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## Deliverable D4.3

# Report on simulation tests with dummy data



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#### Authors and reviewers

<b>Main responsible:</b>	Hellenic Energy Exchange (HENEX), Emmanouil Bakirtzis, <a href="mailto:e.bakirtzis@enexgroup.gr">e.bakirtzis@enexgroup.gr</a> Hellenic Energy Exchange (HENEX), Aikaterini Forouli, <a href="mailto:a.forouli@enexgroup.gr">a.forouli@enexgroup.gr</a> Hellenic Energy Exchange (HENEX), Georgios Papazoglou, <a href="mailto:g.papazoglou@enexgroup.gr">g.papazoglou@enexgroup.gr</a>
<b>Author(s)/contributor(s):</b>	HENEX, Georgios Papazoglou HENEX, Aikaterini Forouli HENEX, Emmanouil Bakirtzis UCL, Nicolas Stevens UCL, Anthony Papavasiliou UP, Athanasios Bachoumis UP, Nikolaos Andriopoulos UP, Alexios Birbas ICOM, Isidoros Kokos ICOM, Dimitris Karagkounis ICOM, Ioanna Lazaridou
<b>Reviewer(s):</b>	ESTABANELL, Joana Alsina Sanchez ICOM, Ilias Lamprinos

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## **Abstract**

This deliverable presents three market mechanisms and tools which enable the trading of flexibility in different time horizons. The mechanisms enable the participation of Flexibility Aggregators and require the engagement and cooperation among system operators (DSOs, TSOs) and the Market Operator (MO). The presented market mechanisms have been designed to be scalable and, operate in a hierarchical level. In all of the presented mechanisms, flexibility is provided as active and reactive power. The proposed mechanisms are: a day-ahead two-level iterative market mechanism, a continuous trading mechanism for grid energy and a real-time mechanism for congestion management and balancing purposes. For each of the proposed market tools, the market structure, actors and roles, and products are described, as well as technical information regarding the mathematical formulation and the solution methodology of the market clearing model. In addition, a simple user interface for the tools' testing is provided. Each mechanism successfully serves its objective: On the day – ahead level, the design of auction-based Day-Ahead (DA) Local Flexibility Markets (LFMs) is proposed, presupposing that a central DAM for social welfare maximization is run on a transmission network level. Operational constraints of both the distribution and transmission networks are considered. In the continuous mechanism, trades are concluded to alleviate or resolve anticipated violations in the distribution network, considering the feasibility of AC network constraints. The implementation allows for partial bid matching and is computationally light, therefore, suitable for continuous trading applications. Last, the real time platform dispatches flexible resources in real time to balance the system while ensuring that network constraints are safeguarded. For each market mechanism, the operation is showcased and verified using simulations with dummy data.

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## **Keyword list**

Flexibility Trading Algorithms, Local Flexibility Markets, Flexibility Aggregator, Distribution System Operator, Distribution Systems, Day – Ahead Market, Continuous Trading, Real Time Trading, TSO – DSO coordination

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## **Disclaimer**

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## Executive summary

The aim of this deliverable is to implement and present the market design and functionalities of different market tools, developed to incorporate flexibility services in the form of active and reactive energy in the distribution grid spanning the whole short-term scheduling horizon, i.e. day-ahead, intra-day and real-time. The presented market mechanisms have been designed to be scalable and, operate in a hierarchical level.

The day ahead market mechanism consists of a central DAM that is run on a transmission network level and a set of auction-based DA LFM's on the distribution level. The central DAM is modelled as an Optimal Power Flow (OPF) problem subject to the DC approximation of the transmission network's constraints, with an objective function of social welfare maximization. The central DAM schedule is disaggregated on a nodal level, where Power Flow analyses are run to check for the feasibility of the central DAM dispatch instructions. In case of violations in the DN, the LFM's are triggered. Each LFM enables the trade of both active and reactive power flexibility, in the form of energy. Active power flexibility is traded amongst Market Participants (MPs), while reactive power flexibility is offered by MPs to the DSO. After the LFM's run and feasibility on all DNs is restored, the central DAM is rerun, in order to adjust the market schedule for any imbalances caused by the updated schedules generated by the LFM's.

The second implementation proposes a continuous network aware local flexibility market that aims to empower DSOs with a market-based instrument for the alleviation of grid violation incidents by exploiting the flexibility of local resources. Within the novel continuous LFM, active and reactive power flexibility located in the distribution system can be traded, so as to successfully handle voltage violations, congestion issues and deviations of the DSO's schedule in the TSO - DSO connection point. The market design engages the Market Operator, the DSO and MP with dispatchable assets. The proposed market operates in a single distribution system and considers network constraints via AC network sensitivities.

Last, a real-time market for clearing energy while accounting for transmission and distribution network constraints is modelled. The market balancing platform that is proposed, trades location-specific real power at the transmission system, and location-specific real and reactive power at the distribution system, producing relevant locational marginal prices. Engaged actors are: the market operators (TSOs and DSOs), the Balancing Service Providers (BSPs) and the Balancing Responsible Parties (BRPs). An important feature of the real time mechanism is that it accommodates TSO-DSO coordination while maintaining decentralized operations for network operators. This is implemented by the Aggregation-Disaggregation System.

Each of the introduced market mechanisms is tested with simulations that use synthetic data. A toy example is included for each mechanism to better showcase the operational principles of each mechanism. Also, a realistic example is also simulated, demonstrating the scalability of the proposed market mechanisms.



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## 1 Introduction

As a result of the deregulation of the electricity sector in the European Union (EU), electricity markets have emerged to guarantee affordable and secure energy supply, while boosting competition and transparency [1]. To a large extent, EU member states have adopted a common framework for electricity markets, that outlines general design principles and rules [2], [3]. According to this framework, there are four main markets, that span in different time horizons, in which electricity can be traded. These are the Day-Ahead Market (DAM), the Intra-Day Market (IDM), the balancing market, and bilateral markets.

This market design framework, however, was developed to satisfy the traditional way in which power systems operated [1]. In the past, the bulk of electricity was generated by large conventional or hydro power plants that were connected to the transmission network. Electricity then would flow through the Distribution Network (DN) to the end-users. In this setting, the secure and efficient operation of the power system assumed two things: i) an adequate ability to forecast demand and ii) that the generating units were dispatchable. A dispatchable unit can regulate its power output (e.g. by controlling its fuel consumption) to satisfy dispatch instructions.

In the past few years, the assumption that most of the electricity is generated by dispatchable units is being challenged. The energy transition of the global energy sector is causing deep transformations in the energy systems worldwide. At the root of the energy transition is the effort to reduce carbon emissions, in order to combat the climate crisis. This has manifested through the proliferation of Renewable Energy Sources (RES) and other forms of Distributed Energy Resources (DERs), as well as the electrification of various industries. The problem with increasing RES penetration is that their power output is variable and not dispatchable, since it is dependent on exogenous variables (e.g. irradiance or wind speed). These unique characteristics of RES have an impact on electricity markets. Their cheap production cost means that they can contribute to lowering production cost, but at the same time their variable power output profiles can cause market price volatility and a difficulty to forecast the net load (i.e. forecasted load minus forecasted RES generation) that has to be serviced by traditional units [4].

As a response to the changing electricity landscape, the EU published a new directive in 2019 [5] to adapt the common market framework to the new realities. This directive crucially focuses on the importance of emerging flexibility technologies, such as storage and demand response, as well as the participation of retail consumers and communities to the markets, either directly or through aggregators. The latter are empowered to sell their generated electricity back to the market, or to provide flexibility services and receive remuneration.

However, electricity markets are not the only part of power systems where the impact of the energy transition manifests in. The effects of the aforementioned changes are also apparent in the distribution network. DNs were designed to accommodate flows from the transmission network to the end users. As many RES and DERs are nowadays connected to the DN, it now has to accommodate bi-directional flows it was not designed to. Moreover, the electrification of various industries and aspects of human activities means DNs are increasingly loaded. In order to be able to withstand these new heavy loading scenarios, Distribution System Operators (DSOs) would traditionally have to rely on the costly solution of reinforcing the distribution network [6].

Recent technological advancements enable distribution system operators to use cost effective solutions to address the operational challenges of the system and create new opportunities for the stakeholders. In this context, Local Flexibility Markets (LFMs) enable assets that lie within the distribution network to trade flexibility in order to alleviate or prevent the operational challenges of the distribution system operator. The concept of LFMs has emerged recently and has received both academic and business interest. Various design approaches for LFMs have been presented, with their main differences being on their timeframes, the type of offered products, their level of network-awareness, and their clearing methodologies.

Implementations of LFMs have been proposed for different timeframes, in accordance with conventional electricity markets. These include long-term LFMs (e.g. [7], [8], [9]), Day-Ahead (DA) LFMs (e.g. [10], [11]), intraday LFMs (e.g. [12]), and real-time LFMs (e.g. [10], [11]). The main differentiation regarding offered products concerns whether flexibility can be traded in the form of capacity or in the form of energy. When traded in the form of capacity, flexibility can be used by Distribution System Operators

(DSOs) as a tool for network reinforcement deferral [13]. This type of products is usually featured in long-term markets (e.g. [10], [11]), where capacity is reserved with long-term contracts, and can, if needed, be activated closer to real-time [13]. When traded in the form of energy, which is usually the case in day-ahead, intraday and real-time LFMs, flexibility is dispatched at specific time intervals, based on the market time unit resolution (e.g. [12], [14]).

Regarding the level of network-awareness, a LFM can either disregard the network constraints, consider them using the Direct Current (DC) approximation, or consider them using the AC power flow equations, or some method based on relaxed AC optimal power flow. Disregarding the network constraints (e.g. [12], [15]) results in LFMs that are very simple to implement and solve; however, there is no guarantee regarding the feasibility of the resulting schedule. The DC approximation is widely used in the transmission network to reflect the network constraints. Some works (e.g. [14]) have used the DC approximation to reflect the distribution network's constraints. Unlike transmission networks, in the distribution networks the DC approximation fails to accurately reflect the network's constraints, due to the different like characteristics between the two [16], and the fact that it disregards the voltage magnitudes of each node, which at the distribution network can significantly deviate from their nominal values [16], [17]. Incorporating the network's constraints using AC (e.g. [17]) or relaxed-AC (e.g. [18]) techniques is realistic, but it adds a level of complexity on the implementation of the LFM, and can cause problems in its scalability [13].

LFMs can implement an auction clearing mechanism or a continuous trading approach. Most auction-based LFMs feature two-sided auctions, with the objective to maximize social-welfare [19], and the market clearing is performed after the gate closure. Continuous trading markets do not feature gate closures, and clear as soon as a pair of bids matches. According to [14] and [20], continuous markets might be the preferred clearing method for LFMs, at least in their first stages, since they are better suited for the low liquidity conditions they are expected to have, until they reach their maturity. Works that explore the capabilities of continuous LFMs can mainly be found in EU and national projects, such as NODES [21], GOPACS [22] and ENERA [23].

In order to adequately satisfy the needs of the stakeholders, a LFM should consider and satisfy the following requirements [24]

- Satisfactory representation of the physical constraints of the networks,
- Scalability,
- Decentralization,
- Respect for institutional boundary conditions, and
- Consistent pricing.

## **1.1 Task 4.2**

The objective of Task 4.2 “Flexibility trading algorithms” is the development and description of novel market mechanisms and market tools that facilitate the roles of the Market Operator, the Flexibility Aggregators and the Distribution System Operators in the context of flexibility trading. To that end, market mechanisms are developed for three timeframes: Day-Ahead, Intra-Day, and Real-Time markets. The market structure, the roles of each actor, and the mathematical formulation of each market mechanism is described in detail, and the relevant software is provided. These mechanisms were initially described in the Deliverable 4.2 of FEVER [25], therefore the contents of some sections of this Deliverable are taken from Deliverable 4.2.

## **1.2 Objectives of the work reported in this deliverable**

The main objective of this deliverable is the development of market mechanisms that enable flexibility trading, are compatible with EU electricity markets, and satisfy the needs of the stakeholders. To do so, the best practices from the literature are identified and adopted by the developed mechanisms. To ensure compatibility with EU electricity markets, market mechanisms are developed for three timeframes: Day-Ahead, Intra-Day, and Real-Time markets. For each market mechanism, the roles of the several stakeholders are described in detail, and the market structure and offered products are tailored to their needs. The market clearing methodology for each market mechanism are also

presented, with each clearing methodology being optimized for the particularities of the market timeframe.

### **1.3 Outline of the deliverable**

The rest of the deliverable is structured as follows: in Section 2 the Day-Ahead market mechanism is presented, in Section 3 the Intra-Day market mechanism is presented and in Section 0 the Real-Time market mechanism is presented. In the context of each market, market structure and the offered products are presented, and the market clearing modelling is formulated. Finally, in Section 5 the conclusions regarding each market mechanism are drawn.

### **1.4 How to read this document**

As pre requirement for reading this document is a good knowledge of the electricity markets design and operations (e.g. [1] provides an overview). Previous basic knowledge on electricity flexibility resources and trading concepts will contribute to a better understanding of the report's content. The document can be read without prior knowledge of any FEVER specific documentation or report.

## 2 Day Ahead Market Mechanism

### 2.1 Nomenclature

#### A. Indices and Sets

$g(G)$	index (set) of generators
$i(I)$	index (set) of buses
$i, j(L)$	branch “from”, “to” bus indices, (set of)
$k(K)$	index (set) of iterations
$n(N)$	index (set) of segments for piecewise linearization of the branch flow limits
$t(T)$	index (set) of trading periods

#### B. Parameters

$C_g^{p(q)}$	coefficients of the generator active (reactive) power output costs, in €/pu (€/pu)
$C_{i,t}^{u(d)}$	cost of upwards (downwards) flexibility at node $i$ and trading period $t$ , in €/pu
$G_{ij}, B_{ij}$	real, imaginary part of the $(i, j)$ element in the admittance matrix, pu
$g_{ij}, b_{ij}$	conductance, susceptance of line $(i, j)$ , pu
$P_g^{\min(\max)}$	minimum (maximum) active power generation, pu
$P_{i,t}^{f, \max}$	maximum active power flexibility at bus $i$ , trading period $t$ , pu
$P_{i,t}^{sch}$	disaggregated scheduled DAM injection at node $i$ and trading period $t$ , pu
$Q_g^{\min(\max)}$	minimum (maximum) reactive power output of generator $g$ , pu
$R_{i,t}^{u(d)}$	upward, downward ramping capacity of flexibility at node $i$ and MTU $t$ , pu
$S_{ij, \max}$	apparent power flow limit of branch $(i, j)$ , pu
$V_i^{\min(\max)}$	minimum (maximum) voltage magnitude at bus $i$ , pu

#### C. Variables

$v_i^{(k)}$	(linear approximation at $k$ -th iteration of) voltage magnitude at bus $i$ , pu
$\theta_i^{(k)}$	(linear approximation at $k$ -th iteration of) voltage angle at bus $i$ , rad
$\theta_{ij}^{(k)}$	(linear approximation at $k$ -th iteration of) voltage angle difference of buses $i$ and $j$ , rad
$s_{ij}^{(k)}$	(linear approximation at $k$ -th iteration of) apparent line flow at line $(i, j)$ , pu
$p_{i,t}^{(k)}, q_{i,t}^{(k)}$	(linear approximation at $k$ -th iteration of) active, reactive power injection at bus $i$ trading period $t$ , pu
$p_g, q_g$	active, reactive power output of generator $g$ , pu
$p_{ij}, q_{ij}$	active, reactive power flow on branch $(i, j)$ , pu
$p_{i,t}^u, p_{i,t}^d$	upward, downward active power flexibility at bus $i$ , trading period $t$ , pu

### 2.2 Introduction

The DAM has emerged as the main trading arena for electricity, as it is the market that routinely has the largest exchange volumes. DSOs can use the disaggregated results of the DAM, as well as their own forecasts for the demand and RES production of the assets that lie in their networks, to accurately predict any violations that are likely to occur during the dispatch.

In this work, we propose the design of auction-based Day-Ahead (DA) LFM. Each LFM operates in a single DN and incorporates its operational constraints in order to prevent any violations. To that end, the LFM enables the trade of both active and reactive power flexibility, in the form of energy. Active power flexibility is traded amongst Market Participants (MPs), while reactive power flexibility is offered by MPs to the DSO.

The LFM presupposes that a central DAM is run on a transmission network level. The central DAM is modelled as an Optimal Power Flow (OPF) problem, subject to the DC approximation of the transmission network's constraints, with an objective function of social welfare maximization. The resulting schedule

of the central DAM is then disaggregated on a nodal basis, on each DN. On a distribution level, Power Flow (PF) analyses are run, to determine whether any violations occur with the dispatch instructions of the central DAM. In the DNs where violations do exist, LFMs are triggered. The LFMs are modelled as OPF problems, subject to a linearized approximation of the full AC network constraints of the DNs, and an objective function of flexibility cost minimization. The LFMs are solved using Sequential Linear Programming (SLP). After the LFMs run and feasibility on all DNs is restored, the central DAM is rerun, in order to adjust the market schedule for any imbalances caused by the updated schedules generated by the LFMs.

## 2.3 Market Design

### 2.3.1 Actors and Roles

The proposed market design covers both active power trading in a central DAM on a transmission system level, and active and reactive flexibility power trading in DA LFMs. The proposed markets engage the Market Operator (MO), MPs, DSOs and Transmission System Operators (TSOs).

#### Market Operator (MO)

On a high level, the MO is responsible for developing and operating the central DAM and DA LFM trading platforms, performing all the necessary actions for clearing the DA and DA LFMs, coordinating and executing the required information exchange between stakeholders and the post-market settlement process.

The development and operation of the DAM and DA LFM trading platforms consists of all the actions necessary to facilitate the participation of the stakeholders in the envisioned markets. The trading platform should be open for MPs to submit, edit, or delete their orders in the orderbook while the gate of the markets is open. The trading platform should also notify the MPs if the bids they place violate any of the rules of the market (e.g. if a bid is price beyond the market price cap, or if it's placed in an invalid node). Once the gate of the markets closes, access to the orderbook should be prohibited to the MPs. Overall, the trading platform should be accessible, secure and reliable.

Clearing the proposed markets is the most vital task undertaken by the MO. Clearing of the proposed markets should be concluded within predefined time limits. The steps the MO follows to clear the markets are aligned with the market structure presented in Figure 1. In an effort to decrease the size of the problem, the bids of the assets that lie on the DN participate in the central DAM in an aggregated manner. The aggregation procedure is conducted by the MO via a procedure described in Section 2.3.3. The resulting bids are called virtual aggregated DN bids and are considered to be submitted in the node of the TN where the DN is connected (the T&D interface node). To solve the central DAM, which is formulated as a DC OPF, and its detailed formulation can be found in Section 2.4.1 the MO must receive from the TSO all the relevant network data in a timely manner. After the central DAM is solved, the MO must disaggregate the virtual aggregated DN bids on an asset basis. The disaggregation algorithm is presented in Section 2.3.3.

Once the results have been disaggregated, the MO must communicate the scheduled injection of each asset of each DN to the respective DSO. Then, each DSO runs a Power Flow (PF) analysis for each Market Time Unit (MTU) (i.e. each dispatch hour in this case) to detect any violations of the network's operational constraints. In case violations exist, the DSO can trigger the DA LFM procedure for their control area. In each DA LFM, assets that lie in that particular DN can provide flexibility to the DSO, to alleviate the violations. Flexibility bids are extracted from the bids submitted in the central DAM, using an algorithm described in Section 2.3.3. The formulation of each DA LFM is described in detail in Section 2.4.2. Since the DA LFMs are network aware, each DSO must provide the required network data to the MO in a timely manner for the formulation of the problem.

The optimization algorithm that solves the DA LFMs may cause a change in the flow at the T&D interface node of each DN, which in turn disturbs the balance of the system. To resolve any potential imbalances, the central market must be re-solved, to account for these changes. The MO must again aggregate the bids of each DN, to formulate the final virtual aggregated DN bids using a procedure described in Section 2.3.3.



Once the central DAM is solved, the final schedule of all the assets must be communicated to the representatives, and the post-market settlement process (which is beyond the scope of this work) begins. The actions undertaken by the MO are considered as part of the DAM schedule disaggregation application, the DAM Scheduler application, and the Power Flow Simulator application, as described in the deliverable D1.2.

### Transmission System Operator (TSO)

In the context of the proposed markets, the TSO is responsible for providing the necessary network data to the MO for the formulation of the central DAM problem. The necessary network data are:

- The topology of the transmission network,
- The characteristics of each line, and
- The thermal limits of each line.

The data must be provided to the MO within a specified window, upon the request of the MO. The actions undertaken by the TSO are considered as part of the Network Data processing Application, as described in deliverable D1.2.

### Distribution System Operators (DSOs)

Since multiple DNs can be connected to a single TN, the proposed markets can accommodate the existence of multiple DSOs. Each DSO is responsible for triggering the DA LFM mechanism in their control region. To that end, each DSO receives the disaggregated central DAM results for the assets that lie in their control region. DSOs then run an AC PF analysis of each MTU of the dispatch day. In case any violations exist, the DA LFM procedure is triggered, and the MO must be notified.

Since the DA LFM formulation is network-aware, each DSO must provide the MO with the required network data to formulate the problem. The required network data are:

- The topology of the DN,
- The characteristics of each line,
- The thermal limits of each line, and
- The minimum and maximum voltage magnitude limits of each bus.

The data must be provided to the MO within a specified window following the triggering of the DA LFM. The DSO is also required to set price caps for the price of flexibility for the DA LFM that runs in their control region. The actions undertaken by the DSO are considered as part of the Network Data processing Application and the Power Flow Simulator, as described in deliverable D1.2.

### Market Participants (MPs)

MPs participate on an asset-basis on both the central DAM and the DA LFMs. MPs submit bids for the assets they represent that are connected to the distribution or transmission network while the gate is open. The different types of bids and the information each bids should contain are specified in Section 2.3.3. The creation of the MPs orders is considered as part of the Bidding Application, as described in deliverable D1.2.

## 2.3.2 Market Structure

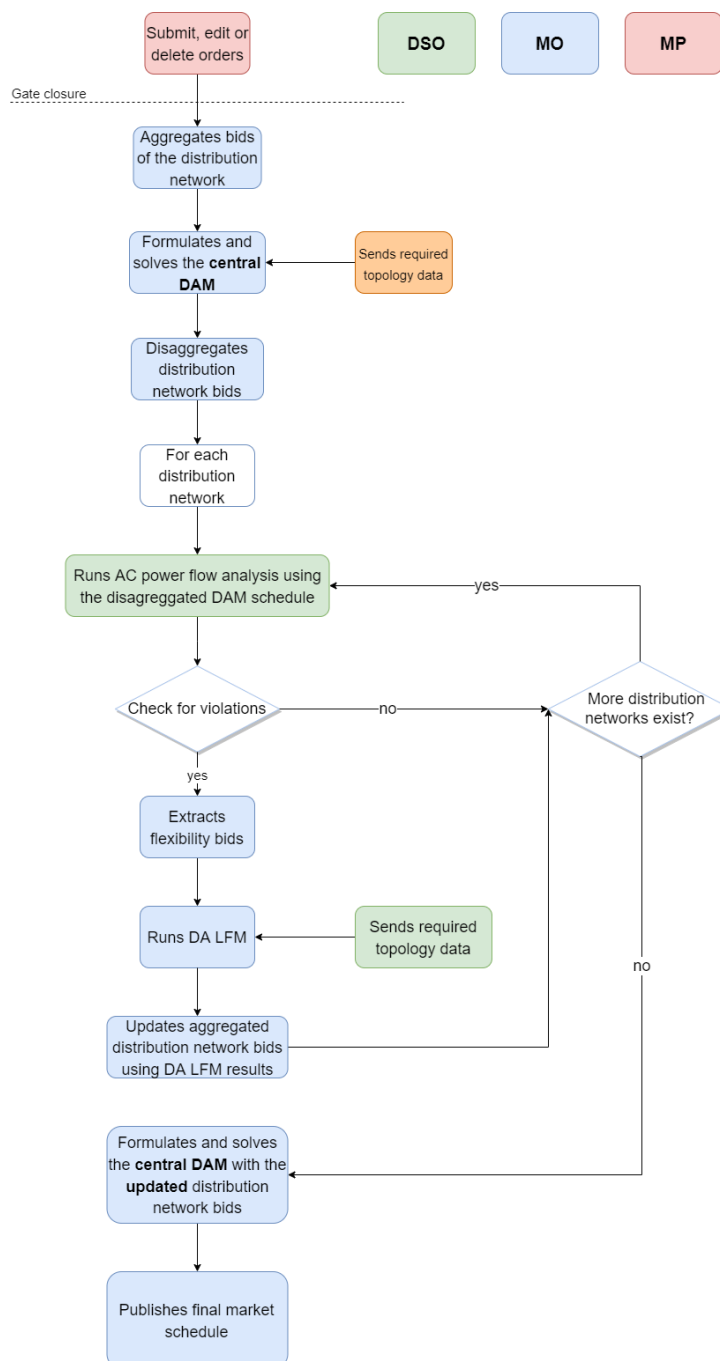
The proposed market structure consists of two distinct market mechanisms: the central DAM and the DA LFMs. The proposed framework describes their operational principles and their interaction. Both the central DAM and the DA LFMs are double sided auctions, with social welfare optimization as their objective functions. The optimization horizon of both market consists of 24 Market Time Units (MTUs). Participation in both markets is asset-based. If the dispatch day for the traded electricity is the day D, the gate closure for both markets is the k-th hour of day D-1, as seen in Figure 1.



Figure 1 Trading timeline of the proposed DAMs.



While the gate is open, MPs can submit, edit, or delete their orders. When the gate closes, the market clearing procedure, which can be seen in Figure 2, and whose description follows, starts.



**Figure 2** Business logic of the proposed markets.

After the gate closure, the MO collects the bids of the assets that lie on each DN and performs their aggregation. The aggregation procedure is conducted by the MO via a procedure described in Section 2.3.3 and the resulting bids are called virtual aggregated DN bids, which are considered to be submitted in the T&D interface node.

Next, upon receiving the necessary network data from the TSO, the MO formulates and solves the central DAM. The central DAM is formulated as a DC OPF problem, and its detailed formulation can be found in Section 2.4.1.

Then, the MO disaggregates the results of the central DAM on an asset basis for the assets that lie on the DN, using the algorithm described in Section 2.3.3. The scheduled injection of each asset is

communicated to the DSO in whose control area the asset lies. Each DSO in turn must evaluate whether the scheduled injections cause any violations on their DNs. To that end, each DSO runs an AC PF analysis, for each MTU using the scheduled injections.

In case violations occur on a DN, the DA LFM procedure is triggered for that DN. The DSO proceeds with the extraction of flexibility bids, using the initially submitted bids and the disaggregated results via the procedure described in Section 2.3.3. Since the DA LFM formulation is network-aware, the MO must also receive the required network information from the DSO to formulate and solve the DA LFM. The MO then formulates and solves the DA LFM. It is worth mentioning that in a production environment, this procedure can be parallelized, offering significant speed gains to the process.

If the DA LFM changes the initial injection at the T&D interface node of any DN, which in turn can disturb the balance of the system, the central DAM needs to be re-solved to restore the system balance. The MO must again aggregate the bids of each DN, to formulate the final virtual aggregated DN bids using a procedure described in Section 2.3.3. The formulation of this problem is identical to that used in the initial run of the central DAM.

Once the central DAM is solved, the final schedule of all the assets must be communicated to the representatives, and the post-market settlement process begins.

## 2.3.3 Products

The envisioned markets offer several types of offers to accommodate the needs of all the different stakeholders. Three broad order categories can be defined: block orders, hybrid orders, and flexibility orders. Each order category can contain multiple order types. The detailed description of all order categories and order types follows.

### 2.3.3.1 Block Orders

Block orders are multi-period energy products that are predominately used for capturing the technical characteristics of conventional power plants (e.g. thermal units) and for hedging the risk associated with volatile DA Market Clearing Prices (MCPs). Therefore, in the proposed setting, block orders are only accepted in the central DAM, and can be submitted only by assets connected to the TN (since that is where conventional units lie).

The block order category contains four distinct types of orders: profile block orders, linked block orders, exclusive group of block orders, and reversible block orders. The reversible block order is a novel type of order, introduced for better capturing the needs of MPs that represent storage units.

All orders that belong to this category must include the following information:

- *Order id*, a unique positive integer that identifies the order (generated by the MO),
- *Asset id*, a unique positive integer that identifies the asset that this order refers to (identified by MPs),
- *Node*, a positive integer indicating the node that this order is submitted in (identified by MPs)
- *Side*, a string identifier, 'B' if the order is on the Buy side (demand) or 'S' if the order is on the Sell side (supply) (identified by MPs),
- *Block price*, a floating point number indicating the cost of the block order (identified by MPs),
- *Block profile*, a sequence of strings in the format of  $\{mtu\_1 @quantity\_1, mtu\_2 @quantity\_2, \dots\}$ , that indicates the block order's profile for each MTU,
- *Block acceptance ratio*, a floating point number between 0 and 100 that indicates the minimum amount of the block profile that can be accepted (identified by MPs),
- *Block relationship*, a string identifier, 'N' if the block order is a profile block order, 'L' if the block order is a linked block order, 'R' if the block order is a reversible block order,
- *Block parent id*, (only applicable to linked block orders) a positive integer indicating the id of the block order that the submitted block order is linked with (identified by MPs), and

*Linked id*, (only applicable to group of exclusive block orders) a positive integer indicating the id of the block order with which the submitted block order is exclusively linked with (identified by MP).

#### Profile block orders

Profile block orders is the most common type of block orders. A profile block order describes an energy injection (sell profile block order) or offtake (buy block order) profile that should be accepted, or rejected as a whole. Sell profile block orders are much more common than buy profile block orders, as they are used to represent the technical characteristics of thermal units. Profile block orders also feature a minimum acceptance ratio, which expresses the minimum ratio of the submitted profile that should be cleared. The cleared profile divided by the submitted profile is defined as the acceptance ratio of the block order, and is always greater than (or equal to) the minimum acceptance ratio. The minimum acceptance ratio and the acceptance ratio are the same for all MTUs of a profile block order.

The acceptance rules of a sell (buy) profile block order are:

- A sell (buy) profile block order should be accepted in its entirety (acceptance ratio equals to 1) if its offer price is lower (higher) than the weighted average Market Clearing Price (MCP) of the MTUs of the delivery day included in the block order, weighted by the respective accepted energy quantities of the sell (buy) block order,
- A sell (buy) profile block order should be partially accepted (acceptance ratio between minimum acceptance ratio and 1) if its offer price is equal to the weighted average MCP of the MTUs of the delivery day included in the block order, weighted by the respective accepted energy quantities of the sell (buy) block order. The acceptance ratio takes such value so that the weighted average MCP is equal to the sell (buy) block order price, and
- A sell (buy) profile block order should not be accepted (acceptance ratio equals to 0) if its offer price is higher (lower) than the weighted average MCP of the MTUs of the delivery day included in the block order.

#### **Linked block orders**

A linked block order consists of individual profile block orders and are linked to each other by a parent-child relationship. A child block order can only be accepted when its parent block order is executed.

The acceptance rules of a linked block order are:

- The acceptance ratio of a parent-type block order is greater or equal to the highest acceptance ratio of its child-type block orders, and
- The acceptance of child-type block orders may allow the acceptance of a parent-type block order, even if the parent-type block order is not acceptable under the rules of profile block orders, if the surplus of the acceptable combination of child-type and parent-type block orders is non-negative.

#### **Exclusive group of block orders**

An exclusive group of block orders consist of a set of profile block orders, for which the sum of accepted ratios cannot be greater than 1. In the special case where the individual profile block orders have a minimum acceptance ratio of 1, at most one of the profile block orders in the group of exclusive block orders is executed.

The acceptance rules of an exclusive group of block orders is the same as the acceptance rules of profile block orders, with the additional rule that the sum of the acceptance ratio of the block orders belonging to the same exclusive group cannot be greater than one.

#### **Reversible block orders**

A reversible block order consists of a modified buy and a sell profile block order. Instead of specifying the profile of an asset for a specific MTU, a reversible block order specifies the desired profile for consecutive MTUs, without specifying the exact MTU each profile should be allocated, or the down-time between the buy and the sell profiles. Each side of the reversible block order is cleared where it maximizes the social-welfare. However, the priority of the buy or the sell side (which is implicitly defined during the submission of the bid by whether the buy or the sell side profile is submitted first) must be respected for the bid to be cleared.

A reversible block order is accepted if any of its potential profile creates a welfare surplus (i.e. the offer price is lower (higher) than the weighted average MCP of the MTUs of the delivery day included in the block order, weighted by the respective accepted energy quantities of the sell (buy) block order).

### 2.3.3.2 Step Orders

Step orders are single-period energy products, which in this case are composed of stepwise orders. Each segment corresponds to an energy quantity that is submitted at the specified price level. For sell step orders, the step order curve is ascending, while for buy step orders, the step curve is descending. Step orders are supported both by bids that are connected to the TN and the DN.

The step order category contains three distinct types of orders: simple step orders, initial virtual aggregated DN orders, and final virtual aggregated DN orders.

All orders that belong to this category must include the following information:

- *Order id*, a unique positive integer that identifies the order (generated by the MO),
- *Asset id*, a unique positive integer that identifies the asset that this order refers to (identified by MPs),
- *Node*, a positive integer indicating the node that this order is submitted in (identified by MPs for simple step orders, defined by the MO for the rest),
- *Side*, a string identifier, 'B' if the order is on the Buy side (demand) or 'S' if the order is on the Sell side (supply) (identified by MPs),
- *Step MTU*, a positive integer number between 0 and 23 that indicates the MTU that the orders is eligible for, and
- *Step points*, a sequence of strings in the format  $\{price\_1@quantity\_1, price\_2@quantity\_2, \dots\}$  that indicates the offer's quantity at each price range.

Also, all step orders follow the same acceptance rules:

- A segment of a buy (sell) step order should be totally accepted if its price is higher (lower) than the MCP for the specific MTU of delivery day D,
- A segment of a buy or sell step order should be partially accepted if its price is equal to the MCP for the specific MTU of delivery day D, and
- A segment of a buy (sell) step order should be rejected if its price is lower (higher) than the MCP for the specific MTU of delivery day D.

#### Simple step orders

Simple step orders can be submitted by MPs that represent assets connected to the TN or the DN. In a buy (sell) step order, energy quantities are submitted on a descending (ascending) price level. An example of buy (red) and a sell (blue) hybrid order can be seen in Figure 3.

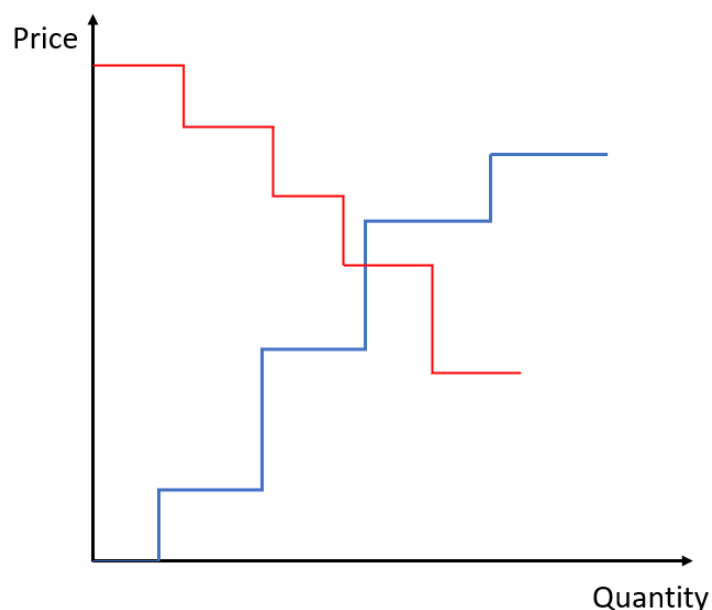


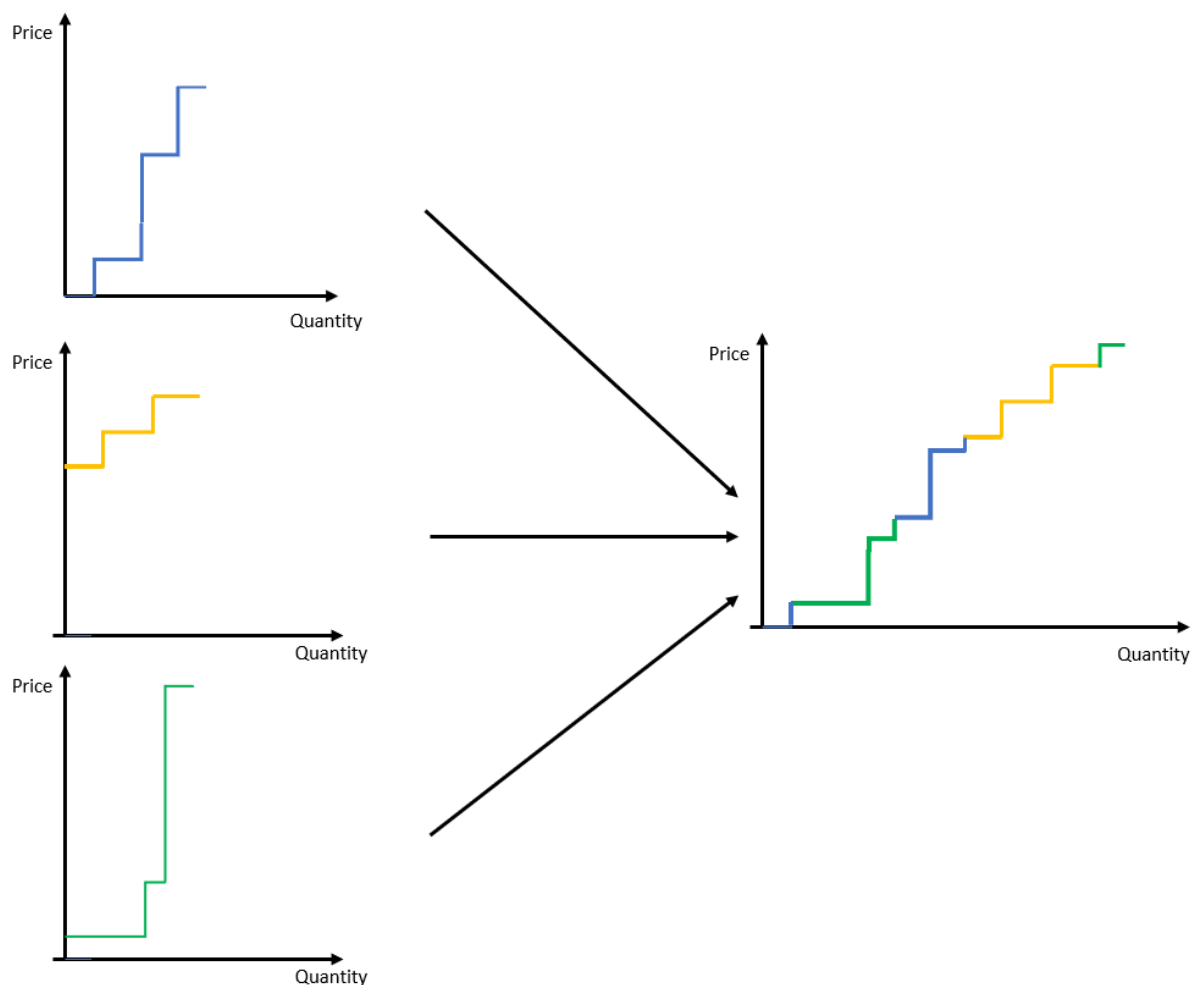
Figure 3 A buy (red) and a sell (blue) simple step order

#### Initial Virtual Aggregated Distribution Network Orders

Assets that lie in the DN participate in the central DAM in an aggregated manner. This happens for several reasons, such as:

- Since practical DNs can contain thousands of nodes, and several DNs can be connected in a single TN, modelling each DN and including it in the formulation of the central DAM would dramatically increase the problem size.
- Institutional limitations on data sharing could prohibit the aggregation of all the sensitive data in a single entity. In the proposed market formulation, data is better segmented and institutional concerns can be alleviated.
- The proposed aggregation procedure can be easily added to existing DAMs, without needing extensive modifications to the existing market processes.

The procedure that is described in this section is performed for each MTU and each DN (therefore for each DN an Initial Virtual Aggregated DN Order is created). The procedure is demonstrated in Figure 4.



**Figure 4** The creation of initial aggregated DN orders from simple step orders.

To create the Initial Virtual Aggregated DN Orders, all the simple step orders of a DN are collected and grouped by MTU and side (buy/sell). For each MTU, sell (buy) orders are ordered in ascending (descending) price. The individual orders are then aggregated in the Initial Virtual Aggregated DN Order, which comprises of the sorted segments of the individual simple step orders. If more than one segments on the same price level exist, the segments are added and priority in the clearing process is given to the order with the older timestamp. From this procedure, two Initial Virtual Aggregated DN Orders for each DN and MTU are created (one for the buy and one for the sell side). The generated order is then submitted to the central DAM using an asset id that indicates which DN it represents (generated by the MO), a node identifier that indicates the node of the TN where the DN is connected (generated by the MO), and the step points that were generated by the aforementioned procedure.

### Final Virtual Aggregated Distribution Network Orders

The DA LFM orders that are triggered in case of infeasibilities in the DN alter the schedule of the assets of the DN. Therefore, the final schedule of the assets of each DN (which is the schedule after the DA LFM orders have been cleared) must be submitted to the central DAM. To guarantee that the final schedule of each asset of the DN is cleared, a special type of simple step orders is used, which is called the Priority Price Taking (PPT) order. PPT sell (buy) orders are simple step orders priced at the minimum (maximum) accepted price of the market. Final Virtual Aggregated DN Orders are formulated as PPTs, so that the submitted quantities will be cleared when submitted to the central market, and therefore the schedule of each DN will remain feasible.

Therefore, for each DN and each MTU  $t$ , two Final Virtual Aggregated DN Orders are created (one for the buy and one for the sell side), as follows:

- For buy orders, a quantity equal to the sum of the initial buy quantities and the downward flexibilities activated by the DA LFM is submitted to the central DAM using an asset id that indicates which DN it represents (generated by the MO), a node identifier that indicates the node of the TN where the DN is connected (generated by the MO), and step points  $\{maximum\ accepted\ price @ q_{b,t}\}$ . Aggregate buy orders also include the DN losses that the DSO buys from the DAM, as explained in the modelling.
- For sell orders, a quantity equal to the sum of the initial sell quantities and the upward flexibilities activated by the DA LFM is submitted to the central DAM using an asset id that indicates which DN it represents (generated by the MO), a node identifier that indicates the node of the TN where the DN is connected (generated by the MO), and hybrid points  $\{minimum\ accepted\ price @ q_{s,t}\}$ .

#### 2.3.3.3 Flexibility Orders

Flexibility orders are used in the DA LFM orders to provide the necessary flexibility to the DSO in order to alleviate the issues of the DN. Therefore, flexibility orders are only created for assets that lie in the DN. Flexibility orders are extracted from the simple hybrid orders that were submitted on the central DAM. From each simple hybrid order, two flexibility orders are extracted: one upward flexibility order, and one downward flexibility order. At this point, the definitions for upward and downward flexibility are provided:

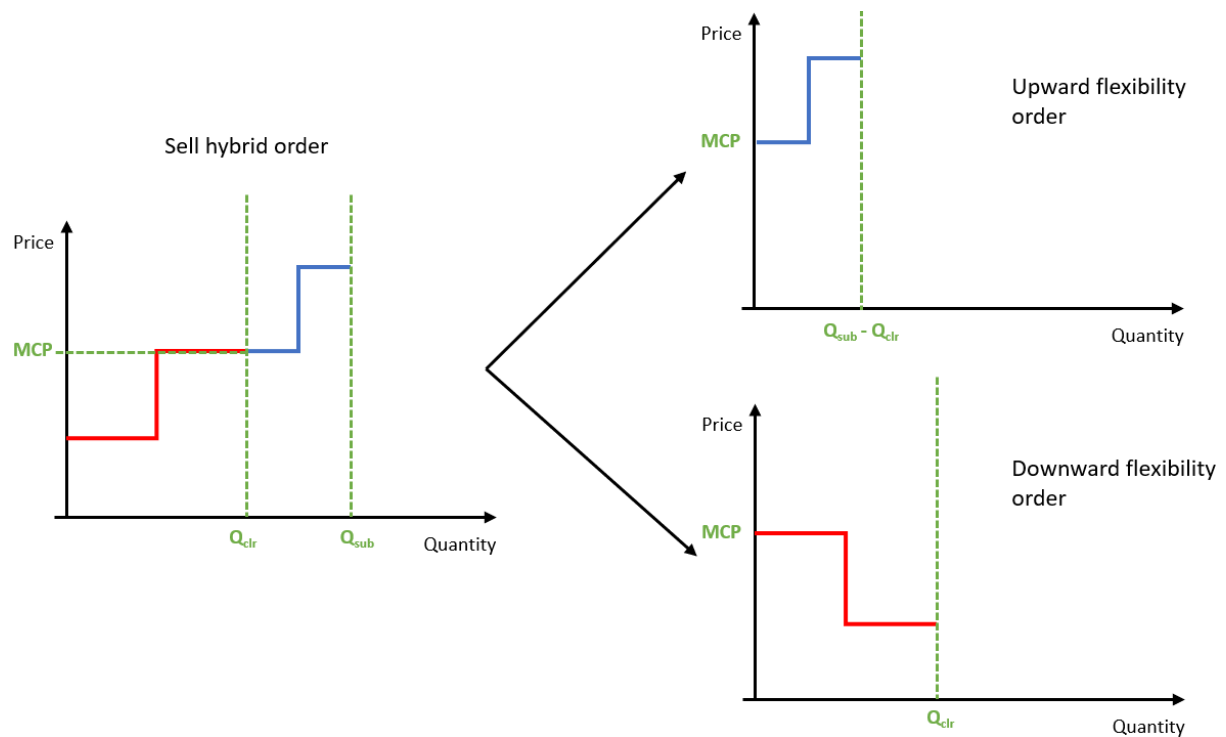
- *Upward flexibility* is defined as flexibility that causes an increase of the net injection in a bus (i.e. increase in generator power output or decrease in load offtake), and
- *Downward flexibility* is defined as flexibility that causes a decrease of the net injection in a bus (i.e. decrease in generator power output or increase in load offtake).

The extraction of flexibility orders from the step orders submitted in the central DAM reflects accurately the actual production cost/utility of the assets. Flexibility orders are created as follows:

For *sell* step orders:

- Segments with a price higher than the MCP are converted to upward flexibility orders, and
- Segments with a price lower than the MCP are converted to downward flexibility orders, after segments are sorted by descending price.

The process can be seen in Figure 5.

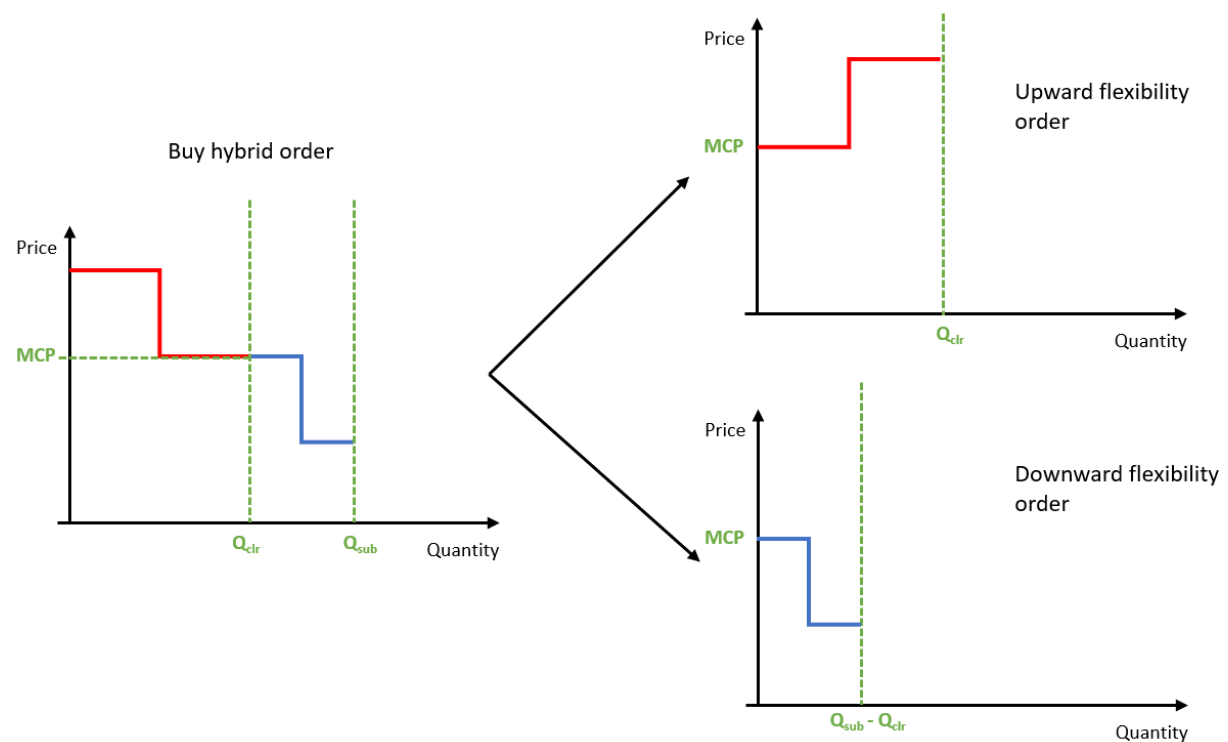


**Figure 5** Extraction of flexibility orders from a sell step order.

For *buy* step orders:

- Segments with a price higher than the MCP are converted to downward flexibility orders after segments are sorted by ascending price, and
- Segments with a price lower than the MCP are converted to upward flexibility orders.

The process can be seen in Figure 6.



**Figure 6** Extraction of flexibility orders from a buy step order

## 2.4 Market Clearing Modelling

In order to capture the physical constraints imposed by the networks, both the central DAM and the proposed DA LFMs must be network aware. Thus, the formulation of both markets belongs in the family of AC Optimal Power Flow (OPF) problems. The AC OPF is a well-documented problem, whose main complexity stems from the Non-Linear (NL) and non-convex nature of the AC Power Flow (PF) equations. A generic NL AC OPF formulation follows:

$$\min_{p_g, q_g} f(p_g, q_g) = \sum_{g \in G} (C_g^p p_g + C_g^q q_g) \quad (2-1)$$

subject to

$$p_i = \sum_{j=1}^N (v_i v_j G_{ij} \cos \theta_{ij} + v_i v_j B_{ij} \sin \theta_{ij}), \quad \forall i, \quad (2-2)$$

$$q_i = - \sum_{j=1}^N (v_i v_j B_{ij} \cos \theta_{ij} - v_i v_j G_{ij} \sin \theta_{ij}), \quad \forall i, \quad (2-3)$$

$$P_g^{\min} \leq p_g \leq P_g^{\max}, \quad \forall g, \quad (2-4)$$

$$Q_g^{\min} \leq q_g \leq Q_g^{\max}, \quad \forall g, \quad (2-5)$$

$$V_i^{\min} \leq v_i \leq V_i^{\max}, \quad \forall i, \quad (2-6)$$

$$-\pi \leq \theta_i \leq \pi, \quad \forall i, \quad (2-7)$$

$$(p_{ij})^2 + (q_{ij})^2 \leq S_{ij, \max}^2, \quad \forall (i, j) \quad (2-8)$$

where  $p_i, q_i$  is the net active, reactive power injection or offtake on bus  $i$ , respectively and,

$$p_{ij} = g_{ij} U_i^2 - U_i U_j (g_{ij} \cos \theta_{ij} + b_{ij} \sin \theta_{ij}) \quad (2-9)$$

$$q_{ij} = -b_{ij} U_i^2 - U_i U_j (g_{ij} \sin \theta_{ij} - b_{ij} \cos \theta_{ij}) \quad (2-10)$$

The expansion of this formulation to multiple MTUs is trivial.

Equations (2-1), (2-2), (2-9), (2-10) and the inequality (2-8) introduce non-linearities to the formulation. While it is possible to directly solve the NL AC OPF problem (e.g. by using Interior Point Methods), the sensitivity of these methods to the choice of initial point and their inability to handle integer variables does not make them ideal for use in market applications.

Therefore, different approaches are used to solve this problem. For the central DAM market, a popular approximation of the AC OPF problem is solved, called the DC OPF problem. For the DA LFMs, a novel method that is based on SLP is used. Both methodologies are described in the following sections.

### 2.4.1 Central Day-Ahead Market

The DC approximation linearizes the AC PF equations using three assumptions:

1. Line resistances are negligible compared to line reactances, and therefore line resistances can be omitted, simplifying the line parameters:

$$g_{ij} \cong 0 \rightarrow z_{ij} = j b_{ij}, \quad \forall (i, j)$$

2. The voltage magnitude of each node is assumed to be equal to 1 p.u.:

$$v_i \cong 1, \quad \forall i$$

3. The differences in voltage angle between nodes is small, therefore the following linearizations can be performed without much loss of accuracy:

$$\sin \theta_{ij} \cong \theta_{ij} \text{ and } \cos \theta_{ij} = 1.$$

All three assumptions are generally accurate in the TN. The DC approximation has been widely used in the industry for decades. However, the DC approximation cannot be applied in the DN (since assumption 1 does not hold for lines of the distribution network) and because it disregards reactive power. Thus, the



DC approximation is adopted for the central DAM. An OPF problem that uses the DC approximation is called a DC OPF problem.

As is usual in DAMs, the proposed central DAM uses an objective function that maximizes social welfare. In general, social welfare can be defined as:

$$welfare = utility\ of\ loads - cost\ of\ generators.$$

In the case of the central DAM, the formulation and welfare of each type of order must be defined first, in order to create the objective function.

### Block orders

Let  $B_p = \{1, \dots, B_{p,max}\}$  the set containing the indexes of all block orders that were submitted in the central DAM. We define the variables  $u_b, r_b$  as the order status and acceptance ratio of each block order  $b \in B_p$ . The order status  $u_b$  is a binary integer variable (i.e. its value can be either 0 or 1) and indicates whether the block order has been accepted or not. The acceptance ratio  $r_b$  is a continuous variable that is bound in the domain  $[0,1]$  and indicates the ratio of the block order that has been cleared.

Considering the above, the welfare introduced by all the block orders is:

$$welfare_{block} = \sum_{b \in B_{p,buy}} r_b P_b \sum_{t \in MTUs} Q_{b,t} - \sum_{b \in B_{p,sell}} r_b P_b \sum_{t \in MTUs} Q_{b,t} \quad (2-11)$$

where  $B_{p,buy} \subseteq B_p$  and  $B_{p,sell} \subseteq B_p$  are subsets of  $B_p$  that contain the buy and sell block orders respectively,  $P_b$  is the submitted price of order  $i$ , and  $Q_{b,t}$  is the submitted quantity of order  $b$  at MTU  $t$ .

To enforce the desired behavior of block orders, the following constraints must also be included in the formulation for  $\forall b$ :

$$r_{min,b} u_b \leq r_b \quad (2-12)$$

$$r_b \leq u_b \quad (2-13)$$

where  $r_{min,b}$  is the minimum acceptance ratio of order  $b$ .

Equation (2-12) enforces that the acceptance ratio of order  $b$  will be no less than the minimum acceptance ratio, and (2-13) enforces that the acceptance ratio of the order will be zero if the order status is zero.

The injection of block orders for each node  $n \in N$  and MTU  $t$  is defined as the auxiliary variable  $p_{i,t,block}$ :

$$p_{i,t,block} = \sum_{b \in B_{i,sell}} r_b Q_{b,t} - \sum_{b \in B_{i,buy}} r_b Q_{b,t}, \quad (2-14)$$

where  $B_{i,buy} = \{b \in B_{p,buy} | n_b = n\}$ ,  $B_{i,sell} = \{b \in B_{p,sell} | n_b = n\}$  are the sets containing the indexes of buy, sell block orders that were submitted in node  $n$  and  $n_b$  is the node in which a block order was submitted in.

### Linked block orders

Linked block orders consist of individual block orders that are linked to each other by a parent-child relationship. Therefore, for the individual block orders in a linked block order, equations (2-12) and (2-13) apply, and its injection for each node and MTU is defined by (2-14). Assuming that  $r_{parent,b}$  is the acceptance ratio of parent of the linked block order with index  $b$  and  $r_{child,b}$  is the acceptance ratio of the child of the linked block order. The following constraint must also be applied in linked block orders, to enforce that the acceptance ratio of a parent-type block order is greater or equal to the acceptance ratio of its child-type block orders:

$$r_{parent,b} \geq r_{child,b}, \forall b \in B_{linked} \quad (2-15)$$

where  $B_{linked}$  is the set containing the indexes of linked block orders.

### Exclusive block orders

An exclusive group of block orders consist of a set of profile block orders, for which the sum of accepted ratios cannot be greater than 1. for the individual block orders in a linked block order, equations (2-12) and (2-13) apply, and its injection for each node and MTU is defined by (2-14). Assuming that  $B_{group,e}$  is the set containing the indexes of each group of exclusive block orders  $e$ , the following constraint must be applied in each group of exclusive block orders to enforce that the sum of accepted ratios is not greater than 1:

$$\sum_{b \in B_{group,e}} r_b \leq 1 \quad (2-16)$$

### Reversible block orders

A reversible block orders consists of all the possible combinations of the supply and demand (given the priority dictated by the bid). To enforce the desired behavior of block orders, the following constraints must also be included in the formulation for  $\forall b$ :

$$r_{min,r} u_{r,p} \leq r_r \quad (2-17)$$

$$r_r \leq \sum_{p \in P_r} u_p \quad (2-18)$$

$$\sum_{p \in P_r} u_p \leq 1 \quad (2-19)$$

where  $r_{min,r}$  is the minimum acceptance ratio of order  $r$ ,  $u_{r,p}$  is a binary variable used to select one of the  $p \in P_r$  profiles of order  $r$ , and  $r_r$  is a continuous variable that is bound in the domain  $[0,1]$  and indicates the ratio of the reversible block order that has been cleared.

Constraint (2-17) enforces that the acceptance ratio  $r_r$  is greater or equal to the minimum acceptance ratio of the order, constraint (2-18) enforces that if no profiles are selected, the acceptance ratio is zero, and constraint (2-19) enforces that at maximum one profile is selected.

### Step orders

Let  $H = \{1, \dots, H_{max}\}$  the set containing the indexes of step orders that were submitted in the central DAM, as well as the aggregated virtual DN orders and  $S_h = \{1, \dots, step_{max}\}$  the set containing the indexes of the segments of each step order  $h$ . We define the variable  $r_{h,s}$  a continuous variable that is bound in the domain  $[0,1]$  and indicates the ratio of each segment of the step orders that has been cleared. The welfare of the step orders is defined as:

$$welfare_{step} = \sum_{h \in H_{sell}} Q_{h,s} P_{h,s} r_{h,s} - \sum_{h \in H_{buy}} Q_{h,s} P_{h,s} r_{h,s} \quad (2-20)$$

where  $H_{sell} \subseteq H$  and  $H_{buy} \subseteq H$  are subsets of  $H$  that contain the buy and sell step orders respectively,  $P_{h,s}$  is the submitted price of the segment  $s$  of order  $h$ , and  $Q_{b,t}$  is the submitted quantity of the segment  $s$  of order  $s$ .

The injection of step orders for each node  $n \in N$  and MTU  $t$  is defined as the auxiliary variable  $p_{i,t,step}$ :

$$p_{i,t,step} = \sum_{h \in H_{i,t,se}} \sum_{s \in S_h} Q_{h,s} r_{h,s} - \sum_{h \in H_{i,t,buy}} Q_{h,s} r_{h,s}, \quad (2-21)$$

where  $H_{i,t,buy} = \{h \in H_{buy} | n_h = n \text{ and } t_h = t\}$ ,  $H_{i,t,sell} = \{h \in H_{sell} | n_h = n \text{ and } t_h = t\}$  are the sets containing the indexes of buy, sell step orders that were submitted in node  $n$  and MTU  $t$ ,  $n_h$  is the node in which a step order was submitted in and  $t_h$  is the MTU the hybrid order was submitted for.

Therefore, the objective function of the central DAM is defined as

$$\max(welfare_{block} + welfare_{hybrid}) \quad (2-22)$$

where  $welfare_{block}$  and  $welfare_{hybrid}$  are defined by (2-11) and (2-20), respectively.

## Network constraints

As already mentioned, the central DAM is network-aware, using the DC approximation to capture the constraints of the TN. This formulation allows us to enforce the power balance of the TN and the thermal line limits imposed on the lines of the TN. Using the assumptions mentioned earlier, equation (2-2) becomes

$$p_{i,t} = \sum_{j \in N} B_{ij}(\theta_i - \theta_j) \quad (2-23)$$

and equation (2-3) is omitted since the DC approximation does not account for reactive power generation. In equation (2-23),  $p_{i,t}$  equals to:

$$p_{i,t} = p_{i,t,block} + p_{i,t,hybrid} \quad (2-24)$$

Equation (2-9) is simplified, and the active power line flow becomes:

$$p_{ij,t} = B_{ij}(\theta_i - \theta_j) \quad (2-25)$$

Equation (2-10) is also omitted. Equation (2-8) now becomes:

$$-S_{ij,max} \leq p_{ij,t} \leq S_{ij,max}, \quad \forall (i,j) \quad (2-26)$$

The complete formulation of the central DAM is the maximization of (2-22) subject to (2-23) and (2-26).

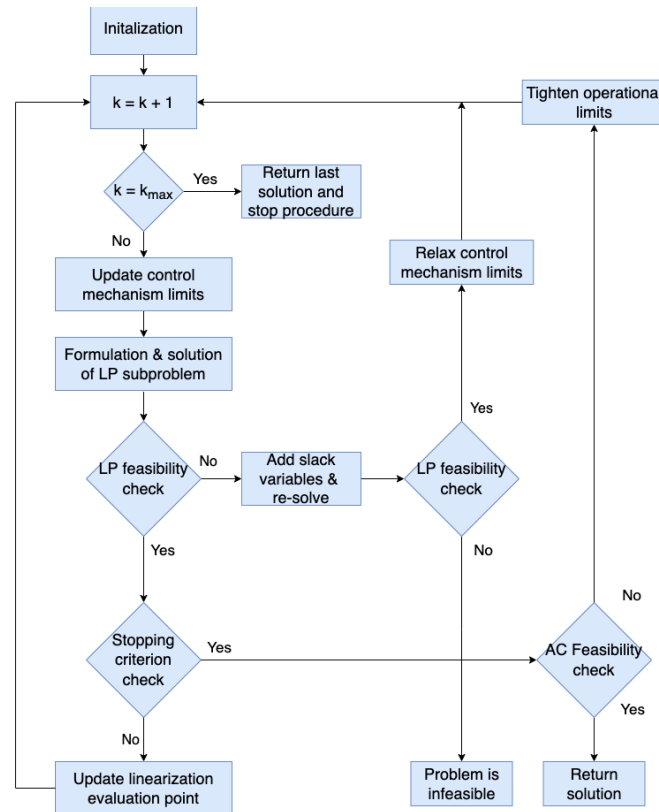
## 2.4.2 Local Day-Ahead Flexibility Markets

The DC approximation cannot be applied with satisfactory accuracy due to the different line characteristics of the DN. Moreover, in the DN it is important to take into account the reactive power generation of the units and the voltage magnitude of each bus. Therefore, a different solution methodology than the one adopted for the central DAM must be followed.

Considering the requirements of a DA LFM, the SLP approach seems to be the most suitable solution methodology. Firstly, SLP uses the same LP solvers market operators have adopted for their day-to-day business, and can leverage their desirable properties (e.g. robustness, unique solutions on each run). Moreover, SLP can easily handle integer variables, which allows for the adoption of more complex order types (e.g. block orders) or the inclusion of discrete system controls in the formulation, and can readily produce Locational Marginal Prices (LMPs) for active and reactive power. Scalability, which SLP features, is also a prerequisite for LFMs, since realistic DNs can contain up to thousands of nodes. Solution speed must also be considered, since a practical LFM should be solved within a specific time window. SLP has been shown to have comparable (and in most cases superior) performance to that of commercial IPM solvers (e.g. [26], [27], [28]). Regarding the accuracy of SLP, it has been shown to be satisfactory when compared against IPM solvers (e.g. [26]–[28]), and superior when compared to the DC approximation (e.g. [26]). Finally, there are two application-specific advantages to the use of SLP in LFMs: i) the existence of a good initial approximation (i.e. the operating point of the system before the LFM runs), which can decrease the number of required iterations before convergence [28], and ii) due to the small capacity of the assets connected to the DN, the solution is expected to be close to the initial point, thus the linear approximation is expected to hold accurately on each LP subproblem.

### 2.4.2.1 Outline of the proposed solution approach

Based on the above, a SLP approach which was introduced in [29] is used, whose outline can be seen in Figure 7.



**Figure 7** The outline of the SLP approach

During the initialization process ( $k = 0$ ), problem variables are initialized and the linearization of the AC OPF is evaluated at the point of operation of the DN prior to any activation of flexibility. The iterative procedure begins by formulating and solving the LP subproblem that is described in the following section. A control mechanism for the step size of voltage magnitude and angle is added in each iteration to the LP subproblem. The feasibility of the LP subproblem is checked in each iteration. In case the LP subproblem is infeasible, slack variables to the step-size limit constraints are added and the problem is re-solved, to infer whether the infeasibility occurs because the original problem is infeasible, or due to the strictness of the limits imposed by the control mechanism.

Each solution is checked against a stopping criterion, which evaluates whether the solution satisfies the AC PF equations (within a specified tolerance). If this criterion is not met, the linearization procedure is performed again, evaluated at the solution that was calculated during the last iteration, and the limits imposed by the control mechanism are updated. The control mechanism is also discussed in a following section.

If the stopping criterion is satisfied, a PF is run and the line flows, bus voltages of PQ buses and reactive power injections of generators are calculated and checked against their respective limits. If any violations arise, the limits on those elements are tightened, and the LP subproblem is solved again. A check of whether the maximum allowed number of iterations,  $k_{max}$  ( $k_{max} = 10$  was used throughout this work), has elapsed is also performed.

#### 2.4.2.2 Formulation of the linear subproblem

The linearization strategy employed for the creation of the linear subproblem was first introduced in [30] to successfully tackle the AC OPF problem in the Transmission Network (TN) via SLP. The authors demonstrate its superiority over a vanilla first-order Taylor series approximation of the AC OPF, requiring minimal extra computational burden. Therefore, this strategy was adopted in this work for the formulation of the linear subproblem. According to [30], (2-2) and (2-3) can be linearized using a combination of first and second order Taylor series expansions and mathematical transformations. At the  $k$ -th iteration they are expressed as:

$$p_i^k = \sum_{j=1}^N \left[ G_{ij}^{p,k} \frac{v_i^2 + v_j^2}{2} + B_{ij}^{p,k} (\theta_{ij} - \theta_{ij,k}) - G_{ij}^{p,k} \frac{v_{ij}^{L,k}}{2} \right], \forall i, k, \quad (2-27)$$

$$q_i^k = \sum_{j=1}^N \left[ B_{ij}^{q,k} \frac{v_i^2 + v_j^2}{2} + G_{ij}^{q,k} (\theta_{ij} - \theta_{ij,k}) - B_{ij}^{q,k} \frac{v_{ij}^{L,k}}{2} \right], \forall i, k, \quad (2-28)$$

where,

$$G_{ij}^{p,k} = (G_{ij} d_{ij,k}^0 + B_{ij} s_{ij,k}^0) + (G_{ij} d_{ij,k}^1 + B_{ij} s_{ij,k}^1) \theta_{ij,k}, \forall i, k, \quad (2-29)$$

$$B_{ij}^{p,k} = (G_{ij} d_{ij,k}^1 + B_{ij} s_{ij,k}^1) v_{i,k} v_{j,k}, \quad \forall i, k, \quad (2-30)$$

$$B_{ij}^{q,k} = (G_{ij} s_{ij,k}^0 - B_{ij} d_{ij,k}^0) - (G_{ij} s_{ij,k}^1 - B_{ij} d_{ij,k}^1) \theta_{ij,k}, \forall i, k, \quad (2-31)$$

$$G_{ij}^{q,k} = (G_{ij} s_{ij,k}^1 - B_{ij} d_{ij,k}^1) v_{i,k} v_{j,k}, \quad \forall i, k, \quad (2-32)$$

$$s_{ij,k}^1 = \cos \theta_{ij,k}, \quad s_{ij,k}^0 = \sin \theta_{ij,k} - \theta_{ij,k} \cos \theta_{ij,k}, \forall i, k, \quad (2-33)$$

$$d_{ij,k}^1 = -\sin \theta_{ij,k}, \quad d_{ij,k}^0 = \cos \theta_{ij,k} + \theta_{ij,k} \sin \theta_{ij,k}, \forall i, k, \quad (2-34)$$

and

$$v_{ij}^{L,k} = 2 \frac{v_{i,k} - v_{j,k}}{v_{i,k} + v_{j,k}} (v_i^2 - v_j^2) - v_{ij,k}^2, \forall i, j, k. \quad (2-35)$$

where  $v_{ij,k}^2 = (v_i^k - v_j^k)^2$ .

According to the same work and following similar approximations, (2-9) and (2-10) for each  $i, j, k$  become:

$$p_{ij}^k = g_{ij} v_i^2 - g_{ij}^{p,k} \frac{v_i^2 + v_j^2}{2} - b_{ij}^{p,k} (\theta_{ij} - \theta_{ij,k}) + g_{ij}^{p,k} \frac{v_{ij}^{L,k}}{2}, \quad (2-36)$$

$$q_{ij}^k = -b_{ij} v_i^2 + b_{ij}^{q,k} \frac{v_i^2 + v_j^2}{2} - g_{ij}^{q,k} (\theta_{ij} - \theta_{ij,k}) - b_{ij}^{q,k} \frac{v_{ij}^{L,k}}{2}, \quad (2-37)$$

where,

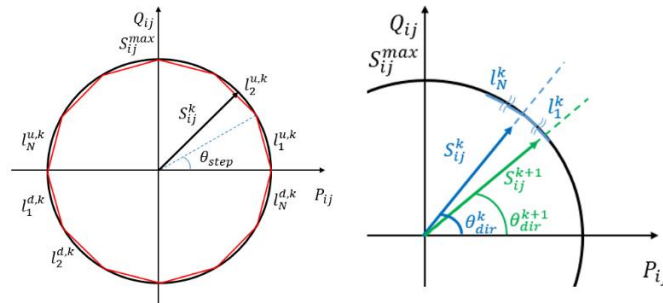
$$g_{ij}^{p,k} = (g_{ij} d_{ij,k}^0 + b_{ij} s_{ij,k}^0) + (g_{ij} d_{ij,k}^1 + b_{ij} s_{ij,k}^1) \theta_{ij,k}, \quad (2-38)$$

$$b_{ij}^{p,k} = (g_{ij} d_{ij,k}^1 + b_{ij} s_{ij,k}^1) v_{i,k} v_{j,k}, \quad (2-39)$$

$$b_{ij}^{q,k} = (-g_{ij} s_{ij,k}^0 + b_{ij} d_{ij,k}^0) - (g_{ij} s_{ij,k}^1 - b_{ij} d_{ij,k}^1) \theta_{ij,k}, \quad (2-40)$$

$$g_{ij}^{q,k} = (g_{ij} s_{ij,k}^1 - b_{ij} d_{ij,k}^1) v_{i,k} v_{j,k}. \quad (2-41)$$

With this formulation, and considering  $v_i^2$  as an independent variable, the NL equations (2-2), (2-3), (2-9), and (2-10) are replaced by their linear counterparts (2-27), (2-28), (2-36), and (2-37) respectively.



**Figure 8** Left: piecewise linearization proposed in [30]; right: the proposed piecewise linearization.

The final source of non-linearity that must be addressed is constraint (2-8). As shown in Figure 8, the constraint imposed by (2-8) is the area within the circle. In [30] a piecewise linearization technique for (2-8) is used, that suggests approximating the quadratic constraint with  $2N$  linear segments  $l_n^u, l_n^d$ , where:

$$N = \frac{180^\circ}{\theta_{step}}, \quad n = \{1, \dots, N\} \quad (2-42)$$

where  $\theta_{step}=12^\circ$  is suggested. Therefore, (2-8) is approximated with:

$$\begin{cases} l_n^{u,k}: q_{ij}^k - a_n^{u,k} p_{ij}^k - b_n^{u,k} \leq 0, \\ l_n^{d,k}: q_{ij}^k - a_n^{d,k} p_{ij}^k - b_n^{d,k} \geq 0, \end{cases} \quad \forall (i,j), k, n \quad (2-43)$$

where the calculation of  $a_n^{u,k}$ ,  $a_n^{d,k}$ ,  $b_n^{u,k}$ , and  $b_n^{d,k}$  is trivial.

While this methodology successfully linearizes the quadratic constraint (2-8), it generates a large amount of linear constraints to replace it with, which can have a negative effect on the performance of the linearized model. The authors in [30] discuss some constraint reduction techniques, but these are based on specific characteristics of the TN, and therefore cannot be applied in this setting.

A novel strategy for constraint reduction is devised, leveraging the iterative nature of the methodology. Specifically, in the first iteration, the thermal line limits of the lines are disregarded (i.e. line limits are not imposed). After the first iteration is solved, the loaded lines are identified as those whose apparent line flow is more than 90% of the line's maximum:

$$I_{loaded}^k = \{(i,j) \in L \mid S_{ij}^k \geq 0.9S_{ij,max}\}. \quad (2-44)$$

Subsequently, the direction of the apparent line flow of each of the loaded lines,  $\theta_{dir,ij}^k$ , is calculated

$$\theta_{dir,ij}^k = \tan^{-1}\left(\frac{q_{ij}^k}{p_{ij}^k}\right), (i,j) \in I_{loaded}^k. \quad (2-45)$$

Piecewise linearization similar to that of the aforementioned method is then performed around the direction of the apparent line flow. The number  $N_k$  of linear segments  $n$  used in each iteration is:

$$N_k = \max\{6, 16 - 2k\}, \quad n = \{1, \dots, N_k\} \quad (2-46)$$

and the angle step  $\theta_{step} = 4^\circ$ . Equation (2-46) allows the reduction of the number of constraints introduced in the latter iterations, where accuracy expected to be satisfactory. The polar angle  $\theta_{l,i}^k$  where each line segment begins can be calculated as follows:

$$\theta_{l,i}^k = \{\theta_{l,i_n}^k \mid \theta_{l,i_n}^k = \theta_{dir,ij}^k - \frac{N_k \theta_{step}}{2} + \frac{n \theta_{step}}{N_k}\}. \quad (2-47)$$

Therefore, in the proposed method constraint (2-43) is used to enforce the thermal line limits (which are enforced only in the loaded lines). The parameters  $a_n^{u,k}$ ,  $a_n^{d,k}$ ,  $b_n^{u,k}$ , and  $b_n^{d,k}$  of (2-43) are calculated using the values of (2-45)–(2-47). Finally, it should be noted that when updating the set of loaded lines (2-44) in subsequent iterations, lines already included in the set should not be removed, to avoid oscillations [11].

The complete formulation of the linear subproblem consists of the objective function (2-1), subject to (2-11), (2-12), (2-4), (2-5), and (2-43) and as  $v_i^2$  is an independent variable, voltage magnitude must be constrained by:

$$V_{i,min}^2 \leq v_i^2 \leq V_{i,max}^2, \quad \forall i. \quad (2-48)$$

The expansion of this formulation to multiple MTUs is trivial. Equations (2-11), (2-12) and (2-43) are re-evaluated in each iteration.

#### 2.4.2.3 Voltage magnitude and angle control mechanisms

The SLP methodology described in [30] which uses the linearization methodology described in the previous section, yielded promising results when applied to various TN topologies, featuring both high accuracy and speed, without needing any control mechanisms. However, when the methodology was applied to the DN, this was not the case. The model oscillated between solutions and failed to achieve satisfactory accuracy and converge. Since this behavior persisted when the model was applied to various DNs, especially if they were heavily loaded, modifications are needed for its application to DNs.

Literature suggests that a mechanism that controls the step of the voltage magnitude and voltage angle between the iterations can solve the oscillation problem. For example, in [26] the authors successfully apply TR-based control mechanisms to control the solution of a SLP OPF and in [27] the authors apply

penalties to control the step size of a similar algorithm. However, while in [26] the method is mathematically sound, a lot of overhead is caused by calculations relative to the determination of the proper radius of the TR.

In an effort to ease the computational overhead, and owing to the particularities of the application of an SLP approach to the DN, a dynamic control mechanism of the step of the voltage angle and voltage magnitude is implemented that manages to solve the oscillation problems of the model, requires minimal computational burden, and adds no extra constraints to the problem.

To that end, voltage magnitude tolerance  $v_k^{tol}$  is defined as:

$$v_k^{tol} = \frac{tol_v}{e^{(k-offset_v)}}, \quad \forall k, \quad (2-49)$$

where  $tol_v = 0.03 \text{ p.u.}$  and  $offset_v = 2$ . Then, we proceed to calculate the lower and upper bounds ( $v_{k,i}^{lb}$  and  $v_{k,i}^{ub}$  respectively) for each iteration and each bus as follows

$$v_{k,i}^{lb} = v_{k-1,i}^2 - v_k^{tol}, \quad \forall i, k, \quad (2-50)$$

$$v_{k,i}^{ub} = v_{k-1,i}^2 + v_k^{tol}, \quad \forall i, k. \quad (2-51)$$

Equation (2-49) provides an effective way to control the voltage magnitude in each iteration. In the first iterations, when the model may not yet be accurate, the denominator of the right hand side of (2-49) is less than one, allowing  $v_k^{tol}$  to take large values. When the accuracy of the model improves, (2-49) successfully constraints the voltage magnitude in the desired range. To add this control mechanism to the formulation, (2-48) is replaced with

$$\max\{V_{i,min}^2, v_{k,i}^{lb}\} \leq (v_i^k)^2 \leq \min\{V_{i,max}^2, v_{k,i}^{ub}\}, \quad \forall i, k, \quad (2-52)$$

therefore not increasing the size of the problem.

Similarly, to control the voltage angle, the term  $\theta_{tol}^k$  is defined as

$$\theta_{tol}^k = \frac{tol_\theta}{k - offset_\theta}, \quad \forall k > offset_\theta \quad (2-53)$$

where  $tol_\theta = 0.01 \text{ rad}$  and  $offset_\theta = 2$ . The lower and upper bounds for each bus ( $\theta_{k,i}^{lb}$  and  $\theta_{k,i}^{ub}$  respectively) can be then calculated as

$$\theta_{k,i}^{lb} = \frac{\theta_{k-1,i} + \theta_{k-2,i}}{2} - \theta_{tol,k}, \quad \forall i, k, \quad (2-54)$$

$$\theta_{k,i}^{ub} = \frac{\theta_{k-1,i} + \theta_{k-2,i}}{2} + \theta_{tol,k}, \quad \forall i, k. \quad (2-55)$$

Equations (2-54) and (2-55) use the mean value of the last two iterations to calculate the voltage angle bounds. The voltage angle control mechanism is included in formulation, by substituting (2-7) only where  $k > offset_\theta$  with

$$\max\{-\pi, \theta_{k,i}^{lb}\} \leq \theta_i^k \leq \min\{\pi, \theta_{k,i}^{ub}\}, \quad \forall i, k > offset_\theta. \quad (2-56)$$

The rapid tightening of voltage magnitude and angle constraints caused by the control mechanism after the second iteration can be justified by: i) the fact that results in [30] demonstrate that the accuracy of this methodology drastically improves after the second iteration, and ii) due to the small capacity of the assets of the DN, dramatic deviations in the values of voltage magnitude and angle were not expected in the first place. In any case, any infeasibilities that may occur due to the control mechanism are alleviated using the subproblem feasibility restoration process, described in the next section. Using these control mechanisms, the model converges with satisfactory accuracy.

#### 2.4.2.4 Stopping criterion and AC feasibility restoration

On each iteration, the solution of the linear subproblem (i.e. the nodal voltage magnitude, angle, active and reactive power injection on each bus  $i$ ,  $v_i^k, \theta_i^k, p_i^k$  and  $q_i^k$  respectively) is checked against the convergence criterion. To that end, the power mismatch for each bus is calculated by directly evaluating the following equations at the solution of the iteration

$$m_{p,i}^k = p_i^k - \sum_{j=1}^N (v_i^k v_j^k G_{ij} \cos \theta_{ij}^k + v_i^k v_j^k B_{ij} \sin \theta_{ij}^k), \quad \forall i, \quad (2-57)$$



$$m_{q,i}^k = q_i^k + \sum_{j=1}^N (v_i^k v_j^k B_{ij} \cos \theta_{ij}^k + v_i^k v_j^k G_{ij} \sin \theta_{ij}^k), \quad \forall i, \quad (2-58)$$

where  $m_{p,i}^k$  and  $m_{q,i}^k$  is the power mismatch at bus  $i$  for active and reactive power respectively. The stopping criterion is satisfied if all the power mismatches fall within the predefined mismatch tolerance  $\varepsilon_m$

$$|m_{p,i}^k| \leq \varepsilon_m \text{ and } |m_{q,i}^k| \leq \varepsilon_m, \quad \forall i, \quad (2-59)$$

where  $\varepsilon_m = 5 \cdot 10^{-5}$  was used throughout this work.

Once the stopping criterion is satisfied, the solution is inserted in an AC PF calculator, to ensure its AC feasibility. During this step, the values of apparent line flows, reactive power generation, and voltage magnitudes of PQ buses are checked against their respective limits. Taking line flows as an example, the following violation ratio is calculated for all lines

$$r_{S,ij} = \frac{S_{ac,ij}}{S_{max,ij}} \quad \forall (i,j), \quad (2-60)$$

where  $S_{ac,ij}$  is the line flow of line  $(i,j)$  as calculated by the AC PF calculator. If  $r_{S,ij} > 1$ , the constraint is violated and the limit is tightened, as follows

$$S_{max,ij}^{new} = \frac{S_{max,ij}}{r_{S,ij}} \quad \forall \{(i,j) \in L \mid r_{S,ij} > 1\}. \quad (2-61)$$

Similar procedures must be followed for reactive power generation and voltage magnitudes of PQ buses. The linear subproblem is then re-solved, using the tightened constraints. If no such violations exist, the solution is AC feasible, and the algorithm returns it.

#### 2.4.2.5 Linear subproblem feasibility check and control mechanism limits relaxation

During each iteration, the convergence of the Linear Programming (LP) solver is examined. Failure of convergence can be caused by three reasons: i) the NL AC OPF problem is infeasible, ii) the limits imposed by the control mechanism are too tight, or iii) the linearization is not accurate enough. If the LP solver fails to converge, actions must be undertaken to pinpoint the cause of the infeasibility, and if possible, restore feasibility.

Inspired by [26] following problem is defined:

$$\min \left\{ \sum_{g \in G} (C_g^p p_g + C_g^q q_g) + \text{penalty} \cdot \sum_{i \in I} (s_{v,i}^+ + s_{v,i}^- + s_{\theta,i}^+ + s_{\theta,i}^-) \right\} \quad (2-62)$$

subject to the linearized PF constraints (2-11), (2-12) the active and reactive power generation limits (2-4), (2-5) the linearized line flow limits (2-43) and the constraints

$$v_{k,i}^{lb} - s_{v,i}^- \leq (v_i^k)^2 \leq v_{k,i}^{ub} + s_{v,i}^+, \quad \forall i, \quad (2-63)$$

$$V_{i,min}^2 \leq (v_i^k)^2 \leq V_{i,max}^2, \quad \forall i, \quad (2-64)$$

$$\theta_{k,i}^{lb} - s_{\theta,i}^- \leq \theta_i^k \leq \theta_{k,i}^{ub} + s_{\theta,i}^+, \quad \forall i \quad (2-65)$$

$$-\pi \leq \theta_i^k \leq \pi, \quad \forall i \quad (2-66)$$

$$s_{v,i}^+, s_{v,i}^-, s_{\theta,i}^+, s_{\theta,i}^- \geq 0, \quad \forall i \quad (2-67)$$

where  $s_{v,i}^+, s_{v,i}^-, s_{\theta,i}^+, s_{\theta,i}^-$  are slack variables used to relax the constraints imposed by the control mechanism (but crucially not the operational constraints of the DN) and  $\text{penalty} = 10^4$ .

If this problem is solved with non-zero slack variable values, it can be concluded that the limits imposed by the control mechanism are too tight and must be relaxed. The control limits are updated as follows, and the problem is re-solved:

$$v_{k+1,i}^{lb} = v_{k,i}^{lb} - m_v s_{v,i}^-, \quad \forall \{i \in I \mid s_{v,i}^- \geq 0\} \quad (2-68)$$

$$v_{k+1,i}^{ub} = v_{k,i}^{ub} + m_v s_{v,i}^+, \quad \forall \{i \in I \mid s_{v,i}^+ \geq 0\} \quad (2-69)$$

$$\theta_{k+1,i}^{lb} = \theta_{k,i}^{lb} - m_\theta s_{\theta,i}^-, \quad \forall \{i \in I \mid s_{\theta,i}^- \geq 0\} \quad (2-70)$$



$$\theta_{k+1,i}^{ub} = \theta_{k,i}^{ub} + m_{\theta} s_{\theta,i}^+, \quad \forall \{i \in I \mid s_{\theta,i}^+ \geq 0\} \quad (2-71)$$

where  $m_v = m_{\theta} = 2$  is the relaxation multiplier for voltage magnitude and angle, respectively. If the solver fails to find a solution to this problem, then either the linearization is not accurate enough and the linearization evaluation point should be changed, or the NL AC OPF problem is infeasible. As a measure of the quality of the linearization, slack variables could also be added in (2-11), (2-12). The use of these slack variables should then be heavily penalized in the objective function. A non-zero value of these variables could be indicative of poor linearization. We omit the use of these variables as we found that the linearizations were accurate throughout our tests.

#### 2.4.2.1 DN losses calculation

To account for the DN losses, in each DN we introduce a virtual generator in the TSO-DSO interface, which produces active energy equal to the losses of the DN. To guarantee this:

- The injection of these virtual generators is included in the nodal power balance constraints 2-27.
- We include an additional total power balance constraint for the DN, where all assets are included except for the virtual generators (not presented in the formulation above).
- There is no cost associated with the generation of these units, i.e. their injection is not included in the objective function (2-62)

The injection schedule of these generators is then passed to the final central DAM as a buy price-taking order, so essentially the DSO buys the DN losses from the DAM. The DSO can socialize this cost associated with the losses.

## 2.5 Day-Ahead Market User Interface

### 2.5.1 General information

The developed interface is based on the Microsoft Excel software, which is a widely utilized environment for the representation of the input and output data. Moreover, it enables the utilization of various macro commands to make data entry more user-friendly, and integrates seamlessly with the Python files that execute the pre-processing, initialization, optimization, and output based on the user-defined input data.

The user may save the developed interface anywhere in their personal computer since the initialization and execution of the optimization code does not depend on the location of the excel file.

### 2.5.2 Setup

The optimization model of the day-ahead market clearing algorithm is written in Python, and its interface has been implemented in Microsoft Excel 365. The day-ahead market clearing tools have been developed for use in Microsoft Windows Operating System. Therefore, to successfully run the model, the following are recommended:

- Microsoft Windows 10,
- Microsoft Excel 365,
- Python v.3.8 or later,
- A valid CPLEX licence key, and
- The required Python dependencies.

For ease of use, a *setup.bat* file is included in the distribution of the mechanism. The *setup.bat* file installs all the required dependences (included in the *requirements.txt* file) in a Python virtual environment named *FEVER-DAM*. It is recommended that the user runs *setup.bat* prior to executing any of the code.

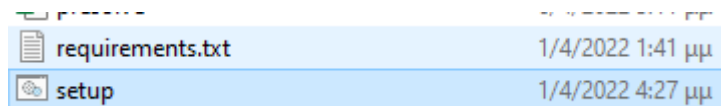


Figure 9 The setup.bat and requirements.txt files

Once the following message is printed on the command prompt, all the dependencies are installed therefore, the rest of the model is ready to be used.

```

-----
*** Dependencies installed! ***
*** You can proceed with using the program. ***
*** Closing the shell... ***
-----

```

**Figure 10** The message after the successful installation of the dependencies through setup.bat

The controls included in the Excel files are shown in the following Sections. Please note that the user should not close the console windows that run the Python scripts, as it will terminate the code execution. The console will automatically close as soon as the optimization procedure terminates successfully.

## 2.5.3 General Worksheets

### 2.5.3.1 Options

**Figure 11** The options sheet

In this worksheet the user defines the topologies of the transmission and distribution networks of the problem, as well as the nodes of the transmission network the distribution networks are connected in. For both transmission and distribution networks, the interface offers a library of existing networks that the user can choose from via a dropdown menu, or the user can create custom networks. The networks in the library come from the pandapower Python package [31].

**Figure 12** The network library dropdown menu for the transmission network.

For both types of networks, the interface offers *Generate Topology* and *Clear Topology* buttons. Generate topology buttons call Python scripts that write the selected topology data in the *Input – Nodes* and *Input – Lines* sheets, while the *Clear Topology* buttons clear the contents of these sheets, in case the users want to use a different topology.

Distribution Network			Generate Distribution Topologies
id	Topology	Connection Node with Transmission	
0	distribution_5_bus	2	Clear Distribution Topology
1	distribution_7_bus	4	
2	custom_network	10	

**Figure 13** The distribution network data

For distribution networks, the additional information on the *Connection Node with Transmission* must be included, which indicates the node of the transmission network the distribution network is connected in.

### 2.5.3.2 Execution

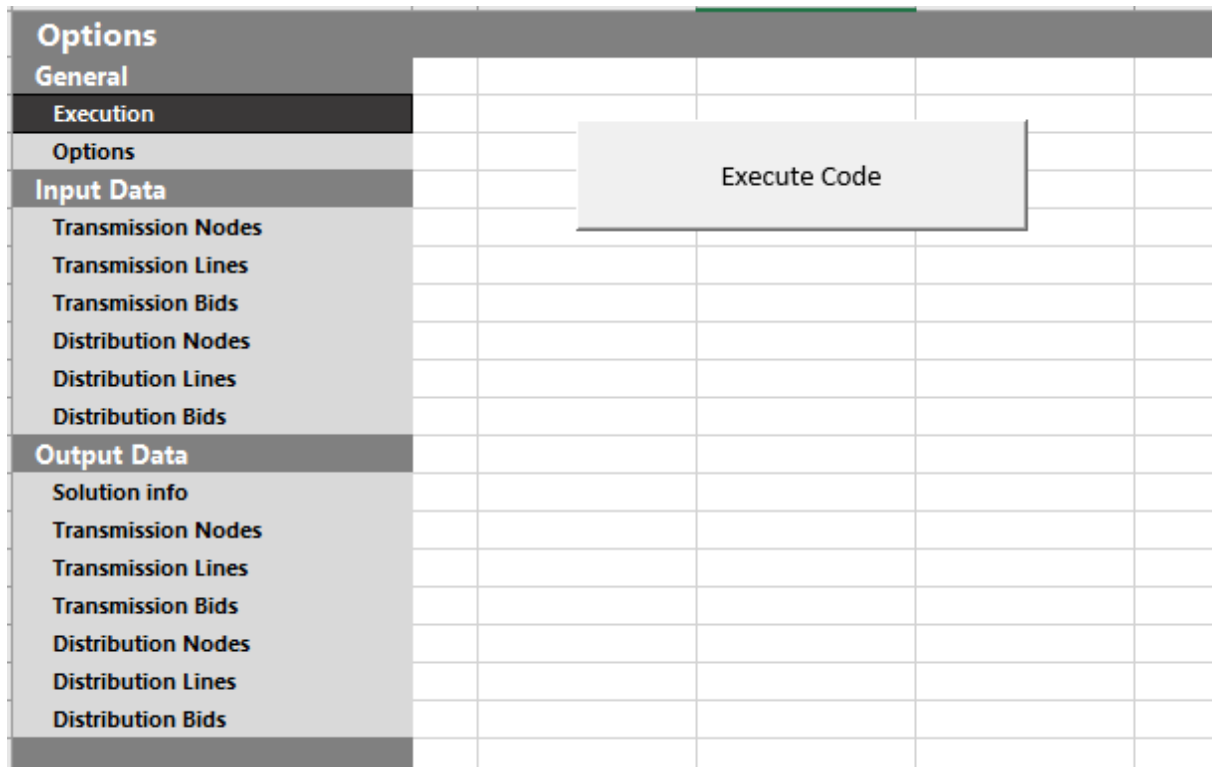


Figure 14 The execute code sheet

This worksheet contains a single button that executes the optimization problem, using the user defined data. Pressing this button calls a VBA script that activates the virtual environment that contains the required dependencies, and calls through it the Python scripts.

```
Reading input data...
Input data read.
Validating input data...
Distribution with ids
Block orders are not supported at a distribution network level. Dropping all block orders submitted in the distribution network.
Some bids on the distribution network with id 1.0 are connected to an invalid node. Dropping them.
Input data validated.
Formulating central DAM problem...
Solving central DAM problem...
Central DAM problem solved!
Disaggregating central DAM results...
Central DAM results disaggregated!
Searching for violations in distribution network with id 1...
Violations detected! Triggering local flexibility market...
Local flexibility market for distribution network with id 1 solved!
```

Figure 15 Snapshot of the console output during this step.

After the successful execution of the optimization code, the console application is automatically closed, and the user is notified that the output data has been refreshed.

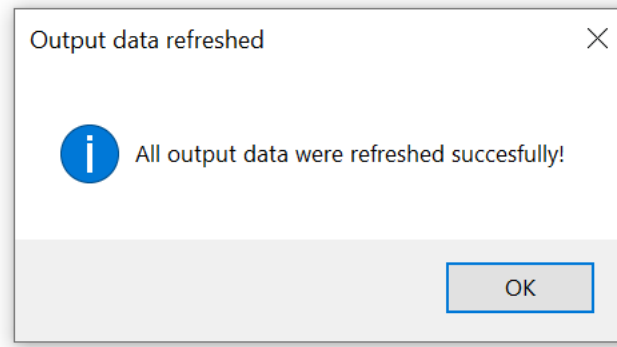


Figure 16: Successful update of all output data

## 2.5.4 Input Worksheets

The following subsection provides an analytical presentation of all worksheets that contain input data, along with a short explanation of all the required input data. All data follow the well-established framework of MATPOWER format.

### 2.5.4.1 Transmission Nodes

This worksheet contains the data related with the high-voltage transmission nodes of the examined power system.

Options														
General														
Execution														
Options														
Input Data														
	bus id (required)	1 for PQ, 2 for PV	Active power der	Reactive power d	Shunt real admitt	Shunt imaginary	Area the node is	Voltage magnitud	Voltage angle set	Base voltage [pu]	Zone the node is	Max. voltage [pu]	Min. voltage [pu]	
	bus_index	type	Pd	Qd	Gs	Bs	area	Vm	Va	baseKV	zone	Vmax	Vmin	
Transmission Nodes	0	3	0	0	0	0	1	1,06	0	132	1	1,06	0,94	
Transmission Lines	1	2	21,7	12,7	0	0	1	1,045	0	132	1	1,06	0,94	
Transmission Bids	2	2	2,4	1,2	0	0	1	1	0	132	1	1,06	0,94	
Distribution Nodes	3	1	7,6	1,6	0	0	1	1	0	132	1	1,06	0,94	
Distribution Lines	4	2	94,2	19	0	0	1	1,01	0	132	1	1,06	0,94	
Distribution Bids	5	5	1	0	0	0	0	1	1	0	132	1	1,06	0,94

Figure 17: Worksheet Transmission Nodes

A brief breakdown of each column follows:

- **Bus\_index** (*required*) contains the id of each bus,
- **Type** (*optional*) contains the type of each bus (1 for PQ buses, 2 for PV buses, 3 for slack buses),
- **Pd** (*required*) contains the non-dispatchable active power load (positive) or generation (negative) of each bus [*pu*],
- **Qd** (*required*) contains the non-dispatchable reactive power load (positive) or generation (negative) of each bus [*pu*],
- **Gs** (*optional, default 0*) contains the real shunt admittance connected on each bus [*pu*],
- **Bs** (*optional, default 0*) contains the imaginary shunt admittance connected on each bus [*pu*],
- **Area** (*optional, default 1*) contains the area the node is in,
- **Vm** (*optional*) contains the voltage magnitude setpoint of each bus [*pu*],
- **Va** (*optional*) contains the voltage angle setpoint of each bus [*pu*],
- **baseKV** (*required*) contains the voltage base of each bus [*kV*],
- **zone** (*optional, default 1*) contains the zone the node is in,
- **Vmax** (*required*) the upper bounds of voltage magnitude [*pu*], and
- **Vmin** (*required*) the lower bounds of voltage magnitude [*pu*].

### 2.5.4.2 Transmission Lines

This worksheet contains the data related with the high-voltage transmission lines of the examined power system.

Options														
General														
Execution														
Options														
Input Data														
	start bus id (req.)	end bus id (req.)	line resistance (r)	line reactance (x)	line shunt reactance (b)	thermal line limit (rateA)	short term thermal limit (rateB)	emergency thermal limit (rateC)	transformer nominal ratio	transformer phase angle	branch status (req.)	min. angle difference	max. angle difference	
	fbus	tbus	r	x	b	rateA	rateB	rateC	ratio	angle	status	angmin	angmax	
Transmission Nodes	0	0	1	0,0192	0,0575	0,0528	22862842,03	250	250	1	0	1	-360	360
Transmission Lines	1	0	2	0,0452	0,1652	0,0408	22862842,03	250	250	1	0	1	-360	360
Transmission Bids	2	1	3	0,057	0,1737	0,0368	22862842,03	250	250	1	0	1	-360	360
Distribution Nodes	3	2	3	0,0132	0,0379	0,0084	22862842,03	250	250	1	0	1	-360	360
Distribution Lines	4	1	4	0,0477	0,1982	0,0418	22862842,03	250	250	1	0	1	-360	360

Figure 18: Worksheet Line Nodes

A brief breakdown of each column follows:

- **Fbus** (*required*) contains the id the line starts from,
- **Tbus** (*required*) contains the id the line ends in,
- **R** (*required*) line resistance [*pu*],
- **X** (*required*) line reactance [*pu*],
- **B** (*required*) line shunt susceptance [*pu*],
- **rateA** (*required*) long term line thermal rating [*pu*],
- **rateB** (*optional*) short term line thermal rating [*pu*],
- **rateC** (*optional*) emergency line thermal rating [*pu*],
- **ratio** (*optional, default 1*) transformer off nominal turns ratio,
- **shift** (*optional, default 0*) phase shifter angle [*deg*],
- **status** (*optional, default 1*) status of the line (online = 1, offline = 0),
- **angmin** (*optional, default -360*) minimum angle difference on the line [*deg.*], and
- **angmax** (*optional, default 360*) maximum angle difference on the line [*deg.*]

### 2.5.4.3 Transmission Bids

This worksheet contains the data related to the bids of the assets of the transmission network.

Options														
General														
Execution														
Options														
Input Data														
	order_id	asset_id	node	side	hbd_mtu	hbd_points	blk_price	blk_acceptance_ratio	blk_mtus	blk_relationship	blk_linked	blk_parent		
Transmission Nodes	1	1	1	S			500 0.6		0@100 1@110 2@110 3@95 4@100	N				
Transmission Lines	2	2	2	S			520 0.2		0@120 1@130 2@125 3@120 4@120	N				
Transmission Bids	3	3	2	S			190 0.1		3@20 4@20	L				2
Distribution Nodes	4	4	3	B		0 900@120 810@150 40@521								
Distribution Lines	5	4	3	B		1 902@140 360@279 50@501 18@531								
Distribution Bids	6	4	3	B		2 502@140 100@600								
Output Data	7	4	3	B		3 521@140 150@601								
Solution Info	8	4	3	B		4 210@140 150@660								
Transmission Nodes	9	2	2				100		1 0@10 1@11 2@-10	R				
Transmission Lines	10	2	2				150		1 0@20 1@21 2@-20	R				

Figure 19 Transmission Bids worksheet.

A brief breakdown of each column follows:

- **Order\_id** (*optional*), contains the id of the bid,
- **Asset\_id** (*optional*), contains the id of the asset the bid corresponds to,
- **Node** (*required*), contains the node the bid is submitted in,
- **Side** (*required*), contains the side of the bid ('B' = buy, 'S' = sell),
- **hbd\_mtu** (*required for step orders*), contains the market time unit of the order,
- **hbd\_points** (*required for step orders*) contains the price-quantity segments of the step orders,
- **blk\_price** (*required for block orders*) contains the price of block orders,
- **blk\_acceptance\_ratio** (*required for block orders*) contains the minimum acceptance ratio for block orders,
- **blk\_mtus** (*required for block orders*) contains the market time unit – quantity pairs of the block orders
- **blk\_relationship** (*required for block orders*) indicates the type of block order ('N' = normal, 'L' = linked, 'E' = exclusive, 'R' = reversible)
- **blk\_linked** (*required for linked block orders*) indicates the order id that the order is linked with, and
- **blk\_parent** (*required for exclusive block orders*) indicates the parent id of the order.

### 2.5.4.4 Distribution Nodes

This worksheet contains the data related to the distribution system nodes of the examined power system.

Options													
General													
Execution													
Options													
Input Data													
	net id (req.)	bus id (required)	1 for PQ, 2 for PV	Active power (kW)	Reactive power (kVAr)	Shunt real admitt.	Shunt imaginary	Area the node is	Voltage magnitude	Voltage angle (deg)	Base voltage (kV)	Zone the node is	Max. voltage (kV)
Transmission Nodes	0	0	0	3	0	0	0	0	1	1	0	12.66	1
Transmission Lines	1	0	1	1	0	0	0	0	1	1	0	12.66	1
Transmission Bids	2	0	2	2	0	0	0	0	1	1	0	12.66	1
Distribution Nodes	3	0	3	1	0.1	1	0	0	1	1	0	12.66	1
Distribution Lines	4	0	4	1	0.2	1.5	0	0	1	1	0	12.66	1

Figure 20 The distribution nodes sheet

This sheet contains the same columns as the Transmission nodes sheet, but requires the extra information on the column **d\_net\_id**, which indicates the distribution network each element belongs in. This information is *required*.

### 2.5.4.5 Distribution Lines

This worksheet contains the data related to the distribution system lines of the examined power system.

Options													
General													
Execution													
Options													
Input Data													
	d_net_id (req.)	start bus id (req.)	end bus id (req.)	line resistance (Ω)	line reactance (Ω)	line shunt react.	thermal line limit	short term therm	emergency therm	transformer nom	transformer phas	branch status (log)	min. angle diff
Transmission Nodes	0	0	0	1	0.00075259	0.000293245	0	250	250	250	1	0	1
Transmission Lines	1	0	1	2	0.003379379	0.004447963	0	250	250	250	1	0	1
Transmission Bids	2	0	1	3	0.008942397	0.010777754	0	250	250	250	1	0	1
Distribution Nodes	3	0	2	3	0.001266568	0.000645139	0	250	250	250	1	0	1
Distribution Lines	4	0	4	2	0.001167988	0.00386085	0	250	250	250	1	0	1

Figure 21 The distribution lines sheet

This sheet contains the same columns as the Transmission lines sheet, but requires the extra information on the column **d\_net\_id**, which indicates the distribution network each element belongs in. This information is *required*.

### 2.5.4.6 Distribution Bids

This worksheet contains the data related to the bids of the assets of the distribution networks.

Options							
General							
Execution							
Options							
Input Data							
	d_net_id	order_id	asset_id	node	side	hbd_mtu	hbd_points
Transmission Nodes	0	1	1	2	S		0 60@2.5   140@0.2
Transmission Lines	0	2	1	2	S		1 62@2.6   145@0.3
Transmission Bids	0	5	3	3	B		0 200@0.1   110@0.05
Distribution Nodes	0	6	3	3	B		1 190@0.11   150@0.04
Distribution Lines	0	7	4	4	B		0 205@0.2   130@0.02
Distribution Bids	0	8	4	4	B		1 210@0.2   130@0.02
Output Data	1	1	1	2	S		0 69@3.5   140@0.2

Figure 22 The distribution bids sheet.

This sheet contains the same columns as the Transmission lines sheet, but requires the extra information on the column **d\_net\_id**, which indicates the distribution network each element belongs in. This information is *required*. The information on block orders is not required, as block orders are not supported in the distribution network.

## 2.5.5 Output Worksheets

The following subsection provides a detailed presentation of all worksheets that contain the output data, namely the results of all optimization processes.

### 2.5.5.1 Solution info

This worksheet contains general information of the solution status, solution time, and objective function values of each problem.

Options					
General					
Execution					
Options					
				[s]	[EUR]
Input Data		Solver Status		Solution time	Objective Function Value
Transmission Nodes	Initial Central DAM	optimal		0.572	12,340.46
Transmission Lines	LFM 1	optimal		0.315	-204.19
Transmission Bids	LFM 2	optimal		0.293	-112.45
Distribution Nodes	Final Central DAM	optimal		0.556	11,059.98
Distribution Lines					
Distribution Bids					
Output Data					
Solution info					

Figure 23 The solution info sheet

### 2.5.5.2 Transmission Nodes

This worksheet contains the results of the transmission nodes, after the final central day-ahead market has been cleared.

Options							
General							
Execution							
Options				[pu]	[rad]	[pu]	[pu]
Input Data		bus_index	Vm	Va	Active Power injection		Reactive Power injection
Transmission Nodes		0	0	1,06	0	0	0
Transmission Lines		1	1	1,045	0.0014	21,7	12,7
Transmission Bids		2	2	1	0.0013	2,4	1,2
Distribution Nodes		3	3	1	0.0019	7,6	1,6
Distribution Lines		4	4	1,01	-0.0002	94,2	19
Distribution Bids		5	5	1	0	0	0
Output Data		6	6	1	0.002	1.3	1
Solution info		7	7	1,01	0.00031	2	1.5
Transmission Nodes							

Figure 24 Transmission Nodes sheet

A brief breakdown of each column follows:

- **Bus\_index** contains the index of each bus,
- **Vm**, contains the voltage magnitude of each bus [pu],
- **Va**, contains the voltage angle of each bus [pu],
- **Active power injection**, contains the net active power injection on each bus (generation – demand) [pu],
- **Reactive power injection**, contains the net reactive power injection on each bus (generation – demand) [pu], and
- **MTU**, the market time unit the results are about.

### 2.5.5.3 Transmission Lines

This worksheet contains the results of the transmission lines, after the final central day-ahead market has been cleared.

Options						
General						
Execution						
Options				[pu]	[pu]	[pu]
Input Data		line_id	S	S_reverse	Limit	
Transmission Nodes		0	0	103.156	-103.1	22862842,03
Transmission Lines		1	1	1.593	-1.59	22862842,03
Transmission Bids		2	2	-99.970	100	22862842,03
Distribution Nodes		3	3	-201.533	201.5	22862842,03
Distribution Lines		4	4	-303.095	303.1	22862842,03
Distribution Bids		5	5	-404.658	404.7	22862842,03
Output Data		6	6	-506.221	506.23	22862842,03
Solution info		7	7	-607.784	607.8	22862842,03
Transmission Nodes		8	8	-709.347	710	22862842,03
Transmission Lines		9	9	-810.910	810.92	22862842,03

Figure 25 Transmission Lines sheet

A brief breakdown of each column follows:

- **Line\_id** contains the index of each line,
- **S**, contains the apparent line flow on each line [pu],
- **S\_reverse**, contains the reverse apparent line flow on each line [pu],
- **Limit**, contains the thermal line limit on each line [pu], and
- **MTU**, the market time unit the results are about.

#### 2.5.5.4 Transmission Bids

This worksheet contains the results of the transmission bids, after the final central day-ahead market has been cleared.

Options						
General						
Execution						
Options						[MWh]
Input Data		bid_id	blk_acc_status	blk_acc_ratio	step_acc_ratio	accepted_q
Transmission Nodes		0	1	1	1	120
Transmission Lines		1	0	0	0	0
Transmission Bids		2	0	0	1	10
Distribution Nodes		3	0	0	1	90
Distribution Lines		4	1 0.9		0	120
Distribution Bids		5	0	0	1	10
Output Data		6	0	0	1	15
Solution info		7	0	0	1	15
Transmission Nodes		8	1	1	0	100
Transmission Lines		9	0	0 0.9		9
Transmission Bids		10	0	0	1	15

Figure 26 The transmission bids sheet

A brief breakdown of each column follows:

- **Bid\_id** contains the index of each bid,
- **Blk\_acc\_status**, contains status of the bid, if the id corresponds to a block bid (0 the bid was rejected, 1 the bid was accepted),
- **Blk\_acc\_ratio**, contains the acceptance ratio of the bid, if the id corresponds to a block order,
- **Step\_acc\_ratio**, contains the acceptance ratio of the bid, if the bid id corresponds to a step order, and
- **Accepted\_q**, the accepted quantity of the order.



### 2.5.5.5 Distribution Systems Results

For the distribution system results, sheets *Distribution Nodes*, *Distribution Lines*, and *Distribution Bids* that contain the distribution system results are generated. These sheets follow the respective structure of the sheets of the transmission network, with the extra information of the  $d\_net\_id$ , which indicates the distribution network each element belongs to.

## 2.6 Results from simulations with dummy data

### 2.6.1 Toy Example

In this section we demonstrate the effectiveness of the proposed DA LFM in solving operational issues of the DN, using a small-scale example. To that end, we use a test power system consisting of a TN that is connected with two DNs. The TN consists of 5 buses, and the DNs of 4 and 5 buses respectively. The topology of this system can be seen in Figure 27. The TN is connected to the DNs using transformers.

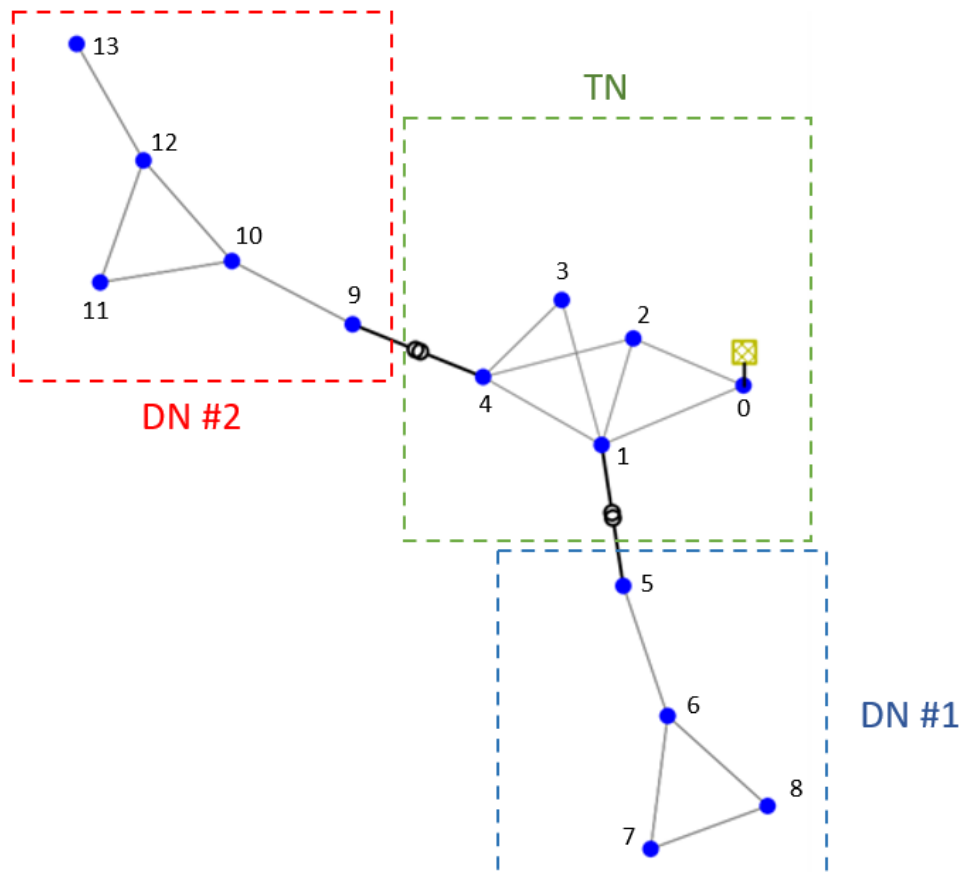


Figure 27 The topology used in the toy example.

For the verification of the proposed DA LFM, we perform a comparison of the following DA LFM formulations:

- **Centralized DA LFM with DC OPF formulation**, in which both the TN and the DN are modelled using the DC approximation, and a single optimization problem consisting of both the TN and the DN is solved,
- **Centralized DA LFM with AC OPF formulation**, in which both the TN and the DN are modelled using the full AC equations, and a single optimization problem consisting of both the TN and the DN is solved,

- **Centralized DA LFM with hybrid OPF formulation**, in which the TN is modelled using the DC approximation, and the DN is modelled using the full AC equations, and a single optimization problem consisting of both the TN and the DN is solved.
- **Decentralized DA LFM with hybrid OPF formulation**, in which the TN is modelled using the DC approximation, and the DN is modelled using the full AC equations, where each DA LFM at each DN is formulated as a separate optimization problem, and is then passed to the central DAM, and
- **Decentralized DA LFM with linear OPF formulation** (proposed DA LFM), in which the TN in which the TN is modelled using the DC approximation, and the DN is modelled using the linearized AC equations, where each DA LFM at each DN is formulated as a separate optimization problem, and is then passed to the central DAM.

The goal of this analysis is two-fold:

1. To showcase the resulting sub-optimality that comes from the employed decentralized DA LFM formulation versus different types of centralized formulations, and
2. To verify the accuracy of the employed linearizations.

As discussed in Section 2.2, we expect centralized formulations to provide a more optimal solution, since the problem has the full visibility of the resources and constraints of the system. However, centralized formulation require a large exchange of data between the stakeholders, complicating the information exchange and possibly violating institutional boundaries, and in realistic scenarios can result in a big non-tractable optimization problem. Decentralized formulations, on the other hand, prioritize trades between the assets of the DN, meaning that some welfare may be lost (in case a trade between assets in different networks would produce better welfare and resolve the operational issues). The advantages of decentralized formulations lies in simplifying the information exchange between the stakeholders, respecting institutional boundaries, and creating multiple smaller optimization problems that can be solved faster and in a more robust way.

The analysis of this section assumes that the central DAM has already been cleared, and has produced the setpoints and flexibility bids for each asset, according to the procedure that was described in Section 2.3.2. The existence of a setpoint (i.e. the assumption that the central DAM has already cleared) is not a prerequisite for centralized methods, as they could directly solve the scheduling problem, while respecting all the network conditions. However, adopting this assumption allows for the direct comparison between centralized and decentralized methods. The goal of this analysis is to calculate the welfare reduction that results from the activation of flexibility in order to alleviate the network in a fair problem setup for both centralized and decentralized methods. Note that the analysis focuses on the welfare reduction that results from the activation of flexibility. As described in section 2.4.2, this method also calculates the losses of each DN with the use of virtual generators. The output of the virtual generators is then added to the final aggregate DN order, allowing the DSO to buy its network's losses from the final central DAM. This also leads to a decrease in welfare but is not reported in the following welfare calculations, as the focus of this report is the activation of flexibilities to resolve operational issues of the DN.

The setpoints for each asset and their corresponding flexibility bids can be seen in Table 1. Some assets are non-dispatchable, and therefore do not provide flexibility.

Table 1 The initial setpoint and flexibility bids of all assets.

Id	Type	Network	Connection bus	Setpoint [MW]	Upward Flexibility Quantity [MW]	Upward Flexibility Cost [€/MW]	Downward Flexibility Quantity [MW]	Downward Cost Quantity [€/MW]
0	Generator	TN	0	132	100	99	50	22
1			2	75	22	105	35	30
2		DN 1	5	10	3	110	-	-
3			8	10.5	5	123	5	90
4		DN 2	9	9	4	122	-	-
5			12	11	2.4	121	1.2	41
6	Load	TN	3	235.3	-	-	-	-
7		DN 1	6	1	-	-	-	-
8			7	3	2	150	1.5	10
9		DN 2	10	4.5	-	-	-	-
10			11	2.2	-	-	-	-
11			13	1.5	0.3	110	0.2	5

The same convention that is used throughout this document is also used for the flexibilities that are shown in

Table 1, i.e. upward flexibility increases the net injection (meaning increased generation for generating units or decreased consumption for loads), a downward flexibility decreases the net injection (meaning decreased generation for generating units or increased consumption for loads).

Using these disaggregated setpoints as inputs, we run a power flow analysis, to determine whether any violations exist. The results of the power flow analysis can be seen in Table 2 for each bus, and in Table 3 for each line.

Table 2 Nodal power flow results for the initial system setpoint

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
0	TN	1	0	1.10	0.90
1		0.966652	-5.754772	1.10	0.90
2		0.985958	-4.151697	1.10	0.90

3		0.949830	-7.930572	1.10	0.90
4		0.964521	-6.131878	1.10	0.90
5	DN 1	1.000881	-151.244834	1.05	0.95
6		1.007320	-151.171750	1.05	0.95
7		1.042128	-149.771398	1.05	0.95
8		<b>1.060132</b>	-149.663083	1.05	0.95
9	DN 2	0.970778	-152.795597	1.05	0.95
10		0.971481	-152.542726	1.05	0.95
11		0.997935	-150.720102	1.05	0.95
12		1.018411	-150.642388	1.05	0.95
13		0.987547	-151.129143	1.05	0.95

Table 3 Line power flow results for the initial system setpoint.

Line Id	Network	From bus	To bus	Loading Percentage [%]
0	TN	0	1	41.912698
1		1	2	37.039868
2		2	0	31.159829
3		1	3	74.867432
4		1	4	12.545361
5		2	4	44.218199
6		3	4	62.476762
7	DN 1	5	6	36.626955
8		6	7	27.651465
9		6	8	15.951882
10		7	8	45.903551
11	DN 2	9	10	24.231173
12		10	11	26.437702

13		10	12	15.402761
14		11	12	<b>108.346143</b>
15		11	13	11.230388
<b>Transformer 1</b>	TN – DN 1	1	5	70.561870
<b>Transformer 2</b>	TN – DN 2	4	9	47.264817

According to the power flow results, the system has an **overvoltage on bus 8** (which belongs to DN #1) and **line 14 is overloaded** (which belongs to DN #2). Therefore, LFMs for both DNs must be triggered, in order to solve these violations.

The first formulation which we use to run the DA LFM is the **Centralized DA LFM with DC OPF formulation**, in which both the TN and the DN are formulated using the DC approximation and a single optimization problem is solved that contains both the TN and the DNs. The expected outcome of this formulation is that the DC OPF will not be able to alleviate any of the network over/under voltages and may fail to detect the network congestions. This is because of the DC OPF's inherent limitation to completely disregard voltage magnitudes and reactive power. Regarding power flows, as the DC OPF does not take into account reactive power flows, it tends to underestimate apparent line flows. Therefore, even though the literature points to the fact that this is not a suitable formulation for this problem, we include it in our analysis for the sake of completeness. The system setpoint after clearing the DA LFM with this formulation can be seen in Table 4 and Table 5.

Table 4 Final system nodal setpoint using the Centralized DA LFM with DC OPF formulation

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
0	TN	1	0	1.10	0.90
1		1	-5.598281	1.10	0.90
2		1	-3.994539	1.10	0.90
3		1	-7.662764	1.10	0.90
4		1	-5.955046	1.10	0.90
5	DN 1	1	-151.063043	1.05	0.95
6		1	-150.888004	1.05	0.95
7		1	-148.860055	1.05	0.95
8		1	-148.388188	1.05	0.95
9	DN 2	1	-152.711663	1.05	0.95
10		1	-152.636262	1.05	0.95
11		1	-150.675376	1.05	0.95

12		1	-150.171764	1.05	0.95
13		1	-151.207195	1.05	0.95

Table 5 Final system line setpoint using the Centralized DA LFM with DC OPF formulation

Line Id	Network	From bus	To bus	Loading Percentage [%]
0	TN	0	1	39.495899
1		1	2	31.114616
2		2	0	29.786133
3		1	3	67.590413
4		1	4	11.680356
5		2	4	38.036308
6		3	4	55.910058
7	DN 1	5	6	37.527767
8		6	7	28.664543
9		6	8	14.636727
10		7	8	45.985051
11	DN 2	9	10	16.165808
12		10	11	27.716636
13		10	12	14.429934
14		11	12	<b>98.247074</b>
15		11	13	8.660254
<b>Transformer 1</b>	TN – DN 1	1	5	66.0
<b>Transformer 2</b>	TN – DN 2	4	9	47.2

Since the formulation completely disregards voltage magnitudes, it is not able to detect the overvoltage on bus 8. Moreover, as the formulation does not consider reactive power, the line flows are significantly underestimated, which in this case means that the formulation fails to detect the violation altogether. This shortcoming of the formulation is due to the line characteristics of the DN, which drastically differ from those of the TN, leading to a major loss of accuracy when it is used in the DN. This can be verified by comparing the results between the calculated values in Table 3 and Table 5 that show a satisfactory

accuracy for the elements of the TN, and considerable differences for the elements of the DNs. As a result of the DC OPF approximation assumptions, the violations are not detected, therefore no flexibilities were activated and the setpoint of the assets of the network is the same as the initial setpoint.

The same problem was formulated next using the **Centralized DA LFM with AC OPF formulation**, in which both the TN and the DN are modelled using the full AC equations and a single optimization problem that contains both the TN and the DNs is solved. In contrast to the DC OPF formulation, the AC OPF formulation explicitly considers the voltage magnitude of each bus and the reactive power. The resulting setpoints can be seen in Table 6 and Table 7.

**Table 6 Final system nodal setpoint using the Centralized DA LFM with AC OPF formulation**

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
0	TN	1	0	1.10	0.90
1		0.966659	-5.870034	1.10	0.90
2		0.985936	-4.247772	1.10	0.90
3		0.949837	-8.045708	1.10	0.90
4		0.964527	-6.246944	1.10	0.90
5	DN 1	1.002013	-151.977465	1.05	0.95
6		1.006544	-151.969974	1.05	0.95
7		1.034495	-151.160550	1.05	0.95
8		<b>1.05</b>	-151.138475	1.05	0.95
9	DN 2	0.971170	-153.100294	1.05	0.95
10		0.971296	-152.869288	1.05	0.95
11		0.995867	-151.232809	1.05	0.95
12		1.014942	-151.200754	1.05	0.95
13		0.986045	-151.535006	1.05	0.95

**Table 7 Final system line setpoint using the Centralized DA LFM with AC OPF formulation**

Line Id	Network	From bus	To bus	Loading Percentage [%]
0	TN	0	1	42.665145
1		1	2	37.316149
2		2	0	31.855629



3		1	3	74.864845
4		1	4	12.540586
5		2	4	44.502925
6		3	4	62.478297
7	DN 1	5	6	25.283872
8		6	7	20.281234
9		6	8	12.281759
10		7	8	38.756443
11	DN 2	9	10	21.857397
12		10	11	24.066511
13		10	12	14.057454
14		11	12	<b>100</b>
15		11	13	9.936627
Transformer 1	TN – DN 1	1	5	63.053181
Transformer 2	TN – DN 2	4	9	44.662341

As can be seen in the results above, this formulation is able to alleviate the operational issues of the system. The activation of flexibilities can be seen in Table 8.

**Table 8 Flexibility activations in the Centralized DA LFM with AC OPF formulation**

Id	Type	Network	Connection bus	New Setpoint [MW]	Flexibility direction	Activated Flexibility
0	Generator	TN	0	135	upward	3
1			2	75	-	-
2		DN 1	5	10	-	-
3			8	8.2	downward	2.3
4		DN 2	9	9	-	-
5			12	10	downward	1
6	Load	TN	3	235.3	-	-

7		DN 1	6	1	-	-
8			7	3	-	-
9		DN 2	10	4.5	-	-
10			11	2.2	-	-
11			13	1.2	upward	0.3

This formulation is able to detect and alleviate both issues of the DNs. Additionally, it is able to do so utilizing the cheapest asset in the network (which is the generator with Id 0, located at bus 0 of the TN). Since the concluded trades result in negative welfare, the constraints that were violated in the initial state of the network are binding after the clearing of the market. This formulation is generally regarded as the most accurate and optimal; however, as discussed earlier, it is not practical for real life implementation, due to the barriers on information sharing, and the size of the optimization problem that would need to be solved in a realistic application, as was analyzed in Section 2.2.

The welfare produced from this formulation is:

$$welfare_{decr} = \sum (flex_{down} \cdot cost_{down} - flex_{up} \cdot cost_{up}) = -82 \text{ €}.$$

The next formulation whose effectiveness is examined is the **Centralized DA LFM with hybrid OPF formulation**, in which the TN is modelled using the DC approximation and the DN is modelled using the full AC equations, and a single optimization problem that contains both the TN and the DNs is solved. The use of the DC formulation in the TN is commonly adopted as it has satisfactory accuracy, while using the AC formulation only in the DN simplifies the problem and enables the calculation of voltage magnitudes (and the imposition of the voltage magnitude constraints) and reactive injections and flows in the DN. The network setpoint using this formulation can be seen in.

**Table 9 Final system nodal setpoint using the Centralized DA LFM with hybrid OPF formulation**

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
0	TN	1	0	1.10	0.90
1		1	-5.687275	1.10	0.90
2		1	-4.068713	1.10	0.90
3		1	-7.751192	1.10	0.90
4		1	-6.042908	1.10	0.90
5	DN 1	1	-151.977465	1.05	0.95
6		1.004891	-152.000000	1.05	0.95
7		1.034161	-151.059270	1.05	0.95
8		1.05	-151.021100	1.05	0.95
9	DN 2	1	-153.000000	1.05	0.95

10		1.000395	-152.773934	1.05	0.95
11		1.025265	-151.149470	1.05	0.95
12		1.044182	-151.107499	1.05	0.95
13		1.015730	-151.434423	1.05	0.95

Table 10 Final system line setpoint using the Centralized DA LFM with hybrid OPF formulation

Line Id	Network	From bus	To bus	Loading Percentage [%]
0	TN	0	1	40.123751
1		1	2	31.402147
2		2	0	30.339225
3		1	3	67.571875
4		1	4	11.643279
5		2	4	38.301868
6		3	4	55.928596
7	DN 1	5	6	25.283872
8		6	7	20.281234
9		6	8	12.281759
10		7	8	38.756443
11	DN 2	9	10	22.126343
12		10	11	24.496237
13		10	12	14.210458
14		11	12	<b>100</b>
15		11	13	9.646221
Transformer 1	TN – DN 1	1	5	57.225183
Transformer 2	TN – DN 2	4	9	40.189044

This formulation also successfully manages to solve the issues of the network, by activating the flexibilities that can be seen in Table 11. The system state differs from the one calculated using the Centralized DA LFM with AC OPF formulation as this formulation assumes that the voltage at the interconnection between the TN and DNs is 1pu. However, this assumption does not sacrifice a lot of accuracy.

**Table 11 Flexibility activations in the Centralized DA LFM with hybrid OPF formulation**

Id	Type	Network	Connection bus	New Setpoint [MW]	Flexibility direction	Activated Flexibility
0	Generator	TN	0	135	upward	2.28
1			2	75	-	-
2		DN 1	5	10	-	-
3			8	8.2	downward	1.88
4		DN 2	9	9	-	-
5			12	10	downward	0.7
6	Load	TN	3	235.3	-	-
7		DN 1	6	1	-	-
8			7	3	-	-
9		DN 2	10	4.5	-	-
10			11	2.2	-	-
11			13	1.2	upward	0.3

Due to the approximations used in the TN, the voltage magnitude in the T-D interface is different to that of the Centralized DA LFM with AC OPF formulation. However, the formulation is able to provide high-quality results that offer satisfactory accuracy, and reduce the complexity of the model in the TN, while retaining the required details in the DN. This assumption results in underestimation of the required flexibility by the system. The welfare produced from this formulation is:

$$welfare_{decr} = \sum (flex_{down} \cdot cost_{down} - flex_{up} \cdot cost_{up}) = -60.82 \text{ €}$$

When comparing the resulting welfare from this formulation with the welfare from the **Centralized DA LFM with AC OPF formulation** one could come to the conclusion that the results given from this formulation are more optimal, as they are associated with a smaller welfare reduction. However, we should note that this is not the case. The smaller welfare reduction associated with this formulation stems from using DC OPF for the TN modeling and the assumption of voltage magnitude equal to 1pu at the T-D interface, that results in the need for less flexibility activation.

In the decentralized formulations, DA LFMs are first formulated for the DNs, and their resulting schedules are then passed to the central DAM. In the **decentralized DA LFM with hybrid OPF formulation** the DA LFMs for the DN are formulated using the full AC equations, while the central DAM market is formulated using the DC approximation. The assets of the DN participate in the central DAM in an aggregated manner. Since the initial power flow results (Table 2 and Table 3) show violations in

both DN 1 and DN 2, according to the Market Design presented in Section 2.3, DA LFMs must be triggered for both DNs.

Contrary to the centralized approaches that were examined earlier, decentralized DA LFMs formulate and solve a LFM for each DN separately. As described in Section 2.4, in this work LFMs are formulated so that violations in the DN are solved in a way that maintains the balance within the DN, so that the flow at the T-D interconnection is maintained (and thus the balance of the system and the initial DAM schedule are not disturbed). Flexibility at the T-D interconnection is priced using the price floor and price cap (for upward and downward flexibility, respectively), which means that it will only be activated in case no other assets are able to provide the required flexibility to alleviate the violations. Activation of flexibility at the T-D interconnection disturbs the power balance of the power system, requiring the central DAM to be resolved, in order to restore the power balance. Let us break down these steps using the **decentralized DA LFM with hybrid OPF formulation**.

First, the LFM for DN 1 is triggered, in which the overvoltage at bus 8 must be alleviated. The LFM includes the assets of DN 1 only, and is formulated as an AC OPF. Since the central DAM is formulated as a DC OPF, a voltage magnitude of 1 pu is assumed at the T-D interconnection. This market produces the network status that can be seen in Table 12 and Table 13.

Table 12 Nodal results from the LFM in DN 1 using the full AC OPF formulation.

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
5	DN 1	1	0.000000	1.05	0.95
6		1.004874	0.019449	1.05	0.95
7		1.034263	0.940730	1.05	0.95
8		<b>1.05</b>	0.978900	1.05	0.95

Table 13 Line results from the LFM in DN 1 using the full AC OPF formulation.

Line Id	Network	From bus	To bus	Loading Percentage [%]
7	DN 1	5	6	27.352889
8		6	7	21.633516
9		6	8	12.956463
10		7	8	40.114215

The LFM successfully resolves the overvoltage in bus 8. The difference in voltage angle amongst this formulation and the Centralized DA LFM with hybrid OPF formulation is trivial, as swapping the reference angle at bus 5 with the results produced by the central DAM produces highly accurate result (while at the same time not affecting the rest of the calculated values). To resolve the overvoltage, the flexibilities seen in are activated.

Table 14 Activated flexibilities in DN 1.

Id	Type	Network	Connection bus	New Setpoint [MW]	Flexibility direction	Activated Flexibility
-	T-D interface	-	5	-	-	-
2	Generator	DN 1	5	10	upward	1.88
3			8	8.2	downward	1.88
7	Load	DN 1	6	1	-	-
8			7	3	-	-

In DN 1, 1.88 of upward flexibility by the generator located at bus 5, and 1.88 of downward flexibility located at bus 8 are dispatched. Since in the decentralized scheme each LFM is solved separately, and the power balance within the DN seeks to be maintained, the downward flexibility provided by the generator located at bus 8 is compensated by upward flexibility provided by the generator located at bus 5, which is a more expensive generator than the one located at bus 0 of the TN. This means that in this decentralized setting the social welfare is reduced, when compared to the centralized schemes.

Moving on, the LFM in DN 2 is triggered to alleviate the congestion in line 14. The LFM includes the assets of DN 2 only, and is also formulated as an AC OPF. This market produces the network status that can be seen in Table 15 and Table 16.

Table 15 Nodal results from the LFM in DN 2 using the full AC OPF formulation.

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
9	DN 2	1	0.000000	1.05	0.95
10		1.000395	0.226066	1.05	0.95
11		1.025265	1.850530	1.05	0.95
12		1.044182	1.892501	1.05	0.95
13		1.015730	1.565577	1.05	0.95

Table 16 Line results from the LFM in DN 2 using the full AC OPF formulation.

Line Id	Network	From bus	To bus	Loading Percentage [%]
11	DN 2	9	10	22.127541
12		10	11	24.498132
13		10	12	14.209427
14		11	12	<b>100</b>

15		11	13	9.676120
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The LFM successfully resolves the congestion on line 14. To resolve the issue, the following flexibilities must be activated.

Table 17 Activated flexibilities in DN 2.

Id	Type	Network	Connection bus	New Setpoint [MW]	Flexibility direction	Activated Flexibility
-	T-D interface	-	8	-	upward	0.4
4	Generator	DN 2	9	9	-	-
5			12	10	downward	0.7
9	Loads	DN 2	10	4.5	-	-
10			11	2.2	-	-
11			13	1.2	upward	0.3

As in the DN 2 there is not enough flexibility to alleviate the congestion and keep the power balance, the LFM has to extract flexibility from the TN, through the TSO-DSO interface. This disturbs the balance of the TN, so the central DAM has to be re-solved in order to restore the power balance. So, the setpoints of the assets of the DN is updated according to the schedule produced by the LFMs, and the aggregation described in Section 2.3.3 is performed, as the aggregate of the assets of the DN is inserted as a priority price taking order in the final DAM formulation. As explained in Section 2.3.2, the final central DAM only needs to be solved only if the solution of the LFM requires flexibility at the T-D interface. Otherwise, there is no need to solve the final central DAM, as the resulting schedule will be the same as to that of the initial central DAM. In this case, the setpoint of the assets of both DNs will remain that seen in Table 14 and Table 17, which results in a feasible dispatch of each DN. The orderbook inserted in the final DAM is depicted in Table 18 Orderbook of the final DAM. Table 18. The aggregate DN orders also include the DN losses as calculated by the virtual generators described in section 2.4.2.1.

Table 18 Orderbook of the final DAM.

Id	Type	Network	Connection bus	Setpoint [MW]	Upward Flexibility Quantity [MW]	Upward Flexibility Cost [€/MW]	Downward Flexibility Quantity [MW]	Downward Cost Quantity [€/MW]
0	Generator	TN	0	132	100	99	50	22
1			2	75	22	105	35	30
2		DN 1 (aggr.)	1	16.5	-	-	-	-
4		DN 2 (aggr.)	4	11.4	-	-	-	-
6	Load	TN	3	235.3	-	-	-	-

As can be seen in Table 18, the total generation is 234.9 MW, while the total load is 235.3 MW. So, an imbalance of 0.4 MW must be settled in the central DAM. Therefore, the following flexibility is activated.

**Table 19 Asset setpoint of the final central DAM.**

<b>Id</b>	<b>Type</b>	<b>Network</b>	<b>Connection bus</b>	<b>New Setpoint [MW]</b>	<b>Flexibility direction</b>	<b>Activated Flexibility</b>
<b>0</b>	<b>Generator</b>	<b>TN</b>	0	132.4	upward	0.4
<b>1</b>			2	75	-	-
<b>2</b>		<b>DN 1 (aggr.)</b>	1	16.5	-	-
<b>4</b>		<b>DN 2 (aggr.)</b>	4	11.4	-	-
<b>6</b>	<b>Load</b>	<b>TN</b>	3	235.3	-	-

Now the total load is 235.3 MW and the total generation is 235.3 MW, which means that the power balance within the system is restored. The resulting setpoint of the system can be seen in Table 20 and Table 21.

**Table 20 Final nodal setpoint of the TN.**

<b>Bus Id</b>	<b>Network</b>	<b>Voltage magnitude [pu]</b>	<b>Voltage angle [deg.]</b>	<b>Max. voltage magnitude [pu]</b>	<b>Min. voltage magnitude [pu]</b>
0	TN	1	0	1.10	0.90
1		1	-5.687275	1.10	0.90
2		1	-4.068713	1.10	0.90
3		1	-7.751192	1.10	0.90
4		1	-6.042908	1.10	0.90
5	DN 1	1	-151.977465	1.05	0.95
9	DN 2	1	-153.000000	1.05	0.95

**Table 21 Final line setpoint of the TN.**

<b>Line Id</b>	<b>Network</b>	<b>From bus</b>	<b>To bus</b>	<b>Loading Percentage [%]</b>
<b>0</b>	TN	0	1	40.123751
<b>1</b>		1	2	31.402147



2		2	0	30.339225
3		1	3	67.571875
4		1	4	11.643279
5		2	4	38.301868
6		3	4	55.928596
Transformer 1	TN – DN 1	1	5	57.225183
Transformer 2	TN – DN 2	4	9	40.189044

So, the total welfare produced from these markets is

$$welfare_{decr} = \sum (welfare_{LFMs} + interface\ flexibility_{cost}) = -81.5 \text{ €}$$

Where  $welfare_{LFMs} = \sum (flex_{down} \cdot cost_{down} - flex_{up} \cdot cost_{up})$  is the welfare of each LFM and  $interface\ flexibility_{cost}$  is the cost the DSO has to pay to buy the required flexibility at the T-D interface from the final DAM (which is calculated as the flexibility at the T-D interface multiplied by the MCP of the final central DAM).

We see that the decentralized formulation causes a further decrease in welfare compared to other formulations, but manages to achieve the goal of the LFMs, which is to alleviate the DN.

Finally, we examine the proposed DA LFM, which is the **decentralized DA LFM with linear OPF formulation**. In this formulation, the TN is modelled using the DC approximation, and the DN is modelled using the linearized AC equations. We want to make a direct comparison between this method and the **decentralized DA LFM with hybrid OPF formulation**, to validate the accuracy of the proposed SLP method.

Again, the LFM for DN 1 is triggered, to alleviate the overvoltage at bus. This market produces the network status that can be seen in Table 22 and Table 23.

Table 22 Nodal results from the LFM in DN 1 using the linearized AC OPF formulation.

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
5	DN 1	1	0.000000	1.05	0.95
6		1.004863	0.019342	1.05	0.95
7		1.034261	0.940732	1.05	0.95
8		1.05	0.979018	1.05	0.95

Table 23 Line results from the LFM in DN 1 using the linearized AC OPF formulation.

Line Id	Network	From bus	To bus	Loading Percentage [%]
7	DN 1	5	6	27.354009
8		6	7	21.623512
9		6	8	12.955254
10		7	8	40.114301

The LFM successfully resolves the overvoltage in bus 8. Comparing the results between the linearized AC OPF and the full AC OPF formulations we can validate the accuracy of the employed SLP methodology. The activated flexibilities can be seen in Table 24, where we can see that this formulation leads to practically the same dispatch as the full AC OPF formulation.

Table 24 Activated flexibilities in DN 1.

Id	Type	Network	Connection bus	New Setpoint [MW]	Flexibility direction	Activated Flexibility
-	T-D interface	-	5	-	-	-
2	Generator	DN 1	5	10.8795	upward	1.8795
3			8	8.6205	downward	1.8795
7	Load	DN 1	6	1	-	-
8			7	3	-	-

The results of the LFM in the DN 2 using the linearized AC OPF formulation can be seen in Table 24 and Table 26.

Table 25 Nodal results from the LFM in DN 2 using the full AC OPF formulation.

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
9	DN 2	1	0.000000	1.05	0.95
10		1.000392	0.226065	1.05	0.95
11		1.025254	1.850523	1.05	0.95
12		1.044176	1.892499	1.05	0.95
13		1.015728	1.565547	1.05	0.95

Table 26 Line results from the LFM in DN 2 using the full AC OPF formulation.

Line Id	Network	From bus	To bus	Loading Percentage [%]
11	DN 2	9	10	22.127381
12		10	11	24.498095
13		10	12	14.209416
14		11	12	<b>100</b>
15		11	13	9.676114

The proposed formulation is again able to resolve the congestion in line 14. Again, the results produced by this formulation are practically identical to those produced by the full AC formulation. The activated flexibilities are shown in Table 27.

Table 27 Activated flexibilities in DN 2.

Id	Type	Network	Connection bus	New Setpoint [MW]	Flexibility direction	Activated Flexibility
-	T-D interface	-	8	-	upward	0.4012
4	Generator	DN 2	9	9	-	-
5			12	10.2988	downward	0.7012
9	Loads	DN 2	10	4.5	-	-
10			11	2.2	-	-
11			13	1.2	upward	0.3

The required flexibility is overestimated by a small amount, as the linearization of the line limits introduced in Section 2.4.2.2 imposes marginally tighter thermal limits on the lines. Thus, the orderbook inserted in the final DAM, the final TN setpoint, and the activated flexibilities can be in the following Tables.

Table 28 Orderbook of the final DAM.

Id	Type	Network	Connection bus	Setpoint [MW]	Upward Flexibility Quantity [MW]	Upward Flexibility Cost [€/MW]	Downward Flexibility Quantity [MW]	Downward Cost Quantity [€/MW]
0	Generator	TN	0	132	100	99	50	22
1			2	75	22	105	35	30
2		DN 1 (aggr.)	1	16.5	-	-	-	-

4		DN 2 (aggr.)	4	11.4	-	-	-	-
6	Load	TN	3	235.3	-	-	-	-

As can be seen in Table 18, the total generation is 234.8988 MW, while the total load is 235.3 MW. So, an imbalance of 0.4012 MW must be settled in the central DAM. Therefore, the following flexibility is activated.

**Table 29 Asset setpoint of the final central DAM.**

Id	Type	Network	Connection bus	New Setpoint [MW]	Flexibility direction	Activated Flexibility
0	Generator	TN	0	132.4	upward	0.4012
1			2	75	-	-
2		DN 1 (aggr.)	1	16.5	-	-
4		DN 2 (aggr.)	4	11.3988	-	-
6	Load	TN	3	235.3	-	-

Now the total load is 235.3 MW and the total generation is 235.3 MW, which means that the power balance within the system is restored. The resulting setpoint of the system can be seen in Table 30 and Table 31.

**Table 30 Final nodal setpoint of the TN.**

Bus Id	Network	Voltage magnitude [pu]	Voltage angle [deg.]	Max. voltage magnitude [pu]	Min. voltage magnitude [pu]
0	TN	1	0	1.10	0.90
1		1	-5.687276	1.10	0.90
2		1	-4.068720	1.10	0.90
3		1	-7.751194	1.10	0.90
4		1	-6.042911	1.10	0.90
5	DN 1	1	-151.977467	1.05	0.95
9	DN 2	1	-153.000020	1.05	0.95

Table 31 Final line setpoint of the TN

Line Id	Network	From bus	To bus	Loading Percentage [%]
0	TN	0	1	40.123758
1		1	2	31.402148
2		2	0	30.339225
3		1	3	67.571875
4		1	4	11.643279
5		2	4	38.301868
6		3	4	55.928596
Transformer 1	TN – DN 1	1	5	57.225183
Transformer 2	TN – DN 2	4	9	40.189044

So, the total welfare decrease produced from these markets is

$$welfare_{decr} = \sum (welfare_{LFMs} + interface\ flexibility_{cost}) = -81.5596 \text{ €}$$

Therefore, the accuracy of this formulation compared to the full AC OPF formulation is again verified.

## 2.6.2 Scaling of mechanism

One of the main prerequisites of the proposed DA LFM mechanism is scalability. To explore the mechanism's scalability, multiple synthetic test cases were created and solved using the proposed mechanism. We examine the scalability of the central market and the LFMs independently, as they only interact to convey the flow at the interface between solutions. The aggregation and disaggregation of DN bids is a simple procedure that does not impose any constraints on the scalability of the model in terms of speed. Since both the central DAM and the LFMs are linear formulations, we expect satisfactory scaling capabilities. All the simulations in this Section were executed for a 24-MTU period, on a MacBook Pro with 16 GB of RAM and processor with clock speed at 2.2 GHz. All problems were formulated with Python (using Pyomo) and solved with the commercial solver CPLEX. The optimality gap was set to  $10^{-4}$  for all simulations.

Table 32 Scaling of the central DAM.

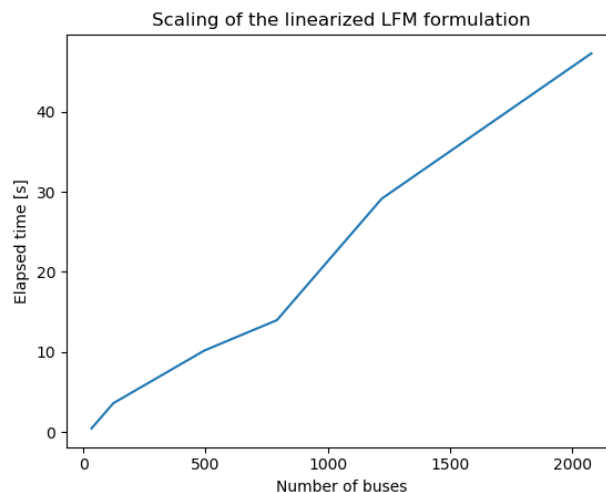
Network	Number of buses	Number of lines	Number of block orders	Solution time [s]
case9	9	9	1	3.02
case14	14	20	2	4.11
case24_ieee_rts	24	38	3	6.75

<b>case_ieee30</b>	30	41	4	6.88
<b>case39</b>	39	46	5	7.41
<b>case57</b>	57	80	6	9.04
<b>case89pegase</b>	89	210	8	15.53
<b>case118</b>	118	186	12	14.97
<b>case145</b>	145	453	14	17.19
<b>case_illinois200</b>	200	245	20	19.94
<b>case300</b>	300	411	30	26.43
<b>case1354pegase</b>	1354	1991	135	46.20
<b>case1888rte</b>	1888	2351	185	57.79
<b>case2848rte</b>	2848	3776	280	82.14
<b>case3120sp</b>	3120	3693	300	106.91

In Table 32 the scaling of the central DAM is examined, in various TNs spanning from 9 to over 3000 buses. All test-cases are found in the library of pandapower [31], and were extended for 24 MTUs using synthetic consumption and generation patterns over a day. The test-cases featured integer variables (i.e. block orders) and different levels of loadings, as both of these parameters affect the solution speed. The mechanism exhibits satisfactory scaling capabilities, as the largest test-case (which consisted of over 3000 buses, 3500 lines and 300 block orders) was solved in a little over 105 seconds.

The scalability of the LFM was also tested in various synthetic test cases, spanning from 33 to over 2000 buses, as can be seen in Figure 28. The results of this simulation have been reported in the paper that introduces this methodology [29]. Again, the simulation was executed for 24 MTUs, and the DNs featured different levels of loading (more details regarding this simulation can be found in [29]). The scalability of this model is also deemed satisfactory, as the largest test-case of 2079 buses and 2331 lines was solved in about 45 seconds.

Thus, the requirement of scalability that was reported for all mechanisms in Section 1 is satisfied for the DAM mechanism.

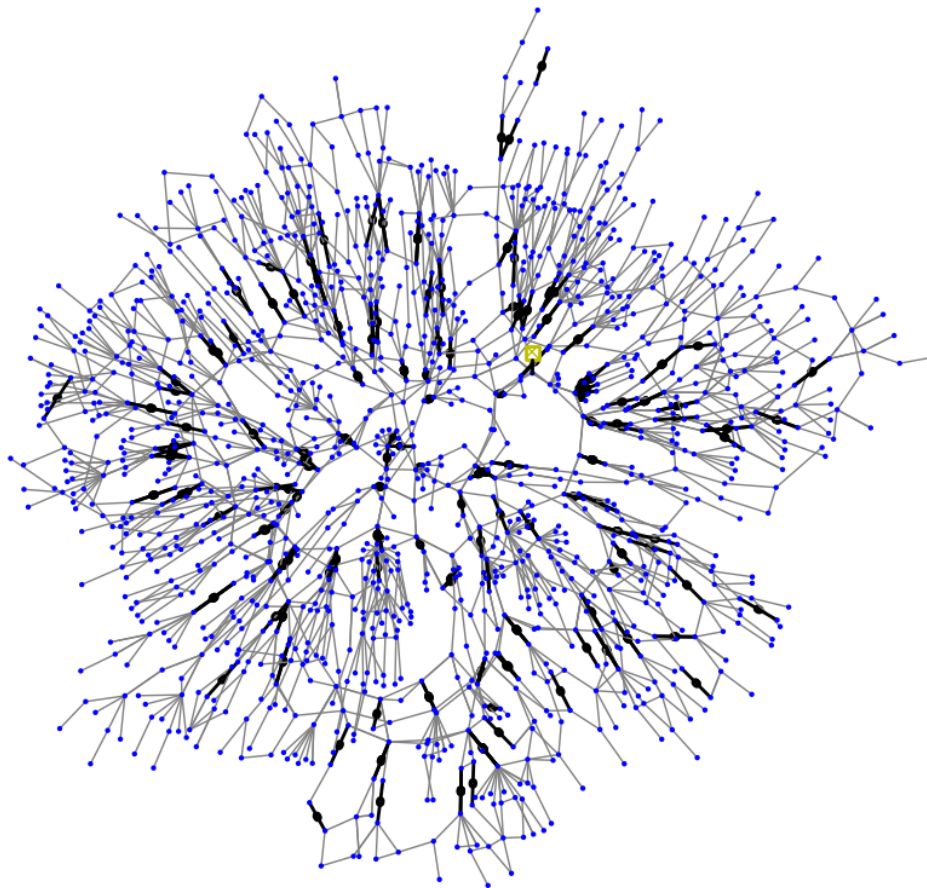


**Figure 28** Scaling of the DA LFM.

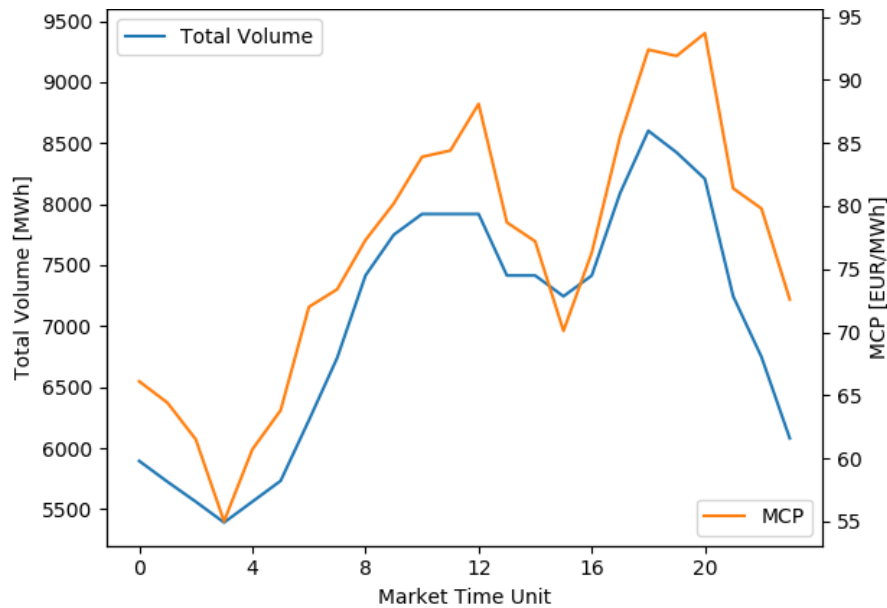
### 2.6.3 Realistic test case

The effectiveness of the DAM mechanism is showcased using a synthetic realistic test case. The test case was created using networks available in pandapower [32]. Specifically, the topology of a 1354 bus TN was used, that had 8 DNs connected to it. The topology of the TN can be seen in Figure 29. The test case assumes the load offtake and RES injection profiles of a spring day. The resulting load profile and the MCP for each MTU of the initial central DAM of the test case can be seen in Figure 30. The average load is 7.02 GWh, maximum load is 8.6 GWh, and the minimum 5.4 GWh, while the average MCP is 76.26 EUR/MWh, the maximum 93.7 EUR/MWh and the minimum 55 EUR/MWh.

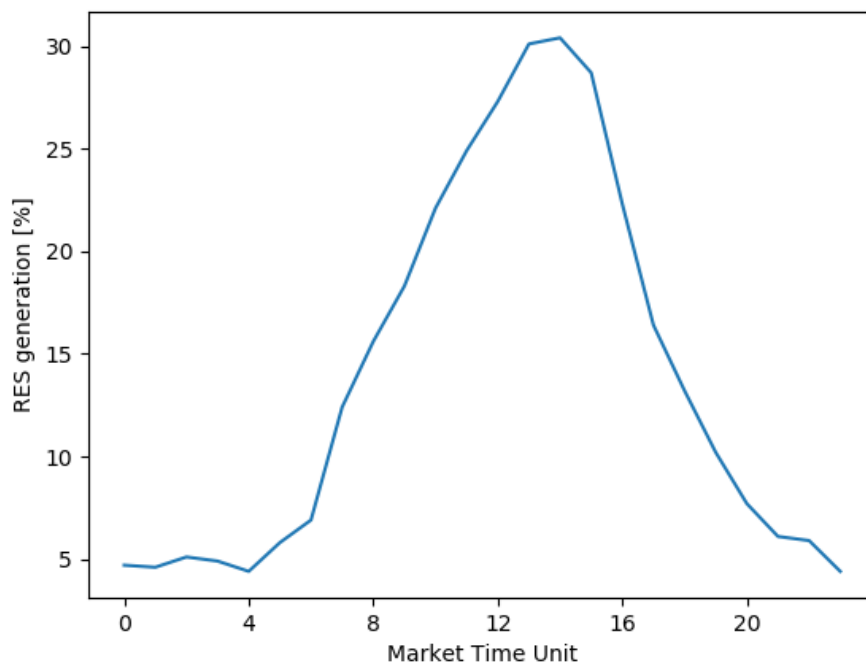
In this system we also assume moderate RES penetration, consisting of wind and solar generation. The profile of the RES injections (as a percentage in the generation mix) according to the initial DAM schedule can be seen in Figure 31. The average participation of RES in the generation mix is 13.85%, the maximum 30.4 % and the minimum 4.4 %. As is typical for a spring day, the peak RES generation is around the midday (11-15 MTUs), with steep ramping of the RES injection before and after the peak. Before sunrise and after sunset, RES injections are significantly reduced.



**Figure 29** The topology of the TN in the realistic test-case.



**Figure 30** Load profile and MCP for each MTU.



**Figure 31** RES injection profile.

In the analysis we will focus on two DNs. DN #1 is a net importer, and features mostly loads, with negligible RES generation within the network. DN #1 has 33 buses and 37 lines. DN #2 on the other hand features significant RES generation, and thus can be an importer or an exporter of energy to the TN, depending on the level of RES generation. DN #2 has 132 buses and 148 lines. It is expected that any potential violations will arise around the peak demand MTUs for DN #1 (that is around MTUs 18-20) and around peak demand or peak RES generation MTUs for DN #2 (that is around MTUs 12-20).

#### DN #1

The profile of the active power flow at the T-D interface between DN #1 and the TN can be seen in Figure 32. It is assumed that a negative flow at the T-D interface means the DN absorbs (imports) energy from the TN, while a positive flow means that the DN exports energy to the TN. In this case, the flow is negative for each MTU, which is expected, since DN #1 does not feature significant RES generation.



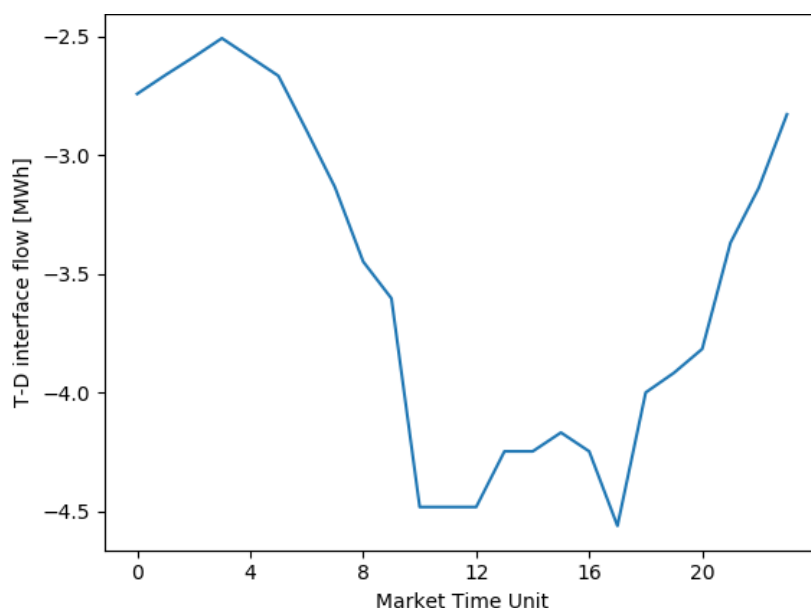


Figure 32 Initial flow at the interface between the TN and DN #1.

The constraints of the network are violated in MTUs 11, 12 and 17, thus a LFM is triggered for DN1 shows some aggregated statistics regarding the activation of flexibilities in order to resolve the issues of the DN.

Table 33 Activation of flexibilities at DN #1.

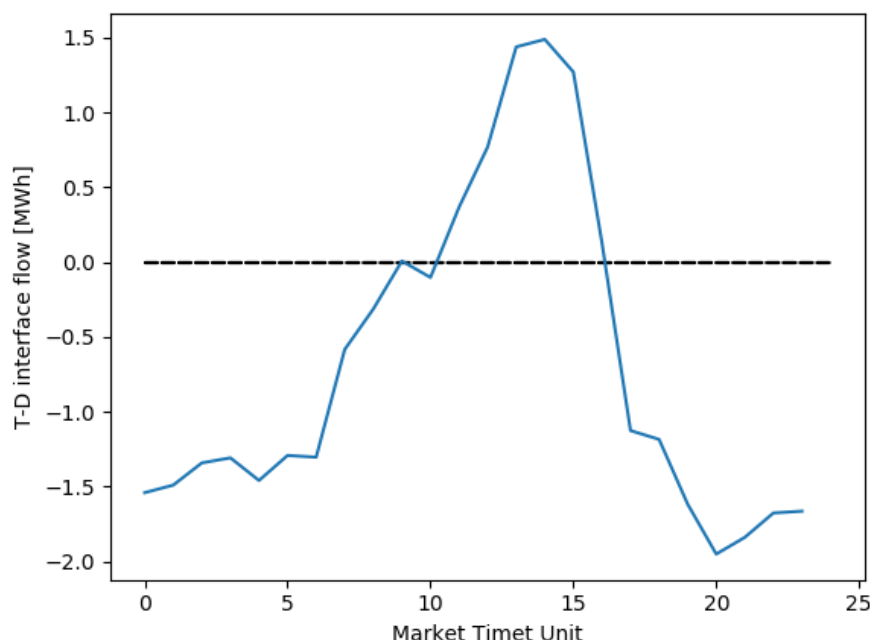
MTU	11	12	17
Number of violations	2	2	3
Total upward flexibility activation [MWh]	0.14	0.155	0.165
Total downward flexibility activation [MWh]	0.14	0.155	0.172
Flexibility at the T-D interface [MWh]	0	0	0.007
Welfare [EUR]	-0.406	-0.665	-1.419

For MTUs 11 and 12 the network has enough flexibility to be able to resolve its issues and keep the power balance within the network, not changing the flow at the T-D interface. In MTU 17, however, DN #1 has to activate some upward flexibility from the T-D interface in order to resolve its issues. For each instance, there is a negative welfare associated with the activation of flexibilities, in line with the results that were presented in the previous Sections. For the rest of the MTUs, no flexibilities were activated and, in turn, the setpoint of the flow at the T-D interface is not changed. We should note that the resulting welfare of the LFM in DN #1 is small. This happens because of two reasons: 1) the price difference between upward and downward activated flexibility is small, and 2) the quantity of the activated flexibilities is limited. These facts apply to all other calculated welfares as well.

#### DN #2

The profile of the active power flow at the T-D interface between DN #2 and the TN can be seen in Figure 33 (the dashed line represents the point where the flow is zero). As discussed earlier, DN #2

features significant RES generation. So, during the day, when RES generation reaches its peak, DN #2 exports energy to the TN. For the rest MTUs, DN #2 imports energy from the TN.



**Figure 33** Initial flow at the interface between the TN and DN #2.

The network is expected to present violations either when load consumption reaches its peak, or when RES output reaches its peak. In Table 34, flexibility activation results of the LFM in DN #2 can be seen.

**Table 34** Activation of flexibilities at DN #2.

MTU	13	14	15	20	21
<b>Number of violations</b>	4	4	3	1	2
<b>Total upward flexibility activation [MWh]</b>	0.26	0.267	0.211	0.141	0.133
<b>Total downward flexibility activation [MWh]</b>	0.304	0.320	0.243	0.141	0.133
<b>Flexibility at the T-D interface [MWh]</b>	-0.044	-0.053	-0.032	-	-
<b>Welfare [EUR]</b>	-1.326	-1.709	-1.688	-0.465	-0.693

According to the results of the LFM, the network has to curtail its export to the TN for MTUs 13, 14 and 15. For MTUs 20 and 21, the DN is able to resolve its issues, using the flexibility within the network. As in the previous cases, there is an associated reduction in welfare with the activation of flexibilities for each MTU.

Similar results could be presented for the rest of the DNs connected to the TN, however they would offer no extra insight to the operation of the proposed market mechanism. After all the LFM's have cleared, aggregation described in Section 2.3 is performed and the priority price taking orders are inserted in the central DAM. The difference between the resulting MCPs between the final and the initial DAM Figure 34.

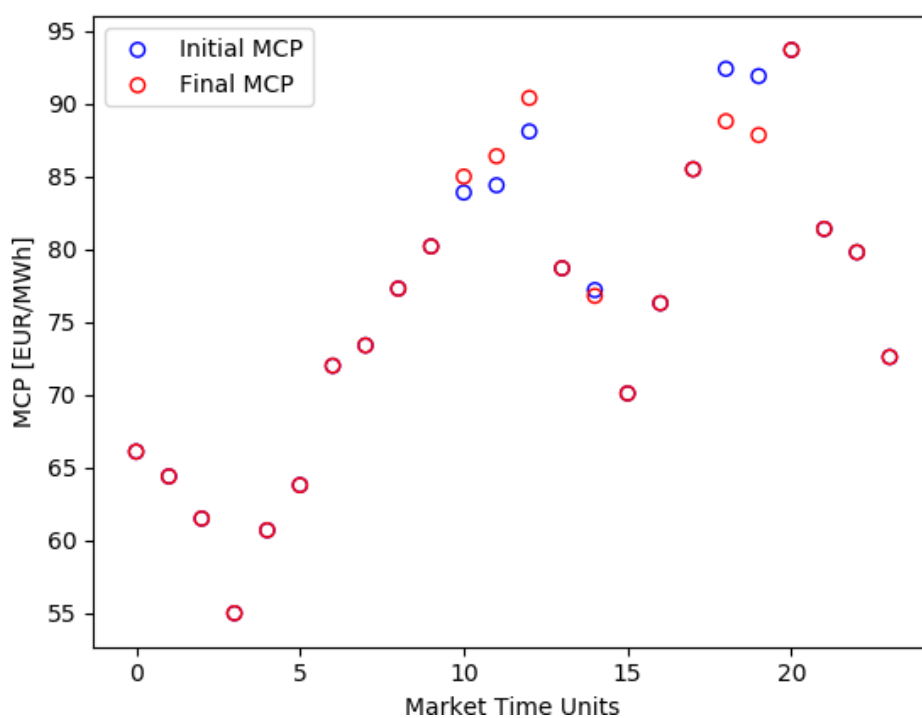


Figure 34 MCP in initial and final DAM.

Table 35 Losses and flexibilities at the T-D interface for all LFMs.

MTU	0	1	2	3	4	5	6	7	8	9	10	11
<b>Flexibility [MWh]</b>	-	-	-	-	-	-	-	-	-	-	-	0.03
<b>Losses [MWh]</b>	3.56	3.498	3.361	3.234	3.398	3.471	3.769	4.092	4.545	4.701	4.772	4.763
<b>Total [MWh]</b>	3.56	3.498	3.361	3.234	3.398	3.471	3.769	4.092	4.545	4.701	4.772	4.793

MTU	12	13	14	15	16	17	18	19	20	21	22	23
<b>Flexibility [MWh]</b>	0.08	-0.13	-0.21	-0.02	-	-	-	0.263	0.132	0.048	0.092	-
<b>Losses [MWh]</b>	4.763	4.778	4.532	4.428	4.536	4.869	5.192	5.119	4.992	4.386	4.109	3.746
<b>Total [MWh]</b>	4.843	4.648	4.322	4.408	4.536	4.869	5.192	5.382	5.124	4.434	4.201	3.746

Table 35 presents the total losses of all DNs of the test case for each MTU and the sum of the total flexibility at the T-D interface of all DNs. The sum of losses and flexibilities of the DNs represents about 0.1% of the total system load for each MTU, which explains why the MCP does not change much in the final DAM schedule. The sum of the flexibility at the T-D interface of all DNs is just a fraction of the bids the DSO submits to the final DAM, and is due to the fact that the formulation promotes the use of flexibility within the DN to resolve its issues, and not the flexibility of the TN, as demonstrated in this Section. A different approach could lead to drastic changes in the flow at the T-D interface, and in turn significant deviations between the final and the initial DAM prices.

As a result of the employed pricing in the T-D interface, the difference between the initial and the final DAM cleared quantities and prices can be seen. As expected, any differences only occur in MTUs with high load consumption or high RES generation. The decrease in welfare due to the LFMs and the subsequent solution of the central DAM is

$$welfare_{decr} = \sum (welfare_{LFMs} + interface\ flexibility_{cost}) = -104.28\ EUR$$

Where  $welfare_{LFMs}$  is the welfare of each LFM and  $interface\ flexibility_{cost}$  is the cost required to buy the flexibility at the T-D interface from the central DAM, and is calculated as the flexibility at the T-D interface, multiplied by the MCP for each MTU.

### 3 Intraday Market Mechanism

#### 3.1 Introduction

The design of a Local Flexibility Market (LFM) where flexibility is traded continuously in the form of energy in order to solve distribution grid issues is proposed. The market operates in a single distribution network and successfully handles voltage violations, congestion issues and deviations of the DSO's schedule in the Transmission System Operator (TSO) - DSO connection point. The above issues are perceived as a result of forecasting errors in the non-dispatchable distributed resources generation and load consumption, errors which do exist between the predictions made in the day-ahead markets and the forecasts in the intra-day market. The LFM transactions respect the network feasibility requirements, and the network feasibility assessment is based on the development of ac power transfer distribution factors (ac PTDFs). The proposed ac PTDFs are suitable for determining the change in the line flows/node voltage magnitudes, for the changes in the injected active or reactive power of the potential bilateral transactions.

#### 3.2 Market Design

The proposed LFM is placed in a market framework that presupposes the operation of a Day-Ahead Market (DAM) by the Market Operator (MO) or an Independent System Operator on the transmission level. The DAM produces market schedules for the production & generation of the assets of the transmission system, aggregate portfolios and flows for transmission-distribution connection buses, for all Market Time Units (MTUs) of a delivery day D. The assets located in the distribution system participate through aggregators portfolios in the DAM, and the portfolio market schedule is disaggregated (through respective nominations) by the aggregator to individual assets after the DAM results. The proposed LFM is a continuous trading mechanism operated for a specific distribution system, which begins after the conclusion of the DAM auction. The market players can place orders continuously for any MTU of the delivery day D if the trading gate is open. The trading gate opens for all MTUs after DAM closure and closes for each MTU one hour before the actual physical delivery. The proposed framework works for any MTU duration (15, 30, 60 minutes etc.). The trading timeline is depicted in Figure 35 for a delivery day D with hourly MTUs.

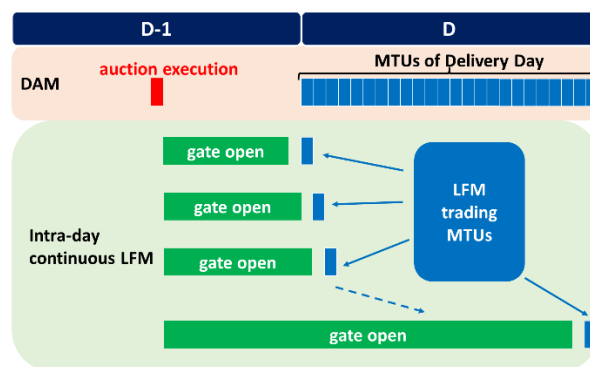


Figure 35 Trading timeline of the intra-day continuous LFM

##### 3.2.1 Actors and Roles

The proposed LFM enables the continuous trading of active and reactive power flexibility in the form of energy in the distribution level. The LFM engages the system operator (DSO), with Market Participants (MPs) and the MO to mitigate anticipated violations of the distribution grid physical limitations.

##### Market Participants (MPs)

MPs represent dispatchable assets, i.e. assets that can alter their generation or consumption based on dispatch instructions, e.g. dispatchable generation, storage, responsive loads etc. MPs submit sell or buy orders for active or reactive power based on their available flexibility. The creation of the MPs orders is considered as part of the Flexibility Service Provider Agent, as described in deliverable D1.2 [33].

Their participation is asset-based, meaning that the submitted order refers to a specific asset located in a specific node, which has an existing market schedule from the DAM. When a MP's trade is concluded, the market schedule of the affected asset is modified, and so is the expected physical injection or offtake of the asset.

### **Distribution System Operator (DSO)**

The DSO after the DAM closure, performs periodically updated forecasts of the non-dispatchable generation and consumption located in the grid for the MTUs of the delivery day. After a forecast is performed, the DSO runs an AC power flow simulation for all forecasted MTUs, identifies anticipated network constraints violations and sends the necessary network data to the MO. When violations are expected the DSO can also submit virtual orders in the market platform. The creation of the DSO orders is considered as part of the Flexibility Service Consumer Agent, as described in deliverable D1.2.

### **Market Operator (MO)**

The MO is responsible for developing and operating the continuous trading market platform, the trade clearing and settlement of transactions. Aligning with the definitions within D1.2, the MO is responsible for the operation of the Intra-day Flexibility Trading Mechanism.

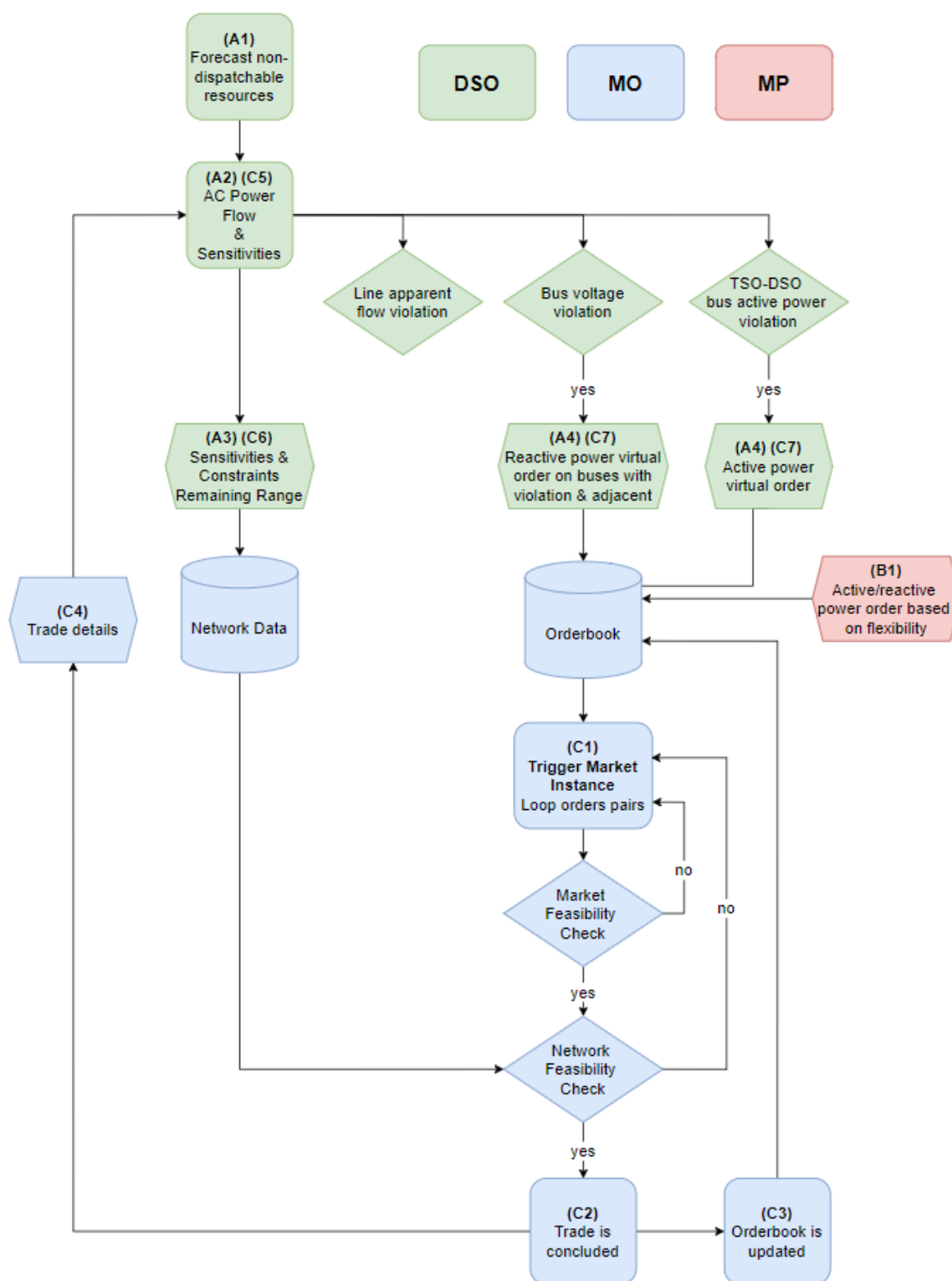
When a new order is submitted the market platform checks all order combinations that can lead to trades based on a prioritization principle as described in C1. A concluded trade leads to an update of the market schedule of the relevant MP assets. Orders can be matched upon two conditions:

(a) Financial feasibility: Two orders can be matched only if they abide the financial rule that a buy order can be matched with a sell order only when the buy order price is higher or equal than the sell order price.

(b) Network feasibility: A buy and sell order can be matched only when their trade would lead to a relief of existing network violations, without creating any new ones. The MO receives from the DSO the necessary network data to perform the network feasibility check.

## **3.2.2 Market Structure**

The market design principles are visualized in the business process flow of Figure 36.



**Figure 36** Flow of the market business process

The basic process flow is defined as the market instance and includes the steps C1, C2, ..., C7. A market instance is triggered when an order is submitted to the orderbook either by the DSO or a MP and is terminated when all the orders of the orderbook have been checked and no more trades can be concluded or when no violation exists. Within a market instance multiple trades can be concluded. A new market instance for the same MTU can be initiated only when the previous one has been concluded. Orders that are submitted while a market instance is active, wait in a queue and enter the orderbook

only when the active market instance is complete. In an actual IT implementation of the proposed business process, we don't expect the market flow to be noticeably disturbed since a market instance can run very fast due the proposed implementation (use of AC sensitivities, no optimization etc.).

The process steps *A1*, ..., *A4* are the DSO actions that can trigger the market instance.

- A1. The DSO performs forecast for the non-dispatchable assets of the distribution grid.
- A2. The DSO runs an AC power flow and calculates the AC sensitivities of the grid state variables with respect to the nodal active and reactive bus power injections. The computation of the AC sensitivities is presented in Section 3.3.1.
- A3. The DSO sends grid data to the MO. Due to constitutional limitations the proposed market design restricts the necessary data that the MO requires to operate the market:
  - a) AC Sensitivities
  - b) Remaining available margin of the grid operational limits. In case of violation the remaining available margin has a negative value.
- A4. The DSO checks if there are any violations and submits the relevant virtual orders in the orderbook based on the analysis of Section 3.3.1.

The process step *B1* includes the MP actions that can trigger the market instance.

- B1. While the trading MTU gate is open, MPs can submit active/reactive power orders based on their available flexibility.

The process steps *C1*, *C2*, ..., *C7* show the evolution of a market instance.

- C1. A market instance is triggered when an order is submitted by a MP or when the DSO performs a new forecast. The orderbook is sorted based on bid/ask price first, and then on order timestamp. All combinations are checked for matching, starting by checking the orders with the lower sell price and the higher buy price. In case of two orders with the same price and direction, the one with the older timestamp is evaluated first.

When two orders are checked, the first check is the financial feasibility check which comprises essentially the following rules:

- a) Only orders of different direction can be matched, i.e. a sell with a buy order.
- b) Only orders of the same power type can be matched, i.e. a sell active power order with a buy active power order.
- c) Active power orders can be matched in different locations, while reactive power orders can be matched only if they are located in the same bus.
- d) A DSO reactive power order can be matched only with a MP reactive power order and vice versa.
- e) A DSO active power order can be matched only with a MP active power order.
- f) A MP active power order can be matched with either a DSO virtual active power order or a MP active power order.
- g) A buy order can be matched with a sell order only when the buy order price is higher than or equal to the sell order price.

The network feasibility check uses the network data that the MO received by the DSO, to check if the pair of orders that has passed the financial feasibility check can conclude to a trade. The network feasibility checks if the order pair can alleviate or resolve existing violations, without creating new ones. The proposed network feasibility implementation provides the functionality of partial matching of bids which is crucial for the proper functioning of the continuous market and is presented in detail in Section 3.3.2.

- C2. A trade is concluded when a pair of orders passes both the financial and network feasibility checks. The trade is cleared at a single price, which is the price of the order that was first submitted (either the sell or buy order). The relevant MPs are informed about their updated market schedule and are compensated with the trade clearing price.
- C3. When a trade is concluded the orderbook is updated. Traded volumes exit the orderbook. If an order has been partially traded, the remaining volume will still be available on the trading platform.



- C4. The MO sends the updated market schedules to the DSO.
- C5. Since a trade is essentially a change in the grid operating point, the DSO runs again an AC power flow for the affected MTU.
- C6. The DSO re-submits the grid data to the MO.
- C7. The DSO re-submits orders in the orderbook based on the updated violation status (older DSO orders are previously deleted from the orderbook).

### 3.2.3 Products

The following orders are traded in order to efficiently provide market solutions to technical problems of the distribution grid:

*MPs active/reactive power orders:* MPs submit the available active/reactive flexibility of their assets in the form of buy or sell active/reactive power orders. The order price is defined by the bidding strategy employed by the MP. The orders are traded within the trading platform to solve anticipated network constraint violations. Due to the network physics, active power orders are most likely to relieve grid congestions or TSO-DSO bus active power violations, while reactive power orders are most likely to relieve bus voltage violations.

*DSO active and reactive power virtual orders:* The DSO does not own any assets in the grid, therefore he submits virtual orders. Virtual orders are orders which can be matched only with MP orders and the relevant violation is essentially alleviated only by the physical deployment of the MP order. Virtual orders are DSO signals about the presence of a violation and the need for flexibility. The DSO virtual orders can be submitted as price taking orders (price cap for buy orders and price floor for sell orders) or as competitive orders based on the DSO's available means for recovering the transaction costs.

Orders by the DSO and the MPs are submitted in a standardized format, which must indicate type, direction, location (network bus), MTU for physical delivery, quantity, price and are given a timestamp upon submission. Thus, a typical order is expressed by:

$$O(d,n,mtu,q,p,t)$$

$d$ : Order direction (sell/buy)

$n$ : Order bus location

$mtu$ : MTU for which the order is submitted

$q$ : Order quantity (MW for active, MVar for reactive orders)

$p$ : Order price in (€/MW or €/MVar)

$t$ : Order submission timestamp (generated by the platform)

## 3.3 Market Clearing Modelling

### 3.3.1 Mathematical Formulation of the Market Clearing Process

The complex physical laws that describe the operation of powers systems dictate that the voltage magnitude on each node, and the apparent power flow on each line, depends on the active and reactive power injections on all the nodes of the network. Trades executed in the proposed market cause changes in the injections of active or reactive power on the nodes the offers are located, which in turn cause changes in the nodal voltage magnitudes and the apparent line flows.

The effect of the change of injection of active or reactive power of each node on the nodal voltage of each bus and the apparent line flows needs to be quantified, to ensure that the trade contributes to relieving existing violations and does not cause any additional violations of the network's constraints. Moreover, due to the continuous nature of the proposed market, this quantification must be done in a fast and efficient way. To this end the proposed LFM uses AC sensitivities.

The sensitivities of the grid's state variables with respect to nodal active and reactive power injection are calculated for a specific operating point of the distribution grid (i.e. the exact relationship is approximated via a linearization that is performed around the network's initial operating point). Therefore, since the sensitivities are dependent on the network's operating point, they need to be recalculated every time the operating conditions of the distribution system change (e.g. due to more recent forecasts, or to trades being matched). Additionally, the accuracy of the AC sensitivities in calculating the updated network state deteriorates if there is significant deviation between the initial operating point, and the final operating point, that can be caused if the injections of the assets change significantly (i.e. large quantities of energy are being exchanged). In any case, the aforementioned limitation is not expected to have adverse effects on the operation of the proposed LFM, since the capacity of the assets connected in the distribution network is up to 10 MW [34], consequently the submitted flexibility orders should be expected to have a quantity of a few MWh, at maximum, considering the ramping capabilities of the assets and the duration of the LFM's MTUs. For reference, in a study utilizing AC sensitivities for allocating power transactions in a TSO-level market [35], the maximum error in line flows for a  $\pm 50$  MWh difference in injections between the initial and the final states (which is far greater than what should be expected in a distribution network) was only 0.98 MWh.

The calculation of the AC sensitivities of line apparent power flow and bus voltage magnitude changes with respect to the bus active and reactive power changes is presented below:

For the analysis we assume a network with  $N$  buses and  $M$  lines, where  $\Delta P, \Delta Q, \Delta \theta$  and  $\Delta U$  are the  $N \times 1$  vectors expressing the delta change of bus active and reactive power, voltage angle and magnitude and  $\Delta S$  is the  $M \times 1$  vector expressing the delta change of line apparent flow. The proposed LFM uses the following sensitivity relationships:

$$\Delta U = K_{U,P} \Delta P \quad (3-1)$$

$$\Delta U = K_{U,Q} \Delta Q \quad (3-2)$$

$$\Delta S = K_{S,P} \Delta P \quad (3-3)$$

$$\Delta S = K_{S,Q} \Delta Q \quad (3-4)$$

where  $K_{U,P}$  and  $K_{U,Q}$  are the  $N \times N$  sensitivity matrices of the bus voltage magnitude with respect to the bus active and reactive power respectively, and  $K_{S,P}$  and  $K_{S,Q}$  are the  $M \times N$  sensitivity matrices of the line apparent flow with respect to the bus active and reactive power respectively. It is noted the apparent flow sensitivities are calculated for both the sending and the receiving ends of each line.

In the proposed LFM  $\Delta P, \Delta Q, \Delta \theta, \Delta U$  and  $\Delta S$  express the differences between two networks states: the initial (known) network state before a trade is concluded, and the final (unknown) network state to check if the trade can be concluded. The LFM is a continuous mechanism where only two orders are checked at a time for a potential match. Therefore, in equations (3-1)–(3-4), only two of the elements of either  $\Delta P$  or  $\Delta Q$  are nonzero for each check, which correspond to the nodes where the assets of the orders under consideration lie. If only active power orders are checked, all elements of  $\Delta Q$  are zero, and vice versa. For the calculation of the sensitivity matrices the TSO-DSO connection bus is used as a slack bus and will absorb any changes in losses.

### **Sensitivities of Nodal Voltage Magnitude with respect to active and reactive nodal power injections**

The steady-state operation of a power system is described by a well-documented system of non-linear power equations, consisting of Kirchhoff's laws and power conservation [26]. A delta change of the network setpoint is expressed by:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = J \begin{bmatrix} \Delta \theta \\ \Delta U \end{bmatrix} \quad (3-5)$$

where  $J$  is the  $2N \times 2N$  Jacobian matrix. Multiplying (3-5) with the inverse Jacobian matrix, it becomes:

$$\begin{bmatrix} \Delta \theta \\ \Delta U \end{bmatrix} = J^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \quad (3-6)$$

where the inverse Jacobian matrix  $J^{-1}$  is equal to:

$$J^{-1} = \begin{bmatrix} \frac{\partial \theta_1}{\partial P_1} & \frac{\partial \theta_1}{\partial P_2} & \dots & \frac{\partial \theta_1}{\partial P_N} & \frac{\partial \theta_1}{\partial Q_1} & \frac{\partial \theta_1}{\partial Q_2} & \dots & \frac{\partial \theta_1}{\partial Q_N} \\ \dots & \dots & \dots & \dots & \dots & \dots & \dots & \dots \\ \frac{\partial \theta_N}{\partial P_1} & \frac{\partial \theta_N}{\partial P_2} & \dots & \frac{\partial \theta_N}{\partial P_N} & \frac{\partial \theta_N}{\partial Q_1} & \frac{\partial \theta_N}{\partial Q_2} & \dots & \frac{\partial \theta_N}{\partial Q_N} \\ \frac{\partial U_1}{\partial P_1} & \frac{\partial U_1}{\partial P_2} & \dots & \frac{\partial U_1}{\partial P_N} & \frac{\partial U_1}{\partial Q_1} & \frac{\partial U_1}{\partial Q_2} & \dots & \frac{\partial U_1}{\partial Q_N} \\ \dots & \dots & \dots & \dots & \dots & \dots & \dots & \dots \\ \frac{\partial U_N}{\partial P_1} & \frac{\partial U_N}{\partial P_2} & \dots & \frac{\partial U_N}{\partial P_N} & \frac{\partial U_N}{\partial Q_1} & \frac{\partial U_N}{\partial Q_2} & \dots & \frac{\partial U_N}{\partial Q_N} \end{bmatrix} \quad (3-7)$$

Equation (3-6) expresses the sensitivity of nodal voltage magnitude and angle with respect to changes of injections of active reactive power in all the nodes of the distribution system. The sensitivities of the nodal voltage magnitude with respect to changes of injections of active or reactive power in all the nodes of the distribution system  $K_{U,P}$  and  $K_{U,Q}$  are derived from (3-7) as:

$$K_{U,P} = \begin{bmatrix} \frac{\partial U_1}{\partial P_1} & \frac{\partial U_1}{\partial P_2} & \dots & \frac{\partial U_1}{\partial P_N} \\ \dots & \dots & \dots & \dots \\ \frac{\partial U_N}{\partial P_1} & \frac{\partial U_N}{\partial P_2} & \dots & \frac{\partial U_N}{\partial P_N} \end{bmatrix} \quad (3-8)$$

$$K_{U,Q} = \begin{bmatrix} \frac{\partial U_1}{\partial Q_1} & \frac{\partial U_1}{\partial Q_2} & \dots & \frac{\partial U_1}{\partial Q_N} \\ \dots & \dots & \dots & \dots \\ \frac{\partial U_N}{\partial Q_1} & \frac{\partial U_N}{\partial Q_2} & \dots & \frac{\partial U_N}{\partial Q_N} \end{bmatrix} \quad (3-9)$$

### Sensitivities of Line Apparent Power with respect to active and reactive nodal power injections

In order to calculate the sensitivity of apparent power flow changes with regards to changes in nodal active and reactive power injections, we first draw from the expressions of the active ( $P_{ij}$ ) and reactive ( $Q_{ij}$ ) power line flows, which for a line starting at node  $i$  and ending at node  $j$ , measured at  $i$ , are equal to:

$$P_{ij} = U_i^2(g_{ij} + g_{ij}^s) - U_i U_j (g_{ij} \cos \theta_{ij} + b_{ij} \sin \theta_{ij}) \quad (3-10)$$

$$Q_{ij} = -U_i^2(b_{ij} + b_{ij}^s) - U_i U_j (g_{ij} \sin \theta_{ij} - b_{ij} \cos \theta_{ij}) \quad (3-11)$$

where  $g_{ij}$  and  $b_{ij}$  are the line conductance and susceptance,  $g_{ij}^s$  and  $b_{ij}^s$  are the line shunt conductance and susceptance, and  $\theta_{ij}$  is the difference between the start bus and bus voltage angles and  $U_{ij}$  are voltage magnitudes of nodes  $i$  and  $j$  respectively. We then calculate the sensitivities of the line apparent flow  $S_{ij}$  with respect to changes in voltages magnitude and angles as:

$$\frac{\partial S_{ij}}{\partial U_n} = \frac{\partial \sqrt{(P_{ij}^2 + Q_{ij}^2)}}{\partial U_n} \quad (3-12)$$

$$\frac{\partial S_{ij}}{\partial \theta_n} = \frac{\partial \sqrt{(P_{ij}^2 + Q_{ij}^2)}}{\partial \theta_n} \quad (3-13)$$

where  $n$  is either one of the starting node  $i$  or ending at node  $j$ . From (3-12) and (3-13), the  $M \times 1$  vector of sensitivities for the changes of line apparent flows,  $\Delta S$ , with respect to changes in voltages and angles is:

$$\Delta S = J_s \begin{bmatrix} \Delta \theta \\ \Delta U \end{bmatrix} \quad (3-14)$$

where  $J_s$  is the  $M \times 2N$  matrix equal to:

$$J_S = \begin{bmatrix} \frac{\partial S_1}{\partial \theta_1} & \frac{\partial S_1}{\partial \theta_2} & \cdots & \frac{\partial S_1}{\partial \theta_N} & \frac{\partial S_1}{\partial U_1} & \frac{\partial S_1}{\partial U_2} & \cdots & \frac{\partial S_1}{\partial U_N} \\ \frac{\partial S_2}{\partial \theta_1} & \frac{\partial S_2}{\partial \theta_2} & \cdots & \frac{\partial S_2}{\partial \theta_N} & \frac{\partial S_2}{\partial U_1} & \frac{\partial S_2}{\partial U_2} & \cdots & \frac{\partial S_2}{\partial U_N} \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial S_M}{\partial \theta_1} & \frac{\partial S_M}{\partial \theta_2} & \cdots & \frac{\partial S_M}{\partial \theta_N} & \frac{\partial S_M}{\partial U_1} & \frac{\partial S_M}{\partial U_2} & \cdots & \frac{\partial S_M}{\partial U_N} \end{bmatrix} \quad (3-15)$$

It is noted that based on (3-8) only four elements of each row have non-zero values.

Combining (3-6) and (3-14), we obtain the sensitivity of line apparent with respect to bus active and reactive power injections:

$$\Delta S = J_S J^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \quad (3-16)$$

where:

$$J_S J^{-1} = \begin{bmatrix} \frac{\partial S_1}{\partial P_1} & \frac{\partial S_1}{\partial P_2} & \cdots & \frac{\partial S_1}{\partial P_N} & \frac{\partial S_1}{\partial Q_1} & \frac{\partial S_1}{\partial Q_2} & \cdots & \frac{\partial S_1}{\partial Q_N} \\ \frac{\partial S_2}{\partial P_1} & \frac{\partial S_2}{\partial P_2} & \cdots & \frac{\partial S_2}{\partial P_N} & \frac{\partial S_2}{\partial Q_1} & \frac{\partial S_2}{\partial Q_2} & \cdots & \frac{\partial S_2}{\partial Q_N} \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial S_M}{\partial P_1} & \frac{\partial S_M}{\partial P_2} & \cdots & \frac{\partial S_M}{\partial P_N} & \frac{\partial S_M}{\partial Q_1} & \frac{\partial S_M}{\partial Q_2} & \cdots & \frac{\partial S_M}{\partial Q_N} \end{bmatrix} \quad (3-17)$$

The sensitivity matrices of the line apparent flow with respect to bus active and reactive power injection and  $K_{S,P}$  and  $K_{S,Q}$  are derived from (3-17) as:

$$K_{S,P} = \begin{bmatrix} \frac{\partial S_1}{\partial P_1} & \frac{\partial S_1}{\partial P_2} & \cdots & \frac{\partial S_1}{\partial P_N} \\ \frac{\partial S_2}{\partial P_1} & \frac{\partial S_2}{\partial P_2} & \cdots & \frac{\partial S_2}{\partial P_N} \\ \vdots & \vdots & \ddots & \vdots \\ \frac{\partial S_M}{\partial P_1} & \frac{\partial S_M}{\partial P_2} & \cdots & \frac{\partial S_M}{\partial P_N} \end{bmatrix} \quad (3-18)$$

$$K_{S,Q} = \begin{bmatrix} \frac{\partial S_1}{\partial Q_1} & \frac{\partial S_1}{\partial Q_2} & \cdots & \frac{\partial S_1}{\partial Q_N} \\ \frac{\partial S_2}{\partial Q_1} & \frac{\partial S_2}{\partial Q_2} & \cdots & \frac{\partial S_2}{\partial Q_N} \\ \vdots & \vdots & \ddots & \vdots \\ \frac{\partial S_M}{\partial Q_1} & \frac{\partial S_M}{\partial Q_2} & \cdots & \frac{\partial S_M}{\partial Q_N} \end{bmatrix} \quad (3-19)$$

It is again noted that  $K_{S,P}$  and  $K_{S,Q}$  need to be calculated for both ends of each line.

### 3.3.2 Solution Methodology

The objective of the LFM is to clear the maximum order quantity to alleviate or eliminate existing violations, without causing violations in other parts of the network. The LFM essentially allows for partial order execution, instead of an all-or-none approach, which increases the liquidity of the market.

The analysis below considers a potential trade between two MPs active power orders, but the rationale for reactive power orders is the same. Assume a buy and sell active power order, submitted in busses  $b$  and  $s$ , respectively. The effect of a potential trade to the network operational constraints, based on (3-1)–(3-4) is expressed as:

$$\Delta S_m = K_{S,P}^{b,m} * \Delta P_b + K_{S,P}^{s,m} * \Delta P_s \quad \forall m \text{ in } M \quad (3-20)$$

$$\Delta U_n = K_{U,P}^{b,n} * \Delta P_b + K_{U,P}^{s,n} * \Delta P_s \quad \forall n \text{ in } N \quad (3-21)$$

where  $\Delta S_m$  is the change in the line apparent flow of line  $l$ ,  $\Delta U_n$  is the change in bus voltage magnitude of bus  $n$ ,  $K_{S,P}^{b,m}$ ,  $K_{S,P}^{s,m}$ ,  $K_{U,P}^{b,n}$ ,  $K_{U,P}^{s,n}$  are the sensitivity matrices' elements from (3-8), (3-18), (3-19), and  $\Delta P_b$  and  $\Delta P_s$  are the order quantities that are executed.

To keep active power and transaction cost balance, the cleared quantities of both orders should match:

$$\Delta P_b = -\Delta P_s \quad (3-22)$$

By defining:

$$K_{S,P}^{diff,m} = K_{S,P}^{b,m} - K_{S,P}^{s,m} \quad (3-23)$$

$$K_{U,P}^{diff,m} = K_{U,P}^{b,m} - K_{U,P}^{s,m} \quad (3-24)$$

Equations (3-20) and (3-21) can be written as:

$$\Delta S_m = K_{S,P}^{diff,m} * \Delta P_b \quad \forall m \in M \quad (3-25)$$

$$\Delta U_n = K_{U,P}^{diff,n} * \Delta P_b \quad \forall n \in N \quad (3-26)$$

In the case where a MP and a DSO order are checked, we need to consider that the DSO order is virtual, therefore it does not lead to market schedule change of any asset. This is implemented by zeroing the sensitivity factors  $K_{S,P}^{b(s),m}$  and  $K_{U,P}^{b(s),n}$  that refer to the bus where the DSO order is submitted.

### Check for contribution to solving the violations

A potential trade should be able to reduce or eliminate existing violations. It is possible that a potential trade can resolve a violation in one part of the network but deteriorate a violation in another part of the network. Therefore, the adopted criterion for the network feasibility check is that the net impact on the violations is positive, i.e. the total improvement is greater than the total deterioration.

The measure used for the evaluation of the (positive/ negative) impact of the trade in each violation is the pu change of the “distance” of each violation from the network limits. In case of voltage and thermal limits violations, the “distance” from a network limit is the difference between the maximum/minimum quantity imposed by the limits and the respective current network values. In case of deviation in the TSO-DSO schedules the “distance” is the difference between the agreed TSO -DSO schedule ( $P_{schedule}$ ) and the current network value  $P_{slack}$ .

For each overloaded line  $m \in M^{viol}$ , we calculate the difference between the apparent power flow limit  $S_m^{max}$ , and the initial line apparent power flow,  $S_m^{init}$ , and the difference between the thermal limit of line  $m$ ,  $S_m^{max}$ , and the line apparent power flow after the potential trade, which is equal to  $S_m^{init} + \Delta S_m$ . We then express the distance as fractions of a defined base unit quantity,  $S_B$ . Thus, in per unit system, for each line  $m$  the “distance” change ( $Ch_m$ ) is equal to:

$$\begin{aligned} Ch_m &= \frac{abs(S_m^{max} - S_m^{init}) - abs(S_m^{max} - S_m^{init} - \Delta S_m)}{S_B} = \frac{-S_m^{max} + S_m^{init} - (-S_m^{max} + S_m^{init} + \Delta S_m)}{S_B} \\ &= -\frac{\Delta S_m}{S_B}, \forall m \in M^{viol} \end{aligned} \quad (3-27)$$

By replacing (3-25) in (3-27), the aggregate impact of the trade to the congested lines is:

$$Ch_{line} = \sum_{m \in M^{viol}} Ch_m = -\frac{K_{S,P}^{diff,m} * \Delta P_b}{S_B}, \forall m \in M^{viol} \quad (3-28)$$

(3-28) is calculated for both the sending and the receiving end of the lines.

Respectively, and as the network voltages are already expressed in pu, for each bus  $n$  within the set of buses with already detected undervoltages ( $N^{under}$ ) or within the set of buses with already detected overvoltages ( $N^{over}$ ):

$$Ch_n = -K_{U,P}^{diff,n} * \Delta P_b, \forall n \in N^{under} \cup N^{over} \quad (3-29)$$

And the aggregate impact to the bus voltage measures is:

$$Ch_{buses} = \sum_{n \in N^{under} \cup N^{over}} Ch_n \quad (3-30)$$

For the deviations in the TSO-DSO schedules:

$$Ch_{TSO-DSO} = -\frac{\Delta P_b}{S_B} \quad (3-31)$$

Thus, the first criterion -necessary condition for network feasibility needs for the sum:

$$Impact(pu) = Ch_{line} + Ch_{buses} + Ch_{TSO-DSO} \quad (3-32)$$

to be positive.

### Check for violations in other parts of the network

A potential trade should not create violations in parts of the network with no violations. There are two sets of network operational constraints that are checked: (a) thermal apparent flow limits of lines and (b) bus voltage magnitude limits.

A potential trade should not cause violations of the line apparent power limits of non-congested lines, thus must respect:

$$S_m^{init} + \Delta S_m \leq S_m^{max} \quad \forall m \in \{M - M^{viol}\} \quad (3-33)$$

here  $S_m^{max}$  is the thermal limit of line  $m$ ,  $S_m^{init}$  is the initial line apparent power flow and  $\Delta S_m$  is the change of the line apparent power flow if the eligible trade is concluded, as calculated by (3-25). Constraint (3-33) applies for all lines  $m$ , apart from the line(s) in  $M^{viol}$  which is the set of lines with already detected violations.

Combining (3-25) and (3-33) the constraints for the maximum accepted order quantity, imposed by the line thermal limits are expressed as:

$$0 \leq S_m^{init} + \Delta P_b * K_{S,P}^{diff,m} \leq S_m^{max} \quad \forall m \in \{M - M^{viol}\} \quad (3-34)$$

In addition the potential trade should not cause violations of the bus voltage magnitude limits of buses without violations, thus respecting:

$$U_n^{min} \leq U_n^{init} + \Delta U_n \leq U_n^{max} \quad \forall n \in \{N - N^{over} - N^{under}\} \quad (3-35)$$

where  $U_n^{min}$  and  $U_n^{max}$  are the minimum and maximum limits of voltage magnitude of bus  $n$ . Constraint (3-35) applies for all buses  $N$ , apart from the buses  $N^{over}$  with already detected overvoltage and the buses  $N^{under}$  with already detected undervoltage.

Combining (3-26) and (3-35), the constraints for the quantity range imposed by the bus voltage limits are expressed as:

$$U_n^{min} - U_n^{init} \leq \Delta P_b * K_{U,P}^{diff,n} \leq U_n^{max} - U_n^{init} \quad \forall n \in \{N - N^{over} - N^{under}\} \quad (3-36)$$

Ultimately, the quantity range of an eligible active power trade, is constrained by the equations sets ((3-34)) and (3-36).

## 3.4 Disturbance generator

### 3.4.1 Concept description

The disturbance generator provides a software tool to replicate the abnormalities that may occur in a real-life distribution network and can be alleviated if the DSO procures flexibility from flexibility service providers (FSPs), under a local flexibility market framework. Due to the fact that this tool will be used for simulation purposes of an Intra-Day local flexibility market framework, we need to simulate abnormalities that exist in steady state and can be forecasted from the operators hours ahead of the real-time operation. Particularly, those abnormalities concern violations in bus voltage limits and thermal loading of lines. According to IEEE:

**Bus Overvoltage/Undervoltage:** Overvoltage is a specific type of long duration variation, refers to a measured voltage having a value greater than the nominal voltage for a period of time greater than 1 min. Typical values are those that exceed the normal operation limits for the DSO, i.e., values greater than 1.05pu. On the other side, by undervoltage we mean that a measured voltage has a value less

than the nominal voltage for a period of time greater than 1 min, when used to describe a specific type of long duration variation. Typical values are those that are below the normal operation limits for the DSO, i.e., values less than 0.95pu.

**Line Congestion:** Congestion takes place when the lines are not sufficient to transfer the power according to market clearing results. The operators, especially the transmission ones, consider that when the line loading exceeds the 75% of the total thermal capacity, there is a high probability of congestion, and thus congestion management measures shall be taken.

Considering the above-mentioned scope and abnormalities that need to be replicated, the disturbance generator is developed using existing open-source software tools. Specifically, we leverage the functionalities of open-source Python Libraries for power system modelling and analysis; Pandapower and Simbench libraries.

- Pandapower: It is an open-source tool for power system modeling, analysis, and optimization with a high degree of automation. In this work, we use it as a foundation to build the network and run the Power Flow (PF),
- Simbench: It is an open-source tool that offers various benchmark datasets for solutions in grid analysis, grid planning and grid operation management covering not only distribution networks but also transmission ones. This dataset is intended to make developments of new methods and solutions independent of non-publicly available individual grid datasets to ensure comparability, transparency as well as transparency of various developments in this field. In this work, the network and used dataset are derived by the Simbench library.

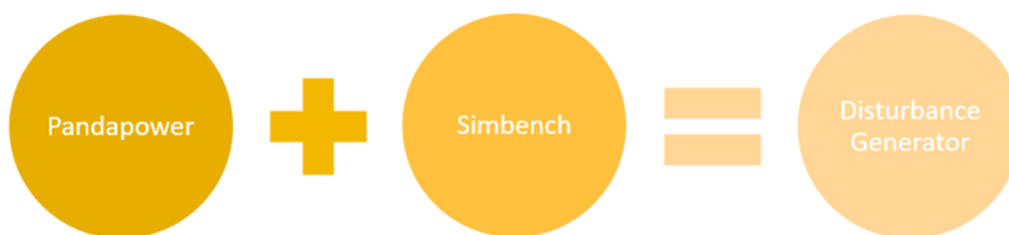
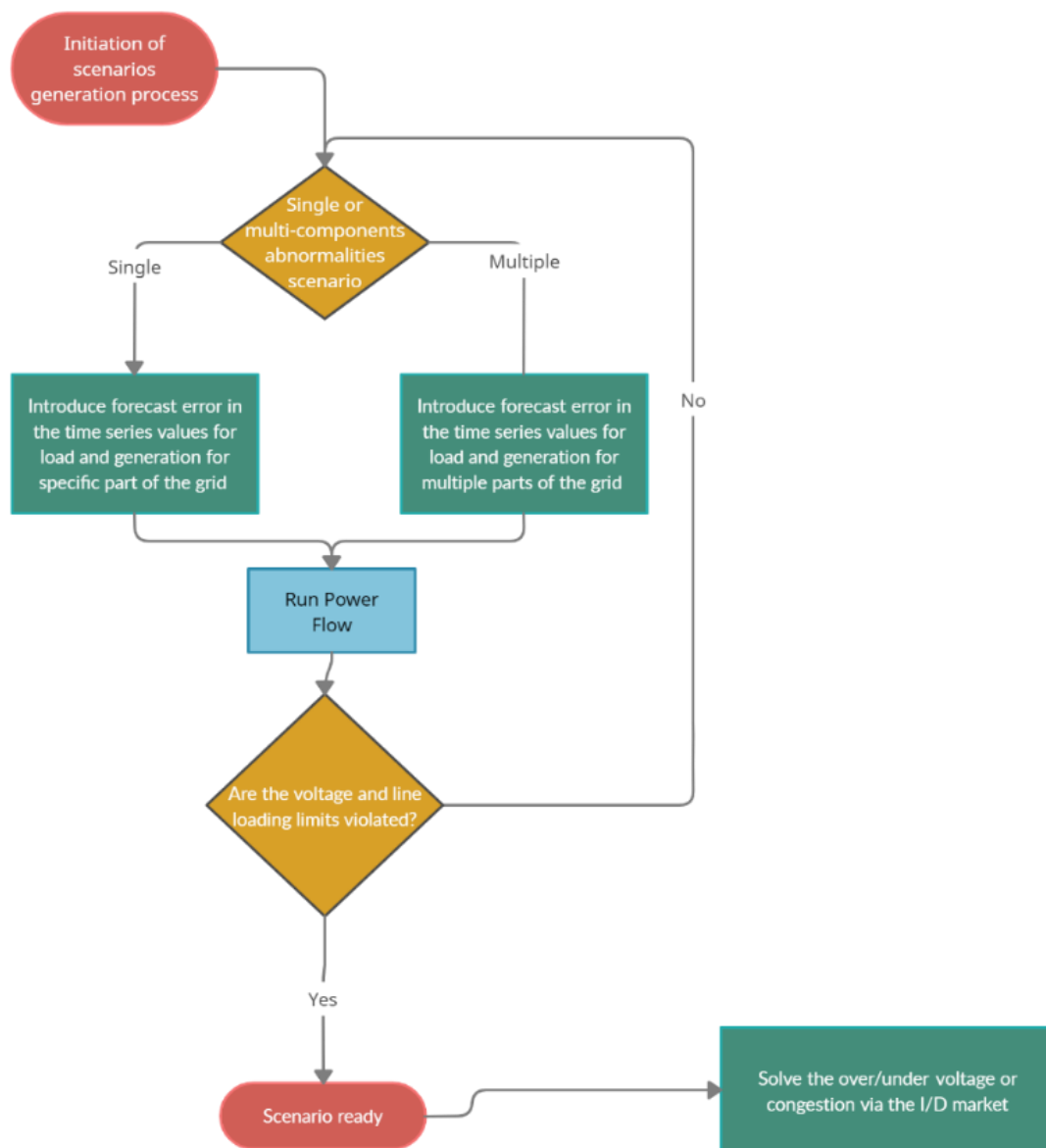


Figure 37: The open-source tools employed for the creation of the disturbance generator

Based on the above functionalities, different disturbance scenarios are simulated, representing voltage violations and congestion issues based on forecasted errors of distributed generation and load consumption, between day-ahead and intra-day predictions.

The methodology followed to generate the disturbance scenarios is depicted in Figure 38.



**Figure 38:** Flow diagram for the disturbance scenarios generation process.

Two different approaches were performed for single and multiple- element abnormalities scenario generation. Specifically:

- For the case that a single component violation scenario generation, the value of loads connected to adjacent buses of the line with the highest loading, is set to zero. Afterwards, power flow simulations are conducted, and the scenario is generated,
- For the case of a multi-component violation scenario generation, forecasting error is introduced in multiple assets of the network (both load and RES generation). The forecasting error value is derived from normal distributions for each load and RES asset with mean value equal to zero and standard deviation deriving directly from a literature review that was conducted regarding the load and generation forecasting error in MV grid assets. The main outcomes were the following ones:

Day-ahead load forecasting: MAPE is less than 10% [36], [37]

Day-ahead PV forecasting: MAPE ranges between 3 to 11% [38]

Hence, several standard deviation values will be explored, trying to replicate as much as possible reality. Due to the fact that we consider a forecasting error in the Intra-day framework, the average



forecasting error will be less than the one in the Day-ahead timeframe, because of the smaller forecasting horizon. In addition to that, due to the close proximity of the assets, the effect of correlation of the forecasting errors is also considered. Hence, different correlation values are used to generate correlated samples for loads and RES forecasting errors, separately.

Based on the above-mentioned methodology, a list of three different disturbance scenarios is created. The table below includes all the information about the specific used disturbance scenarios.

**Table 36: Description of disturbance scenarios**

Scenario ID	Event Name	Number of Components	Description
0	Normal Operation	None	Normal Operation of the network without experiencing any violations.
1a	Single Component	Single	Congestion in a single component violation caused either by either unexpected curtailment of RES, or disconnection of load, or single network component failure.
1b	Single Component	Single	Voltage violation in a single component violation caused either by either unexpected curtailment of RES, or disconnection of load, or single network component failure.
2	Unexpected sunny day	Multiple	Multiple components violation due to the simultaneously increase of the local RES production. An unexpected sunny day implies that the forecasting error between the Day-ahead and Intraday markets of the local production has a high correlation due to the proximity of the RES assets.
3	Unexpected Extreme cold with high heating electrification rate	Multiple	Multiple components violation due to the simultaneously increase of the local load consumption. An unexpected sunny day implies that the forecasting error between the Day-ahead and Intraday markets of the local consumption has a high correlation due to the proximity of the loads connected to the same MV network.

### 3.4.2 Network topologies

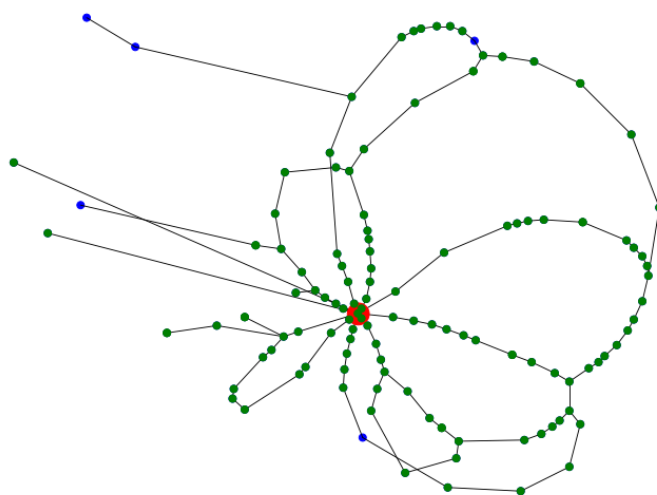
As a benchmark, the MV network topologies included in the below table, are utilized. The first column includes the Network ID, which is used to communicate the topology between the disturbance generator tool and the Intraday market simulator. The second column depicts the nomenclature of the specific network topology, as introduced by Simbench library. The last column includes an extended description of the network topology.

**Table 37: Network topology ID and information.**

Network ID	Simbench ID	Description
0	1-MV-semiurb--2-no_sw	A semi-urban MV network with rated voltage equal to 20kV. In total, there are 122 buses, 126 lines and 112 supply points of RES, i.e., Wind, PV, Biomass and Hydro.

1	1-MV-comm--2-no_sw	A MV network in a commercial area with rated voltage equal to 20kV. In total, 111 buses exist, along with 113 lines, 90 supply points of RES and 106 consumption points.
2	1-MV-urban--2-no_sw	An urban MV network with rated voltage equal to 20kV. In total, 144 buses exist, along with 147 lines, 134 RES supply points, and 139 consumption points.
3	1-MV-rural--2-no_sw	A rural MV network with rated voltage equal to 20kV. In total, 99 buses exist, along with 101 lines, 102 RES supply points, and 96 consumption points.
4	Merging all the above network topologies under a unified connected network	A MV network with 959 buses, 1036 lines, 969 loads, 930 distributed energy resources.

As an example, the Network with id = 0 is presented below. This refers to a semi-urban MV network with rated voltage equal to 20kV. In total, there are 122 buses, 126 lines and 112 supply points of Renewable Energy Sources (RES), i.e., Wind, PV, Biomass and Hydro. The below figure and table illustrate and provide information about the network topology, respectively.



**Figure 39:** Network topology of the used benchmark. With green colour are the buses where RES is installed. The blue ones are buses without RES. The red circle denotes the single point of connection with the transmission system.

**Table 38: Benchmark distribution network specifications<sup>1</sup>.**

SimBench Model ID	Urbanization Character	Rated voltage [kV]	No. supply points	Transformer types	Generation types
1-MV-semiurb-0-sw	semi-urban	20	112	2x40MVA	Wind, PV, Biomass, Hydro

<sup>1</sup> <https://simbench.de/en/download/datasets/>

For the values of the load consumption and RES production, the timeseries dataset provided by Simbench is used. A weekly timespan is considered, with a 15-minute resolution. The figures below illustrate the profiles for both local generation and consumption.

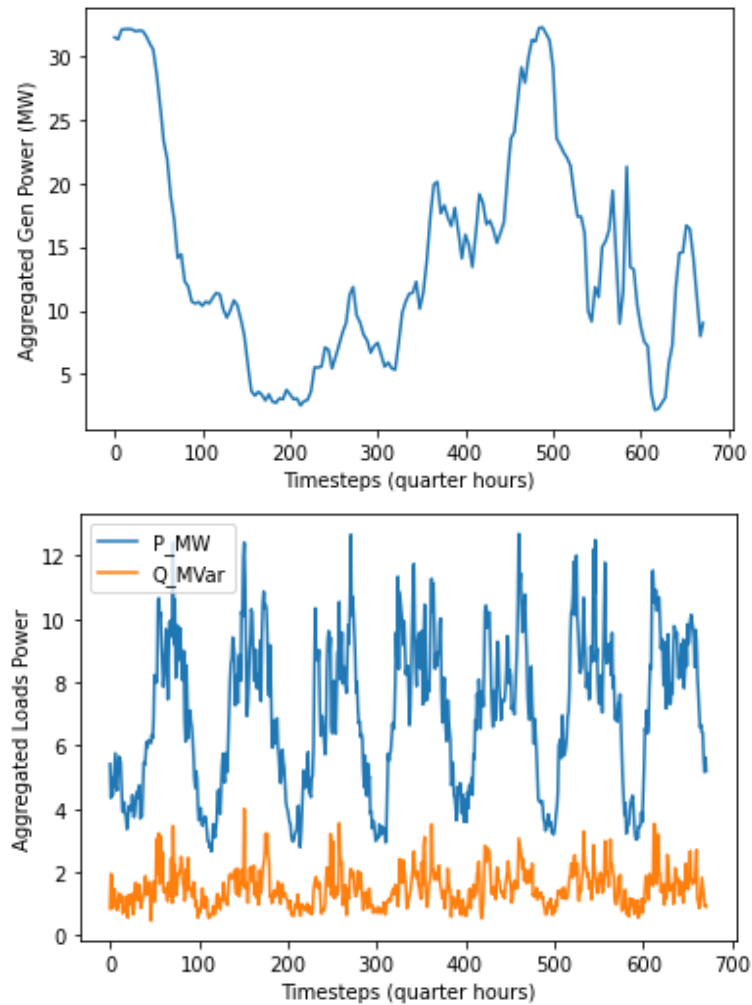
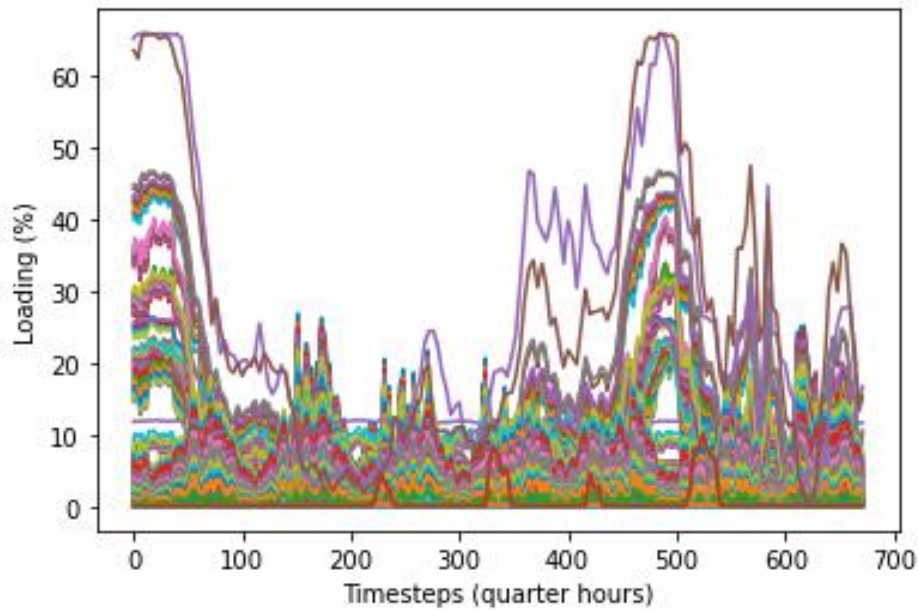
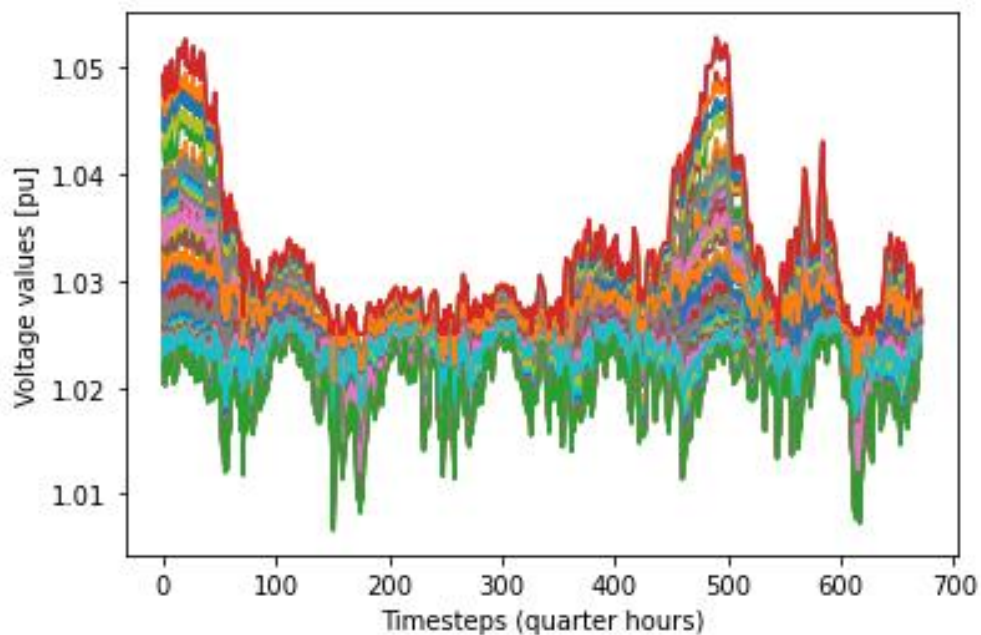


Figure 40: Aggregated local generation (left) and production (right) profile.

Using the functionalities of Pandapower library, a PF for a weekly timespan and 15-minute resolution is executed in order to derive the values of the buses' voltage and lines' loading. The following figures illustrate the results under normal grid operation.



**Figure 41:** Loading of distribution lines under normal grid operation for a weekly timespan. The different colors depict the values for the 126 lines.



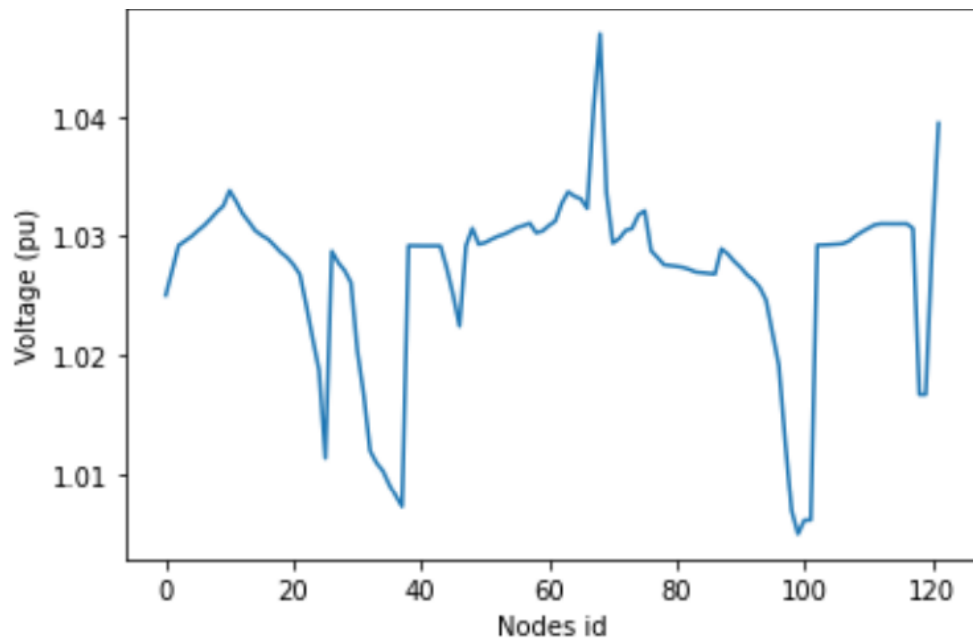
**Figure 42:** Voltage values for the distribution network buses under normal grid operation for a weekly timespan. The different colors depict the values for the 122 buses.

#### 3.4.2.1.1 Examples of disturbance scenarios generation

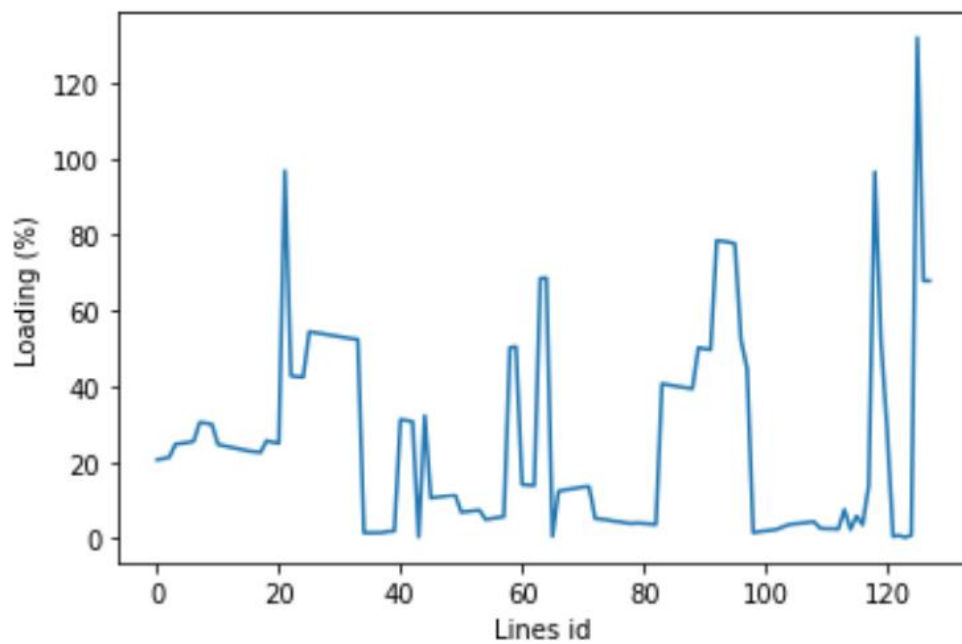
All scenarios presented below are applied to the benchmark network topology with id 0 as presented above. The scenarios are applied to the 20<sup>th</sup> simulated quarter of the day.

##### Scenario 1 – Line overloading

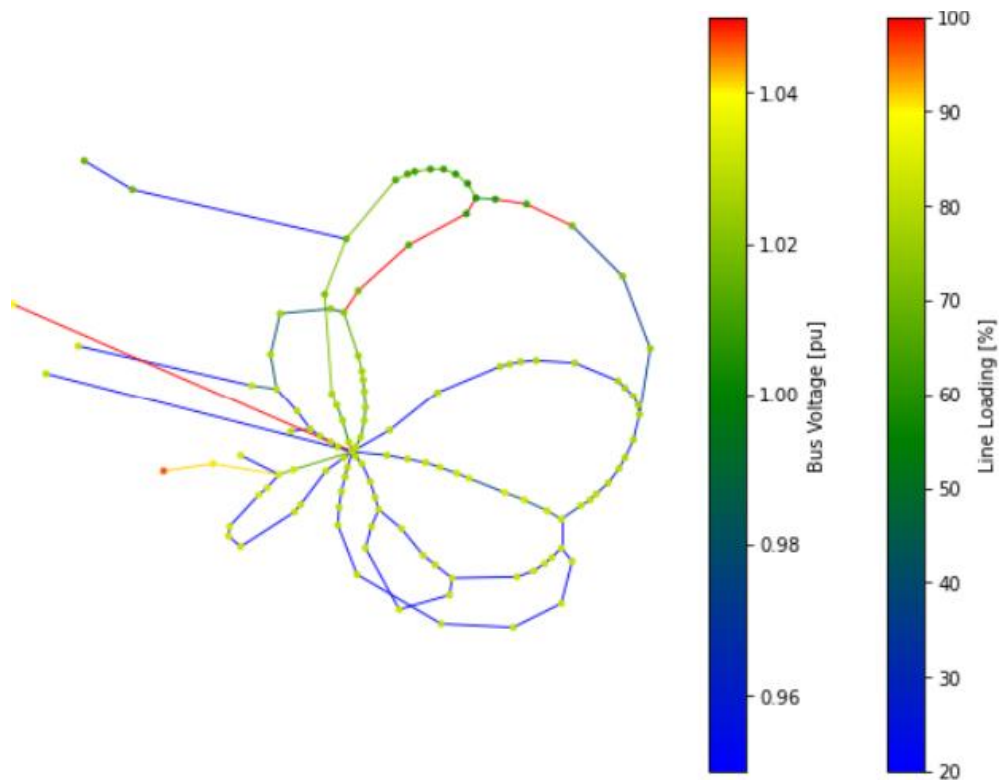
By disconnecting the load connected to the bus with id 121 (the one that is connected solely to the line with id 124), the line loading exceeds the 100% of the thermal limit, as depicted in the following figures.



**Figure 43:** Voltage values for each node for a particular market time unit for scenario 1.



**Figure 44:** Loading for intraday forecast in case of single component violation

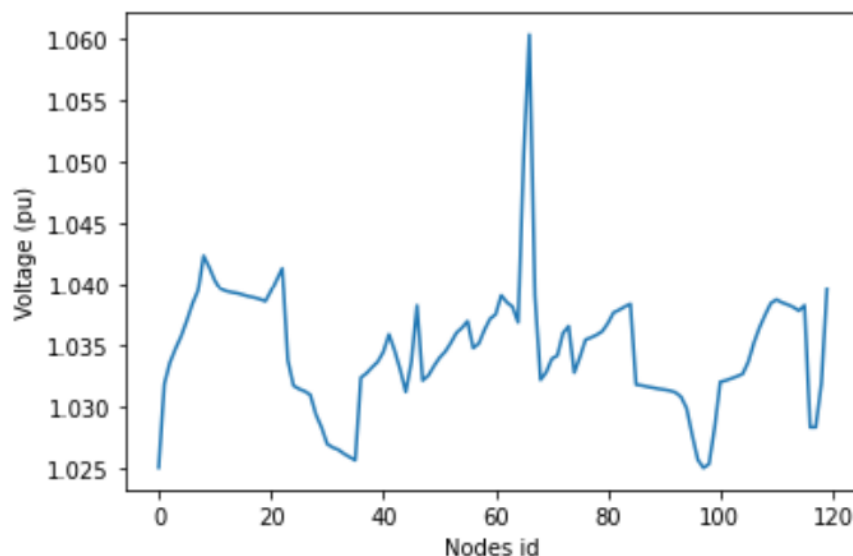


**Figure 45:** Bus Voltage in pu and line loading in percentage for the benchmark model scenario 1. Congested lines are illustrated with the dark red colour

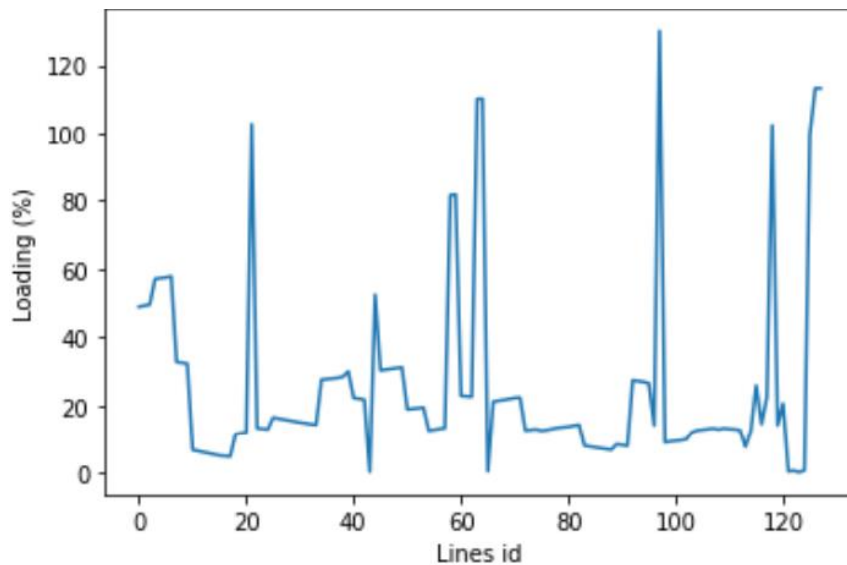
### Scenario 2: Simulation of an unexpected Sunny day

Forecast error of RES: Mean=6 & Standard Deviation=10 & Correlation 0.9

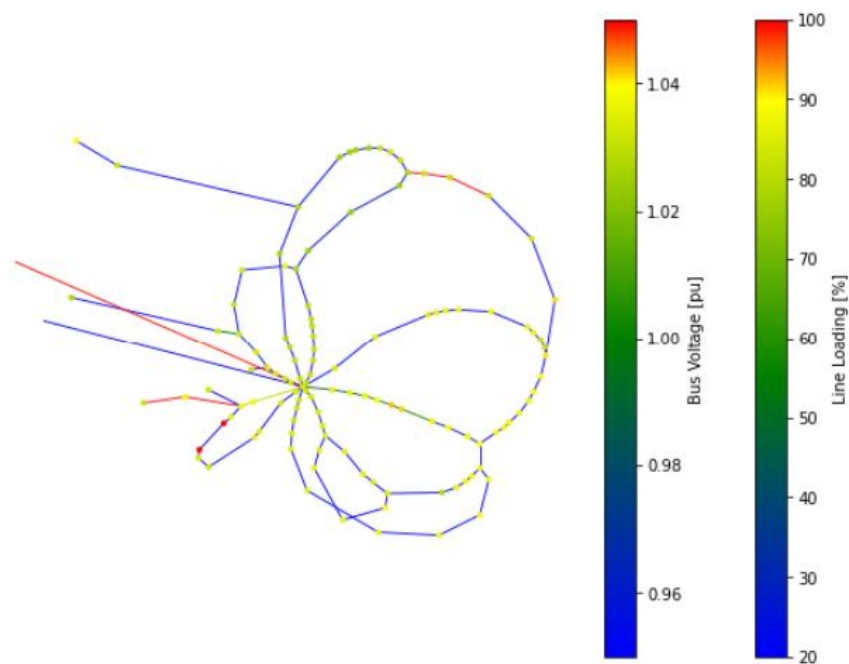
This scenario replicates the under-forecasting of local RES production for all the area, thus there is a high correlation. In real-life application, this could be due to differentiation in intraday weather forecasts, i.e., sunnier than it was expected.



**Figure 46:** Voltage values for each node for a particular market time unit for scenario 2



**Figure 47:** Amperage values (%) in each line for a particular market time unit.

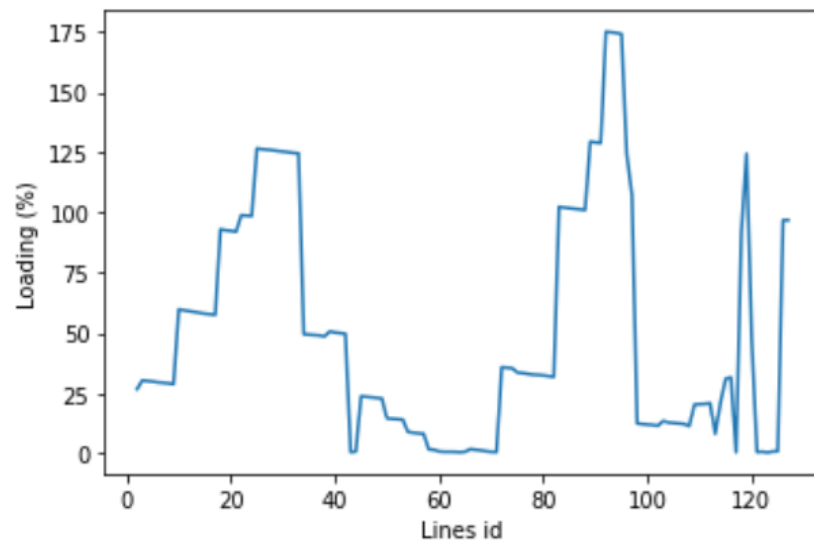


**Figure 48:** Bus Voltage in pu and line loading in percentage for the benchmark model in case of the sunny day scenario for a particular market time unit.

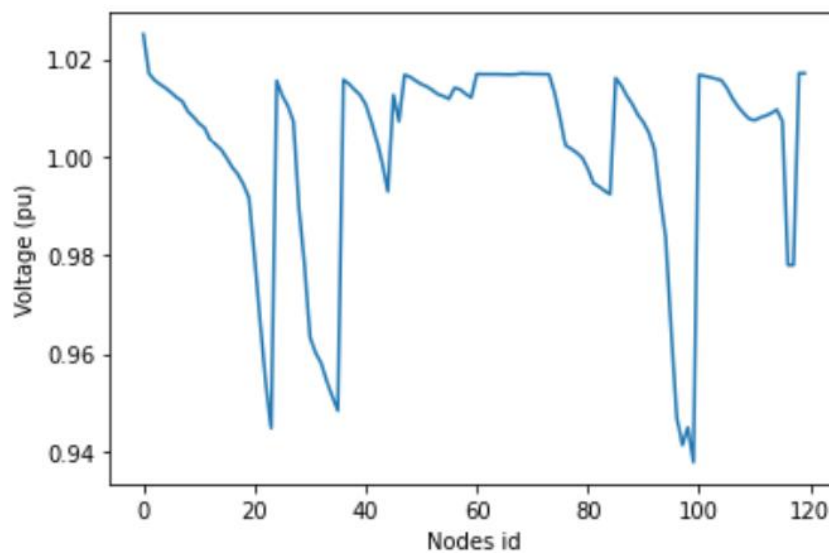
### Scenario 3: Unexpected Extreme Cold Event with high level of Heating electrification

Forecast error of Load: Mean=10 & Correlation =0.9 & Standard Deviation =10

This scenario replicates the under forecasting of local production. In real-life application, this could be due to differentiation in intraday weather forecasts, i.e., extreme unpredicted cold in an area with high heating electrification rate.

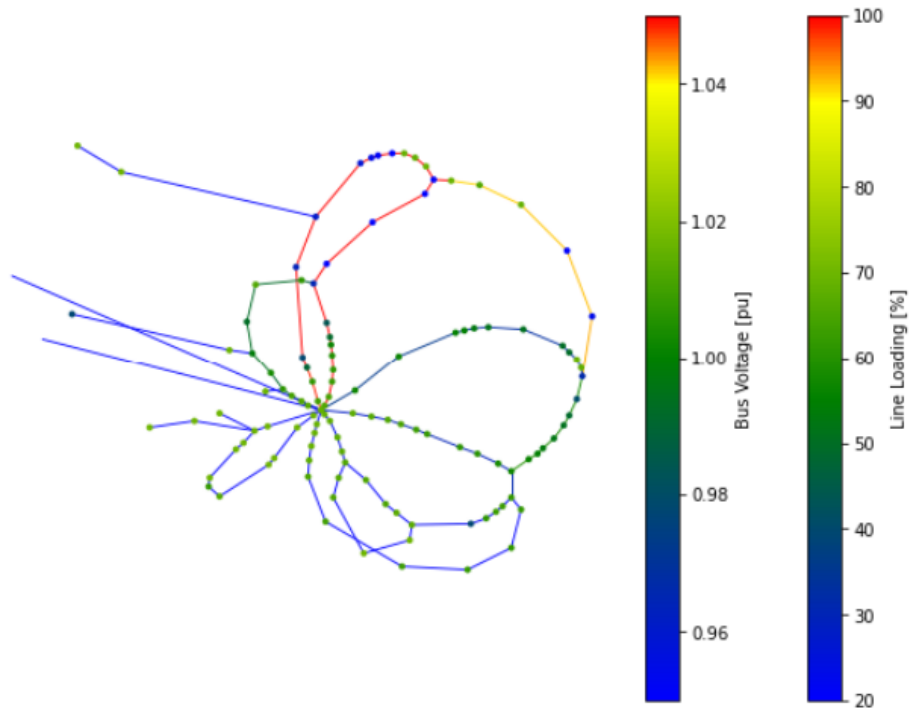


**Figure 49:** Lines Loading for a particular market time unit in case of scenario 3



**Figure 50:** Nodes voltage for a particular market time unit in case of scenario 3





**Figure 51:** Bus Voltage in pu and line loading in percentage for the benchmark model in case of scenario 3.

### 3.5 Intraday Market Application Prototype

#### 3.5.1 Scope

Within the scope of T4.2 a need was identified to create an application with a Graphical User Interface (GUI), facilitating end-user interaction and access to simulation results for the intraday market. The objective of the GUI solution was to:

- Facilitate realization of tests related to intraday market operation
- Act as a prototype for a real-world application
- Minimize interventions to implemented simulation software

A conceptual analysis is presented in the following figure (Figure 52). The initial prototype intraday market developed in WP4, apart from the market execution application was complemented with a power flow simulator and a grid disturbance simulator, enabling testing/validation of the solution. The GUI aims to manage the triggering process of these applications as well as bring all information generated by them to the end-users. Different types of users were envisioned depending on their role in the market, as well as a user type related to the application administration, presented in the next subchapter.

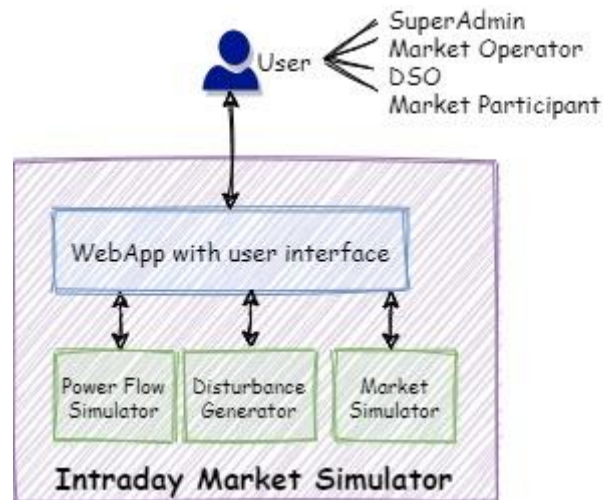


Figure 52 Scope of Intraday Market Application Prototype

### 3.5.2 End-Users' Requirements Analysis

The users of the application and their main operations are presented in

Table 39 below, whilst Figure 53 presents a list of requirements per type of user - elaborated through interactive discussions - where requirements are presented in the form of a user story map [39].

Table 39 Application's User Roles

User Role	Role Description	Main operations
<b>Market Operator</b>	Responsible for the operation of the market. Monitors the operation of the market and can intervene in its operation.	View daily market units with status, View events for market unit, View violations of market unit, View order book of market unit, Add manual order in market unit, modify gate closure of market unit, run Market, set mode of operation (auto/manual), request DSO to solve power flow, Create report,
<b>Distribution System Operator</b>	The main beneficiary of the market operation; identifies possible violation in the grid and communicates them to the market. May also assume the role of the Market Operator.	Create simulation scenario, upload grid model, upload disturbance scenario, run power flow, run disturbance simulation, send violations to market, visualize power flow, visualize disturbance simulation, view history of simulations, view market results or violation.
<b>Market Participant (MP)</b>	Owner of dispatchable assets in the grid; able to participate in the market through buy/sell order for own assets affected by a violation, facilitating its resolution	Receive notification on violation (for own affected assets), View available market time units (based on affected assets), Submit order, Modify Order, Delete Order, View Assets, View Asset market schedule, View order book (own orders).
<b>Admin</b>	A super-user able to access all the functions of other roles. Mostly considered for the parameterisation of the application as well as the testing phase of the project.	All above.

## Deliverable D4.3

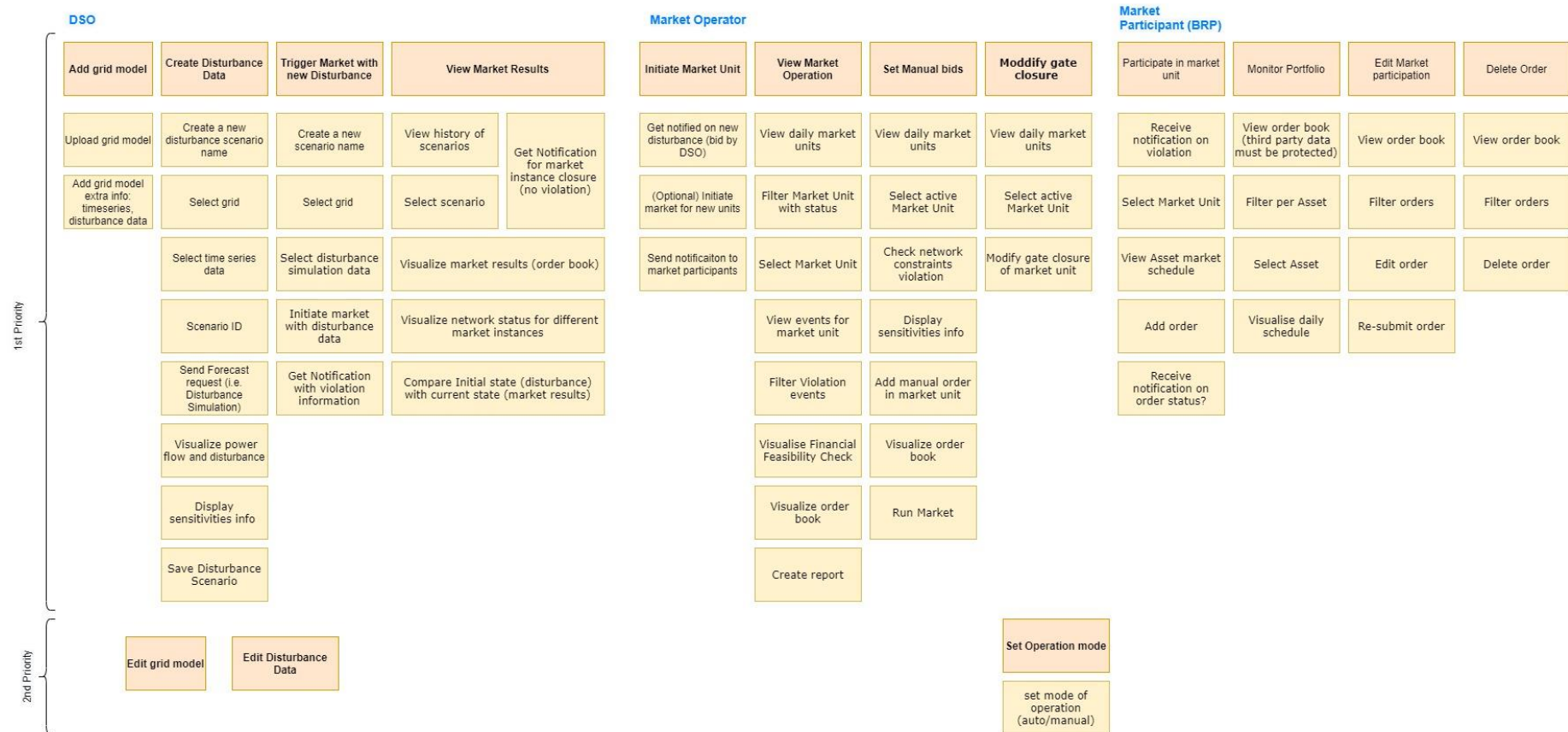


Figure 53 Story Board of Intraday Market Application Prototype

### 3.5.3 Functional View

The functional view of the system defines the system's architecturally significant functional elements, the responsibilities of each, the interfaces they offer and the dependencies between elements.

A component diagram, presenting the main functional elements is presented in Figure 54 and analysed in the next subchapter (3.5.3.1).

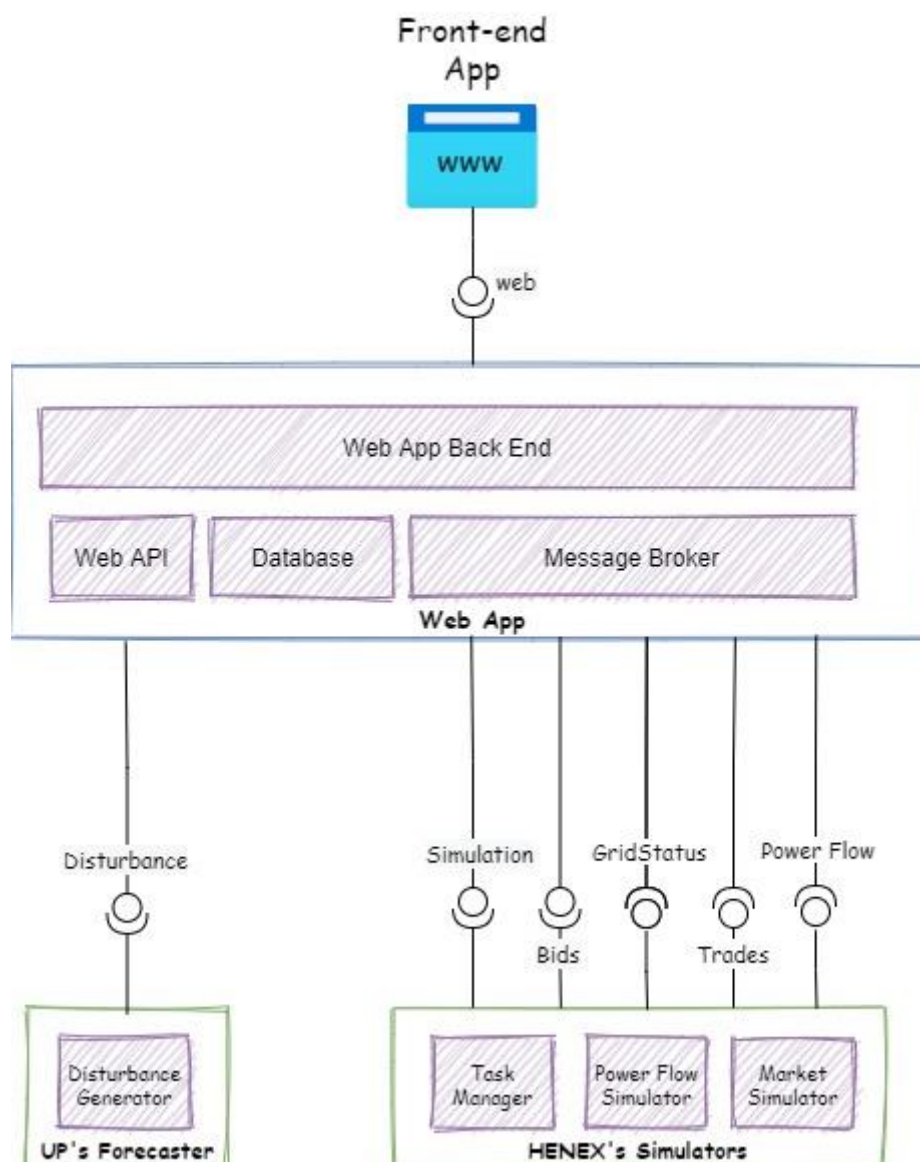


Figure 54 Intraday Market Application Prototype - Component diagram

#### 3.5.3.1 Functional Elements

This section aims to define the responsibilities and interfaces offered by main functional elements (Web App - Table 40, Forecaster - Table 41 and Simulators - Table 42) of the solution.

Table 40 Intraday Market Application Prototype - Web App

Element Name	Web App
Responsibilities	Responsible for providing a GUI to the end user, as well as supporting the realisation of the business processes. Composed

	of a Database for storing data, Web API for REST communications and Message Broker for asynchronous communications.
<b>Interfaces</b>	REST Interface for synchronous requests, Web socket for end-user notification Message queue for asynchronous communications

Table 41 Intraday Market Application Prototype - Forecaster

Element Name	Forecaster
<b>Responsibilities</b>	Enables the creation of Disturbance scenarios, corresponding to realistic event.
<b>Interfaces</b>	Interface for retrieving disturbance scenario data.

Table 42 Intraday Market Application Prototype - Simulators

Element Name	Simulators
<b>Responsibilities</b>	Enable the realisation of the power flow simulation and market operation. A task manager provides the management of the business flow as well as the interactions with the WebApp.
<b>Interfaces</b>	Message queue for asynchronous communications Local file system (for temporary data storage)

### 3.5.3.2 Functional Scenarios

In this section some interaction diagrams are presented to explain how the functional elements interact with each other.

Initially a complete description of the flow in the data flow diagram of Figure 55 is presented. The role assumed by each component is presented based on the market business process of the intraday market analysed in section 3.2.2 (Figure 36).

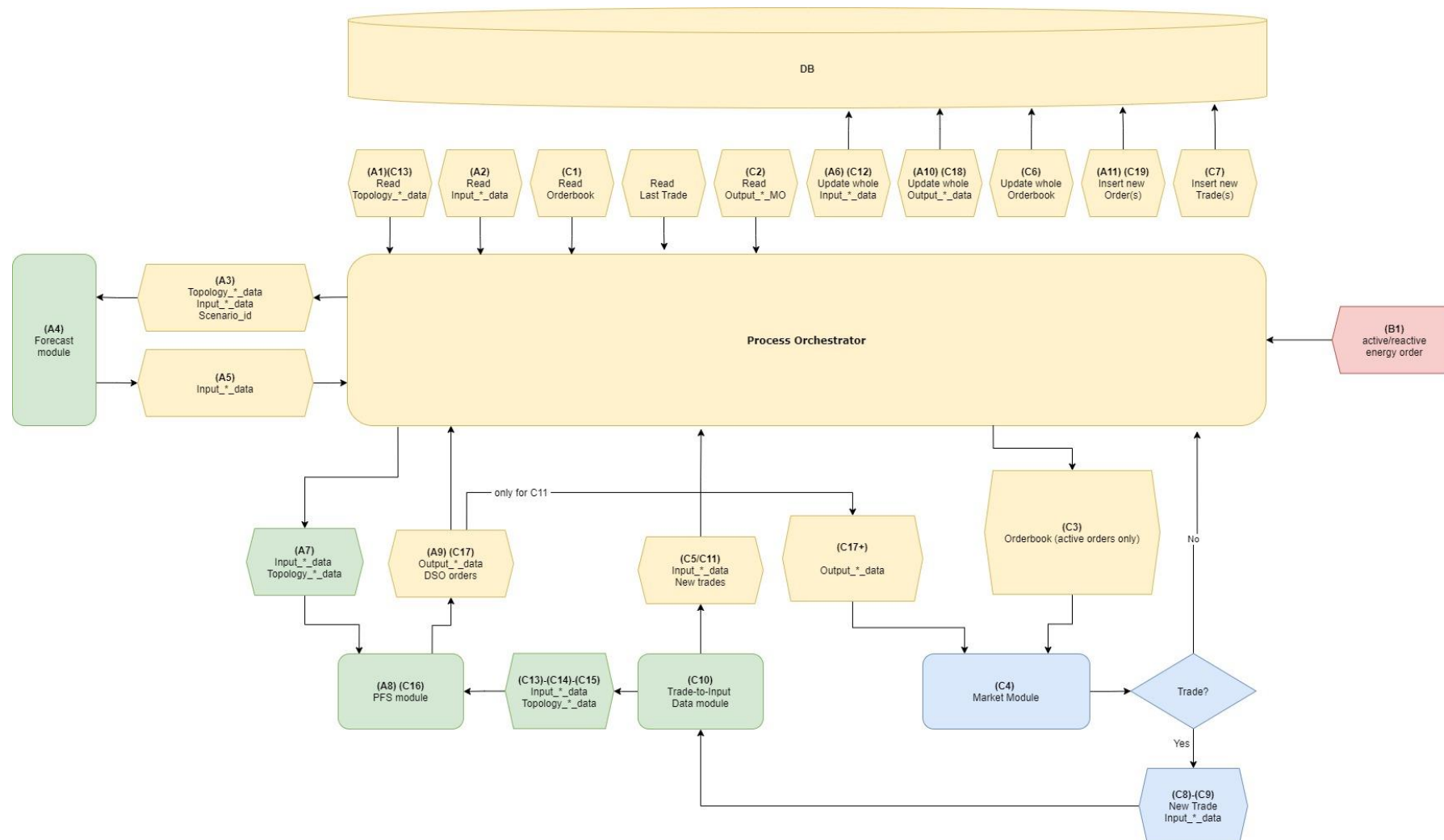


Figure 55 Intraday Market Application Prototype - Business process on a component basis

A high-level view of the market activation process, based on a (simulated) grid disturbance is presented in Figure 56. Initially the user (DSO) can create some disturbance data (e.g. unexpected increase in PV production) for a specific grid topology and generate the corresponding timeseries of grid operation. Then, from the GUI, the user (DSO) can run a power flow analysis for the specific grid topology and disturbance data. The process will check for any violation and in case a problem detection in the grid, a market unit will be automatically instantiated.

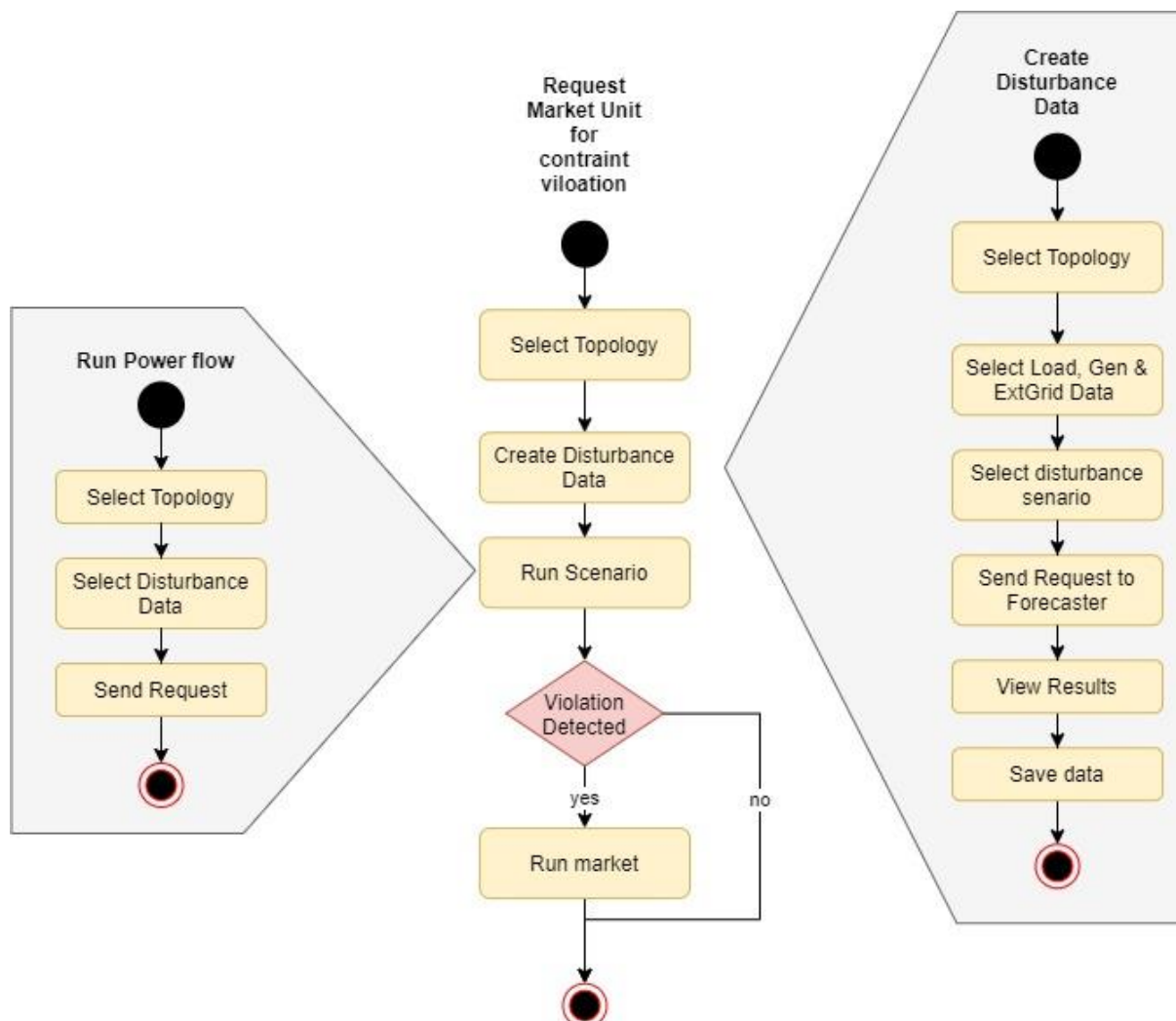


Figure 56 Intraday Market Application Prototype - High Level process diagram

A more granular view of the process related to the GUI application activities related to the market instantiation/operation is presented in Figure 57 and Figure 58. The different steps of the process map to business process of the intraday market analyzed in section 3.2.2.

As presented in Figure 57, initially a request for power flow simulation is issued and the application is waiting for the result of the process. As soon as received, the results are stored and if there is a violation detected, the application is sending the proper notification to the different users and is able to accept bids.

In Figure 58 a trade cycle is presented. Initially the order book is sent containing all active bids (if any). The process waits for the results of the simulation: the updated grid conditions and trades – outcome of a bid/offer match in the market - and the new violations/DSO order (if any) - detected by the power flow analysis. The users are notified for new trades/ new violations or for the resolution of the grid issues (in case no further violation is detected).



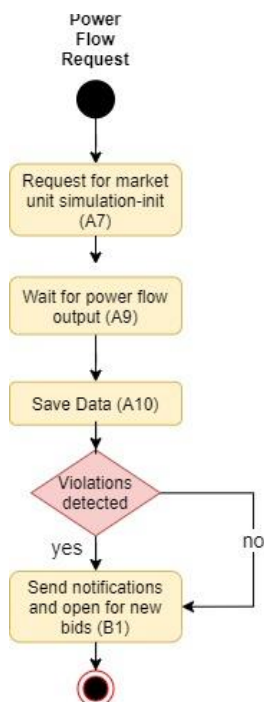


Figure 57 Intraday Market Application Prototype - Market Unit Operation (GUI)

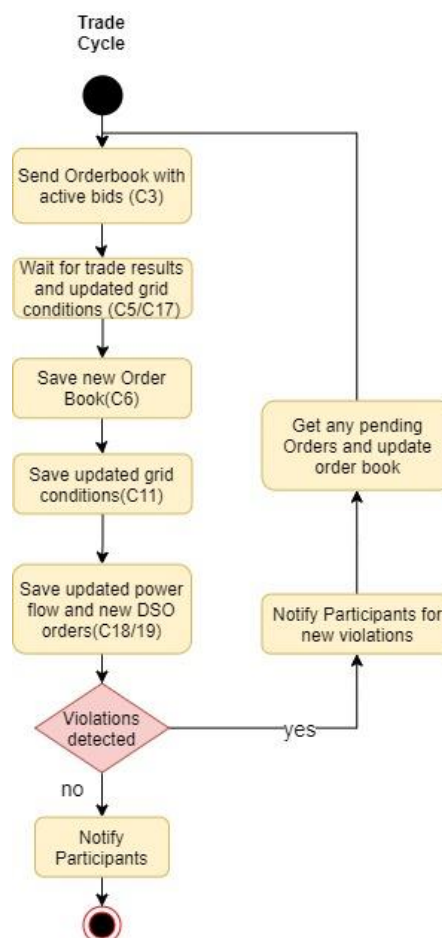


Figure 58 Intraday Market Application Prototype – Trade cycle (GUI)

### 3.5.4 Deployment View

This view presents the environment where the different solutions are deployed and main communication channel. The following figure presents how the different components analysed in the Functional View are deployed in ICOM's and HENEX's servers.

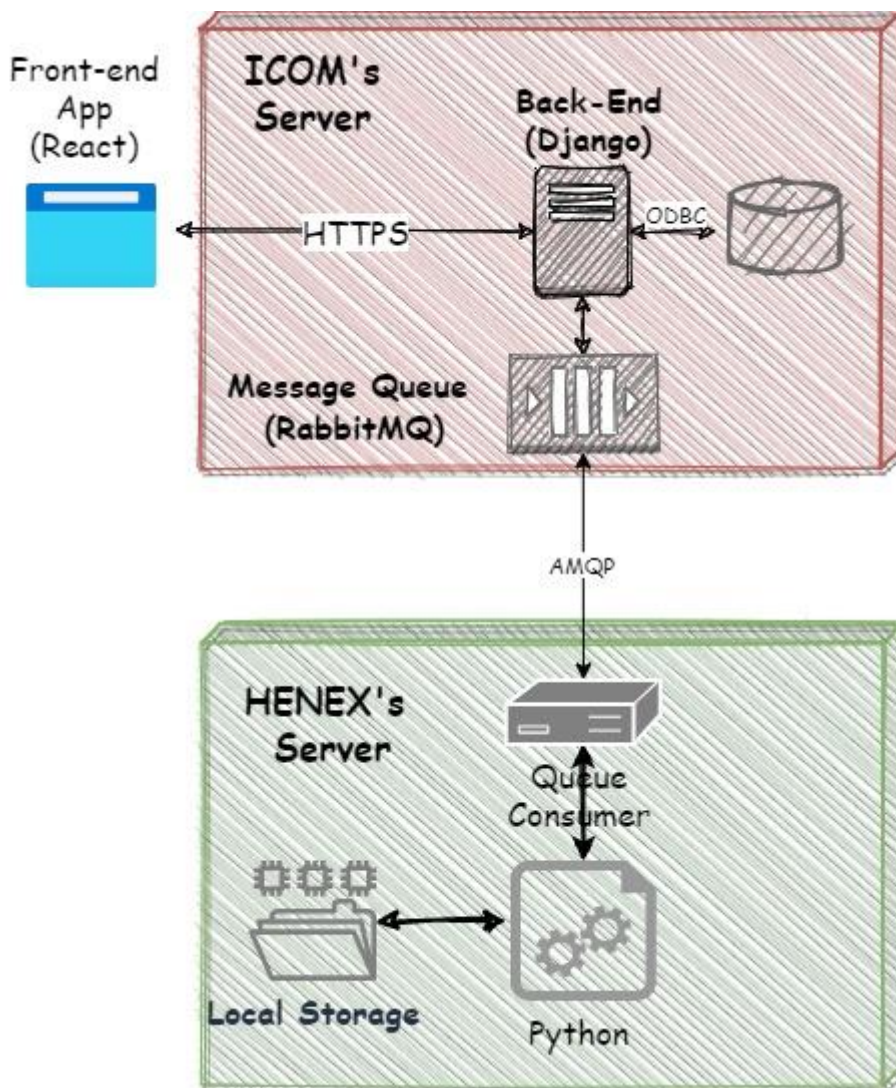


Figure 59 Deployment Diagram of Intraday Market Application Prototype

### 3.5.5 Information View

The aim of this section is to present the domain data model, specifying the structure of data stored in the GUI application database and those communicated among the different components.

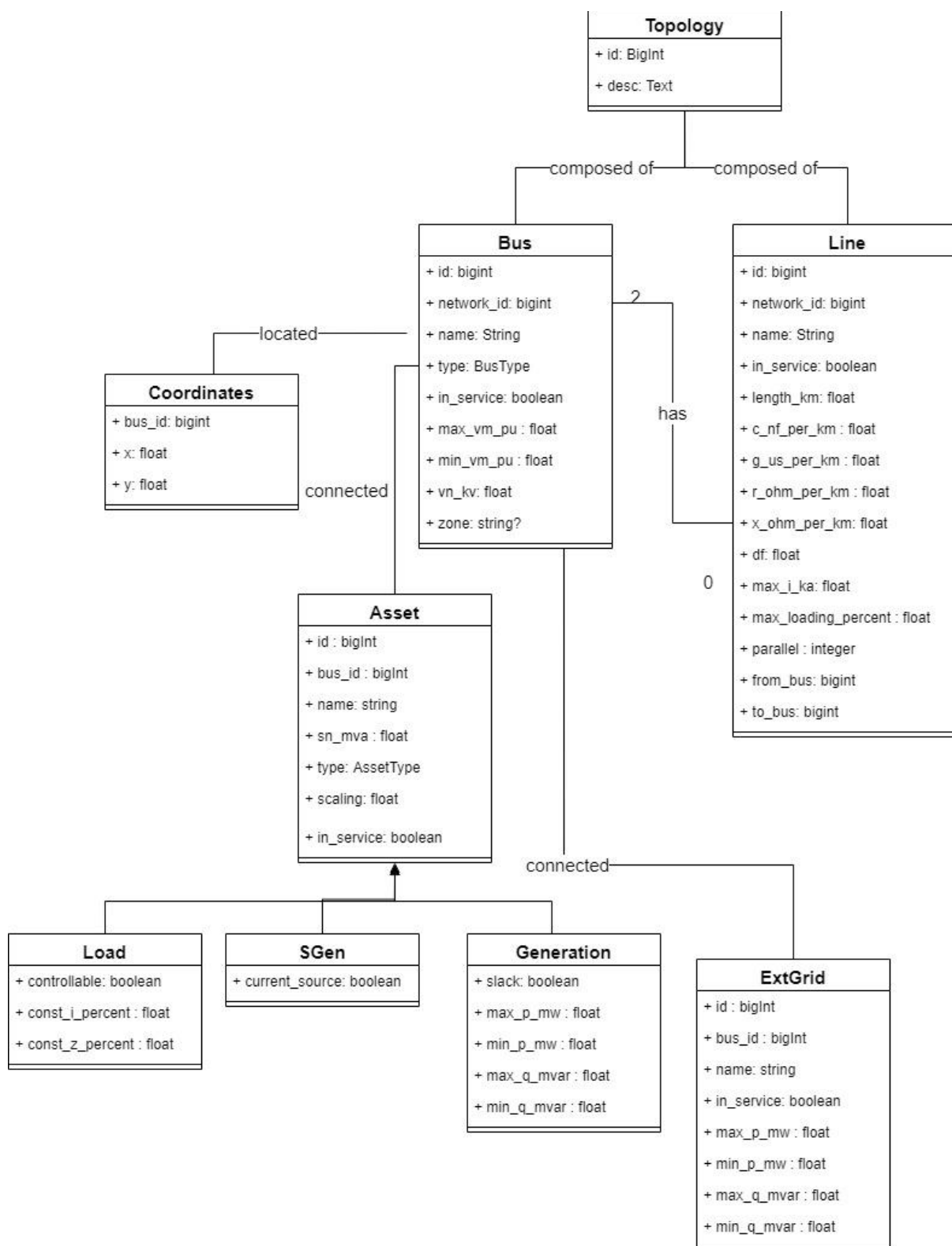


Figure 60 Grid Topology data model

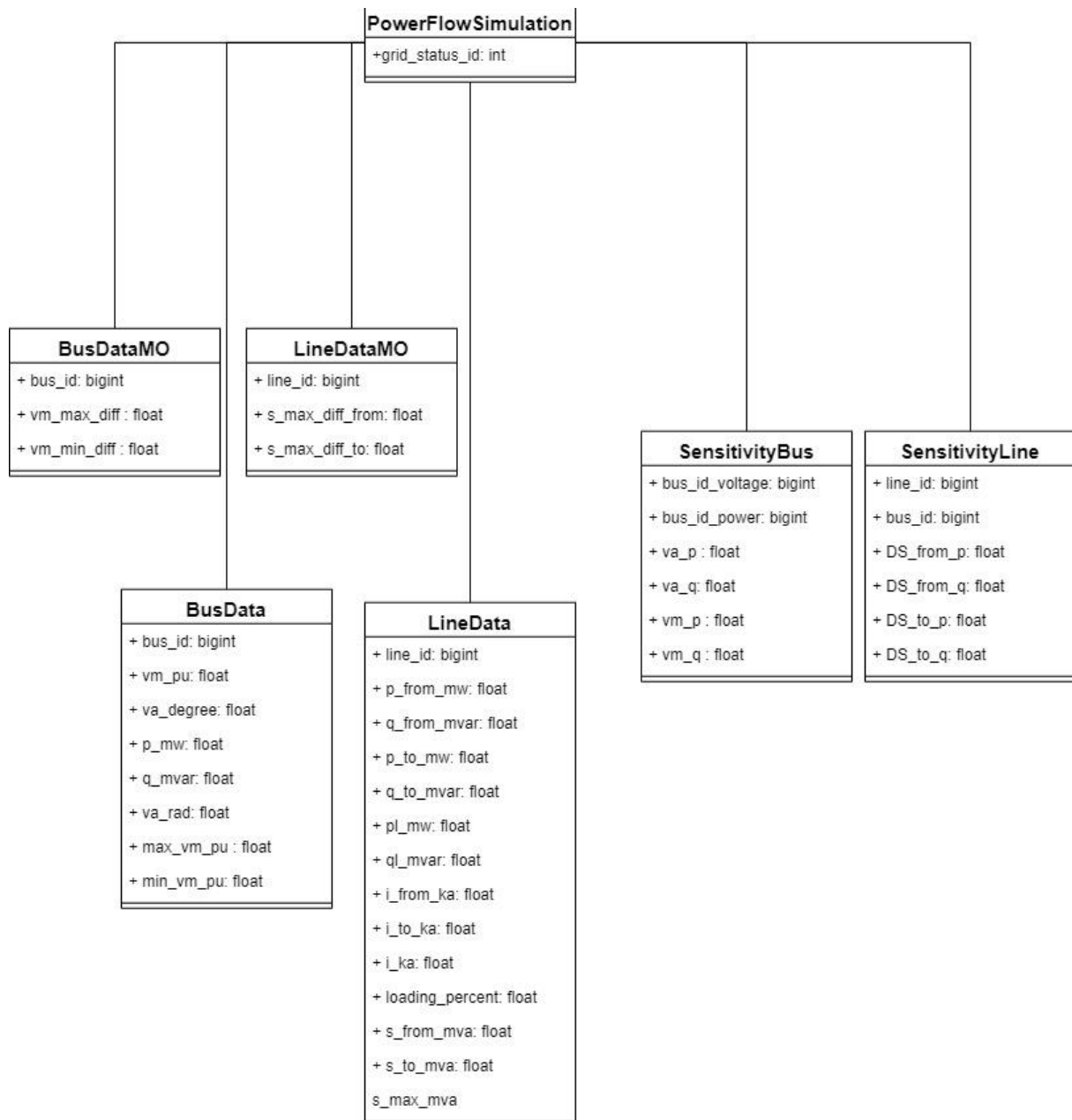


Figure 61 Power Flow Simulation data model

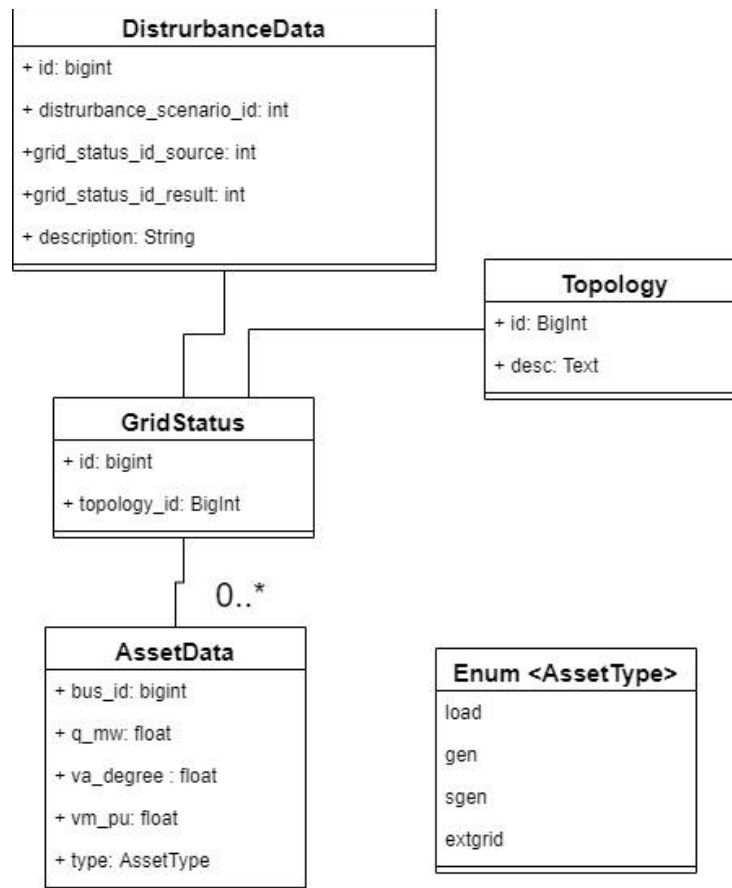


Figure 62 DistrurbanceData data model

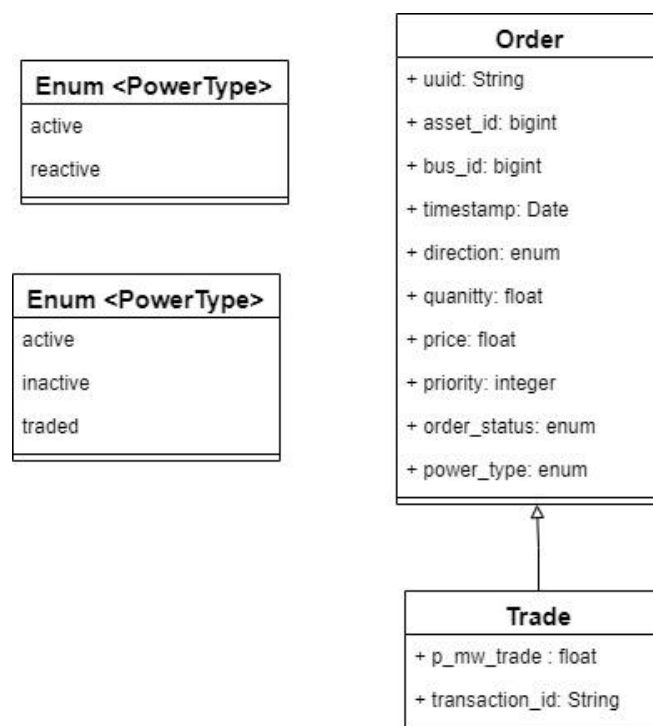


Figure 63 Order data model

### 3.5.6 User Interface design

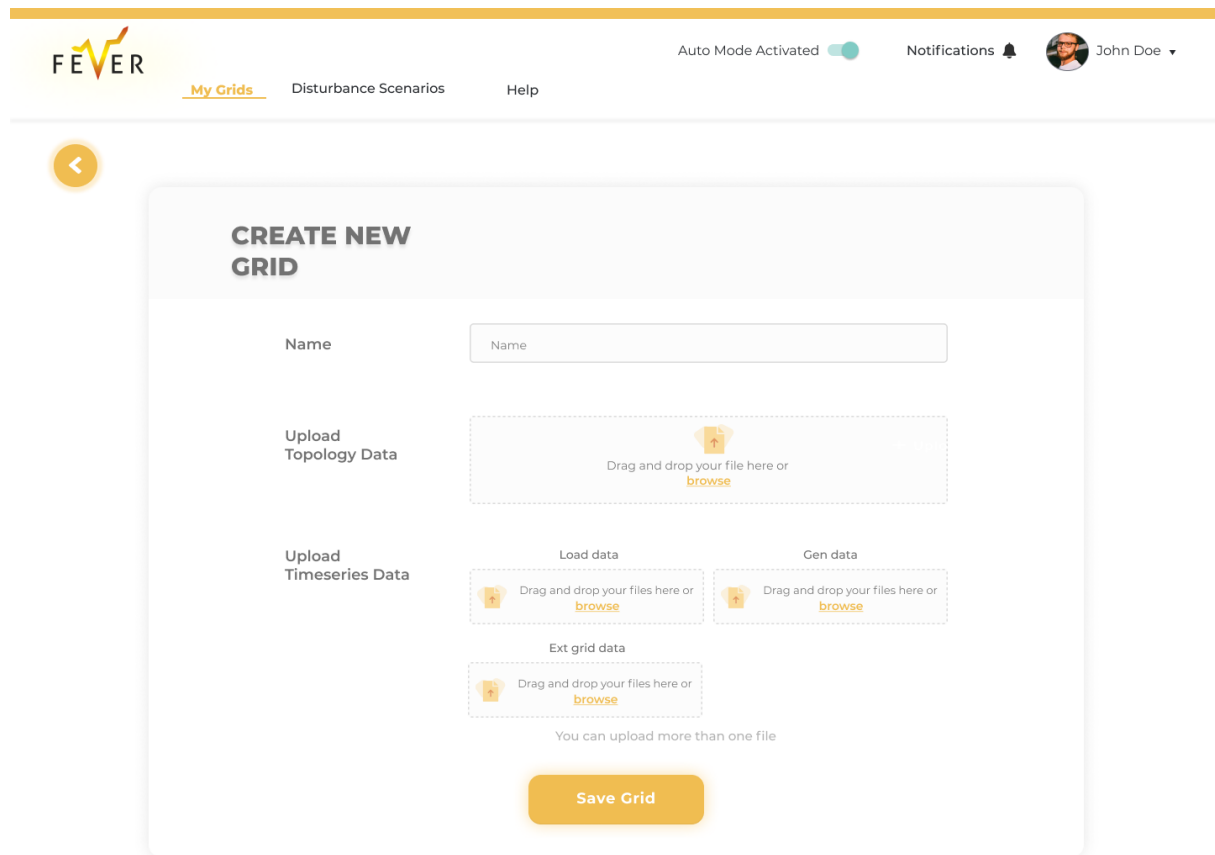
This section presents the design of the graphical user interfaces of the prototype solution, focusing on the perspective of DSO (as Market Operator) and BSP.

#### 3.5.6.1 User Interface Design for DSO

This subsection presents the user interfaces of the application for users with the role of DSO.

To acquire access privileges and be able to navigate to all application pages, the user needs to login using personal credentials. Once successfully logged in, the user can view and edit profile information by following the profile link at the top right of the navigation bar. The navigation bar at the top of each screen has links for quick access to: *My Grids*, *Disturbance Scenarios*, *Help*, *Auto Mode Activation/Deactivation*, *Notifications*.

The user interface for creating a new grid model is shown in Figure 64. In order to add a new grid model, the user needs to upload the topology of the grid and information on Load, Generation as well as external grid data. After saving the new grid model the user can find all the saved grid models on the “My Grids” screen (Figure 65). From the navigation bar, the user can find this screen by selecting the “My Grids” link.



The screenshot displays the 'CREATE NEW GRID' form within the FEVER application interface. The top navigation bar includes the FEVER logo, a 'My Grids' link (highlighted), 'Disturbance Scenarios', and 'Help'. On the right, it shows 'Auto Mode Activated' with a toggle switch, 'Notifications' with a bell icon, and a user profile for 'John Doe'. The form itself is titled 'CREATE NEW GRID' and contains the following elements:

- Name:** A text input field with the placeholder 'Name'.
- Upload Topology Data:** A large dashed box with a file upload icon and the text 'Drag and drop your file here or browse'.
- Upload Timeseries Data:** A section containing three smaller dashed boxes:
  - Load data:** 'Drag and drop your files here or browse'.
  - Gen data:** 'Drag and drop your files here or browse'.
  - Ext grid data:** 'Drag and drop your files here or browse'.
- Ext grid data:** A note below the boxes stating 'You can upload more than one file'.
- Save Grid:** A prominent orange button at the bottom of the form.

Figure 64 Create New Grid Form

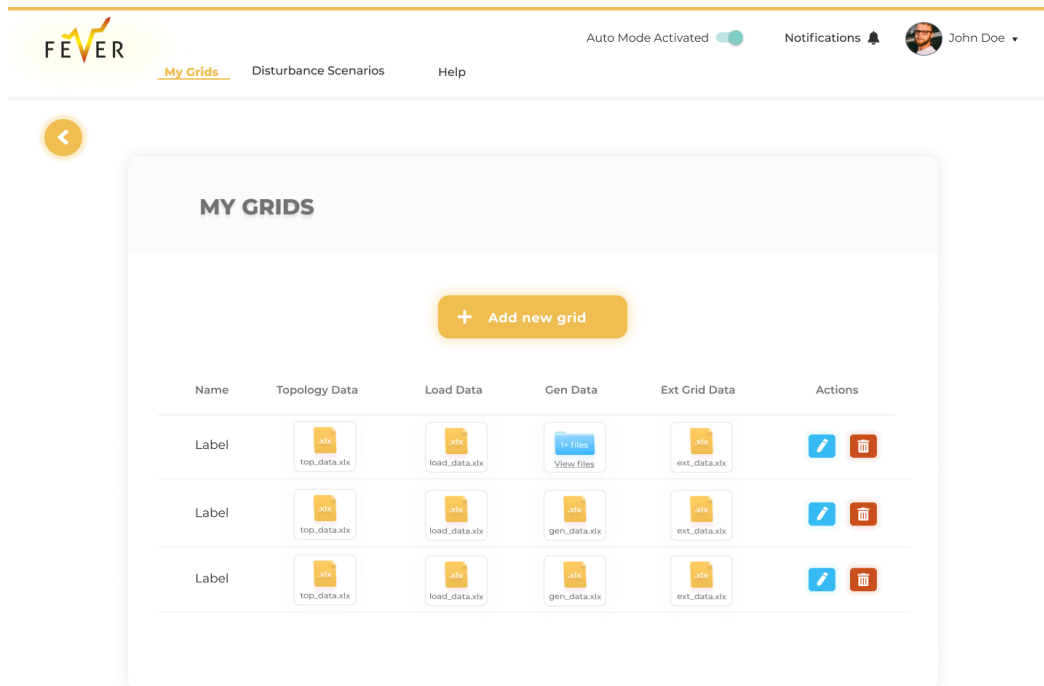


Figure 65 My Grids

After the user selects the “My Grids” link, all the saved grid models are presented in a list. The following information are displayed about each grid model: *Name (the descriptive name of each grid model), file on Topology, Load, Generation and Ext Grid Data*. The user is also given the option to either edit a saved grid model or delete it. If the user has uploaded more than one file in a certain data category of a saved grid model, all the uploaded files are accessible by clicking on the “view files” option. After selecting the “View Files” link, a modal appears (Figure 66), in which the user can view all the uploaded files for this data category and is given the option to delete a specific file.

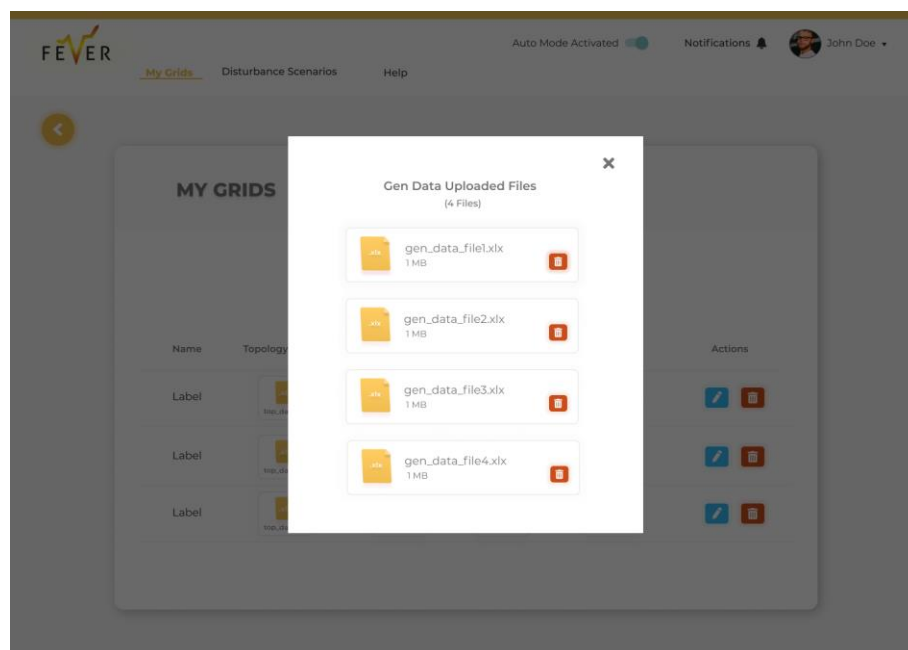


Figure 66 View Files Modal

**CREATE NEW SCENARIO**

Name

Topology Data  [+ Upload new grid](#)

Disturbance Data  [+ Upload new data](#)

[Save Scenario](#)

Figure 67 Create new Scenario Form

The design for creating a new scenario is shown in Figure 67. To add a new disturbance scenario, the user needs to select topology and disturbance data. After saving the new scenario, the user can find all the saved scenarios on the “Disturbance Scenarios” screen (Figure 68). From the navigation bar, the user can find this screen by selecting the “Disturbance Scenarios” link. All the disturbance scenarios are presented in a list. The following information is displayed about each scenario: *Name (the descriptive name of each scenario), Network data, Topology Data, Date Created, Status (of simulation), Market Status*.

**SCENARIO LIST**

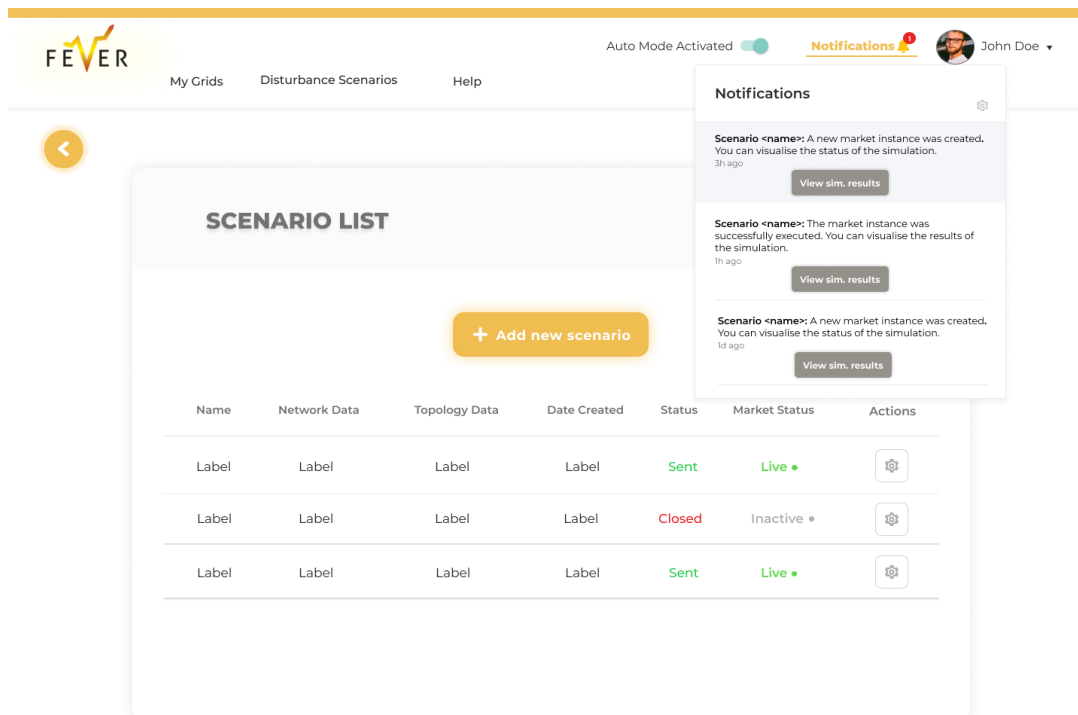
[+ Add new scenario](#)

Name	Network Data	Topology Data	Date Created	Status	Market Status	Actions
Label	Label	Label	Label	Sent	Live •	
Label	Label	Label	Label	Closed	Inactive •	
Label	Label	Label	Label	Sent	Live •	

Figure 68 Scenario List



From the navigation bar, the user can find new or past notifications by selecting the “bell” icon. The example of Figure 69, presents DSO related notifications on new market units, violation information, market unit closure - no violation etc. Additionally, depending on the type of the notification, different buttons appear so the user is given the option to perform different actions.

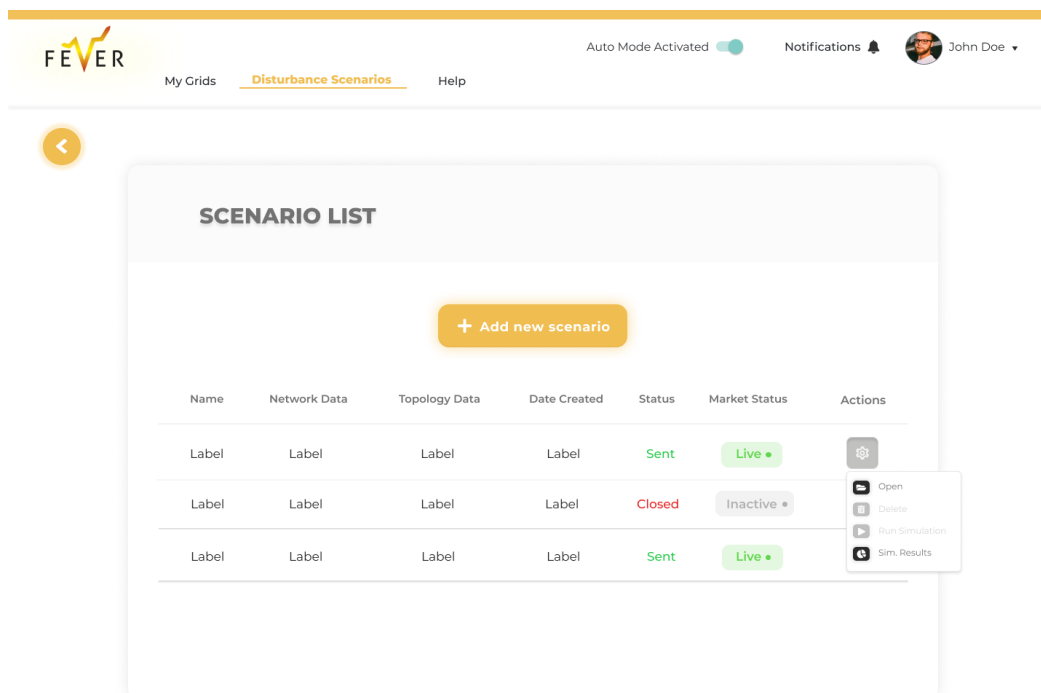


The screenshot shows the FEVER interface with a notification overlay. The notification panel on the right lists three scenarios with their details and a 'View sim. results' button for each.

**Scenario List Table:**

Name	Network Data	Topology Data	Date Created	Status	Market Status	Actions
Label	Label	Label	Label	Sent	Live •	
Label	Label	Label	Label	Closed	Inactive •	
Label	Label	Label	Label	Sent	Live •	

Figure 69 Notifications – DSO Example



The screenshot shows the FEVER interface with the Scenario List page. A context menu is open for the Actions column, displaying options: Open, Delete, Run Simulation, and Sim. Results.

**Scenario List Table:**

Name	Network Data	Topology Data	Date Created	Status	Market Status	Actions
Label	Label	Label	Label	Sent	Live •	
Label	Label	Label	Label	Closed	Inactive •	
Label	Label	Label	Label	Sent	Live •	

Figure 70 Scenario List Actions

By clicking on the “cog” on the actions column (Figure 70), the user is given the option to either open a scenario, run a simulation, view simulation results or delete the scenario (this action is available only if the scenario status is closed).

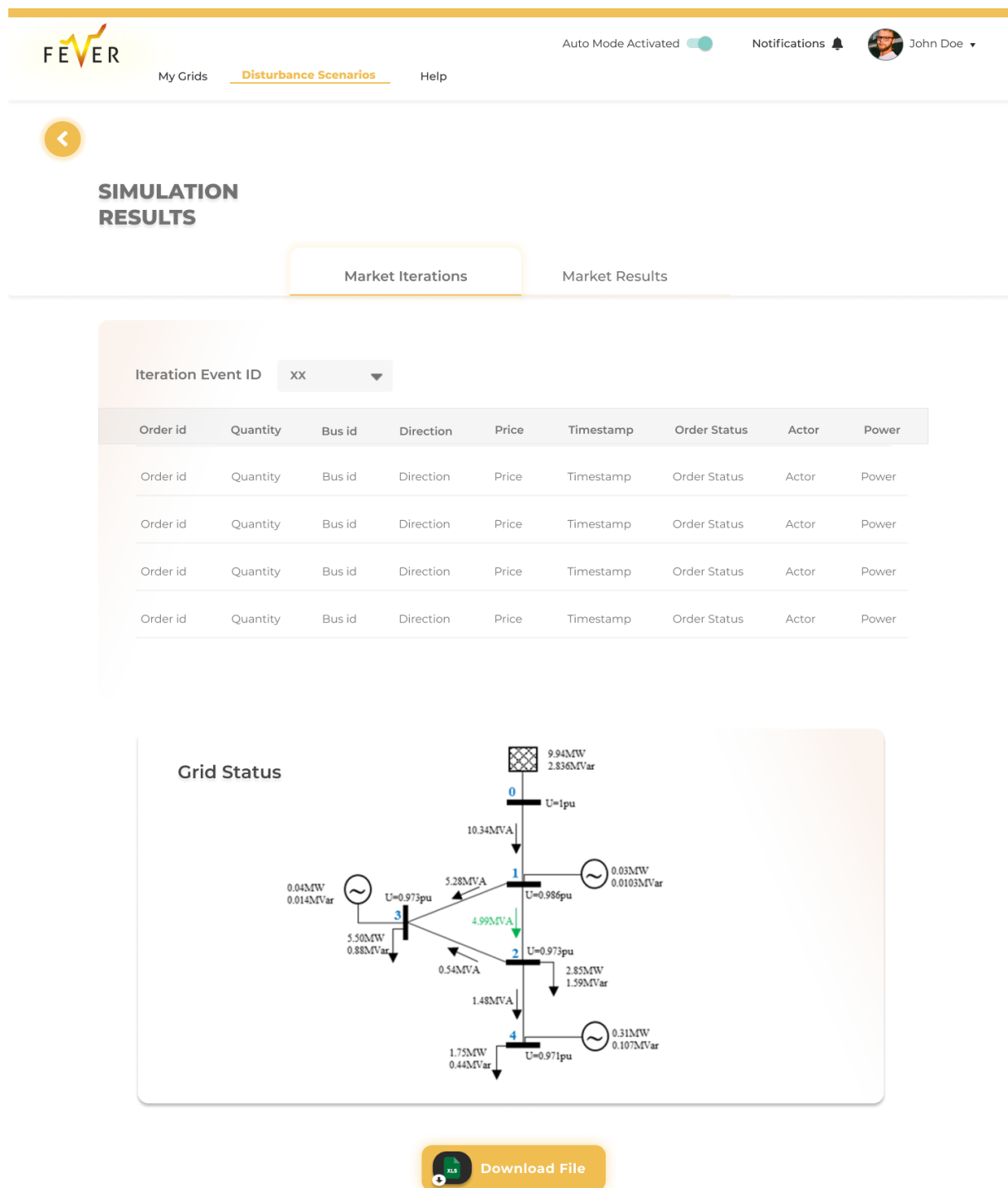


Figure 71 Simulation Results - Status Tab

The user can be directed in the simulation results screen Figure 71, either through a notification (as depicted in Figure 69) or through the options given in the action column in the Disturbance Scenarios Screen (as depicted in Figure 70). In this screen the user is provided with the options to check the Market Status or the Market Results (upon Market Unit termination). After the user selects the “Market

Status” tab, they can customize the results displayed on their screen using filters (Event). This way the screen demonstrates a list with the order book of a specific market iteration. The following information are displayed about each iteration event: *Order ID, Quantity, Bus ID, Direction, Price, Timestamp, Order Status, Actor, Power*. Note in that in the case were the DSO is not the Market Operator, only the traded orders will appear in the list (not the bids).

Furthermore, in order to facilitate for the DSO to understand the impact of each market event to the grid status, a graph illustrates the network status (Figure 71 bottom of the page) for each event (i.e. trade in the case of DSO). The user is also given the option to download a file containing market status date.

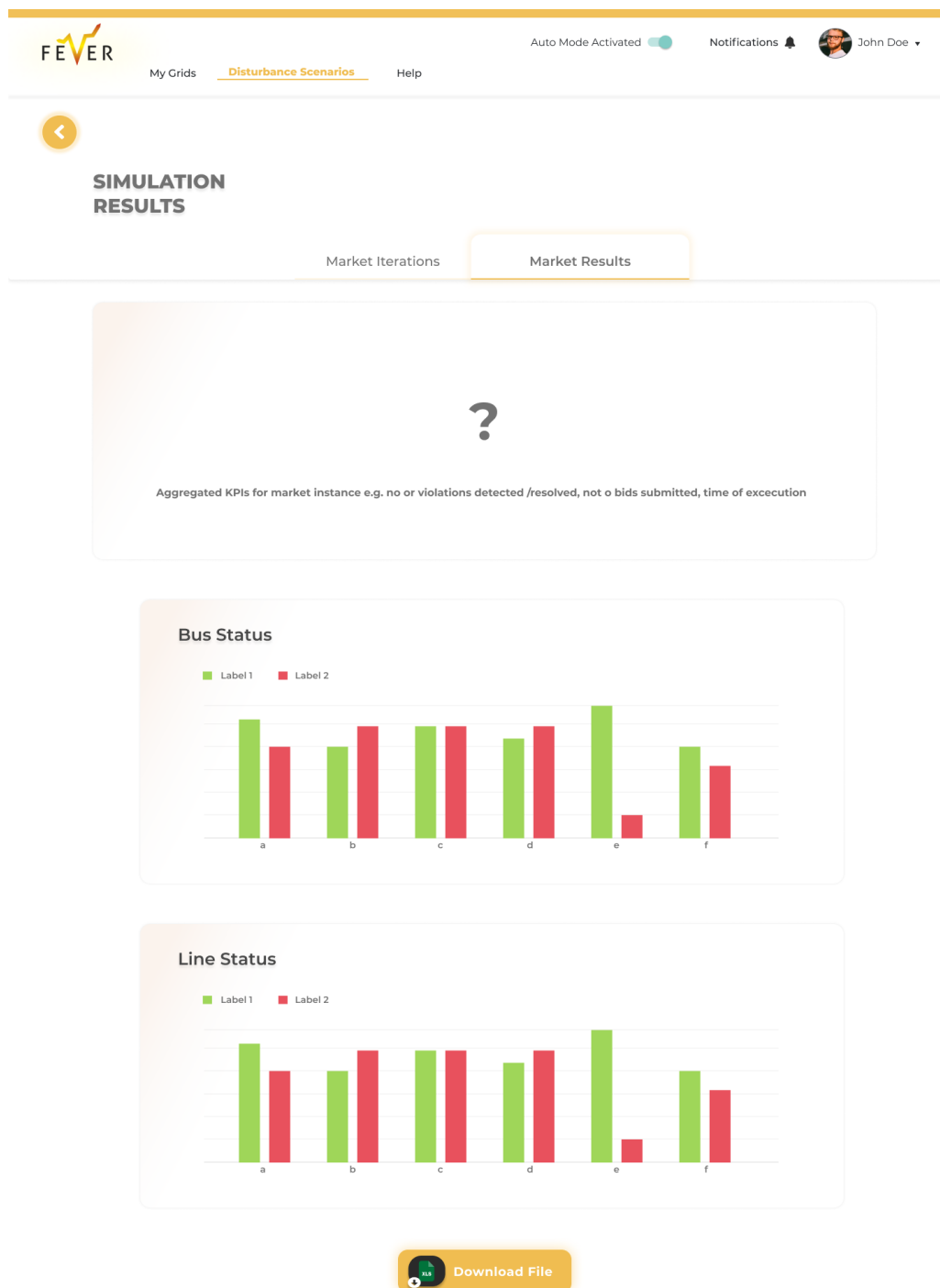


Figure 72 Simulation Results – Market Results Tab

In the same page, the market unit's results – upon market termination – can also be access through the “Market Results” tab. Figure 72 presents a dashboard with market results, which includes different KPIs (i.e. No of grid problems, No of problems solved per type No. of bids, No. of trades, Total Quantities in KWh, Total Quantities in KVarh, Market well-fare). Furthermore, two charts are presented, illustrating the bus status and the line status, so the user can compare initial state (disturbance) with current state (market operation).

### 3.5.6.2 User Interface Design for MP

This subsection presents the user interfaces of the application for users with the role of MP.

To acquire access privileges and be able to navigate to all application pages, the market participant needs to login using personal credentials. Once successfully logged in, they can view and edit profile information by following the profile link at the top right of the navigation bar. The navigation bar at the top of each screen has links for quick access to: *My Assets*, *Market Participations*, *Auto Mode (Activation/ Deactivation)*, *Notifications*, *Help*.

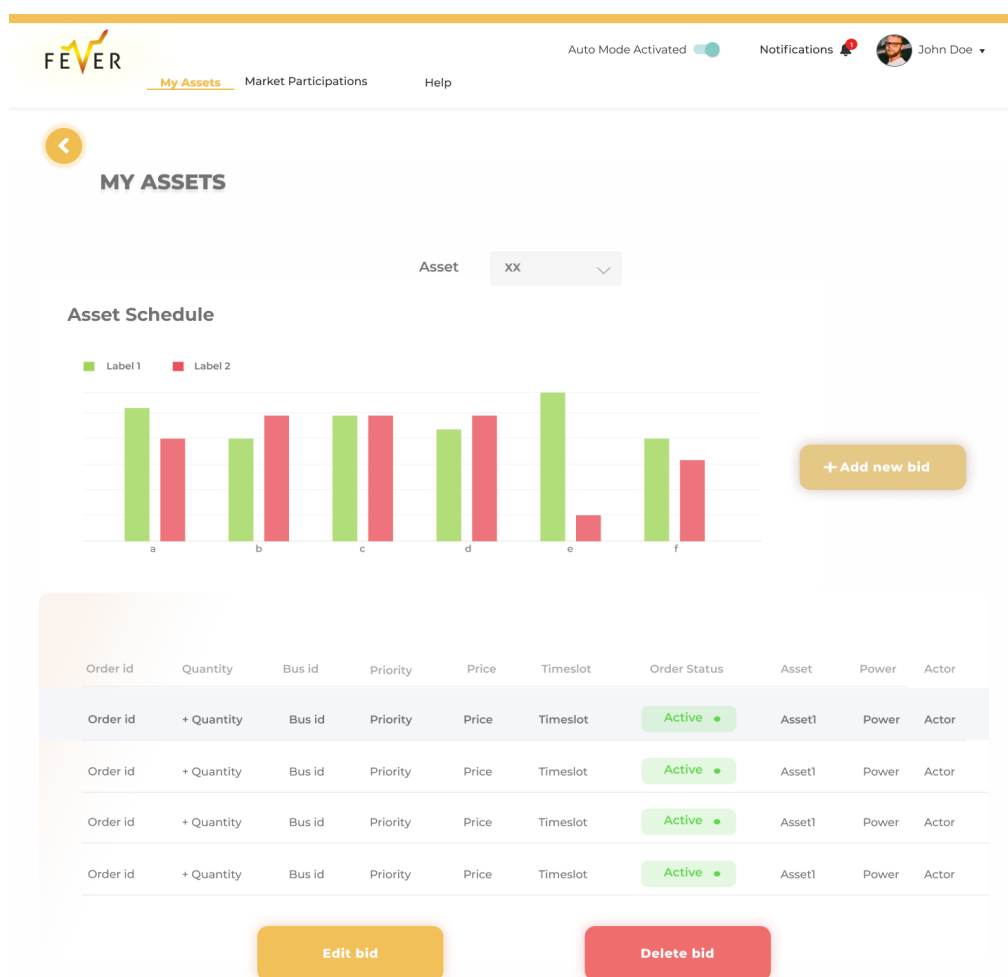
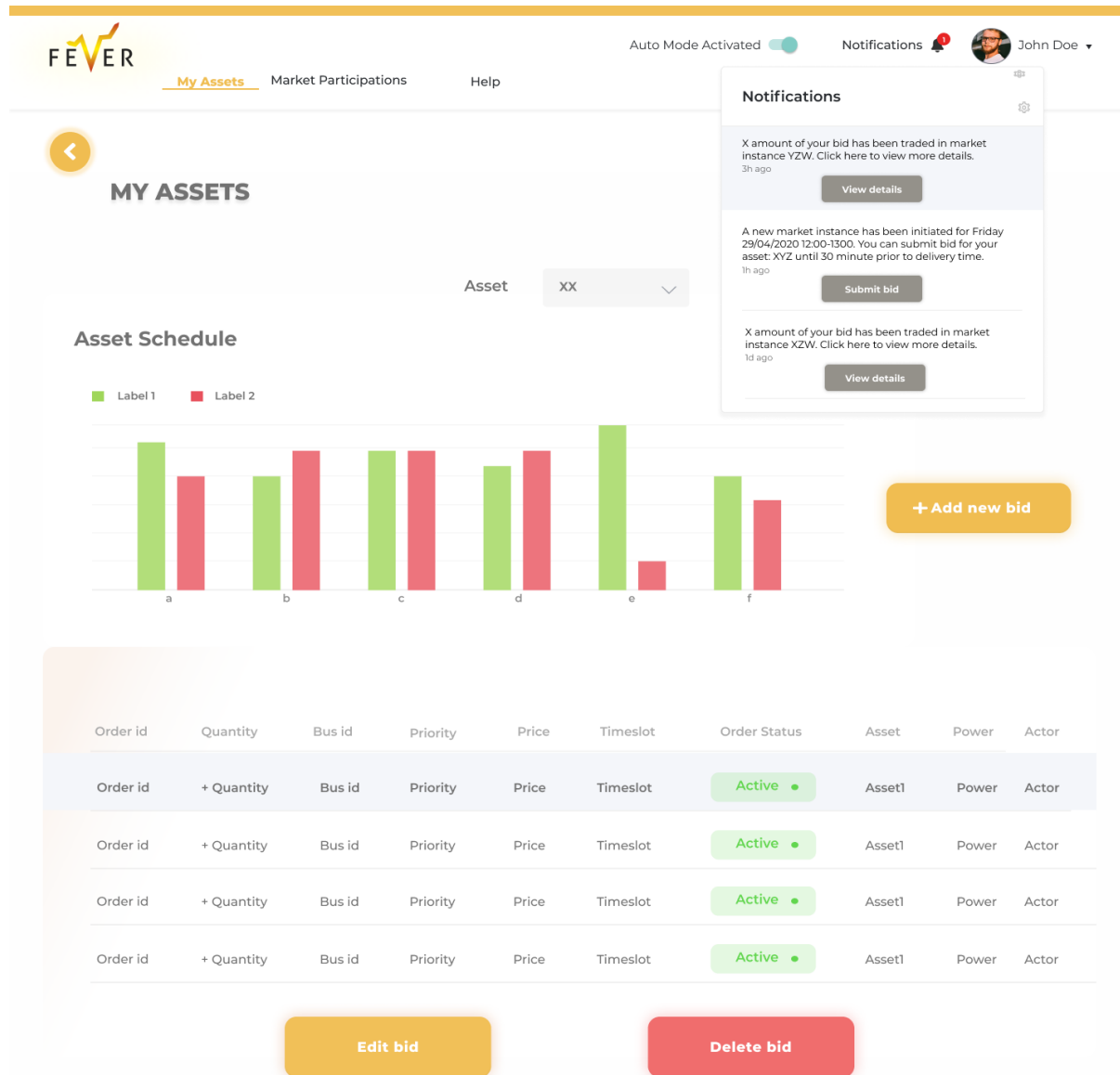


Figure 73 My Assets

Using the link “My Assets”, the user can navigate to a screen demonstrating each asset's daily schedule (Figure 73). The user can add a new bid for a specific asset by clicking the “Add new bid” button.

A list is presented at the bottom of the page, illustrating the order book. The following information are displayed in the order book: *Order ID, Quantity, Bus ID, Priority, Price, Timeslot, Order Status, Asset, Power, Actor*. When an order is selected from the list, available buttons (edit, delete etc.) related to that offer (for the specific asset) are displayed at the bottom of the list, so the user can perform different actions.



**Figure 74 Market Participant Notifications**

From the navigation bar, the user can find new or past notifications by selecting the “bell” icon. The market participant receives a notification on violation detected, order status etc. (Figure 74). Additionally, depending on the type of the notification, different buttons appear so the user is given the option to perform different actions.

In “My Assets” page (Figure 73), if the user clicks the “Add new bid” button, they are directed to the “create new bid form” (Figure 75). After saving the bid, the user can find all the bids for the specific asset, in the order book, on “My Assets” screen.

Auto Mode Activated

Notifications

John Doe

My Assets

Market Participations

Help

CREATE NEW BID

Select Market Instance

Market Instance

Select Asset

Asset

Quantity

1

Direction

Direction

Price

Price

Power

Power

Save Bid

Figure 75 Create new bid Form

Auto Mode Activated

Notifications

John Doe

My Assets

Market Participations

Help

MARKET PARTICIPATIONS

Market Instance :

Date

XX

Location

XX

Node

XX

Order id	Quantity	Price	Timestamp	Order Status	Asset	Power
Order id	+ Quantity	Price	Timestamp	Active	Asset1	Power
Order id	-Quantity	Price	Timestamp	Active	Asset2	Power
Order id	+ Quantity	Price	Timestamp	Active	Asset3	Power
Order id	+ Quantity	Price	Timestamp	Active	Asset4	Power

Action 1

Action 2

Figure 76 Market Participations

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The Market Participations page is shown in Figure 76. From the navigation bar, the user can find it by selecting the “Market Participations” link. In the screen the user is provided with the options to customize the results displayed on their screen using filters (Market Unit Date, Location and Node). This way they are able to search for specific market units. When an order is selected from the list, available buttons (edit, delete etc.) related to that offer are displayed at the bottom of the list to perform different actions.

### 3.6 Results from simulations with dummy data

#### 3.6.1 Toy Examples

##### 3.6.1.1 Single line congestion

This section demonstrates how the proposed LFM can mitigate an anticipated line overload by means of a simple numerical example. A test distribution system with 5 buses, 5 lines, 3 loads and 3 DERs is used as illustrated in Figure 77. Bus 0 is considered as the slack bus. The DER generators are modelled with a constant active and reactive power feed-in. The upper and lower bus voltage limits are 1.05pu and 0.95pu respectively, while the line thermal limits are given in Table 43.

Table 43: Line Thermal Limits

Line index	“From bus” index	“To bus” index	$S_m^{max}$ (MVA)
0	0	1	12.54
1	1	2	5.023
2	1	3	6.755
3	2	3	5.023
4	4	2	6.755

The DSO runs the AC power flow and calculates the initial flows and voltages, as well as the AC sensitivities of the grid state variables with respect to the nodal active and reactive bus power injections.

The initial state of the test distribution system is shown in Figure 77. It can be observed that line 1 is overloaded.

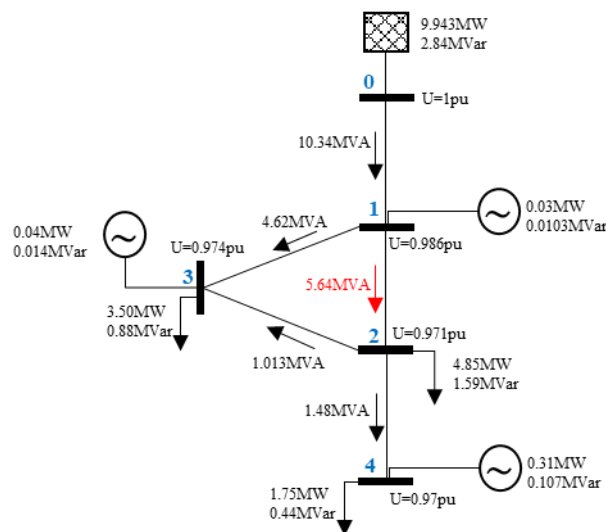


Figure 77: Initial state of a network with line overload

As there is an anticipated network constraint violation, the DSO sends the necessary network data (AC sensitivities and remaining available margin of line 1-2 operational limit) to the MO. The LFM gate opens for orders submission, and MPs can submit their orders based on their available flexibility. Since a MP order is submitted, a market instance is triggered. It is assumed that the following orders are submitted in the orderbook by the MPs (BSPs). Since the example refers to a line congestion issue, and not to a voltage violation or deviation of the DSO's schedule in the TSO – DSO connection point, there are no orders submitted by the DSO. The submitted orders are prioritized based on the principles described in C1.

**Table 44: Initial Orderbook for line overloading**

Order id	Bus id	Quantity (MW)	Direction	Price (€/MW)	Priority	Order status	Actor	Power
1	4	14	S	50	1	A	MP	P
2	1	17	B	3	3	A	MP	P
3	2	1	S	4	2	A	MP	P
4	3	4	B	5	5	A	MP	P

As described in C1 when two orders are checked, first the financial feasibility check is conducted, which comprises of a set of rules, relevant to the orders direction, power type, involved actors, location of the flexibility asset and price. As only MPs are involved in the trades, and only active power orders are submitted, only the orders' direction, and price rules apply for the financial feasibility check. The check for orders' location can be omitted since it is applicable only for reactive power orders. Considering the assigned priorities and the prerequisite that a trade is conducted only between two orders of opposite direction, the following checks for financial feasibility are conducted.

**Table 45: Checks for financial feasibility**

Orders checked (ids)	Status
1 – 2	Not feasible price of sell order (id = 1) higher than the price of the buy order (id = 2)
1 – 4	Not feasible price of sell order (id = 1) higher than the price of the buy order (id = 4)
3 – 2	Not feasible price of sell order (id = 3) higher than the price of the buy order (id = 2)
3 – 4	Feasible price of sell order (id = 3) higher than the price of the buy order (id = 4)

The pair [order id = 3, order id = 4] which corresponds to a buy order of 4 MW submitted by the dispatchable load in bus 3 and a sell order of 1 MW submitted by the dispatchable load in bus 2 is financially feasible and will be further evaluated as part of the network feasibility check.



For the network feasibility check the feasible range of the quantity that can be cleared between the two orders needs to be calculated, so as the overload of line 1-2 could be alleviated or eliminated, also ensuring that no further violations would be created. Since the cleared quantity should be the same for the two orders, whether the quantity of 1 MW can solve the congestion is examined and if so, whether it can be fully or partially cleared. The sensitivity factors of the apparent power flow at both ends of all lines, to the active power changes in buses 3 and 2, are depicted in Table 46.

**Table 46: Line Apparent Power Flow Sensitivity Factors for the initial state**

Line index		Sensitivity factors $K_{S,P}$		$K_{S,P}^{diff,m}$
		Bus 3	Bus 2	
From bus	0	1.014	1.020	-0.006
	1	0.329	0.660	-0.331
	2	0.657	0.332	0.325
	3	-0.310	0.311	-0.621
	4	$-3.55 \cdot 10^{-15}$	$-4.44 \cdot 10^{-15}$	$8.88 \cdot 10^{-16}$
To bus	0	0.985	0.991	-0.006
	1	0.320	0.639	-0.319
	2	0.642	0.324	0.318
	3	-0.315	0.316	-0.631
	4	$8.70 \cdot 10^{-6}$	$1.18 \cdot 10^{-5}$	$-3 \cdot 10^{-6}$

The sensitivity factors of the voltage magnitude of each bus to active power changes in buses 3 and 2 are shown in Table 47.

**Table 47: Voltage Magnitude Sensitivity Factors for the initial state**

Bus index	Sensitivity factors $K_{S,U}$		$K_{S,U}^{diff,n}$
	Bus 3	Bus 2	
0	0	0	0
1	0.001214925	0.001224315	-9.39E-06
2	0.001914775	0.002598323	-0.000683548
3	0.002569388	0.001926367	0.000643021
4	0.001917429	0.002601924	-0.000684495

### Check for contribution to solving the violations

A potential trade should be able to reduce or eliminate existing violations. In the examined network a single violation is considered, congestion in line 1, meaning that only Eq (3-28) is effective out of the

set of equations (3-28) - (3-30) and thus the impact of the trade in (3-32) will be only affected by  $Ch_{line}$  (here  $Ch_{line}$  for both the sending and receiving end of the line should be evaluated).

As explained in the methodological part, for the trade to be feasible the result of Eq (3-32) should be positive.

Since Eq (3-32) is equal to:

$$Ch_{line} = - \frac{K_{S,P}^{diff,m} * \Delta P_b}{S_B}$$

- “From Bus”: For bus line  $m = 1$ , the sensitivity factor  $K_{S,P}^{diff,1} = -0.331$  is negative (Table 46),  $S_B = 1MVA$  and  $\Delta P_b$  is always positive. So,  $Ch_{line}$  turns out to be positive, meaning that the trade helps in alleviating the congestion.
- “To Bus”:  $Ch_{line}$  is equal to  $0.319 * \Delta P_b > 0$ . This means that the trade helps in alleviating the congestion.

### Check for violations in other parts of the network

As explained in the methodological part, a potential trade should not create violations in parts of the network with no violations. There are two sets of network operational constraints that are checked: (a) thermal apparent flow limits of non-congested lines and (b) bus voltage magnitude limits of buses without violations.

The violations’ check at line level will only be relevant for the lines that correspond to positive line apparent power flow sensitivity factors ( $K_{S,P}^{diff,m}$ ), since a negative value of the  $K_{S,P}^{diff,m}$  sensitivity factors is considered to cause a reduction in the line apparent flow. From Table 46 we can see that the selected pair of bids has a positive sensitivity factor only for line 2. So, this is the line that determines the maximum possible traded value in terms of respecting the thermal apparent flow limits.

Regarding the bus voltage magnitude limits, an undervoltage problem could be caused by a positive sensitivity factor  $K_{S,U}^{diff,n}$ , since a positive sensitivity factor will mean that the load of the examined bus increases. Accordingly, an overvoltage would be the result of a negative sensitivity factor  $K_{S,U}^{diff,n}$ . Since, as depicted in Table 47, the  $K_{S,U}^{diff,n}$  sensitivities of the evaluated pair are negative for buses 1, 2 and 4, we expect that the trade will reduce the voltage magnitude of these buses and so, we need to limit the cleared quantity until the point where no undervoltages are caused. Respectively, we expect for the trade execution to increase the voltage magnitude of bus 3, and thus need to check the maximum quantity that could be cleared in order not to cause any overvoltage in bus 3.

Applying the values of Table 43, Table 46, Table 47 and Figure 77 to equations (3-34) and (3-36) for the line and for the voltage magnitude limits, the following limitations apply:

**Table 48: Maximum Acceptable Quantity Range of Trade**

Network element index		Equation	Upper Limit (MW)
Line apparent power flow limits at “from bus	2	(3-34)	6.57
Line apparent power flow limits at “to bus”	2	(3-34)	6.88
Bus voltage limits index	0	(3-36)	-
	1	(3-36)	6779.12

	2	(3-36)	114.99
	3	(3-36)	37.73
	4	(3-36)	116.8

The limits shown in Table 48 impose a maximum order quantity of 6.57 MW to ensure that no further line or voltage constraint will be violated. The minimum order quantity to fully resolve the congestion is determined by line 1 and is equal to 1.86 MW ( $K_{S,p}^{diff,1}/\Delta S_1$ ). If the submitted quantity is less than 1.87 MW, and since (3-32) is true, the orders will be feasible and thus fully accepted. This is because even if the cleared quantity does not fully solve the overload, it reduces the overload and thus leads to a better condition for the grid. In case where the submitted quantity is greater than 6.57 MW, the orders will be cleared up to the quantity that is within the feasible range, meaning up to the maximum limit of 6.57 MW. This is because a quantity greater than 6.57 MW will lead to a new overload in line 2, as it can be easily understood from the respective limitation of Table 48. Owing to the above analysis, the quantity of 1 MW can be fully cleared, but it is expected that the congestion will not be fully resolved. Since a trade is essentially a change in the grid operating point, the DSO runs again an AC power flow, considering a load increase of 1 MW at node 3 and an equal load decrease at node 2. The results are shown in Figure 78 where indeed the overload of line 1 has been alleviated, but still not fully resolved, as expected.

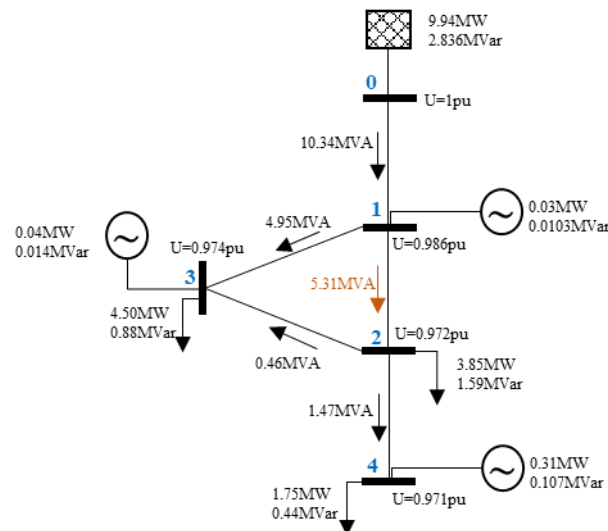


Figure 78: Network with line overload after trade execution

After the trade is concluded the orderbook is updated and formulated as follows:

Table 49: Orderbook after trade execution

Order id	Bus id	Quantity (MW)	Direction	Price (€/MW)	Priority	Order status	Actor	Power
1	4	14	S	50	1	A	MP	P
3	2	1	S	4	2	T	MP	P
2	1	17	B	3	3	A	MP	P
4	3	3	B	5	5	A	MP	P
4	3	1	B	5	5	T	MP	P

Traded volumes marked with red, exit the orderbook. The order with id =4 is partially traded, so the remaining volume will still be available on the trading platform. Since there are no feasible trades in the new orderbook of Table 49 (price of the sell order is greater than the prices of the buy orders) and the overload is still not resolved, a new order by the MPs is expected to rerun the market. Let us consider the following orderbook, updated with a new sell order on bus 2.

Table 50: Orderbook updated with new order

Order id	Bus id	Quantity (MW)	Direction	Price (€/MW)	Priority	Order status	Actor	Power
1	4	14	S	50	1	A	MP	P
2	1	17	B	3	2	A	MP	P
4	3	3	B	5	3	A	MP	P
5	2	0.9	S	4	4	A	MP	P

Following the evaluation procedure which implies that the order with the highest priority is evaluated in pairs with the orders of opposite priority, the first financially feasible pair is the one with orders [order id = 4, order id = 5], which correspond to a buy order of 3 MW submitted by the dispatchable load in bus 3 and a sell order of 0.9 MW submitted by the dispatchable load in bus 2. For the network feasibility check, the sensitivity factors of the apparent power flow at both ends of all lines, to the active power changes in buses 3 and 2, and the sensitivity factors of the voltage magnitude of each bus to active power changes in buses 3 and 2 are depicted in Table 51 and Table 52 respectively.

Table 51: Line Apparent Power Flow Sensitivity Factors After 1<sup>st</sup> Trade

Line index		Sensitivity factors $K_{S,P}$		$K_{S,P}^{diff,m}$
		Bus 3	Bus 2	
From bus	0	1.016	1.018	-0.002
	1	0.328	0.653	-0.325
	2	0.661	0.333	0.328
	3	-0.202	0.202	-0.404
	4	0	0	0
To bus	0	0.987	0.989	-0.002
	1	0.319	0.635	-0.316
	2	0.645	0.325	0.32
	3	-0.212	0.212	-0.424
	4	$8.70 \cdot 10^{-6}$	$1.17 \cdot 10^{-5}$	$-3 \cdot 10^{-6}$

Table 52: Voltage Magnitude Sensitivity Factors After Trade

Bus index	Sensitivity factors $K_{S,U}$		$K_{S,U}^{diff,n}$
	Bus 3	Bus 2	
0	0	0	0
1	0.001218174	0.001220939	-2.765E-06
2	0.001919442	0.002588889	-0.000669447
3	0.002578504	0.001921465	0.000657039
4	0.001922098	0.002592471	-0.000670373

### Check for contribution to solving the violations

Following the rules presented in 3.3.2 and in line with the process explained for the previous trade, since from Table 51, the sensitivity factor  $K_{S,P}^{diff,1} = -0.325$  for line  $m = 1$  is still negative for both the sending and receiving ends of the line, the trade will contribute to solving the congestion and its feasibility will be determined by the next check on violations in other parts of the network.

### Check for violations in other parts of the network

As already explained, the violations' check at line level will only be relevant for the lines that correspond to positive line apparent power flow sensitivity factors ( $K_{S,P}^{diff,m}$ ). From Table 51 we can see that the selected pair of bids has a positive sensitivity factor only for line 2. So, this is the line that determines the maximum possible traded value in terms of respecting the thermal apparent flow limits.

Regarding the bus voltage magnitude limits, an undervoltage problem could be caused by a positive sensitivity factor  $K_{S,U}^{diff,n}$ , while an overvoltage would be the result of a negative sensitivity factor  $K_{S,U}^{diff,n}$ . Since, as depicted in Table 52, the  $K_{S,U}^{diff,n}$  sensitivities of the evaluated pair are negative for buses 1, 2 and 4, it is expected that the trade will reduce the voltage magnitude of these buses and so, the cleared quantity must be limited to the point where no undervoltages are caused. Respectively, we expect for the trade execution to increase the voltage magnitude of bus 3, and thus need to check the maximum quantity that could be cleared in order not to cause any overvoltage in bus 3.

Applying the values of Table 43, Table 51, Table 52 and Figure 78 to equations (3-34) and (3-36) for the line and for the voltage magnitude limits, the following limitations apply:

Table 53: Acceptable Quantity Range of Second Trade

Network element index		Equation	Upper Limit (MW)
Line apparent power flow limits at "from bus"	2	(3-34)	5.51
Line apparent power flow limits at "to bus"	2	(3-34)	5.83
Bus voltage limits index	0	(3-36)	-
	1	(3-36)	23019.84

	2	(3-36)	116.41
	3	(3-36)	35.94
	4	(3-36)	118.25

The limits shown in Table 53 impose a maximum order quantity of 5.51 MW to ensure that no further line or voltage constraint will be violated. If the submitted quantity is less than 5.51 MW, and since the result of (3-32) is positive, the orders will be feasible and thus fully accepted. Owing to the above analysis, the quantity of 0.9 MW can be fully cleared, and it is expected to fully resolve the congestion. To test this, we rerun the power flow, considering a load increase of 0.9 MW at node 3 and an equal load decrease at node 2. The results are shown in Figure 79 where indeed the overload of line 1 has been resolved.

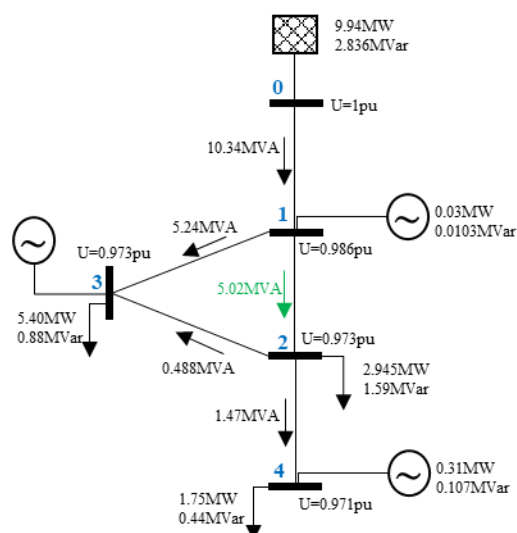


Figure 79: Network with line overload after second trade execution

### 3.6.1.2 One voltage violation

Here the proposed approach in solving an overvoltage is tested. For that, the network also used in subsection 3.6.1.1 is used, and is assumed that the DSO AC power flow run resulted in the grid state variables of Figure 80.

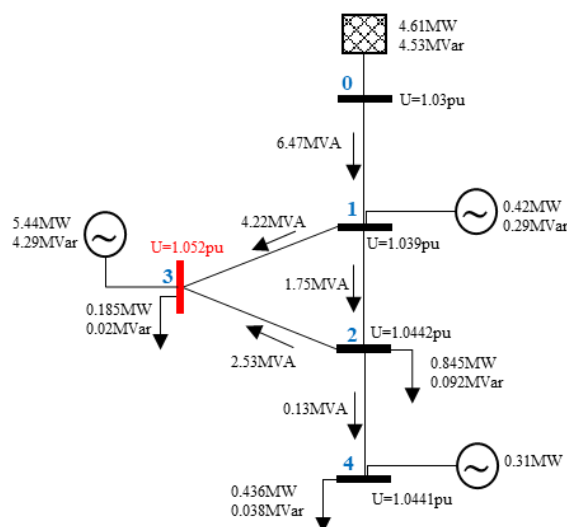


Figure 80: Initial state of a network with overvoltage

Since an overvoltage is detected, the DSO sends the required grid data to the MO in order to open the trading MTU gate for MP orders' submission. As explained before, in case of a voltage violation, the DSO also submits virtual orders. Virtual orders are DSO signals about the presence of a violation and the need for flexibility. The DSO virtual orders are here submitted as price taking orders (price cap for buy orders (e.g. 500 €/MVar) and price floor for sell orders (e.g. 0.5 €/MVar)). The quantity of the DSO orders is calculated as the quantity needed to be submitted by the MPs to each of the buses to reach an optimal operating point of 1p.u. in the bus with the voltage violation. In the examined example, the distance of voltage magnitude from the selected operating point is 0.051842 pu.

For the network of Figure 80, the AC sensitivities of the voltage magnitude for the bus with the overvoltage (here bus 3) with respect to the nodal reactive bus power injections are shown in Table 54. The sensitivity factors are used for the calculation of the DSO orders quantities.

**Table 54: Calculation of DSO orders for overvoltage initial state**

Bus index	Bus 3	Quantity of DSO order (MVar)
	Sensitivity factors $K_{S,U}$	
0	1.00E-08	-
1	0.000777016	$\frac{0.051842}{0.000777016} = 66.72$
2	0.001630866	$\frac{0.051842}{0.001630866} = 31.79$
3	0.002474122	$\frac{0.051842}{0.002474122} = 20.95$
4	0.001631017	$\frac{0.051842}{0.001631017} = 31.79$

To solve the overvoltage, the MPs need to buy reactive power flexibility in order to increase the reactive power of the loads. This means that the DSO submits virtual sell orders of reactive power. The DSO virtual orders can be matched only with MP orders and the relevant violation is essentially alleviated only by the physical deployment of the MP order. Here the DSO orders can be matched with MP reactive power orders of opposite direction (buy orders). Assuming the orderbook of Table 55, the pair of financially feasible orders which will be evaluated first for its network feasibility is [order id = 0, order id = 4].

**Table 55: Initial Orderbook for overvoltage**

Order id	Bus id	Quantity (MVar)	Direction	Price (€/MVar)	Priority	Order status	Actor	Power
0	3	20.95	S	0.5	1	A	DSO	Q
1	4	31.79	S	0.5	2	A	DSO	Q
2	2	31.79	S	0.5	3	A	DSO	Q
3	1	66.72	S	0.5	4	A	DSO	Q
4	3	0.5	B	4	5	A	MP	Q

#### Check for contribution to solving the violations

The first check on the network feasibility is already true since a buy MP order will always help in alleviating an overvoltage.

#### Check for violations in other parts of the network

As already explained, the violations' check at line level will only be relevant for the lines that correspond to positive line apparent power flow sensitivity factors ( $K_{S,Q}$ ).

**Table 56: Line Apparent Power Flow Sensitivity Factors for the initial state**

Line index		Sensitivity factors $K_{S,Q}$
		Bus 3
From bus	0	-0.6736296
	1	-0.2549258
	2	-0.4330104
	3	-0.1905612
	4	0
To bus	0	-0.6757664
	1	-0.2552669
	2	-0.4425107
	3	-0.1911019
	4	8.00E-07

Table 51 shows that all sensitivity factors for the selected pair of orders is negative, meaning that a trade between the two orders is expected to decrease all line flows. Also, since here the effect of one order, and not of a pair of orders, is evaluated, a buy order will always lead in a decrease of the voltage magnitude. Thus, here the maximum quantity that can be cleared in order not to cause an undervoltage to any of the network buses must be evaluated. For this, the voltage magnitude sensitivity factors to the reactive power injection of bus 3 will be used (Table 57).

**Table 57: Voltage Magnitude Sensitivity Factors for overvoltage for the initial state**

Bus index	Sensitivity factors $K_{S,U}$
	Bus 3
0	1.00E-08
1	0.000765364
2	0.001622381
3	0.002474122
4	0.001622559



The upper and lower bus voltage limits are 1.05pu and 0.95pu respectively. For the network of Figure 80, and given the sensitivity factors of Table 57, equation (3-36) implies the following limitations:

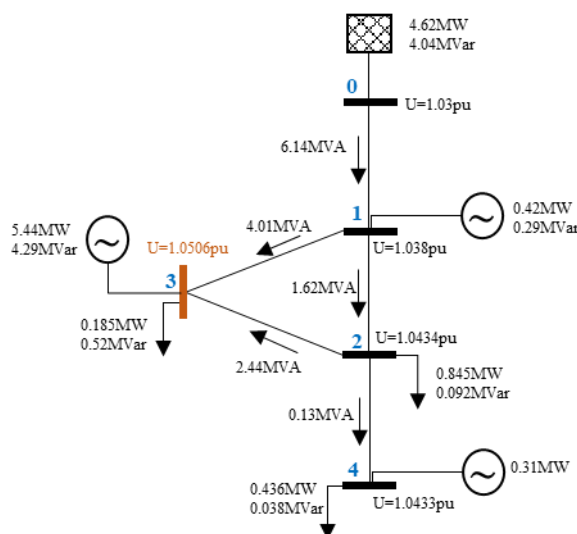
**Table 58: Acceptable Quantity Range of Trade**

Network element index		Equation	Upper Limit (MVar)
Bus voltage limits index	0	(3-36)	-
	1	(3-36)	115.86
	2	(3-36)	58.09
	4	(3-36)	58.01

The limits shown in Table 57 impose a maximum order quantity of 58.01 MVar to ensure that no further voltage constraint will be violated. If the submitted quantity is less than 58.01 MVar the orders will be feasible and thus fully accepted. Also, the minimum quantity to solve the overvoltage will be

$$\frac{|\Delta U_3|}{K_{S,U}^3} = \frac{0.00184}{0.00247} = 0.74$$

Owing to the above analysis, the quantity of 0.5 MVar can be fully cleared, though will not fully resolve the overvoltage. To test this, the power flow is rerun, considering a load increase of 0.5 MVar at node 3. The results are shown in Figure 81. We see that the voltage magnitude of bus 3 is closer to the maximum limit of 1.05p.u., but the overvoltage still exists.



**Figure 81: Network with overvoltage after trade execution**

Since a trade is essentially a change in the grid operating point, the DSO runs again the AC power flow and calculates the new AC sensitivities and DSO orders. Here, the distance of the voltage magnitude from the selected operating point is 0.0506 p.u.

**Table 59: Calculation of DSO orders for overvoltage after trade**

Bus index	Bus 3	Quantity of DSO order
	Sensitivity factors $K_{S,U}$	

0	1.00E-08	-
1	0.000778755	$\frac{0.0506}{0.000778755} = 64.98$
2	0.001635367	$\frac{0.0506}{0.001635367} = 30.94$
3	0.002482374	$\frac{0.0506}{0.002482374} = 20.38$
4	0.001635519	$\frac{0.0506}{0.001635519} = 30.94$

When a MP order is submitted, the market clearing process is run again. The MP order with id = 5 can be cleared with the DSO order of the highest priority. This is the one corresponding to bus 3. The order is financially feasible and helps in alleviating the overvoltage. This is always the case when evaluating a MP order against a DSO order of the same power type and opposite direction.

Table 60: Orderbook for overvoltage updated with new order

Order id	Bus id	Quantity	Direction	Price	Priority	Order status	Actor	Power
0	3	20.38	S	0.5	1	A	DSO	Q
1	4	30.94	S	0.5	2	A	DSO	Q
2	2	30.94	S	0.5	3	A	DSO	Q
3	1	64.98	S	0.5	4	A	DSO	Q
5	3	0.4	B	4	5	A	MP	Q

The maximum acceptable order quantity to avoid violations in other parts of the network must be defined. For the line violations, we check the line apparent power flow sensitivity factors ( $K_{s,q}$ ), and check equation ((3-34)) only in case of a positive sensitivity factor. For the network of Figure 81, the sensitivity factors of line apparent power flows are as follows:

Table 61: Line Apparent Power Flow Sensitivity Factors for overvoltage after trade

Line index		Sensitivity factors $K_{s,q}$
		Bus 3
From bus	0	-0.6343185
	1	-0.2417542
	2	-0.4028051
	3	-0.1755909
	4	0
To bus	0	-0.6342618

	1	-0.2412359
	2	-0.4108165
	3	-0.1755702
	4	8.00E-07

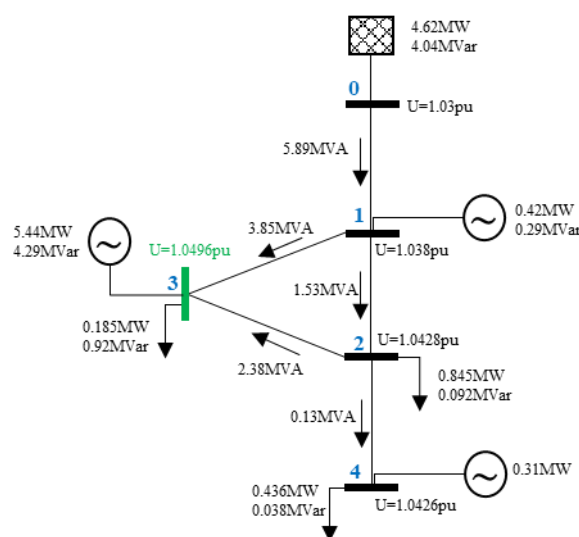
From Table 95 it can be seen that all sensitivity factors for the selected pair of orders is negative or equal to zero, meaning the trade is expected to decrease all line flows.

Also, as here the impact of a buy order is examined, the maximum quantity that can be cleared in order not to cause an undervoltage to any of the network buses must be evaluated. For the network of Figure 81, and given the sensitivity factors of Table 62, equation (3-36) implies the following limitations:

**Table 62: Voltage Magnitude Sensitivity Factors and Acceptable Quantity Range**

Bus index	Sensitivity factors $K_{S,U}$	Equation	Upper Limit (MVar)
	Bus 3		
0	1.00E-08	(3-36)	inf
1	0.000768958	(3-36)	114.82
2	0.001628498	(3-36)	57.37
4	0.001628676	(3-36)	57.29

The above limits impose a maximum order quantity of 57.29 MVar to ensure that no further voltage constraint will be violated. This means that the quantity of 0.4 MVar can be fully cleared. To test the effect of the new trade, we rerun the power flow, considering a load increase of 0.4 MVar at node 3. The results are shown in Figure 82 from which is evident that the overvoltage in bus 3 has been resolved.



**Figure 82: Network with overvoltage after second trade execution**

### 3.6.1.3 Multiple violations

Here we demonstrate the effectiveness of the proposed methodology in solving multiple violations. As shown in Figure 83, the network topology is the same as in the previous examples, but a new operating point is considered which causes three-line overloads and one undervoltage in bus 4. As the network characteristics remain the same, the line thermal limits are considered equal to those of Table 43, and the upper and lower bus voltage limits equal to 1.05pu and 0.95pu respectively. Also, a deviation in the scheduled and offered quantities of the TSO – DSO connection point is considered.

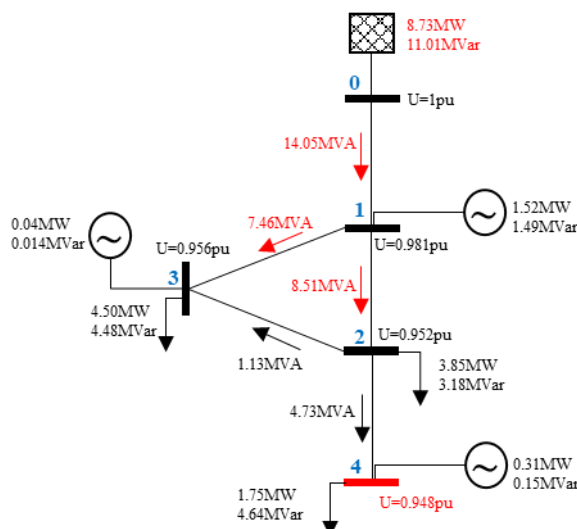


Figure 83: Example of a network with multiple violations

Figure 83 shows the results of the AC power flow run by the DSO and indicates the violations that need to be resolved. The DSO sends to the MO the data required for the operation of the market and submits virtual orders of active and reactive power. Assuming that the scheduled active power exchange in the TSO – DSO connection point is equal to 0.83 MW, the DSO needs to request the consumption of 7.89 MW in order to reach the requested quantity. For the alleviation of the undervoltage, the DSO submits a set of orders, following the methodology already explained in Table 54. The market gate is open for MPs orders submission. Considering that a MP has submitted an active order, the orderbook is formulated as follows:

Table 63: Orderbook for multiple congestions

Order id	Bus id	Quantity	Direction	Price	Priority	Order status	Actor	Power
0	4	14.5 MVar	B	500 €/MVar	1	A	DSO	Q
1	2	17.6 MVar	B	500 €/MVar	2	A	DSO	Q
2	3	26.6 MVar	B	500 €/MVar	3	A	DSO	Q
3	1	57.9 MVar	B	500 €/MVar	4	A	DSO	Q
4	0	7.89 MW	B	500 €/MW	5	A	DSO	P
5	1	0.4 MW	S	35 €/MW	6	A	MP	P

As trades are allowed only between MPs or the DSO and the MPs and need to be of the same power type and opposite direction, the DSO order with the highest priority (namely order with id 0) is evaluated with the single MP order (order with id 5), which is submitted in bus 1.

In order to check the feasibility of the trade, first the contribution to solving the violations needs to be evaluated. As three types of violations appear in the network, each element of Eq (3-32) is evaluated. For the selected network, the base unit quantity for power is  $S_B = 1MVA$ .

For each of the congested lines, the sensitivities of each line apparent flow to an active power injection in bus 1 needs to be calculated. These sensitivities are:

**Table 64: Line Apparent Power Flow Sensitivity Factors for the network with multiple violations**

Line index		Sensitivity factors $K_{S,P}$
		Bus 1
From bus	0	0.6470907
	1	0.0007481
	2	0.0006231
To bus	0	0.6148304
	1	4.67E-05
	2	7.78E-05

In (3-28)  $\Delta P_b$  is negative for a sell order, so, the trade decreases the distance from the line limits by  $Ch_{lines}^{from} = 0.6484619 * |\Delta P_b| pu$  and  $Ch_{lines}^{to} = 0.6149549 * |\Delta P_b| pu$  for the sending and receiving ends respectively.

For the evaluation of the sign and value of (3-30) the sensitivity factor of the voltage measure of bus 4 to the active power injection in bus 1 needs to be evaluated. This is equal to  $K_{U,P}^1 = 0.001219432$  and since in case of a sell order  $\Delta P_b$  is negative, the trade decreases the distance from the lower limit for the voltage by  $Ch_{buses} = 0.001219432 * |\Delta P_b| pu$ .

For the deviations in the TSO-DSO schedule, the decrease in the distance is equal to  $Ch_{TSO-DSO} = |\Delta P_b|$ .

Based on the above calculations, the impact of the trade in solving the network's violations is positive and, based on (3-32), equal to  $Impact^{from} = 1.649681332 |\Delta P_b|$  and  $Impact^{to} = 1.616174332 |\Delta P_b|$  for the receiving and sending end of the lines respectively.

Next, the maximum quantities of the trade need to be defined, in order to prevent the creation of violations in other parts of the network. The acceptable quantities imposed by the bus voltage limits are determined by the sensitivities of the bus voltages to the injection of active power in bus 1. The sensitivities and resulting maximum acceptable quantities are shown in Table 65.

**Table 65: Acceptable Quantity Range of Trade due to bus voltage limits**

Network element index		Equation	Sensitivity factors $K_{U,P}$	Upper Limit (MW)
			Bus 1	
Bus voltage limits index	0	(3-36)	0	-
	1	(3-36)	0.001177	58.62
	2	(3-36)	0.001215	80.72

	3	(3-36)	0.00121	78.00
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For the apparent line flow of the non-congested line (line 3), the sensitivities to the active power flow injection for both flow directions are very limited ( $-0.0000019$  for the sending end and  $0.0000745$  for the receiving end), which cause the upper limit to be a very high quantity, meaning that practically they cannot affect the traded quantities. This means that the pair of orders passes both the financial and network feasibility checks and the quantity of 0.4MW can be fully cleared. The MO sends the updated market schedules to the DSO and since a trade is essentially a change in the grid operating point, the DSO runs again an AC power flow (Figure 84).

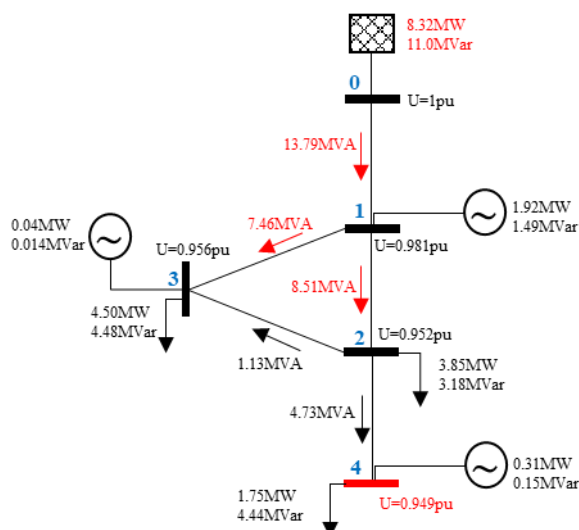


Figure 84: Network of multiple violations after first trade

As there are still violations in the network, the DSO re – submits updated orders in the orderbook and waits for the provision of flexibility by the MPs. In order to evaluate all possible types of trades, let's consider that a MP order of reactive power is submitted in the orderbook as shown below.

Table 66: Orderbook for multiple congestions

Order id	Bus id	Quantity	Direction	Price	Priority	Order status	Actor	Power
0	4	14.4 MVar	B	500 €/MVar	1	A	DSO	Q
1	2	17.4 MVar	B	500 €/MVar	2	A	DSO	Q
2	3	26.3 MVar	B	500 €/MVar	3	A	DSO	Q
3	1	57.3 MVar	B	500 €/MVar	4	A	DSO	Q
4	0	7.48 MW	B	500 €/MW	5	A	DSO	P
5	2	0.7 MVar	S	42 €/MVar	6	A	MP	Q

Considering that reactive power orders can be matched only if they are located in the same bus, the first pair of orders that satisfies the financial feasibility rules described in C1, is the pair of orders submitted in bus 2.

After passing the financial feasibility check, the orders need to be checked for their network feasibility. For the network feasibility, first the impact of the trade in solving the network's violations based on (3-32) needs to be evaluated. Here, as the trade involves reactive power orders, it would not impact the active

power quantity of the TSO – DSO connection point ( $Ch_{TSO-DSO} = 0$ ). For the calculation of the remaining elements of (3-32), namely the impact of the trade in the congested lines ( $Ch_{lines}$ ), and bus with undervoltage ( $Ch_{buses}$ ), the same process as for the first trade is followed.

For each of the congested lines, the sensitivities of each line apparent flow to a reactive power injection in bus 2 are calculated.

**Table 67: Line Apparent Power Flow Sensitivity Factors for the network with multiple violations after the first trade**

Line index		Sensitivity factors $K_{s,q}$
		Bus 2
From bus	0	0.8819928
	1	0.5624185
	2	0.2721914
To bus	0	0.855091
	1	0.5288957
	2	0.2576581

For the bus with the violation (bus 4), the sensitivity factor of the voltage measure to the reactive power injection in bus 2 is  $K_{U,p}^2 = 0.002945133$ . Based on the above calculations, the impact of the trade in solving the network's violations is positive and, based on (3-32), equal to  $Impact^{from} = 1.719547833|\Delta P_b|$  and  $Impact^{to} = 1.644589933|\Delta P_b|$  for the receiving and sending end of the lines respectively.

The next check refers to preventing the creation of violations in other parts of the network. For that, the maximum quantities imposed by the bus voltage and line flow limits need to be determined. As the sensitivity of the apparent line flow of the non-congested line (line 3) to the reactive power flow injection in bus 2 is positive, a sell order in bus 2 would only reduce the apparent power flow of line 3 and thus the trade will not cause any congestion problem to the flow of line 3. The maximum quantities imposed by the voltage limits are shown in Table 68.

**Table 68: Acceptable Quantity Range of Trade due to bus voltage limits**

Network element index		Equation	Sensitivity factors $K_{U,p}$	Upper Limit (MVar)
			Bus 2	
Bus voltage limits index	0	(3-36)	1.10E-08	4545455
	1	(3-36)	0.00093439	73.35476
	2	(3-36)	0.00293324	33.25625
	3	(3-36)	0.00195573	47.99925

As none of the above quantities is greater than the quantity of the trade (0.7 MVar), the trade can be fully cleared and, based on the new market schedules sent by the MO to the DSO, the new AC power flow is ran and leads to the operating condition of Figure 85. It is observed that the undervoltage is solved, but still, most of the network lines are overloaded and the scheduled TSO – DSO active power transfer is not yet reached.

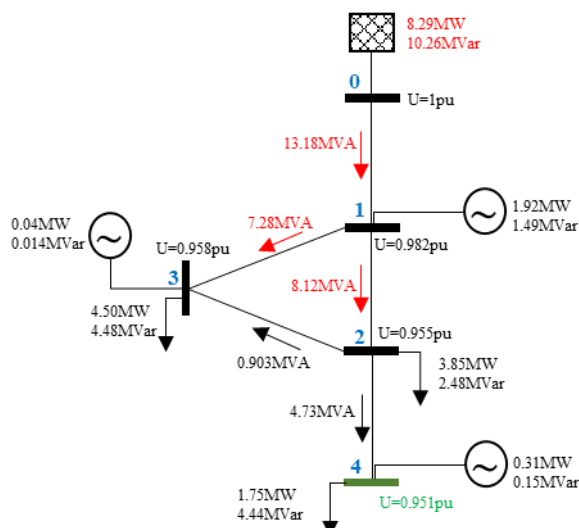


Figure 85: Network of multiple violations after second trade

To resolve the remaining issues, a new market instance is run based on the grid state variables of Figure 85. The DSO calculates and sends to the MO all the necessary data required to operate the market and submits virtual orders. While the trading MTU gate is open, MPs can submit active/reactive power orders based on their available flexibility. As there is no voltage violation, the DSO only submits a virtual order of active power, which refers to the TSO – DSO connection point. To investigate all available types of trades, we assume that also two MPs orders of active power are available, which are of higher priority than the DSO virtual order (Table 66). This means that the trade between the two MPs needs to be first assessed for its feasibility.

Table 69: Orderbook for multiple congestions

Order id	Bus id	Quantity	Direction	Price	Priority	Order status	Actor	Power
0	2	0.8 MW	B	50 €/MW	1	A	MP	P
1	0	7.44 MW	B	500 €/MW	2	A	DSO	P
2	3	7 MW	S	28 €/MW	3	A	MP	P

In order to check the contribution of the trade to solving the violations, we need to check if the value of Eq (3-32) is positive.

Table 70: Line Apparent Power Flow Sensitivity Factors for the congested lines

Line index		Sensitivity factors $K_{S,P}$		$K_{S,P}^{diff,m}$
		Bus 2	Bus 3	
From bus	0	0.692	0.689	0.0023845
	1	0.446	0.226	0.220618
	2	0.237	0.467	-0.22977
To bus	0	0.660	0.657	0.0023



	1	0.421	0.212	0.208213
	2	0.225	0.443	-0.21839

From Table 70, Eq (3-28) and (3-30), Eq (3-32) is evaluated to  $Impact^{from} = 0.0067669|\Delta P_b|$  and  $Impact^{to} = 0.007874|\Delta P_b|$ , from which it can be understood that the impact of the trade is positive. Delving in more detail, the results of the Table 70 show that the trade will result in higher loading for lines 0 and 1, since the relevant sensitivity factors ( $K_{S,P}^{diff,m}$ ) are positive, but in parallel, the loading of line 2 will decrease. Since the decrease of line 2 loading is higher than the increase in the loading of lines 0 and 1, the impact of the trade is positive and could be ultimately cleared.

For the identification of the trade acceptable range, the buses and lines of the network with no violations must be checked. For that we use the sensitivity factors of the voltage magnitude of each bus (Table 99) and the apparent flow of lines 3 and 4, to active power changes in buses 3 and 2.

**Table 71: Voltage Magnitude Sensitivity Factors for the examined trade**

Bus index	Sensitivity factors $K_{S,U}$		$K_{S,U}^{diff,n}$
	Bus 2	Bus 3	
0	0	0	0
1	0.001227075	0.001223895	3.18E-06
2	0.002640244	0.001957387	0.000683
3	0.001956944	0.002624569	-0.00067
4	0.002650902	0.001965289	0.000686

As explained in the first example, a positive sensitivity factor  $K_{S,U}^{diff,n}$  could result in an undervoltage problem, since a positive sensitivity factor will mean that the load of the examined bus increases; and, accordingly, an overvoltage would be the result of a negative sensitivity factor  $K_{S,U}^{diff,n}$ .

**Table 72: Line Apparent Power Flow Sensitivity Factors for the non congested lines**

Line index		Sensitivity factors $K_{S,P}$		$K_{S,P}^{diff,m}$
		Bus 2	Bus 3	
From bus	3	0.1076785	-0.1076384	0.215317
	4	0	0	0
To bus	3	0.1117984	-0.1114766	0.223275
	4	0.0001092	8.10E-05	2.82E-05

The violations' check at line level is relevant for the lines that correspond to positive line apparent power flow sensitivity factors ( $K_{S,P}^{diff,m}$ ). This means that both lines need to be checked, although, given the values of the respective sensitivity factors, we expect that the margin imposed by line 4 will be high and thus will not affect the results. Based on the above analysis, the limitations on the maximum traded quantities are formulated as follows:

Table 73: Maximum Acceptable Quantity Range of Trade

Network element index		Equation	Upper Limit (MW)
Line apparent power flow limits at “from bus	3	(3-34)	13.304
	4	(3-34)	-
Line apparent power flow limits at “to bus”	3	(3-34)	12.93
	4	(3-34)	11924.55
Bus voltage limits index	0	(3-36)	-
	1	(3-36)	10097.31
	2	(3-36)	6.59
	3	(3-36)	-138.57
	4	(3-36)	<b>0.999</b>

The limits shown in Table 48 impose a maximum order quantity of 0.999 MW to ensure that no further line or voltage constraint will be violated. This means that the trade of 0.8MW will be fully cleared. Since a trade is essentially a change in the grid operating point, the DSO runs again an AC power flow, considering a load increase of 0.8 MW at node 2 and an equal load decrease at node 3. The results are shown in Figure 86.

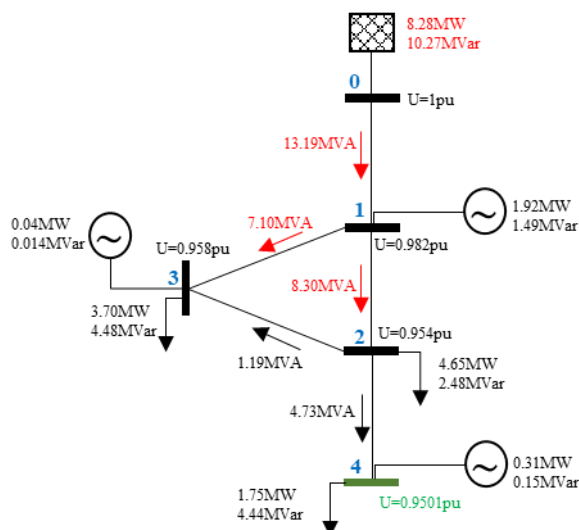


Figure 86: Network with multiple violations after third trade execution

### 3.6.2 Model validation in large MV networks

#### 3.6.2.1 Market model validation – network of 100 buses

The scalability of the proposed mechanism is first tested in the network with id = 0 shown in section 3.4.2, under the unexpected sunny day scenario described in section 3.4.1. The examined network setpoint is given in Annex C (C.1). The disturbance scenario selected for the market simulation replicates the under-forecasting of local RES production for the whole area and contains 11 violations; 2 overvoltages, 8 line congestions and a deviation in the schedule of the TSO-DSO connection point. A

line congestion is considered when the line loading exceeds the line thermal capacity, while the upper and lower bus voltage limits are 1.05pu and 0.95pu respectively. The scheduled active power exchange between the TSO – DSO is considered equal to -9.13 MW, while its current value is equal to -28.364MW. Table 74 gives an overview of the line congestions and Table 75 presents the overvoltages.

**Table 74: Line flows exceeding line thermal capacity**

Overloaded lines	Apparent flow measured in the sending end (from)	Apparent flow measured in the receiving end (to)	Distance from the limit (from)	Distance from the limit (to)	Maximum thermal limit
21	5.838	5.795	-0.3820	-0.3395	5.456
63	6.246	6.315	-0.7900	-0.8593	5.456
64	6.3217	6.380	-0.8651	-0.9241	5.456
97	7.624	7.649	-1.9084	-1.9329	5.456
118	5.748	5.778	-0.2919	-0.3223	7.353
125	11.247	11.332	-0.3096	-0.3942	10.938
126	14.182	14.276	-1.9711	-2.0654	12.211
127	14.182	14.276	-1.9711	-2.0654	12.211

**Table 75: Buses with overvoltages**

Buses with violation	Voltage measure (pu)	Violation of operational limit
65	1.050555	-0.000554975
66	1.06036	-0.010360249

The DSO sends to the MO the necessary data to operate the market and submits virtual orders of active and reactive power to the orderbook. For active power, a sell order of 19.232 MW is submitted in bus 0. In addition, sell reactive power orders are submitted by the DSO in different parts of the network in order to solve the network overvoltages. The virtual orders submitted by the DSO are presented in Table 105 of Annex C (C.1). The impact of three types of trades will be presented below:

- **Case 1** Active power trade between the DSO and the MP
- **Case 2** Reactive power trade between the DSO and a MP
- **Case 3** Active power trade between two MPs

### Case 1: Active power trade between the DSO and a MP

It is assumed that a MP is willing to buy active power (0.4 MW) at bus no 21 to respond to the DSO flexibility needs. The MP order can be traded with the DSO active power order submitted in bus 0 (Table 105 of Annex C (C.1)). As the DSO order is a price taking sell order, the trade is financially feasible. The network feasibility of the trade is assessed by checking the contribution of the trade to solving the violations (Eq (3-32)) and the creation of violations in other parts of the network (Eq (3-34), (3-36)). For the first check,  $S_B = 1MVA$  is used as the base unit quantity for power. The sensitivity factors of the line apparent power flow of the congested lines and voltage magnitude of the buses with overvoltage to the active power change of bus 21 are presented in Table 76 and Table 77 respectively. From Eq. (3-28), (3-30), (3-31), (3-32) it is observed that the potential trade will lead to a positive impact in the network violations, equal to  $3.360021292 * |\Delta P_b|$  and  $3.373584192 * |\Delta P_b|$ , to the sending and receiving ends respectively.

**Table 76: Case 1: Line Apparent Power Flow Sensitivity Factors for the congested lines**

Line id	Sensitivity factors $K_{S,P}$	
	from	to
21	-0.4711213	-0.4646464
63	-5.25E-05	-2.42E-05

64	-2.42E-05	0.0000000
97	-0.45723	-0.4600711
118	-0.4600139	-0.4646595
125	-3.63E-05	0.0000000
126	-0.4864691	-0.4927147
127	-0.4864691	-0.4927147

Table 77: Case 1: Voltage Magnitude Sensitivity Factors for the buses with the overvoltage

Bus index	Sensitivity factors $K_{s,u}$
65	0.00021991
66	0.000217903

In order to assure that the potential trade does not create any new violations in the network, we need to calculate the impact of the trade to the non-congested lines and buses without violations, and from that the maximum quantity that can be traded. Depending on the value of the respective sensitivity factor (Table 106 and Table 107 of Annex C), the trade could either increase or decrease the apparent power flow of a line or the voltage of a bus, meaning that only some of the lines and/or buses could impose a limit to the maximum traded quantity. For the examined network and operating point, 45 lines are negatively affected by the trade, meaning that the trade would potentially increase their loading, but, still, the negative impact of the trade on them is low. The maximum limit based on (3-34) is 10.33 MW and is imposed by line 20. The limitations of (3-36) imposed by the bus voltages imply a maximum quantity of 24.58 MW. Ultimately the margin for the examined trade is the lowest between the two quantities (10.33 MW – 24.58 MW), and, thus, the trade of 0.4 MW is fully traded. The MO informs the DSO about the new trade and the updated market schedules and the DSO runs again the power flow to calculate the new operating point.

It is expected that the trade will alleviate the line congestions and overvoltages, meaning that the distance from the operational limits will be closer to zero. Also, we expect that no new violation will be caused in the network. The active power of the TSO – DSO connection point is expected to change due to the active power trade and be closer to the initial quantity of -9.13 MW (Table 78). These remarks are validated by comparing the AC power flow results of the new operating point to the network variables' values before the trade (Table 79 for the line apparent flow and Table 80 for the voltages), from which it can be seen that the aggregated impact of the trade is positive. In detail, the results of the new power flow are provided in C.2.

Table 78: Case 1: Impact of trade to the TSO – DSO connection point schedule

Power after trade	Power before trade	Reduction of violation due to trade
-28.35981	-28.363872	0.0041

Table 79: Case 1: Impact of trade to the reduction of congestions

Congested lines	Distance from the limit (from) – after trade	Distance from the limit (to) – after trade	Distance from the limit (from) – initial	Distance from the limit (to) – initial	Reduction of congestion due to trade (from)	Reduction of congestion due to trade (to)
21	-0.29198882	-0.250771794	-0.38200111	-0.33950428	0.090012	0.088732
63	-0.79001537	-0.859316751	-0.79003653	-0.85932650	2.12E-05	9.75E-06
64	-0.86509396	-0.924106035	-0.86510372	-0.92410604	9.76E-06	2.54E-11
97	-1.82113426	-1.845077124	-1.90837591	-1.93285712	0.087242	0.08778
118	-0.20409624	-0.233609067	-0.29190378	-0.32233531	0.087808	0.088726
125	-0.30956594	-0.39427027	-0.30958058	-0.39427027	1.46E-05	2.62E-12

126	-1.77596205	-1.867712013	-1.97111465	-2.06539362	0.195153	0.197682
127	-1.77596205	-1.867712013	-1.97111465	-2.06539362	0.195153	0.197682

Table 80: Case 1: Impact of trade to the reduction of voltage violations

Buses with violation	Violation of operational limit (after trade)	Violation of operational limit (initial)	Reduction of violation due to trade
65	-0.000466295	-0.000554975	8.86796E-05
66	-0.010272379	-0.010360249	8.78701E-05

**Case 2: Reactive power trade between a MP and the DSO**

It is assumed that a MP is willing to buy reactive power (0.04 MVar) at bus no 66 to respond to the DSO flexibility needs. The MP order will be traded with the DSO reactive power order submitted in the same bus (Table 105 of Annex C (C.1)). As the DSO order is a price taking sell order, the trade is financially feasible. The network feasibility of the trade is assessed by checking the contribution of the trade to solving the violations (Eq (3-32)) and the creation of violations in other parts of the network (Eq (3-34), (3-36)). For the first check,  $S_B = 1MVA$  is used as the base unit quantity for power. The sensitivity factors for the line apparent power flow of the congested lines and voltage magnitude of the buses with overvoltage to the trade of bus 66 are presented in Table 81 and Table 82 respectively. Taking into consideration that the loading of a line decreases when the relevant line apparent power flow sensitivity factor is negative, and that a buy reactive power order always contributes in solving an overvoltage, the trade will lead to a positive impact in the network violations, equal to  $0.006193446 * |\Delta P_b|$  and  $0.016487146 * |\Delta P_b|$ , when calculating power flows on the sending and receiving ends respectively.

Table 81: Case 2: Line Apparent Power Flow Sensitivity Factors for the congested lines

Line id	Sensitivity factors $K_{S,Q}$	
	from	to
21	0.0000171	-0.0000142
63	-0.0001376	-0.0000634
64	-0.0000635	0
97	-0.0000546	-0.0000364
118	-0.0000365	-0.0000142
125	-0.0000620	0
126	-0.0026657	-0.0079227
127	-0.0026657	-0.0079227

Table 82: Case 2: Voltage Magnitude Sensitivity Factors for the buses with the overvoltage

Bus index	Sensitivity factors $K_{S,U}$
65	0.000576705
66	0.000571441

In order to prevent the creation of any other violation in the network, the maximum quantity that can be traded is calculated. For that, the impact of the trade to the non-congested lines and buses without violations is investigated. Depending on the value of the respective sensitivity factor (Table 110 and Table 111 of Annex C.3), the trade could either increase or decrease the apparent power flow of a line or the voltage of a bus, meaning that only some of the lines and/or buses could impose a limit to the maximum traded quantity. For the examined network and operating point, 32 lines are negatively affected by the trade, meaning that the trade would potentially increase their loading, but, still, the negative impact of the trade on them is low. The maximum limit based on (3-32) is 140.96 MVar and is

imposed by line 59. The limitations of (3-36) imposed by the bus voltages imply a maximum quantity of 95.5 MVar. Ultimately the margin for the examined trade is the lowest between the two quantities (140.96 MVar – 95.5 MVar), and, thus, the trade can be fully cleared. The DSO is informed by the MO for the new market schedule and runs again the power flow to check the changes of the new operating point.

It is expected that the trade will alleviate most of the line congestions and all overvoltages, meaning that the distance from the operational limits will be closer to zero. In particular, we expect an increase in the loading of line 21 (when calculated from the sending end) and a decrease in the loading of the remaining congested lines. Also, we expect that no new violation will be caused in the network. The active power of the TSO – DSO connection point is expected not to be changed significantly, as the cleared trade is of reactive power. These remarks are validated by comparing the AC power flow results of the new operating point to the network variables' values before the trade (Table 83 for the line apparent flow and Table 84 for the voltages), from which we can see that the aggregated impact of the trade is positive. In detail, the results of the new power flow are provided in Annex C.3.

**Table 83: Case 2: Impact of trade to the reduction of congestions**

Congested lines	Distance from the limit (from) – after trade	Distance from the limit (to) – after trade	Distance from the limit (from) – initial	Distance from the limit (to) – initial	Reduction of congestion due to trade (from)	Reduction of congestion due to trade (to)
21	-0.382001791	-0.339503708	-0.38200111	-0.33950428	-6.8243E-07	5.6797E-07
63	-0.790030626	-0.859323784	-0.79003653	-0.85932650	5.9018E-06	2.7200E-06
64	-0.865101002	-0.924106035	-0.86510372	-0.92410604	2.7220E-06	0
97	-1.908373723	-1.932855663	-1.90837591	-1.93285712	2.1863E-06	1.4578E-06
118	-0.291902321	-0.322334745	-0.29190378	-0.32233531	1.4609E-06	5.6782E-07
125	-0.309578103	-0.39427027	-0.30958058	-0.39427027	2.4816E-06	0
126	-1.971032174	-2.065101144	-1.97111465	-2.06539362	8.2474E-05	2.9247E-04
127	-1.971032174	-2.065101144	-1.97111465	-2.06539362	8.2474E-05	2.9247E-04

**Table 84: Case 2: Impact of trade to the reduction of voltage violations**

Buses with violation	Violation of operational limit (after trade)	Violation of operational limit (initial)	Reduction of violation due to trade
65	-0.000530241	-0.000554975	8.86796E-05
66	-0.010335741	-0.010360249	8.78701E-05

### Case 3: Active power trade between MPs

In this section, the trading of active power between two MPs is presented (Table 85).

**Table 85: Case 3: MPs orders**

Order id	Bus id	Quantity	Direction	Price	Priority	Order status	Actor	Power
239	10	0.8 MW	B	34 €/MW	239	A	MP	P
240	20	0.5 MW	S	23 €/MW	240	A	MP	P

The network feasibility of the trade is assessed by checking the contribution of the trade to solving the violations (Eq (3-32)) and the creation of violations in other parts of the network (Eq (3-34), (3-36)). For the first check,  $S_B = 1MVA$  is used as the base unit quantity for power. The sensitivity factors for the line apparent power flow of the congested lines and voltage magnitude of the buses with overvoltage to the examined trade are presented in Table 76 and Table 77 respectively. From Eq. (3-28), (3-30), (3-32) it is true that the trade will lead to a positive impact in the network violations, equal to  $0.757269826 * |\Delta P_b|$  and  $0.757829426 * |\Delta P_b|$ , when calculating power flows on the sending and receiving ends respectively.

Table 86: Case 3: Line Apparent Power Flow Sensitivity Factors for the congested lines

Line index		Sensitivity factors $K_{S,P}$		$K_{S,P}^{diff,m}$
		Bus 10	Bus 20	
From bus	21	-0.0858021	-0.3422432	-0.2564411
	63	-5.26E-05	-5.26E-05	0
	64	-2.42E-05	-2.43E-05	-1.00E-07
	97	-0.0832022	-0.3318869	-0.2486847
	118	-0.0837277	-0.3339697	-0.250242
	125	-3.64E-05	-3.64E-05	0
	126	-0.4856584	-0.4866093	-0.0009509
	127	-0.4856584	-0.4866093	-0.0009509
To bus	21	-0.0845963	-0.3374274	-0.2528311
	63	-2.42E-05	-2.42E-05	0
	64	0	0	0
	97	-0.0837131	-0.3339625	-0.2502494
	118	-0.0845932	-0.3374256	-0.2528324
	125	0	0	0
	126	-0.4919896	-0.4929478	-0.0009582
	127	-0.4919896	-0.4929478	-0.0009582

Table 87: Case 3: Voltage Magnitude Sensitivity Factors for the buses with the overvoltage

Bus index	Sensitivity factors $K_{S,U}$		$K_{S,U}^{diff,n}$
	Bus 10	Bus 20	
65	0.000220317	0.00022038	6.30E-08
66	0.000218306	0.000218369	6.30E-08

In order to prevent the creation of any other violation in the network, the maximum quantity that can be traded is calculated. For that, the impact of the trade to the non-congested lines and buses without violations is investigated. Depending on the value of the respective sensitivity factor (Table 114 and Table 115 of Annex C.4), the trade could either increase or decrease the apparent power flow of a line or the voltage of a bus, meaning that only some of the lines and/or buses could impose a limit to the maximum traded quantity. For the examined network and operating point, 79 lines are negatively affected by the trade, meaning that the trade would potentially increase their loading, but, still, the negative impact of the trade on them is low. The maximum limit based on (3-34) is 4.92 MW and is imposed by line 9. The limitations of (3-36) imposed by the bus voltages imply a maximum quantity of 10.25 MW. Ultimately the margin for the examined trade is the lowest between the two quantities (4.92 MW - 10.25 MW), and, thus, the trade can be fully cleared. The DSO is informed by the MO for the new market schedule and runs again the power flow to check the changes of the new operating point.

It is expected that the trade will alleviate the line congestions and overvoltages, meaning that the distance from the operational limits will be closer to zero. Also, we expect that no new violation will be caused in the network. The active power of the TSO – DSO connection point is expected not to be changed significantly, as the net active power change due to the trade is zero. These remarks are validated by comparing the AC power flow results of the new operating point to the network variables' values before the trade (Table 88 for the line apparent flow and Table 89 for the voltages), from which it can be seen that the aggregated impact of the trade is positive. In detail, the results of the new power flow are provided in Annex C.4.

Table 88: Case 3: Impact of trade to the reduction of congestions

Congested lines	Distance from the limit (from) – after trade	Distance from the limit (to) – after trade	Distance from the limit (from) – initial	Distance from the limit (to) – initial	Reduction of congestion due to trade (from)	Reduction of congestion due to trade (to)
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21	-0.31409008	-0.272570555	-0.38200111	-0.33950428	0.06791103	0.066933725
63	-0.79003621	-0.859326358	-0.79003653	-0.85932650	3.2E-07	1.42E-07
64	-0.86510358	-0.924106035	-0.86510372	-0.92410604	1.4E-07	5E-09
97	-1.84258448	-1.866656537	-1.90837591	-1.93285712	0.06579143	0.066200583
118	-0.22567746	-0.255407395	-0.29190378	-0.32233531	0.06622632	0.066927915
125	-0.30958037	-0.39427027	-0.30958058	-0.39427027	2.1E-07	0
126	-1.96908250	-2.063329329	-1.97111465	-2.06539362	0.00203215	0.002064291
127	-1.96908250	-2.063329329	-1.97111465	-2.06539362	0.00203215	0.002064291

Table 89: Impact of trade to the reduction of voltage violations

Buses with violation	Violation of operational limit (after trade)	Violation of operational limit (initial)	Reduction of violation due to trade
23	-0.000553648	-0.000554975	1.32727E-06
35	-0.010358934	-0.010360249	1.31459E-06

### 3.6.2.2 Market model validation – network of 1000 buses

In this section the proposed methodology is validated in a large MV network. In particular, the network with id = 4 shown in section 3.4.2. The loading scenario under which the market solution is validated is depicted in Figure 87.

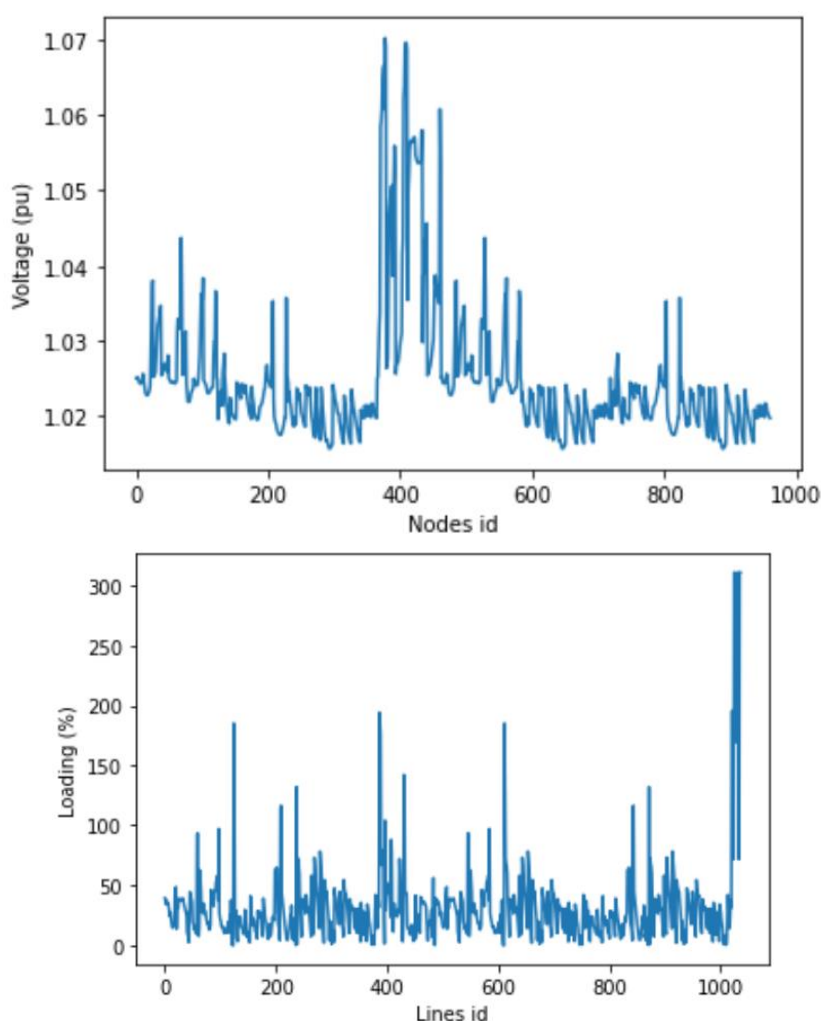


Figure 87: Line loading and voltage magnitude data for the large MV network



In the network setpoint there are 30-line congestions, 49 overvoltages and deviations in the TSO – DSO connection point schedules. For the alleviation of the violations, the impact of two active power MPs orders will be investigated

**Table 90: MPs orders for the network of 1000 buses**

Order id	Bus id	Quantity	Direction	Price	Actor	Power
1	463	1 MW	S	26 €/MW	MP	P
2	430	0.3 MW	B	32 €/MW	MP	P

The impact of the potential trade is calculated using

- the sensitivity factors of the line apparent power flow (of the congested lines) to the active power injection of the buses where the orders have been submitted
- the sensitivity factors of the voltage (of the buses with voltage violations) to the active power injection of the buses where the orders have been submitted

These are depicted in Table 91 and Table 92 respectively.

**Table 91: Trade line apparent power flow sensitivity factors for the congested lines**

Line id	$K_{S,P}^{diff,m}$	
	from	to
97	0	0
124	0	0
125	0	0
208	0	0
209	0	0
237	0	0
386	-0.00018	-0.00016
387	-0.00016	-0.00015
388	-0.00015	-0.00014
396	-7.25E-05	4.90E-06
430	-0.70735	-0.72132
431	-0.72111	-0.74142
584	0.018067	0.018136
611	0.000132	0
612	8.55E-05	0
842	0	0
843	0	0
871	0	0
1020	0	0
1021	0	0
1024	0	0
1025	0	0
1026	-0.3008	-0.30527
1027	-0.3008	-0.30527
1028	0.305824	0.310513
1029	0.305824	0.310513
1030	0	0

1031	0	0
1034	0	0
1035	0	0

Table 92: Trade voltage measure sensitivity factors for the violated buses

Bus index	$K_{s,u}^{diff,n}$
368	0.000260692
369	0.000260515
370	0.00026016
371	0.000259201
372	0.000258899
373	0.000258787
374	0.000260164
375	0.000257878
376	0.000258181
381	0.001952384
382	0.002099006
383	0.002221746
384	0.002271069
385	0.002442468
387	0.000263237
388	0.000261989
389	0.00026075
390	0.000261515
403	0.000259798
404	0.000259464
405	0.000258251
406	0.000258088
407	0.000258101
408	0.000258302
410	0.002109444
411	0.00281546
412	0.003922212
413	0.004232829
414	0.00436595
415	0.004315999
416	0.004258125
417	0.00422186
418	0.004061842
419	0.003741241
420	0.003494943
421	0.003051162
422	0.002965075
423	0.002915076
424	0.002886491
425	0.002887153
426	0.002887013
427	0.002886846
428	0.002886594

429	0.002886318
430	0.004717739
431	0.004716849
438	0.000263256
458	0.000260166
459	0.002887031

Since the net change in the active power injection is zero, the impact of the trade to the network violations, based on Eq (3-32), is determined by the impact of the trade to the line apparent power flows ( $1.4007047 * |\Delta P_b|$  - from and  $1.4345641 * |\Delta P_b|$  - to) and voltage measure value ( $0.09655732 * |\Delta P_b|$ ). From (3-32) it is true that the trade will lead to a positive impact in the network violations, equal to  $1.497262 * |\Delta P_b|$  and  $1.53112142 * |\Delta P_b|$ , when calculating power flows on the sending and receiving ends respectively. Based on the impact of the trade to the non-congested lines and buses (equations (3-34) and (3-36)) without violations, the maximum quantity that can be traded is 30.64MW, which means that the trade can be fully cleared.

It is expected that the new network operating point will lead to a reduction in the sum of the violations from the operating limits. We validate this by rerunning the network, which leads to the results of the following table. Please note that the sum of the violations is the metric used in Eq (3-32).

**Table 93: Sum of distance of violations from operational limits before and after trade**

Type of violations	Sum of distance from limits (initial)	Sum of distance from limits (after trade)
Line congestions	174.58742 pu	174.30727 pu
Overvoltages	0.62167pu	0.58424pu

## 4 Real Time Market Mechanism

### 4.1 Introduction

In recent years, the deployment of renewable and flexibility resources in medium and low-voltage distribution systems has generated an interest by industry stakeholders and the academic community for designing and implementing “flexibility” platforms [40]. The potential benefits of such platforms are numerous. They can support an increased deployment of distributed renewable supply, safeguard the distribution network (DN) and postpone DN expansion, and mobilize demand-side flexibility. The latter objective, in itself, produces numerous short-term operational efficiencies and long-term benefits in terms of generating robust investment signals for the market [41].

In a nutshell, such flexibility platforms aim at transposing the advanced optimization functions that coordinate resources at the high-voltage grid down to the medium (and eventually low) voltage network. The interest is in accommodating DN constraints (voltage limits, reactive power flows, power losses, thermal limits of lines, and so on) in the optimization of system operation. This challenge necessarily increases the scale of the resulting coordination problem, since resources need to be accounted for at the scale of individual distribution nodes. Recent European legislation underscores the importance of Transmission-Distribution (T&D) coordination ([42], [43]).

The implementation of a T&D platform should be capable of meeting several challenging requirements that are exposed in the following paragraphs [11].

- a) **Physical considerations:** Flexibility platforms typically include two physical complications: (i) market bids at both the T&D level can be non-convex, and (ii) the DN model is based on a non-convex alternating current (AC) power flow. Non-convex market offers at the distribution level can be understood because of the disaggregated representation of resources in DNs. Linear approximations of power flow are not adequate for representing a number of relevant DN constraints, due to the lower voltage level at which these systems operate. A commonly employed approximation [44] is to consider convex relaxations of the AC power flow equations in order to represent DN constraints, and linear approximations for a meshed transmission network (TN).
- b) **Scalability:** Integrating T&D networks naturally leads to considering market clearing problems of very large scale [40]. Certain flexibility platforms [45] additionally incorporate multi-interval look-ahead [46]. The very large scale of the problem is compounded by the challenge that a real-time / balancing dispatch and market clearing platform is afforded a very limited run time.
- c) **Decentralization:** In addition to computational concerns, there are also institutional drivers for considering a decentralized integration of flexibility platforms. Indeed, it is not uncommon for TSOs to be reluctant of undertaking the responsibility for optimizing the management of assets at the level of DNs, since the monitoring, optimization, control and settlement of these assets introduces overwhelming complexity to TSO operations. On the other hand, DSOs may also be reluctant of surrendering the control of assets to an entity that has no visibility of their network constraints and may therefore overload DN assets through the activation of flexible distribution resources.
- d) **Institutional boundary conditions:** European market operations are becoming increasingly integrated, especially closer to real time. Since T&D flexibility platforms are typically situated at or near real time, it is necessary to define a precise interface between these platforms and the European balancing market. Moreover, any flexibility market proposal should account for the roles and responsibilities of implicated market actors, including TSOs (typically responsible for balancing and congestion management at transmission level) and DSOs (typically responsible for congestion management at distribution level). Finally, it is important to acknowledge the spatial and temporal resolution at which system information (e.g. imbalances) can be measured.
- e) **Consistent pricing:** Flexibility market clearing platforms are further required to generate price signals that are consistent with dispatch instructions. Since the matching problem is non-convex, uniform market clearing prices are not guaranteed to exist. This is due both to the non-convexity of the market offers [47], as well as the non-convexity of the AC power flow [48].

## 4.2 Market Design

The market platform that we propose aims at implementing a real-time market for clearing energy while accounting for T&D network constraints. In EU jargon, we implement an integrated real-time congestion management and balancing platform. The market dispatches flexible resources in real time to balance the system while ensuring that network constraints are safeguarded. The platform produces locational marginal prices (LMPs) for energy at the transmission level, and LMPs for real and reactive power at the distribution level. Reserve capacity [40] is considered as being out of scope for the present work.

### 4.2.1 Actors and Roles

The market platform that we propose trades location-specific real power at the transmission system, and location-specific real and reactive power at the distribution system. We assume a single meshed TN connected to a number of DNs, with each DN interconnected to the TN via a unique feeder, which we will also refer to as a T&D interconnection (see Figure 81). The interconnection is assumed to be part of the DN.

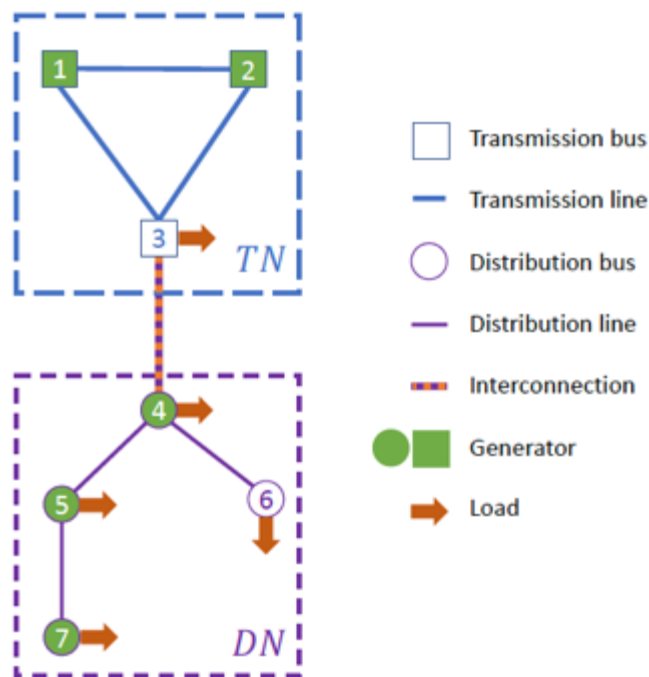


Figure 88: Illustration of the T&D network structure.

We consider the following agents in our market model:

- a) **Transmission System Operator (TSO):** The TSO procures real power from BSPs that are connected in the TN, as well as real power from the DSO at the T&D interface (e.g. the medium-to-high-voltage feeders). The TSO collects payments from BRPs for real power, as well as payments from the DSO for the exchange of real power at the T&D interface.
- b) **Distribution System Operator (DSO):** The DSO is responsible for congestion management at the level of the DN. We envision a DSO that operates an active distribution management system.
- c) **Balancing Service Provider (BSP):** BSPs operate assets that can be actively dispatched in order to resolve congestion and balance the system, i.e. they are the owners of reserve assets. This is precisely what we refer to as “flexibility”. In EU jargon, we specifically refer to BSPs as owners of automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR) assets. These correspond to reserve resources that can respond within a few seconds to a few minutes. In terms of the mathematical models that are presented in the sequel, we will identify BSPs as price-responsive “generators”.

- d) **Balancing Responsible Party (BRP)**: Balancing responsible parties are owners of non-flexible assets, i.e. assets that are not controllable and that induce imbalances in real time. DN BRPs face a location-specific price for real power and reactive power, against which their imbalances are settled. TN BRPs face a location-specific price for real power. In terms of the mathematical models that are presented in the sequel, we will identify BRPs as price-inelastic “loads” at each bus of the network.
- e) **Aggregation-Disaggregation System (ADS)**: The ADS implements the decentralization of T&D system operations by aggregating distribution system BSP offers, trading energy at the T&D interface, and subsequently disaggregating the interface flow to BSP activations within the DN. The flexibility platform also determines the location-specific real and reactive prices of the DN.

The actors listed above are aligned with the ones defined in deliverable D1.1 of FEVER, except for the ADS, which is specific to this deliverable. In practice, the ADS could either be the DSO or an independent market operator (MO), which are both defined in D1.1.

## 4.2.2 Market Structure

In order to accommodate TSO-DSO coordination while maintaining decentralized operations for network operators, we propose the introduction of an ADS which relies on Residual Supply Functions (RSFs) ([49], [50]). The idea of the RSF is to evaluate the cost of exporting real power flow from the DN at the level of the interface. One RSF is defined for every T&D interface. An important advantage of RSFs is their direct interpretation as bids in the balancing market operated by the TSO, which mask the complexity of the underlying DN. The ADS computes an RSF by collecting the market bids of all BSPs that are connected to the DN of a given DSO, as well as the relevant DN parameters from the DSO. The RSF can then be bid into the wholesale market and compete on equal footing with the BSP offers of transmission-level BSPs. The clearing of the market implies a net position for the DSO. This net position needs to be disaggregated to individual BSPs at the DN by the disaggregation function of the ADS. Note that this idea can be generalized to interactions between system operators, for example the coordination of European balancing platforms [49]. Figure 82 provides an illustration of the timeline of events that we envision in the implementation of our proposed hierarchical market design.

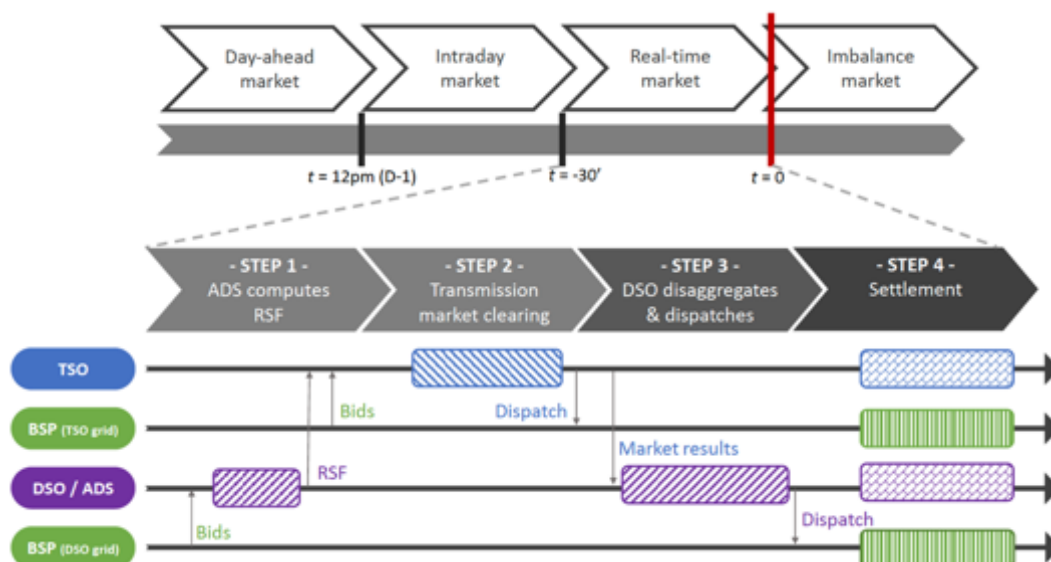


Figure 89: Sequence of events in our proposed market platform.

## 4.2.3 Market Products

There are mainly two “market bidding” types encountered in electricity markets: (i) *unit bidding* — where each unit (physical asset) is bid in the market through its technical characteristics (e.g. min up and down

time, ramp constraints, etc.) — and (ii) *portfolio bidding* — where the market participants submit generic market orders aggregating their portfolio of assets (e.g. stepwise hourly curves, block bids, exclusive blocks, etc.). Type (i) is largely used in the US markets which rely on unit commitment models. Type (ii) is more of the flavor of what the EU markets are doing — such as the current design of Euphemia, the EU DA market, or the envisioned design of MARI, the EU mFRR balancing market [51].

The bids that we consider in this work are more of type (ii): they obey the logic of *portfolio bidding*, similar to the bids used in the single day-ahead European market coupling model. More specifically, they are based on the market product specifications of the SmartNet project (see [52] or Section 3.3 of [53]).

Let's first notice that a market order has three dimensions (quantity, price and time) which can be combined and used in different ways to create a variety of market orders. The bids are defined recursively as follows. It is composed of three building blocks: the first building blocks are the S-bids, which are combined to create Q-bids, which are themselves combined to create Qt-bids. More specifically:

- The first unit that is used to define a complete bid is the *segment bid* (or S-bid). The S-bid is essentially a kind of *hourly order* in Euphemia: it is a simple step or interpolated segment of quantity proposed for a certain marginal price (which is either constant or linear) and which is subject to either a *continuous* or a discrete acceptance. Note that we allow consumption and production bids, so we have no assumptions on the signs of the minimum and maximum quantity. More specifically, each S-bid involves a minimum and maximum power output constraint ( $Q_0$  and  $Q_1$ ) at a corresponding price ( $P_0$  and  $P_1$ ). Each S-bid is associated with a certain node at a certain moment in time. Furthermore, each S-bid is associated to a Q-bid which groups together multiple S-bids. A S-bid is activated only if the associated Q-bid is also activated.
- A Q-bid links together several S-bids of the same node and at the same moment in time. The Q-bid is therefore a curve composed of segments (the S-bids). The Q-bid is activated only if the associated Qt-bid is also activated. Consecutive Q-bids of a Qt-bid can be linked with minimum up and down time constraints as well as with ramp constraints. Also, logical constraints can be defined over Q-bids, essentially: exclusive constraints between different Q-bids of the same Qt-bid (preventing two Q-bids of an exclusive group to be accepted together) and implication constraints (if the Q-bid "a" is activated, then the Q-bid "b" must also be activated).
- Finally, Q-bids are also linked over time and we refer to such bids as Qt-bids — this can be seen as a kind of block bid in Euphemia. A Qt-bid is activated if at least one of the associated Q-bids is also activated. Exclusive and implication constraints can also be defined on Qt-bids.

### 4.3 Market Clearing Modelling

In this section, we gradually build up the market clearing problem that we aim at solving. We specifically focus on providing an accurate account of the non-convexities of the *primal* problem (i.e. the optimization program that the market clearing tool is solving in order to establish the commitment / dispatch instructions and the net positions of the nodes). The topology of the networks considered is presented in Figure 81. We display a single DN in the figure, whereas the test systems in our case study include multiple DNs that are connected to TN buses.

We denote by  $\mathcal{B} = \mathcal{TB} \cup \mathcal{DB}$  the set of buses which is the union of the set of transmission buses and distribution buses. Similarly, the set of generators  $\mathcal{G} = \mathcal{TG} \cup \mathcal{DG}$  is the union of the set of transmission generators and the set of distribution generators, and  $\mathcal{L} = \mathcal{TL} \cup \{l' = (i', j')\} \cup \mathcal{DL}$  is the set of directed lines (we use superscript  $R$  to designate the union of the set of lines and their reverse directions). The set of lines is the union of the transmission lines, interconnection lines and distribution lines. The parameters of the problem gather the admittance matrix  $Y_{ik} = G_{ik} + jB_{ik}$ ,  $i \in \mathcal{B}$ ,  $k \in \mathcal{B}$ , and fixed loads  $D_i^p$  and  $D_i^q$  imposed by the BRPs.  $\bar{z}$  (resp.  $\underline{z}$ ) designates the upper (resp. lower) capacity of a certain quantity  $z$ .



### 4.3.1 Mathematical Formulation of the Market Clearing Process

#### 4.3.1.1 Optimal Power Flow Constraints

We first expose the market clearing constraints on a single time period. We present the relevant constraints for each part of the network.

a) *Transmission*. The AC power flows equations can be written as:

$$\begin{aligned} f_{ij}^p &= -G_{ij}v_i^2 + v_i v_j (G_{ij} \cos(\theta_i - \theta_j) + B_{ij} \sin(\theta_i - \theta_j)), \forall (i, j) \in \mathcal{DL}^R \\ f_{ij}^q &= B_{ij}v_i^2 + v_i v_j (G_{ij} \sin(\theta_i - \theta_j) - B_{ij} \cos(\theta_i - \theta_j)), \forall (i, j) \in \mathcal{DL}^R \\ \underline{v}_i &\leq v_i \leq \overline{v}_i, \forall i \in \mathcal{DB} \end{aligned}$$

Where  $G_{ij}$  and  $B_{ij}$  stand for the conductance and the susceptance,  $f^p$  denotes the real power flow,  $f^q$  denotes the reactive power flow,  $v$  is the voltage magnitude, and  $\theta$  is the voltage angle. We assume that the DC approximation of the power flow equations holds in the TN. We therefore use the classical  $B - \theta$  formulation (i.e. voltage angle linearized power flow, see for instance [54]). This formulation is derived from the previous AC power flow equations, assuming that the voltage magnitudes are equal to 1, that the conductances are negligible ( $G_{ij} \ll B_{ij}$ ), that the angle differences are small enough so that  $\sin(\theta_i - \theta_j) \approx \theta_i - \theta_j$ . The variables of interest are therefore the real power injections  $p$ , the real power flows  $f^p$ , and the voltage angles  $\theta$ . The transmission constraints are described as follows:

$$p_g - D_i^p = \sum_{j \in \delta(i)} f_{ij}^p, \quad \forall i \in \mathcal{TB} \quad (1a)$$

$$f_{ij}^p = B_{ij}(\theta_i - \theta_j), \quad \forall (i, j) \in \mathcal{TL}^R \quad (1b)$$

$$\underline{f}_l^p \leq f_l^p \leq \overline{f}_l^p, \quad \forall l \in \mathcal{TL}^R \quad (1c)$$

$$\underline{p}_g \leq p_g \leq \overline{p}_g, \quad \forall g \in \mathcal{TG} \quad (1d)$$

where  $\delta(i) = \{j \in \mathcal{B} | (i, j) \in \mathcal{L}^R\}$ .

b) *Distribution*: We rely on the AC power flows equations (see above) for representing the distribution network. We employ the quadratic relaxation [55], [56], which is exact for radial networks. This relaxation introduces a change of variables. Voltage magnitudes  $v$ , and angles  $\theta$ , are replaced by variables  $c$  and  $s$ , which are defined as:

$$c_{ij} = v_i v_j \cos(\theta_i - \theta_j), \forall (i, j) \in \mathcal{DL}^R \quad (2a)$$

$$s_{ij} = -v_i v_j \sin(\theta_i - \theta_j), \forall (i, j) \in \mathcal{DL}^R \quad (2b)$$

$$c_{ii} = v_i^2, s_{ii} = 0, \quad \forall i \in \mathcal{DB} \quad (2c)$$

This change of variables removes angles  $\theta$  and results in a formulation of AC-OPF as a non-convex quadratic program. The other variables are the classical real (resp. reactive) power injections  $p$  (resp.  $q$ ) and flows  $f^p$  (resp.  $f^q$ ). The distribution constraints are the following:

$$\sum_{g \in \mathcal{G}_i} p_g - D_i^p = \sum_{j \in \delta(i)} f_{ij}^p + G_{ij} c_{ii}, \quad \forall i \in \mathcal{DB} \quad (3a)$$

$$\sum_{g \in \mathcal{G}_i} q_g - D_i^q = \sum_{j \in \delta(i)} f_{ij}^q - B_{ij} c_{ii}, \quad \forall i \in \mathcal{DB} \quad (3b)$$

$$f_{ij}^p = -G_{ij} c_{ii} + G_{ij} c_{ij} - B_{ij} s_{ij}, \quad \forall (i, j) \in \mathcal{DL}^R \quad (3c)$$

$$f_{ij}^q = B_{ij} c_{ii} - G_{ij} s_{ij} - B_{ij} c_{ij}, \quad \forall (i, j) \in \mathcal{DL}^R \quad (3d)$$

$$c_{ij}^2 + s_{ij}^2 = c_{ii} c_{jj}, \quad \forall (i, j) \in \mathcal{DL} \quad (3e)$$

$$\underline{v}_i^2 \leq c_{ii} \leq \overline{v}_i^2, \forall i \in \mathcal{DB} \quad (3f)$$



$$(f_l^p)^2 + (f_l^q)^2 \leq \overline{f_l^2}, \quad \forall l \in \mathcal{DL}^R \quad (3g)$$

$$\underline{f_l^p} \leq f_l^p \leq \overline{f_l^p}, \quad \underline{f_l^q} \leq f_l^q \leq \overline{f_l^q}, \quad \forall l \in \mathcal{DL}^R \quad (3h)$$

$$p_g^2 + q_g^2 \leq \overline{pq_g^2}, \quad \underline{p_g} \leq p_g \leq \overline{p_g}, \quad \forall g \in \mathcal{DG} \quad (3i)$$

The non-convexities of constraints (3) result from the quadratic equality (3e). As such, the problem is a non-convex QCP, which means a NP-hard problem (and therefore challenging to solve [54]). Therefore, multiple technics have been developed to convexify the previous problem [54] in order to make it computationally more tractable. The most popular choices of relaxation are semi-definite programming (SDP) relaxation and second-order cone programming (SOCP) relaxation. These are convex relaxations of the QCP which make the problem more tractable while, at the same time, being much tighter than the classical DC relaxation of AC OPF (as employed for the transmission network) as it keeps constraints on the reactive power as well as on voltage within the model, which, for distribution network, are paramount features. The SOCP relaxation has been extensively studied (e.g. [56], [55], [57]) on radial networks, and often provides feasible AC dispatch in practice [18]. It is therefore a very appropriate choice, constituting a good tradeoff between accuracy and computational tractability. We therefore use this relaxation for coping with computational effort. The SOCP formulation relaxes constraint (3e) to:

$$c_{ij}^2 + s_{ij}^2 \leq c_{ii}c_{jj}, \quad \forall (i, j) \in \mathcal{DL} \quad (4)$$

- c) *Interconnection*: At the interface, we assume that there is a lossless line defined by a single variable  $f_{l'}^p$ . For ease of modeling, we duplicate this variable in both networks by introducing:  $f_{l'}^{p,T}$  and  $f_{l'}^{p,D}$ . The interconnection constraints are then:

$$f_{l'}^p = f_{l'}^{p,T}, \quad f_{l'}^p = f_{l'}^{p,D}, \quad \underline{f_{l'}^p} \leq f_{l'}^p \leq \overline{f_{l'}^p},$$

- d) *Concise Notation*: The set of decision variable is split between transmission decisions,  $x^T = (p_{\mathcal{TG}}, f_{\mathcal{TL}}^p, \theta, f_{l'}^{p,T})$  (here  $p_{\mathcal{TG}}$  truncates the vector of real power injections limited to the transmission generators), distribution decisions  $x^D = (p_{\mathcal{DG}}, q, c, s, f_{\mathcal{DL}}^p, f^q, f_{l'}^{p,D})$  and interconnection decision  $f_{l'}^p$ . In order to develop a concise formulation, we separate power balance constraints, operational constraints and generation constraints. Concretely, (1) is replaced by:

$$\begin{aligned} F_i^{DC}(x^T) &= 0, \quad \forall i \in \mathcal{TB} \Leftrightarrow (1a) \\ (f_{\mathcal{TL}}^p, \theta) &\in \mathcal{OC}^{DC} \Leftrightarrow (1b) - (1c) \\ p_g &\in \mathcal{GC}_g^{DC}, \quad \forall g \in \mathcal{TG} \Leftrightarrow (1d) \end{aligned}$$

In the same spirit, we change (3) to:

$$\begin{aligned} F_i(x^D) &= 0, \quad \forall i \in \mathcal{DB} \Leftrightarrow (3a) - (3b) \\ (c, s, f_{\mathcal{DL}}^p, f^q) &\in \mathcal{OC} \Leftrightarrow (3c) - (3h) \\ (p_g, q_g) &\in \mathcal{GC}_g, \quad \forall g \in \mathcal{DG} \Leftrightarrow (3i) \end{aligned}$$

We also introduce  $\mathcal{OC}^{SOC}$  when necessary, defined as:

$$(c, s, f_{\mathcal{DL}}^p, f^q) \in \mathcal{OC}^{SOC} \Leftrightarrow (3c) - (3d), (3f) - (3h), (4)$$

#### 4.3.1.2 Non-Convex Offers

We introduce binary variables  $y_g$  for each generator  $g$ , which can represent all the flavors of binary variables encountered in unit commitment problems or the binary acceptance ratio of the market orders defined earlier, such as the Q-bid and Qt-bid. The previously defined set  $\mathcal{GC}_g$  is now extended to incorporate the binary constraints:

$$(p_g, q_g, y_g) \in \mathcal{GC}_g, \quad y_g \in \{0, 1\}^{d_g}, \quad \forall g \in \mathcal{DG}$$

The set  $\mathcal{GC}_g$  can incorporate various features. These include linked bids, exclusive acceptance, minimum acceptance duration, and so on. The set therefore include inter-temporal constraints. The same holds for  $\mathcal{GC}_g^{DC}$ .

#### 4.3.1.3 The Integrated T&D Real-Time Market Clearing Model

Before writing the complete problem, note that our model is multi-period on a time horizon  $\mathcal{T} = \{1, \dots, t_f\}$ . In a multiperiod setting, the power balance constraints and operational constraints must be satisfied at every time-step and generation constraints involve time-coupling (such as ramp constraints for example). The details of the bid and coupling constraints are provided in [53]. We make the use of subscript  $t$  to refer to a certain time period. The formulation of the integrated T&D market clearing problem is as follows:

$$\min \sum_{g \in \mathcal{G}} \sum_{t \in \mathcal{T}} c_{gt} p_{gt} \quad (5a)$$

$$F_{i,t}^{DC}(x_t^T) = 0, (\lambda_{i,t}), \quad \forall i \in \mathcal{TB}, t \in \mathcal{T} \quad (5b)$$

$$(f_{\mathcal{T}L,t}^p, \theta_t) \in \mathcal{OC}^{DC}, \quad \forall t \in \mathcal{T} \quad (5c)$$

$$(p_g, y_g) \in \mathcal{GC}_g^{DC}, \quad \forall g \in \mathcal{TG} \quad (5d)$$

$$f_{l',t}^p = f_{l',t}^{p,T}, \quad \forall t \in \mathcal{T} \quad (5e)$$

$$f_{l',t}^p = f_{l',t}^{p,D}, \quad \forall t \in \mathcal{T} \quad (5f)$$

$$\underline{f}_{l'}^p \leq f_{l',t}^p \leq \overline{f}_{l'}^p, \quad \forall t \in \mathcal{T} \quad (5g)$$

$$F_{i,t}(x_t^D) = 0, (\lambda_{i,t}) \quad \forall i \in \mathcal{DB}, t \in \mathcal{T} \quad (5h)$$

$$(c_t, s_t, f_{DL,t}^p, f_t^q) \in \mathcal{OC} \quad \forall t \in \mathcal{T} \quad (5i)$$

$$(p_g, q_g, y_g) \in \mathcal{GC}_g, \quad \forall g \in \mathcal{DG} \quad (5j)$$

$$y_g \in \{0,1\}^{d_g}, \quad \forall g \in \mathcal{DG} \quad (5k)$$

This problem is a mixed integer non-linear problem, and its linear relaxation is non-convex. Integrality results from the introduction of binary variables  $y$ . In addition to binary variables, non-convexities originate from constraint (5i) which models power flow equations in the DN. Inter-temporal constraints appear in two constraints: (5d) and (5j). Note that, even if we do not explicitly define them in problem (5), slack variables are introduced and are penalized at a high cost.

### 4.3.2 Solution Methodology

In order to cope with institutional requirements, we propose a decentralized approach based on DN RSFs. This is essentially a hierarchical approach that is treating the DN and TN as separated. Mathematically, it can be seen as an approximation of a Benders decomposition in the special case of a convex market clearing problem: a Benders decomposition simply divides the original (“complicated”) problem into a *master* (“simpler”) problem, corresponding here to the TN problem, and the (“complicated”) *subproblems*, corresponding here to the DN problem. The steps of the procedure are indicated in Figure 2. We detail the different steps in the following paragraphs.

#### 4.3.2.1 Computing the RSF (Step 1)

The RSF corresponds to the gradient of the least cost at which a given amount of real power can be exported from a DN to the T&D interface. In order to compute the RSF, we solve distribution problems for different levels of real power flow exports. Note that, in principle, the RSF is  $|\mathcal{T}|$ -dimensional. Indeed, the total cost of export depends on the flow level for every time period of the considered horizon. By contrast, real-time energy markets admit one-dimensional bids (a marginal cost curve for each market time unit). In order to overcome this issue, we rely on the fact that the interface flow may not vary drastically from one time period to another. We therefore consider the projection of the total cost function at the vector of equal exports for all time intervals, when computing the RSF.

Concretely, we compute the RSF on  $N$  equally spaced points  $E_{l'}^n$  (time-independent) between the lower and upper interconnection flow limits ( $E_{l'}^1 = \underline{f}_{l'}^p$  and  $E_{l'}^N = \overline{f}_{l'}^p$ ). In order to derive the associated value of the RSF, mathematically denoted by  $\tilde{\mu}_{l',t}$ , which is time dependent, we solve the following SOCP problem:

$$\min \sum_{g \in DG} \sum_{t \in T} C_{gt} p_{gt} \quad (6a)$$

$$(5f) - (5h), (5j) \quad (6b)$$

$$(c_t, s_t, f_{DL,t}^p, f_t^q) \in \mathcal{OC}^{SOC} \quad \forall t \in T \quad (6c)$$

$$f_{l',t}^p = E_{l'}^n, \quad (\mu_{l'}) \quad \forall t \in T \quad (6d)$$

$$y_g \in [0,1]^{dg}, \quad \forall g \in DG \quad (6e)$$

This problem provides a primal-dual solution. Using a sensitivity argument, the RSF slope  $\tilde{\mu}_{l',t}^n$  is obtained as the dual optimal value associated with constraint (6d) for real power flow level  $E_{l'}^n$ . Note that problem (6) relies on the SOCP relaxation of the OPF constraints as well as a continuous relaxation of the binary variables  $y$ . Previous experimental work indicates that an approximation of the RSF can provide satisfactory results in practice [49], since the crucial step in the procedure is the disaggregation that accounts for the local constraints of the DN when activating distribution-level BSPs.

#### 4.3.2.2 Transmission market clearing (Step 2)

Once the RSF is computed, it is explicitly bid into the transmission market clearing model. This results in the following model for step 2:

$$\min \sum_{g \in TG} \sum_{t \in T} C_{gt} p_{gt} + \sum_{t \in T} \sum_{n=1} \tilde{\mu}_{l',t}^n f_{l',t}^{p,n} \quad (7a)$$

$$(5b) - (5e) \quad (7b)$$

$$f_{l',t}^p = \sum_{n=1} f_{l',t}^{p,n}, \quad \forall t \in T \quad (7c)$$

$$E_{l'}^{n-1} \leq f_{l',t}^p \leq E_{l'}^n, \quad \forall n = 2, \dots, N, \quad t \in T \quad (7d)$$

$$y_g \in \{0,1\}^{dg}, \quad \forall g \in TG \quad (7e)$$

Note, therefore, that distribution system resources are not bid explicitly into the wholesale market. They are rather aggregated into the RSF, which is computed by the ADS (or DSO), since its derivation requires information about the DN. Note also that since the interconnection is part of the DN, constraint (5g) is not explicitly expressed in (7) but should be captured by the RSF.

From (7), we deduce binary variables  $\hat{y}_g, g \in TG$  for transmission system resources. After fixing the binary variables, we solve the following LP:

$$\min \sum_{g \in TG} \sum_{t \in T} C_{gt} p_{gt} + \sum_{t \in T} \sum_{n=1} \tilde{\mu}_{l',t}^n f_{l',t}^{p,n} \quad (8a)$$

$$(5b) - (5c), (5e), (7d) \quad (8b)$$

$$(p_g, \hat{y}_g) \in \mathcal{GC}_g^{DC}, \quad \forall g \in TG \quad (8c)$$

$$f_{l',t}^p = \sum_{n=1} f_{l',t}^{p,n}, \quad (\mu_{l',t}) \quad \forall t \in T \quad (8d)$$

From this problem, we deduce dispatch decisions for the TN  $\hat{x}^T$ , interface flows  $\hat{f}_{l'}^p$ , and interface prices  $\hat{\mu}$ .

Given the solutions of the previous problems, we arrive to a complete binary solution  $\hat{y}^T$ , as well as a primal solution  $\hat{x}^T$  for the TN. The pricing step aims at deriving LMPs  $\lambda$  that are coherent with the primal market clearing solution. We refer to coherent prices as prices that keep the Lost Opportunity Cost (LOC) as low as possible. Adapting this idea to our context leads to the following TN subproblem, which is an LP:

$$\min \sum_{g \in TG} \sum_{t \in T} C_{gt} p_{gt} + \sum_{t \in T} \tilde{\mu}_{l',j',t}^n f_{l',j',t}^p \quad (9a)$$

$$(5b) - (5c), (7c) - (7d), (8c) \quad (9b)$$

The LMPs  $\hat{\lambda}^T$  are derived as the dual multipliers of constraints (5b).

#### 4.3.2.3 Disaggregating the distribution decisions (Step 3)

Given a target export quantity ( $\hat{f}_{l',t}^p$  decided by the TSO), the DSO disaggregates this export level optimally to individual distribution resources by solving the following MISOCP:

$$\min \sum_{g \in DG} \sum_{t \in T} C_{gt} p_{gt} \quad (10a)$$

$$(5h), (5j), (6c) \quad (10b)$$

$$\hat{f}_{l',t}^p = f_{l',t}^{p,D}, \quad \forall t \in T \quad (10c)$$

$$y_g \in \{0,1\}^{d_g}, \quad \forall g \in DG \quad (10d)$$

This problem yields distribution binary variables  $\hat{y}_g, g \in DG$  and distribution dispatch decisions  $\hat{x}^D$ . If the distribution dispatch decisions are not physically feasible, the following continuous non-linear problem is solved:

$$\min \sum_{g \in DG} \sum_{t \in T} C_{gt} p_{gt} \quad (11a)$$

$$(5h) - (5i), (10c) \quad (11b)$$

$$(p_g, q_g, \hat{y}_g) \in \mathcal{GC}_g, \forall g \in DG \quad (11c)$$

Prices are deduced with the same technique as in the TN. We employ the interface price  $\hat{\mu}$  in order to value the exports (or imports) by solving the following SOCP:

$$\min \sum_{g \in DG} \sum_{t \in T} C_{gt} p_{gt} - \sum_{t \in T} \hat{\mu}_{l',j',t}^n f_{l',j',t}^p \quad (12a)$$

$$(5g) - (5h), (6c), (11c) \quad (12b)$$

The LMPs  $\hat{\lambda}^D$  are derived as the dual multipliers of constraints (5h).

#### 4.3.2.4 Overall Algorithm

The steps of the overall process are summarized in Algorithm 1. Each step of Figure 82 corresponds to one or two steps in Algorithm 1.

---

##### Algorithm 1 Algorithm of the RSF approach.

---

- 1: **Step 1:** Compute the RSF by solving (6) for  $N$  flow levels.
  - 2: **Step 2.1:** Solve the transmission system primal problem (7) and derive  $\hat{y}_g, g \in TG$ .
  - 3: **Step 2.2:** Fix the transmission binary decisions and solve (8) to derive  $\hat{x}^T, f_{l',t}^p$  and  $\hat{\mu}$ .
  - 4: **Step 2.3:** Solve (9) to obtain transmission LMPs  $\hat{\lambda}^T$ .
  - 5: **Step 3.1:** Solve the distribution system primal problem (10) to derive  $\hat{y}_g, g \in DG$  and  $\hat{x}^D$ .
  - 6: **Step 3.2:** If  $\hat{x}^D$  is not feasible, solve (11) and update  $\hat{x}^D$ .
  - 7: **Step 3.3:** Solve (12) to obtain distribution LMPs  $\hat{\lambda}^D$ .
-

#### 4.3.2.5 Parallelization

A number of steps of the approach can be executed in parallel. Step 1 can be parallelized in two ways: each distribution network can compute the RSF independently, and each of the  $N$  flow levels can be computed separately. Using the decomposability of the T&D network, Steps 3.1, 3.2 and 3.3 can also be executed in parallel, for each DN separately.

### 4.4 Real Time Mechanism User Interface

#### 4.4.1 Business Logic & High-Level Description

##### 4.4.1.1 Software Interface

The developed interface is based on the Microsoft Excel software, since the aforementioned platform provides a state-of-the-art and widely-utilized environment for the analytical representation of the input and output data. Moreover, it enables the utilization of various macro commands for the creation of the Julia code-required files, the initialization of the optimization procedure and the update of all output data.

The user may save the developed interface anywhere in their personal computer since the initialization and execution of the optimization code does not depend on the location of the excel file. It should be noted though that the code can only be executed from the computer that the interface has successfully been installed (i.e. we cannot install the software in a server machine and initialize the execution from another client computer).

##### 4.4.1.2 Model Execution

The optimization model of the real-time balancing market clearing algorithm is written in the Julia programming language. For its successful execution the software interface creates a batch file that initializes the code execution through the Microsoft Windows console. The user should not close the console at any point, an action that will terminate the code execution. The console will automatically close as soon as the optimization procedure terminates successfully.

##### 4.4.1.3 Market Clearing Procedure

The basic market clearing procedure comprises 4 steps and is presented in the following figure:

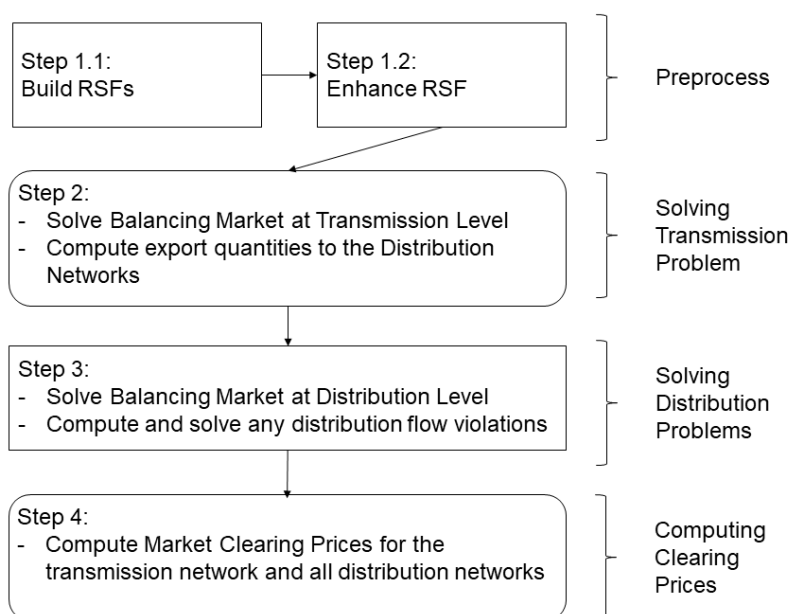


Figure 90: TSO-DSO coordination and Balancing Market solution algorithm

In **Step 1**, the basic Residual Supply Functions (RSF) for all distributed networks are computed through an iterative procedure and are enhanced with additional points that ensure the better performance of the optimization algorithm.

The above-mentioned RSFs are then used in **Step 2** of the algorithm, where the Balancing Market at the transmission problem is solved. The results of this optimization procedure are the dispatch instructions of the transmission-level resources along with the cleared quantities of all submitted RSFs (exported quantities to the distribution networks).

The exported quantities are then passed to the respective distribution networks, along with the calculated interface prices (where interface are the nodes that connect the transmission and distribution systems) and are used for the clearing of the respective networks (**Step 3** of the algorithm).

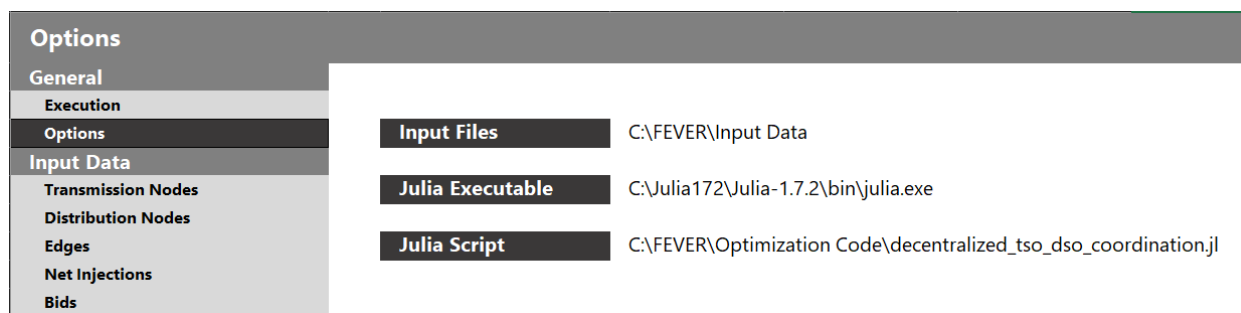
Finally, after fixing all binary decisions of the optimization problems, the respective problems are solved again in **Step 4**, for the computation of all locational Market Clearing Prices.

For a more analytical presentation of the TSO-DSO coordination approach and the subsequent clearing of the real-time balancing market, the user is referred to [53] and [24].

## 4.4.2 Interface Analytical Presentation

### 4.4.2.1 General Worksheets

#### 4.4.2.1.1 Options



Options	
General	
Execution	
Options	
Input Data	
Transmission Nodes	
Distribution Nodes	
Edges	
Net Injections	
Bids	

Input Files	C:\FEVER\Input Data
Julia Executable	C:\Julia172\Julia-1.7.2\bin\julia.exe
Julia Script	C:\FEVER\Optimization Code\decentralized_tso_dso_coordination.jl

Figure 91: Worksheet Options

In this worksheet the user inserts some basic directories that are required for the successful execution of the optimization code.

**Input Files:** The directory that contains the required for the initialization of the Julia code input .csv files. These files are created by pressing the button “Prepare Files”, in the “Execution” worksheet, as it will be presented in the following subsection. By default, the input files’ directory is “C:\FEVER\Input Data”. The user should create this directory, as instructed in the complementary installation README file.

**Julia Executable:** The full path of the currently installed Julia executable .exe file. It should be noted that the respective file path depends on the currently installed Julia version and may be different to each user.

**Julia Script:** The full path of the .jl Julia file that contains the developed optimization code. By default, the file path is “C:\FEVER\Optimization Code\decentralized\_tso\_dso\_coordination.jl”. The user should create the “C:\FEVER\Optimization Code” directory, as instructed in the complementary installation README file.

#### 4.4.2.1.2 Execution

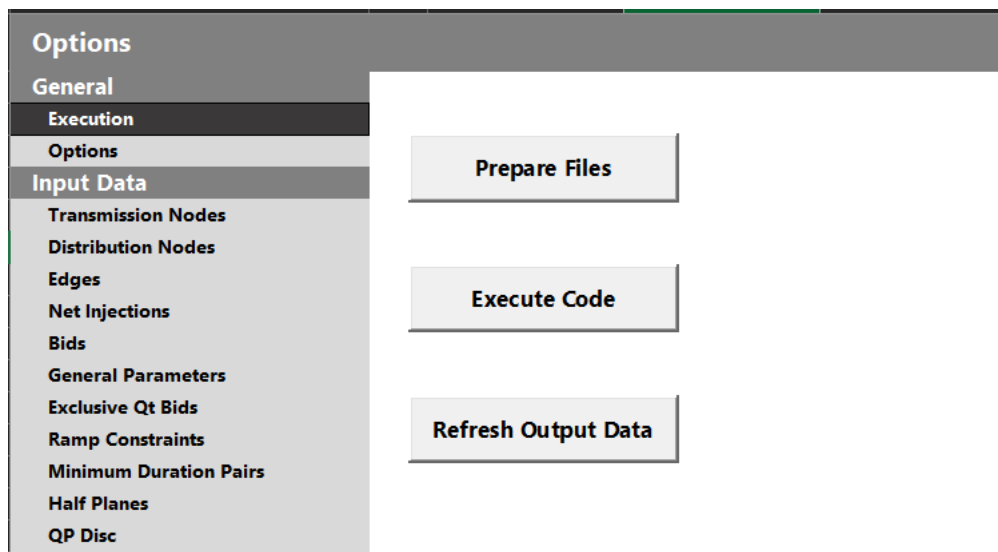


Figure 92: Worksheet Execution

This worksheet contains three buttons that are used for the successful initialization and execution of the developed real-time balancing market software.

**Button “Prepare Files”:** By pressing this button, the required for the code execution input data .csv files are created in the “C:\FEVER\Input Data” directory. After the successful creation of the respective .csv files, the following message appears in the interface.

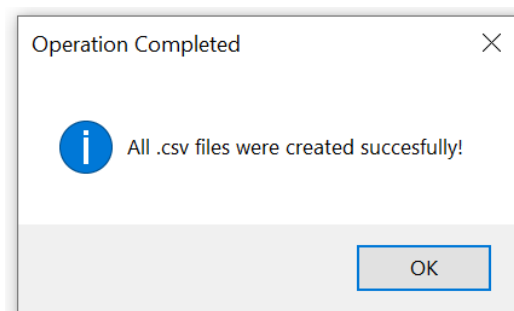


Figure 93: Successful creation of input .csv files

**Button “Execute Code”:** This button initializes the execution of the optimization code. A batch file is created that contains the required commands for executing the optimization .jl Julia file in the Microsoft Windows console. The console application is then initialized and dynamically presents the output of the optimization procedure.

```

C:\Windows\system32\cmd.exe
>>>>>>> Calculate X [15:35:19] Start
>>>>>>> Calculate G [15:35:19] Start
>>>>>>> Calculate B [15:35:19] Start
[15:35:19] Process exclusive qt bids...
[15:35:19] Calculating ramping data...
[15:35:22] Calculating distribution network configuration...
[15:35:23] Process bids per distribution network...
[15:35:24] Reprocessing ramping data...
[15:35:24] Final bids processing...
[15:35:24] Reading problem functions...
[15:35:29] Executing optimization code...

#####
### Step 1.1: Build RSF ###
#####

Starting decomposition...
Starting 4 Distribution networks problems.
>1. SOLVED Distribution network problem: DN-10150000.

```

Figure 94: Console application dynamically demonstrating the optimization code execution

After the successful execution of the optimization code, the console application is automatically closed, and the user is asked if she/he would like to refresh the output data. If the user selects the “YES” option then the results are automatically updated and the respective message appears in the interface; if a negative answer is given, then the user should manually refresh the output data through the “Refresh Output Data” button.

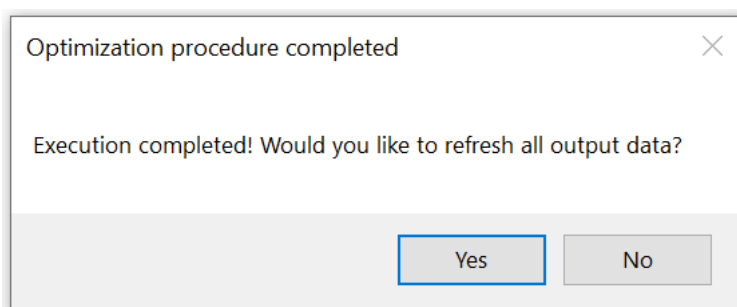


Figure 95: Refresh output data after successful code execution

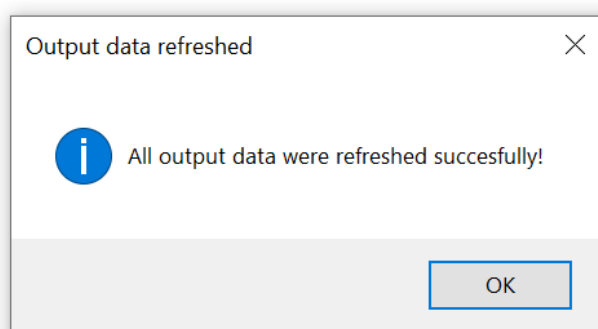


Figure 96: Successful update of all output data

**Button “Refresh Output Data”:** By pressing this button the user can manually refresh the output data.



#### 4.4.2.2 Input Data Worksheets

The following subsection provides an analytical presentation of all worksheets that contain input data, along with a short explanation of all the required input data. All data follow the template that was proposed in the SmartNet Horizon 2020 project [58].

##### 4.4.2.2.1 Transmission Nodes

This worksheet contains the data related with the high-voltage transmission nodes of the examined power system.

Transmission Nodes	
General	
Execution	
Options	
Input Data	
Transmission Nodes	
Distribution Nodes	
Edges	
Net Injections	
Bids	
General Parameters	
Exclusive Qt Bids	
Ramp Constraints	
Minimum Duration Pairs	
Half Planes	
QP Disc	

Transmission Node	Reference Node
896	0
1468	1
1505	0
1507	0
1508	0
1537	0
1557	0
1558	0
1579	0
1584	0
1585	0

Figure 97: Worksheet Transmission Nodes

Column **Transmission Node**: The ID of the examined transmission node.

Column **Reference Node**: A binary [1/0] flag denoting that the respective transmission node is the reference node (based on which all transmission network power flow angles are calculated), if equal to 1.

##### 4.4.2.2.2 Distribution Nodes

This worksheet contains the data related with the medium- and low-voltage distribution nodes of the examined power system.

Distribution Nodes						
General						
Execution						
Options						
Input Data						
Transmission Nodes						
Distribution Nodes						
Edges						
Net Injections						
Bids						
General Parameters						
Exclusive Qt Bids						
Ramp Constraints						

Distribution Node	Minimum Voltage Level [p.u.]	Maximum Voltage Level [p.u.]	Shunt Conductance [G]	Shunt Susceptance [B]	Minimum Reactive Production [MW]	Maximum Reactive Production [MW]
10060000	0.9025	1.1025	0	0	0	0
10060001	0.9025	1.1025	0	0	0	0
10060002	0.9025	1.1025	0	0	0	0
10060003	0.9025	1.1025	0	0	0	0
10060004	0.9025	1.1025	0	0	0	0
10060005	0.9025	1.1025	0	0	0	0
10060006	0.9025	1.1025	0	0	0	0
10060007	0.9025	1.1025	0	0	0	0

Figure 98: Worksheet Distribution Nodes

Column **Distribution Node**: The ID of the examined distribution node.

Column **Minimum Voltage Level**: The minimum allowed voltage level of the examined distribution node, in p.u.

Column **Maximum Voltage Level**: The maximum allowed voltage level of the examined distribution node, in p.u.

Column **Shunt Conductance**: The distribution node shunt conductance [G], in Siemens (S).

Column **Shunt Susceptance**: The distribution node shunt susceptance [B], in Siemens (S).

Column **Minimum Reactive Production**: The minimum allowed reactive production in the examined distribution node, in MW.

Column **Maximum Reactive Production**: The maximum allowed reactive production in the examined distribution node, in MW.

#### 4.4.2.2.3 Edges

This worksheet contains all data related with the edges (transmission lines) of the examined power system.

Edges							
General							
Execution							
Options							
Input Data							
Transmission Nodes							
Distribution Nodes							
Edges							
Net Injections							
Bids							
General Parameters							
Exclusive Qt Bids							
Ramp Constraints							
Edge	Node From	Node To	Resistance (R)	Shunt Conductance (G)	Reactance (X)	Shunt Susceptance (B)	Edge Power Limit (S)
250	1584	1586	0	0	0.00025	0	9000
251	1584	1585	0	0	0.00025	0	9000
281	1743	1746	0	0	0.00025	0	9000
282	1743	1744	0	0	0.00025	0	9000
283	1743	1745	0	0	0.00025	0	9000
298	1834	1835	0	0	0.00025	0	9000
1373	1587	896	0	0	0.000055	0	108.645312
1912	1584	1834	0	0	0.000046	0	1240.21766

Figure 99: Worksheet Edges

Column **Edge**: The ID of the examined edge (transmission line).

Column **Node From**: The ID of the transmission or distribution node that the examined edge begins from.

Column **Node To**: The ID of the transmission or distribution node that the examined edge ends to.

Column **Resistance**: The resistance [R] of the examined edge, in Ohm ( $\Omega$ ).

Column **Shunt Conductance**: The shunt conductance [G] of the examined edge, in Siemens (S).

Column **Reactance**: The reactance [X] of the examined edge, in Ohm ( $\Omega$ ).

Column **Shunt Susceptance**: The distribution node shunt susceptance [B], in Siemens (S).

Column **Edge Power Limit**: The power limit of the examined edge, in MW.

#### 4.4.2.2.4 Net Injections

This worksheet contains the applied active and reactive net injections in all examined transmission/distribution nodes and trading periods.

Net Injections			
General			
Execution			
Options			
Input Data			
Transmission Nodes			
Distribution Nodes			
Edges			
Net Injections			
Bids			
General Parameters			
Exclusive Qt Bids			
Ramp Constraints			
Minimum Duration Pairs			
Node	Trading Period	Active Power Injection	Reactive Power Injection
896	1	0	0
896	2	0	0
896	3	0	0
896	4	0	0
1468	1	6.777794715	-4.771938182
1468	2	8.193387416	-4.934529415
1468	3	10.73017657	-5.097120648
1468	4	15.35725892	-5.200589538
1505	1	0	0

Figure 100: Worksheet Net Injections

Column **Node**: The ID of the examined transmission or distribution node.

Column **Trading Period**: The trading period at which the respective net injection corresponds to.

Column **Active Power Injection**: The active power injection of the examined transmission or distribution node at the respective trading period, in MWh.

Column **Reactive Power Injection**: The reactive power injection of the examined transmission or distribution node at the respective trading period, in MWh.

#### 4.4.2.2.5 General Parameters

This worksheet contains some general parameters that are required for the successful execution of the market clearing algorithm.

General Parameters		
General		
Execution		
Options		
Input Data		
Transmission Nodes		
Distribution Nodes		

	[quarter]	[quarter]
RSF Points	Start Time	End Time
300	1	4

Figure 101: Worksheet General Parameters

Column **RSF Points**: The number of points that are used in Step 1 of the algorithm for the ex-post processing of the distribution networks' Residual Supply Functions, according to reference [53].

Column **Start Time**: Integer number denoting the start time of the real-time optimization horizon, usually in quarters.

Column **End Time**: Integer number denoting the end time of the real-time optimization horizon, usually in quarters.

#### 4.4.2.2.6 Bids

This worksheet contains all the required bid data that are submitted in the transmission and distribution nodes.

The bid format follows the one that was proposed in the SmartNet project (see [52] and [53]); thus, for an analytical explanation of all the presented fields the user is referred to [58]. In general, each "QBid" bid is submitted at a specific "Trading Period" and comprises one or more "QBidSeg" segments. Moreover, "QtBids" bids associate various bids that are submitted in different trading periods.

Additionally, a low and high quantity/price pair is submitted for each bid. If the low price is different than the high price, then the submitted bid constitutes a piecewise-linear bid, whereas on the case where the two submitted prices are the same then the respective bid follows the stepwise format.

Bids												
General												
Execution												
Options												
Input Data												
Transmission Nodes												
Distribution Nodes												
Edges												
Net Injections												
Bids												
General Parameters												
Exclusive Qt Bids												
Ramp Constraints												
Minimum Duration Pairs												

				[quarter]	[MWh]	[MWh]	[MWh]	[MWh]	[1/Q]	[1/Q]	[1/Q]
Node	QtBids	QBid	QBidSeg	Period	Low Quantity	Low Price	High Quantity	High Price	Low To High Quantity	Alpha Omega Set	No New Act
1468	91	271	271	1	0	-36	-0.013695333	-36	1	0	0
1468	92	272	272	1	0	-36	0.018788667	-36	1	0	0
1537	93	273	273	1	0	-36	-0.011630667	-36	1	0	0
1537	94	274	274	1	0	-36	0.015202	-36	1	0	0
10060114	95	275	275	1	0	-36	-0.0106064	-36	1	0	0
10060114	96	276	276	1	0	-36	0.011017067	-36	1	0	0
1468	97	277	277	1	0	25.1	0.0735	25.1	0	0	0
1468	97	277	278	1	0	-4.7	-4.27579711	-4.7	0	0	0
1468	97	277	279	1	-4.27579711	-3	-21.32645459	-3	0	0	0

Figure 102: Worksheet Options

Column **Node**: The transmission or distribution node ID that the examined bid is submitted to.

Column **QtBids**: The QtBid ID of the examined bid.

Column **QBid**: The ID of the examined bid.

Column **QBidSeg**: The segment ID of the examined bid.

Column **Period**: The trading period that the examined bid is submitted to.

Column **Low Quantity**: The quantity part of the examined bid's low price/quantity pair, in MWh.

Column **Low Price**: The price part of the examined bid's low price/quantity pair, in €/MWh.

Column **High Quantity**: The quantity part of the examined bid's high price/quantity pair, in MWh.

Column **High Price**: The price part of the examined bid's high price/quantity pair, in €/MWh.

Column **Low To High Quantity**: A [1/0] binary flag denoting that the lower bound of the examined bid's clearing variable is set equal to the higher bound, thus effectively setting the submitted bid's clearing condition to "Fill-or-Kill".

Column **Alpha Omega Set**: A [1/0] binary flag denoting the QtBids that cannot start and end at the same time, which is the period showcased in the column Period. If the user has entered data in the "Alpha Omega Set" worksheet then this flag is not taken into consideration.

Column **No New Act**: A [1/0] binary flag denoting the bids that cannot be activated during the examined clearing session, if equal to 1. If the user has entered data in the "No New Act" worksheet then this flag is not taken into consideration.

#### 4.4.2.2.7 Exclusive Qt Bids

This worksheet contains an incidence matrix that associates various QtBids that belong in the same exclusive group. For each exclusive group, only one QtBid may be executed in any given real-time balancing market clearing session.

Exclusive Qt Bids	
General	
Execution	
Options	
Input Data	
Transmission Nodes	
Distribution Nodes	
Edges	

ID	QtBid
1	91
1	92
2	93

Figure 103: Worksheet General Parameters

Column **ID**: The ID of the examined Exclusive Group.

Column **QtBid**: The ID of the examined QtBid that belongs to the Exclusive Group.

#### 4.4.2.2.8 Ramp Constraints

This worksheet contains all required data for the enforcement of ramp constraints in a subset of the submitted QtBids.

Ramp Constraints				
General				
Execution				
Options				
Input Data				
Transmission Nodes				
Distribution Nodes				
Edges				
Net Injections				
Bids				

QtBids	QBid	Ramp Constraint	Real Power Increase Rate	Ramp Flag
294	1065	9	0.2997	0
294	1066	9	0.2997	0
294	1067	9	0.2997	0
294	1068	9	0.2997	0
294	1065	10	-0.2997	1

Figure 104: Worksheet Ramp Constraints

Column **QtBids**: The ID of the examined QtBid.

Column **QBid**: The ID of the examined QBid.

Column **Ramp Constraint**: The ID of the examined Ramp Constraint.

Column **Real Power Increase Rate**: The maximum allowed upward (positive) or downward (negative) power change between two consecutive trading periods for the examined bid, in MW/examined period granularity.

Column **Ramp Flag**: A [1/0] flag that denotes that the examined ramp constraint is on the upward (if equal to 0) or the downward (if equal to 1) direction.

#### 4.4.2.2.9 Minimum Duration Pairs

This worksheet contains all required data for the enforcement of the Minimum Duration Pair constraint in two QBids that belong in the same QtBid. This constraint enforces the activation of the first QBid in the constraint only if the second one has been activated.

Minimum Duration Pairs				
General				
Execution				
Options				
Input Data				
Transmission Nodes			[quarter]	[quarter]
Distribution Nodes				
Edges				
Net Injections				
Bids				

QtBids	QBid 1	QBid 2	QBid 1 Period	QBid 2 Period
337	1237	1237	1	1
337	1237	1238	1	2
337	1238	1238	2	2
337	1237	1239	1	3
337	1238	1239	2	3

Figure 105: Worksheet Minimum Duration Pairs

Column **QtBids**: The ID of the examined QtBid.

Column **QBid 1**: The ID of the first examined QBid.

Column **QBid 2**: The ID of the second examined QBid.

Column **QBid 1 Period**: The trading period that the first examined QBid is submitted.

Column **QBid 2 Period**: The trading period that the second examined QBid is submitted.

#### 4.4.2.2.10 Half Planes

This worksheet contains all required data for the enforcement of an additional constraint that limits the clearing of the examined QtBid, based on a half-plane that constraints the bid's clearing space. For a more analytical explanation of this half-plane related constraint, the user is referred to [58].

Half Planes				
General				
Execution				
Options				
Input Data				
Transmission Nodes			[p.u.]	[1/0]
Distribution Nodes				
Edges				
Net Injections				
Bids				
General Parameters				
Exclusive Qt Bids				
Ramp Constraints				
Minimum Duration Pairs				
Half Planes				

ID	QtBid	QP Half-Plane Slope	QP Half-Plane Offset	QP Half-Plane Constraint
1	320	0.05	0	0
2	320	0.05	0	0
3	320	0.05	0	0
4	320	0.05	0	0
5	321	0.05	0	0
6	321	0.05	0	0
7	321	0.05	0	0
8	321	0.05	0	0
9	322	0.05	0	0
10	322	0.05	0	0

Figure 106: Worksheet Half Planes

Column **ID**: The ID of the examined constraint.

Column **QtBid**: The ID of the examined QtBid.

Column **QP Half-Plane Slope**: The slope of the enforced half-plane.

Column **QP Half-Plane Offset**: The offset of the enforced half-plane.

Column **QP Half-Plane Constraint**: A [1/0] flag that denotes the enforcement of the examined constraint, if equal to 1.

#### 4.4.2.2.11 QP Disc

This worksheet contains all required data for the enforcement of an additional constraint that limits the clearing of the examined QtBid, based on a disk that constraints the bid's clearing space. For a more analytical explanation of this half-plane related constraint, the user is referred to [53].

QP Disc						
General						
Execution						
Options						
Input Data						
Transmission Nodes						[MW]
Distribution Nodes						
Edges						
Net Injections						

QtBid	QBids	QP Disk Constraint ID	QP Disk From	QP Disk To	QP Disk Max
264	945	16	-1	-1	0.1791
264	946	16	-1	-1	0.1791
264	947	16	-1	-1	0.1791
264	948	16	-1	-1	0.1791

Figure 107: Worksheet QP Disc

Column **QtBid**: The ID of the examined QtBid.

Column **QBids**: The ID of the examined QBids.

Column **QP Disk Constraint ID**: The ID of the examined constraint.

Column **QP Disk Max**: The radius of the examined disk, in MW.

#### 4.4.2.2.12 Alpha Omega Set

This worksheet contains all required data for the enforcement of the constraint imposing the rule that a bid cannot be starting and ending at the same time. For a more analytical explanation of the respective constraint the user is referred to [58].

Alpha Omega Set		
General		
Execution		
Options		
Input Data		
Transmission Nodes		
Distribution Nodes		
Edges		
Net Injections		

Qt Bids	QBid	Period

Figure 108: Worksheet Alpha Omega Set

Column **QtBids**: The ID of the examined QtBid.

Column **QBid**: The ID of the examined QBids.

Column **Period**: The period at which the bid cannot start and end at the same time.

#### 4.4.2.2.13 No New Act

This worksheet contains all required data for the enforcement of the constraint imposing the fact that a bid cannot be activated during the examined clearing session.

No New Act		
General		
Execution		
Options		
Input Data		
Transmission Nodes		
Distribution Nodes		
Edges		
Net Injections		

Qt Bids	QBid	Period

Figure 109: Worksheet No New Act

Column **QtBids**: The ID of the examined QtBid.

Column **QBid**: The ID of the examined QBid.

Column **Period**: The period at which the bid cannot be activated in the respective session.

#### 4.4.2.3 Output Data Worksheets

The following subsection provides an analytical presentation of all worksheets that contain the output data, namely the results of all optimization processes.

##### 4.4.2.3.1 Execution Time

This worksheet contains the total problem execution time, in seconds. Five different execution times presentation methodologies are listed:

- **Sequential Time**: denotes the total execution time, in the case where all the optimization problems are solved sequentially, namely one after the other.
- **Parallel Opt Time**: denotes an approximation of the total execution time, as if the distribution problems were solved under the optimal parallel approach.
- **Parallel 16 Time**: denotes an approximation of the total required execution time, as if the respective distribution subproblems were solved in parallel in 16 threads.
- **Parallel 32 Time**: denotes an approximation of the total required execution time, as if the respective distribution subproblems were solved in parallel in 32 threads.
- **Parallel 64 Time**: denotes an approximation of the total required execution time, as if the respective distribution subproblems were solved in parallel in 64 threads.

Execution Time	
General	
Execution	
Options	
Input Data	
Transmission Nodes	
Distribution Nodes	
Edges	
Net Injections	

Optimization Method	Total Execution Time [s]
<b>Sequential Time</b>	137.48
<b>Parallel opt Time</b>	35.06
<b>Parallel 16 Time</b>	51.61
<b>Parallel 32 Time</b>	44.62
<b>Parallel 64 Time</b>	40.49

Figure 110: Worksheet Execution Time

##### 4.4.2.3.2 Additional Information

This worksheet contains various information about the overall market clearing optimization problem. For an analytical definition of the presented metrics the user is referred to [24]:

- **Total Slack**: The total violations of the distribution power flows, in MWh.
- **Maximum Slack**: The maximum violation of all distribution power flows, in MWh.
- **LOC**: Total Lost Opportunity Cost, in €.
- **PLP**: The Producer Load Payments, in €.
- **Overall Welfare**: The overall Welfare, defined as the Social Welfare minus the summation of all Slack Costs, in €.
- **Social Welfare**: The overall Social Welfare of all optimization problems, in €.
- **Slack Cost (all)**: The cost that is associated with the penalization of all slack variables, in all optimization problems, in €.
- **Slack Cost (distribution)**: The cost that is associated with the penalization of all slack variables that appear in the distribution networks, in €.



Additional Information			
General			
Execution			
Options			
Input Data			
Transmission Nodes			
Distribution Nodes			
Edges			
Net Injections			
Bids			
General Parameters			
Exclusive Qt Bids			
Ramp Constraints			
Minimum Duration Pairs			
Half Planes			
QP Disc			
Alpha Omega Set			
No New Act			

Category	Value	Unit
<b>Slack Info:</b>		
Total Slack	1.2527825E-05	[MWh]
Maximum Slack	6.4869490E-07	[MWh]
<b>Violations:</b>		
TanGap	9.5981025E-11	
SOCPCGap	1.0813293E-07	
LOC	0.79	[€]
PLP	355,898.66	[€]
SW	-7,874.66	[€]
Social Welfare	-7,874.78	[€]
Slack Cost (all)	0.11	[€]
Slack Cost (distribution)	0.01	[€]
normSW	-104,426.65	[€]
Merchandising Surplus	5,790.92	[€]

Figure 111: Worksheet Additional Information

#### 4.4.2.3.3 TN Active Power Flow

This worksheet presents the power flow of each transmission line ("Edge") and for each trading period ("Tx"), in MWh.

Transmission Network (TN) Active Power Flow					
General					
Execution					
Options					
Input Data					
Transmission Nodes					
Distribution Nodes					
Edges					
Net Injections					

Edge	T1	T2	T3	T4
1373	0	0	0	0
2089	-54.887	-56.658	-58.725	-61.417
2343	32.465	31.291	29.709	28.579
2038	87.352	87.949	88.434	89.995
10060149	6.111	7.608	9.849	13.852
2076	89.207	98.783	108.645	108.645

Figure 112: Worksheet TN Active Power Flow

#### 4.4.2.3.4 TN Market Clearing Prices

This worksheet presents the Market Clearing Prices of node "Transmission Node" belonging to the examined transmission network and for each trading period ("Tx"), in €/MWh.

Transmission Network (TN) Market Clearing Prices					
General					
Execution					
Options					
Input Data					
Transmission Nodes					
Distribution Nodes					
Edges					
Net Injections					
Bids					

Transmission N	T1	T2	T3	T4
896	67.013	67.013	67.013	67.013
1468	67.013	67.013	67.013	67.013
1505	67.013	67.013	67.013	67.013
1507	67.013	67.013	67.013	67.013
1508	67.013	67.013	67.013	67.013
1537	67.013	67.013	58.884	25.1
1557	67.013	67.013	67.013	67.013

Figure 113: Worksheet TN Market Clearing Prices

#### 4.4.2.3.5 TN Clearing Quantities

This worksheet presents the cleared quantity ("Quantity") of each examined bid "QtBid" (consisting of several "QBids" bids and "QBidSeg" segments and submitted in trading period "ForT" and transmission node "Node"), in MWh.



Transmission Network (TN) Clearing Quantities						
General						
Execution						
Options						
Input Data						
Transmission Nodes						
Distribution Nodes						
Edges						
Net Injections						

Node	QtBids	QBid	QBidSeg	ForT	Quantity
1537	295	1069	1291	1	0
1537	294	1065	1287	1	0
1537	294	1068	1290	4	-0.999
1537	303	1103	1325	3	-0.044
1537	254	907	1075	3	0.197
1468	339	1245	1531	1	0

Figure 114: Worksheet TN Market Clearing Prices

#### 4.4.2.3.6 TN Exported Quantities

This worksheet presents the quantities that are exported from the transmission system to the respective distribution systems. These quantities are associated with the transmission line “Edge” that is connected to the respective distribution networks and presented for each trading period “Tx”, in MWh.

Transmission Network (TN) Exported Quantities					
General					
Execution					
Options					
Input Data					
Transmission Nodes					
Distribution Nodes					

Edge	T1	T2	T3	T4
10060149	31.053	32.549	34.79	38.794
10060114	33.696	35.348	37.66	42.129
10150026	57.763	60.413	62.003	65.183
10060056	33.184	34.505	36.669	40.251

Figure 115: Worksheet TN Exported Quantities

#### 4.4.2.3.7 DN Active Power Flow

This worksheet presents the active power flow of each distribution line “Edge” belonging to distribution network “DN” and for each trading period (“Tx”), in MWh.

Distribution Networks' (DN) Active Power Flow						
General						
Execution						
Options						
Input Data						
Transmission Nodes						
Distribution Nodes						

DN	Edge	T1	T2	T3	T4
DN-10150000	10150017	0.448	0.506	0.568	0.73
DN-10150000	10150012	3.344	3.526	3.475	3.084
DN-10150000	10150021	0	0	0	0
DN-10150000	10150013	2.736	2.911	2.86	2.748

Figure 116: Worksheet DN Active Power Flow

#### 4.4.2.3.8 DN Active Clearing Prices

This worksheet presents the active Market Clearing Prices of node “Node” belonging to distribution network “DN” and for each trading period (“Tx”), in €/MWh.

Distribution Networks' (DN) Active Clearing Prices						
General						
Execution						
Options						
Input Data						
Transmission Nodes						
Distribution Nodes						

DN	Node	T1	T2	T3	T4
DN-10150000	10150017	66.934	66.928	58.805	25.065
DN-10150000	10150013	66.974	66.971	58.845	25.082
DN-10150000	10150021	66.999	66.998	58.869	25.094
DN-10150000	10150012	66.197	66.142	58.098	24.764

Figure 117: Worksheet DN Active Clearing Prices

#### 4.4.2.3.9 TN Active Clearing Quantities

This worksheet presents the cleared active quantity “Active Quantity” of each examined bid “QtBid”, consisting of several “QBids” bids and “QBidSeg” segments and submitted in trading period “ForT” and distribution node “Node” that belongs in distribution network “DN”, in MWh.

Distribution Networks' (DN) Clearing Quantities							
General							
Execution							
Options							
Input Data							
Transmission Nodes							
Distribution Nodes							
Edges							

DN	Node	QtBids	QBid	QBidSeg	ForT	Active Quantity
DN-10150000	10150019	373	1366	1652	3	0
DN-10150000	10150019	371	1357	1643	1	0
DN-10150000	10150019	373	1365	1651	2	0
DN-10150000	10150000	260	931	1115	3	0.099
DN-10150000	10150000	99	286	308	2	0

Figure 118: Worksheet DN Active Clearing Quantities

#### 4.4.2.3.10 DN Reactive Power Flow

This worksheet presents the reactive power flow of each distribution line “Edge” belonging to distribution network “DN” and for each trading period (“Tx”), in MWh.

Distribution Networks' (DN) Reactive Power Flow						
General						
Execution						
Options						
Input Data						
Transmission Nodes						
Distribution Nodes						
Edges						

DN	Edge	T1	T2	T3	T4
DN-10150000	10150017	-0.003	-0.004	-0.004	-0.003
DN-10150000	10150012	-0.003	-0.003	-0.003	-0.002
DN-10150000	10150021	0	0	0	0
DN-10150000	10150013	-0.004	-0.005	-0.005	-0.003
DN-10150000	10150024	0	0	0	0

Figure 119: Worksheet DN Reactive Power Flow

#### 4.4.2.3.11 DN Reactive Clearing Prices

This worksheet presents the reactive Market Clearing Prices of node “Node” belonging to distribution network “DN” and for each trading period (“Tx”), in €/MWh.

Distribution Networks' (DN) Reactive Clearing Prices						
General						
Execution						
Options						
Input Data						
Transmission Nodes						
Distribution Nodes						

DN	Node	T1	T2	T3	T4
DN-10150000	10150017	0	0	0	0
DN-10150000	10150013	0	0	0	0
DN-10150000	10150021	0	0	0	0
DN-10150000	10150012	0	0	0	0

Figure 120: Worksheet DN Reactive Clearing Prices

#### 4.4.2.3.12 TN Reactive Clearing Quantities

This worksheet presents the cleared reactive quantity “Reactive Quantity” of each examined bid “QtBid”, consisting of several “QBids” bids and “QBidSeg” segments and submitted in trading period “ForT” and distribution node “Node” that belongs in distribution network “DN”, in MWh.

Distribution Networks' (DN) Reactive Clearing Quantities							
General							
Execution							
Options							
Input Data							
Transmission Nodes							
Distribution Nodes							
Edges							

DN	Node	QtBids	QBid	QBidSeg	ForT	Active Quantity
DN-10150000	10150019	373	1366	1652	3	0
DN-10150000	10150019	371	1357	1643	1	0
DN-10150000	10150019	373	1365	1651	2	0
DN-10150000	10150000	260	931	1115	3	0
DN-10150000	10150000	99	286	308	2	-0.034

Figure 121: Worksheet DN Reactive Clearing Quantities

## 4.5 Results from simulation with dummy data

### 4.5.1 Toy example

The best way to understand the functioning of the RSF is with an example. Let us consider the example in Figure 122 accompanied with Table 94 displaying generation capacities and costs.

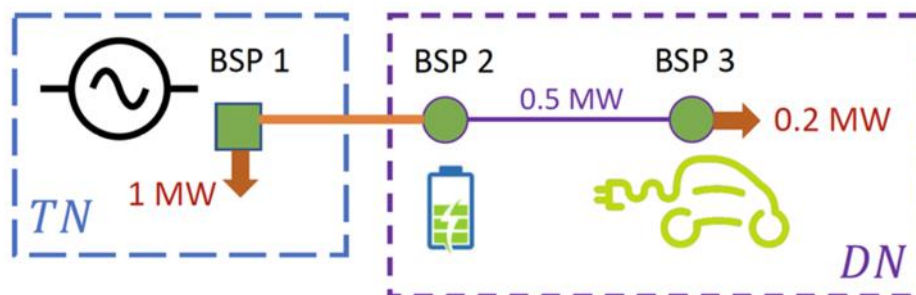


Figure 122 Simple T&amp;D example

Note that it is assumed neither losses nor reactive power in the distribution network for simplicity and that there is a 0.5 MW real power flow limit on the line connecting BSP 2 and BSP 3. The imbalances to cover are a 1 MW load located on the single transmission bus and a 0.2 MW load at bus 3. These imbalances can either be covered by the expensive transmission BSP (BSP 1) or by the cheaper distributed renewable resources (BSP 2 and BSP 3).

Table 94 Data of toy example

BSP	Capacity	Marginal Cost
BSP 1	3 MW	20 €/MWh
BSP 2	1 MW	15 €/MWh
BSP 3	1 MW	10 €/MWh

In a centralized setting, the solution would be the following:

- BSP 1: activate 0 MW, clearing price 15€/MWh.
- BSP 2: activate 0.5 MW, clearing price 15€/MWh.
- BSP 3: activate 0.7 MW, clearing price 10€/MWh.

Let's now consider a decentralized solution framework. The first task of the ADS is to aggregate the distribution flexibility. This is easily done by considering the distribution network as only one bus at the transmission level. This is represented in Figure 123.

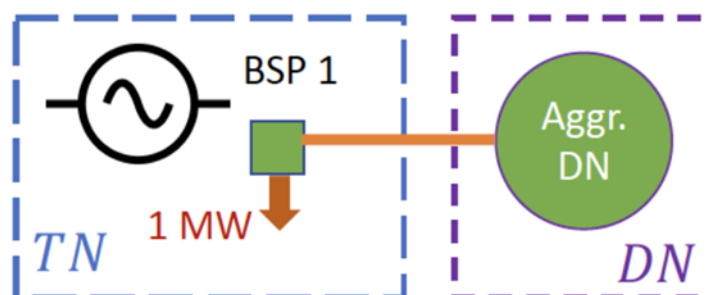
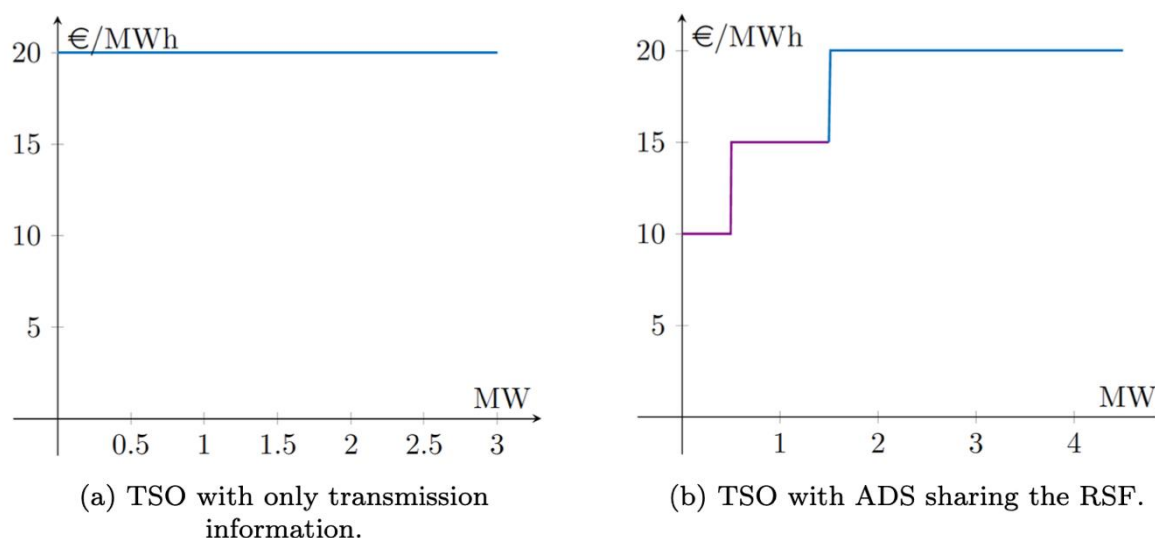


Figure 123 Aggregation from the ADS of the example

The aggregation of the distribution network would need to capture the BRP imbalances, BSP offers and physics of the distribution networks while sharing a minimal amount of information with the TSO. The goal of the work is to show how the RSF can guarantee this property. If the TSO does not take into account the distribution network, the only possibility is to activate BSP 1 (Figure 124a). The role of the ADS is then to build the RSF by assuming different levels of interface flows. In this example, considering for instance 0 MW, 0.5 MW, 1 MW, 1.5 MW and 2 MW interface flow levels provides an exact

representation of the RSF. What the TSO is facing for covering the imbalance is represented in Figure 124b: the violet part of the curve is the RSF while the blue part of the curve represents BSP 1.



**Figure 124** On the example of the Figure 122, depending on the willingness to collaborate, the TSO faces the following options in (a) the ‘only transmission information’ case and (b) the case where the ADS shares the RSF.

In the transmission balancing market, the system imbalance is matched against +1 MW of the RSF. The TSO is then buying 1 MW to the ADS at the price indicated by the RSF of 15 €/MWh. The primal/dispatch part of the disaggregation function then runs, with an aim of finding the most efficient way to evacuate 1 MW while respecting network constraints and distribution imbalances (−0.2 MW at bus 3). The cheapest way for this to be achieved is by activating BSP2 and BSP3 upward by 0.5 MW and 0.7 MW respectively. The dual/pricing part of the disaggregation function then runs, with an aim at determining prices that are coherent with the dispatch and the balancing price. Concretely, a price of 15 €/MWh at bus 2 and 10 €/MWh at bus 3 is deduced. The interface price of 15 €/MWh is consistent with the partial activation of BSP2, which is indifferent about any quantity of activation, since it is making a zero-profit margin.

Aiming at precisely representing the financial interactions between the actors in a decentralized market clearing platform, the resulting settlement table of the example is drawn in Table 95. In Table 95, the financial position of the different transmission and distribution actors is reported, presented in the columns of the table.

**Table 95** Settlement table of the example

Settlements	Transmission			Distribution			
	BSP 1	BRP 1	TSO	ADS	BSP 2	BSP 3	BRP 3
TM-BSP	0 €	-	-15 €	+15 €	-	-	-
Quantity (MW)			-1	+1			
Price (€/MWh)			15	15			
ADS Dis.	-	-	-	-14.5 €	+7.5 €	+7 €	-
Quantity (MW)				-1.2	+0.5	+0.7	
Price (€/MWh)				[10;15]	15	10	
TM-BRP	-	-15 €	+17 €	-	-	-	-2 €
Quantity (MW)		-1	+1.2				-0.2
Price (€/MWh)		15	[10;15]				10
ADS Rebal.	-	-	-2 €	+2 €	-	-	-
Quantity (MW)			-0.2	+0.2			
Price (€/MWh)			10	10			
Total	0 €	-15 €	0 €	+2.5 €	+7.5 €	+7 €	-2 €

The settlement is divided in 4 phases:

1. Transmission market BSP (TM-BSP) settlement. This is the transmission market cleared by the TSO when taking into account transmission BSP offers and the virtual distribution bid sent by the ADS, i.e. the RSF.
2. ADS disaggregation (ADS Dis.). The ADS determines the distribution BSP activations in accordance with the interface power flow cleared in the TM-BSP.
3. Transmission market BRP (TM-BRP) settlement. The TSO collects transmission and distribution BRP payments with respect to the LMPs cleared in the previous steps.
4. ADS Rebalancing (ADS Rebal.). The TSO reallocates the distribution BRP payments received to compensate the ADS which is in charge of managing the congestion in the distribution network with the DSO.

In the first phase, the TM-BSP, the TSO requests 1 MW to the ADS which is bought at a price of 15€/MWh without activating transmission BSP offers. The ADS then disaggregates the interface flow by requesting the activation of BSP 2 and BSP 3 who are remunerated according to the locational marginal prices (respectively 15€/MWh and 10€/MWh). Note that, at the same time, the ADS covers for distribution BRP imbalance: here a 0.2 MW-load located at bus 3, which pushes the ADS to request a total of 0.7 MW from BSP 3. The next step consists in the BRP settlement in which the TSO collects payments from transmission and distribution BRPs (BRP 1 and BRP 3) who are facing locational prices (15€/MWh at bus 1, 15€/MWh at bus 3). Finally, the TSO redistributes the payment received by the distributed BRPs (here BRP 3) to the ADS. The last row shows what each participant paid or got paid. As expected, BSPs and BRPs are remunerated according to their consumption and the locational marginal price cleared. The TSO and the ADS shares the congestion rent which appears through price differences at each location. The congestion rent is here fairly assigned: the TSO is not facing any price difference in its network while the ADS has a congested line (the line connecting buses 2 and 3) and a price difference between these two buses. The ADS receives a compensation of +2.5€ (=  $(15 - 10) \times 0.5$ ).

In practice, computing an exact representation of the RSF is not tractable because of the complexity of the distribution networks. We show in this work how approximations of the RSF provide satisfactory results. We also point out that the RSF is only relevant for the decentralized version of our proposed market clearing platform. The centralized versions of the market clearing platform do not rely on the RSF.

## 4.5.2 Realistic test case

### 4.5.2.1 Test case setup

The test cases that we consider are derived from data sets that were used in the European project SmartNet [59]. For each of the test cases that we present, we receive as input the topology of the T&D network, the bids associated with the generators at each node, and a time horizon of 3 or 4 time steps. Given that each market time unit of the European balancing market corresponds to a 15-minute step, the horizon of the problem corresponds to 45 minutes or 1 hour.

Networks from the Italian and Danish power systems are considered. For the Italian system, we consider three test cases: a medium-sized one, called small it, and two other ones based on the same network topology, called Italy1 and Italy2. For the Danish system, we consider only one test case called Denmark. Instance small it is a medium-sized example, which serves towards validating our approaches, while Italy1, Italy2 and Denmark are more realistic instances. An overview of the Italian and Danish test systems is provided in Table 96. reports for each test case: the number of time-steps, the number of transmission buses, the number of distribution buses, the number of distribution networks, the number of bids, the number of binary variables, the number of variables and the number of constraints. RPI and RPVB are obtained as follows:

Table 96 Overview of the Italian and Danish test cases used in the numerical experiments

Test Case	small_it	Italy1	Italy2	Denmark
$ \mathcal{T} $	4	3	3	4
$ \mathcal{TB} $	27	4,236	4,236	209
$ \mathcal{DB} $	175	1,822	1,822	2,981
# DNs	4	50	50	73
# Bids	1,667	12,318	26,578	25,923
# Binary	4,222	29,660	51,510	90,688
# Variables	25,342	244,052	298,226	391,040
# Constraints	26,401	248,864	310,272	429,931

#### 4.5.2.2 Examined approaches

The proposed RSF approach is compared with two extreme cases. In the first case, the DSO-connected flexibility bids are not considered in the TSO market (No-DSO-Bids approach), while in the second case, all the DSO-connected bids are passed over to the TSO market but without accounting for the DSO grid constraints (No-DSO-Network approach). These two alternatives, although “extreme”, are compatible with the EU market design and are considered by practitioners in similar context [60]. They are therefore regarded as highly relevant EU benchmarks.

Two centralized approaches are also considered and compared them with the decentralized RSF approach — although not compatible with the institutional separation of DSO and TSO, a centralized approach provides an interesting “idealized” benchmark for a computational analysis. The first alternative, referred to as *Relaxation*, relies on the SOCP relaxation in order to provide dispatch decisions and LMPs. Indeed, in this approach, the MISOCP version of our problem is solved and the primal decisions are deduced. Binary variables are fixed to their optimal value and the remaining SOCP is solved in order to compute the LMPs. Note that the *Relaxation* approach provides a lower bound for the problem but does not guarantee AC feasibility in the DN. For this reason, we also consider an alternative centralized approach, namely *Hybrid*. This method recovers feasibility in the DNs if the dispatch is not AC feasible

#### 4.5.2.3 Enhancing the Computation of RSF

The RSF is computed by using equally spaced points in the interval imposed by the line limits of each interface line. Since these limits are often large compared to the potential values of the interface flow, taking equally spaced points might cause computing the RSF on flow values that are far from being optimal. As an example, Figure 125 shows that the computation of the RSF on the import side (negative values) lacks of interest and one could assume that importing, in that case, is costless. Ideally, one should detect where it is relevant to add points to the RSF. Assuming that we decide to build the RSF with  $N$  points, what we suggest is the following: (i) evaluate the RSF on  $N/2$  equally spaced points between lower and upper interface flow limits; (ii) detect the 3 consecutive points with the highest price difference, and denote their flow values  $f_0, f_1, f_2$ ; (iii) evaluate the RSF on  $N/2$  equally spaced points between  $f_0$  and  $f_2$ . By applying this, we see how the precision of the blue curve improves compared to the equally spaced points curve in magenta (Figure 125 and Figure 126)



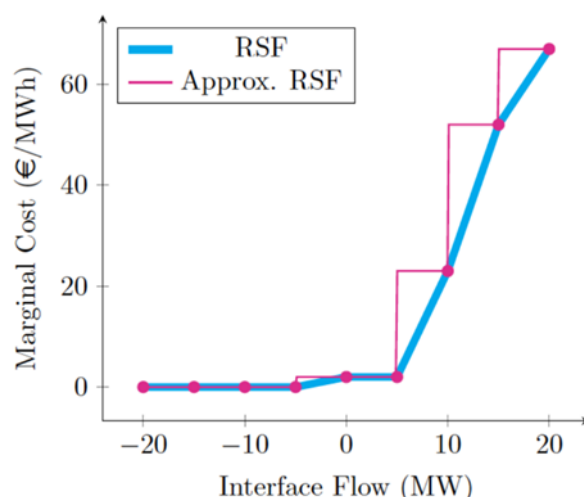


Figure 125 Example of the basic computation of the RSF.

To measure the impact of the precision of the RSF, we report the evolution of the primal objective values as well as the LOCs for the medium-size example, small it, for 10, 20 and 30 points on the RSF (Figure 127). The figures show how the enhancement step increases the quality of the solution with the same number of points on the RSF. Even if the enhancement makes the approach less parallelizable (one needs to split the computation for the first  $N/2$  points before computing the remaining  $N/2$  as opposed to directly compute  $N$  points), we will use this enhancement when displaying the results later.

#### 4.5.2.4 Number of points on the RSF

We conduct a sensitivity analysis on the number of points that should be considered when computing the RSF. To do so, we report the objective value, the lost opportunity cost and the solve time for a different number of points on the RSF for the test case Italy1 (Figure 128). The general trend is as expected: the solution improves as the number of points increases. Note however that the objective value and the LOC are not strictly decreasing as a function of the number of points: indeed, this is due to the discretization of the RSF that can be favourable even if fewer points are used. It should also be noted that considering 400 points for this particular test case leads to a costly computation (+4,000 seconds for this run). Even if the approach is parallelizable, the additional computational cost of having 400 points appears to be vain compared to the solutions with 300 or 350 points. For this reason, in the simulations, we decide to adopt 300 points on the RSF for Italy1, Italy2 and Denmark which are of the same scale. Since small it is of smaller scale, we consider only 100 points for this test case.

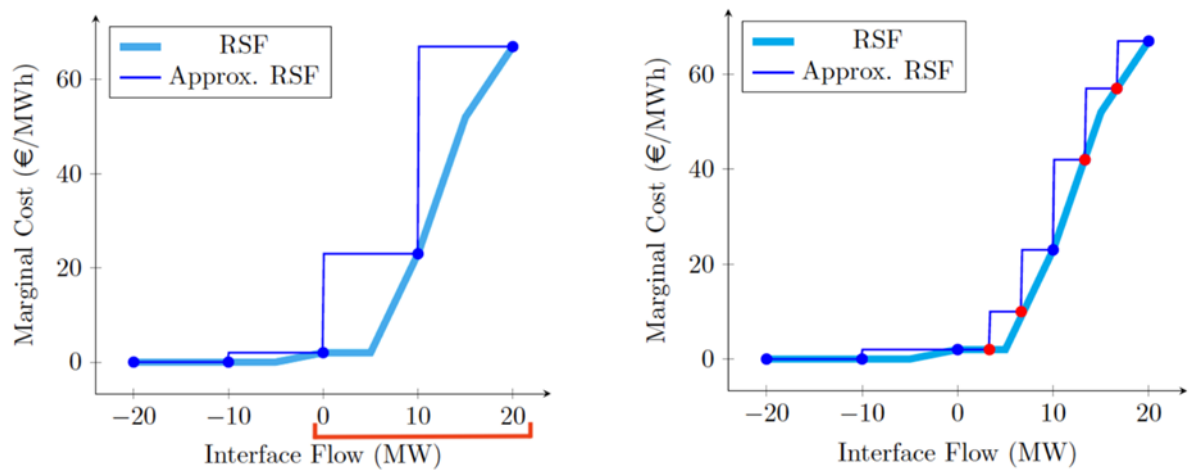


Figure 126 Enhancing the RSF by intelligently choosing the points to compute. Left figure: Step (i) (Evaluate the RSF for -10 MW, 0 MW, 10MW, 20 MW) and Step (ii) (detect the points of interest: 0, 10 and 20 MW). Right figure: Step (iii) (Evaluate the RSF for 4 additional points between 0 and 20 MW).

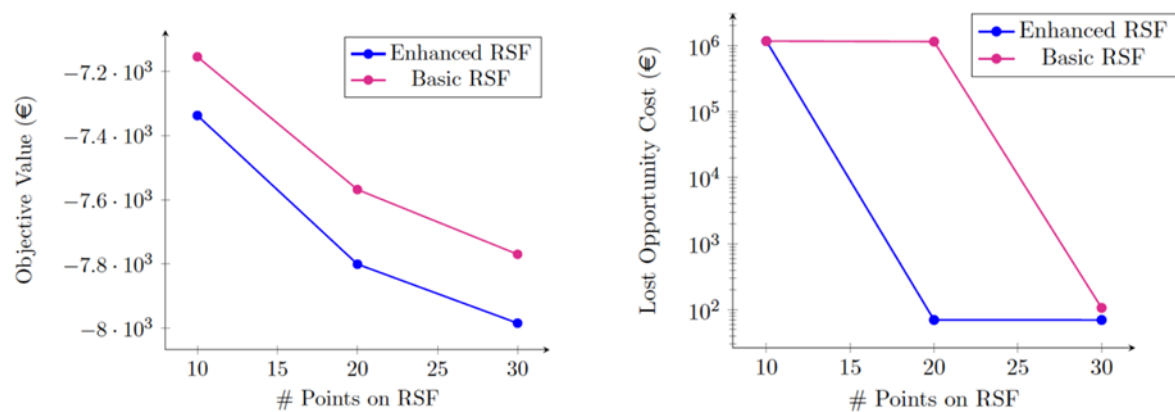


Figure 127 Evolution of the objective value and the LOC of the small it test case as a function of the number of points on the RSF by using two different point selection strategies: Basic vs. Enhanced. Left figure: Comparison of the objective value. Right figure: Comparison of the LOC

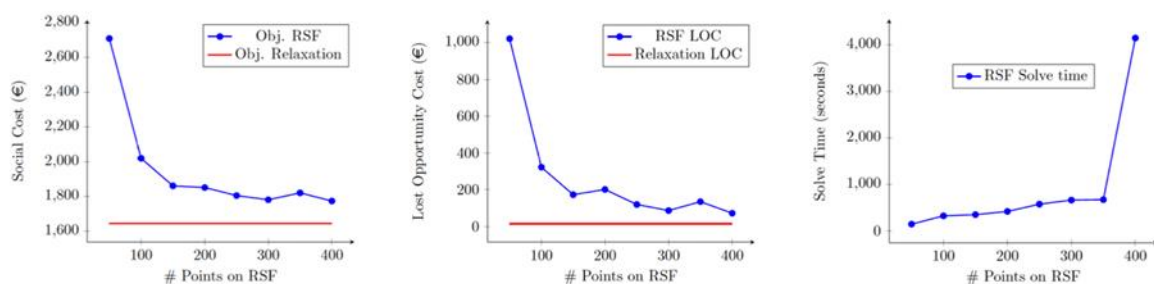


Figure 128 Assessment of the RSF approach as a function of the number of points considered in Step 1. The left, middle and right figures are respectively the objective value, the LOC and the solve time



#### 4.5.2.5 Simulations

**Computational setting.** The clearing algorithms are implemented in Julia (version 1.1.1) using JuMP on a MacBook Pro 2016, with a 2.9 GHz Dual-Core Intel Core i5 processors. LPs, SOCPs, MILPs, MISOCPs, are solved using Mosek (version 9); NLPs are solved using IPOPT (version 3.13.2).

**Tolerance.** The feasibility tolerance of the solvers is set to  $\varepsilon = 1e-6$ . When showing the results, the only constraint that might be violated are the AC constraints relaxed in the SOCP grid model in the *Relaxation* approach. The maximum constraint violation is then reported in Table 97 in column Max. Viol.

**EU benchmarks:** Table 97 compares the results of the proposed RSF approach with the two extreme cases. The No-DSO-Bids approach safeguards the DSO from any network constraint violations since it prevents the TSO from using the DSO-connected resources. This is reflected in the “Slack” column, which measures (in MWh) the network constraints violation. Nonetheless, it leads to a higher system cost since the TSO cannot access some of the least-cost bids from the DSO grid. On the other hand, the No-DSO-Network approach provides full access to the DSO-connected bids to the TSO. Since some of the bids passed to the TSO are not grid-secured, the approach leads to constraint violations (as observed in the Slack column), translating into the DSO having to perform an ex-post redispatch, harming the total cost. Additionally, the proposed approach provides more accurate economic signals, highlighted by the lower LOC value in all cases. All-in-all, the hierarchical RSF approach outperforms the other two approaches.

**Table 97 Comparison of the RSF approach with the EU benchmarks**

Test case	Approach	Cost	Slack (MWh)	LOC (€)
MediumIt	No-DSO-Bids	$-7.730e^{+3}$	0.00	$11.55e^{+3}$
	RSF	$-7.855e^{+3}$	0.00	20.27
	No-DSO-Network	$-8.360e^{+3}$	9.93	176.09
Italy1	No-DSO-Bids	$2.646e^{+3}$	0.00	969.84
	RSF	$1.787e^{+3}$	0.00	90.79
	No-DSO-Network	$7.908e^{+3}$	56.66	$3.19e^{+3}$
Italy2	No-DSO-Bids	$13.606e^{+3}$	0.00	$5.614e^{+3}$
	RSf	$8.142e^{+3}$	0.00	159.28
	No-DSO-Network	$10.939e^{+3}$	2.26	$3.038e^{+3}$
Denmark	No-DSO-Bids	$-9.347e^{+3}$	0.00	937.49
	RSF	$-10.073e^{+3}$	0.11	265.96
	No-DSO-Network	$-9.443e^{+3}$	16.55	$1.209e^{+3}$

**Centralized Benchmarks and Computational Analysis.** Each approach is tested on each test case. The results are presented in Table 98. From left to right, the columns display the name of the test case, the approach used, the objective value of the primal problem, the absolute gap to the lower bound (obtained using the Relaxation approach), the maximum violation of a constraint of the primal solution, the PLP, the LOC, and the solve time in seconds. Note that the RSF is computed with 300 points for all the test systems.

The results on the medium-sized example, small it, demonstrate that all the approaches provide similar results in terms of objective value. For the largest instances (Italy1, Italy2 and Denmark), the objective values of the Relaxation and Hybrid approaches confirm the quality of the SOCP relaxation of the AC-OPF on radial networks. Note, however, that for the Danish test system, even if the Relaxation solution is almost feasible ( $MV = 2e-6$ ), both Hybrid and RSF provide solutions for which the objective is significantly different. We further note that the solve time for all the approaches is significant for the Danish test case (more than 5 minutes). Executing the RSF sequentially also leads to time-consuming computations. Figure 129 presents how parallelization can decrease substantially the execution time of the RSF approach. In particular, using 16 processors ensures execution times of less than 5 minutes for the three largest test cases. On the contrary, it is not possible to parallelize centralized schemes. This underlines the potential weaknesses of considering centralized schemes in addition to not preserving privacy.

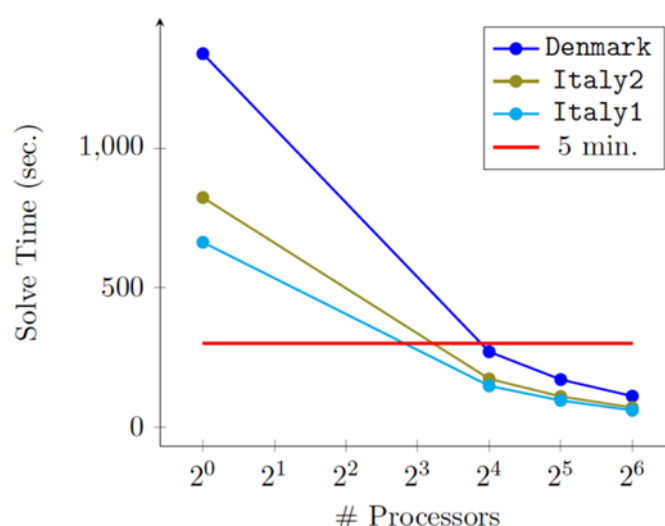
The differences between objective values of methods ensuring a feasible dispatch (Hybrid and RSF) are quite small. Moreover, compared to the trading volume of the market (an estimation is for example

PLP), these differences could even be assumed negligible as well as the LOC which is always larger when using the RSF approach than the centralized approaches.

To sum up, the RSF approach provides slightly suboptimal solutions while maintaining privacy of the different actors and relies on decomposability which allows for heavy parallelization of the framework. This validation of the RSF approach is not only shown on a medium-sized example, small it, but also on three national-scale realistic instances of the problem (Italy1, Italy2, Denmark).

**Table 98 Comparison of the RSF with centralized approaches**

Test case	Approach	Objective	Gap (€)	MV	LOC (€)	Time (s)
MediumIt	Relaxation	$-7.872e+3$	-	$1e^{-6}$	0.59	5.39
	Hybrid	$-7.872e+3$	0.01	$3e^{-7}$	0.53	10.17
	RSF	$-7.855e+3$	8.09	$1e^{-7}$	20.27	85.90
Italy1	Relaxation	$1.644e+3$	-	$2e^{-4}$	14.66	85.54
	Hybrid	$1.648e+3$	3.79	$5e^{-7}$	14.30	89.23
	RSF	$1.781e+3$	136.52	$9e^{-7}$	86.37	662.5
Italy2	Relaxation	$7.998e+3$	-	$1e^{-4}$	29.68	160.7
	Hybrid	$8.001e+3$	2.57	$4e^{-7}$	32.25	166.9
	RSF	$8.147e+3$	149.22	$1e^{-6}$	166.01	823.2
Denmark	Relaxation	$-1.023e+4$	-	$2e^{-6}$	30.30	362.6
	Hybrid	$-9.951e+3$	274.92	$8e^{-7}$	33.41	375.4
	RSF	$-9.518e+3$	707.97	$9e^{-7}$	592.57	1,340



**Figure 129 Evolution of the solution time of the RSF approach with respect to the number of processors on the Italian and Danish test cases**

#### 4.5.2.6 Settlements in the Danish Case Study

Moreover, the RSF approach we develop implements a simple market design aiming at fairly remunerating each actor participating in the market. Practically, we draw a settlement table to show how the approach is able to define the cash flows and remunerations of each participant. We illustrate the insights of such settlement tables on the Danish test system (Table 99).

In Table 99, we aggregate the transmission (resp. distribution) BSPs (BSPT resp. BRPD), BRPs (BRPT resp. BRPD) and the total remunerations or payments are reported (over the 4 time-steps of the test case). In this test case, the power is mostly flowing from the transmission network to the different distribution networks: the ADS is buying power from the transmission network for a total cost of 3,061€. The ADS compensates the distribution BSPs when disaggregating. The TSO is collecting payments from BRPs in both transmission and distribution before reallocating the BRPD payments to the ADS. In total, the TSO and the ADS are collecting congestion revenue, the TSO's revenue being significantly more important.

Even if the number of buses is more important in the distribution network in this test case, we observe that most of the power is consumed and produced in the transmission network (Table 100), which explains the scale of the revenues and costs.

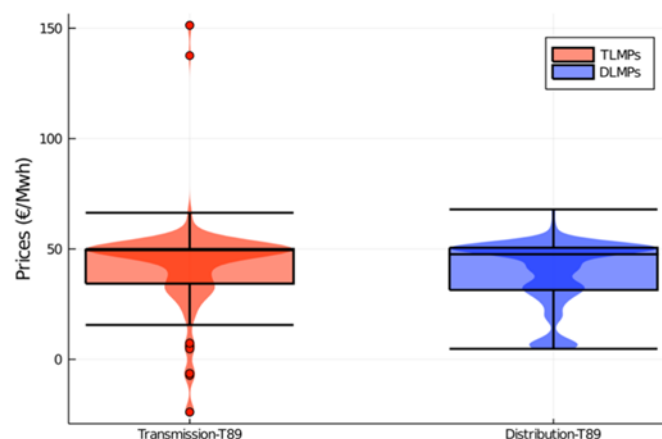
**Table 99 Settlement table of the Denmark test case**

Settlements	Transmission			Distribution		
	BSPT	BRPT	TSO	ADS	BSPD	BRPD
TM-BSP	+11,371 €	-	-8,311 €	-3,061 €	-	-
ADS Dis.	-	-	-	-568 €	+568 €	-
TM-BRP	-	-803,062 €	+808,713 €	-	-	-5,651 €
ADS Rebal.	-	-	-5,651 €	+5,651 €	-	-
Total	-11,371 €	-803,062 €	+794,751 €	+2,022 €	+568 €	-5,651 €

To understand why the TSO is collecting an important congestion revenue, we draw a box plot representation of the transmission and distribution LMPs computed for one time-step ( $t = 89$ ) on the Denmark test case in Figure 130. When comparing the LMPs of both networks, we notice that even if the lower, middle and upper quartiles are of the same scale, the spread of the transmission LMPs is more important. This observation stresses the potential significant differences between prices at certain locations. Note also some negative transmission prices: 208 MW withdrawn for  $t = 89$  have negative valuations, i.e. some consumers are paid to consume power instead of paying which leads to negative prices in certain locations where only this type of bid has been accepted. The disparity in locational pricing implicitly shows how congested the transmission network is.

**Table 100 Power produced and consumed in the Denmark test case.**

Transmission		Distribution	
Power injected	Power withdrawn	Power injected	Power withdrawn
19,756 MW	-19,561 MW	550 MW	-723 MW



**Figure 130 A box plot representation of the LMPs in the Danish test case for  $t=89$ .**

#### 4.5.2.7 Conclusions & Perspectives

We develop and implement a decentralized market clearing T&D platform capable of respecting several technical requirements. The platform offers several advantages:

1. it preserves the privacy of the TSO and the DSOs by a careful exchange of only border information at the interface.
2. dispatch decisions are AC feasible in the distribution network, which is relevant due to distribution system flexibility and renewable supply.
3. in addition to primal decisions, the LMPs cleared in a straightforward way provide satisfactory results and incentivize the use of flexibility and signal investments in specific locations.

4. the RSF approach is highly parallelizable and respects the time-limit imposed by short-term markets.
5. by comparing the RSF approach to three other centralized approaches, impossible to apply in practice, we show the slight suboptimality of the RSF approach.
6. intensive testing on large-scale systems shows the applicability of the RSF approach in a realistic setting.

These aspects stress the benefit of the prototyped platform implemented in this work. Even if the platform is already promising, improvements are already worth considering. For example, the selection of points of interest on the RSF could largely be improved through market experience and historical data. To validate this work, broader experiments on different topologies should be tested. Also, the LMPs were cleared using IP pricing and a comparison of different price clearing techniques are of interest to enhance the quality of the framework. Extending by considering large-scale test systems to assess the pricing techniques could definitely be studied in the future. The RSF approach could also be applied towards hierarchical balancing in markets with zonal pricing.

## 5 Conclusion

Given the wider penetration of DERs within the electricity system, the need to develop flexibility platforms has emerged to facilitate or coordinate the trade, dispatch and/or settlement of energy or system services between DERs and operators of the transmission and distribution systems. This report gives a detailed description of the market and operational characteristics of three new market mechanisms that are developed within the scope of FEVER Task 4.2, as well as information on the developed solution algorithms.

The proposed mechanisms allow trading of flexibility services in different time horizons, from day – ahead trades to real time trading for balancing purposes and engage system operators of both the transmission and the distribution system, ensuring their successful cooperation. In addition, the algorithmic design is optimised to ensure the scalability of the proposed mechanisms. All mechanisms (day – ahead, continuous and real time) are based upon innovative principles regarding the market clearing process, the assessment of the network feasibility and the integration of transmission and distribution markets.

For the day-ahead allocation of flexibility the proposed mechanisms include flexibility as a market tool by solving a day-ahead optimization problem, considering both the central market mechanisms and the decentralized local distribution grid. In the latter, the several technical constraints and grid issues can be identified and resolved via the proposed market mechanism. Here the day-ahead market mechanism should be capable of meeting a number of challenging requirements that require the application of tailored methodologies. For the modelling of the LFM within the DA market mechanism, a linearized AC OPF model is presented, that successfully, efficiently, and accurately linearizes the constraints imposed by the DN. Then, the proposed DA LFM is formulated and presented. The results indicate that the proposed LFM manages to achieve its objectives of resolving congestion and voltage issues, as well as solving imbalances in the DN. Additionally, the methodology can be also applied in a multi-period optimization setting, therefore the complexity introduced by intertemporal constraints is also addressed. Some limitations and topics for further research regarding the DAM mechanism include a) the central DAMs are solved via a DC OPF. This disregards voltage magnitudes and reactive power quantities, but greatly reduces the size of the problem and the solution speed. As described, the DC approximations hold with relative accuracy in the TN; however, the overall accuracy of the model would be improved if AC OPF was adopted for the central DAM; b) the proposed methodology yields suboptimal results, when compared to a methodology than incorporates all the elements of all the Transmission and Distribution Networks in a single problem. However, such a methodology results in a very large problem (which is difficult to solve) and there are institutional limitations regarding the sharing of sensitive network data. Further research could be conducted for the identification of constraint reduction mechanisms of such a problem, and to pinpoint the least required amount of information required to be exchanged to implement this mechanism; c) finally, it should also be noted that introducing an iterative procedure between the central DAM and LFMs that solves the markets until the prices of the markets converge could lead to better price discovery. Further research on this topic can focus on using LMPs at the T&D interconnection nodes as a means of conveying pricing information from one level to the other

In order to further enhance the secure operation of the distribution grid in case of unpredictable events, a continuous intraday trading mechanism is proposed, where the DSO and aggregators can trade grid energy to resolve emerging issues. The continuous trading market aims at solving violations detected by the DSO on an intraday basis, by explicitly considering AC network feasibility and ensuring the efficient solution of multiple distribution network violations. The proposed network feasibility implementation also provides the functionality of partial matching of bids which is crucial for the liquidity of the continuous market and is modelled in a computationally light basis, being, therefore, suitable for continuous trading applications. Additionally, the LFM requires minimal information exchange between the DSO and the MO to respect institutional limitations. Trades within the proposed framework are cleared at a single price, which is the price of the order that was first submitted (either the sell or buy order). The selected implementation on the determination of the trade execution price follows the rules of the European intraday continuous market (incorporated in the XBID project), which imply that two financially feasible orders are matched at the price of the order with the oldest timestamp [61]. Another possible implementation is setting the lowest price between the two orders as the trade execution price. However, alternative pricing mechanisms also exist. For example, in GOPACS market-based flexibility platform [62], non-intuitive trades are allowed (sell price greater than buy price), participants are

compensated with pay-as-bid mechanism and the grid operator pays the spread between the buy and sell orders. While it is true that further assessment is required to identify the most appropriate pricing mechanisms for different local flexibility markets, it is evident that the price formation selected within the scope of this report is based on the rules of a well-established operational continuous market and stems upon the principle of providing an advantage to the participant that facilitated first the congestion solution. Ideas to extend the work on the methodological part will be to further analyse the limitations of using AC sensitivities to traded quantities as well as the effect of trading to grid losses. Last, the effects of an unbalanced three-phase distribution system could also be investigated.

With the aim to connect the energy markets with the (future) real-time electricity balancing markets such as MARI, this deliverable further proposes a real-time multi-layer iterative mechanism for congestion management and balancing purposes. While the balancing platform foreseen in Europe relies on a zonal model of the grid and therefore does not model the intra-zonal constraints<sup>2</sup>, the objective of the hierarchical mechanism is to implicitly model the intra-zonal network constraints through the merit order that is transferred to the balancing market platform. The developed transmission and distribution real-time market clearing platform accounts for the complexity of the physics of the networks and non-convex bid structures and is able to return a dispatch solution as well as prices. An important feature that such a framework should incorporate is decentralized decision-making. This motivates the hierarchical structure of the framework through the introduction of a residual supply function, which is included to the market clearing platform in order to preserve the privacy of the different entities and parallelize the computational effort. Important institutional barriers relate to the adoption of fine-grained locational prices, since compromises need to be reached with existing boundary conditions of power and system operations in practice. This issue will be further explored in the upcoming integration of the RTBM mechanism with the real-world pilots. The pricing of reactive power in real time is also a forward-looking feature of the mechanism, which may not be entirely aligned with current operational practices. An important extension of the model is the introduction of reserve products in the platform, which will be the topic of future research.

The proposed market mechanisms and tools have been validated using dummy data in toy examples and realistic test cases. Simulations results indicate that the proposed mechanisms exhibit satisfactory scalability and accuracy and are able to efficiently address issues of the DN. Further simulation tests will be conducted within the scope of Task 4.3 using the real data from the pilots and the findings will be documented in D4.4.

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<sup>2</sup> See for instance the [slides](#) of the MARI Stakeholder Workshop.



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## 8 List of abbreviations

Abbreviation	Term
AC	Alternating Current
AC PF	Alternating Current Power Flow
ADS	Aggregation-Disaggregation System
aFRR	automatic Frequency Restoration Reserve
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
DA	Day-Ahead
DAM	Day-Ahead Market
DC	Direct Current
DER	Distributed Energy Resources
DSO	Distribution System Operator
DN	Distribution Network
GUI	Graphical User Interface
IDM	Intra-Day Market
LP	Linear Programming
LFM	Local Flexibility Market
LMP	Locational Marginal Price
MCP	Market Clearing Price
mFRR	manual Frequency Restoration Reserve
MCP	Market Clearing Price
MO	Market Operator
MP	Market Participant
MTU	Market Time Unit
NL	Non-Linear
OPF	Optimal Power Flow
PTDF	Power Transfer Distribution Factors
RES	Renewable Energy Sources
RSF	Residual Supply Function
RSF	Residual Supply Functions
SLP	Sequential Linear Programming
T&D	Transmission-Distribution
TN	Transmission Network
TSO	Transmission System Operator

## Annex A Intraday Market Application Prototype: Simulators' Data Structures

<i>File Name.type</i>	<i>Columns</i>
<b>Topology_bus_data</b>	<b>network_id</b>   integer   ID of the network <b>bus_id</b>   integer   ID of the bus <b>in_service</b>   boolean   specifies if the bus is in service <b>max_vm_pu</b>   float*   Maximum voltage <b>min_vm_pu</b>   float   Minimum voltage <b>name</b>   string   name of the bus <b>type</b>   string   type variable to classify buses <b>vn_kv</b>   float   rated voltage of the bus [kV] <b>zone</b>   string   can be used to group buses, for example network groups / regions
<b>Topology_line_data</b>	<b>network_id</b>   integer   ID of the network <b>line_id</b>   integer   ID of the line <b>c_nf_per_km</b>   float   capacitance of the line [nano Farad per km] <b>df</b>   float   derating factor (scaling) for max_i_ka <b>from_bus</b>   integer   Index of bus where the line starts <b>g_us_per_km</b>   float   dielectric conductance of the line [micro Siemens per km] <b>in_service</b>   boolean   specifies if the line is in service <b>length_km</b>   float   length of the line [km] <b>max_i_ka</b>   float   maximal thermal current [kilo Ampere] <b>max_loading_percent</b>   float   Maximum loading of the line <b>name</b>   string   name of the line <b>parallel</b>   integer   number of parallel line systems <b>r_ohm_per_km</b>   float   resistance of the line [Ohm per km] <b>std_type</b> to_bus   string   standard type which can be used to easily define line parameters with the pandapower standard type library <b>type</b>   string   type of line <b>x_ohm_per_km</b>   float   inductance of the line [Ohm per km]
<b>Topology_load_data</b>	<b>network_id</b>   integer   ID of the network <b>bus_id</b>   bus_id   integer   ID of the bus <b>const_i_percent</b>   float   percentage of p_mw and q_mvar that is associated to constant current load at rated voltage [%%] <b>const_z_percent</b>   float   percentage of p_mw and q_mvar that is associated to constant impedance load at rated voltage [%%]



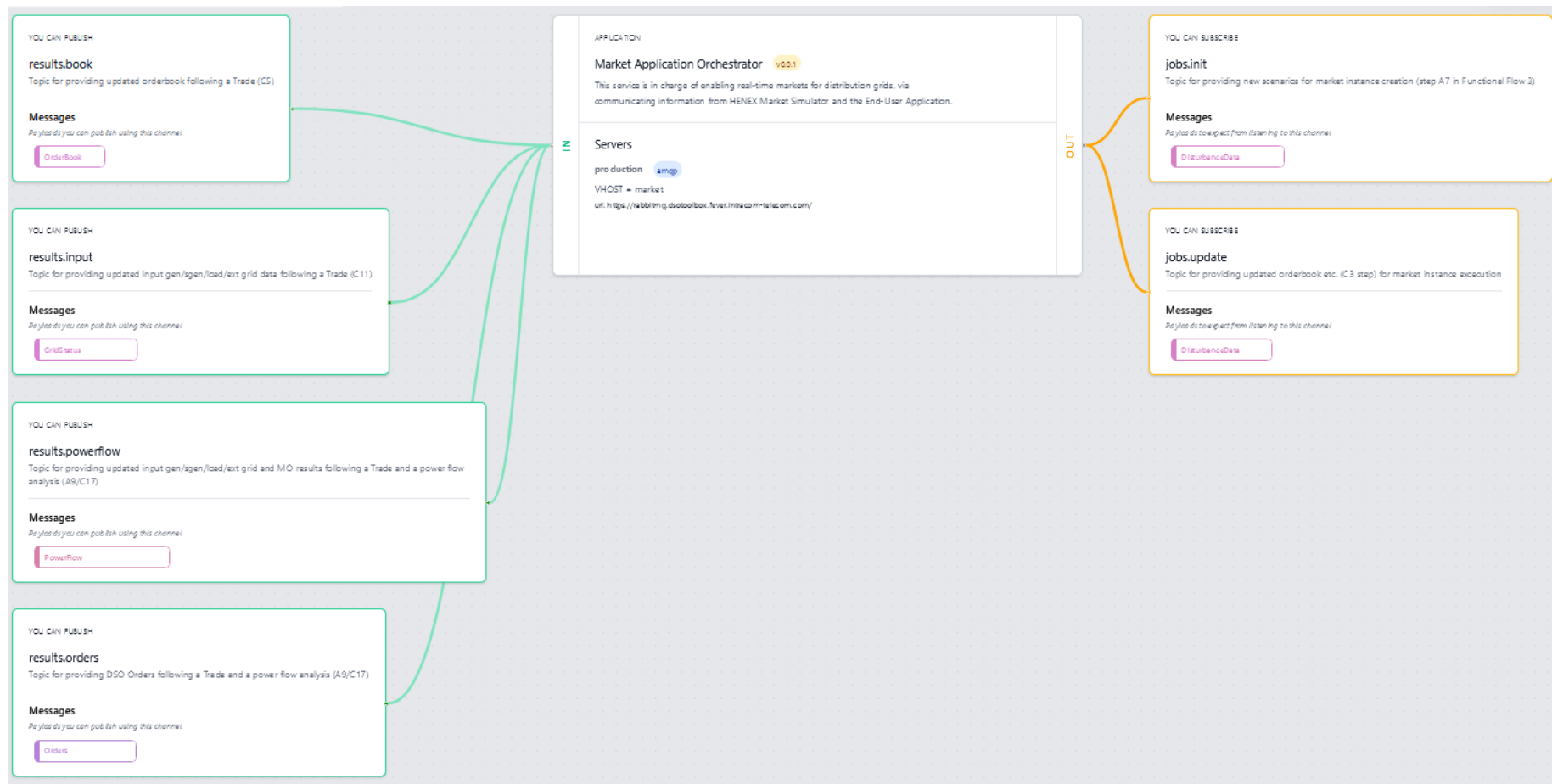
	<b>controllable</b>   boolean   specifies if the load is controllable <b>in_service</b>   boolean   specifies if the load is in service <b>name</b>   string   name of the load <b>scaling</b>   float   scaling factor for active and reactive power <b>sn_mva</b>   float   rated power of the load [kVA] <b>type</b>   string   type variable to classify the load
<b>Topology_gen_data</b>	<b>network_id</b>   integer   ID of the network <b>bus_id</b>   integer   ID of the bus <b>controllable</b>   boolean   Whether this generator is controllable by the optimal powerflow <b>in_service</b>   boolean   specifies if the generator is in service. <b>Name</b>   str   name of the generator <b>Scaling</b>   float   scaling factor for the active power <b>sn_mva</b>   float   nominal power of the generator [MVA] <b>type</b>   string   type variable to classify generators <b>slack</b>   boolean   specifies if slack <b>max_p_mw</b>   float   Maximum active power injection <b>min_p_mw</b>   float   Minimum active power <b>max_q_mvar</b>   float   Maximum reactive power <b>min_q_mvar</b>   float   Minimum reactive power
<b>Topology_ext_grid_data</b>	<b>network_id</b>   integer   ID of the network <b>bus_id</b>   integer   ID of the bus <b>in_service</b>   boolean   specifies if the external grid is in service <b>name</b>   string   name of the external grid <b>max_p_mw</b>   float   Maximum active power <b>min_p_mw</b>   float   Minimum active power <b>max_q_mvar</b>   float   Maximum reactive power <b>min_q_mvar</b>   float   Minimum active power
<b>Topology_bus_geodata</b>	<b>network_id</b>   integer   ID of the network <b>bus_id</b>   integer   ID of the bus <b>x</b>   float   x coordinate of bus location <b>y</b>   float   y coordinate of bus location <b>coords</b>
<b>Input_load_data</b>	<b>Network_id</b>   integer   ID of the Network <b>event_id</b>   integer   ID of the event <b>bus_id</b>   integer   ID of the bus

	<p><b>p_mw</b>   float   active power of the load [kW]</p> <p><b>q_mvar</b>   float   reactive power of the load [kVar]</p>
<b>Input_gen_data</b>	<p><b>Network_id</b>   integer   ID of the Network</p> <p><b>event_id</b>   integer   ID of the event</p> <p><b>bus_id</b>   integer   ID of the connected bus</p> <p><b>p_mw</b>   float   the real power of the generator [MW]</p> <p><b>vm_pu</b>   float   voltage set point of the generator [p.u]</p>
<b>Input_ext_grid_data</b>	<p><b>Network_id</b>   integer   ID of the Network</p> <p><b>event_id</b>   integer   ID of the event</p> <p><b>bus_id</b>   integer   ID of the bus</p> <p><b>va_degree</b>   float   angle set point [degree]</p> <p><b>vm_pu</b>   float   voltage set point [p.u]</p>
<b>Output_bus_data</b>	<p><b>Network_id</b>   integer   ID of the Network</p> <p><b>event_id</b>   integer   ID of the event</p> <p><b>bus_id</b>   integer   ID of the bus</p> <p><b>vm_pu</b>   float   voltage magnitude [p.u]</p> <p><b>va_degree</b>   float   voltage angle [degree]</p> <p><b>p_mw</b>   float   resulting active power demand [MW]</p> <p><b>q_mvar</b>   float   resulting reactive power demand [Mvar]</p> <p><b>va_rad</b>   float   voltage angle [rad]</p> <p><b>max_vm_pu</b>   float   Maximum voltage</p> <p><b>min_vm_pu</b>   float   Minimum voltage</p>
<b>Output_line_data</b>	<p><b>Network_id</b>   integer   ID of the Network</p> <p><b>network_id</b>   integer   ID of the network</p> <p><b>line_id</b>   integer   ID of the line</p> <p><b>from_bus</b>   integer   Index of bus where the line starts</p> <p><b>to_bus</b>   integer   Index of bus where the line ends</p> <p><b>p_from_mw</b>   float   active power flow into the line at "from" bus [MW]</p> <p><b>q_from_mvar</b>   float   reactive power flow into the line at "from" bus [MVar]</p> <p><b>p_to_mw</b>   float   active power flow into the line at "to" bus [MW]</p> <p><b>q_to_mvar</b>   float   reactive power flow into the line at "to" bus [MVar]</p> <p><b>pl_mw</b>   float   active power losses of the line [MW]</p> <p><b>ql_mvar</b>   float   reactive power consumption of the line [MVar]</p> <p><b>i_from_ka</b>   float   Current at from bus [kA]</p> <p><b>i_to_ka</b>   float   Current at to bus [kA]</p>

	<b>i_ka</b>   float   Maximum of i_from_ka and i_to_ka [kA] <b>loading_percent</b>   float   line loading [%] <b>s_from_mva</b>   float   apparent power flow into the line at "from" bus [MVA] <b>s_to_mva</b>   float   apparent power flow into the line at "to" bus [MVA] <b>s_max_mva</b>   float   max apparent power flow [MVA]
<b>Output_external_grid_data</b>	<b>Network_id</b>   integer   ID of the Network <b>event_id</b>   integer   ID of the event <b>bus_id</b>   integer   ID of the bus <b>p_mw</b>   float   active power supply at the external grid [MW] <b>q_mvar</b>   float   reactive power supply at the external grid [MVar]
<b>Output_load_data</b>	<b>Network_id</b>   integer   ID of the Network <b>event_id</b>   integer   ID of the event <b>bus_id</b>   integer   ID of the bus <b>p_mw</b>   float   resulting active power demand after scaling and after considering voltage dependence [MW] <b>q_mvar</b>   float   resulting reactive power demand after scaling and after considering voltage dependence [MVar]
<b>Output_generators_data</b>	<b>Network_id</b>   integer   ID of the Network <b>event_id</b>   integer   ID of the event <b>bus_id</b>   integer   ID of the bus <b>p_mw</b>   float   resulting active power demand after scaling [MW] <b>q_mvar</b>   float   resulting reactive power demand after scaling [MVar]
<b>Output_Sensitivity_BusVoltage</b>	<b>Network_id</b>   integer   ID of the Network <b>event_id</b>   integer   ID of the event <b>bus_id_voltage</b>   integer   ID of the bus that corresponds to the voltage derivative <b>bus_id_power</b>   integer   ID of the bus that corresponds to the power derivative <b>va_p</b>   float   Derivative voltage angle [rad]/ bus resulting active power demand [MW] <b>va_q</b>   float   Derivative voltage angle [rad]/ bus resulting reactive power demand [MVar] <b>vm_p</b>   float   Derivative voltage magnitude [rad]/ bus resulting active power demand [MW] <b>vm_q</b>   float   Derivative voltage magnitude [rad]/ bus resulting reactive power demand [MVar]
<b>Output_Sensitivity_LineFlow</b>	<b>Network_id</b>   integer   ID of the Network <b>event_id</b>   integer   ID of the event <b>line_id</b>   integer   ID of the line

	<p><b>bus_id</b>   integer   ID of the bus</p> <p><b>DS_from_p</b>   float   Derivative apparent power flow [MVA]/ « from » bus resulting active power demand [MW]</p> <p><b>DS_from_q</b>   float   Derivative apparent power flow [MVA]/ « from » bus resulting reactive power demand [MVar]</p> <p><b>DS_to_p</b>   float   Derivative apparent power flow [MVA]/ « to » bus resulting active power demand [MW]</p> <p><b>DS_to_q</b>   float   Derivative apparent power flow [MVA]/ « to » bus resulting reactive power demand [MVar]</p>
<b>Output_bus_data_MO</b>	<p><b>Network_id</b>   integer   ID of the Network</p> <p><b>event_id</b>   integer   ID of the event</p> <p><b>bus_id</b>   integer   ID of the bus</p> <p><b>vm_max_diff</b>   float   Maximum voltage- voltage magnitude [pu]</p> <p><b>vm_min_diff</b>   float   Minimum voltage- voltage magnitude [pu]</p>
<b>Output_line_data_MO</b>	<p><b>Network_id</b>   integer   ID of the Network</p> <p><b>event_id</b>   integer   ID of the event</p> <p><b>line_id</b>   integer   ID of the line</p> <p><b>s_max_diff_from</b>   float   max apparent power flow [MVA] - apparent power flow into the line at "from" bus [MVA]</p> <p><b>s_max_diff_to</b>   float   max apparent power flow [MVA] - apparent power flow into the line at "to" bus [MVA]</p>
<b>Trades</b>	<p><b>event_id</b>   integer   ID of the event</p> <p><b>bus_id</b>   integer   ID of the bus</p> <p><b>p_mw_trade/ q_mvar_trade</b>   FLOAT   traded quantity, positive for sell, negative for buy</p>
<b>Orderbook</b>	<p>The file includes the orderbook and it is updated every time a new event takes place (order submission/ execution etc). A new file is created per Session. Table columns are</p> <ul style="list-style-type: none"> <li>• Unique order ID (generated by the application)</li> <li>• Order data submitted by user (price, quantity, etc..) <ul style="list-style-type: none"> <li>◦ Direction (Buy/Sell)</li> <li>◦ Price (€/MWh - €/MVar)</li> <li>◦ Quantity (MWh - MVar)</li> <li>◦ Node / Asset ID where the bid was submitted</li> </ul> </li> <li>• Priority based on timestamp when the order was submitted</li> <li>• Order status (active/traded)</li> <li>• Event ID</li> </ul>

## Annex B Intraday Market Application Prototype: Message Broker Specification



## Annex C Data for intraday model validation in a large MV network

### C.1 Input data and results

Table 101: Load data

load_id	bus_id	p_mw	q_mvar
0	2	0.025991	0.028899
1	4	0.023276	0.008096
2	5	0.01916	0.012312
3	6	0.01916	0.012312
4	7	0.01264	0.004639
5	8	0.01264	0.004639
6	9	0.01916	0.012312
7	10	0.009701	0.004454
8	11	0.01264	0.004639
9	12	0.017074	0.005571
10	13	0.01264	0.004639
11	14	0.01916	0.012312
12	15	0.01916	0.012312
13	16	0.01916	0.012312
14	17	0.01916	0.012312
15	18	0.01916	0.012312
16	19	0.01264	0.004639
17	20	0.01264	0.004639
18	21	0.01916	0.012312
19	22	0.01916	0.012312
20	23	0.01264	0.004639
21	24	0.017074	0.005571
22	25	0.017074	0.005571
23	26	0.01264	0.004639
24	27	0.01264	0.004639
25	28	0.01264	0.004639
26	29	0.017074	0.005571
27	30	0.009701	0.004454
28	31	0.009701	0.004454
29	32	0.017074	0.005571
30	33	0.01264	0.004639
31	34	0.01264	0.004639
32	35	0.017074	0.005571
33	36	0.009701	0.004454
34	37	0.009701	0.004454
35	38	0.009701	0.004454
36	39	0.009701	0.004454
37	40	0.009701	0.004454
38	41	0.009701	0.004454
39	42	0.01264	0.004639
40	43	0.017074	0.005571
41	44	0.01264	0.004639
42	45	0.017074	0.005571
43	46	0.009701	0.004454
44	47	0.01264	0.004639
45	48	0.009701	0.004454
46	49	0.01264	0.004639
47	50	0.01264	0.004639
48	51	0.01264	0.004639
49	52	0.01264	0.004639
50	53	0.01264	0.004639
51	54	0.009701	0.004454
52	55	0.009701	0.004454
53	56	0.009701	0.004454
54	57	0.01264	0.004639

55	58	0.017074	0.005571
56	59	0.01264	0.004639
57	60	0.01264	0.004639
58	62	0.01264	0.004639
59	63	0.017074	0.005571
60	64	0.009701	0.004454
61	65	0.005826	0.007105
62	66	0.005826	0.007105
63	67	0.005826	0.007105
64	68	0.009701	0.004454
65	69	0.005826	0.007105
66	70	0.01916	0.012312
67	71	0.01264	0.004639
68	72	0.017074	0.005571
69	73	0.017074	0.005571
70	74	0.005826	0.007105
71	75	0.009701	0.004454
72	76	0.009701	0.004454
73	77	0.009701	0.004454
74	78	0.009701	0.004454
75	79	0.01264	0.004639
76	80	0.01916	0.012312
77	81	0.01916	0.012312
78	82	0.009701	0.004454
79	83	0.009701	0.004454
80	84	0.017074	0.005571
81	85	0.017074	0.005571
82	86	0.01264	0.004639
83	87	0.023276	0.008096
84	88	0.01916	0.012312
85	89	0.01916	0.012312
86	90	0.01916	0.012312
87	91	0.01916	0.012312
88	92	0.01916	0.012312
89	93	0.01916	0.012312
90	94	0.01264	0.004639
91	95	0.01916	0.012312
92	96	0.01264	0.004639
93	97	0.01264	0.004639
94	98	0.01916	0.012312
95	99	10	0.004639
96	101	10	0.005571
97	102	0.01916	0.012312
98	103	0.01264	0.004639
99	104	0.01264	0.004639
100	105	0.01916	0.012312
101	106	0.01264	0.004639
102	108	0.009701	0.004454
103	109	0.009701	0.004454
104	110	0.01264	0.004639
105	111	0.017074	0.005571
106	112	0.01264	0.004639
107	113	0.009701	0.004454
108	114	0.005826	0.007105
109	115	0.017074	0.005571
110	116	0.017074	0.005571
111	107	0.031442	0.020461
112	69	0.006152	0.011871
113	92	0.015961	0.042672
114	98	0.006368	0.01359
115	92	0	0
116	69	0	0
117	98	0	0
118	92	0	0

119	107	0	0
120	98	0	0
121	107	0	0

Table 102: Generators data

Gen_id	bus_id	p_mw	q_mvar	type
0	2	4.820819	0	Wind_MV
1	4	0	0	Iv_RES
2	5	0	0	Iv_RES
3	6	0	0	Iv_RES
4	7	0	0	Iv_RES
5	8	0	0	Iv_RES
6	9	0	0	Iv_RES
7	10	0	0	Iv_RES
8	11	0	0	Iv_RES
9	12	0	0	Iv_RES
10	13	0	0	Iv_RES
11	14	0	0	Iv_RES
12	15	0	0	Iv_RES
13	16	0	0	Iv_RES
14	17	0	0	Iv_RES
15	18	0	0	Iv_RES
16	19	0	0	Iv_RES
17	20	0	0	Iv_RES
18	21	0	0	Iv_RES
19	22	0	0	Iv_RES
20	23	0	0	Iv_RES
21	24	0	0	Iv_RES
22	25	0	0	Iv_RES
23	26	0	0	Iv_RES
24	27	0	0	Iv_RES
25	28	0	0	Iv_RES
26	29	0	0	Iv_RES
27	30	0	0	Iv_RES
28	31	0	0	Iv_RES
29	32	0	0	Iv_RES
30	33	0	0	Iv_RES
31	34	0	0	Iv_RES
32	35	0	0	Iv_RES
33	36	0	0	Iv_RES
34	37	0	0	Iv_RES
35	38	0	0	Iv_RES
36	39	0	0	Iv_RES
37	40	0	0	Iv_RES
38	41	0	0	Iv_RES
39	42	0	0	Iv_RES
40	43	0	0	Iv_RES
41	44	0	0	Iv_RES
42	45	0	0	Iv_RES
43	46	0	0	Iv_RES
44	47	0	0	Iv_RES
45	48	0	0	Iv_RES
46	49	0	0	Iv_RES
47	50	0	0	Iv_RES
48	51	0	0	Iv_RES
49	52	0	0	Iv_RES
50	53	0	0	Iv_RES



51	54	0	0	Iv_RES
52	55	0	0	Iv_RES
53	56	0	0	Iv_RES
54	57	0	0	Iv_RES
55	58	0	0	Iv_RES
56	59	0	0	Iv_RES
57	60	0	0	Iv_RES
58	62	0	0	Iv_RES
59	63	0	0	Iv_RES
60	64	0	0	Iv_RES
61	65	0	0	Iv_RES
62	66	0	0	Iv_RES
63	67	0	0	Iv_RES
64	68	0	0	Iv_RES
65	69	0	0	Iv_RES
66	70	0	0	Iv_RES
67	71	0	0	Iv_RES
68	72	0	0	Iv_RES
69	73	0	0	Iv_RES
70	74	0	0	Iv_RES
71	75	0	0	Iv_RES
72	76	0	0	Iv_RES
73	77	0	0	Iv_RES
74	78	0	0	Iv_RES
75	79	0	0	Iv_RES
76	80	0	0	Iv_RES
77	81	0	0	Iv_RES
78	82	0	0	Iv_RES
79	83	0	0	Iv_RES
80	84	0	0	Iv_RES
81	85	0	0	Iv_RES
82	86	0	0	Iv_RES
83	87	0	0	Iv_RES
84	88	0	0	Iv_RES
85	89	0	0	Iv_RES
86	90	0	0	Iv_RES
87	91	0	0	Iv_RES
88	92	0	0	Iv_RES
89	93	0	0	Iv_RES
90	94	0	0	Iv_RES
91	95	0	0	Iv_RES
92	96	0	0	Iv_RES
93	97	0	0	Iv_RES
94	98	0	0	Iv_RES
95	99	0	0	Iv_RES
96	101	0	0	Iv_RES
97	102	0	0	Iv_RES
98	103	0	0	Iv_RES
99	104	0	0	Iv_RES
100	105	0	0	Iv_RES
101	106	0	0	Iv_RES
102	108	0	0	Iv_RES
103	109	0	0	Iv_RES
104	110	0	0	Iv_RES
105	111	0	0	Iv_RES
106	112	0	0	Iv_RES
107	113	0	0	Iv_RES
108	114	0	0	Iv_RES
109	115	0	0	Iv_RES
110	116	0	0	Iv_RES

111	61	1.232117	0	Biomass_MV
112	56	0	0	PV_MV
113	82	0	0	PV_MV
114	101	11.90096	0	Wind_MV
115	98	0	0	PV_MV
116	48	2.982837	0	Hydro_MV
117	24	6.519077	0	Wind_MV
118	69	0	0	PV_MV
119	68	6.389765	0	Wind_MV
120	10	5.407134	0	Wind_MV
121	120	0	0	Wind_MV
122	121	11.33217	0	Wind_MV

Table 103: Bus data

bus_id	vm_pu	va_degree	p_mw	q_mvar
0	1.025	0	28.36387	0.124596
1	1.031815	0.603432	-4.79483	0.028899
2	1.033563	0.645415	0.023276	0.008096
3	1.034694	0.672675	0.01916	0.012312
4	1.035705	0.696993	0.01916	0.012312
5	1.036966	0.718517	0.01264	0.004639
6	1.038341	0.742017	0.01264	0.004639
7	1.039429	0.760665	0.01916	0.012312
8	1.042349	0.810556	-5.39743	0.004454
9	1.041409	0.79657	0.01264	0.004639
10	1.040329	0.780732	0.017074	0.005571
11	1.039587	0.769979	0.01264	0.004639
12	1.03939	0.770795	0.01916	0.012312
13	1.039285	0.771284	0.01916	0.012312
14	1.039206	0.771666	0.01916	0.012312
15	1.039079	0.772323	0.01916	0.012312
16	1.038949	0.773093	0.01916	0.012312
17	1.038857	0.773705	0.01264	0.004639
18	1.038726	0.774795	0.01264	0.004639
19	1.038561	0.776592	0.01916	0.012312
20	1.039399	0.823417	0.01916	0.012312
21	1.040368	0.874988	0.01264	0.004639
22	1.041321	0.924752	-6.502	0.005571
23	1.033736	0.673977	0.017074	0.005571
24	1.031678	0.597749	0.01264	0.004639
25	1.031408	0.586598	0.01264	0.004639
26	1.031221	0.57896	0.01264	0.004639
27	1.030933	0.570605	0.017074	0.005571
28	1.029324	0.525706	0.009701	0.004454
29	1.028283	0.49881	0.009701	0.004454
30	1.026931	0.47263	0.017074	0.005571
31	1.026645	0.467388	0.01264	0.004639
32	1.026457	0.463958	0.01264	0.004639
33	1.026133	0.458078	0.017074	0.005571
34	1.025861	0.453175	0.009701	0.004454
35	1.025609	0.448693	0.009701	0.004454
36	1.032336	0.61263	0.009701	0.004454
37	1.032684	0.618814	0.009701	0.004454
38	1.033176	0.62754	0.009701	0.004454
39	1.033617	0.635401	0.009701	0.004454
40	1.03442	0.649994	0.01264	0.004639
41	1.035854	0.702769	0.017074	0.005571
42	1.03455	0.66331	0.01264	0.004639
43	1.032985	0.61555	0.017074	0.005571
44	1.031173	0.559682	0.009701	0.004454
45	1.033611	0.63529	0.01264	0.004639

46	1.03821	0.782139	-2.97314	0.004454
47	1.032102	0.608401	0.01264	0.004639
48	1.032487	0.615063	0.01264	0.004639
49	1.033262	0.628534	0.01264	0.004639
50	1.033945	0.640485	0.01264	0.004639
51	1.034435	0.649113	0.01264	0.004639
52	1.035142	0.662421	0.009701	0.004454
53	1.035971	0.678548	0.009701	0.004454
54	1.036388	0.686848	0.009701	0.004454
55	1.036928	0.69774	0.01264	0.004639
56	1.034738	0.654119	0.017074	0.005571
57	1.035103	0.660314	0.01264	0.004639
58	1.03621	0.680641	0.01264	0.004639
59	1.037117	0.699155	-1.23212	0
60	1.037483	0.700468	0.01264	0.004639
61	1.039032	0.72705	0.017074	0.005571
62	1.03846	0.716454	0.009701	0.004454
63	1.038105	0.709925	0.005826	0.007105
64	1.03683	0.686885	0.005826	0.007105
65	1.050555	1.1325	0.005826	0.007105
66	1.06036	1.468514	-6.38006	0.004454
67	1.039001	0.727823	0.011979	0.018976
68	1.03215	0.608708	0.01916	0.012312
69	1.032762	0.618256	0.01264	0.004639
70	1.033859	0.635918	0.017074	0.005571
71	1.034137	0.640473	0.017074	0.005571
72	1.035958	0.67146	0.005826	0.007105
73	1.036519	0.681361	0.009701	0.004454
74	1.032739	0.635011	0.009701	0.004454
75	1.033991	0.677309	0.009701	0.004454
76	1.035413	0.724766	0.009701	0.004454
77	1.035596	0.727592	0.01264	0.004639
78	1.035815	0.730996	0.01916	0.012312
79	1.036106	0.735434	0.01916	0.012312
80	1.036771	0.745678	0.009701	0.004454
81	1.037628	0.760047	0.009701	0.004454
82	1.037844	0.76385	0.017074	0.005571
83	1.038108	0.768527	0.017074	0.005571
84	1.038333	0.772519	0.01264	0.004639
85	1.031767	0.601346	0.023276	0.008096
86	1.031693	0.598079	0.01916	0.012312
87	1.031593	0.593516	0.01916	0.012312
88	1.031514	0.589817	0.01916	0.012312
89	1.031419	0.585268	0.01916	0.012312
90	1.031355	0.582069	0.035121	0.054983
91	1.031271	0.578135	0.01916	0.012312
92	1.03113	0.571257	0.01264	0.004639
93	1.030778	0.554369	0.01916	0.012312
94	1.029848	0.534795	0.01264	0.004639
95	1.027659	0.490147	0.01264	0.004639
96	1.025645	0.450979	0.025528	0.025901
97	1.024985	0.437933	10	0.004639
98	1.025298	0.443222	0	0
99	1.02829	0.490885	-1.90096	0.005571
100	1.031984	0.605712	0.01916	0.012312
101	1.032103	0.607319	0.01264	0.004639
102	1.032265	0.609579	0.01264	0.004639
103	1.032439	0.612125	0.01916	0.012312
104	1.032635	0.61499	0.01264	0.004639
105	1.033631	0.63983	0.031442	0.020461
106	1.035186	0.676429	0.009701	0.004454
107	1.036426	0.705389	0.009701	0.004454
108	1.037456	0.729238	0.01264	0.004639
109	1.038389	0.750673	0.017074	0.005571

110	1.038684	0.752761	0.01264	0.004639
111	1.038442	0.745102	0.009701	0.004454
112	1.038278	0.739904	0.005826	0.007105
113	1.03807	0.733304	0.017074	0.005571
114	1.03778	0.724065	0.017074	0.005571
115	1.038216	0.78179	0	0
116	1.028297	0.497951	0	0
117	1.028298	0.497902	0	0
118	1.031834	0.602288	0	0
119	1.039591	0.997717	-11.3322	0

Table 104: Line data

line_id	from_bus	to_bus	s_from_mva	s_to_mva	max_s_mva
0	1	2	3.306145	3.311937	6.54715205
1	2	3	3.335124	3.33892	6.54715205
2	3	4	3.357942	3.361349	6.54715205
3	4	5	3.380379	3.384584	5.71576766
4	5	6	3.397176	3.401783	5.71576766
5	6	7	3.41437	3.418039	5.71576766
6	7	8	3.437067	3.446958	5.71576766
7	8	9	1.951304	1.949839	5.71576766
8	9	10	1.937078	1.935463	5.71576766
9	10	11	1.918223	1.917155	5.71576766
10	11	12	0.394138	0.3982	5.71576766
11	12	13	0.375874	0.378194	5.71576766
12	13	14	0.35585	0.357722	5.71576766
13	14	15	0.335373	0.338609	5.71576766
14	15	16	0.316211	0.319854	5.71576766
15	16	17	0.297396	0.30024	5.71576766
16	17	18	0.286809	0.291272	5.71576766
17	18	19	0.277885	0.284307	5.71576766
18	19	20	0.648881	0.649729	5.45596004
19	20	21	0.665735	0.666677	5.45596004
20	21	22	0.678114	0.67903	5.45596004
21	22	23	5.837961	5.795464	5.45596004
22	1	24	1.008192	1.006503	7.35255568
23	24	25	0.995061	0.991753	7.35255568
24	25	26	0.980255	0.978005	7.35255568
25	26	27	0.966483	0.964761	5.71576766
26	27	28	0.949069	0.940086	5.71576766
27	28	29	0.931197	0.926245	5.71576766
28	29	30	0.910556	0.907783	5.71576766
29	30	31	0.890877	0.890417	5.71576766
30	31	32	0.877905	0.87761	5.71576766
31	32	33	0.865099	0.86461	5.71576766
32	33	34	0.847668	0.847277	5.71576766
33	34	35	0.837669	0.83733	5.71576766
34	1	36	1.625677	1.626639	5.71576766
35	36	37	1.636251	1.636904	5.71576766
36	37	38	1.646515	1.647443	5.71576766
37	38	39	1.657048	1.657892	5.71576766
38	39	40	1.680265	1.681883	5.71576766
39	40	41	1.694384	1.696753	5.45596004
40	41	42	1.255439	1.253911	5.45596004
41	42	43	1.241025	1.239208	5.45596004
42	43	44	1.221857	1.219781	5.45596004
43	39	45	0.014024	0.013464	5.71576766
44	41	46	2.966635	2.973374	5.45596004
45	1	47	1.788002	1.788548	5.71576766
46	47	48	1.801129	1.801865	5.71576766

47	48	49	1.814445	1.81595	5.71576766
48	49	50	1.828518	1.829872	5.71576766
49	50	51	1.842429	1.843417	5.71576766
50	51	52	1.113165	1.114513	5.71576766
51	52	53	1.124014	1.125784	5.71576766
52	53	54	1.135229	1.136187	5.71576766
53	54	55	1.145615	1.146908	5.71576766
54	51	56	0.743111	0.743338	5.71576766
55	56	57	0.760391	0.760746	5.71576766
56	57	58	0.77333	0.775228	5.71576766
57	58	59	0.787622	0.79012	5.71576766
58	1	60	4.815068	4.841806	5.71576766
59	60	61	4.85439	4.86173	5.71576766
60	61	62	1.355949	1.354847	5.71576766
61	62	63	1.345297	1.34463	5.71576766
62	63	64	1.339038	1.336776	5.71576766
63	61	65	6.245997	6.315287	5.45596004
64	65	66	6.321064	6.380066	5.45596004
65	61	67	0.02147	0.022441	5.45596004
66	1	68	1.243118	1.243438	5.71576766
67	68	69	1.262785	1.263354	5.71576766
68	69	70	1.276054	1.277267	5.71576766
69	70	71	1.294348	1.294688	5.71576766
70	71	72	1.311771	1.314367	5.71576766
71	72	73	1.320063	1.320975	5.71576766
72	1	74	0.710034	0.710661	5.45596004
73	74	75	0.720407	0.721261	5.45596004
74	75	76	0.731026	0.732002	5.45596004
75	76	77	0.741786	0.741811	5.71576766
76	77	78	0.754529	0.754581	5.71576766
77	78	79	0.773969	0.774	5.71576766
78	79	80	0.793434	0.793589	5.71576766
79	80	81	0.803325	0.804122	5.71576766
80	81	82	0.81374	0.814033	5.71576766
81	82	83	0.830994	0.831365	5.71576766
82	83	84	0.848314	0.848639	5.71576766
83	1	85	0.603008	0.601967	7.35255568
84	85	86	0.58113	0.57938	7.35255568
85	86	87	0.563724	0.561109	7.35255568
86	87	88	0.545646	0.543383	7.35255568
87	88	89	0.528185	0.525212	7.35255568
88	89	90	0.510233	0.507993	7.35255568
89	90	91	0.493683	0.491633	5.71576766
90	91	92	0.479187	0.475394	5.71576766
91	92	93	0.465882	0.456361	5.71576766
92	93	94	1.613831	1.611371	5.71576766
93	94	95	1.599084	1.593669	5.71576766
94	95	96	1.581294	1.576815	5.71576766
95	96	97	1.552481	1.550975	5.71576766
96	97	98	0.827033	0.827325	5.71576766
97	97	99	7.624144	7.648625	5.71576766
98	1	100	0.602939	0.601425	6.54715205
99	100	101	0.622295	0.621253	6.54715205
100	101	102	0.634465	0.633158	6.54715205
101	102	103	0.646342	0.645058	6.54715205
102	103	104	0.665767	0.664386	6.54715205
103	104	105	0.677537	0.678025	5.45596004
104	105	106	0.712134	0.712924	5.45596004
105	106	107	0.723207	0.723849	5.45596004
106	107	108	0.734139	0.734681	5.45596004
107	108	109	0.747909	0.748412	5.45596004
108	109	110	0.766173	0.764934	5.71576766
109	110	111	0.785348	0.783281	5.71576766
110	111	112	0.77485	0.773434	5.71576766

111	112	113	0.7694	0.767581	5.71576766
112	113	114	0.752272	0.749672	5.71576766
113	59	55	0.449294	0.450716	5.71576766
114	55	114	0.727022	0.734357	5.71576766
115	110	11	1.533008	1.534967	5.71576766
116	19	84	0.861511	0.86117	5.71576766
117	64	73	1.3311	1.330579	5.71576766
118	99	23	5.747864	5.778295	5.45596004
119	98	35	0.827325	0.827709	5.71576766
120	93	44	1.209801	1.209866	5.71576766
121	46	115	0.042065	3.34E-13	10.9379008
122	29	116	0.066633	0.015403	10.9379008
123	116	117	0.015403	1.32E-12	10.9379008
124	1	118	0.075313	6.32E-13	10.9379008
125	1	119	11.24748	11.33217	10.9379008
126	0	1	14.18207	14.27635	12.2109582
127	0	1	14.18207	14.27635	12.2109582

Table 105: DSO orders

order_id	bus_id	Quantity	Direction	Price	Priority	Event_id	order_status	Actor	Power
0	66	21.38222	S	0.5	1	2	A	DSO	Q
1	66	26.96065	S	0.5	2	2	A	DSO	Q
2	65	26.96805	S	0.5	3	2	A	DSO	Q
3	65	32.49518	S	0.5	4	2	A	DSO	Q
4	67	69.98672	S	0.5	5	2	A	DSO	Q
5	61	69.99476	S	0.5	6	2	A	DSO	Q
6	62	72.69693	S	0.5	7	2	A	DSO	Q
7	63	74.49399	S	0.5	8	2	A	DSO	Q
8	60	78.01898	S	0.5	9	2	A	DSO	Q
9	64	81.76765	S	0.5	10	2	A	DSO	Q
10	73	83.7663	S	0.5	11	2	A	DSO	Q
11	67	84.33053	S	0.5	12	2	A	DSO	Q
12	61	84.34031	S	0.5	13	2	A	DSO	Q
13	62	87.59618	S	0.5	14	2	A	DSO	Q
14	72	87.66176	S	0.5	15	2	A	DSO	Q
15	63	89.76156	S	0.5	16	2	A	DSO	Q
16	60	94.00898	S	0.5	17	2	A	DSO	Q
17	64	98.52595	S	0.5	18	2	A	DSO	Q
18	73	100.9343	S	0.5	19	2	A	DSO	Q
19	71	103.2619	S	0.5	20	2	A	DSO	Q
20	72	105.6281	S	0.5	21	2	A	DSO	Q
21	70	106.1678	S	0.5	22	2	A	DSO	Q
22	69	119.6335	S	0.5	23	2	A	DSO	Q
23	71	124.4254	S	0.5	24	2	A	DSO	Q
24	70	127.9269	S	0.5	25	2	A	DSO	Q
25	68	128.8238	S	0.5	26	2	A	DSO	Q
26	22	134.4898	S	0.5	27	2	A	DSO	Q
27	21	134.4966	S	0.5	28	2	A	DSO	Q
28	23	134.4969	S	0.5	29	2	A	DSO	Q
29	20	134.5062	S	0.5	30	2	A	DSO	Q
30	99	134.5166	S	0.5	31	2	A	DSO	Q
31	77	134.5209	S	0.5	34	2	A	DSO	Q
32	76	134.5209	S	0.5	33	2	A	DSO	Q
33	78	134.5209	S	0.5	32	2	A	DSO	Q
34	79	134.5213	S	0.5	35	2	A	DSO	Q

35	19	134.5213	S	0.5	36	2	A	DSO	Q
36	84	134.5216	S	0.5	37	2	A	DSO	Q
37	83	134.522	S	0.5	38	2	A	DSO	Q
38	82	134.5223	S	0.5	39	2	A	DSO	Q
39	81	134.5227	S	0.5	40	2	A	DSO	Q
40	80	134.5231	S	0.5	41	2	A	DSO	Q
41	18	134.5245	S	0.5	42	2	A	DSO	Q
42	97	134.5252	S	0.5	43	2	A	DSO	Q
43	17	134.5263	S	0.5	44	2	A	DSO	Q
44	96	134.5266	S	0.5	45	2	A	DSO	Q
45	16	134.5277	S	0.5	46	2	A	DSO	Q
46	15	134.5299	S	0.5	47	2	A	DSO	Q
47	98	134.5316	S	0.5	48	2	A	DSO	Q
48	14	134.5324	S	0.5	49	2	A	DSO	Q
49	13	134.5345	S	0.5	50	2	A	DSO	Q
50	95	134.5352	S	0.5	51	2	A	DSO	Q
51	75	134.5367	S	0.5	52	2	A	DSO	Q
52	35	134.5374	S	0.5	53	2	A	DSO	Q
53	12	134.5374	S	0.5	54	2	A	DSO	Q
54	94	134.5399	S	0.5	55	2	A	DSO	Q
55	44	134.5406	S	0.5	56	2	A	DSO	Q
56	93	134.541	S	0.5	57	2	A	DSO	Q
57	91	134.5417	S	0.5	58	2	A	DSO	Q
58	92	134.5417	S	0.5	59	2	A	DSO	Q
59	34	134.542	S	0.5	61	2	A	DSO	Q
60	90	134.542	S	0.5	60	2	A	DSO	Q
61	107	134.5424	S	0.5	62	2	A	DSO	Q
62	11	134.5431	S	0.5	63	2	A	DSO	Q
63	106	134.5435	S	0.5	64	2	A	DSO	Q
64	108	134.5435	S	0.5	65	2	A	DSO	Q
65	10	134.5445	S	0.5	66	2	A	DSO	Q
66	89	134.5453	S	0.5	67	2	A	DSO	Q
67	43	134.5456	S	0.5	68	2	A	DSO	Q
68	109	134.546	S	0.5	69	2	A	DSO	Q
69	9	134.5463	S	0.5	70	2	A	DSO	Q
70	33	134.547	S	0.5	71	2	A	DSO	Q
71	8	134.5474	S	0.5	72	2	A	DSO	Q
72	105	134.5474	S	0.5	73	2	A	DSO	Q
73	110	134.5478	S	0.5	74	2	A	DSO	Q
74	7	134.5492	S	0.5	75	2	A	DSO	Q
75	88	134.5503	S	0.5	77	2	A	DSO	Q
76	6	134.5503	S	0.5	76	2	A	DSO	Q
77	111	134.5513	S	0.5	78	2	A	DSO	Q
78	5	134.5517	S	0.5	79	2	A	DSO	Q
79	119	134.5521	S	0.5	80	2	A	DSO	Q
80	42	134.5524	S	0.5	81	2	A	DSO	Q
81	4	134.5531	S	0.5	82	2	A	DSO	Q
82	74	134.5531	S	0.5	83	2	A	DSO	Q
83	32	134.5531	S	0.5	84	2	A	DSO	Q
84	112	134.5542	S	0.5	85	2	A	DSO	Q
85	87	134.5546	S	0.5	86	2	A	DSO	Q
86	3	134.5564	S	0.5	87	2	A	DSO	Q
87	31	134.5564	S	0.5	88	2	A	DSO	Q
88	113	134.5578	S	0.5	89	2	A	DSO	Q
89	104	134.5589	S	0.5	90	2	A	DSO	Q



90	41	134.5599	S	0.5	91	2	A	DSO	Q
91	86	134.5603	S	0.5	92	2	A	DSO	Q
92	2	134.5607	S	0.5	93	2	A	DSO	Q
93	103	134.5607	S	0.5	94	2	A	DSO	Q
94	30	134.5614	S	0.5	95	2	A	DSO	Q
95	102	134.5624	S	0.5	96	2	A	DSO	Q
96	114	134.5628	S	0.5	97	2	A	DSO	Q
97	46	134.5628	S	0.5	98	2	A	DSO	Q
98	115	134.5639	S	0.5	99	2	A	DSO	Q
99	101	134.5642	S	0.5	100	2	A	DSO	Q
100	85	134.5649	S	0.5	101	2	A	DSO	Q
101	100	134.5653	S	0.5	102	2	A	DSO	Q
102	40	134.566	S	0.5	103	2	A	DSO	Q
103	39	134.5667	S	0.5	104	2	A	DSO	Q
104	45	134.5667	S	0.5	105	2	A	DSO	Q
105	38	134.5671	S	0.5	107	2	A	DSO	Q
106	37	134.5671	S	0.5	106	2	A	DSO	Q
107	36	134.5675	S	0.5	108	2	A	DSO	Q
108	1	134.5678	S	0.5	109	2	A	DSO	Q
109	24	134.5682	S	0.5	110	2	A	DSO	Q
110	47	134.5685	S	0.5	111	2	A	DSO	Q
111	25	134.5689	S	0.5	112	2	A	DSO	Q
112	26	134.5692	S	0.5	113	2	A	DSO	Q
113	48	134.57	S	0.5	114	2	A	DSO	Q
114	118	134.571	S	0.5	115	2	A	DSO	Q
115	27	134.5718	S	0.5	116	2	A	DSO	Q
116	49	134.5725	S	0.5	117	2	A	DSO	Q
117	50	134.575	S	0.5	118	2	A	DSO	Q
118	55	134.5757	S	0.5	119	2	A	DSO	Q
119	54	134.5764	S	0.5	121	2	A	DSO	Q
120	51	134.5764	S	0.5	120	2	A	DSO	Q
121	53	134.5768	S	0.5	122	2	A	DSO	Q
122	52	134.5771	S	0.5	123	2	A	DSO	Q
123	59	134.5778	S	0.5	124	2	A	DSO	Q
124	56	134.5778	S	0.5	125	2	A	DSO	Q
125	57	134.5796	S	0.5	126	2	A	DSO	Q
126	28	134.5811	S	0.5	128	2	A	DSO	Q
127	58	134.5811	S	0.5	127	2	A	DSO	Q
128	29	134.5818	S	0.5	129	2	A	DSO	Q
129	116	134.5843	S	0.5	130	2	A	DSO	Q
130	117	134.5847	S	0.5	131	2	A	DSO	Q
131	69	144.1525	S	0.5	132	2	A	DSO	Q
132	68	155.2264	S	0.5	133	2	A	DSO	Q
133	22	162.0536	S	0.5	134	2	A	DSO	Q
134	21	162.0614	S	0.5	135	2	A	DSO	Q
135	23	162.0623	S	0.5	136	2	A	DSO	Q
136	20	162.0731	S	0.5	137	2	A	DSO	Q
137	99	162.0858	S	0.5	138	2	A	DSO	Q
138	78	162.091	S	0.5	141	2	A	DSO	Q
139	76	162.091	S	0.5	140	2	A	DSO	Q
140	77	162.091	S	0.5	139	2	A	DSO	Q
141	19	162.0914	S	0.5	142	2	A	DSO	Q
142	79	162.0914	S	0.5	143	2	A	DSO	Q
143	84	162.0919	S	0.5	144	2	A	DSO	Q
144	83	162.0923	S	0.5	145	2	A	DSO	Q



145	82	162.0927	S	0.5	146	2	A	DSO	Q
146	81	162.0932	S	0.5	147	2	A	DSO	Q
147	80	162.0936	S	0.5	148	2	A	DSO	Q
148	18	162.0953	S	0.5	149	2	A	DSO	Q
149	97	162.0962	S	0.5	150	2	A	DSO	Q
150	17	162.0975	S	0.5	151	2	A	DSO	Q
151	96	162.0979	S	0.5	152	2	A	DSO	Q
152	16	162.0993	S	0.5	153	2	A	DSO	Q
153	15	162.1019	S	0.5	154	2	A	DSO	Q
154	98	162.104	S	0.5	155	2	A	DSO	Q
155	14	162.1049	S	0.5	156	2	A	DSO	Q
156	13	162.1075	S	0.5	157	2	A	DSO	Q
157	95	162.1084	S	0.5	158	2	A	DSO	Q
158	75	162.1101	S	0.5	159	2	A	DSO	Q
159	35	162.111	S	0.5	160	2	A	DSO	Q
160	12	162.111	S	0.5	161	2	A	DSO	Q
161	94	162.1141	S	0.5	162	2	A	DSO	Q
162	93	162.1149	S	0.5	163	2	A	DSO	Q
163	44	162.1149	S	0.5	164	2	A	DSO	Q
164	91	162.1158	S	0.5	165	2	A	DSO	Q
165	90	162.1162	S	0.5	167	2	A	DSO	Q
166	92	162.1162	S	0.5	166	2	A	DSO	Q
167	107	162.1167	S	0.5	169	2	A	DSO	Q
168	34	162.1167	S	0.5	168	2	A	DSO	Q
169	108	162.118	S	0.5	170	2	A	DSO	Q
170	106	162.118	S	0.5	171	2	A	DSO	Q
171	11	162.118	S	0.5	172	2	A	DSO	Q
172	10	162.1197	S	0.5	173	2	A	DSO	Q
173	89	162.1201	S	0.5	174	2	A	DSO	Q
174	43	162.1206	S	0.5	175	2	A	DSO	Q
175	109	162.121	S	0.5	176	2	A	DSO	Q
176	9	162.1215	S	0.5	177	2	A	DSO	Q
177	33	162.1228	S	0.5	178	2	A	DSO	Q
178	105	162.1228	S	0.5	179	2	A	DSO	Q
179	8	162.1232	S	0.5	181	2	A	DSO	Q
180	110	162.1232	S	0.5	180	2	A	DSO	Q
181	7	162.1249	S	0.5	182	2	A	DSO	Q
182	6	162.1262	S	0.5	184	2	A	DSO	Q
183	88	162.1262	S	0.5	183	2	A	DSO	Q
184	111	162.128	S	0.5	185	2	A	DSO	Q
185	119	162.1284	S	0.5	186	2	A	DSO	Q
186	5	162.1284	S	0.5	187	2	A	DSO	Q
187	42	162.1289	S	0.5	188	2	A	DSO	Q
188	32	162.1297	S	0.5	189	2	A	DSO	Q
189	4	162.1302	S	0.5	190	2	A	DSO	Q
190	74	162.1302	S	0.5	191	2	A	DSO	Q
191	112	162.131	S	0.5	192	2	A	DSO	Q
192	87	162.1319	S	0.5	193	2	A	DSO	Q
193	31	162.1336	S	0.5	194	2	A	DSO	Q
194	3	162.1336	S	0.5	195	2	A	DSO	Q
195	113	162.1354	S	0.5	196	2	A	DSO	Q
196	104	162.1367	S	0.5	197	2	A	DSO	Q
197	41	162.138	S	0.5	198	2	A	DSO	Q
198	86	162.1389	S	0.5	199	2	A	DSO	Q
199	2	162.1389	S	0.5	200	2	A	DSO	Q

200	103	162.1389	S	0.5	201	2	A	DSO	Q
201	30	162.1397	S	0.5	202	2	A	DSO	Q
202	102	162.1411	S	0.5	203	2	A	DSO	Q
203	46	162.1415	S	0.5	204	2	A	DSO	Q
204	114	162.1415	S	0.5	205	2	A	DSO	Q
205	115	162.1428	S	0.5	206	2	A	DSO	Q
206	101	162.1432	S	0.5	207	2	A	DSO	Q
207	85	162.1441	S	0.5	208	2	A	DSO	Q
208	100	162.1445	S	0.5	209	2	A	DSO	Q
209	40	162.1454	S	0.5	210	2	A	DSO	Q
210	39	162.1463	S	0.5	212	2	A	DSO	Q
211	45	162.1463	S	0.5	211	2	A	DSO	Q
212	37	162.1467	S	0.5	214	2	A	DSO	Q
213	38	162.1467	S	0.5	213	2	A	DSO	Q
214	36	162.1471	S	0.5	215	2	A	DSO	Q
215	1	162.1476	S	0.5	216	2	A	DSO	Q
216	24	162.148	S	0.5	217	2	A	DSO	Q
217	47	162.1485	S	0.5	218	2	A	DSO	Q
218	25	162.1489	S	0.5	219	2	A	DSO	Q
219	26	162.1493	S	0.5	220	2	A	DSO	Q
220	48	162.1502	S	0.5	221	2	A	DSO	Q
221	118	162.1515	S	0.5	222	2	A	DSO	Q
222	27	162.1524	S	0.5	223	2	A	DSO	Q
223	49	162.1532	S	0.5	224	2	A	DSO	Q
224	50	162.1559	S	0.5	225	2	A	DSO	Q
225	55	162.1567	S	0.5	226	2	A	DSO	Q
226	51	162.158	S	0.5	227	2	A	DSO	Q
227	54	162.158	S	0.5	228	2	A	DSO	Q
228	53	162.1585	S	0.5	229	2	A	DSO	Q
229	52	162.1589	S	0.5	230	2	A	DSO	Q
230	59	162.1598	S	0.5	231	2	A	DSO	Q
231	56	162.1598	S	0.5	232	2	A	DSO	Q
232	57	162.162	S	0.5	233	2	A	DSO	Q
233	28	162.1633	S	0.5	234	2	A	DSO	Q
234	58	162.1633	S	0.5	235	2	A	DSO	Q
235	29	162.1646	S	0.5	236	2	A	DSO	Q
236	116	162.1676	S	0.5	237	2	A	DSO	Q
237	117	162.1676	S	0.5	238	2	A	DSO	Q
238	0	19.23205	S	0.5	0	2	A	DSO	P

## C.2 Case1: Intraday model active power trade (DSO – MP)

Table 106: Line Apparent Power Flow Sensitivity Factors for a trade in bus 21

Line id	Sensitivity factors $K_{S,P}$	
	from	to
0	-0.158758	-0.1593383
1	-0.1593122	-0.1596854
2	-0.159647	-0.1599802
3	-0.1599423	-0.1603423
4	-0.1603281	-0.160763
5	-0.1607493	-0.1610933
6	-0.1610573	-0.1619786
7	0.1616623	0.1612784
8	0.1613089	0.1608621
9	0.1609002	0.1605897
10	0.3297889	0.3278891
11	0.3291055	0.3280146
12	0.3292718	0.3283841
13	0.3296818	0.3281359
14	0.3294852	0.3277373
15	0.3291441	0.3277733
16	0.3281025	0.3259564
17	0.3262663	0.3231873
18	-0.5174238	-0.5183058
19	-0.5203644	-0.5213986
20	0.4643326	0.4652561
21	-0.4711213	-0.4646464
22	0.1908145	0.1909925
23	0.1907757	0.1911272
24	0.1909206	0.1911605
25	0.1909573	0.1910655
26	0.190807	0.1913167
27	0.1911798	0.1913586
28	0.1921122	0.1916503
29	0.1916586	0.1915352
30	0.1915447	0.1914616
31	0.1914715	0.1913231
32	0.1913402	0.1912101
33	0.1912265	0.191101
34	-0.0726822	-0.0727171
35	-0.072741	-0.0727643
36	-0.0727882	-0.0728212
37	-0.0728453	-0.0728749
38	-0.0728696	-0.0729222
39	-0.0729494	-0.0731524
40	0.0736617	0.0734727
41	0.0734652	0.0732384
42	0.073229	0.0729665
43	-2.70E-06	0
44	-5.70E-06	-4.00E-07
45	-0.1143209	-0.1144076
46	-0.1143746	-0.1144906
47	-0.1144579	-0.1146894
48	-0.1146578	-0.1148593
49	-0.1148286	-0.1149723
50	-0.0731475	-0.0733228
51	-0.0732993	-0.0734907
52	-0.0734709	-0.0735621
53	-0.0735435	-0.0736574
54	-0.0417919	-0.0418798
55	-0.0418441	-0.0419427

56	-0.0419151	-0.0421624
57	-0.0421439	-0.0422917
58	-5.51E-05	-4.41E-05
59	-4.41E-05	-4.11E-05
60	-1.18E-05	-1.18E-05
61	-1.19E-05	-1.19E-05
62	-1.20E-05	-1.24E-05
63	-5.25E-05	-2.42E-05
64	-2.42E-05	0
65	4.00E-07	0
66	-1.57E-05	-1.53E-05
67	-1.57E-05	-1.50E-05
68	-1.51E-05	-1.40E-05
69	-1.41E-05	-1.38E-05
70	-1.40E-05	-1.27E-05
71	-1.27E-05	-1.25E-05
72	-0.1860866	-0.186342
73	-0.186464	-0.1868144
74	-0.1869274	-0.1873292
75	-0.1874345	-0.1873476
76	-0.1874583	-0.1873552
77	-0.1876368	-0.1875283
78	-0.1877839	-0.1875413
79	-0.1876549	-0.1871724
80	-0.1873301	-0.1871857
81	-0.187387	-0.1872193
82	-0.1874203	-0.1872851
83	0.1951324	0.195335
84	0.194666	0.1950285
85	0.1940896	0.1946607
86	0.1936279	0.1941475
87	0.1929894	0.1937053
88	0.1924314	0.1929969
89	0.1866746	0.1872108
90	0.1848286	0.1858607
91	0.1846156	0.1872874
92	0.269253	0.2688724
93	0.2688244	0.2678733
94	0.2678417	0.2668873
95	0.2667661	0.266461
96	0.1907719	0.1909565
97	-0.45723	-0.4600711
98	-0.0629648	-0.0630242
99	-0.0629887	-0.0630297
100	-0.0630205	-0.0630659
101	-0.0630594	-0.0630964
102	-0.0630798	-0.0631189
103	-0.063116	-0.0632318
104	-0.063199	-0.0633826
105	-0.0633741	-0.0635206
106	-0.0635118	-0.0636335
107	-0.0636255	-0.0637359
108	-0.0637272	-0.063785
109	-0.1153537	-0.1154686
110	-0.1153291	-0.1154101
111	-0.1152298	-0.1153377
112	-0.1151225	-0.1152863
113	0.0411043	0.0408743
114	-0.1155043	-0.1150667
115	-0.1790157	-0.1792721
116	-0.1873158	-0.1874491
117	-1.23E-05	-1.25E-05
118	-0.4600139	-0.4646595
119	0.1909565	0.1911204

120	0.0729156	0.072958
121	-3.30E-05	0
122	-0.0001285	-2.97E-05
123	-2.97E-05	0
124	-3.27E-05	0
125	-3.63E-05	0
126	-0.4864691	-0.4927147
127	-0.4864691	-0.4927147

Table 107: Voltage Magnitude Sensitivity Factors for a trade in bus 21

Bus index	Sensitivity factors $K_{S,U}$ for a trade in bus 21
0	5.00E-09
1	0.000382
2	0.000382
3	0.000382
4	0.000381
5	0.000381
6	0.00038
7	0.00038
8	0.000379
9	0.000379
10	0.00038
11	0.00038
12	0.00038
13	0.00038
14	0.00038
15	0.00038
16	0.00038
17	0.00038
18	0.00038
19	0.00038
20	0.00038
21	0.00038
22	0.000379
23	0.000382
24	0.000383
25	0.000383
26	0.000383
27	0.000383
28	0.000384
29	0.000384
30	0.000385
31	0.000385
32	0.000385
33	0.000385
34	0.000385
35	0.000385
36	0.000382
37	0.000382
38	0.000382
39	0.000382
40	0.000382
41	0.000381
42	0.000382
43	0.000382
44	0.000383
45	0.000382
46	0.00038
47	0.000382
48	0.000382

49	0.000382
50	0.000382
51	0.000382
52	0.000381
53	0.000381
54	0.000381
55	0.000381
56	0.000382
57	0.000381
58	0.000381
59	0.000381
60	0.000657
61	0.000731
62	0.000704
63	0.000687
64	0.000627
65	0.001875
66	0.001858
67	0.000731
68	0.000399
69	0.00043
70	0.000484
71	0.000498
72	0.000585
73	0.000612
74	0.000382
75	0.000382
76	0.000381
77	0.000381
78	0.000381
79	0.000381
80	0.000381
81	0.000381
82	0.000381
83	0.00038
84	0.00038
85	0.000383
86	0.000383
87	0.000383
88	0.000383
89	0.000383
90	0.000383
91	0.000383
92	0.000383
93	0.000383
94	0.000383
95	0.000384
96	0.000385
97	0.000385
98	0.000385
99	0.000384
100	0.000382
101	0.000382
102	0.000382
103	0.000382
104	0.000382
105	0.000382
106	0.000381
107	0.000381
108	0.000381
109	0.00038
110	0.00038
111	0.00038
112	0.00038

113	0.00038
114	0.00038
115	0.00038
116	0.000384
117	0.000384
118	0.000382
119	0.00038

Table 108: Bus data results after active power trade (DSO - MP)

bus_id	vm_pu	va_degree	p_mw	q_mvar
0	1.025	0	27.97352	0.134307
1	1.031725	0.59503	-4.79483	0.028899
2	1.033426	0.635573	0.023276	0.008096
3	1.034526	0.661913	0.01916	0.012312
4	1.03551	0.685415	0.01916	0.012312
5	1.036738	0.70617	0.01264	0.004639
6	1.038075	0.728839	0.01264	0.004639
7	1.039135	0.746833	0.01916	0.012312
8	1.041977	0.794992	-5.39743	0.004454
9	1.040993	0.780005	0.01264	0.004639
10	1.039862	0.763007	0.017074	0.005571
11	1.039084	0.751448	0.01264	0.004639
12	1.038793	0.750284	0.01916	0.012312
13	1.038636	0.749673	0.01916	0.012312
14	1.038515	0.749174	0.01916	0.012312
15	1.038318	0.748333	0.01916	0.012312
16	1.03811	0.747473	0.01916	0.012312
17	1.037959	0.746851	0.01264	0.004639
18	1.037744	0.746133	0.01264	0.004639
19	1.037465	0.745547	0.41916	0.012312
20	1.038453	0.796529	0.01916	0.012312
21	1.039585	0.85265	0.01264	0.004639
22	1.040695	0.906752	-6.502	0.005571
23	1.033229	0.659064	0.017074	0.005571
24	1.031582	0.589223	0.01264	0.004639
25	1.0313	0.577825	0.01264	0.004639
26	1.031105	0.570014	0.01264	0.004639
27	1.030805	0.561514	0.017074	0.005571
28	1.029126	0.515785	0.009701	0.004454
29	1.028041	0.488349	0.009701	0.004454
30	1.026632	0.461475	0.017074	0.005571
31	1.026334	0.456084	0.01264	0.004639
32	1.026138	0.452554	0.01264	0.004639
33	1.0258	0.446501	0.017074	0.005571
34	1.025515	0.441448	0.009701	0.004454
35	1.025252	0.436826	0.009701	0.004454
36	1.032241	0.604206	0.009701	0.004454
37	1.032587	0.610376	0.009701	0.004454
38	1.033074	0.619082	0.009701	0.004454
39	1.033511	0.626925	0.009701	0.004454
40	1.034307	0.641487	0.01264	0.004639
41	1.035728	0.693996	0.017074	0.005571
42	1.034408	0.654202	0.01264	0.004639
43	1.032824	0.606033	0.017074	0.005571
44	1.03099	0.54968	0.009701	0.004454
45	1.033505	0.626814	0.01264	0.004639
46	1.038084	0.773385	-2.97314	0.004454
47	1.032001	0.599733	0.01264	0.004639
48	1.032373	0.606043	0.01264	0.004639
49	1.03312	0.61881	0.01264	0.004639

50	1.033779	0.630147	0.01264	0.004639
51	1.034252	0.638336	0.01264	0.004639
52	1.034933	0.650977	0.009701	0.004454
53	1.035731	0.666327	0.009701	0.004454
54	1.036133	0.67424	0.009701	0.004454
55	1.036654	0.684635	0.01264	0.004639
56	1.034545	0.6431	0.017074	0.005571
57	1.034899	0.649008	0.01264	0.004639
58	1.035972	0.668477	0.01264	0.004639
59	1.036852	0.686294	-1.23212	0
60	1.037393	0.692083	0.01264	0.004639
61	1.038942	0.71867	0.017074	0.005571
62	1.03837	0.708072	0.009701	0.004454
63	1.038015	0.701542	0.005826	0.007105
64	1.03674	0.678498	0.005826	0.007105
65	1.050466	1.12419	0.005826	0.007105
66	1.060272	1.46026	-6.38006	0.004454
67	1.038912	0.719443	0.011979	0.018976
68	1.03206	0.600306	0.01916	0.012312
69	1.032672	0.609856	0.01264	0.004639
70	1.033769	0.627522	0.017074	0.005571
71	1.034047	0.632078	0.017074	0.005571
72	1.035868	0.663071	0.005826	0.007105
73	1.03643	0.672973	0.009701	0.004454
74	1.032501	0.62213	0.009701	0.004454
75	1.033557	0.658484	0.009701	0.004454
76	1.034759	0.699335	0.009701	0.004454
77	1.034915	0.701808	0.01264	0.004639
78	1.035101	0.704798	0.01916	0.012312
79	1.03535	0.7087	0.01916	0.012312
80	1.035922	0.717752	0.009701	0.004454
81	1.036658	0.730597	0.009701	0.004454
82	1.036844	0.734019	0.017074	0.005571
83	1.037073	0.73824	0.017074	0.005571
84	1.037267	0.741854	0.01264	0.004639
85	1.031673	0.592864	0.023276	0.008096
86	1.031593	0.589471	0.01916	0.012312
87	1.031485	0.584729	0.01916	0.012312
88	1.031399	0.580883	0.01916	0.012312
89	1.031297	0.57615	0.01916	0.012312
90	1.031227	0.572819	0.035121	0.054983
91	1.031134	0.568778	0.01916	0.012312
92	1.030979	0.561713	0.01264	0.004639
93	1.030589	0.544341	0.01916	0.012312
94	1.029628	0.524423	0.01264	0.004639
95	1.027364	0.478954	0.01264	0.004639
96	1.025282	0.439019	0.025528	0.025901
97	1.0246	0.425714	10	0.004639
98	1.024926	0.431179	0	0
99	1.027867	0.478265	-1.90096	0.005571
100	1.031883	0.597133	0.01916	0.012312
101	1.031995	0.598618	0.01264	0.004639
102	1.032148	0.600716	0.01264	0.004639
103	1.032313	0.60309	0.01916	0.012312
104	1.032498	0.605768	0.01264	0.004639
105	1.03344	0.62913	0.031442	0.020461
106	1.034916	0.66356	0.009701	0.004454
107	1.036094	0.690824	0.009701	0.004454
108	1.037074	0.713291	0.01264	0.004639
109	1.037961	0.733502	0.017074	0.005571
110	1.038243	0.73544	0.01264	0.004639
111	1.038022	0.728337	0.009701	0.004454
112	1.037873	0.723521	0.005826	0.007105
113	1.037685	0.717408	0.017074	0.005571



114	1.037423	0.708866	0.017074	0.005571
115	1.03809	0.773037	0	0
116	1.028055	0.487489	0	0
117	1.028056	0.487441	0	0
118	1.031744	0.593885	0	0
119	1.039502	0.989383	-11.3322	0

Table 109: Line data after active power trade (DSO – MO)

line_id	from_bus	to_bus	s_from_mva	s_to_mva	max_s_mva
0	1	2	3.212888	3.218319	6.54715205
1	2	3	3.241528	3.245093	6.54715205
2	3	4	3.264147	3.267348	6.54715205
3	4	5	3.28641	3.29037	5.71576766
4	5	6	3.302975	3.307316	5.71576766
5	6	7	3.319915	3.323374	5.71576766
6	7	8	3.342433	3.35176	5.71576766
7	8	9	2.04619	2.044485	5.71576766
8	9	10	2.031749	2.029853	5.71576766
9	10	11	2.012645	2.011382	5.71576766
10	11	12	0.582712	0.585049	5.71576766
11	12	13	0.563662	0.564976	5.71576766
12	13	14	0.543611	0.544646	5.71576766
13	14	15	0.523324	0.525072	5.71576766
14	15	16	0.503741	0.505667	5.71576766
15	16	17	0.484316	0.485782	5.71576766
16	17	18	0.472433	0.474732	5.71576766
17	18	19	0.461354	0.464684	5.71576766
18	19	20	0.734338	0.735305	5.45596004
19	20	21	0.751913	0.752999	5.45596004
20	21	22	0.764681	0.765741	5.45596004
21	22	23	5.747949	5.706732	5.45596004
22	1	24	1.04376	1.042137	7.35255568
23	24	25	1.030624	1.027446	7.35255568
24	25	26	1.015879	1.013719	7.35255568
25	26	27	1.002129	1.00046	5.71576766
26	27	28	0.984681	0.975982	5.71576766
27	28	29	0.967041	0.962246	5.71576766
28	29	30	0.946969	0.944262	5.71576766
29	30	31	0.927331	0.926882	5.71576766
30	31	32	0.91435	0.914062	5.71576766
31	32	33	0.901529	0.901052	5.71576766
32	33	34	0.884087	0.883706	5.71576766
33	34	35	0.874079	0.873749	5.71576766
34	1	36	1.612016	1.612978	5.71576766
35	36	37	1.622582	1.623234	5.71576766
36	37	38	1.632837	1.633765	5.71576766
37	38	39	1.643361	1.644205	5.71576766
38	39	40	1.66658	1.668198	5.71576766
39	40	41	1.680689	1.68302	5.45596004
40	41	42	1.2694	1.267836	5.45596004
41	42	43	1.254943	1.253084	5.45596004
42	43	44	1.235725	1.233599	5.45596004
43	39	45	0.014023	0.013464	5.71576766
44	41	46	2.966633	2.973374	5.45596004
45	1	47	1.720918	1.721409	5.71576766
46	47	48	1.734014	1.734676	5.71576766
47	48	49	1.747281	1.748638	5.71576766
48	49	50	1.761229	1.762454	5.71576766
49	50	51	1.775035	1.775931	5.71576766
50	51	52	1.070214	1.071441	5.71576766

51	52	53	1.080961	1.082597	5.71576766
52	53	54	1.09206	1.092954	5.71576766
53	54	55	1.102399	1.103611	5.71576766
54	51	56	0.718598	0.718764	5.71576766
55	56	57	0.735843	0.73613	5.71576766
56	57	58	0.748735	0.750454	5.71576766
57	58	59	0.762864	0.765248	5.71576766
58	1	60	4.815046	4.841788	5.71576766
59	60	61	4.854372	4.861713	5.71576766
60	61	62	1.355944	1.354842	5.71576766
61	62	63	1.345292	1.344626	5.71576766
62	63	64	1.339033	1.336771	5.71576766
63	61	65	6.245975	6.315277	5.45596004
64	65	66	6.321054	6.380066	5.45596004
65	61	67	0.02147	0.022441	5.45596004
66	1	68	1.243111	1.243432	5.71576766
67	68	69	1.262779	1.263348	5.71576766
68	69	70	1.276048	1.277261	5.71576766
69	70	71	1.294342	1.294682	5.71576766
70	71	72	1.311766	1.314362	5.71576766
71	72	73	1.320058	1.32097	5.71576766
72	1	74	0.600175	0.600628	5.45596004
73	74	75	0.610335	0.610953	5.45596004
74	75	76	0.620683	0.621388	5.45596004
75	76	77	0.63114	0.631174	5.71576766
76	77	78	0.643857	0.643921	5.71576766
77	78	79	0.663222	0.663256	5.71576766
78	79	80	0.682614	0.682778	5.71576766
79	80	81	0.692476	0.693375	5.71576766
80	81	82	0.702934	0.703265	5.71576766
81	82	83	0.720151	0.720565	5.71576766
82	83	84	0.737438	0.737797	5.71576766
83	1	85	0.639378	0.638409	7.35255568
84	85	86	0.617346	0.615719	7.35255568
85	86	87	0.599757	0.597331	7.35255568
86	87	88	0.581537	0.579441	7.35255568
87	88	89	0.563881	0.561132	7.35255568
88	89	90	0.545761	0.543694	7.35255568
89	90	91	0.527597	0.525694	5.71576766
90	91	92	0.512608	0.509091	5.71576766
91	92	93	0.499244	0.490443	5.71576766
92	93	94	1.664676	1.662193	5.71576766
93	94	95	1.649877	1.644397	5.71576766
94	95	96	1.631997	1.627445	5.71576766
95	96	97	1.602991	1.601463	5.71576766
96	97	98	0.863451	0.863737	5.71576766
97	97	99	7.536902	7.560845	5.71576766
98	1	100	0.565928	0.56436	6.54715205
99	100	101	0.585268	0.584189	6.54715205
100	101	102	0.597411	0.59606	6.54715205
101	102	103	0.609254	0.60793	6.54715205
102	103	104	0.628665	0.627243	6.54715205
103	104	105	0.6404	0.640817	5.45596004
104	105	106	0.674971	0.675648	5.45596004
105	106	107	0.68594	0.686492	5.45596004
106	107	108	0.696792	0.697259	5.45596004
107	108	109	0.710495	0.710931	5.45596004
108	109	110	0.728701	0.727414	5.71576766
109	110	111	0.717115	0.715012	5.71576766
110	111	112	0.706638	0.705195	5.71576766
111	112	113	0.701235	0.699381	5.71576766
112	113	114	0.68416	0.681505	5.71576766
113	59	55	0.473253	0.474518	5.71576766
114	55	114	0.658812	0.66628	5.71576766

115	110	11	1.427575	1.429345	5.71576766
116	19	84	0.750641	0.750266	5.71576766
117	64	73	1.331095	1.330574	5.71576766
118	99	23	5.660056	5.689569	5.45596004
119	98	35	0.863737	0.864111	5.71576766
120	93	44	1.223614	1.223678	5.71576766
121	46	115	0.042055	2.36E-13	10.9379008
122	29	116	0.066602	0.015396	10.9379008
123	116	117	0.015396	9.35E-13	10.9379008
124	1	118	0.0753	4.23E-13	10.9379008
125	1	119	11.24747	11.33217	10.9379008
126	0	1	13.98692	14.07867	12.2109582
127	0	1	13.98692	14.07867	12.2109582

### C.3 Case 2: Intraday Model reactive power trade (DSO – MP)

Table 110: Line Apparent Power Flow Sensitivity Factors for a trade in bus 66

Line id	Sensitivity factors $K_{S,Q}$	
	from	to
0	-3.34E-05	-2.87E-05
1	-2.90E-05	-2.60E-05
2	-2.65E-05	-2.38E-05
3	-2.43E-05	-2.11E-05
4	-2.13E-05	-1.78E-05
5	-1.80E-05	-1.53E-05
6	-1.56E-05	-8.30E-06
7	1.12E-05	1.01E-05
8	9.90E-06	8.60E-06
9	8.40E-06	7.40E-06
10	3.92E-05	3.76E-05
11	3.70E-05	3.60E-05
12	3.55E-05	3.47E-05
13	3.41E-05	3.26E-05
14	3.22E-05	3.03E-05
15	3.00E-05	2.84E-05
16	2.85E-05	2.58E-05
17	2.59E-05	2.16E-05
18	-1.31E-05	-1.30E-05
19	-1.35E-05	-1.33E-05
20	-1.35E-05	-1.33E-05
21	1.71E-05	-1.42E-05
22	-8.80E-06	-6.40E-06
23	-7.70E-06	-3.00E-06
24	-4.20E-06	-1.00E-06
25	-2.20E-06	-1.00E-07
26	-1.50E-06	9.10E-06
27	8.40E-06	1.39E-05
28	2.39E-05	2.56E-05
29	2.55E-05	2.56E-05
30	2.55E-05	2.56E-05
31	2.55E-05	2.55E-05
32	2.55E-05	2.55E-05
33	2.55E-05	2.54E-05
34	-1.56E-05	-1.46E-05
35	-1.49E-05	-1.43E-05
36	-1.45E-05	-1.37E-05
37	-1.39E-05	-1.32E-05
38	-1.33E-05	-1.22E-05

39	-1.24E-05	-1.07E-05
40	9.40E-06	8.20E-06
41	8.10E-06	6.60E-06
42	6.50E-06	4.80E-06
43	-3.40E-06	0
44	-5.30E-06	-4.00E-07
45	-2.01E-05	-1.94E-05
46	-1.99E-05	-1.89E-05
47	-1.94E-05	-1.76E-05
48	-1.81E-05	-1.65E-05
49	-1.70E-05	-1.59E-05
50	-9.20E-06	-8.10E-06
51	-8.40E-06	-7.40E-06
52	-7.60E-06	-7.30E-06
53	-7.50E-06	-7.10E-06
54	-7.40E-06	-6.40E-06
55	-6.90E-06	-5.80E-06
56	-6.20E-06	-4.50E-06
57	-4.70E-06	-4.90E-06
58	0.0591541	0.062747
59	0.0618376	0.0628228
60	-0.0433175	-0.0447777
61	-0.0444248	-0.0453411
62	-0.0444715	-0.0477667
63	0.0135552	0.0071428
64	0.0060117	0.0006981
65	1.40E-06	0
66	0.0415053	0.0425234
67	0.0399305	0.041741
68	0.0406064	0.0437831
69	0.0423625	0.0431452
70	0.0417495	0.0467523
71	0.045487	0.0470118
72	-6.20E-06	-5.70E-06
73	-6.10E-06	-5.40E-06
74	-5.80E-06	-5.00E-06
75	-5.40E-06	-4.70E-06
76	-5.10E-06	-4.30E-06
77	-5.30E-06	-4.30E-06
78	-5.20E-06	-3.30E-06
79	-3.50E-06	-2.00E-06
80	-2.20E-06	-2.00E-06
81	-2.10E-06	-1.90E-06
82	-2.00E-06	-1.90E-06
83	-2.50E-06	-5.00E-07
84	-4.10E-06	-9.00E-07
85	-5.40E-06	-8.00E-07
86	-5.30E-06	-1.50E-06
87	-5.90E-06	-1.10E-06
88	-5.50E-06	-2.00E-06
89	-1.82E-05	-1.56E-05
90	-2.04E-05	-1.57E-05
91	-1.80E-05	-6.30E-06
92	2.78E-05	2.83E-05
93	2.80E-05	2.87E-05
94	2.84E-05	2.83E-05
95	2.73E-05	2.72E-05
96	2.49E-05	2.52E-05
97	-5.48E-05	-3.65E-05
98	-1.40E-05	-1.15E-05
99	-1.25E-05	-1.09E-05
100	-1.12E-05	-9.10E-06
101	-9.40E-06	-7.50E-06
102	-8.20E-06	-6.20E-06

103	-6.40E-06	-5.80E-06
104	-6.70E-06	-5.70E-06
105	-5.80E-06	-5.00E-06
106	-5.20E-06	-4.40E-06
107	-4.60E-06	-3.90E-06
108	-4.10E-06	-2.40E-06
109	-1.47E-05	-1.35E-05
110	-1.35E-05	-1.27E-05
111	-1.25E-05	-1.15E-05
112	-1.14E-05	-1.00E-05
113	6.60E-06	5.50E-06
114	-6.60E-06	-9.70E-06
115	-1.07E-05	-1.00E-05
116	-1.90E-06	-1.90E-06
117	0.0468535	0.0460212
118	-3.66E-05	-1.42E-05
119	2.52E-05	2.54E-05
120	4.30E-06	4.80E-06
121	-3.09E-05	0
122	-4.98E-05	-1.15E-05
123	-1.15E-05	0
124	-5.59E-05	-2.87E-05
125	-6.22E-05	-2.60E-05
126	0.0072873	-2.38E-05
127	0.0072873	-2.11E-05

Table 111: Voltage Magnitude Sensitivity Factors for a trade in bus 66

Bus index	Sensitivity factors $K_{S,U}$ for a trade in bus 66
0	5.00E-09
1	0.000383074
2	0.000382476
3	0.000382086
4	0.000381737
5	0.000381294
6	0.00038081
7	0.000380426
8	0.000379393
9	0.00037975
10	0.000380159
11	0.000380439
12	0.000380529
13	0.000380576
14	0.000380612
15	0.00038067
16	0.000380729
17	0.000380771
18	0.000380829
19	0.000380903
20	0.000380642
21	0.000380337
22	0.000380034
23	0.00038283
24	0.000383142
25	0.000383277
26	0.000383369
27	0.000383501
28	0.000384229
29	0.00038469
30	0.000385253
31	0.000385371

32	0.000385448
33	0.000385581
34	0.000385692
35	0.000385795
36	0.000382896
37	0.000382776
38	0.000382607
39	0.000382455
40	0.000382175
41	0.000381693
42	0.0003822
43	0.000382808
44	0.000383512
45	0.000382457
46	0.000380844
47	0.00038298
48	0.000382853
49	0.000382596
50	0.000382368
51	0.000382204
52	0.000381965
53	0.000381682
54	0.000381538
55	0.000381351
56	0.000382104
57	0.00038198
58	0.000381599
59	0.000381279
60	0.000657847
61	0.000732114
62	0.000705342
63	0.000688602
64	0.000628306
65	0.001876669
66	0.002824758
67	0.000732136
68	0.000400147
69	0.000430827
70	0.000485212
71	0.000498775
72	0.000586612
73	0.000613527
74	0.000382802
75	0.00038243
76	0.000382003
77	0.000381942
78	0.000381868
79	0.000381769
80	0.000381539
81	0.000381238
82	0.000381161
83	0.000381066
84	0.000380986
85	0.000383102
86	0.000383145
87	0.000383204
88	0.00038325
89	0.000383306
90	0.000383344
91	0.000383391
92	0.000383469
93	0.000383662
94	0.00038405
95	0.000384955

96	0.000385778
97	0.000386046
98	0.000385921
99	0.000384828
100	0.00038302
101	0.000382981
102	0.000382928
103	0.000382869
104	0.000382803
105	0.000382471
106	0.000381949
107	0.000381531
108	0.000381182
109	0.000380865
110	0.000380759
111	0.000380843
112	0.0003809
113	0.000380971
114	0.000381069
115	0.000380846
116	0.000384695
117	0.000384695
118	0.000383081
119	0.000380269

Table 112: Bus data results after reactive power trade (DSO - MP)

bus_id	vm_pu	va_degree	p_mw	q_mvar
0	1.025	0	28.36385474	0.084541015
1	1.031799703	0.60396714	-4.794828632	0.028898762
2	1.033547826	0.645951033	0.023275665	0.008095984
3	1.034678612	0.67321257	0.019159895	0.012311689
4	1.035689743	0.697530796	0.019159895	0.012311689
5	1.036951182	0.719055564	0.012640149	0.004638544
6	1.038325468	0.742556319	0.012640149	0.004638544
7	1.039414208	0.761204572	0.019159895	0.012311689
8	1.042333911	0.811097403	-5.397433554	0.004454045
9	1.041394126	0.797110874	0.012640149	0.004638544
10	1.040313913	0.781273213	0.017073891	0.005571171
11	1.039572001	0.770519399	0.012640149	0.004638544
12	1.039374376	0.771335654	0.019159895	0.012311689
13	1.03926995	0.771824874	0.019159895	0.012311689
14	1.039190906	0.772206916	0.019159895	0.012311689
15	1.039064051	0.772863689	0.019159895	0.012311689
16	1.03893393	0.773634018	0.019159895	0.012311689
17	1.03884153	0.774246284	0.012640149	0.004638544
18	1.038711201	0.775336311	0.012640149	0.004638544
19	1.038545523	0.777133337	0.019159895	0.012311689
20	1.039384146	0.823959711	0.019159895	0.012311689
21	1.040352681	0.875532226	0.012640149	0.004638544
22	1.041305609	0.925297888	-6.502003417	0.005571171
23	1.033721182	0.674515321	0.017073891	0.005571171
24	1.031663189	0.598284147	0.012640149	0.004638544
25	1.031393071	0.587132377	0.012640149	0.004638544
26	1.031205873	0.579494092	0.012640149	0.004638544
27	1.030918101	0.571139345	0.017073891	0.005571171
28	1.029308177	0.52623895	0.009700564	0.004454045
29	1.028267342	0.499343297	0.009700564	0.004454045
30	1.026915409	0.473161734	0.017073891	0.005571171
31	1.026629734	0.467920164	0.012640149	0.004638544
32	1.02644191	0.464489435	0.012640149	0.004638544

33	1.026117743	0.458610143	0.017073891	0.005571171
34	1.025845172	0.453706829	0.009700564	0.004454045
35	1.025593456	0.449224711	0.009700564	0.004454045
36	1.032320221	0.613165382	0.009700564	0.004454045
37	1.032669207	0.619349493	0.009700564	0.004454045
38	1.033160573	0.628075931	0.009700564	0.004454045
39	1.033601729	0.635937467	0.009700564	0.004454045
40	1.034405117	0.650530712	0.012640149	0.004638544
41	1.035838895	0.703307332	0.017073891	0.005571171
42	1.034534637	0.663846584	0.012640149	0.004638544
43	1.03296976	0.616085732	0.017073891	0.005571171
44	1.031158138	0.560215792	0.009700564	0.004454045
45	1.033596137	0.635825597	0.012640149	0.004638544
46	1.038195183	0.782679314	-2.973136474	0.004454045
47	1.032086454	0.608935546	0.012640149	0.004638544
48	1.032471526	0.615598398	0.012640149	0.004638544
49	1.033246751	0.629070055	0.012640149	0.004638544
50	1.033929313	0.641021724	0.012640149	0.004638544
51	1.034420029	0.649649586	0.012640149	0.004638544
52	1.035126601	0.66295812	0.009700564	0.004454045
53	1.035955556	0.679085764	0.009700564	0.004454045
54	1.036372692	0.687385827	0.009700564	0.004454045
55	1.036912875	0.698278505	0.012640149	0.004638544
56	1.034722261	0.654656172	0.017073891	0.005571171
57	1.03508768	0.660851142	0.012640149	0.004638544
58	1.036194363	0.681178822	0.012640149	0.004638544
59	1.037101697	0.699693059	-1.232117425	0
60	1.037459631	0.702446845	0.012640149	0.004638544
61	1.039006553	0.729420925	0.017073891	0.005571171
62	1.038431996	0.719343414	0.009700564	0.004454045
63	1.03807519	0.713139449	0.005826366	0.007105112
64	1.036794179	0.691270013	0.005826366	0.047105112
65	1.050530241	1.134890159	0.005826366	0.007105112
66	1.060335741	1.47091973	-6.380064523	0.004454045
67	1.038976326	0.730193541	0.011978659	0.018976499
68	1.032133108	0.609509392	0.019159895	0.012311689
69	1.032743003	0.619537939	0.012640149	0.004638544
70	1.033835303	0.638052373	0.017073891	0.005571171
71	1.034111595	0.64282058	0.017073891	0.005571171
72	1.035925816	0.675188732	0.005826366	0.007105112
73	1.036484727	0.685513282	0.009700564	0.004454045
74	1.032723623	0.635546666	0.009700564	0.004454045
75	1.033976111	0.677846952	0.009700564	0.004454045
76	1.035397472	0.725305599	0.009700564	0.004454045
77	1.035580902	0.728131186	0.012640149	0.004638544
78	1.035799735	0.731535206	0.019159895	0.012311689
79	1.036091069	0.73597335	0.019159895	0.012311689
80	1.036755788	0.746217976	0.009700564	0.004454045
81	1.037612556	0.760587914	0.009700564	0.004454045
82	1.037828424	0.76439033	0.017073891	0.005571171
83	1.038092794	0.769067533	0.017073891	0.005571171
84	1.038317542	0.773060386	0.012640149	0.004638544
85	1.031751368	0.601880575	0.023275665	0.008095984
86	1.031677603	0.598614002	0.019159895	0.012311689
87	1.031577434	0.594050659	0.019159895	0.012311689
88	1.031498461	0.590351415	0.019159895	0.012311689
89	1.031404128	0.585802733	0.019159895	0.012311689
90	1.031339911	0.582603631	0.035121381	0.054983202
91	1.031255199	0.578669703	0.019159895	0.012311689
92	1.031114764	0.571791764	0.012640149	0.004638544
93	1.030762695	0.554902833	0.019159895	0.012311689
94	1.02983224	0.535328701	0.012640149	0.004638544
95	1.027643285	0.490679884	0.012640149	0.004638544
96	1.025629228	0.451510739	0.025528254	0.025901439



97	1.024969757	0.438463708	10	0.004638544
98	1.025282097	0.443753048	0	0
99	1.028274615	0.491417519	-1.90095824	0.005571171
100	1.031968224	0.606247377	0.019159895	0.012311689
101	1.032087559	0.607853932	0.012640149	0.004638544
102	1.032249386	0.610113764	0.012640149	0.004638544
103	1.032424055	0.612660471	0.019159895	0.012311689
104	1.032619752	0.615524867	0.012640149	0.004638544
105	1.033615561	0.640366599	0.031442224	0.020461308
106	1.035170542	0.676966707	0.009700564	0.004454045
107	1.036410737	0.70592733	0.009700564	0.004454045
108	1.037440708	0.729777348	0.012640149	0.004638544
109	1.038373407	0.751213433	0.017073891	0.005571171
110	1.038669146	0.753301262	0.012640149	0.004638544
111	1.03842683	0.745642065	0.009700564	0.004454045
112	1.03826235	0.740444067	0.005826366	0.007105112
113	1.038054824	0.733843628	0.017073891	0.005571171
114	1.037765264	0.724604622	0.017073891	0.005571171
115	1.038200977	0.782330972	0	0
116	1.028281508	0.498483516	0	0
117	1.028282307	0.498434982	0	0
118	1.031818625	0.602822579	0	0
119	1.039576206	0.998263355	-11.33217112	0

Table 113: Line data after reactive power trade (DSO – MO)

line_id	from_bus	to_bus	s_from_mva	s_to_mva	max_s_mva
0	1	2	3.306143583	3.311936056	6.54715205
1	2	3	3.335122441	3.338919327	6.54715205
2	3	4	3.357940507	3.361347994	6.54715205
3	4	5	3.380377783	3.384582695	5.71576766
4	5	6	3.39717486	3.401782093	5.71576766
5	6	7	3.414369203	3.418038526	5.71576766
6	7	8	3.437065964	3.446957237	5.71576766
7	8	9	1.951304304	1.94983982	5.71576766
8	9	10	1.937078803	1.935463169	5.71576766
9	10	11	1.918223213	1.917155629	5.71576766
10	11	12	0.394139841	0.398201356	5.71576766
11	12	13	0.375875651	0.378195517	5.71576766
12	13	14	0.355851503	0.357723034	5.71576766
13	14	15	0.33537408	0.338610181	5.71576766
14	15	16	0.316212252	0.319855372	5.71576766
15	16	17	0.297397173	0.300241009	5.71576766
16	17	18	0.286809673	0.291272784	5.71576766
17	18	19	0.27788582	0.284308061	5.71576766
18	19	20	0.648880928	0.649728034	5.45596004
19	20	21	0.665734695	0.666676198	5.45596004
20	21	22	0.678113714	0.679029716	5.45596004
21	22	23	5.837961835	5.795463752	5.45596004
22	1	24	1.008191206	1.006502675	7.35255568
23	24	25	0.995060451	0.991752556	7.35255568
24	25	26	0.980254773	0.978004813	7.35255568
25	26	27	0.966482478	0.96476099	5.71576766
26	27	28	0.949069206	0.940086773	5.71576766
27	28	29	0.931197299	0.92624604	5.71576766
28	29	30	0.910557299	0.907783801	5.71576766
29	30	31	0.890877935	0.890418116	5.71576766
30	31	32	0.877906261	0.877611428	5.71576766
31	32	33	0.865099554	0.864610615	5.71576766
32	33	34	0.847669035	0.847277728	5.71576766
33	34	35	0.837669978	0.83733085	5.71576766

34	1	36	1.62567656	1.626638447	5.71576766
35	36	37	1.636250694	1.636903121	5.71576766
36	37	38	1.6465146	1.647442587	5.71576766
37	38	39	1.657047769	1.657891658	5.71576766
38	39	40	1.680264426	1.68188279	5.71576766
39	40	41	1.694383193	1.696752702	5.45596004
40	41	42	1.255439505	1.253911803	5.45596004
41	42	43	1.241024889	1.239208564	5.45596004
42	43	44	1.221857133	1.219780929	5.45596004
43	39	45	0.014024112	0.013464377	5.71576766
44	41	46	2.96663436	2.973374213	5.45596004
45	1	47	1.788000913	1.788547015	5.71576766
46	47	48	1.801127807	1.801863939	5.71576766
47	48	49	1.814444514	1.815949469	5.71576766
48	49	50	1.828516926	1.829870963	5.71576766
49	50	51	1.84242862	1.843416139	5.71576766
50	51	52	1.113164591	1.114512514	5.71576766
51	52	53	1.124013199	1.125783206	5.71576766
52	53	54	1.135228504	1.136186295	5.71576766
53	54	55	1.14561488	1.146907306	5.71576766
54	51	56	0.743110467	0.743337821	5.71576766
55	56	57	0.760390565	0.760746091	5.71576766
56	57	58	0.773329985	0.775227923	5.71576766
57	58	59	0.787621905	0.790119479	5.71576766
58	1	60	4.81530485	4.84213754	5.71576766
59	60	61	4.854699944	4.862065762	5.71576766
60	61	62	1.355267148	1.354329446	5.71576766
61	62	63	1.344702615	1.344139962	5.71576766
62	63	64	1.338427884	1.336540184	5.71576766
63	61	65	6.24599067	6.315283828	5.45596004
64	65	66	6.321061045	6.380066079	5.45596004
65	61	67	0.021469725	0.02244094	5.45596004
66	1	68	1.242951195	1.243361211	5.71576766
67	68	69	1.262534599	1.26326304	5.71576766
68	69	70	1.275898201	1.277391978	5.71576766
69	70	71	1.294394088	1.294802953	5.71576766
70	71	72	1.311808567	1.314848743	5.71576766
71	72	73	1.320446225	1.321495349	5.71576766
72	1	74	0.710033954	0.710661014	5.45596004
73	74	75	0.720406289	0.721260878	5.45596004
74	75	76	0.731026202	0.732002013	5.45596004
75	76	77	0.741785998	0.741810999	5.71576766
76	77	78	0.754528596	0.754580943	5.71576766
77	78	79	0.773968925	0.773999907	5.71576766
78	79	80	0.793434157	0.793588959	5.71576766
79	80	81	0.803324567	0.804121662	5.71576766
80	81	82	0.813739708	0.814032614	5.71576766
81	82	83	0.830994407	0.831364818	5.71576766
82	83	84	0.848314315	0.848638571	5.71576766
83	1	85	0.603007775	0.601967252	7.35255568
84	85	86	0.58112964	0.579379699	7.35255568
85	86	87	0.563723705	0.561108902	7.35255568
86	87	88	0.545646231	0.543382872	7.35255568
87	88	89	0.528184946	0.525212081	7.35255568
88	89	90	0.510232651	0.507993101	7.35255568
89	90	91	0.493681958	0.491632672	5.71576766
90	91	92	0.479186082	0.475393668	5.71576766
91	92	93	0.465880938	0.456361228	5.71576766
92	93	94	1.613831683	1.611371687	5.71576766
93	94	95	1.599084914	1.593669995	5.71576766
94	95	96	1.581294709	1.576816533	5.71576766
95	96	97	1.55248249	1.5509759	5.71576766
96	97	98	0.827033507	0.827325992	5.71576766
97	97	99	7.624141388	7.648623328	5.71576766

98	1	100	0.602938102	0.601424266	6.54715205
99	100	101	0.622294488	0.621252815	6.54715205
100	101	102	0.634464774	0.633157165	6.54715205
101	102	103	0.646341993	0.645057462	6.54715205
102	103	104	0.665766509	0.664385847	6.54715205
103	104	105	0.67753647	0.678024597	5.45596004
104	105	106	0.712133911	0.712924078	5.45596004
105	106	107	0.72320706	0.723848735	5.45596004
106	107	108	0.734138909	0.734681216	5.45596004
107	108	109	0.747908772	0.748412031	5.45596004
108	109	110	0.766172741	0.764934208	5.71576766
109	110	111	0.785347878	0.783280667	5.71576766
110	111	112	0.774849838	0.773433209	5.71576766
111	112	113	0.769399486	0.767580724	5.71576766
112	113	114	0.752271935	0.749672018	5.71576766
113	59	55	0.449293961	0.450716503	5.71576766
114	55	114	0.727021453	0.734356994	5.71576766
115	110	11	1.533007877	1.534967076	5.71576766
116	19	84	0.861510747	0.861170096	5.71576766
117	64	73	1.3316304	1.331035011	5.71576766
118	99	23	5.747862365	5.778294789	5.45596004
119	98	35	0.827325992	0.827710201	5.71576766
120	93	44	1.209800836	1.209866221	5.71576766
121	46	115	0.042063604	4.72E-13	10.9379008
122	29	116	0.066631068	0.01540255	10.9379008
123	116	117	0.01540255	2.96E-12	10.9379008
124	1	118	0.075310549	2.62E-13	10.9379008
125	1	119	11.24747895	11.33217112	10.9379008
126	0	1	14.18199037	14.27605934	12.2109582
127	0	1	14.18199037	14.27605934	12.2109582

## C.4 Case 3: Intraday Model active power trade between MPs

Table 114: Line Apparent Power Flow Sensitivity Factors for orders in buses 10 and 20

Line id	Sensitivity factors $K_{S,P}$ bus 10		Sensitivity factors $K_{S,P}$ bus 20	
	from	to	from	to
0	-0.4200574	-0.4215248	-0.1974899	-0.1982466
1	-0.4215055	-0.42245	-0.1982059	-0.1986925
2	-0.4224231	-0.4232669	-0.1986328	-0.1990672
3	-0.4232405	-0.4242825	-0.199008	-0.1995258
4	-0.4242728	-0.4254061	-0.1995036	-0.2000666
5	-0.4253975	-0.4262941	-0.2000449	-0.2004902
6	-0.4262716	-0.4286735	-0.2004337	-0.2016261
7	0.4282419	0.4273434	0.2009642	0.2004699
8	0.4273917	0.426344	0.2005205	0.1999443
9	-0.5731432	-0.5722948	0.2000067	0.1996058
10	-0.1826541	-0.1809406	0.3884714	0.3834786
11	-0.1816609	-0.1806396	0.385567	0.3826104
12	-0.1813924	-0.1805266	0.384787	0.3822834
13	-0.1813217	-0.1797458	0.3845811	0.380041
14	-0.1805638	-0.1786962	0.3823858	0.3770507
15	-0.1795253	-0.1779834	0.3794034	0.3750324
16	-0.1777562	-0.1752774	0.3743948	0.367493
17	-0.1748858	-0.1712726	0.3664171	0.3565746
18	0.0816698	0.0817701	-0.6430119	-0.6438672
19	0.0823615	0.0824838	0.3312566	0.3317651
20	0.082725	0.0828483	0.3326033	0.3331144

21	-0.0858021	-0.0845963	-0.3422432	-0.3374274
22	0.0341	0.0341565	0.1371122	0.1372969
23	0.0340942	0.034207	0.1370854	0.1374531
24	0.0341466	0.0342249	0.1372493	0.1375032
25	0.034165	0.0342099	0.1373014	0.137439
26	0.0341335	0.0343709	0.1371817	0.1378894
27	0.0343265	0.0344521	0.1377446	0.1380896
28	0.0347838	0.0348097	0.1390636	0.1389709
29	0.034793	0.0347941	0.1389384	0.1389003
30	0.0347807	0.0347815	0.1388752	0.1388496
31	0.0347679	0.034769	0.1388242	0.1387779
32	0.0347534	0.0347543	0.1387509	0.1387099
33	0.0347425	0.0347426	0.1386907	0.1386496
34	-0.0130928	-0.0130944	-0.0524737	-0.0524909
35	-0.0131015	-0.0131027	-0.0525133	-0.0525249
36	-0.0131097	-0.0131115	-0.0525472	-0.0525637
37	-0.0131185	-0.0131201	-0.0525862	-0.0526011
38	-0.0131186	-0.0131214	-0.0525959	-0.0526224
39	-0.0131292	-0.0131657	-0.0526473	-0.0527958
40	0.0133375	0.0133032	0.0533192	0.0531839
41	0.0132986	0.0132574	0.0531719	0.0530097
42	0.0132519	0.0132043	0.0529949	0.0528072
43	-2.10E-06	0	-2.60E-06	0
44	-3.60E-06	-3.00E-07	-5.00E-06	-4.00E-07
45	-0.2432801	-0.2434502	-0.1421522	-0.1422661
46	-0.2434042	-0.2436321	-0.1422202	-0.1423725
47	-0.2435866	-0.2440419	-0.1423271	-0.1426312
48	-0.2439984	-0.2443952	-0.1425869	-0.1428518
49	-0.2443534	-0.2446366	-0.1428086	-0.1429976
50	-0.1555752	-0.1558787	-0.0909933	-0.091232
51	-0.1558526	-0.1561817	-0.0911971	-0.0914604
52	-0.1561634	-0.1563194	-0.0914298	-0.0915562
53	-0.1563035	-0.1564979	-0.091527	-0.0916855
54	-0.089003	-0.0891479	-0.051961	-0.0520793
55	-0.089096	-0.0892577	-0.0520295	-0.0521629
56	-0.0892191	-0.0896091	-0.0521241	-0.0524673
57	-0.0895903	-0.0898024	-0.0524388	-0.0526552
58	-5.51E-05	-4.41E-05	-5.52E-05	-4.41E-05
59	-4.42E-05	-4.12E-05	-4.42E-05	-4.12E-05
60	-1.18E-05	-1.19E-05	-1.18E-05	-1.19E-05
61	-1.19E-05	-1.20E-05	-1.19E-05	-1.20E-05
62	-1.20E-05	-1.24E-05	-1.20E-05	-1.24E-05
63	-5.26E-05	-2.42E-05	-5.26E-05	-2.42E-05
64	-2.42E-05	0	-2.43E-05	0
65	4.00E-07	0	4.00E-07	0
66	-1.57E-05	-1.53E-05	-1.57E-05	-1.53E-05
67	-1.57E-05	-1.50E-05	-1.57E-05	-1.50E-05
68	-1.51E-05	-1.40E-05	-1.51E-05	-1.40E-05
69	-1.41E-05	-1.39E-05	-1.41E-05	-1.39E-05
70	-1.40E-05	-1.27E-05	-1.40E-05	-1.27E-05
71	-1.28E-05	-1.25E-05	-1.28E-05	-1.25E-05
72	-0.1046225	-0.1048078	-0.2322866	-0.232687
73	-0.104817	-0.1050688	-0.2327723	-0.233317
74	-0.1050758	-0.105362	-0.2333958	-0.2340159
75	-0.1053672	-0.1053962	-0.2340892	-0.2340697
76	-0.1054028	-0.1054353	-0.2341473	-0.2341225
77	-0.10545	-0.1055003	-0.2343218	-0.2343112
78	-0.1055085	-0.1056159	-0.2344906	-0.234463
79	-0.1056273	-0.1056906	-0.2345469	-0.2343491
80	-0.1057183	-0.1057233	-0.2344718	-0.2343993
81	-0.1057592	-0.105766	-0.2345556	-0.2344723

82	-0.1058029	-0.1058092	-0.2346297	-0.2345634
83	0.0348357	0.0348995	0.1400586	0.1402723
84	0.0346946	0.034806	0.1395725	0.1399494
85	0.0345262	0.0346975	0.1389858	0.1395712
86	0.0343934	0.0345461	0.138517	0.1390435
87	0.0342107	0.0344173	0.1378706	0.1385888
88	0.034052	0.0342122	0.1373034	0.1378649
89	0.0325291	0.0326675	0.1317956	0.1322981
90	0.0320519	0.032314	0.1300361	0.1309939
91	0.0319885	0.0326747	0.1297947	0.1322983
92	0.0486182	0.0485854	0.1946125	0.1944212
93	0.048563	0.0484757	0.1943565	0.1938658
94	0.0484568	0.0483616	0.1938146	0.1933036
95	0.0482727	0.0482438	0.193072	0.1929124
96	0.0347255	0.0347305	0.138504	0.1385765
97	-0.0832022	-0.0837131	-0.3318869	-0.3339625
98	-0.133713	-0.1337635	-0.0783606	-0.0784541
99	-0.1337583	-0.1337953	-0.0783932	-0.0784574
100	-0.1337947	-0.133828	-0.078441	-0.0785161
101	-0.1338332	-0.1338482	-0.0785026	-0.0785697
102	-0.1338769	-0.1338934	-0.0785303	-0.0786014
103	-0.1339057	-0.1341597	-0.0785919	-0.078746
104	-0.1341902	-0.1345922	-0.0786765	-0.0789191
105	-0.1345922	-0.1349129	-0.0789036	-0.079097
106	-0.1349121	-0.1351787	-0.0790813	-0.0792419
107	-0.1351772	-0.1354186	-0.0792278	-0.079373
108	-0.1354162	-0.1354901	-0.0793579	-0.0794461
109	-0.244185	-0.244441	-0.1442746	-0.1443528
110	-0.2441309	-0.2443109	-0.1442302	-0.1442856
111	-0.2439097	-0.2441475	-0.1441259	-0.1442012
112	-0.2436771	-0.2440352	-0.1440124	-0.1441287
113	0.0875413	0.0870581	0.0507469	0.0504093
114	-0.2445415	-0.2435566	-0.1442245	-0.1439372
115	-0.3797646	-0.3802532	-0.2231284	-0.2235153
116	-0.1058462	-0.10584	-0.2346279	-0.2346932
117	-1.24E-05	-1.25E-05	-1.24E-05	-1.25E-05
118	-0.0837277	-0.0845932	-0.3339697	-0.3374256
119	0.0347305	0.0347314	0.1385765	0.1386326
120	0.0131978	0.0131994	0.0527769	0.0527943
121	-2.08E-05	0	-2.90E-05	0
122	-4.77E-05	-1.10E-05	-0.0001022	-2.36E-05
123	-1.10E-05	0	-2.36E-05	0
124	-3.27E-05	0	-3.27E-05	0
125	-3.64E-05	0	-3.64E-05	0
126	-0.4856584	-0.4919896	-0.4866093	-0.4929478
127	-0.4856584	-0.4919896	-0.4866093	-0.4929478

Table 115: Voltage Magnitude Sensitivity Factors for orders in buses 10 and 20

Bus index	Sensitivity factors $K_{S,U}$ bus 10	Sensitivity factors $K_{S,U}$ bus 20
0	0	0
1	0.000224117	0.000224181
2	0.000443883	0.000324445
3	0.000585234	0.000388939
4	0.000710926	0.000446291
5	0.000867161	0.000518173
6	0.001036825	0.000596237
7	0.001170798	0.000657882
8	0.00152817	0.000822331
9	0.001733011	0.00091689
10	0.001969661	0.001026127
11	0.001750231	0.00110173
12	0.001657591	0.001301123
13	0.001606114	0.00141189
14	0.001564924	0.001500497
15	0.001494886	0.001651116
16	0.001418654	0.001815011
17	0.001360954	0.001939027
18	0.001276455	0.002120611
19	0.001165149	0.002359754
20	0.001026158	0.003373518
21	0.00087295	0.002775543
22	0.000725962	0.002201813
23	0.000616936	0.001771293
24	0.000229666	0.00024584
25	0.000240761	0.000289149
26	0.000248525	0.00031946
27	0.000260085	0.000364871
28	0.000325562	0.00062211
29	0.000367908	0.000788483
30	0.000421769	0.001000126
31	0.000433306	0.001045463
32	0.000440995	0.001075683
33	0.000454448	0.001128559
34	0.000465976	0.001173871
35	0.000476733	0.001216156
36	0.000228447	0.000241661
37	0.000231333	0.000253314
38	0.000235373	0.000269627
39	0.000238979	0.000284193
40	0.000245468	0.000310408
41	0.000257703	0.000359243
42	0.0002727	0.00041723
43	0.000290894	0.000487585
44	0.000312274	0.000570271
45	0.000238981	0.000284195
46	0.00025713	0.000358445
47	0.000262214	0.000246061
48	0.000313013	0.000275236
49	0.000414623	0.000333594
50	0.000503544	0.000384665
51	0.000567066	0.000421148
52	0.000663984	0.000476816
53	0.00077707	0.000541772
54	0.000833618	0.000574253
55	0.000906326	0.000616017
56	0.000602247	0.000441351
57	0.000643905	0.000465274
58	0.000768883	0.000537043
59	0.000870723	0.000595525
60	0.000222973	0.000223037

61	0.000222659	0.000222723
62	0.000222778	0.000222842
63	0.000222852	0.000222916
64	0.000223115	0.000223179
65	0.000220317	0.00022038
66	0.000218306	0.000218369
67	0.000222666	0.00022273
68	0.000224052	0.000224116
69	0.000223932	0.000223996
70	0.000223715	0.000223779
71	0.00022366	0.000223724
72	0.000223292	0.000223356
73	0.000223178	0.000223242
74	0.000361436	0.000537815
75	0.000544659	0.000956267
76	0.000749433	0.001423903
77	0.000775426	0.001482415
78	0.000805937	0.001551099
79	0.000845483	0.001640122
80	0.000933601	0.001838492
81	0.001046569	0.002092803
82	0.001074809	0.002156376
83	0.001108692	0.002232653
84	0.001136922	0.002296207
85	0.000227484	0.000237335
86	0.000232869	0.000258378
87	0.000240496	0.000288187
88	0.000246776	0.000312732
89	0.000254624	0.000343409
90	0.000260228	0.000365318
91	0.000268037	0.000396047
92	0.0002817	0.000449816
93	0.000316825	0.000588054
94	0.000346623	0.000705107
95	0.000417026	0.000981673
96	0.000481979	0.001236834
97	0.000503618	0.001321846
98	0.000490176	0.001269003
99	0.0005385	0.001461702
100	0.000261475	0.000245803
101	0.00028709	0.000260629
102	0.000321244	0.000280395
103	0.000357531	0.000301396
104	0.000397019	0.000324249
105	0.000595259	0.000437945
106	0.000887484	0.000605546
107	0.001117182	0.000737292
108	0.001305171	0.000845121
109	0.001472305	0.000940989
110	0.001524199	0.000971195
111	0.00144249	0.000924224
112	0.001386316	0.000891932
113	0.001314823	0.000850835
114	0.00121269	0.000792125
115	0.000257131	0.000358447
116	0.000367913	0.000788493
117	0.000367914	0.000788494
118	0.000224121	0.000224185
119	0.000222477	0.00022254



Table 116: Bus data results after active power trade (DSO - MP)

bus_id	vm_pu	va_degree	p_mw	q_mvar
0	1.025	0	28.35981196	0.123618633
1	1.031813644	0.60335933	-4.794828632	0.028898762
2	1.033642749	0.646956335	0.023275665	0.008095984
3	1.034825617	0.67524837	0.019159895	0.012311689
4	1.035883058	0.700478334	0.019159895	0.012311689
5	1.037201468	0.722745745	0.012640149	0.004638544
6	1.038637619	0.747048	0.012640149	0.004638544
7	1.039775207	0.766325493	0.019159895	0.012311689
8	1.042825199	0.817881277	-5.897433554	0.004454045
9	1.041720992	0.800946586	0.012640149	0.004638544
10	1.040450812	0.781688965	0.017073891	0.005571171
11	1.039577406	0.768559247	0.012640149	0.004638544
12	1.039214228	0.766249231	0.019159895	0.012311689
13	1.039017829	0.765000785	0.019159895	0.012311689
14	1.038865209	0.76399225	0.019159895	0.012311689
15	1.038613277	0.762284166	0.019159895	0.012311689
16	1.03834705	0.760479751	0.019159895	0.012311689
17	1.038151654	0.75914271	0.012640149	0.004638544
18	1.037870516	0.757377304	0.512640149	0.004638544
19	1.037794335	0.760151875	0.019159895	0.012311689
20	1.038746194	0.809999422	0.019159895	0.012311689
21	1.039839529	0.864879564	0.012640149	0.004638544
22	1.040912175	0.917797036	-6.502003417	0.005571171
23	1.033418147	0.669293867	0.017073891	0.005571171
24	1.031672667	0.597588295	0.012640149	0.004638544
25	1.031393626	0.586260221	0.012640149	0.004638544
26	1.031200182	0.578498353	0.012640149	0.004638544
27	1.030903188	0.570043768	0.017073891	0.005571171
28	1.029241017	0.524573841	0.009700564	0.004454045
29	1.028166385	0.497306308	0.009700564	0.004454045
30	1.026771451	0.470648049	0.017073891	0.005571171
31	1.026476564	0.465303876	0.012640149	0.004638544
32	1.026282599	0.461804657	0.012640149	0.004638544
33	1.025947687	0.455805342	0.017073891	0.005571171
34	1.025665907	0.450798989	0.009700564	0.004454045
35	1.025405597	0.446220563	0.009700564	0.004454045
36	1.032330615	0.612543105	0.009700564	0.004454045
37	1.032677236	0.618717615	0.009700564	0.004454045
38	1.033165292	0.627430672	0.009700564	0.004454045
39	1.033603492	0.635280317	0.009700564	0.004454045
40	1.034401559	0.649852302	0.012640149	0.004638544
41	1.035825174	0.702429657	0.017073891	0.005571171
42	1.034509021	0.662733867	0.012640149	0.004638544
43	1.032929707	0.614685595	0.017073891	0.005571171
44	1.031101113	0.558474714	0.009700564	0.004454045
45	1.033597899	0.635168448	0.012640149	0.004638544
46	1.038181493	0.781803786	-2.973136474	0.004454045
47	1.032100189	0.608293195	0.012640149	0.004638544
48	1.032484985	0.614910025	0.012640149	0.004638544
49	1.03325966	0.628289754	0.012640149	0.004638544
50	1.03394174	0.640161111	0.012640149	0.004638544
51	1.034432111	0.64873168	0.012640149	0.004638544
52	1.035138156	0.661952987	0.009700564	0.004454045
53	1.035966496	0.677979036	0.009700564	0.004454045
54	1.036383323	0.686228369	0.009700564	0.004454045
55	1.03692311	0.697055893	0.012640149	0.004638544
56	1.034734151	0.653706523	0.017073891	0.005571171
57	1.035099343	0.659863929	0.012640149	0.004638544
58	1.036205344	0.680079097	0.012640149	0.004638544
59	1.03711212	0.698501858	-1.232117425	0
60	1.037481217	0.70039491	0.012640149	0.004638544



61	1.039030209	0.726977627	0.017073891	0.005571171
62	1.038458466	0.716380899	0.009700564	0.004454045
63	1.03810342	0.709852163	0.005826366	0.007105112
64	1.036828756	0.686811901	0.005826366	0.007105112
65	1.050553648	1.132428584	0.005826366	0.007105112
66	1.060358934	1.468443316	-6.380064523	0.004454045
67	1.038999983	0.727750206	0.011978659	0.018976499
68	1.03214848	0.608634587	0.019159895	0.012311689
69	1.03276095	0.618182949	0.012640149	0.004638544
70	1.033857822	0.635845008	0.017073891	0.005571171
71	1.034135254	0.640400379	0.017073891	0.005571171
72	1.035956875	0.671387639	0.005826366	0.007105112
73	1.036518057	0.681288191	0.009700564	0.004454045
74	1.032625101	0.631662586	0.009700564	0.004454045
75	1.033727545	0.669613341	0.009700564	0.004454045
76	1.034981233	0.712240659	0.009700564	0.004454045
77	1.035143723	0.714820086	0.012640149	0.004638544
78	1.035337974	0.717935371	0.019159895	0.012311689
79	1.035597447	0.72199951	0.019159895	0.012311689
80	1.036191169	0.731412039	0.009700564	0.004454045
81	1.036956916	0.744718632	0.009700564	0.004454045
82	1.03715003	0.748255825	0.017073891	0.005571171
83	1.037387099	0.752615103	0.017073891	0.005571171
84	1.037589099	0.756343309	0.012640149	0.004638544
85	1.031762591	0.601216081	0.023275665	0.008095984
86	1.031684479	0.597858777	0.019159895	0.012311689
87	1.031578152	0.59316683	0.019159895	0.012311689
88	1.031494108	0.589361617	0.019159895	0.012311689
89	1.031393435	0.584680399	0.019159895	0.012311689
90	1.031324691	0.581386579	0.035121381	0.054983202
91	1.031233721	0.57737845	0.019159895	0.012311689
92	1.031082336	0.57037051	0.012640149	0.004638544
93	1.030702112	0.553146465	0.019159895	0.012311689
94	1.029747933	0.533338414	0.012640149	0.004638544
95	1.027502916	0.48813145	0.012640149	0.004638544
96	1.025437127	0.448440658	0.025528254	0.025901439
97	1.024760417	0.435218228	10	0.004638544
98	1.025083497	0.440628329	0	0
99	1.028036642	0.487889901	-1.90095824	0.005571171
100	1.031981898	0.605608908	0.019159895	0.012311689
101	1.03210105	0.607194447	0.012640149	0.004638544
102	1.032262635	0.609426266	0.012640149	0.004638544
103	1.032437044	0.611943219	0.019159895	0.012311689
104	1.032632459	0.614775251	0.012640149	0.004638544
105	1.033627285	0.639434634	0.031442224	0.020461308
106	1.035180811	0.675766766	0.009700564	0.004454045
107	1.036419858	0.704517474	0.009700564	0.004454045
108	1.037448888	0.728196166	0.012640149	0.004638544
109	1.038380747	0.749480282	0.017073891	0.005571171
110	1.03867604	0.751529498	0.012640149	0.004638544
111	1.038434167	0.743942787	0.009700564	0.004454045
112	1.038269992	0.738794646	0.005826366	0.007105112
113	1.038062852	0.73225769	0.017073891	0.005571171
114	1.037773845	0.723109427	0.017073891	0.005571171
115	1.038187287	0.781455444	0	0
116	1.028180549	0.496446527	0	0
117	1.028181348	0.496397993	0	0
118	1.031832566	0.602214769	0	0
119	1.039590044	0.99764492	-11.33217112	0

Table 117: Line data after active power trade (DSO – MO)

line_id	from_bus	to_bus	s_from_mva	s_to_mva	max_s_mva
0	1	2	3.455297856	3.461558646	6.54715205
1	2	3	3.484768481	3.488867121	6.54715205
2	3	4	3.507923967	3.511601407	6.54715205
3	4	5	3.530666674	3.535222739	5.71576766
4	5	6	3.547828415	3.552817711	5.71576766
5	6	7	3.565418676	3.569390347	5.71576766
6	7	8	3.588453936	3.599155648	5.71576766
7	8	9	2.298754765	2.29652508	5.71576766
8	9	10	2.283799291	2.281293954	5.71576766
9	10	11	2.264099507	2.262414548	5.71576766
10	11	12	0.729850121	0.731612402	5.71576766
11	12	13	0.710588643	0.711575199	5.71576766
12	13	14	0.690581896	0.69135412	5.71576766
13	14	15	0.670409967	0.671705635	5.71576766
14	15	16	0.650765949	0.652185902	5.71576766
15	16	17	0.6312404	0.632313875	5.71576766
16	17	18	0.619071427	0.620753523	5.71576766
17	18	19	0.146537378	0.157160636	5.71576766
18	19	20	0.712999851	0.713932135	5.45596004
19	20	21	0.730433926	0.731478392	5.45596004
20	21	22	0.743118174	0.744137596	5.45596004
21	22	23	5.770050121	5.728530599	5.45596004
22	1	24	1.034908905	1.033272891	7.35255568
23	24	25	1.021773711	1.018571049	7.35255568
24	25	26	1.007017738	1.004841157	7.35255568
25	26	27	0.993263562	0.991585805	5.71576766
26	27	28	0.975823623	0.967077779	5.71576766
27	28	29	0.958145805	0.953327508	5.71576766
28	29	30	0.937983152	0.935280028	5.71576766
29	30	31	0.918351947	0.917904113	5.71576766
30	31	32	0.905374085	0.905087397	5.71576766
31	32	33	0.892557119	0.892082488	5.71576766
32	33	34	0.87511923	0.874740361	5.71576766
33	34	35	0.865115822	0.864787997	5.71576766
34	1	36	1.61540249	1.616365292	5.71576766
35	36	37	1.625970428	1.626623418	5.71576766
36	37	38	1.636227819	1.637156521	5.71576766
37	38	39	1.646754601	1.64759908	5.71576766
38	39	40	1.669973491	1.671592927	5.71576766
39	40	41	1.684085588	1.686425463	5.45596004
40	41	42	1.265954513	1.264400196	5.45596004
41	42	43	1.251508053	1.249659824	5.45596004
42	43	44	1.232302029	1.230188938	5.45596004
43	39	45	0.014024127	0.013464377	5.71576766
44	41	46	2.966634169	2.973374199	5.45596004
45	1	47	1.785759461	1.786297823	5.71576766
46	47	48	1.798887061	1.799612923	5.71576766
47	48	49	1.812201883	1.813686413	5.71576766
48	49	50	1.826262229	1.827598503	5.71576766
49	50	51	1.840164485	1.841139385	5.71576766
50	51	52	1.11169368	1.113012896	5.71576766
51	52	53	1.122522106	1.124259133	5.71576766
52	53	54	1.133712976	1.134654496	5.71576766
53	54	55	1.144091577	1.145363312	5.71576766
54	51	56	0.742309129	0.742520905	5.71576766
55	56	57	0.759582331	0.759919887	5.71576766
56	57	58	0.77251097	0.774356755	5.71576766
57	58	59	0.786758268	0.789215136	5.71576766
58	1	60	4.815067632	4.841805384	5.71576766
59	60	61	4.854389734	4.861729497	5.71576766
60	61	62	1.355948876	1.354846676	5.71576766

61	62	63	1.345296565	1.344630379	5.71576766
62	63	64	1.339037531	1.336775781	5.71576766
63	61	65	6.245996255	6.315286402	5.45596004
64	65	66	6.321063621	6.380066079	5.45596004
65	61	67	0.021469681	0.02244094	5.45596004
66	1	68	1.243117703	1.24343786	5.71576766
67	68	69	1.262785038	1.263354245	5.71576766
68	69	70	1.276053799	1.277266982	5.71576766
69	70	71	1.294348071	1.294687679	5.71576766
70	71	72	1.311771095	1.314366614	5.71576766
71	72	73	1.320062637	1.320975401	5.71576766
72	1	74	0.627138177	0.627633034	5.45596004
73	74	75	0.637339898	0.63801414	5.45596004
74	75	76	0.647743911	0.648513972	5.45596004
75	76	77	0.658264879	0.65830756	5.71576766
76	77	78	0.670990219	0.671063992	5.71576766
77	78	79	0.690362656	0.690412551	5.71576766
78	79	80	0.709766023	0.70996417	5.71576766
79	80	81	0.719662854	0.720579932	5.71576766
80	81	82	0.73014524	0.730477231	5.71576766
81	82	83	0.747371759	0.747787381	5.71576766
82	83	84	0.764669364	0.765029881	5.71576766
83	1	85	0.630322371	0.629339578	7.35255568
84	85	86	0.608319511	0.606669394	7.35255568
85	86	87	0.59076558	0.588302837	7.35255568
86	87	88	0.572572952	0.570443988	7.35255568
87	88	89	0.554953994	0.552161463	7.35255568
88	89	90	0.53686629	0.534765414	7.35255568
89	90	91	0.519028348	0.51709467	5.71576766
90	91	92	0.504140337	0.500565451	5.71576766
91	92	93	0.490786809	0.481837233	5.71576766
92	93	94	1.652104953	1.649633621	5.71576766
93	94	95	1.637322973	1.631874365	5.71576766
94	95	96	1.619478075	1.614958106	5.71576766
95	96	97	1.590521476	1.58900337	5.71576766
96	97	98	0.854498068	0.85478019	5.71576766
97	97	99	7.558352147	7.582424202	5.71576766
98	1	100	0.601610945	0.600069409	6.54715205
99	100	101	0.620964056	0.619903956	6.54715205
100	101	102	0.633122655	0.631791062	6.54715205
101	102	103	0.644982792	0.643673407	6.54715205
102	103	104	0.66440581	0.66299888	6.54715205
103	104	105	0.676156399	0.676639688	5.45596004
104	105	106	0.71078543	0.711568487	5.45596004
105	106	107	0.721857978	0.72249407	5.45596004
106	107	108	0.732790605	0.733328346	5.45596004
107	108	109	0.746561442	0.747060647	5.45596004
108	109	110	0.76482711	0.763568796	5.71576766
109	110	111	0.782431432	0.780391716	5.71576766
110	111	112	0.771939139	0.770541644	5.71576766
111	112	113	0.766480258	0.764685928	5.71576766
112	113	114	0.749345336	0.746781016	5.71576766
113	59	55	0.449933823	0.451328996	5.71576766
114	55	114	0.724209456	0.731433418	5.71576766
115	110	11	1.528994629	1.530906641	5.71576766
116	19	84	0.777882407	0.77750601	5.71576766
117	64	73	1.331099797	1.330578866	5.71576766
118	99	23	5.681637501	5.711367439	5.45596004
119	98	35	0.85478019	0.855150909	5.71576766
120	93	44	1.22020565	1.220268678	5.71576766
121	46	115	0.042062495	2.36E-13	10.9379008
122	29	116	0.066617985	0.015399525	10.9379008
123	116	117	0.015399525	1.32E-12	10.9379008
124	1	118	0.075312584	1.66E-13	10.9379008

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<b>125</b>	1	119	11.24748122	11.33217112	10.9379008
<b>126</b>	0	1	14.18004069	14.27428752	12.2109582
<b>127</b>	0	1	14.18004069	14.27428752	12.2109582