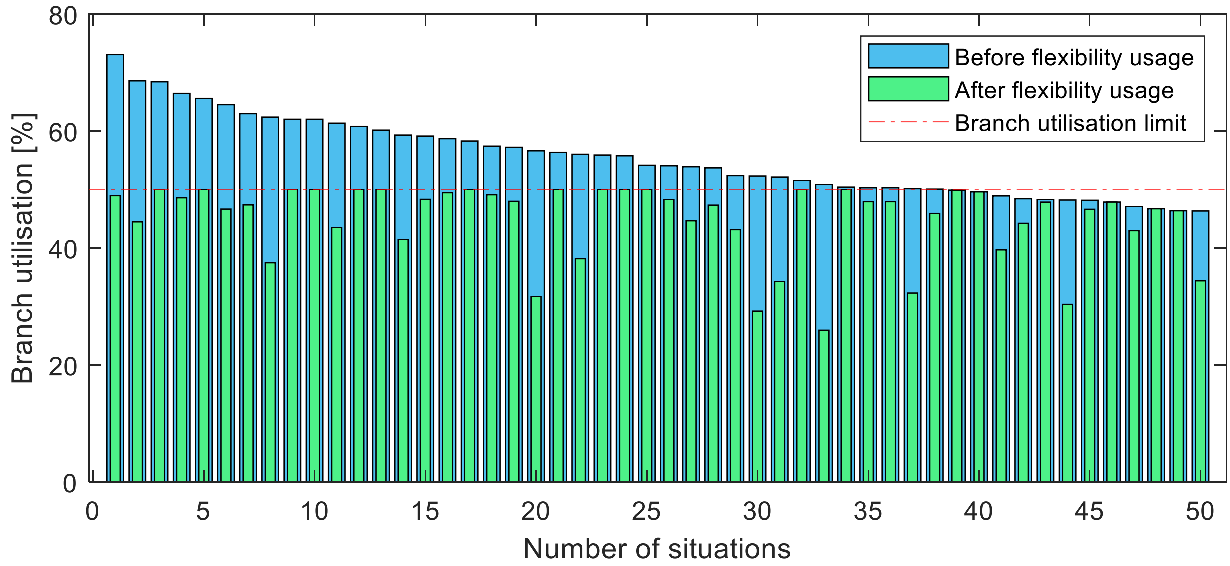
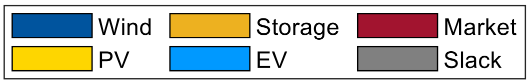


Figure 18 - Effect of the flexibility usage on the utilisation of branches within different situations of the 97-node test case

The usage of flexibility together with the underlying activation prices are shown in Figure 19 and Figure 20. It can be seen that the flexibility usage follows the pattern of the validation case. All negative flexibility comes from RES curtailment (PV and Wind), whereas positive flexibility comes from the Intraday market. A total of $23.87\ MWh$ is activated to relieve the congestions.



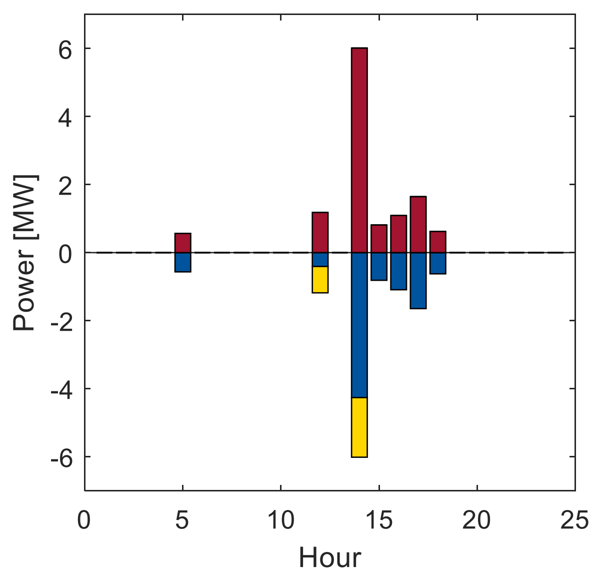


Figure 19 - Flexibility activation within the grid within the 97-node test case

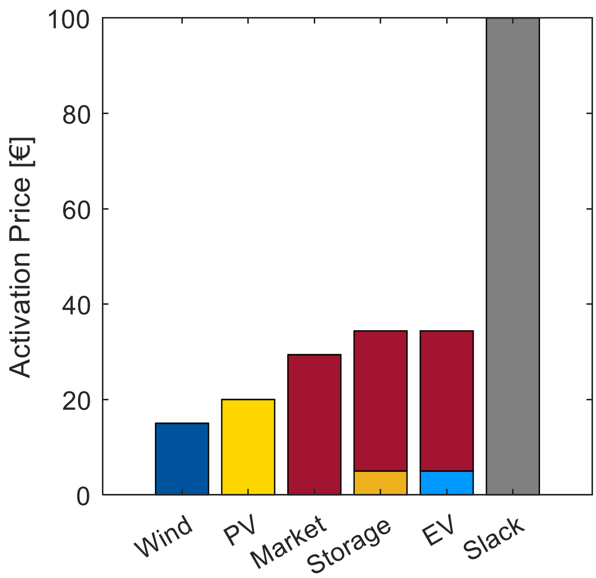


Figure 20 - Activation prices for flexibility per technology within the 97-node test case

Within this test case, high negative flexibility potentials based on the high installed capacities of RES exist. Storage and EVs offer significantly lower flexibility potentials due to lower installed capacities as well as more complex restrictions and the need for compensation of the flexibility usage. These additional compensation costs increase the actual activation costs of Storages and

EVs so that they are not used for flexibility provision. To further examine the potential of flexibility provision by storages and EVs, additional sensitivities are performed.

3.3.3 Sensitivity Analyses

Within sensitivity analyses, selected adaptions are made to the assumptions to investigate their impact on the results. This includes

- Adaption of the activation prices for the grid operator
- Increase of the available flexibility potential of storages

SENSITIVITY ANALYSIS – "ACTIVATION PRICES"

Firstly, adaptions are made to the activation prices by reducing the price for flexibility bought on the energy markets (necessary for balancing the activation and the compensation of storages and electric vehicles) to a constant value of *5€.* This reduction that is shown in Figure 22 does not affect the operational planning decisions of the participants and therefore not the congestions, but only the activation decision of the grid operator. Reducing the costs for market-based flexibility access partially reduces the activation costs for storages and EVs (since the costs for their compensation are reduced). Therefore, this type of flexibility becomes more attractive to the grid operators. Consequently, as shown in Figure 21, also storages and to a lower extent EVs are used for negative flexibility provision. Since their potential is limited, also RES are used for negative flexibility provision. Due to the low prices for market-based flexibility, only positive flexibility is used for positive balancing. It should be noted that a solution, solely using market-based flexibility is not valid, since the local congestions cannot be relieved by this type of flexibility.

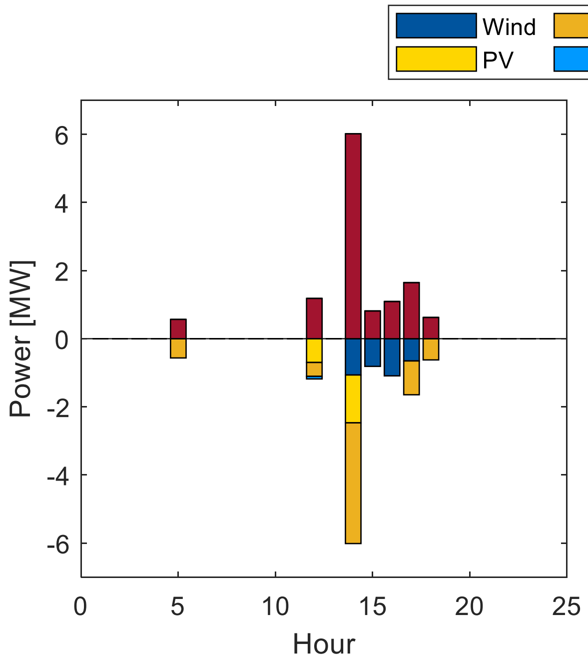


Figure 21 - Flexibility activation within the grid within the sensitivity analysis "Activation Prices"

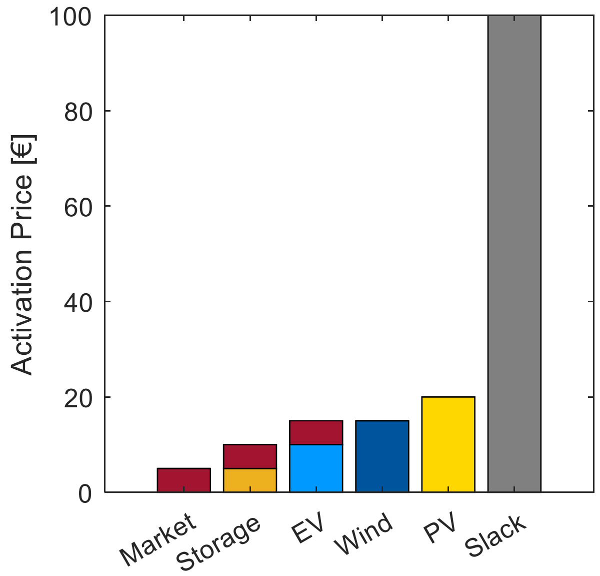


Figure 22 - Adapted activation prices for flexibility per technology within the sensitivity analysis "Activation Prices"

SENSITIVITY ANALYSIS – "INCREASED STORAGE CAPACITIES"

Within a second sensitivity analysis the available flexibility potential is adapted by increasing the installed capacity as well as the storage capacity of the installed storages by 10%, also depicted in Figure 23. The aim is to investigate what effect this has on the quality and quantity of the occurring congestions as well as the activated flexibility within congestion management.

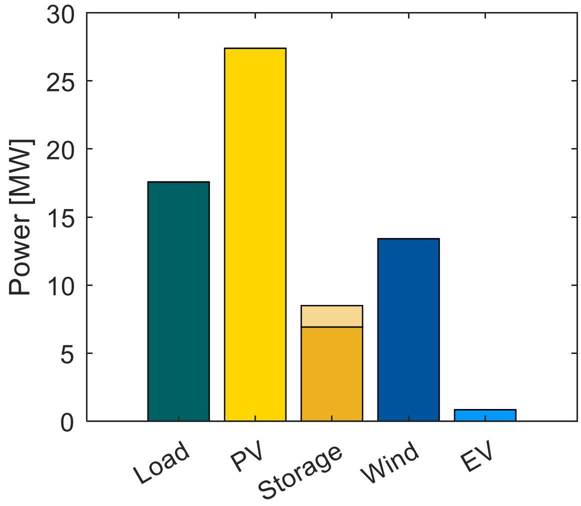


Figure 23 - Summed, installed capacities of different technologies within the sensitivity analysis "Increased Storage Capacities"

The increased (dis)charging power as well as storage capacity of the connected storages affects the operational planning as well as the resulting grid operation planning. The increased ability for arbitrary trading decisions increases the number of situations with congestions (42) as well as their extent[16] that is also depicted in Figure 24.

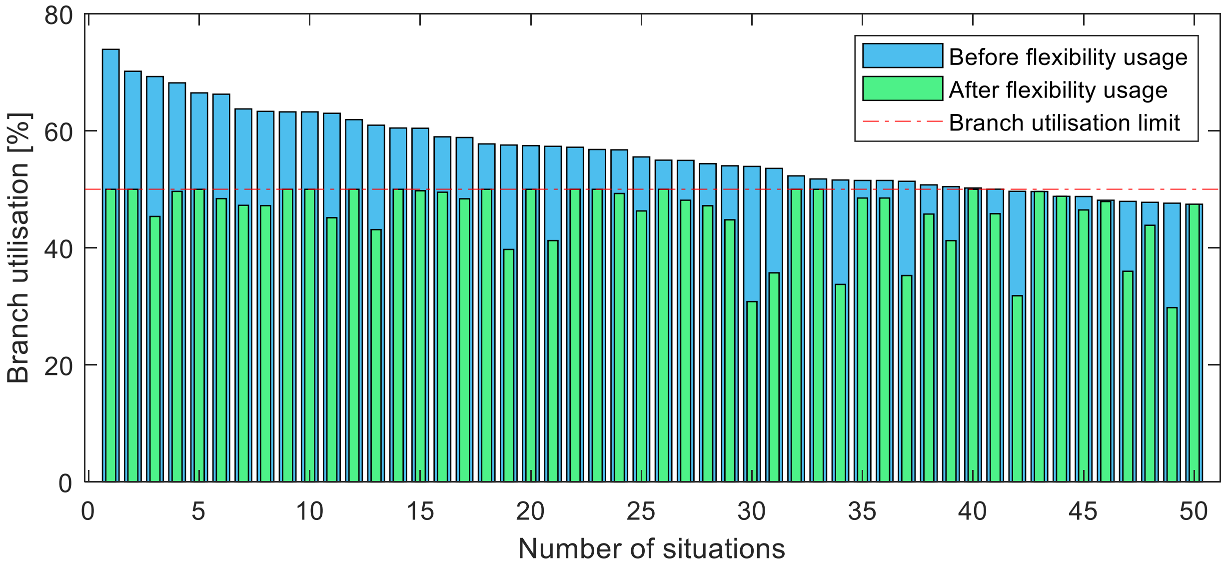


Figure 24 - Effect of the flexibility usage on the utilisation of branches within different situations of the sensitivity analysis "Increased Storage Capacities"

With respect to the flexibility activation, based on the activation prices used in the 97-node test case, a higher flexibility usage is needed compared to the original test case as shown in Figure 25. The sum of all activated flexibility ($26.10\ MWh$) results in an $9{,}3\%$ increase regarding the activated flexibility. As the original activations costs are considered in this sensitivity analysis, negative flexibility is only provided by RES. If the activation prices are lowered to the level of the sensitivity analysis "Activation Prices", it can be seen that storages are used increasingly (shown in Figure 27).

[16] The highest branch utilisation raises from 73% to 75%.

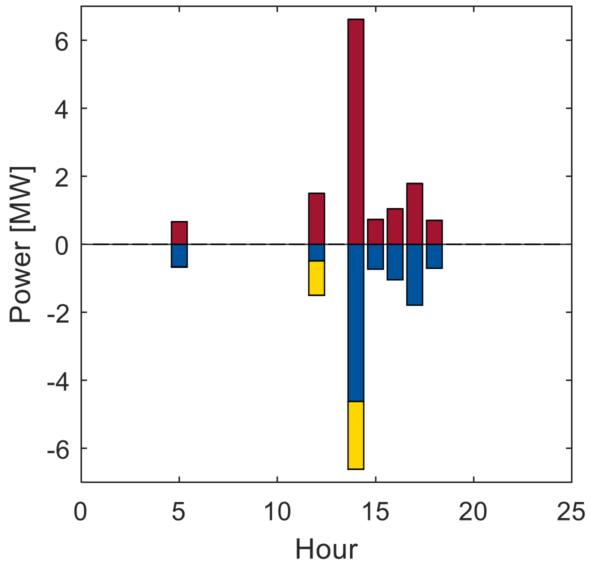


Figure 25 - Flexibility activation within the grid within the sensitivity analysis “Increased Storage Capacities”

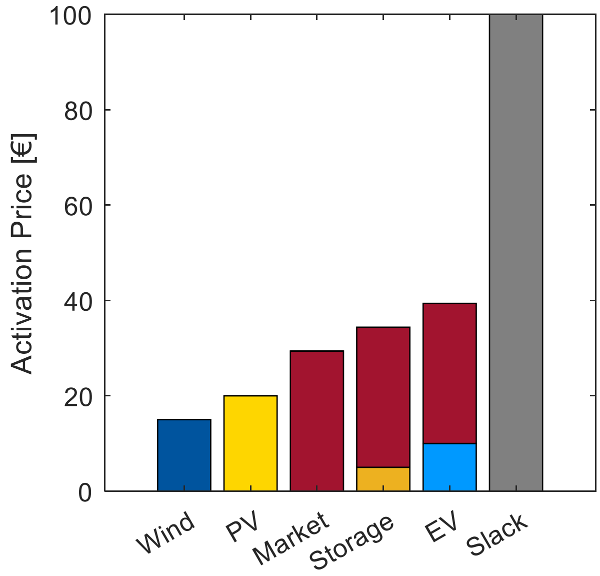


Figure 26 - Adapted activation prices for flexibility per technology within the sensitivity analysis “Increased Storage Capacities”

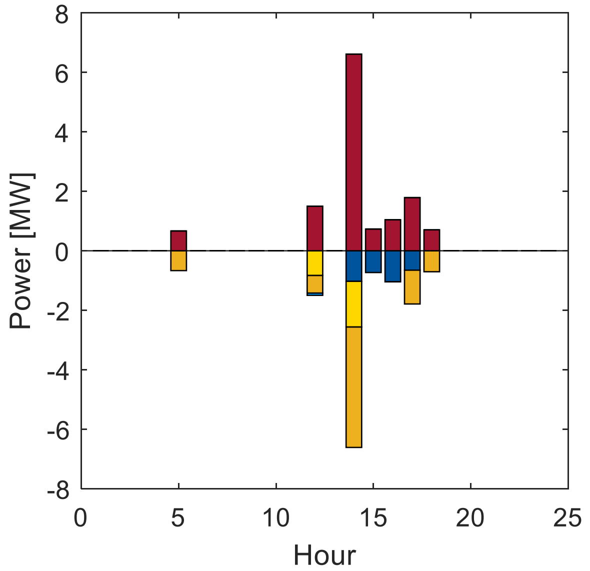


Figure 27 - Flexibility activation within the grid within the sensitivity analysis “Increased Storage Capacities” assuming lowered activation costs

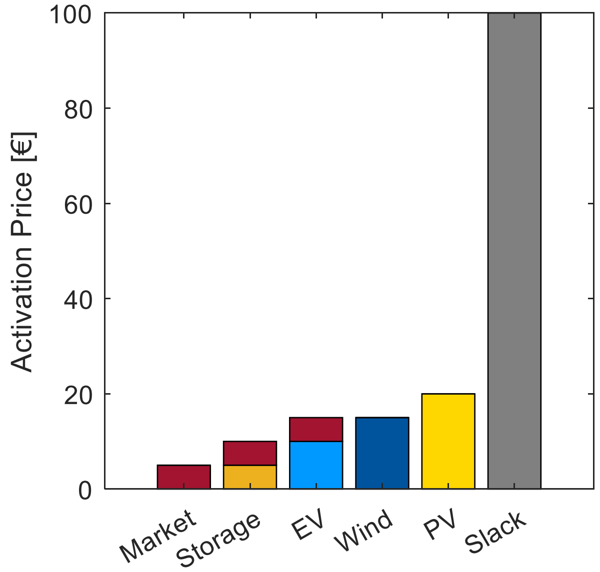


Figure 28 - Adapted activation prices for flexibility per technology within the sensitivity analysis “Increased Storage Capacities” assuming lowered activation costs

3.4 Conclusions & Outlook

RESULTS AND CONCLUSIONS

Within the developed framework, the process of congestion management incorporating a market for positive and negative flexibility has been modelled in detail. It has been shown that occurring congestions within the framework can be relieved using operational flexibility of the participating units that have placed their bids for flexibility on the CM market.

For market participants, the CM market provides additional marketing opportunities. Bidding into the positive CM market without certainty whether the bid will be activated later, thus generating additional activation profits (which is exactly the setup within the test case), poses a risk to the unit operator because generation capacity needs to be withheld. Due to lower price incentive for the capacity reservation as well as the reduced installed capacity of capable units, the bid volume for positive flexibility is significantly lower than for negative flexibility. It could be shown that the hurdles for the provision of negative flexibility are notably lower, whereas the potential is unlike higher (with the participation of RES). For these type of units participating in the CM market and being remunerated for their potential curtailment is an additional source of income.

Regarding the usage of storages and electric vehicles within the investigations, their potential usability for flexibility provision is rather limited. This is based on their limited installed capacity as well as more complex restrictions compared to RES that apply to storage technologies from an operational viewpoint. This is especially valid for the need to compensate the storage energetically for a flexibility provision in another time step to ensure that the SOC remains valid at all times. The costs for the compensation need to be considered as well, which might affect the attractiveness of this technology for the grid operator during activation.

SHORTCOMINGS AND OUTLOOK

The results obtained within the test case are specific and can only be generalised to a limited extent. With respect to the modelling, some of the assumptions can be challenged such as the access of all low voltage assets to the wholesale electricity market. Some assets may follow different operational schemes such as the optimisation of self-consumption. The aggregation to medium voltage grid nodes also neglects possible congestions within the low voltage grid, which would limit the accessible flexibility potential.

Anticipating prices for the markets and using fixed time series for the operational planning ignores uncertainties that exist in reality during the operational planning. It is expected that the results for the grid operation planning are affected indirectly by these uncertainties.

For future investigations, different grid structures could be considered. Additionally, the resulting voltage level and voltage-based congestions should be considered.

4 Simulation-based Approach for Evaluating Congestion Management Markets by Tampere University

4.1 Motivation and Purpose

Since Demos could cover some aspects of congestion management markets (CMMs), the simulation-based approach aims to complement the picture by looking at the problem from different angles/aspects. As Demos mainly focus on TSO-related issues, the simulations will look at the problem, particularly from the distribution network side. The objectives of the simulations are as follows.

An appropriate sensitivity analysis in predictive grid optimization (PGO) for voltage congestion types will be proposed because it impacts the flexibility need's quantity and location. The rebound effect, DSO-prosumer coordination, and service parameterization (flexibility need attributes) are some topics that will be analysed.

From the local flexibility market (LFM) perspective, flexibility product attributes can be varied in the simulations to understand their impact. Attributes such as congestion area (i.e., using customer Id), minimum bid size, and bid resolution are candidates for change since they can significantly impact the market liquidity.

It seems essential for a DSO to know the extent and situation where a flexibility market can be relied on and used. Therefore, we plan to define scenarios to show when approaches based on flexibility procurement are beneficial for DSO.

4.2 Methodological Approach

All the simulations have been carried out using a simulation environment where the congestion management process of all stakeholders and the reality of data exchange between stakeholders and their processes have been taken into account to emulate system operation reality. One aim of such a simulation environment is to integrate real software components and systems utilized by different stakeholders in the different parts of their decision-making processes of planning, operational, and trading processes. The simulation environment has been designed based on service-oriented architecture (SOA), where the pieces of the system are abstract with a few dependencies [1], [2].

Figure 29 depicts the architecture of the environment. The distribution management system (DMS), where DSO's monitoring and decision-making happens, contains two components: predictive grid optimization (PGO) and state monitoring (SM). On the energy communities' (ECs) side, the economic dispatch (ED) component is the portfolio optimizer and decision-maker. Connection of ECs, LFM, and DSO occurs over the message bus. The environment utilizes a publish-and-subscribe pattern to carry relevant messages between different components. For example, PGO sends the flexibility need of DSO to a predetermined topic on the message bus, and LFM receives them because LFM has already subscribed to the topic where PGO is releasing its messages. The data concerning grid topology and its parameters are available in the network information system (NIS), and customers' data are accessible from the customer information system (CIS). All the message exchanges are stored for result analysis and component debugging in the database. Further explanation of components is available in deliverable D3.4.

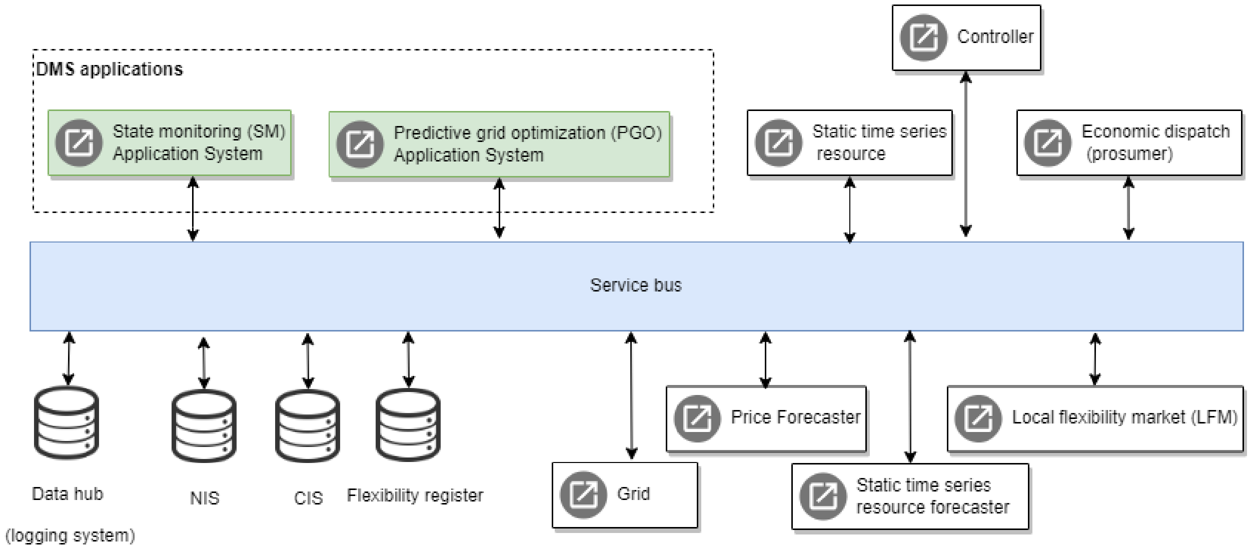


Figure 29 - SOA architecture of the simulation environment

4.2.1 Simulation Environment

The application systems (components of the simulation environment) are divided into core and domain components, as shown in figure 30. Core components include platform manager, simulation manager, log reader, and log writer. Domain components comprise predictive grid optimization (PGO), state monitoring (SM), economic dispatch (ED), controller, price forecaster, static time-series resource, storage resource, static time-series resource forecaster, grid, and local flexibility market (LFM). As shown in the figure below, the components can exchange data using the advanced messaging queuing protocol (AMQP[17]) on a server with RabbitMQ[18] software. The log writer stores all the message exchanges between components in the MongoDB[19] database that can be accessed using the log reader. Each component can be run in a separate platform; in addition, running a component on a container is also possible. Besides, the simulation environment supports parallel simulation runs meaning that several instances of the simulations can be run simultaneously because all the components follow object-oriented programming (OOP).

In the start-up of a simulation run, each component should be parametrized. The required parameters of a component could be different from one another because the given parameters are associated with the internal functionality of components. For example, PGO receives the LFM opening time in the start message [3], whereas storage resource needs the initial state of its controllable resource. Since each simulation run is dedicated to studying one scenario, changing the components' start-up parameters creates various distinct scenarios. This feature is handy from a research perspective because the simulation environment sets the stage for evaluating very different ideas and perspectives.

To understand the scale of the environment, a one-week simulation of the 359 buses distribution network with one-hour resolution requires about 910,000 message exchanges between different components using RabbitMQ software. Since several researchers contributed to developing the environment, detailed documentation was created, reviewed, and used as a reference for the development process to ensure consistency and compatibility of each component with the whole environment. The simulation environment is open-source; therefore, the source code of components and a manual for users and developers are available [1]. The idea behind designing

[17] AMQP is an open standard application layer protocol for message-oriented middleware. The defining features of AMQP are message orientation, queuing, routing (including point-to-point and publish-and-subscribe), reliability and security.

[18] RabbitMQ is an open-source message-broker software that originally implemented AMQP.

[19] MongoDB is a source-available cross-platform document-oriented database program.

such a large environment is that a user could readily install the simulation environment on a computer and utilize it for complex energy system studies, such as distribution system studies. In addition, if functionality is non-existent in the environment due to the extendibility feature, a new component with desired functionalities can be developed and added to the environment [4].

For instance, to simulate scenarios related to the temperature dependency of load demand, a thermodynamic model of houses, storages, etc., can be added to the environment. The component of a thermodynamic model will change the behaviour of the storage resource (in terms of production, consumption, heat loss, etc.) in response to different ambient temperatures. This will further impact load demand according to controller decisions. The system may also include any number of hierarchical controllers like a thermostat and possible higher-level controllers like energy management of prosumer and an energy community. Therefore, several components will interact to find the final equilibrium of hourly load demand. The time resolution of simulation may be freely defined and is not limited to hourly resolution. Still, the idea of the environment is to realize a quasi-steady-state analysis of energy systems, which is aimed at slowly evolving conditions. The simulation environment's modularity and extendibility provide a high degree of freedom to researchers aiming to study various topics about energy systems, especially the interactions between resources, controllers, markets, stakeholders, etc.

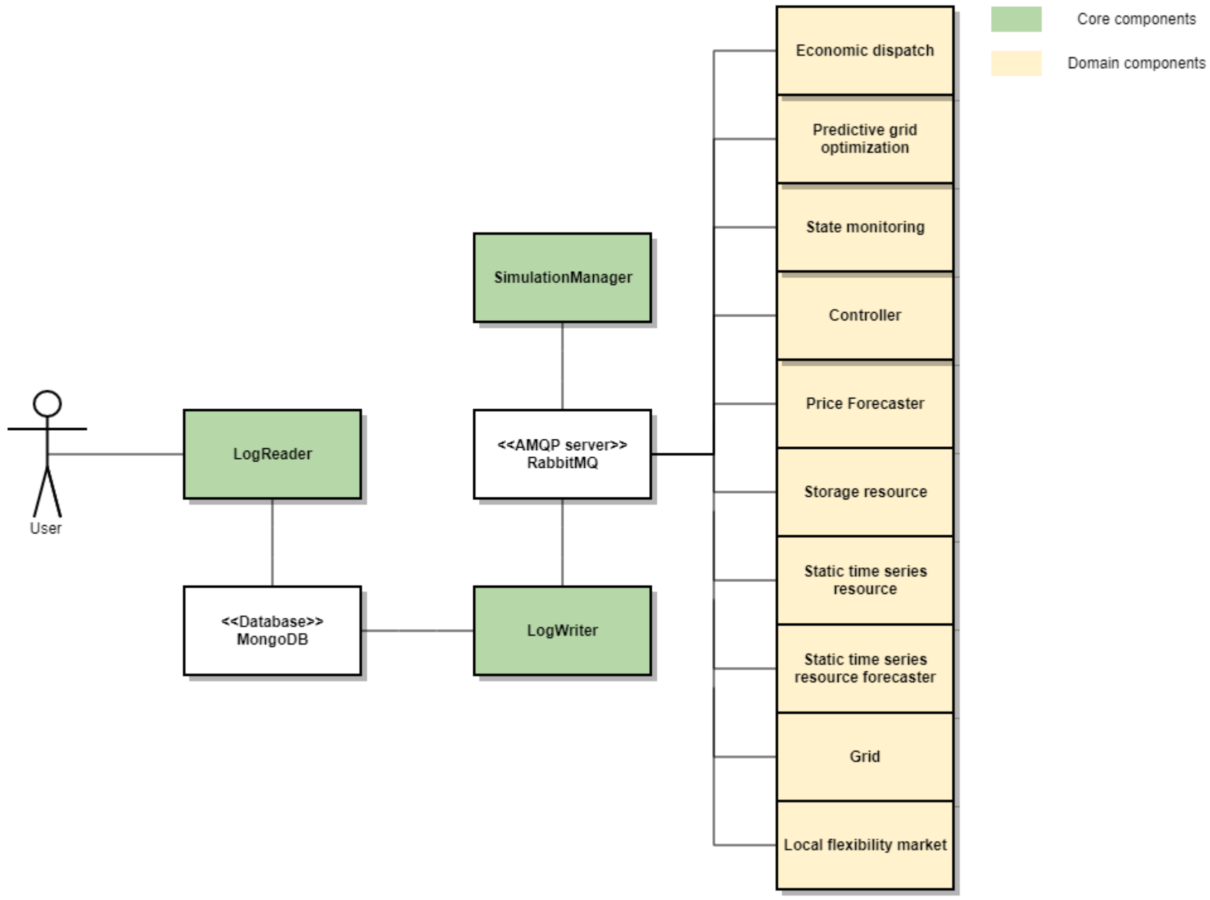


Figure 30 - Core and domain components connected through RabbitMQ

4.2.2 Distribution Management System (DMS)

DSOs utilize DMS as a software package in their control centre for their network monitoring and decision-making. DMS contains several application systems[20], each responsible for one or more functionalities. As shown in Figure 29, DMS, among others, contains two application systems (components), including predictive grid optimization (PGO) and state monitoring (SM). PGO's

[20] Work force management, state estimation, fault management, asset management are some examples.

operational timeframe is the day ahead when PGO procures flexibility from LFM, while SM's operation occurs in real-time for activation verification and its impact on congestion when flexibility is activated.

4.2.3 The workflow of DSO's flexibility procurement, activation

Before entering the discussion about flexibility procurement's workflow, it seems necessary to explain three components: static time-series resource, storage resource, and controller. Resources like loads and generators are given a static time series in the simulation environment. Therefore, they follow the values in the time series corresponding to the simulated time. Grid utilizes the state of the static time series resources in its power flow calculations. The resources that ECs can control are called storage resources. In fact, the flexibility of the storage resources is sold to the LFM. Each storage resource has a controller (i.e., like in real-world cases); therefore, new schedules of the resources are sent to the specific resource's controller. Finally, the controller commands its storage resource to realize flexibility activation.

The workflow of simulations leading to flexibility procurement in the day-ahead time frame is shown in figure 31. It has been designed so that the LFM operates between noon to 17 pm, one day, ahead of actual operating time. Grid calculates the network state forecasts according to load and production forecasts of the next day. Subsequently, PGO receives the network state forecasts from the grid and evaluates the voltage values according to the given limits (e.g., -4/+10 percent for bus voltages). Suppose the forecasted voltage values are not within limits. In that case, PGO creates flexibility need attributes including activation time, flexibility volume (kWh), duration (min), area (customer Id), and direction (up or down-regulation) [5]. Then, the bids are formed and dispatched to the LFM. LFM informs the ECs about the existing flexibility needs. According to their internal portfolio optimization, ECs then send their offers to the market no later than 4 pm. The DSO's decision-making in PGO occurs between 4 to 5 pm, and PGO sends the selected offers to LFM. All the ECs are informed about the accepted offers at 5 pm by LFM.

Once an offer is traded in the market, the responsible EC uses its economic dispatch (ED) to make new schedules of its storage resources to meet its promises. In addition, LFM stores the traded flexibility and reminds the market results every hour to assure that flexibility activation is not missed. In the operational time frame, as shown in figure 32, ED sends schedules (i.e., considering all of the commitments resulting from participation in different markets) to the relevant storage resource's controller. Afterward, the control state changes the state of the storage resource, leading to flexibility activation. The grid performs power flow based on static time series resources and states of storage resources. Finally, it publishes the network state (currents and voltages of grid assets) for SM, where grid performance monitoring and verifying the flexibility activation happens.

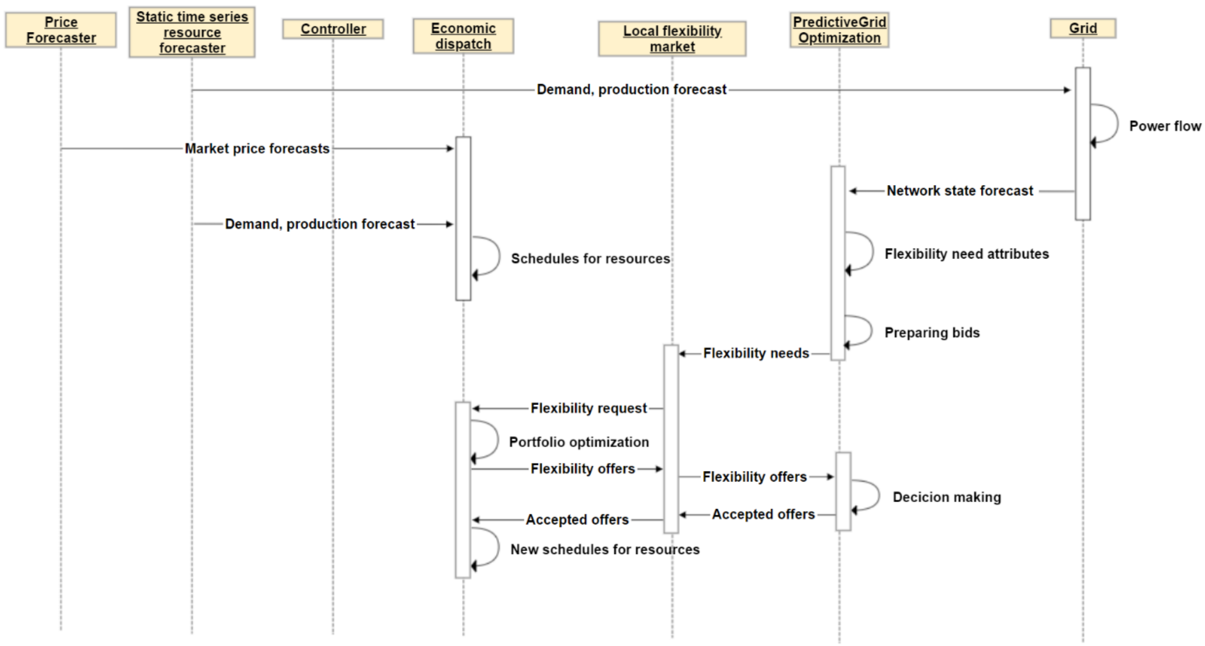


Figure 31 - sequence diagram of component's interaction in the day ahead time frame

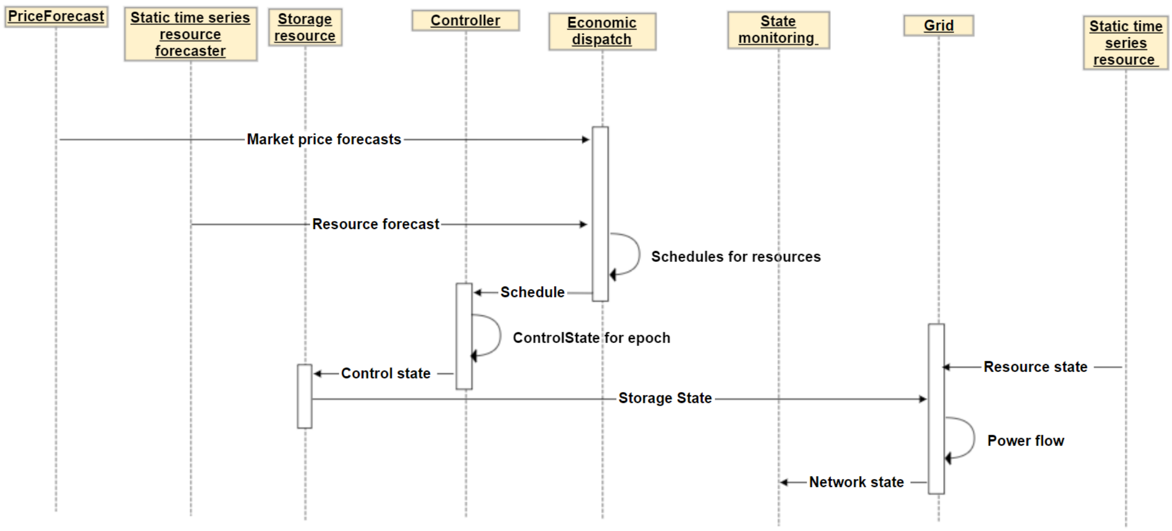


Figure 32 - sequence diagram of component's interaction in the operational time frame

4.2.4 Flexibility Need

A flexibility need has several attributes available in reference [5]. The flexibility product in the current LFM market design is standardized. Some of them are explained in the following:

“Bid resolution” in kW specifies the minimum margin between two flexibility offers with different flexibility volumes. For example, if bid resolution is 5 kW, then offers could be integer coefficients of 5 (e.g., 5, 10, 15, etc.).

“Real power min” is the minimum power in kW that is acceptable in the market. It must be equal to a positive-integer coefficient of bid resolution. “Real power min” is often smaller than the volume of the real flexibility needed because it lowers the entry barrier for smaller-scale flexibilities to participate in the market.

"Real power request" represents the real DSO's flexibility needs in kW that is expected to receive at a specific location and time. Therefore, it must be equal to a positive-integer coefficient of bid resolution.

"CustomerId" is an identification number unique for each customer, known to DSO and its corresponding EC. When flexibility need's area is known in PGO, the "customerIds" within the congestion area is found; therefore, using the customer Id, only ECs that have customers inside the congestion zone participate in the LFM. The reason why "customerId" is used is that grid data can be tied to private customers' information, and customer data protection mandates that the data is not published (e.g., to LFM where several parties have access to). In other words, to protect customer information, using "customerIds", a translation occurs in PGO in terms of congestion area before sending flexibility needs to the market, assuring that sensitive data is not published.

The duration when the flexibility requires to keep activated is 60 minutes in the current simulations. The value must equal a positive-integer coefficient of 15 minutes (e.g., 15, 30, 45, 60, 75, etc.)

4.2.5 Sensitivity Analysis

Since the PGO's input is forecasted voltages, there is a need to translate voltage violation to flexibility need volume in kW. Sensitivity analysis is the method used in PGO to determine the flexibility need's volume and congestion area.

FLEXIBILITY NEEDS CALCULATION

The sensitivities are determined by an approximate method proposed in [6]. Some simplifying assumptions have been made in the technique. Constant current models are used for loads and generators, and the phase difference between voltages is assumed to be negligible. As a result of these assumptions, the voltage sensitivities can be represented by the following simple equation:

$$\left[S_{I_p}\right] = -[R] \tag{3.1}$$

$$\left[S_{I_q}\right] = -[X] \tag{3.2}$$

where

$S_{I_p} = \begin{bmatrix} \frac{\partial V_1}{\partial I_{p1}} & \cdots & \frac{\partial V_1}{\partial I_{pn}} \\ \vdots & \ddots & \vdots \\ \frac{\partial V_n}{\partial I_{p1}} & \cdots & \frac{\partial V_n}{\partial I_{pn}} \end{bmatrix}$ is the voltage sensitivity matrix in proportion to real node currents I_p,

$S_{I_q} = \begin{bmatrix} \frac{\partial V_1}{\partial I_{q1}} & \cdots & \frac{\partial V_1}{\partial I_{qn}} \\ \vdots & \ddots & \vdots \\ \frac{\partial V_n}{\partial I_{q1}} & \cdots & \frac{\partial V_n}{\partial I_{qn}} \end{bmatrix}$ is the voltage sensitivity matrix in proportion to reactive node currents I_q and

R is the real and X the imaginary part of the impedance in the impedance matrix $[Z]$. The diagonal element of $[Z]$ (i.e., $[Z_{ii}]$) are equal to the sum of the branch impedances forming the path from the origin (i.e., substation to node i). The off-diagonal elements $\left[Z_{ij}\right]$ are equal to the sum of the branch impedances forming the path from the origin to the common node of the paths from the origin to nodes i and j, respectively. Node i is the node whose voltage change is analyzed, and node j the node whose reactive or real power is changed to control the voltage at node i. Hence, the controllable resource at node j can affect the voltage at node i more the longer (electrically) the common path from the origin to nodes i and j is.

This method calculates the voltage sensitivities based on only network impedances. In reality, however, other variables such as substation voltage, the voltage at the node i, and net real and reactive node currents also affect the sensitivity value. Hence, the method only gives approximate values of the sensitivities. However, these are adequate for flexibility need's volume calculation. The benefit of the method is its simplicity and the fact that the sensitivity matrices need to be updated only if the network's switching state changes. All data required for determining the sensitivity values are already available at the DMS under the network information system (NIS). Composing the sensitivity matrices is calculated once at the beginning of each simulation.

In this method, it is assumed that reactive and real power control affects voltages only on the feeder they are connected to because the origin is defined to be the primary substation (bus 1 in figure 33). This is not, naturally, utterly true because impedance also exists in the high voltage (HV) network and the substation transformer. Suppose also these impedances are included in the voltage sensitivity calculations. In that case, the origin should be defined to be the node representing the ideal voltage source behind the HV network impedance. It should be noted that considering HV network impedance is not an easy task because it requires a DSO to have online monitoring of HV lines as impedance is not static due to switching actions, maintenance, etc. Therefore, the proposed voltage sensitivity has been chosen due to enough accuracy and simplicity. In addition, since flexibility needs only involve active powers, only S_{I_p} is taken into account, and reactive power is ignored in the calculations. In practice, primary and secondary voltage control utilizing DG's reactive power control, transformer with online tap changer (OLTC), etc., can change the distribution network's voltage profile as well.

CONGESTION AREA DETERMINATION

In the simulation environment, as mentioned in section 4.2.1, to parameterize each component in the start-up, those parameters are sent via start message [3]. For example, in the start message, PGO is informed about minimum and maximum voltage limits, LFM operation time, forecasts horizon, etc. Relative sensitivity (rs) is one of those parameters required for PGO's parameterization. It is used to specify the area where flexibilities could join the LFM. Its value varies between 0 and 100. The larger the rs, the larger areas of the network can participate in solving congestion. Suppose the value is 100, then flexibilities throughout the whole distribution feeder can participate in LFM. Therefore, the value should be reasonable so that the area is neither small nor too large. Finding an optimum rs value could be an interesting research question because it can significantly impact liquidity in the LFM, considering that an optimum rs is time-dependent. S_{I_p} is used to calculate the flexibility area. Suppose bus i experiences congestion; then, the aim is to realize whether a flexibility resource connected to bus j is inside the flexibility area or not. The flexibility resource connected to bus j can participate in the market only if:

$$RS_{j\to i} < 1 - \left({}^{rs}/_{100}\right) \tag{3.3}$$

where

$$Relative\ Sesitivity\left(RS_{j\to i}\right) = \frac{[S_{I_{p(i,j)}}]}{[S_{I_{p(i,i)}}]} \tag{3.4}$$

The voltage sensitivity matrix is used to assess the impact of flexibility at bus j on congestion at bus i. As a normalization measure, the division of voltage sensitivities is used to yield the relative sensitivity (RS) to facilitate utilizing a parameter (rs) from 0 to 100 in the PGO's start-up.

Once the buses inside the flexibility area are known, PGO translates them to "customerIds", so LFM's published information does not contain sensitive information. By looking at the "customerIds", each EC could realize whether their resources are inside the flexibility request zone or not.

4.2.6 Decision Making in PGO

The current implementation of decision-making in PGO selects the cheapest offer per kWh, which means the price of flexibility is divided by its volume; afterward, a merit order list of offers is created. The selection process starts with taking the cheapest offer, and if more flexibility volume is needed, the second cheapest offer is selected. Simplicity is the feature of the method chosen in the current simulations. It should be noted that the DSO's decision-making is a research topic, and several studies could be dedicated to that. For instance, offer selection could be so that an objective function including a hard constraint for congestion removal and a term for power loss reduction is introduced, and the best answer to the function is selected.

4.2.7 Grid, Loads, and Energy Communities (ECs)

Figure 33 illustrates the understudy distribution network. It consists of 359 buses, including 248 medium and 110 low voltage (LV) buses. The network is a real one and is located in Finland. Data from network information system (NIS) like grid topology, impedances, etc. and customer information system (CIS) like the number of customers, customer types, load profiles (hourly values for the whole year) of customer types, annual energies, etc. are used in the simulations; nevertheless, due to confidentiality of the data, further details cannot be provided. For better readability, more important buses and network equipment from a network analysis perspective are shown in the graph.

The consumption in the area retrieved from smart meters is very temperature dependant; therefore, when the temperature falls well below zero, the heating loads significantly rise, leading to under-voltage congestion on the tale of the network. The simulation horizon is one week, from Jan 17 to Jan 23, 2013. The temperature history during that period, especially Jan 18 and 19, reached below -15 degrees centigrade [7]. Therefore, an under-voltage situation is expected during those times. Three different load models are used to study the impact of forecast inaccuracy, including perfect, noisy, and load model forecasts. The perfect forecast does not mismatch with load levels in operation time. The noisy forecast is created by adding a random variable to the perfect forecast. The load model forecast is the DSO’s load forecast done some years ago for planning purposes.

As shown in Figure 33, ECs are located in buses 69, 73, and 75, with the ability to provide up and down-regulation depending on the distribution system operator's (DSO) flexibility need and operational capabilities of ECs. ECs include passive load demand, photovoltaic (PV) production, and battery storage. Load demand and PV production are considered non-flexible, and PV production is close to zero during January considered in the simulation case. Batteries are identical in size with 25 kWh energy capacity and 50 kW power.

The main aim of the batteries is to optimize the energy purchase of ECs on the day-ahead market, and secondly, to provide flexibility services if there are requests from DSO on LFM. Therefore, the total capacity of batteries will not be available for LFM. For example, the battery is planned to be empty when DSO requests up-regulation (demand reduction) because the next hours are the cheapest on the day-ahead market. The price of flexibility service depends on the cost of modifying energy optimization of ECs due to flexibility provision. This is realized by recalculating the economic dispatch of EC to make an offer for the flexibility request. Flexibility pricing includes only the marginal cost of redispatching the flexibility resources from ECs viewpoint. The balancing cost of the retailer and the aggregator’s profit and gaming opportunities are not considered, which should be added as well to the offer prices. Therefore this simulation will give very optimistic results compared to reality in terms of flexibility cost of DSO.

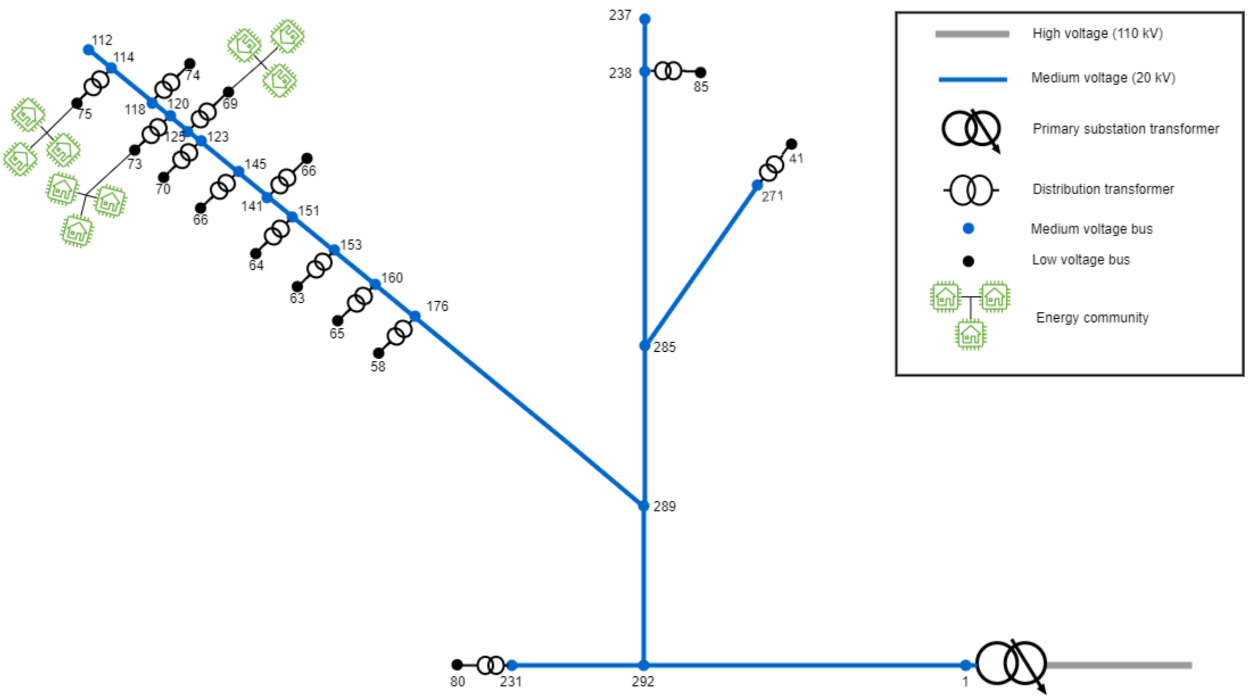


Figure 33 - Grid topology

4.3 Exemplary Results

Several scenarios have been designed to meet the goals of the simulations. Some exemplary results are shown in Figures 34 and 35.

Table 1 - Scenarios

Scenario	Features	Involved components
Reference	This simulation is considered as the reference for the rest of the simulation scenarios. The idea is that ED will only participate in day-ahead market and there is no PGO and LFM in the simulation.	1. Core components 2. State monitoring 3. Grid 4. Controller 5. Economic dispatch 6. Static time series resource 7. Static time series resource forecaster 8. price forecaster
1	This simulation considers perfect forecast on the resource forecaster, a neutral decision making on PGO side (neither over-purchase nor under-purchase), and open offers are not considered in ED optimisation.	1. Core components 2. State monitoring 3. Grid 4. Controller 5. Economic dispatch 6. Static time series resource 7. Static time series resource forecaster 8. price forecaster 9. PGO 10. LFM
2	This simulation considers noisy perfect forecast on the	1. Core components 2. State monitoring

	resource forecaster, a neutral decision making on PGO side (neither over-purchase nor under-purchase), and open offers are not considered in ED optimisation.	3. Grid 4. Controller 5. Economic dispatch 6. Static time series resource 7. Static time series resource forecaster 8. price forecaster 9. PGO 10. LFM
3	This simulation considers: load-profile forecast on the resource forecaster, a neutral decision making on PGO side (neither over-purchase nor under-purchase), and open offers are not considered in ED optimisation.	1. Core components 2. State monitoring 3. Grid 4. Controller 5. Economic dispatch 6. Static time series resource 7. Static time series resource forecaster 8. price forecaster 9. PGO 10. LFM

4.3.1 Reference Scenario

As mentioned in section 4.2.2, due to severe cold on Jan 19 and 20th year 2013, there is an expectation of under-voltage in some LV buses. Figure 34 illustrates that some buses' voltage during those hours is below the minimum acceptable limits (0.96 p.u.). The red areas in the figure represent the under-voltage situation, while the rest are within good voltage levels. Voltage profile proves the high temperature-dependency of voltage because 18 and 19 Jan are the coldest days during the simulations (i.e., hours 30 to 70), which is expected to be eliminated by flexibility purchase. However, since under-voltage situation constantly occurs at the same locations, due to the rebound effect, it is expected that ECs around that location may not be able to eliminate congestion for some hours.

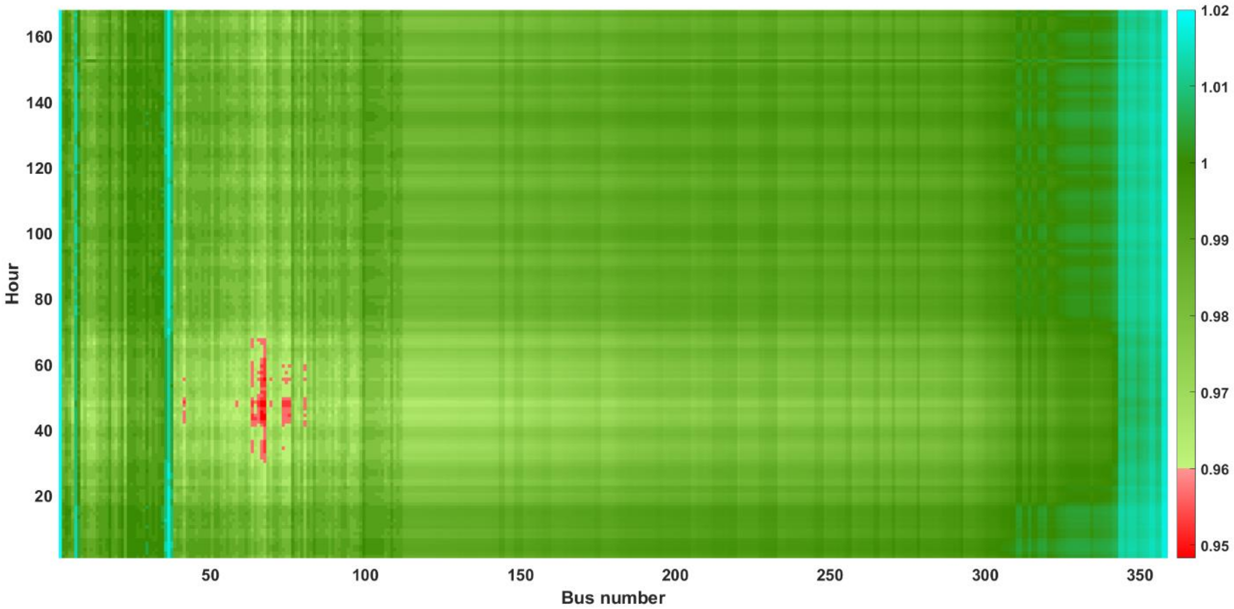


Figure 34 - Reference scenario's voltage profile

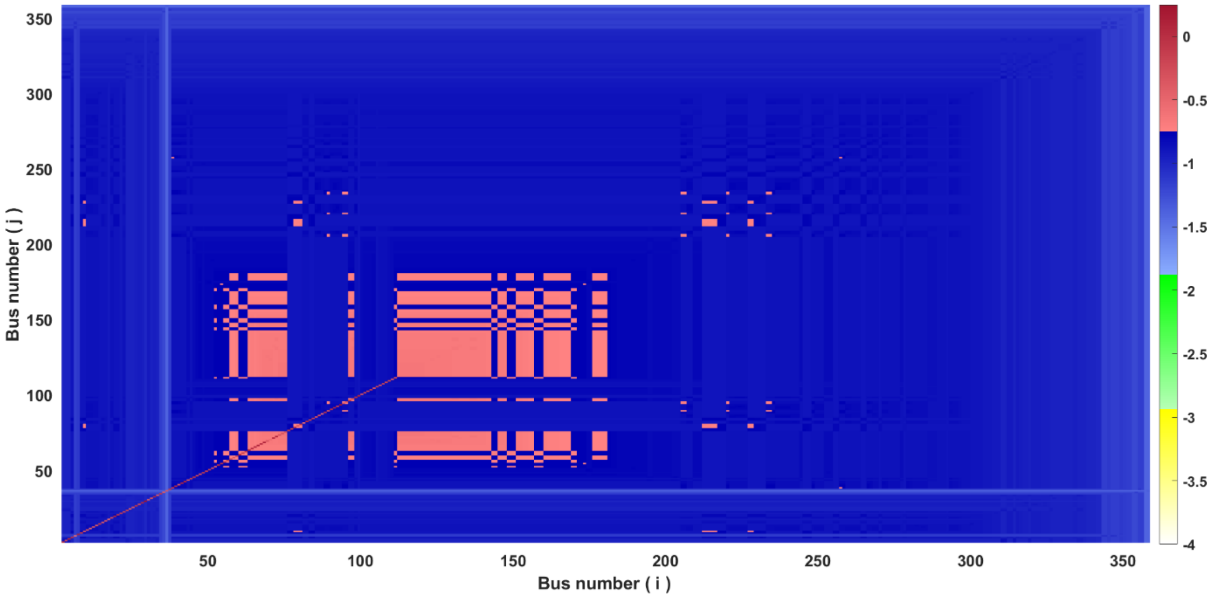


Figure 35- Logarithmic plot of sensitivity matrix $0.5\log_{10}(S_{I_p})$

Figure 36 depicts sensitivity matrix (S_{I_p}) values meaning that it shows the impact of the flexibility activation (current injection or consumption) on one bus (e.g., bus i) to voltage change on another bus (e.g., bus j). The X-axis represents bus i, and Y-axis represents bus j. The voltage sensitivity matrix is symmetric; however, normalization in relative sensitivity (RS) calculations makes RS asymmetric. The values in the sensitivity matrix range from 0 to 3.1309 (average= 0.0172, standard deviation (SD)= 0.0254). Since the maximum value in the matrix is 123 times the value of SD, the dispersion of matrix values is great, making it a hard-to-read plot. Therefore, the logarithm function has been used to scale down the values and have a meaningful plot. The color bar highlights the sensitivity ranging from -4 to 0.5 (highest possible sensitivity). Each color represents one-quarter of sensitivity value's scale. Yellow, green, blue, and red represent up to 25, 50, 75, and 100 percent sensitivity, respectively. Therefore, the red areas indicate a relatively good sensitivity. The graph has valuable information that can help us to understand the impact of flexibility on congestion in different voltage levels of distribution systems:

- The farest the bus from the primary substation, the highest sensitivity because of the weaker network on its tales. On the other hand, the probability of voltage violation is higher in the weaker network areas. In other words, voltage violation can happen more often in the weaker areas than in the stronger areas and can be solved with a smaller flexibility volume.
- The sensitivity matrix contains the voltage dependency of a bus on another bus's flexibility; it also indicates the weaker network areas. For example, the red areas in figure 36 depict the network areas with a high impedance prone to a voltage deviation. Therefore, the sensitivity matrix can increase DSOs visibility toward its network useful for planning purposes.

Table 2 - Comparison of strong versus weak buses' congestion

Congestion	Positive feature	Negative feature
Weak bus (e.g., LV bus far from the primary substation)	• less flexibility volume is needed	• may happen more often
Strong bus (e.g., MV bus close to the primary substation)	• may rarely happen	• more flexibility volume is required

4.4 Discussion

CONGESTION ON LV GRID

Low voltage congestion requires low voltage flexibility, often under the distribution transformer where the congestion is located. When LV congestion occurs, the MV feeder usually has an acceptable voltage level. The problem is caused by a high impedance distribution transformer and weak LV lines. To solve the congestion in the LV bus, the required flexibility in the MV feeder is much larger than in LV feeder due to the strength difference of the MV and LV sides. For example, a 3 percent voltage change on an LV bus may require 300 kW flexibility on the LV side, whereas the equivalent flexibility needed on the MV side will be in MW magnitude. On the other hand, if several LV buses under different distribution transformers experience congestion, then flexibility procurement on the MV side is reasonable. Therefore, congestion management in the LV grid is very case dependant.

Adoption of LFM for LV congestions depends on the regularity and severity of congestion on the LV side. If LV congestion occurs occasionally, LFM can be an option. Otherwise, alternatives like reinforcement of LV or MV lines should be considered if the problem is reoccurring. However, since reinforcement is time-consuming (e.g., permission, designing, financing, implementation, etc.), LFM could support the network during the transition.

REBOUND EFFECT, RECOVERY TIME

When flexibility is required continuously for some time (e.g., half a day), under certain circumstances, the rebound effect can significantly reduce the flexibility provider's ability to participate in the market. The problem is intensified when the flexibility provider's portfolio is limited; therefore, the recovery time of its flexibility resources directly reduces the market participation. The following example clarifies the matter.

Suppose that flexibility is required from 3 pm to 9 pm on a certain LV area. Figure 37 illustrates a synthetic FSP's stationary battery's state of charge (SOC) during that time. Due to technical reasons, SOC beyond 80 and below 20 percent is avoided in FSP's economic dispatch (ED) as a hard constraint. The SOC falls from 70 percent at 3 pm to near 20 percent at 5 pm as a result of flexibility delivery. Due to ED's internal optimization results (e.g., influenced by high electricity price), the battery is awaiting from 5 pm to 7 pm. Afterward, ED decides to charge up the battery again. The raised example highlights the rebound effect's importance and impact on the FSP's offers in LFM. In this situation, although the stationary battery is available for congestion management, due to 4 hours recovery time (2 hours awaiting, two hours charging), FSP can only solve the congestion for the first two hours. In this case, the ability of SFP in providing flexibility is dependant on the size (kWh) of the stationary battery, diversity of FSP's portfolio (i.e., if it exists), hard constraints defined by technical considerations (i.e., freedom of operation), flexibility price, etc. The diversity of FSP's portfolio can diminish the impact of the rebound effect because it largens the ED's solution space. Similarly, higher flexibility prices can reduce the impact of the rebound effect because it minimizes awaiting time.

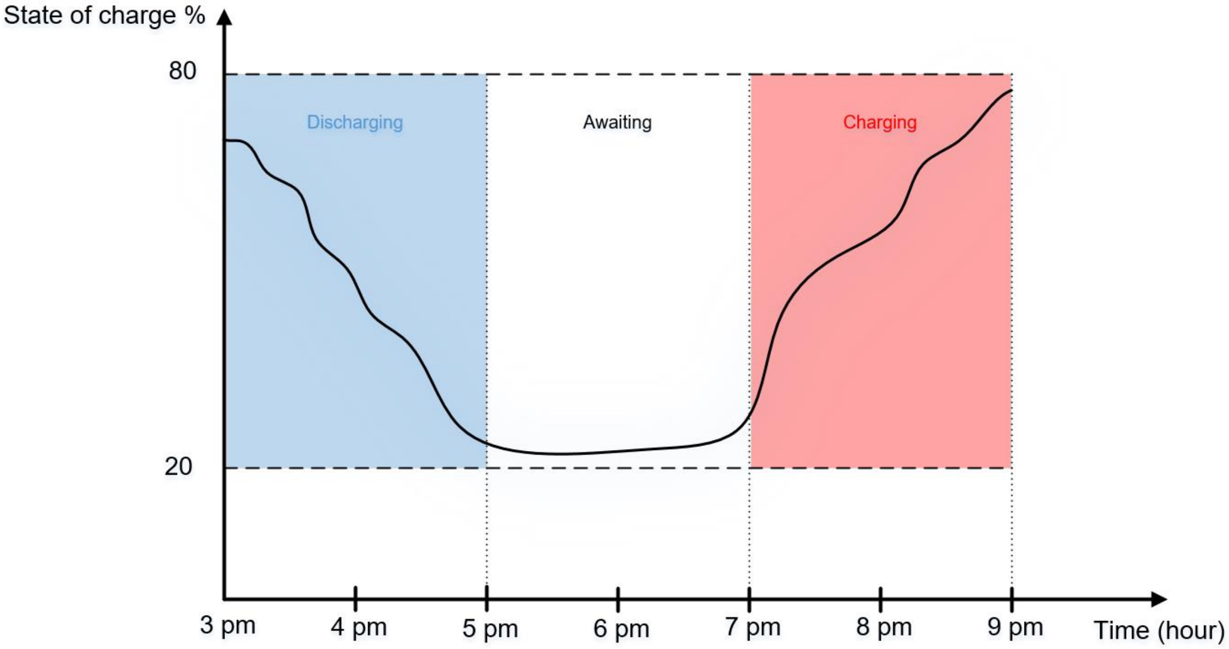


Figure 36 – Stationary battery's SOC

LFM DESIGN

The current LFM design is such that LFM accepts bids only based on DSO's request. This means that DSO defines what bids should be offered to LFM. Therefore, all bids in LFM are somehow acceptable by DSO and need to put them in price order in PGO and select the cheapest one/ones. The benefit of the proposed LFM is to increase the market liquidity from DSO's needs viewpoint. In addition, as the proposed LFM is very localized, a lower entry barrier for small-scale flexibilities is provided. In fact, opening such a local market offers a revenue channel for small-scale flexibilities that otherwise might be unused. The drawback is that it is a very specialized market, and there might not be many aggregators operating at all. Besides, it may lead to many marketplaces, which might be specialized for a specific area of one DSO. The myriad of markets is not favourable because participation in all of them increases the cost of aggregators due to marketplace entry fees, optimization complexity, etc.

Another way to realize LFM, especially if multiple stakeholders are utilizing the same market simultaneously, would be such that all kinds of offers are accepted. Later, DSO needs to filter out those bids which are acceptable for her. DSO may publish flexibility need information in a similar way than we have proposed to increase the number of acceptable offers, but those are not the only acceptable bids for LFM. In this way, flexibility buyer and provider adapt their market participation strategy with respect to each other.

Settlement is always one of the most important aspects of any market. We have not considered settlement stages in the current simulations, including baseline methodology and reimbursement calculation. In practice, flexibility price in the trading phase could be different from what is paid to flexibility providers. In addition, gaming-related issues that are dominant in local markets have not been considered.

SHORTCOMINGS

In the current simulations, congestion in terms of voltage violation has been taken into account. Nevertheless, overloading prediction should be added to PGO's functionality. PGO should find the root cause of congestion when both voltage and overloading are taken into account because they may have a mutual impact on each other. For instance, under-voltage in a network area might be caused by the overloading of a line feeding that network area. Therefore both under-voltage and overloading are linked, and they require only one up-regulation flexibility in the congestion area.

FUTURE STUDIES

Evaluating the LFM with different product designs seems interesting from a research perspective. Flexibility product attributes such as congestion area, minimum bid size and bid resolution could be changed to highlight their impact on LFM operation and its usefulness for stakeholders. For example, by increasing the relative sensitivity value in the start message (rs), the congestion area can be largened with the cost of a larger electrical distance from the flexibility provision point to the actual congested bus. In this way, liquidity is expected to be increased because more flexible resources fall inside the congestion zone, but the flexibility impact of the congestion is reduced due to a larger impedance between flexibility location and congested bus.

4.5 Conclusions & Outlook

The outcome of the simulations are as follows:

- The simulation environment can simulate multi-stakeholder decision-making problems without making assumptions of stakeholders' interactions (interactions might be both synergy benefits or conflict-of-interests).
- The case study shows some complexities of DSO level market-based congestion management, including liquidity issues when flexibility needs are local.
    - LFM utilization in the day ahead for upcoming congestion is not ideal when congestion occasionally occurs, especially in specific locations. Instead, long-term contracts seem more attractive. In this way, the DSO can inform the aggregator about the next day's flexibility activation before the day-ahead market closure (e.g., 10 am). Otherwise, the aggregator could utilize the flexibility in the day-ahead market and other following markets. In this manner, flexibility is cheaper and more reliable for DSO.
- The rebound effect impacts the ability of flexibility providers in market participation significantly under certain circumstances, such as when the size (kWh) of the flexibility resource is small compared to the needs, diversity of FSP's portfolio is limited (e.g., one kind of technology is being used), hard constraints defined by technical considerations are strict, etc. Local flexibility needs and rebound effect are two factors that can significantly reduce LFM's benefit for DSOs.

5 Conclusions

The aim of the application of simulation-based methods was to gain additional insights regarding the usability of congestion management markets. Within work package 3, two different capable frameworks have been developed that could consider different viewpoints.

With respect to market participants and flexibility providers, it has been shown that additional markets offer additional marketing opportunities for the market participants. This also affects their operational decisions and needs to be taken into account when the available flexibility potential is assessed. In that sense it is also important to develop an understanding of all markets where the flexibility assets participate in order to have a realistic view of the local flexibility market.

For grid operators, CM markets offer additional flexibility that can be used for congestion management. It has been shown that the available flexibility potential is highly dependent on the grid structure, the underlying constraints and might be unequally distributed. Within the congestion management of DSOs, it could also be shown that for voltage congestions very local flexibility is needed.

With respect to the market design, it should be noted that the conclusions are limited to the underlying design and general conclusions can hardly be drawn. This is based on the fact that a general assessment of different market designs would need simulative approaches that could evaluate designs that might differ fundamentally in their design.

It should be noted that the developed frameworks are also limited and present a certain extract from reality. For simplification, some aspects have been neglected that might have a significant influence on CM markets and the process of congestion management of the grid operator. This may include but is not limited to the following aspects: Uncertainties regarding the market prices and the feed-in of RES, aspects of behavioural economics or specific regulatory aspects.

6 References

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