A novel smart grid architecture that facilitates high RES penetration through innovative markets towards efficient interaction between advanced electricity grid management and intelligent stakeholders

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OPF objectives and challenges towards smart grids with high RES penetration

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Glossary of Acronyms

Acronym	Definition
AC	Alternative Current
ACER	Agency for the Cooperation of Energy Regulators
AON	All or Nothing
ATP	Automated Trading Platform
BSP	Balance Service Providers
CAPEX	Capital Expenditure
CEER	Council of European Energy Regulators
CEW	Central Western European
DLMPs	Distribution Locational Marginal Prices
DA	Day Ahead
DAD	Day Ahead Dispatch
DMS	Distribution Management System
DN	Distribution Network
DNDA	Distribution Network Dispatch Algorithm
DNPA	Distribution Network Payment Algorithm
DSIC	Dominant-Strategy-Incentive-Compatible
DSO	Distribution System Operator
Dx.x	Deliverable
EDSO	European Distribution System Operators Association
EMS	Energy Management System
ENTSO-e	European Network of Transmission System Operators for Electricity
EV	Electric Vehicles
FERC	US Federal Energy Regulatory Commission
FMCT	Flexibility Market Clearing Toolkit
FMO	Flexibility Market Operator
FOK	Fill or Kill
FSP	Flexibility Service Provider
FST	Flex Suppliers' Toolkit
GUI	Graphical User Interface
HVDC	High Voltage Direct Current
I-DLFM	Interactive Distribution Level Flexibility Market
ICT	Information and Communication Technology
IOC	Immediate or Cancel
KPI	Key Performance Indicators
KKT	Karush-Kuhn-Tucker optimality conditions
LMPs	Locational Marginal Prices
MC	Market Clearing
MILP	Mixed Integer Linear Program
MO	Market Operator
MPEC	Mathematical Programs with Equilibrium Constraints
OPEX	Operational Expenditure
OPF	Optimal Power Flow
P-DLFM	Proactive Distribution Level Flexibility Market
PDISCO	Profit Maximizing Distribution Company
PTDF	Power Transfer Distribution Factor

PV	Photovoltaic
QC	Quadratically Constrained Program
R-DLFM	Reactive Distribution Level Flexibility Market
R&I	Research and Innovation
RES	Renewable Energy Sources
S/W	Software
SCADA	Supervisory Control and Data Acquisition
SCUC	Security-Constrained Unit Commitment
SDP	Semi-Definite Programming
SESP	Smart Energy Service Provider
SOCP	Second Order Cone Program
SOB	Shared Order Book
SOBD	Shared Order Book for bids down
SOBU	Shared Order Book for bids up
TN	Transmission Network
TSO	Transmision Network Operator
VCG	Vickrey-Clarke-Groves
WP	Work Package

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Document History

Document History Summary

Revision Date	File version	Summary of Changes
15/10/2020	v0.1	Final ToC circulated within the entire consortium.
30/10/2020	v0.6	Draft version edited by deliverable editor was circulated to all partners.
11/11/2020	v0.7	HOPS reviewed the draft version and provided comments to the deliverable editor.
19/11/2020	v0.8	AIT gathers all review comments from members and circulates a pre-final version to all partners.
02/12/2020	v0.9	DTU reviews the pre-final version of the deliverable and provides comments for changes to the Coordinator.
03/12/2020	v1.0	Coordinator addresses minor comments from all partners and submits the deliverable in ECAS portal.

Executive Summary

FLEXGRID's goal is to propose advanced optimal power flow (OPF) algorithms that can boost the capabilities of current solutions used for market clearing in Europe. There are three main issues we will be dealing with: i) tractable formulations for nodal pricing using convex approximations of AC power flow equations, ii) scalable integration of all security constraints in a market context; and iii) guarantees of optimality, while considering forecast uncertainty and control of controllable devices (topology switching, tap-changing transformers, HVDC, etc.).

This deliverable elaborates on deliverable D2.2 [1] and contains the detailed architecture design of all WP5 subsystems and their interactions as well as the respective technical specifications. It also includes a survey of all state-of-the-art research approaches and sets the research objectives and challenges for work package 5 (WP5) research.

This deliverable is structured in 6 different chapters. After the introduction in chapter 1, chapter 2 presents the current state-of-the art in relation to Distribution Level Flexibility Markets and coordination of flexibility service provisioning in order to select suitable flexibility market architectures. Three different market architectures are selected highlighting their advantages and disadvantages and will be further investigated and developed in the project.

- ***Reactive distribution level flexibility market (R-DLFM)***.
- ***Proactive distribution level flexibility market (P-DLFM)***.
- ***Interactive distribution level flexibility market (I-DLFM).***

In order to put the different architectures into practice, several computations are required during the market operation. The different algorithms to be developed and used are presented in Chapter 3. Moreover, the implementation of the architectures will pose opportunities and challenges which are presented in Chapter 4. The implementation of the architectures will be done using the Flexibility Market Clearing Toolkit (FMCT). The initial architecture for the FMCT is presented in Chapter 5. Chapter 6 concludes the work and gives an overview of the future development for WP5.

A part of the flexibility market clearing could be auction based such as day-ahead flexibility market, using the AC-OPF. However, moving closer to real-time, it could become more relevant to have a continuous market. Instead of a market clearing considering all bids and clearing once and for all, this model would be continuously matching bids. This is often the case for intraday markets. The difference and novelty here are that we take the distribution network constraints into account and make sure that two bids would only match if their activation would not deteriorate the situation of the network, in terms of line congestions and voltage deviations.

In this deliverable, the operation of the Flexibility Market Clearing Toolkit is described. It shows how the research algorithms will be integrated in the toolkit. It also describes in a high-level of abstraction the structure of the graphical user interface (GUI) associated with the FMCT.

Chapter 1. Introduction

With respect to the exploitation of OPF towards Market Clearing (MC) in parts of the US and the Central Western European (CWE) region, they are solving a DC Optimal Power Flow. In that, all power flow equations are simplified (e.g., no thermal losses, no reactive power) and linearized. In the rest of Europe and specific parts of the US they are still solving an Economic Dispatch problem (also called Power Exchange or Power Pool). This is still an optimization procedure, but only the active power generation and demand is taken into account, while assuming that the underlying network is a copper-plate (thus neglecting all power flow constraints). Lately, in some parts of the US, e.g. PJM or CAISO, they clear the market by an approximated AC-OPF, where they try to consider the full non-linear behavior of the power flow equations through an iterative procedure. The US Federal Energy Regulatory Commission (FERC) has stated that the "ultimate goal of ISO software is the security-constrained, AC Optimal Power Flow with unit commitment and corrective control".

FLEXGRID's goal is to propose advanced OPF algorithms that can boost the capabilities of current solutions used for MC in Europe. There are three main issues we will be dealing with: i) tractable formulations for nodal pricing using the full AC power flow equations, ii) scalable integration of all security constraints in a market context; and iii) guarantees of optimality while considering forecast uncertainty and control of controllable devices (topology switching, tap-changing transformers, HVDC, etc.). We group this in two main tasks (A-B):

A) Europe is operated under a zonal pricing scheme, but there are currently discussions both at a regional and at an ENTSO-e level for the possibility of moving to nodal pricing. Parts of the US are already operating under a nodal pricing regime, taking under consideration the full AC Power Flow equations. FLEXGRID will demonstrate solutions of how such a market setup can be (i) feasible, (ii) scalable,(iii) optimal in the European context and (iv) interact with WP3 and WP4 algorithms towards holistic future smart grid architecture.

FLEXGRID will develop an AC-OPF market clearing algorithm that will consider forecast uncertainty (both because of fluctuating renewable energy resources (RES) and uncertain demand due to electrical vehicles (EVs) and prosumers at the distribution level) and corrective control actions. Solving such an optimization problem at a pan-European level is almost intractable. In our work, we will use an iterative procedure, where all non-linear equations will be linearized around the current operating point, and only the binding inequality constraints will be included in the optimization instance at each iteration. FLEXGRID plans to push the state-of-the-art a few steps forward. First, it will consider forecast uncertainty through robust optimization (chance-constraints). Second, it will include corrective control actions (e.g., topology switching) in the form of linear decision rules with integer variables. Third, using techniques based on convex relaxations, we will provide guarantees either that our solution corresponds to the true global optimal, or that is at a certain maximum distance from it.

B) The second task of our work in FLEXGRID is to rethink from scratch the operation of current electricity markets, eliminating costs that can exceed 1 billion Euros per year. Currently in Europe (CWE region), the system is divided into zones, and the market is cleared based on a DC-OPF algorithm. This procedure includes approximations and simplifications related to the most critical contingencies that can occur in each zone. Due to the inaccuracy of these approximations, redispatch measures are often required after each market clearing. In Germany alone, the cost of such redispatch measures exceeded 1 billion Euros in 2017. In this project we plan to propose and demonstrate innovative solutions to substantially reduce or eliminate such redispatch costs.

Building on FLEXGRID consortium's background knowledge, we propose a data-driven security constrained Optimal Power Flow. Through computationally efficient procedures, we propose the creation of a large database where millions of possible operating points for the power system will be assessed and stored. These operating points will be classified as safe or unsafe for a combination of several different security indices, commonly considered by system operators. Such indices are for example the N-1 security criterion, small-signal stability, voltage stability, transient stability. This is a task that is currently being performed on a daily basis by several regional security coordination centers, such as TSC, Coreso, and the Nordic RSCI. Subsequently, using classification methods based on decision trees, we can extract from that database –which will be daily updated –the safe operating region: this region corresponds to the feasible space of our optimal power flow algorithm used for market clearing. Through a straightforward procedure FLEXGRID can transform the decision tree into a set of conditional linear rules that can be encoded as a mixed integer linear program (MILP) in the market clearing.

We need to make two remarks concerning scalability at this point. First, the market clearing algorithm currently used in CWE/Europe, called Euphemia, already uses a MILP approach, as it has to account, e.g., for block offers from the generators. Besides that, MILP approximations have reached a mature development stage, and are considered very computationally efficient. As a result, we expect that our MILP-based solution will be both fast and very scalable. Second, generating a large dataset of possible safe and unsafe operating points is definitely a time-consuming task. However, this is a task that is being daily performed by all system operators in Europe, so this database can be daily populated with new operating points and their classification.

1.1. Scope of the Document

This deliverable elaborates on D2.2 and contains the detailed architecture design of all WP5 subsystems and their interactions as well as the respective technical specifications. It also includes a survey of all state-of-the-art research approaches and sets the research objectives and challenges for WP5 research.

1.2. Structure of the Document

This deliverable is structured in 6 different chapters. After having the introduction in chapter 1, chapter 2 presents the current state of the art in relation to Distribution Level Flexibility Markets and coordination of flexibility services' provisioning in order to select the best flex market architecture. Three different market architectures are selected highlighting their advantages and disadvantages and will be further investigated and developed in the project.

- ***Reactive distribution level flexibility market (R-DLFM)***. FMO may run the day-ahead energy market at the distribution network (DN) level right after the respective transmission network (TN) level market clearing results are available. The main advantage of the proposed R-DLFM model is that it is compatible with the existing energy market architecture and respective regulatory framework. This is mainly due to the fact that all existing TN-level market clearing processes remain unaffected and perform in a business-as-usual manner. R-DLFM model may also have several disadvantages that need to be taken into consideration. Firstly, all markets are operating in a sequential manner (i.e. each market takes as input the results of the previous market without being able to change anything in the dispatch schedule that has been decided), so social welfare results are expected to be sub-optimal. Furthermore, no actual TSO-DSO and MO-FMO coordination may take place because the energy resources at TN and DN levels are not pooled together.
- ***Proactive distribution level flexibility market (R-DLFM)***. Here the sequence of markets starts with market #3 operated by the FMO, which is a day-ahead energy market at the DN level (cf. market sequence: 3 → 4 → 1 → 2 → 6 → 5). Right afterwards, the day-ahead reserve market at DN-level is operated by the DSO. These two markets should publish their results before the gate closure of the traditional day-ahead wholesale energy market (TN-level). The main architectural assumption is that the FMO and the DSO clear their day-ahead energy/reserve markets before MO/TSO. The main advantage of P-DLFM model is that DN constraints are taken into consideration in a proactive way. A main drawback is that the TSO may experience high re-dispatch costs, because it can only use the most expensive reserve capacity from the DN-level resources. Another major drawback is that social

welfare results may be much worse than optimal, because the proposed dynamic pre-qualification process is based on stochastic RES, consumption modeling and confidence intervals and thus forecast inaccuracies should be taken into consideration.

- ***Interactive distribution level flexibility market (I-DLFM).*** A main advantage of I-DLFM model is that it can maximize the social welfare and thus provide optimal network operation and market efficiency outcomes. Moreover, the proposed model adopts a decentralized scheme (via decomposition algorithms), which can achieve results similar or very close to the ideal case of centralized optimization market model. Moreover, it can also be a practical and scalable solution as the complex MO-FMO and/or TSO-DSO coordination problem is decomposed in sub-problems, which can be solved more easily and within the timing constraints set by the regulatory framework and today's real business. One of the main drawbacks of the proposed I-DLFM model is that it is incompatible with the existing regulatory framework and assumes several advancements regarding the ICT infrastructure needed to support the proposed advanced coordination schemes.

In order to put into practice, the different architectures, several computations are required during the market operation. The different algorithms to be developed and used are presented in Chapter 3.

Also, the implementation of the architectures will pose opportunities and challenges, which are presented in Chapter 4.

The implementation of the architectures will be done using the Flexibility Market Clearing Toolkit. The initial architecture for the FMCT is presented in Chapter 5. Chapter 6 concludes the work and gives and overview of the future development for WP5.

Chapter 2. Current state-of-the-art on Distribution Level Flexibility Markets and coordination of flexibility services' provisioning

2.1. Research motivation for Distribution Level Flexibility Markets (DLFM)

Low and medium voltage network (or else distribution network) are emerging as an increasingly important component of power system operations. Moreover, several experts consider the so called three "D"s, namely "Decarbonization", "Decentralization" and "Digitalization" as the main drivers for change in the area of smart grids [2]. "Decarbonization" will mainly be achieved via the installation of new low-carbon and renewable energy generators and the gradual phase out of conventional energy generators, which produce high levels of carbon emissions. "Decentralization" means that these low-carbon technologies are expected to be installed in a distributed fashion not only by large companies, but also from numerous and small RES investors at the distribution network. "Digitilization" introduces advanced ICT infrastructures that enable efficient monitoring and control of all the available network and customer-related assets. Digitilization also offers new ways to exchange goods and services by new business models based on the paradigm of 'digital business' by peer-to-peer and transparent transactions via the use of online trading platforms and marketplaces.

Nowadays, the approximate modelling of the distribution grid as a "copper plate" in the wholesale electricity markets represents the existing situation in Europe. However, with the increased shares of distributed energy resources (DERs), and especially renewable electricity, as well as new sources/patterns of demand, such as electric vehicles and more flexible industrial demand, distribution grids are expected to experience increasingly more local congestion and voltage-related problems in the future. Hence, the occurrence of binding constraints needs to be dealt with at the distribution network (DN) level. This in turn means a much more active role of the DSO, while a longer-term vision could be the introduction of locational marginal price signals in distribution grids (i.e. d-LMPs) [3].

While today the TSO is the main actor procuring flexibility from flexible units to ensure system stability, in the future, DSOs are expected to procure flexibility to solve issues in their network, too. As DSOs might use the same sources of flexibility with the TSO, this flexibility has to be used in a coordinated way. Different market-based and non-market based approaches for the coordination of flexibility used by the TSO and the DSOs are possible [4]. When using flexibility to cope with one grid operation challenge, this might have an impact on other grid operation aspects. For example, the activation of DN-level flexibility for system balancing by the TSO might cause congestion on the distribution grid. Another example could be that the activation of DN-level flexibility by a DSO to solve a local congestion problem may cause higher balancing costs at the transmission network level.

Another problem is that today's TSOs/Market Operators (MOs) run the risk of issuing suboptimal economic dispatch decisions. TSOs also run the risk of issuing dispatch orders to DER providers or aggregators that are infeasible due to DN constraints or that conflict with dispatch instructions sent by the DSO to consumers, DER providers or aggregators. Conflicting DSO and TSO activation orders result from the so called "tier by-passing", wherein an actor in the DN makes a physical commitment without incorporating distribution-level network externalities. DSOs, on the other hand, have visibility into distribution system operations but, to date, have little to no experience creating economically optimal system operations. In addition, DSOs have little to no visibility into transmission system conditions, and, in many cases, into the investment or operation decisions of DER owners. As a result, DSOs (and, equally often, TSOs) lack knowledge of the potential for DERs or demand to take action to support system operations. This has led to a variety of discussions over how to coordinate DSO operations with demand, DER providers, aggregators, and TSOs [5].

According to the above-mentioned commercial trends and research challenges, there is a need for the DSO to ensure that local DN constraints are integrated into the existing market clearing processes and become an active buyer of flexibility in a similar way that the TSO does. Moreover, there is a need for a new market actor called Flexibility Market Operator (FMO), who will facilitate an online marketplace for trading the energy produced and consumed locally, while ensuring the security constraints of the DN and act as a mediator for participation of distributed local resources into the wholesale markets operated by the MO and the ancillary services' markets operated by the TSO.

FLEXGRID introduces the novel concept of "Distribution Level Flexibility Market - DLFM" which is operated in an efficient manner by an independent company (e.g. NODES) in collaboration with the DSO. As shown in the figure below, FLEXGRID considers the "market" domain, in which MO and FMO collaborate to better coordinate the operation of wholesale and local energy markets, while in the "network" domain, there is a TSO-DSO collaboration in order to achieve better network operation outcomes. The ultimate goal of FLEXGRID is to propose optimal trade-offs between optimal market and network operations (or else economic efficiency vs. reliability under future high RES penetration scenarios). The DLFM operated by the FMO is the central architectural proposition of FLEXGRID project. Within WP5 work, we will design, develop and evaluate (via system-level simulations) various energy market architectures investigating the impact that the proposed DLFM could have in existing markets' and network' operations (see more in section 2.4 below).

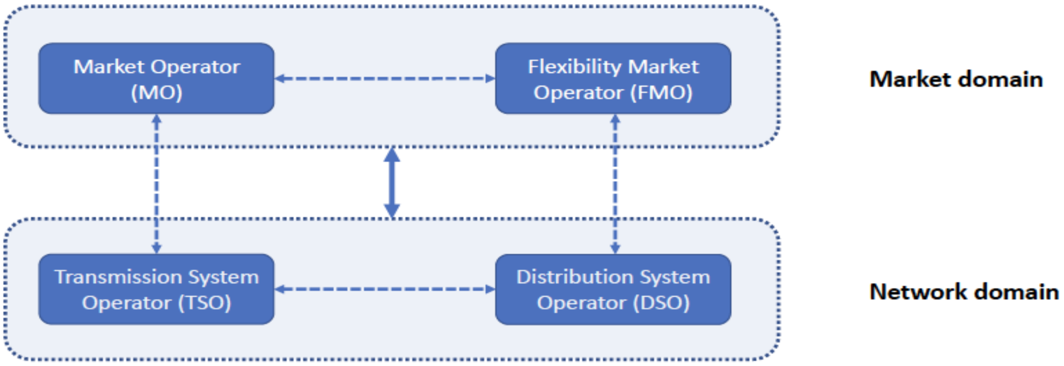


Figure 1: MO-FMO collaboration for better market efficiency outcomes and TSO-DSO collaboration for better network operation outcomes

2.2. Recommendations from EU bodies

At the EU level, TSOs have been the only ones procuring flexibility services connected to the distribution network, while the role of DSOs is currently limited to validate that such flexibility can indeed be provided. The TSO dominant position (i.e. DSOs being only very weakly represented) has been the main trigger for the debates around TSO-DSO coordination within Europe. "Traffic lights" concept was an initial attempt to signal the DN state to the market [6]. In a second attempt to provide solutions, DSOs have started to actively manage congestion in their network. But, since the same flexibility resources could also be potentially used for congestion management and frequency control by the TSOs, conflicts might arise due to the misalignment of TSOs, DSOs, and market players' actions. Even though in many EU countries there are no rules in place that allow DSOs to activate flexibility services to redispatch the system at the distribution level, the Clean Energy Package [7] presents clear provisions that will enable DSOs to procure flexibility services via market-based solutions, and is expected to generate new schemes for TSO-DSO coordination [8].

In the tables below (Table 1-Table 3), the most important and relevant recommendations from EU bodies have been gathered. Based on this survey work, we also outline the FLEXGRID R&I contributions.

Table 1: Recommendations from CEER/ACER and related FLEXGRID R&I contributions

Recommendations from CEER/ACER [9]	FLEXGRID R&I contributions
It is pivotal to differentiate between the use of flexibility in the market and the use of flexibility in the network. CEER considers that the acknowledgement of the use of flexibility in the market and in the network are both important.	Advanced modelling of DERs in order to allow them to facilitate network and market flexibility. Model both energy and capacity products at DN level and develop market architectures in which both types of flexibility will be traded efficiently FMO facilitates small DERs' participation in existing wholesale markets
If alternatives to network expansion provide a less-expensive solution, they must be rewarded by appropriate incentives. Alternatives to network expansion must be non-discriminatory, transparent and compliant with unbundling rules	Study the optimal CAPEX vs. OPEX trade-off problem for the DSO through techno-economic analysis (invest on network reinforcement or procure flexibility through innovative market architectures that FLEXGRID develops)
A level playing field is pivotal to facilitate market participation in flexibility use at distribution level. CEER believes with regard to the establishment of standardised EU definitions that there is no 'one-size-fits-all' approach	System-level simulations and comparative studies for various DLFM models and energy market architectures Comparison of market-based solutions (DLFM) against other non-market-based solutions in which SOs adopt direct control policies
CEER considers that general principles should be tackled at the EU level (competition, efficiency, non-distortion), but that **enough margin must be left to adapt flexibility schemes to local situations**	Simulation of various case studies and contexts at DN level (e.g. various DN topologies, mix of locals RES/FlexAssets, liquidity levels, types of DN issues) and empirical evolvement of architecture according to them.
A real-time market approach would, in theory, give a DSO more flexibility when buying flexibility, and restrict it to only purchasing what it really needs. However, in practice, there will be few situations when close-to-real-time liquidity will be sufficient to make a market feasible, let alone efficient. In most cases, the lack of liquidity will make long-term contracting more advisable as it ensures the availability of flexibility, even if it brings the concomitant risk of over-contracting and liquidity being withdrawn from the market	Modelling various flexibility assets of both energy and capacity products in DLFM and development of energy market architectures according to these models. Simulation of various market architectures and comparison of the results Development of day ahead, intraday and real time markets in order to maximize liquidity and trading efficiency.
There are examples where **DSOs could provide flexibility to reduce the overall costs of the system,** e.g. transmission system issues being solved more efficiently; cost reductions to contribute to reductions in overall system costs; increased real-time liquidity. However, DSOs may only provide	Introduction of FMO as a new market actor acting as an intermediary between TN-level and DN-level markets and network Development of FLEXGRID Automated Trading Platform (ATP) where the DSO/TSO act as FlexBuyers procuring flexibility services from ESPs/ aggregators

flexibility as non-frequency ancillary services within the network without unduly distorting the market. **The DSO may not itself provide flexibility to the market**	API development for MO-FMO interaction API development for TSO-FMO interaction

Table 2: Recommendations from ENTSOE-EDSO and related FLEXGRID R&I contributions

Recommendations from ENTSOE-EDSO [10]	FLEXGRID R&I contributions
TSOs and DSOs should pursue **an integrated system approach** when developing new solutions and should avoid any isolated solution	Evaluate the efficiency of the interaction between the proposed DLFM and the TSO markets in various energy market architectures that FLEXGRID proposes.
The long-term view of system operators is that congestion should be solved through a **market-based allocation of flexibility services**, where technically feasible and cost-efficient **rather than compulsory limitation procedures**	Propose various DLFM models and quantify the improvement compared with existing compulsory limitation procedures Accurate network models that operate efficient DLFMs.
There are 2 ways of enabling more FSPs being qualified: a. **conditional grid pre-qualification**, where the pre-qualification is dependent on certain conditions being met b. **dynamic grid pre-qualification, where the pre-qualification can change over time**, however, the aim is to increase the pre-qualified capacity, when new information on the grid is available"	Case of static pre-qualification of DERs residing at the DN will be compared with the case of a Proactive DLFM model, in which the DLFM is cleared before the existing day-ahead wholesale energy market Modelling of RES uncertainties and robust OPF methods at DN level Novel AC-OPF algorithms for DLFM clearing DLFM architectures able to cope up with dynamic disturbances (e.g. inaccurate production and/or consumption forecasts)
The **different options for market models, coordination and platforms** give a European framework, which is recommended to be the basis for the Member States to discuss, and after taking into account their national specificities, agree on Member State level on implementation	Simulate and evaluate the performance of various DLFM architectures. Investigate various case studies/contexts Demonstrate respective results to facilitate policy making at both EU and MS-level
Irrespective of the options chosen, **SOs should always exchange all the relevant information from their grid and the relevant connected assets**, from structural data (potential flexibility services and their characteristics) to more dynamic data (forecast and activation of bids): this is needed to allow efficient flexibility procurement without creating issues on the grid	FLEXGRID assumes that (at least and not only) basic network/grid data is available for advanced market clearing processes and all market clearing results are made publicly available. FMO (and the FLEXGRID ATP) acts as an intermediary between the TSO and DSO by making each one's decisions transparent

Table 3: Recommendations from EU DSO associations and related FLEXGRID R&I contributions

Recommendations from EU-level DSOs [11]	FLEXGRID R&I contributions
DSOs strongly recommend that any activation of a distribution connected grid user by a TSO or a market party is only	The introduction of a DLFM enables the DSOs to interact with the TSOs and manage their network according to the transmission

allowed where control architectures ensure that the DSO oversees operations as part of its active system management responsibilities, and, among other things, has prior notification, assessment and a means of blocking any potentially damaging control signals	level markets' decisions concerning the distribution connected grid users. FLEXGRID provides advanced network and market clearing models (AC-OPF) and algorithms for the DN Accurate DN topology models are taken into consideration in all proposed optimal scheduling, planning and bidding algorithms FLEXGRID assumes that the DSO has an advanced Distribution Management System (DMS) in order to perform active network management actions.
Incentivise DSOs to use flexibility for congestion management, where it is cost-effective to do so. DSOs should be able to decide on the best solution to address specific challenges, **either through flexibility solutions or through network reinforcement**	Study the optimal CAPEX vs. OPEX trade-off problem for the DSO (i.e. years ahead study) Techno-economic analysis and business modelling for DSO (invest on network reinforcement or procure flexibility from DLFM)
Enable DSOs to choose the best and most cost-efficient technology to operate the distribution system. Legislation shall not limit a choice of technologies available to DSOs to carry out their legal obligations. Still, DSOs have to guarantee that the use of these technologies **do not lead to market disturbance**. **Whenever more efficient, a market-based solution is preferable.**	Propose various DLFM models and showcase how these can outperform existing solutions Derive the requirements that a DN should meet in order to apply for a DLFM solution to be cost-effective
Prevent the double use of flexibility resources when used for congestion management in distribution network. Flexibility providers shall have the possibility to simultaneously offer flexibility services for distribution congestion management, transmission congestion management and system balancing, **but flexibility should be only used once in the same timeframe. The regulatory framework should clearly avoid that FSPs profit from the creation of grid congestion and must also be adapted to detect and prevent this.**	The capacity trading in energy market architectures that FLEXGRID proposes do not allow easy manipulation. Advanced TSO-DSO coordination is enabled via the FLEXGRID ATP and interactive markets. Proposed DLFM architectures solve the flexibility double activation problem FLEXGRID proposes market power mitigation models for FSPs FLEXGRID proposes an advanced market clearing algorithm that incentivizes FSPs' truthful bidding

Last but not least, having strong liaisons with H2020 BRIDGE initiative[1], FLEXGRID consortium already has a good knowledge of and compatibility with current regulations, available/emerging standards, existing and emerging smart grid market architectures, market-related barriers and network-related constraints. As a matter of fact, the latest BRIDGE findings and recommendations are being used as input to FLEXGRID research activities. For more details, please see table 19 in [12].

[1] https://www.h2020-bridge.eu/

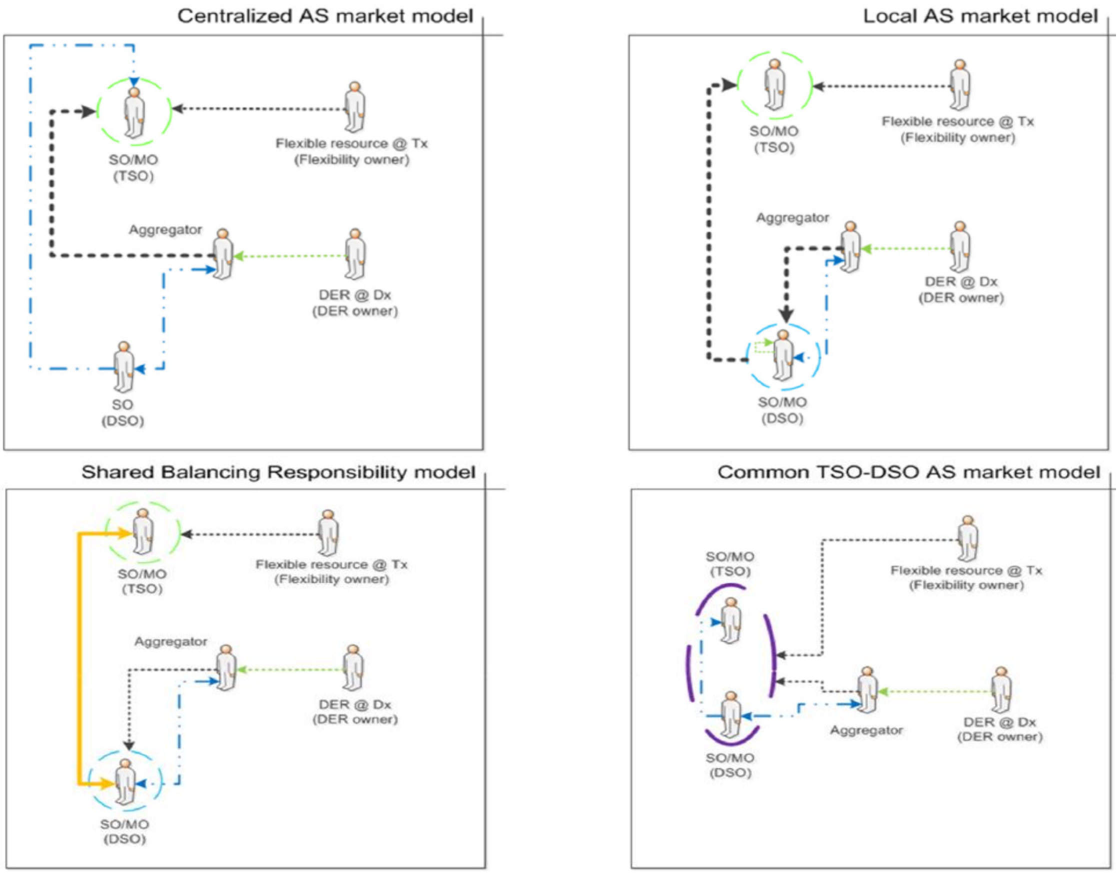
2.3. Categorization of TSO-DSO coordination schemes and related research work from the international literature

There are several recent survey papers in the international literature, which try to categorize various TSO-DSO coordination schemes that have been proposed by individual research groups and collaborative research projects such as [3] [5] [13] [14] [15].

Generally, a centralized market model implies a dominant TSO role, while DSO's role is limited. This type of models is closer to the one used today. The problem is that distribution network (DN) constraints are not taken into consideration in today's market clearing process and also that DERs cannot have access to the wholesale markets. TSO is the only FlexBuyer and contracts DER directly from the DN, while DSO can be involved in a rather static pre-qualification process that may take place before the TN-level market clearing and may lead to inefficient market clearing results (e.g. renewable energy spillage).

On the other hand, local market and shared balancing responsibility models can deal with the above-mentioned problems by enhancing the DSO's role. Hence, DSO is the only FlexBuyer at the DN level or else full priority for local flexibility activation is given to the DSO. To avoid imbalances incurred by DSO activations, communication between TSO and DSO should be organized to ensure that the DSO notifies the TSO for these flexibility activations. In this case, DSO needs to have advanced distribution management systems (DMS) in order to be able to efficiently monitor and control the DN. This implies high CAPEX on new ICT infrastructure, while an efficient and automated communication between TSO's energy management system (EMS) is also a pre-requisite.

Finally, in common TSO-DSO market models, both TSO and DSO are FlexBuyers. The decentralized market model variant assumes an iterative communication process between the TSO and DSO until the entire system converges to an optimal social welfare. The problem with this type of market models is that it is quite difficult to be adopted in reality and should be seen as a potential solution in the long term.



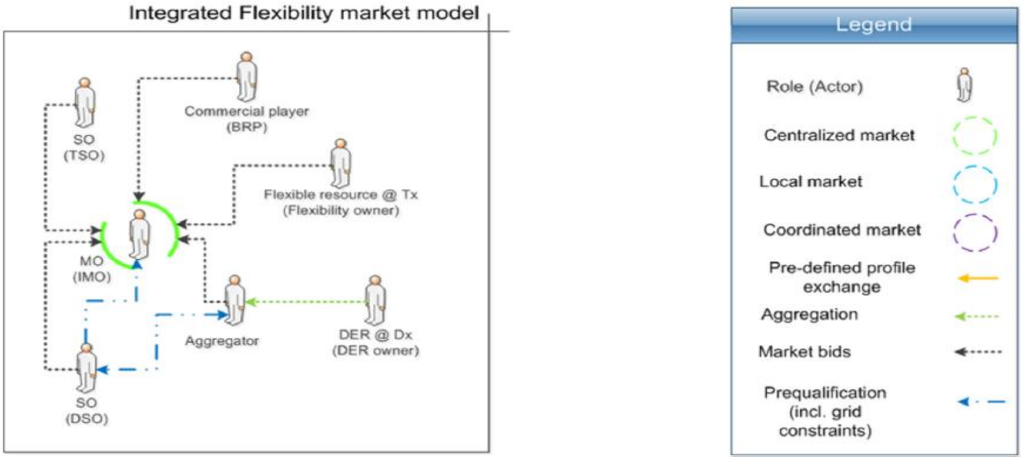


Figure 2: Comparison of various Ancillary Services (AS) market models (i.e. TSO-DSO coordination schemes) [13]

Figure 2 illustrates all proposed TSO-DSO coordination schemes so far. In the following subsections, we give an overview about relevant research work for each market model category.

Centralized Market Model (TSO is the only FlexBuyer)

This coordination scheme dispatches resources by ignoring the distribution network (DN) constraints (i.e. too complex to model). TSO clears a market for ancillary services at the transmission level, using resources from the transmission and distribution system, but without accounting for DN constraints. In order not to violate DN constraints, resources need to be pre-qualified, in the sense that DN-level resources are not offered in the TSO market if they may violate DN constraints [13]. The problem of this model is cured by the FLEXGRID Proactive DLFM. FLEXGRID Proactive DLFM (P-DLFM) model extends the existing "pre-qualification" idea to the wholesale energy market. But, what happens if an abrupt change occurs in the DN due to high RES penetration and uncertainty/volatility of RES? DSO constraints are not necessarily considered close to real-time, thus the potential of local flexibility that can be realized with this approach will be necessarily limited, as DSOs and TSOs will be cautious in their qualification procedures [3].

This model is the best in line with the EU framework currently in place. Nevertheless, the standardization of processes and the optimization of TSO-DSO cooperation is crucial to enhance the efficiency of the scheme. Another major problem with this market model is that it will have serious problems when the DER penetration in the DN level will reach high levels in the future. That's why several H2020 R&I projects such as FLEXGRID investigate new market models and smart grid architectures, in which the DSO is more enhanced. Within FLEXGRID, this market model will be the benchmark based on which the proposed DLFM architectures will be evaluated.

Local Market Model (DSO is the only FlexBuyer for DN-level resources)

In this market model, DSO clears a local market (i.e. DLFM) for reserve before a transmission-level market is cleared. The local DN market may commit a fraction of the reserve capacity for the use by the local DSO, while the residual reserve capacity (i.e. the more expensive part, since the DSO reserve market is cleared first) may be available to the TSO. DSO has priority because it can re-dispatch the amount of real power injection from the transmission system, when a DN problem occurs closer to real time. The dispatch per TSO-DSO interface is not fixed. The problem is that the TSO may experience high re-dispatch costs to deal with a problem in its network, because it can only use the most expensive reserve capacity. Another basic problem is that the reserve capacity is not fully utilized, because for example the DN may not experience a big problem, but the cheapest reserve capacity will not be available at the TSO level. One final problem is that the same resource can be activated in opposite directions, depending on the imbalance for which it is activated. (i.e. double activation problem). For example, if there is a positive transmission-level imbalance and a negative distribution-level imbalance, a distributed resource may be activated upwards by the TSO and downwards by the DSO. As shown in [16], the Local Ancillary Services model is dominated by the Centralized Ancillary Services model described above in terms of allocative efficiency (i.e. maximize Social Welfare), but it deals with high RES uncertainty at the DN level and incentivizes the local RES and FlexAsset investments in the long term. FLEXGRID extends this local market model idea considering also participation of DERs in both day-ahead wholesale and local energy markets.

Recently, there have been several novel research works that propose a local market model as well as its interaction with the wholesale markets. For example, [8] proposes a decentralized sequential market involving 'rational expectation' from the leaders. Under this design, the DSOs activate reserve strategically, with the aim of minimizing their activation costs, while forming rational expectations regarding the actions of the other DSOs and the TSO. Each DSO activates reserves taking into account local distribution network constraints, and sends a signal based on their local activation to the TSO. The TSO then activates resources connected to the transmission grid and aggregated distribution grid-connected reserves, taking into account transmission grid constraints. In this coordination scheme, the DSOs act first, anticipating the behavior of the other DSOs and the TSO. This market design is formulated as a Stackelberg game involving DSOs (multi-leaders) and a TSO (follower).
[**Error! Reference source not found.**] proposes a hybrid TSO-DSO model (Option A), which is similar to the FLEXGRID P-DLFM model. In this model, the DSO clears demand, DER and aggregator schedules before these schedules are cleared by the MO/TSO. The DSO and TSO may accept solutions that do not maximize total system welfare, but that do meet all system constraints. In such an instance, either the DSO or TSO could have primacy in the case of conflicts. One mechanism for establishing primacy would be to assess the marginal value of the two conflicting dispatch options to determine which dispatch order should be executed, with the second actor then finding a feasible but potentially suboptimal alternative dispatch decision. This is likely to be more efficient, albeit more complex, than a solution in which one actor has primacy in case of all conflicts.

[14] surveys several local market models such as [17] [18], in which the DSO plays a non-strategic role. More specifically, non-strategic DSO moves first and clears the local market (DLFM), then, if the demand cannot be fulfilled or there is supply that cannot be consumed, i.e., if the order book is not completely cleared, the DSO imports or exports electricity from higher voltage grid levels. DSO has the priority over the TSO for the allocation of flexibility resources from the distribution grid. After solving local grid constraints, DSO aggregates and offers the remaining bids to the TSO. In this scheme, a trading platform operated directly by the DSO or else by a 3rd party entity like the FMO actor (in collaboration with the DSO) proposed by FLEXGRID project needs to be implemented.

There are also other local market models, in which the DSO acts as a strategic player. For example, [19] proposes a methodology to optimize the trading strategies of a profit maximizing proactive distribution company (PDISCO) in the real-time market by mobilizing the demand response. While this is not in line with EU regulation, a separate entity from the DSO (e.g. the proposed FMO) could take on the role of PDISCO to manage the distributed resources, and coordinate with the DSO to respect network constraints and provide congestion management services. The PDISCO (or else FMO) renders continuous offers and bids strategically to a transmission-level real-time market. The upper-level problem expresses the PDISCO's profit maximization, while the lower-level problem minimizes the operation cost of the transmission-level real-time market. To solve the proposed model, a primal-dual approach is used to translate this bi-level model into a single-level MPEC. [20] presents the modelling of PDISCO together with profit maximizing distributed generation. PDISCO in this framework is basically an aggregator that acts in the wholesale market by finding the best aggregated offer based on the individual offers received from the DGs, while respecting the network constraints. The upper-level problem is DGs' profit maximization and the lower-level problem the PDISCO's offers to day-ahead and real-time markets (could also be modelled vice versa). [21] proposes a new market player role titled smart energy service provider (SESP), a communication platform that would facilitate trading and scheduling of energy, flexibility and other services to all members of a local community (cf. H2020 EMPOWER project). The SESP supervises the local market operations with the aim to maximize social welfare for its members, while also acting as an aggregator able to participate in wholesale markets for supplementing its local market operations. The local market supports trade of end-user flexibility for the benefit of the DSO and its operations for managing grid bottlenecks and providing power curtailments under request. The local market also supports power system balancing in the TSO's central market. The main problem with strategic DSO models is the difficulty in reallocation of the benefits among local resources. In addition to this, DSO acting as the only strategic aggregator in the distribution grid might create large market power for the DSO and this can hamper the competitiveness of the electricity market (i.e. social welfare of the system as a whole).

Finally, there are also many other research and commercial pilot proposals regarding the operation of a local energy market, in which the DSO will be the only FlexBuyer [22] [23] [24] [25]. However, these approaches deal only with the local network and market problems without taking into consideration the collaboration with the TSO (i.e. reserve, balancing market at the transmission network level) and MO (wholesale energy markets).

Shared Balancing Responsibility Model (DSO has balancing responsibility for its DN)

The shared balancing responsibility model requires that the TSO clears transmission-level imbalances by using transmission level resources only, and the DSO clears distribution-level imbalances by using distribution level resources only. The injection to the distribution network is fixed to the result of the TSO imbalance clearing. So, this model separates the dispatch in the transmission and the distribution network by fixing the linking variable of the two network, which is the active power flow at the TSO-DSO interface (cf. proposed FLEXGRID Reactive DLFM model). The MO/TSO is the first mover and fixes the price or quantity of the power in every TSO-DSO interface point. Then, the FMO/DSO dispatches the local resources. This fixed value is equal to the value obtained from a forward reserve capacity auction in case of reserve/balancing markets and equal to the value obtained from the day-ahead auction in case of wholesale markets. No substantial TSO-DSO coordination takes place, because the market clearing processes are sequential assuming a fixed input parameter (i.e. as a result of a previous market clearing process). It is similar to the FLEXGRID Reactive DLFM (R-DLFM) model, where priority is given to the TSO. The problem is that DSO may experience high (or even unacceptable) flexibility costs to deal with its local DN problems. Another problem is that too much reserve capacity over-provisioning may be needed, which comes at a relatively high activation cost, because resources of the transmission and distribution network are not pooled together. Generally, this model appears to be the least efficient solution in terms of social welfare, but it does not violate physical constraints and no ICT investment costs are needed for TSO-DSO coordination (i.e. in practice, historical data might help operators to fix the flow of power at one interface). This scheme is explicitly mentioned as possible future DSO-TSO coordination scheme at the EU level in the context of SmartNet project [13]. FLEXGRID, via its proposed Reactive DLFM (R-DLFM) aims at extending this scheme for possible MO-FMO collaboration, too.

[8] proposes a simultaneous non-cooperative game and a decentralized market design with 'bounded rational' agents, in the sense of agents, which do not anticipate the reactions of one another through an explicit reaction function. In this scheme, we assume that the DSO clears its local market (DLFM) by activating local reserves (solar PV power generations, demand response flexibilities) and assuming a desired injection by the TSO, taking into account local distribution grid constraints and offering a defined distribution grid capacity for the TSO needs. On its side, the TSO clears the global market by activating resources connected to the transmission grid and aggregated reserves activated by the DSOs, taking into account transmission grid constraints and distribution grid capacities allowed by the DSOs. We model this scheme as a (simultaneous) non-cooperative game. The shared balancing responsibility game is analyzed under perfect and imperfect information on the operational parameters and network topology.

[5] proposes a hybrid TSO-DSO model (Option B), which is similar to the FLEXGRID R-DLFM model. In this model, the DSO clears demand, DER and aggregator schedules after these schedules have been already

cleared by the MO/TSO. The DSO and TSO may accept solutions that do not maximize total system welfare, but that do meet all system constraints.

As an example of fixed price in the TSO-DSO connection point, in [17], the local energy market operator (cf. FMO) maximizes the social welfare in the local area based on the offering/bidding parameters (prices and quantities) from different players and day-ahead prices in the connection point of the distribution and transmission systems. As an example of fixed quantity in the TSO-DSO connection point, reference [18] proposes to let the TSO coordinate the generation in the temporal dimension, while the DSO optimizes the spatial distribution of electric vehicles (EVs) through controlling the charging and discharging schedules of the EVs.

Decentralized common TSO-DSO Market Model (both TSO and DSO are FlexBuyers)

The Common TSO-DSO AS market model provides a common market for flexible resources connected to the transmission and distribution grid. The market is jointly operated by the TSO and the DSO. Both, TSO and DSO, are Flexbuyers in this market. Flexibility is allocated to the system operator with the highest need, with the aim to decrease system costs as a whole, which is beneficial from a social welfare point of view. In other words, there is no upfront priority for the TSO or the DSO. The concept of a common market could be defined in 2 different ways. According to the first variant, all bids are offered and cleared in one market session, taking into account transmission and distribution grid constraints simultaneously (see more details in the "centralized common TSO-DSO market model in section 2.3.6 below). The drawback of this system might be that, in cases where the market is large and multiple bids are offered, the optimization process becomes mathematically heavy. An alternative approach (second variant) could be that the market is organized in a decentralized way. This means that a separate local market (DLFM), operated by the DSO, for local DSO needs, runs first, taking into account local grid constraints, but without any formal commitment to the market participants. The preliminary results are shared with the TSO market and integrated into a second market optimization that takes into account the system-level objectives. Based on the outcome of the second optimization, a communication is sent to the local market specifying which bids are accepted and for whom (for the DSO or the TSO). The decentralized common TSO-DSO AS market model could be considered as an extension of the Local market model (cf. section 2.3.2 above). In more detail, similar to the Local market model, there is a local market operated by the DSO. However, in this scheme, the DSO has no priority to use the local resources first, as resources are allocated to the system operator with the highest needs [13].

Two categories of decentralized designs emerge: hierarchical and distributed designs [8]. Decentralized market designs may avoid costly communication between the agents. A drawback is that all the agents may not have access to the same information due to current privacy constraints, which may limit data exchange (but this is actually an advantage regarding TSO-DSO coordination). From an algorithmic point of view, such a setting enables the implementation of algorithms that preserve privacy of the local market agents (requiring from them to share not more than their dual variables - e.g., local prices - updates). Hierarchical design involves agents in local markets (e.g. DSO level), which perform operations/computations independently and simultaneously and interact with other agents, known as centralized controllers (TSO level), at a higher level in the hierarchical structure. Such a hierarchical interaction can be backwards in Stackelberg game settings (leader-follower type models) under the assumption that the leaders anticipate the rational reaction of the local market agents seen as followers. In that case, the leaders incorporate explicitly in their optimization problems, the rational reaction functions of the followers. The closed form expression of the latter is obtained by solving first the followers' optimization problems at the lower level of the Stackelberg game, considering as fixed the decision variables of the leaders. The leaders, at the upper level, then incorporate the followers' rational reaction functions, expressed as functions of the leaders' decision variables only, directly in their optimization problems, therefore proceeding backwards. Alternatively, the hierarchical interaction can be forwards in case of decentralized control algorithms, assuming that a centralized controller coordinates the outputs of the local optimization problems based on the locally reported information [8].

FLEXGRID's Interactive DLFM (I-DLFM) model aims at extending the decentralized common TSO-DSO market model by applying it for wholesale and local energy markets' coordination (cf. MO-FMO coordination).

Integrated Flexibility Market Model (TSO, DSO and BSPs are FlexBuyers)

The Integrated Flexibility market model provides a common market for flexible resources connected to the transmission and distribution grid. This model introduces the participation of both regulated (system operators) and commercial market parties to procure flexibility in a common market. The presence of non-regulated players requires the introduction of an independent market operator to guarantee neutrality (cf. FMO proposed by FLEXGRID). This also implies that, in contrast with the other coordination schemes, a new entity will have a role in the data management and settlement of the market. This implies additional interaction between system operators and the independent market operator to share or transfer certain data. This is the only coordination scheme that allows direct competition between regulated and non-regulated players and where flexibility is available for regulated and non-regulated players under the same conditions. The flexibility is allocated to the party with the highest willingness to pay. Also, TSOs and DSOs have the possibility to resell previously contracted but non-used flexibility back to the market at the same price they contracted the flexibility initially [13].

This coordination scheme has the advantage of high liquidity due to the presence of additional buyers of flexibility. Moreover, system operators are allowed to resell previously contracted flexibility back to the market, which is also supporting the liquidity. However, the presence of both regulated and non-regulated parties in one common market raises some concerns. First, flexibility is allocated to the party with the highest willingness to pay. This effect is beneficial from a global social welfare point of view but might not necessarily lead to the lowest costs for system operators. Moreover, system operators might each activate flexibilities that negatively influence each other's positions, leading to unnecessary grid costs. Second, it will be more complex for the TSO to determine the amount of ancillary services to be procured to guarantee the system balance as commercial parties can buy flexible resources almost in real-time to balance their positions. This situation could lead the TSO to buy additional capacity upfront to guarantee sufficient resources to control the system balance. A third element is the fact that the opening of ancillary service markets for non-regulated parties could hinder the development and liquidity of intra-day markets [13].

Centralized common TSO-DSO Market Model (fully integrated market clearing)

In this model, transmission and distribution network resources are dispatched according to an integrated optimization of the entire system. This coordination scheme resolves the imbalance by simultaneously accounting for transmission and distribution constraints. The goal of the system operator is to minimize the cost of reserve activation. In this scheme, the operations of the DSO are effectively absorbed by the TSO. The problem with this model is complexity and that each DSO (slave) should provide ALL their DN topology data to the TSO (master). A more practical solution can be the decentralized optimization model described in section 2.3.4 above, which can achieve (converge to) an identical TSO dispatch via an iterative process. The Centralized Common Market model sets the first-best standard in terms of allocative efficiency (i.e. maximizes social welfare), however it is challenging to implement due to the large scale of the optimization problem, the communication requirements and the fact that DSO needs to disclose all its private information about its network topology and constraints.

[26] proposes this type of fully integrated market clearing model. Hence, reserve and congestion management requirements by TSOs and DSOs, as well as the energy demand are co-optimized and in

simultaneous competition to each other. In practice, this is computationally expensive; however, it could be approximated via decomposition techniques, and vertical market coupling, or distributed algorithms. In [5], an "enhanced TSO" model is proposed, which is rather computationally infeasible using the algorithms currently employed by TSOs to clear security-constrained economic dispatch of bulk power systems. It is also assessed that "enhanced TSO" models would effectively resemble an expanded version of the market clearing and system operation models in place in the U.S. and Europe today, but with one or two orders of magnitude greater number of network branches, users, and decisions. The centralized common TSO-DSO market model is used as a benchmark to assess the performance of decentralized market designs like the FLEXGRID Interactive DLFM model.

2.4. Summary of the proposed FLEXGRID Distribution Level Flexibility Market (DLFM) Architectures

Following up **Error! Reference source not found.** descriptions, FLEXGRID proposes holistic energy market architectures in which both energy and ancillary services are traded. To realize this vision, sophisticated interactions between market and network domains at both transmission and distribution network are required.

Assumptions about the organization of FLEXGRID DLFM architectures

Given the fact that nowadays there is no real DLFM operating in the entire EU area, but only some pilot projects that demonstrate interesting proof-of-concept results, we assume the current regulatory framework and how this can be extended to facilitate FLEXGRID innovations (based on recommendation from various EU bodies as extensively described in section 2.2 above). We follow the Nord Pool paradigm currently operating in the EU Nordic countries as EU's regulatory baseline assuming that:

- The Market Operator - MO (e.g. Nord Pool) operates day-ahead and intra-day energy markets at the transmission network (TN) level.
- The Flexibility Market Operator – FMO (e.g. NODES) operates day-ahead and intra-day energy markets at the distribution network (DN) level.
- The Transmission System Operator – TSO operates the day-ahead reserve and balancing energy markets at the TN level.
- The Distribution System Operator – DSO operates the day-ahead reserve and balancing energy markets at the DN level.

In the Nord Pool paradigm currently operating in Nordic countries, the day-ahead market gate closure takes place at 12:00pm of the previous day (D-1). The day-ahead market clearing results take place at 14:00 of D-1 following an auction-based trading model and uniform pricing. Then, all market stakeholders including the TSO are informed about the day-ahead dispatch. The next step is for the day-ahead reserve market to take place by the TSO in the afternoon of D-1. The TSO solves a TN-aware day-ahead dispatch by applying the TN-level constraints. In some countries, this process is also called Integrated Scheduling Process (ISP). In the meantime, the intra-day energy market opens at 15:00 of D-1 and closes approximately at 23:00 of D-1, where a continuous bi-lateral electronic trading takes place. Finally, the balancing market's gate closure takes place at 23:15 for delivery time of 00:00-01:00 of day D, 00:15 for delivery time of 01:00-02:00 of D, etc. Here, we should note that the goal is for gate closure time to be as close as possible to real time (e.g. 15 minutes before delivery), not before the intra-day gate closure time, while sufficient time for the necessary balancing processes by the TSO should be ensured. Without lack of generality, we may assume that all market stakeholders can re-position themselves (for their portfolio's possible imbalances) via the balancing energy market, so the intra-day market process can be neglected without causing any substantial differences in the proposed FLEXGRID energy market architectures. We may also assume that forward energy markets may exist, but they can be easily represented by day-ahead markets without affecting substantially FLEXGRID's architectural models, too.

Conclusively, let us assume the sequence of the 3 following markets: i) day-ahead energy market, ii) day-ahead reserve market, and iii) near-real-time balancing energy market. Finally, let us assume that this sequence of 3 markets may also take place for the distribution network level, too. Therefore, we may have a total of 6 markets as follows:

Table 4: Summary of markets assumed within FLEXGRID

Market #1	Market Operator (MO) operates the day-ahead energy market at the Transmission Network (TN) level
Input	Bids from all market participants and basic power flow constraints at the TN level Depending on the energy market architecture selected from the FLEXGRID's various options, the market clearing process of Market #1 either ignores the DN topology, or implicitly takes it into account.
Output	Market clearing results (TN-aware price €/MWh per TN node and day-ahead energy dispatch per accepted market participant)
Market #2	TSO operates the day-ahead reserve market at the TN level
Input	Bids from all market participants at TN level + Day Ahead Dispatch (DAD) schedules from MO + RES/demand forecasts + maintenance-related info from assets and grid + TN topology and constraints Depending on the energy market architecture selected from the FLEXGRID's various options, the market clearing process of Market #2 either ignores the DN topology, or implicitly takes it into account.
Output	Reserve market clearing results at TN level (price €/MW and reserve capacity commitment per accepted market participant)
Market #3	Flexibility Market Operator (FMO) operates the day-ahead energy market at the Distribution Network (DN) level
Input	Bids from all market participants at DN level (incl. FlexAssets) + DAD schedule from MO at all TSO-DSO coupling points or day-ahead energy market price forecasts (depending on the selection of energy market architecture from the FLEXGRID's various options)+ DN topology constraints
Output	Market clearing results (DN-aware price €/MWh and DAD per accepted market participant and DN node)
Market #4	DSO operates the day-ahead reserve market at the DN level
Input	Bids from all market participants at DN level + DAD schedules from FMO + local RES/demand forecasts + maintenance-related info (if any)
Output	Reserve market clearing results at DN level (price €/MW per DN node and reserve capacity commitment per accepted market participant)
Market #5	TSO operates the balancing energy market at the TN level
Input	Bids from all market participants at TN level (incl. DER aggregators) + updated RES/demand forecasts + updated data from SCADA/EMS Depending on the energy market architecture selected from the FLEXGRID's various options, the market clearing process of Market #5 either ignores the DN topology, or implicitly takes it into account.
Output	Balancing energy market clearing results at TN level (i.e. prices €/MWh per TN node and Up/Down activation energy quantities per accepted market participant)

Market #6	DSO operates the balancing energy market at the DN level (only when DSO has a balancing responsibility for its DN operation)
Input	Bids from all market participants at DN level + updated local RES/demand forecasts + updated data from Distribution Management System (DMS)
Output	Balancing energy market clearing results at DN level (i.e. prices €/MWh per DN node and Up/Down activation energy quantities per accepted market participant)

In the table above, we briefly described each one of the 6 proposed markets. The questions that naturally arise are: "OK, but which is the timing (sequence) of these markets? And how does this timing affect the market architecture model (i.e. how inputs/outputs change)? What happens if we eliminate/merge one or more of these 6 markets" in each architectural model variant? The subsections below provide detailed answers for these questions.

Reactive Distribution Level Flexibility Market (R-DLFM) architecture

The algorithmic steps of Reactive Distribution Level Flexibility Market (R-DLFM) architecture have been extensively described in section 2.2.1 of FLEXGRID deliverable D2.2 [1]. The sequence and timing of markets in R-DLFM architecture are illustrated in the figure below. The basic characteristic of R-DLFM is that transmission network (TN) level markets are cleared before the DN-level ones, so the 3 types of DLFMs operate reactively according to the market clearing results of the preceding TN-level markets.

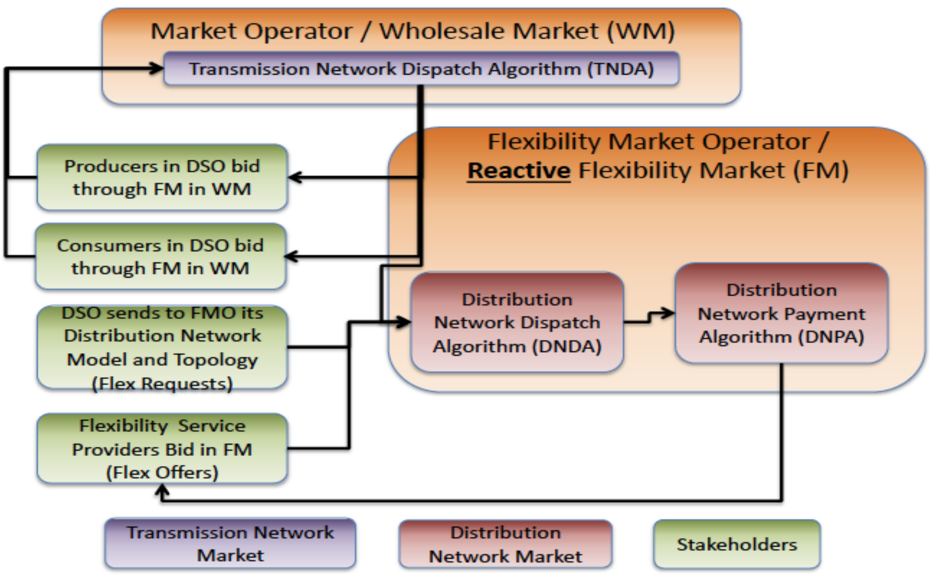


Figure 3: Reactive Distribution Level Flexibility Market (R-DLFM) [1]

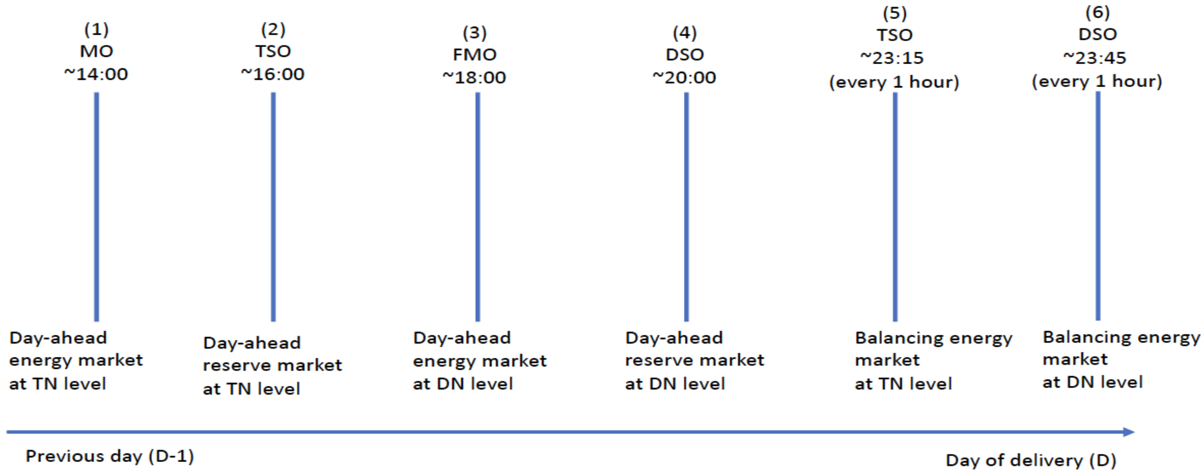


Figure 4: Sequence and timing of markets in FLEXGRID R-DLFM architecture

R-DLFM Architectural variants

In the basic R-DLFM model, the sequence and timing of the markets is the one described in Figure 4 above (i.e. 1 → 2 → 3 → 4 → 5 → 6). We consider that the FMO may run the day-ahead energy market at the DN level right after the respective TN-level market clearing results are available (i.e. approximately at 14:00). So, we may assume that all the DN-level market stakeholders can provide their FlexOffers until 17:00 (or so). Then, the FMO runs the DN-aware market clearing process and publishes the results at around 18:00 (or so). Then, the day-ahead reserve market at the DN level may run in a way that resembles the respective procedure at the TN-level. This process may end up at 20:00 (or so), which means that DSO has contracted the required reserve units in order to deal with potential local congestion and voltage control problems at its DN. In case that the DSO has a balancing responsibility for its network, then a balancing energy market at the DN level may also take place right after the TN-level balancing energy market. This market clearing process should be quick enough in order for the near-real-time dispatch schedule to be effectively communicated to all distributed market participants.

In case of an Energy-Only-Market (i.e. a type of market design where generators are remunerated for the electric energy they generate, but not for their reserve capacity provision) setup, reserve markets (2) and (4) could be eliminated. This would mean that there are no capacity products (or else flexibility availability contracts) that are traded, and all types of energy scarcity contexts are handled via the energy-only markets. In this case, TSOs and DSOs may use as reserves their own flexibility resources and/or acquire flexibility resources through bilateral agreements.

If the regulatory framework remains as is and the DSO has no balancing responsibility for its DN (or else the TSO is the only responsible entity for all possible imbalances at both TN and DN levels), then market #6 can be eliminated. Market #3 could also close before market #2, because these two markets may not interact in the R-DLFM model.

DN-level DERs may also directly bid in market #1 via an aggregator entity (as it is done nowadays) and also bid their residual (or else not accepted) bids in market #3. This implies the fact that the proposed R-DLFM can also be applicable without changing anything in the current regulatory framework.

Finally, Market #3 could be eliminated. In this case, DN-level DERs can only bid in Markets #4 and #6 or only in #4. In more detail, this means that local FlexAssets only bid their capacity and not energy curve for the day ahead. So, FMO actor could be by-passed. Then, local FlexAssets could only participate in DSO-level reserve market in response to FlexRequests made by the local DSO (either on day-ahead and/or near-real-time basis).

R-DLFM architecture pros and cons

The main advantage of the proposed R-DLFM model is that it is compatible with the existing energy market architecture and respective regulatory framework. This is mainly due to the fact that all existing TN-level market clearing processes (i.e. day-ahead energy, intra-day energy, reserve, ancillary services and balancing energy markets) remain unaffected and perform in a business-as-usual manner. All proposed DN-level markets operate after the respective TN-level ones, so the former take as fixed input the results of the latter. By doing so, DN-level constraints are taken into account and thus local congestion, local balancing and voltage control issues can be solved, which is a major pre-requisite in high RES penetration scenarios at the DN level. Finally, relatively small ICT investment costs are needed to support the TSO-DSO and MO-FMO coordination, because there are rather static communication messages that need to be exchanged between the pre-mentioned system and market operators.

However, R-DLFM model may also have several disadvantages that need to be taken into consideration. Firstly, all markets are operating in a sequential manner (i.e. each market takes as input the results of the previous market without being able to change anything in the dispatch schedule that has been decided), so social welfare results are expected to be sub-optimal. Furthermore, no actual TSO-DSO and MO-FMO coordination may take place because the energy resources at TN and DN levels are not pooled together. There may also emerge other more practical problems, which are mainly related with the timing constraints of each market's operation. More specifically, TSO needs to wait for results of market #3 and #4 before gathering them for clearing market #5 (i.e. balancing market). Moreover, DSO needs to wait for results of market #5 before being able to clear market #6. Hence, there may be a very short notice for the DERs/FlexAssets to react in the needed ramp up/down activations. The proposed WP5 market clearing algorithms take into consideration the computational complexity and aim at achieving a desirable trade-off between accuracy and complexity.

Proactive Distribution Level Flexibility Market (P-DLFM) architecture

The algorithmic steps of Proactive Distribution Level Flexibility Market (P-DLFM) architecture have been extensively described in section 2.2.2 of FLEXGRID deliverable D2.2 [1]. The sequence and timing of markets in P-DLFM architecture are illustrated in the figure below. The basic characteristic of P-DLFM is that distribution network (DN) level markets are cleared before the TN-level ones, so the 3 types of DLFMs operate proactively and thus based on their results, the TN-level markets follow. This process can also be seen as a "DN feasibility check" in order to mitigate the main drawback of the aforementioned R-DLFM model, which is the difficulty to manage an infeasible or expensive TN-level dispatch schedule.

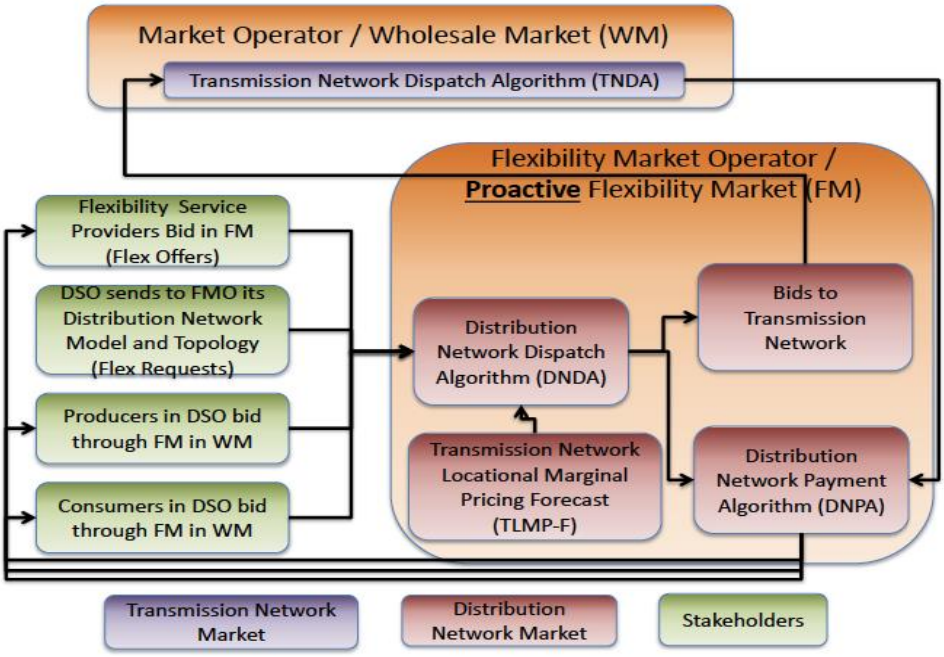


*Figure 5: Proactive Distribution Level Flexibility Market (P-DLFM) [**Error! Reference source not found.**]*

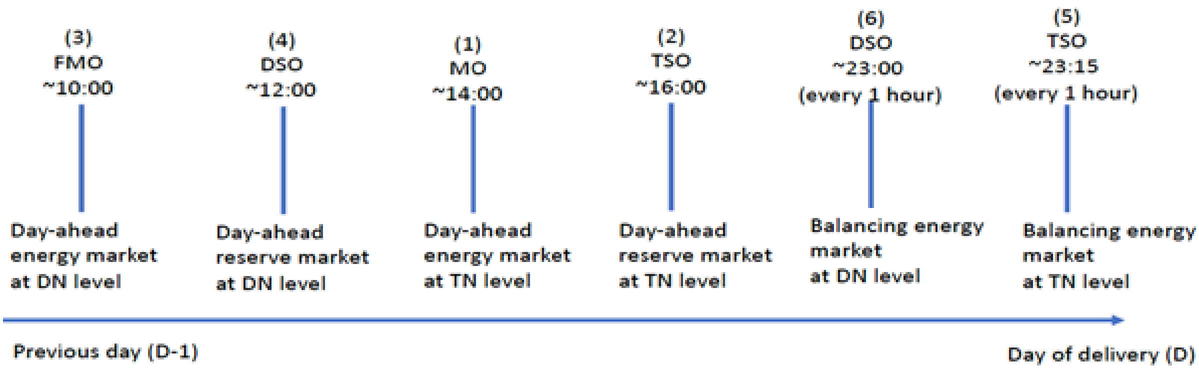


Figure 6: Sequence and timing of markets in FLEXGRID P-DLFM architecture

P-DLFM Architectural variants

As shown in the figure above, the sequence of markets starts with market #3 operated by the FMO, which is a day-ahead energy market at the DN level (i.e. 3 → 4 → 1 → 2 → 6 → 5). Right afterwards, the day-ahead reserve market at DN level is operated by the DSO. These two markets should publish their results before the gate closure of the traditional day-ahead wholesale energy market (TN-level). At the same time, they should operate as close as possible to the actual delivery time in order to be able to incorporate any possible forecast inaccuracies. Indicatively, the FMO could publish its dispatch schedule at 10:00 of D-1 for market #3, while the DSO could publish respective results approximately at 12:00 for market #4. Subsequently, at the TN and wholesale market level, markets #1 and #2 take place as usual. Finally, for near-real-time balancing markets, the DSO may run a proactive balancing energy market right before the traditional balancing energy market operated by the TSO. Thus, the local congestion and voltage problems at the DN level can be directly solved by the DSO, while the results of market #5 can be used as input to the market #6.

If we assume a static grid/DER pre-qualification process at the DN level, then market #3, #4 and #6 may be eliminated. This is what is mostly done nowadays (cf. centralized market model taking into consideration DN-level constraints, too). However, this static procedure incurs highly sub-optimal results, which will be getting increasingly worse in a future of high RES penetration (see more details in [**Error! Reference source not found.**]. FLEXGRID P-DLFM aims at making the current grid/DER pre-qualification processes more dynamic in order to lower the re-dispatch as well as the over-provisioning costs, while facilitating the integration of more distributed RES at the DN level.

The main architectural assumption is that the FMO and the DSO clear their day-ahead energy/reserve markets before MO/TSO. Then, they publish their results and residual (non-accepted) bids to the TSO/MO. Two subcases may be assumed: i) either MO/TSO use the DN-level market clearing results as input or ii) MO/TSO put the DN-level results as additional constraints in their problem (e.g. by having some kind of confidence intervals to make sure that physical constraints are respected).

Another architectural assumption is that all rejected bids from the DN-level markets (i.e. the most expensive ones) may be forwarded to the respective TN-level markets. Finally, we may assume that P-DLFM could be used together with R-DLFM in order to achieve better results both in terms of network operation and markets' efficiency.

P-DLFM architecture pros and cons

The main advantage of P-DLFM model is that DN constraints are taken into consideration in a proactive way and thus local congestion and voltage control issues in high DER/RES penetration scenarios at the DN level can be proactively solved with low cost. DER/FlexAssets at DN level may also participate in wholesale markets and realize higher revenues incentivizing thus new RES/FlexAsset investments in the long term. Local/P2P energy trading can also be facilitated boosting the idea of EU autonomous energy communities. Furthermore, TSOs remain in charge of balancing responsibility for the entire network and are thus able to activate the necessary reserves on time (i.e. they do not have to wait for DSO's decisions like in R-DLFM case). Finally, P-DLFM could be compatible with the existing energy market architecture even though a clear dynamic pre-qualification process needs to be defined, which can be a quite challenging research task.

However, P-DLFM model has also some disadvantages. A main drawback is that the TSO may experience high re-dispatch costs, because it can only use the most expensive reserve capacity from the DN-level resources. The TSO's costs may be higher, because TSO follows up DN-level market decisions. Another major drawback is that social welfare results may be much worse than optimal because pre-qualification process is based on stochastic RES, consumption modeling and confidence intervals. As a matter of fact, there may be cases in which inaccurate forecasting may lead to highly inefficient proactive DN-level decisions and market clearing results. In this case, the market clearing at DN level is not compatible with the clearing in the TN level and FMO has to manage and/or pay the cost of this difference.

Interactive Distribution Level Flexibility Market (I-DLFM) architecture

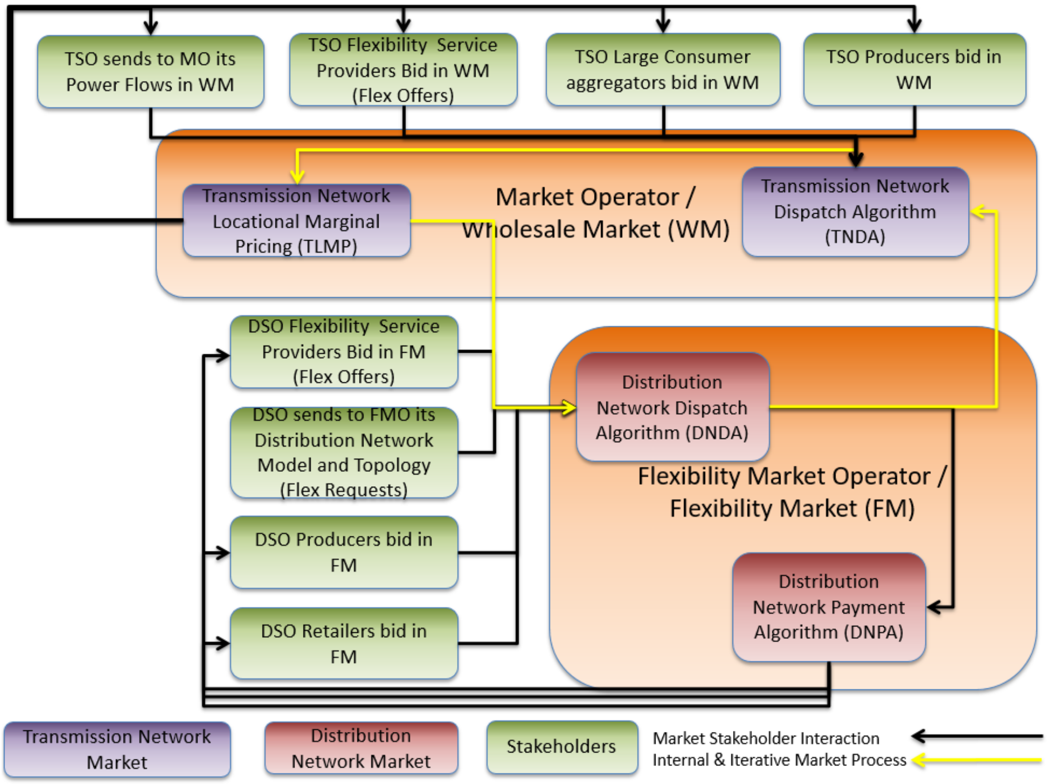


*Figure 7: Interactive Distribution Level Flexibility Market (I-DLFM) [**Error! Reference source not found.**]*

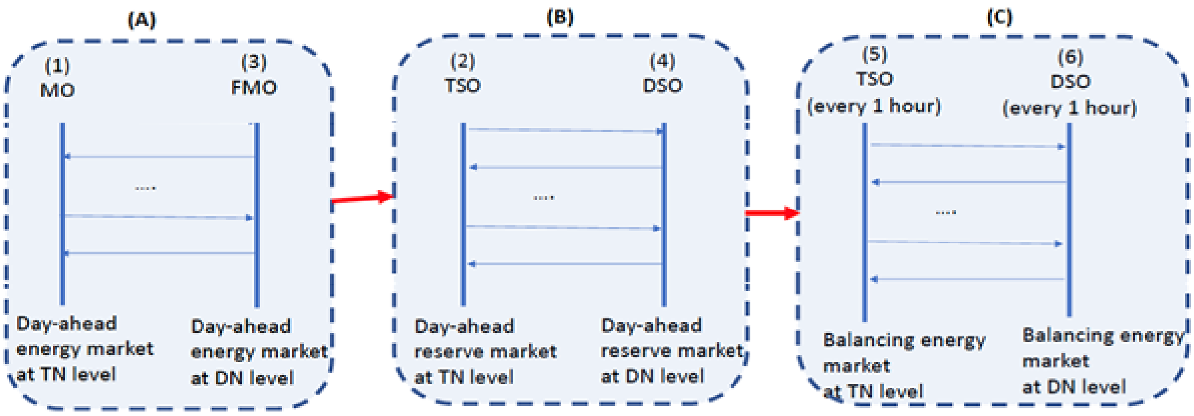


Figure 8: Sequence and timing of markets in FLEXGRID I-DLFM architecture

I-DLFM Architectural variants

As illustrated in Figure 8 above, in the I-DLFM model, we consider an iterative process that takes place between the MO/FMO and between TSO/DSO until they converge to an optimal dispatch schedule for both TN and DN levels. As already explained earlier, we assume three basic markets at both TN and DN levels: A) day-ahead energy markets (interaction between market #1 and #3), B) day-ahead reserve markets (interaction between market #2 and #4), and C) near-real-time balancing energy markets (interaction between market #5 and #6). For example, in the day-ahead energy market context, MO initially runs an instance of its market clearing problem at the TN level and sends the results to the FMO. Then, the FMO takes as input the MO's results and runs its own market clearing problem at the DN level.

The respective results (e.g. Lagrange multiplies) are sent back to the MO, who runs another round of the TN-level market clearing. Of course, the dispatch schedules that are decided in each round of algorithm's execution are virtual and are not actuated in reality. After several algorithmic iterations (i.e. several message exchanges between MO and FMO), the process converges to an overall dispatch schedule (i.e. at both TN and DN levels) that maximizes the social welfare[2]. A similar iterative process may take place for day-ahead reserve markets and near-real-time balancing markets (cf. TSO-DSO collaboration).

Regarding indicative timing of markets' operation and gate closure, the interactive day-ahead energy market (A) may be cleared by 16:00, the interactive day-ahead reserve market (B) may be cleared by 20:00 and finally the interactive balancing energy market (C) may open 45 minutes before delivery time and may be closed 15 minutes before delivery time[3]. Markets (A) and (B) could be co-optimized (cf. paradigm from USA's power exchanges) and then run iteratively. Finally, in a centralized common market model (see section 2.3.1 above), markets #3, #4 and #6 may not exist.

I-DLFM architecture pros and cons

A main advantage of I-DLFM model is that it can maximize the social welfare and thus provide optimal network operation and market efficiency outcomes. Moreover, the proposed model adopts a decentralized scheme (via decomposition algorithms), which can achieve results similar or very close to the ideal case of centralized optimization market model (cf. section 2.3.1 above). Moreover, it can also be a practical and scalable solution as the complex MO-FMO and/or TSO-DSO coordination problem is decomposed in sub-problems, which can be solved more easily and within the timing constraints set by the regulatory framework and today's real business. Apart from scalability feature, the proposed I-DLFM provides a privacy-preserving solution, in which participants may exchange the minimum information per iteration cycle (e.g. Lagrangian dual variables or else price updates) before the system converges to its global optimum.

One of the main drawbacks of the proposed I-DLFM model is that it is incompatible with the existing regulatory framework and assumes several advancements regarding the ICT infrastructure needed to support the proposed advanced coordination schemes. More specifically, in order to support a reliable and accurate MO-FMO and TSO-DSO coordination, advanced S/W platforms and coordination centres need to be developed from scratch. Another major disadvantage comes up in cases where the market is large and a vast number of complex bids are offered, rendering thus the optimization process mathematically "heavy", being thus not able to deal with the stringent timing constraints. Bidding format structure is also a critical research thread in order to deal with the trade-off "modelling accuracy vs. computational complexity". Finally, FMO may need detailed distribution network data and constraints in order to be able to provide accurate feedback to MO, or else the results will be somehow similar to the R-DLFM and P-DLFM cases.

Conclusively, the novel FLEXGRID contributions related with I-DLFM model can be summarized as follows:

- FLEXGRID extends the decentralized common TSO-DSO market model for ancillary services' provisioning (proposed by H2020 SmartNet project [**Error! Reference source not found.**] and other highly cited research papers from the international literature such as [**Error! Reference source not found.**] [**Error! Reference source not found.Error! Reference source not found.**]) to wholesale energy markets, too.
- FLEXGRID proposes a holistic energy market architecture model that incorporates both energy and ancillary services' markets and is able to cope with the optimal management of TNs and DNs
- FLEXGRID proposes a novel MO-FMO interaction scheme together with TSO-DSO interaction.

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[2] By the term "social welfare", we mean market efficiency and it is generally defined as the sum of all suppliers' profits and the "profits" from the demand side (i.e. consumers' utility minus costs).
[3] This process may take place every 1 hour like the way it is currently done in today's balancing markets.

Chapter 3. Optimal Power Flow algorithms for market clearing

3.1. Convexified AC Optimal Power Flow (AC-OPF)

Introduction and FLEXGRID contributions

The AC-OPF is an optimization problem aiming to determine the best dispatch of generators and loads in an electrical network, so that all the physical and operational constraints are respected. It is the most accurate representation of such a system, but it is a non-linear and non-convex problem and as a consequence, there is no guarantee that a solution can be found. Because of that, simplifications are used when it comes to market clearing algorithms. Very often, the network constraints are completely ignored with the assumption of a "copperplate network". The DC-OPF is also used. This model includes the line flow limits and is linear. However, it requires assumptions that could hold for a transmission network but are not valid on the distribution scale. On the other hand, the DC-OPF does not consider voltages, reactive power, currents and losses. For these reasons, it is not a good enough candidate when it comes to modelling management of congestions and voltage with flexibility in the distribution network.

One way to obtain a solution to the AC-OPF is to use a convex relaxation. The idea is to solve the problem on a larger, convex space, by relaxing the constraints responsible of the non-convexity. If the solution obtained is feasible for the original, non-convex AC-OPF, then it is the optimal solution. This is the approach chosen here. With such a model, it will be possible to:

- Represent the power flows in a distribution network
- Identify possible voltage deviations
- Identify possible line congestions
- Assist the DSO with the formulation of FlexRequests to avoid line congestions and voltage deviations
- Perform market clearing in a flexibility market
- Integrate the network model in bilevel problems, which require convex low-level problems

To the best of our knowledge, market clearing with a convex relaxation of the AC-OPF is a novelty. An important challenge is to be able to retrieve meaningful locational marginal prices (LMPs) for active and for reactive power.

Related work in the international literature

There has been a lot of interest for convex relaxation of AC-OPF in the last years. Detailed surveys are available in [27], [28] and [29]. Some widely used relaxations are:

- Semi-Definite Programming (SDP)
- Quadratically Constrained Programming (QC)
- Second Order Cone Program (SOCP)

There is generally a tradeoff between the tightness of the relaxation (e.g. how small the resulting super set is) and the computational time. SDP and QC are tighter than SOCP but they take longer to solve [30], [31].

In the literature on flexibility markets, the network constraints are generally ignored [32], and the resulting market clearing might not be feasible because of physical reasons. In [33], the peer-to-peer exchanges between neighboring microgrids are determined with the help of a SOCP, taking into account the network constraints.

In [25] flexibility market clearing structures are proposed. They require the DSO to be able to identify its need for flexibility, both for line congestion and voltage deviation management, and to be able to check if the submitted offers would improve the dispatch. This should be achieved by an OPF but no details are given regarding this network model.

Basic system model to be followed

The main idea here is to use an SOCP relaxation of the AC-OPF, including line constraints, losses, voltage and reactive power. This model will be general enough so that it can be used for different applications (market clearing, identification of flexibility needs by the DSO, verification of a given dispatch).

We carried out a comparison of different SOCP formulations in [34]. Among the methods compared, the one introduced in [14] showed the most promising results for active distribution grids and general radial network, so it is the chosen approach here. The AC-OPF is first augmented with additional constraints and then relaxed. The objective function can be adjusted depending on the intended use of the model:

- Minimization of the costs (or maximization of the social welfare)
- Minimization of voltage deviations
- Minimization of congestions
- Empty objective function to evaluate the feasibility of a given dispatch

This model can be enhanced to help decision making for the DSO, by including the possibility to cut off some users in case of unfeasible dispatch. This is modelled by adding slack variables in the constraints for line capacity and voltage limits, associated with a high penalty cost in the objective function.

Basic problem formulation and algorithmic solutions

NOMENCLATURE

	Sets and indices
l	Index referring to a bus or to a line. Bus l is at the downstream end of line l. Bus 0 is the root node. Bus 1 is connected to the root node by line 1.
$\mathcal{L}$	Set of non-root nodes l or lines l in the distribution grid.
$\mathrm{up}(l)$	Bus upstream of bus l.
$\mathcal{L}_l$	Set of buses or lines downstream of bus l.
	Parameters (physical quantities are in p.u.)
z_l	Impedance of line l.
b_l	Half shunt capacitance of line l.
v_0	Squared magnitude of the root node (substation) voltage.
v_l^{min}	Squared lower voltage bound at bus l.
v_l^{max}	Squared upper voltage bound at bus l.
I^{max}	Squared current bound for line l.
$\mathbf{G}_{l,m}$	Adjacency matrix of the oriented graph of the network: $\mathbf{G}_{l,m} = 1$ if $l = \mathrm{up}(m)$ and 0 otherwise.
$C_l^{\mathfrak{R}}, C_l^{\mathfrak{I}}$	Active and reactive power withdrawal cost functions, bus l.
$C_0^{\mathfrak{R}}, C_0^{\mathfrak{I}}$	Active and reactive power import cost functions.
S_l	Feasible region of complex power withdrawal at bus l.
S_l	**Variables**
v_l	Squared magnitude of the complex voltage at bus l.
f_l	Squared magnitude of current in central element of line l.

$\bar{v}_l, \bar{f}_l$	Auxiliary variables.
s_l	Complex power withdrawal at bus l: $s_l = p_l + jq_l$.
S_l^t	Complex power flow entering line l from upstream bus up(l): $S_l^t = P_l^t + jQ_l^t$
S_b^t	Complex power flow entering bus l from line l: $S_l^b = P_l^b + jQ_l^b$.
$\hat{S}_l^t, \bar{S}_l^t$	Complex auxiliary variables (real and imag. parts as above).
$\hat{S}_l^b, \bar{S}_l^b$	Complex auxiliary variables (real and imag. parts as above).

For a radial distribution network, using the branch flow model, with lines represented by a π-model, the non-convex AC-OPF can be expressed as follows:

$$\min_{s_l, v_l, f_l, S_l^b, S_l^t} \sum_{l \in \mathcal{L}} \left(C_l^{\Re}(p_l) + C_l^{\Im}(q_l) \right) + C_0^{\Re}(P_1^t) + C_0^{\Im}(Q_1^t) \tag{1}$$

$$\text{s.t.} \begin{cases} S_l^b = s_l + \sum_{m \in \mathcal{L}} \left(\mathbf{G}_{l,m} S_m^t \right), & (2) \\ S_l^t = s_l + \sum_{m \in \mathcal{L}} \left(\mathbf{G}_{l,m} S_m^t \right) + z_l f_l - j\left(v_{\text{up}(l)} + v_l\right) b_l. & (3) \\ v_l = v_{\text{up}(l)} - 2\Re\left(z_l^* \left(S_l^t + j v_{\text{up}(l)} b_l \right) \right) + |z_l|^2 f_l, & (4) \\ f_l = \dfrac{\left| S_l^t + j v_{\text{up}(l)} b_l \right|^2}{v_{\text{up}(l)}}, & (5) \\ v_l^{\min} \le v_l \le v_l^{\max} & (6) \\ \left| S_l^b \right|^2 \le I_l^{\max} v_l, |S_l^t|^2 \le I_l^{\max} v_{\text{up}(l)} & (7) \\ \left| S_l^b \right| \le S_l^{\max}, |S_l^t| \le S_l^{\max}, & (8) \\ s_l \in \mathcal{S}_l \}, \forall l \in \mathcal{L} & (9) \end{cases}$$

The objective here is to minimize the cost associated with active and reactive power (1). Equations (2)-(5) express the load flow. Equations (6)-(8) give the bounds on bus voltages, line currents and apparent power flow. Equation (9) ensures that the complex power withdrawal at each non-root node remains within a feasible region $\mathcal{S}_l \subset \mathbb{C}$.

This problem is augmented with the following constraints, $\forall l \in \mathcal{L}$:

$$\hat{S}_l^t = s_l + \sum_{m \in \mathcal{L}} \left(\mathbf{G}_{l,m} \hat{S}_m^t \right) - j\left(\bar{v}_{\text{up}(l)} + \bar{v}_l\right) b_l. \tag{10}$$

$$\bar{v}_l = \bar{v}_{\text{up}(l)} - 2\Re\left(z_l^* \left(\hat{S}_l^t + j \bar{v}_{\text{up}(l)} b_l \right) \right) \tag{11}$$

$$\bar{S}_l^t = s_l + \sum_{m \in \mathcal{L}} \left(\mathbf{G}_{l,m} \bar{S}_m^t \right) + z_l \bar{f}_l \tag{12}$$

$$\bar{f}_l v_l \ge \max\left\{ \left(\hat{P}_l^b\right)^2, \left(\bar{P}_l^b\right)^2 \right\} + \max\left\{ \left(\hat{Q}_l^b - \bar{v}_l b_l\right)^2, \left(\bar{Q}_l^b - v_l b_l\right)^2 \right\}, \tag{13}$$

$$\begin{aligned} &\bar{f}_l v_{\text{up}(l)} \\ &\quad \ge \max\left\{ \left(\hat{P}_l^t\right)^2, (\bar{P}_l^t)^2 \right\} + \max\left\{ \left(\hat{Q}_l^t - \bar{v}_{\text{up}(l)} b_l\right)^2, \left(\bar{Q}_l^t - v_{\text{up}(l)} b_l\right)^2 \right\}, \end{aligned} \tag{14}$$

$$\bar{S}_l^b = s_l + \sum_{m \in \mathcal{L}} \left(\mathbf{G}_{l,m} \bar{S}_m^t \right), \qquad \hat{S}_l^b = s_l + \sum_{m \in \mathcal{L}} \left(\mathbf{G}_{l,m} \hat{S}_m^t \right), \tag{15}$$

$$\tag{16}$$

$$\bar{v}_l \le v_l^{\max}, \tag{17}$$

$$\begin{aligned} &\max\left\{ \hat{P}_l^b, \bar{P}_l^b \right\}^2 + \max\left\{ \hat{Q}_l^b, \bar{Q}_l^b \right\}^2 \le v_l I_l^{\max}, \\ &\max\left\{ \hat{P}_l^t, \bar{P}_l^t \right\}^2 + \max\left\{ \hat{Q}_l^t, \bar{Q}_l^t \right\}^2 \le v_l I_l^{\max}, \end{aligned} \tag{18}$$

$$P_l^t \le \bar{P}_l^t \le P_l^{\max}, Q_l^t \le \bar{Q}_l^t \le Q_l^{\max}. \tag{19}$$

where $P_l^{\max}$ and $Q_l^{\max}$ are parameters chosen so that they do not restrict the feasible space of the augmented problem.

The relaxed OPF problem is obtained by relaxing constraint (5):

$$v_{\mathrm{up}(l)} f_l \geq \left| S_l^t + j v_{\mathrm{up}(l)} b_l \right|^2 \quad (20)$$

Which then gives the following:

$$\min_{s_l, v_l, f_l, S_l^b, S_l^t} \sum_{l \in \mathcal{L}} \left(C_l^{\Re}(p_l) + C_l^{\Im}(q_l) \right) + C_0^{\Re}(P_1^t) + C_0^{\Im}(Q_1^t) \quad (11)$$

$$\text{s.t. (2)-(4),(20),(6)-(9),(10)-(19), } \forall l \in L \quad (12)$$

Datasets to be used for simulation setup and most important KPIs

In order to test the proposed algorithms, the following inputs are necessary:

- Parameters of the tested distribution network (topology, operating limits…)
- Sets of FlexRequest and FlexOffers for this network
- Planned production and consumption of the assets in this network

The following KPIs will be studied to evaluate the performance of the algorithms:

- Tightness of the relaxation
- Exactness of the relaxation
- Optimality gap
- Total computational runtime
- Social Welfare
- Curtailment

When it comes to the market clearing application, the following KPIs will also be considered:

- Cost reduction achieved (compared to grid reinforcement)
- Number of transactions
- Volume of transactions
- Market utilization factor

More details on these KPIs are available in the following table:

Table 5: KPIs to evaluate the performance of the algorithms

KPI	Description
Tightness of the relaxation	Largest relaxed constraint residual over the test period
Exactness of the relaxation	The optimal solution is feasible for the AC-OPF
Optimality gap	Gap between the value of the objective function of the AC-OPF at the optimal solution and the value of the objective function of the relaxed AC-OPF at the optimal solution
Total computational runtime	How long it takes for the algorithm to return results. It should stay below a defined threshold.
Social Welfare	Difference between how the actors value flexibility and the money they get for it
Curtailment	Total reduction in the amount of energy due to line congestions or voltage deviations

Cost reduction achieved	Difference in cost with implementing a reinforcement of the network instead of having flexibility markets
Number of transactions	Number of bids matches in the flexibility market over the evaluation period
Volume of transactions	Quantity of energy or capacity traded in the flexibility market over the evaluation period
Market utilization factor	Number of times that the market is used per year

3.2. Continuous market matching algorithm

Introduction and FLEXGRID contributions

A part of the flexibility market clearing could be auction based such as day-ahead flexibility market, using the AC-OPF as presented in section 3.1. However, moving closer to real-time, it could become more relevant to have a continuous market. Instead of a market clearing considering all bids and clearing once and for all, this model would be continuously matching bids. This is often the case for intraday markets. The difference and novelty here is that we need to take the distribution network constraints into account and make sure that two bids would only match if their activation would not deteriorate the situation of the network, in terms of line congestions and voltage deviations.

Related work in the international literature

Continuous markets are commonly used at the intraday level. In [35], the trading problem of a flexible storage unit in the continuous intraday market is modelled. In [36], the efficiency of continuous double auction for intraday markets is questioned. They argue that when the cost of flexibility provided by markets participants is time dependent (more expensive closer to real-time), an auction-based market could be more suitable. In [37], a decentralized market with continuous double auction and based on blockchain is designed in order to facilitate transactions between distributed generations and consumers. However, these continuous markets do not take the physical constraints of the network into account.

Other market options have been studied to consider the distribution network. In [38], the DSO directly negotiates with the flexibility aggregators, through an iterative process to agree on a price. Apart from that, peer-to-peer markets have gained a lot of attention lately. In [39], TSO and DSO participate in the market along with prosumers. Both network operators take into account the physical constraints of their respective network to decide on the trades they want to get involved in. However, in this example, the prices of the trades are decided by the independent market operator.

Basic system model to be followed

For a continuous market application, a matching algorithm needs to be designed. It should perform the following tasks:

- Find a match for a newly added bid
- Add unmatched bids to the proper Shared Order Book (SOB)
- Order the SOBs
- Perform a check on the distribution network: line congestions and voltage deviations.

Regarding the dispatch validation part of the algorithm, several options will be considered:

- Using the relaxed AC-OPF with a different objective function (minimizing line congestions and voltage deviations)
- Implementing AC-PTDF (Power Transfer Distribution Factor)
- Applying a branch-flow method

- Training a learning structure to label a given dispatch as acceptable or not with regards to line congestions and voltage deviations

Basic problem formulation and algorithmic solutions

Any bid entering the market is called an offer. It has an associated location in the system (bus), price, quantity and direction: up if it offers to increase the load at this bus and down if it offers to decrease the load at this bus. When an offer is submitted, there is a tentative to find a match with the existing offers. An offer up can only match with an offer down if the price of the offer up is greater or equal to the price of the offer down.

Whenever a match is found, a power flow validation algorithm is run: the match can only be confirmed if line congestions and voltage deviations are avoided. If this is not the case, the next match is evaluated. The total flow is illustrated in Figure 9.

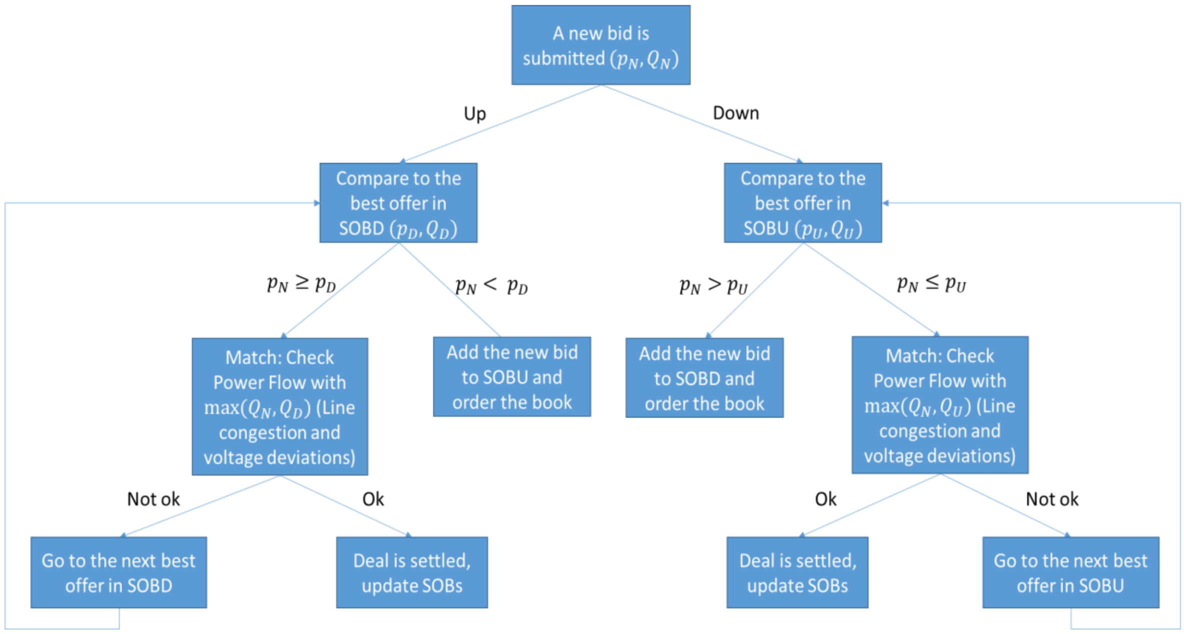

Figure 9: Flow diagram triggered by the submission of a new bid to the continuous flexibility market

If no match can be found or if the new offer was only partially matched, the remainder is added to the Shared Order Book (SOB) to be matched later. There are two SOBs: one for bids up (SOBU) and one for bids down (SOBD). The SOBs are always ordered so that offers can match based on their ranking in the SOBs: the offer up with the highest price is always matched with the offer down with the lowest price. If some offers have the same price, the oldest offer has priority. Therefore, the SOBU is ordered so that the highest price is first, and the SOBD is ordered so that the lowest price is first.
The DSO participates in this market similarly as the other participants. He would issue an offer up at a given bus when he needs the load to decrease at this bus, and an offer down at a given bus when he needs a load increase at this bus. The main difference is that the DSO would set extreme prices, to make sure that his offers are prioritized.
The payments are executed in a pay-as-bid fashion. When bids match, both sides get the price they bid as a payment. As a consequence, there will be a surplus for the market when the participants did not bid the same price.
The matching algorithm is designed to be able to take into account different types of execution restrictions:

- IOC (immediate or cancel): If the offer cannot be matched immediately, it is deleted without being added to the book. Partial execution are allowed.
- FOK (fill or kill): Similar to IOC except that partial executions are not allowed.

- AON (all or nothing): Can only match for its full quantity.

3.3. Datasets to be used for simulation setup and most important KPIs

In order to test the continuous market clearing algorithms, the following inputs are necessary:

- Parameters of the tested distribution network (topology, operating limits…)
- Sets of FlexRequest and FlexOffers for this network
- Planned production and consumption of the assets in this network

The following KPIs will be studied to evaluate the performance of the algorithms:

- Total computational runtime
- Social Welfare
- Cost reduction achieved (compared to grid reinforcement)
- Number of transactions
- Volume of transactions
- Market utilization factor

It is very important for treatment of new bids to happen fast, in order to avoid a long latency when many offers are submitted in a short amount of time.

More details on these KPIs are available in Table 6:

Table 6: KPIs to evaluate the performance of the algorithms

KPI	Description
Total computational runtime	How long it takes for the algorithm to return results. It should stay below a defined threshold.
Social Welfare	Difference between how the actors value flexibility and the money they get for it
Cost reduction achieved	Difference in cost with implementing a reinforcement of the network instead of having flexibility markets
Number of transactions	Number of bids matches in the flexibility market over the evaluation period
Volume of transactions	Quantity of energy or capacity traded in the flexibility market over the evaluation period
Market utilization factor	Number of times that the market is used per year

3.4. Multi-Period model

Introduction and FLEXGRID contributions

In the previous sections, the temporality has not been addressed. However, it is important to consider time, especially in a flexibility market, for the following reasons:

- To properly integrate the behavior of charging and discharging batteries
- To allow block offers (contracts extending over several time periods, which must be matched all together)
- It should be possible to offer a load decrease at a given time period under the condition to get a load increase of the same amount at another time period (load shifting)

Related work in the international literature

The need to consider multi-period market clearing for flexibility markets has been addressed in [40], which insists on the fact that the DSO has to take into account the payback effect, which is the will for participants to consume later when they reduce their load due to the provision of flexibility.

Solving a relaxed AC-OPF over several time periods has already been studied. In [41], a security-constrained unit commitment (SCUC) based on SDP is introduced. Although this can solve in polynomial times for small systems, there is no proof of scalability for large network. In [42], an SOCP formulation is used in a multi-period framework to help decision making for investment in storage units.
What about line congestions and voltage deviations? What are the limits?

In [38], the continuous flexibility market is cleared considering a 24-hour trading period in order to consider the charging and discharging patterns of home batteries and electric vehicles.

3.5. Modelling aspects

The multi-period formulations would be evolutions of the AC-OPF and continuous auction algorithms introduced in the previous sections. The main challenge is the introduction of integers, which would increase the computational burden and will be an additional difficulty to ensure the scalability of the models.
The management of the payback effect should be a responsibility of the aggregator. The aggregator should offer to its customers the possibility to shift their load, and he would then oversee formulating the proper bids on the flexibility market. However, to help this behavior, it should be possible to submit a type of block offer consisting of a block up and a block down.

3.6. Incentive compatibility and market power mitigation for FSPs in a DLFM context

In the two above-mentioned market clearing schemes for the proposed Distribution Level Flexibility Markets (DLFM), it is assumed that all market participants (i.e. individual FlexAssets or the portfolios of FSP companies) submit truthful bids to the Flexibility Market Operator (FMO) in a competitive manner. However, this is a strong assumption given the fact that in the future, FSPs may act strategically, compromising thus the social welfare (or else market efficiency). In this section, we propose a market clearing scheme, which achieves social welfare maximization (or else minimizes the cost of flexibility procurement) and is at the same time incentive compatible (i.e. the reward structure of the proposed pricing scheme incentivizes FSPs to bid their true valuation function for the service that they provide).

Introduction and FLEXGRID contributions

As already stated in the previous sections, today's distribution grids cope with congestion avoidance and voltage control problems by constraining future RES investments, curtailing peak RES generation or establishing static and long-term availability contracts between the DSO and the FSP (i.e. FlexAssets). However, research work in FLEXGRID takes a market-based approach by focusing on:

- the evolvement of the current energy markets' operation towards new energy market architectures that better accommodate distributed and high RES penetration in the distribution grid
- the efficient aggregation of end-user flexibility assets by FSPs and their optimal and parallel use in multiple energy markets
- the optimal use of FSPs' assets and their operation according to market-based signals.

FLEXGRID proposes the development of a distribution level flexibility market (DLFM), which guarantees the constraint satisfaction of the distribution network and will enable the dynamic and efficient exploitation of distributed and small-scale flexibility assets (i.e. controllable loads, energy storage, electric vehicles etc.). When a flexibility service is required at a particular node of the distribution grid and timeslot, the set of eligible FlexAssets that can offer this service is often very small due to topology constraints. In such cases, the challenge is to guarantee truthful (as opposed to strategic) player participation towards achieving high market efficiency. Therefore, FLEXGRID proposes an optimal and incentive compatible mechanism in order to achieve high market efficiency (i.e. flexibility services' procurement with the lowest possible cost) and truthful FlexOffers from the involved FlexAssets (or else FSPs).

Conclusively, the proposed market clearing scheme elaborates on the two market clearing schemes described above (i.e. network-aware "pay-as-clear" and "pay-as-bid" schemes) by developing:

- A Vickrey-Clarke-Groves (VCG) mechanism for the DLFM's reward structure, so that strategic FSPs cannot cheat the system for their own benefit.
- An optimization and data exchange framework able to provide a dispatch schedule that respects distribution network constraints with the minimum flexibility cost.

Finally, it should be noted that Reactive DLFM (R-DLFM) model is considered (see more in section 2.4.2), which is compatible with the existing energy market architecture.

Related work from the international literature

The optimal operation (and constraint satisfaction) of the distribution network has been extensively studied in the literature, albeit mostly within a "direct control" [4] architecture. Truthful bidding in electricity markets has been addressed in studies, where techniques from game theoretic mechanism design are employed in wholesale [43] or local [44] - [45] electricity markets. However, to the best of our knowledge, game-theoretic studies for local electricity markets have not accounted for the operational constraints of the distribution network, while studies that address operational issues of the distribution network did not aim at obtaining an efficient market procedure [46].

As far as dispatch algorithms are concerned, energy markets use a set of optimization problems that are important for market clearing in electricity grids, known as Optimal Power Flow (OPF) (see more details in the sections above). As long as we assume that the market participants (FSPs) truthfully and honestly declare their costs, Distribution Locational Marginal Prices (DLMPs) for each node of the distribution network can be calculated in three main ways as extensively described in [47]. The first concerns duality analysis of the problem formulated with a global power balance constraint, the second a duality analysis of a second-order cone program relaxation, and the third an analysis of marginal losses' impact on price.

Regarding the declaration of the participants' local parameters and costs, [48] assumes that market participants accurately provide the operator with their preferences, and the latter optimizes the social welfare. Additionally, [49] assumes that market players (e.g., consumers) forecast their energy requirements and truthfully report their forecast to an aggregator. Furthermore, [50] deals with a set of truthful consumers that participate in a centrally coordinated load controller, whose objective is to meet demand side management requirements. In these three studies, market players honestly reveal and send their bids. The studies in [51] also assume that market players bid truthfully, which is rather a strong assumption for future liberalized energy markets.

The work in [52] develops two simple billing rules and proves that best-response dynamics converges to Nash Equilibrium, while [53] proposes a game-theoretic mechanism that also accommodates coupling constraints. Recent studies, [54] and [55], present payment algorithms that consider an additional

[4] By the term "direct control", we mean that the DSO is responsible for controlling the loads and other types of FlexAssets directly via its DMS in order to keep the DN operation within acceptable limits.

requirement, namely the pricing fairness of the consumption allocation. Furthermore, [56] studies the effect of the FSP's profit policy. However, these studies also assume that market players truthfully interact with the payment algorithm, and thus they don't compromise the algorithm's properties. It is, however, well reported (e.g. using bi-level programming [46]; see also references therein) that a participant can benefit through strategic bidding, while compromising social welfare. It is therefore necessary to apply a different (and thus more complex) market clearing process in order to guarantee that non-truthful bidding will not be beneficial to the bidder.

Game theory is a well-established theoretical tool that allows the relaxation of the truthful bidding assumption. In more detail, a game is typically defined by a set N of n players, a set S_i, where $i \in N$, of strategies available to each player (e.g. bids) and a set of payoffs that maps each joint strategy combination $\times\{S_i, i \in N\}$ to a set of player rewards (payoffs) $\times\{R_i, i \in N\}$. Mechanism design theory is a subfield of game theory in which there is a system designer that tries to design the game's reward structure. More specifically, this research work develops a Vickrey-Clarke-Groves (VCG)-based pricing mechanism [**Error! Reference source not found.**] in a setting where a given set of resources (i.e. flexibility service requirements) needs to be allocated to a number of players (FSPs) based on their FlexOffers. Assuming rational, selfish and strategic players, typical criteria for such a mechanism include:

- Efficiency of the allocation in terms of Social Welfare (i.e. whether the service is fulfilled at the minimum cost).
- Tractability of the outcome (i.e. whether an efficient allocation can be computed in polynomial time).
- Incentive compatibility (i.e. whether the reward structure incentivizes players to bid their true valuation for the service).

System model and problem statement

The design of a flexibility market in the distribution level requires specifying: i) its interaction with the existing energy markets and the DSO, and ii) the bidding protocols of the market participants/players (FSPs). In addition, there are two major algorithms that are involved in the operation of the DLFM as illustrated in Figure 3. The first one relates to the allocation rule (cf. Distribution Network Dispatch Algorithm - DNDA) and the second relates to a pricing rule for the market participants (cf. Distribution Network Payment Algorithm - DNPA).

Our work focuses on developing a novel DNPA by leveraging on the well-known VCG mechanism. VCG mechanism is provably [57] the unique Dominant-Strategy-Incentive-Compatible (DSIC) [5] welfare maximizing mechanism. It achieves incentive compatibility by solving the welfare maximizing problem n times, where each time the problem is solved with one player absent from the market, plus one more time with all participants in order to find the optimal payments. In order to define the reward of a player i, the mechanism calculates the sum of the accepted FlexOffers of other users $j \in N/i$, in two cases (in the former, i is present in the system and in the latter i is absent from the system). The compensation of i is defined as the difference between these two values.

The proposed system model considers a Reactive Distribution Level Flexibility Market (R-DLFM) architecture proposed within FLEXGRID project (see more details in section 2.4.2 above). In more detail, we consider a Flexibility Market Operator (FMO), which operates a DLFM on behalf of the DSO in the distribution network level. The FMO's objective is to procure the necessary flexibility at the minimum cost to the DSO, in order for the latter to avoid congestion problems and voltage violation issues. The steps of the process that the proposed R-DLFM follows can be summarized as follows:

[5] DSIC is the strongest form of incentive compatibility.

- **Step 1**: The FMO takes as input the wholesale day-ahead energy market dispatch that is composed from the power flows in the coupling point with TSO and the dispatch that concerns prosumers and consumers in its distribution network.
- **Step 2**: DSO sends information that suffice to model its distribution network to FMO.
- **Step 3**: FSPs (e.g. aggregators) connected to the DSO send their FlexOffers to FMO.
- **Step 4**: FMO generates Distribution Network Dispatch (DND) through the execution of an optimization algorithm noted as Distribution Network Dispatch Algorithm (DNDA) which:
    - respects distribution network constraints (i.e. a) active/reactive power balance, b) mitigates network congestion, c) accommodates voltage control
    - implements fundamental economic rules, which means that distribution network constraints will be satisfied by activating FlexOffers in the least costly manner. More details about the Distribution Network Dispatch Algorithm (DNDA) are provided below.
- **Step 5**: Flexibility assets (FSPs) are compensated for their operation according to a Distribution Network Payment Algorithm (DNPA) that FMO executes. More details about the Distribution Network Dispatch Algorithm (DNPA) are provided below.

Problem formulation

As already explained above, we consider that the proposed DLFM takes place after a distribution network agnostic wholesale day-ahead energy market clearing process and also after the publication of day-ahead energy market dispatch schedule for all market participants. Then, the FSPs declare their flexibility assets' (i.e. residing at DN level) capabilities and costs. Then, the FMO seeks to ensure the feasible and reliable operation of the distribution network by procuring the necessary flexibility at minimum cost. Thus, the FMO solves an Optimal Power Flow (OPF) problem in order to calculate the optimal dispatch schedule at the DN level.

The FMO's objective function tries to minimize the cost of flexibility procurement via the optimal (active/reactive power) dispatch of the FSPs. Each FSP/individual FlexAsset bids its active/reactive power capacity and the minimum price at which it will provide it. Furthermore, each MW of reduction in the load/generation calculated in day-ahead energy market dispatch will incur high societal and monetary costs for the load representatives and distributed generators (i.e. Lost Load, RES spillage, penalties for the possible deviation from the scheduled operating points of day-ahead energy market dispatch schedule, etc.). All these costs are represented in the FMO's objective function. Subsequently, this optimization problem is subject to several constraints that should be expressed through respective mathematical equations. In a nutshell, these constraints are related with: i) constraints of the flexible devices/assets, and ii) distribution network constraints, which are (among others) a function of active/reactive power flow and the nodal voltage magnitude. More technical details about the problem formulation of the proposed Distribution Network Dispatch Algorithm (DNDA) will be provided in the next deliverable D5.2.

Regarding the proposed Distribution Network Payment Algorithm (DNPA), in contrast with the recent literature that typically uses the LaGrangeian multipliers to produce nodal Distribution Locational Marginal Prices (DLMPs), the proposed DNPA leverages on the Vickrey-Clarke-Groves (VCG) mechanism. Thus, according to the Distribution Network Dispatch Algorithm (DNDA) described above, the optimal market dispatch is achieved and in the same time, it is also ensured that it is to each participant's (FSP's) best interest to truthfully declare their true opportunity cost for providing the required service. In other words, FSPs cannot benefit from falsely inflating their bids or not offering their whole capacity. Therefore, based on DNDA's results, the FMO calculates the rewards to each FSP using the Clarke pivot rule: $r_i = \boldsymbol{C_f}(\boldsymbol{x}_{-i}) - \boldsymbol{C_f^{-i}}(\boldsymbol{x}_{-i})$, where r_i is the payment to FSP *i*, $\boldsymbol{C_f}(\boldsymbol{x}_{-i})$ denotes the flexibility cost of FSPs that belong to set F/i in case that i participates in the market, and $\boldsymbol{C_f^{-i}}(\boldsymbol{x}_{-i})$ denotes the flexibility cost of FSPs' that belong to set F/i in case that FSP *i* is excluded from the market. The second term in the payment rule represents the contribution of FSP *i* in the total flexibility cost. In order for the first term to be calculated, the optimization problem (cf. DNDA) is solved without considering the bids and capacity of FSP *i*. In this way, the FMO offers an efficient clearing process of a topology aware market in the distribution network level.

Simulation setup, required datasets and KPIs to be measured

Our goal is to setup system-level simulations in order to compare our proposed VCG-based DLFM to a DLMP-based DLFM and pay-as-bid DLFM under various market setups and levels of Distributed Generation (DG) penetration at the DN level. We will simulate an imperfect DLFM, in which there is one strategic FSP that chooses its optimal bidding strategy in order to maximize its profits, while the other FSPs truthfully bid in the market. In order for the strategic FSP to achieve higher market profits, it can either declare a higher cost of its services than the true one (economic withholding), or offer a lower flexibility capacity (physical withholding). Our goal is to show that in a DLMP-based and pay-as-bid DLFM, an FSP that acts strategically can manipulate the market in order to achieve higher profits, thus resulting in a higher flexibility cost for the FMO, in contrast to our proposed VCG-based DLFM, in which every FSP is incentivized to declare its true cost and capacity.

The simulation setup may include several “what-if” scenarios regarding (non-exhaustive list):

- Several levels of DLFM liquidity (i.e. high, medium, low, etc.)
- Several variants of distribution network setups (i.e. IEEE x-node test cases)
- Several levels of distributed generation penetration
- Several sizes and sites of RES/FlexAssets residing in the DN
- Several strategic bidding cases from one or more FSPs

The major Key Performance Indicators (KPIs) that will be measured are (non-exhaustive list):

- Optimality/social welfare
- Market efficiency (especially in relatively low liquidity DLFM cases)
- Incentive guarantees/strategy proof market mechanism
- Fairness in the way that FSPs are reimbursed according to their contribution
- Cost of flexibility procurement by the FMO/DSO
- Accuracy in the modeling of the distribution network
- Scalability (i.e. mathematical/algorithmic complexity)
- FSP’s profits
- Energy cost reduction for end users
- RES curtailment/spillage to keep the DN within acceptable operating limits

Chapter 4. Distribution Level Flexibility Market: Opportunities and Challenges for TSO/DSO operation

4.1. Direct control of FlexAssets by DSO/TSO

In this sub-chapter, five models for TSO-DSO coordination will be presented. Each coordination scheme will determine the operational processes and information exchanges between system operators related to prequalification, procurement, activation and settlement of flexibility-based services that impact both transmission and distribution system level.

Each coordination scheme is characterized by a set of roles, taken up by TSOs, DSOs and other market players, and a general market design, in line with these roles. The distinction between roles is essential as the increased need for coordination between system operators should not create any confusion in allocating respective roles and responsibilities [58].

A role is defined as an intended behavior of a specific market party which is unique and cannot be shared. Each role has certain responsibilities inherent to the role. A role defines how one market party interacts with another market party during a certain transaction [59].

Centralized AS market model

In this scheme, The TSO contracts DER directly from DER owners connected to the DSO grid for AS purposes. The DSO can procure and use resources to solve local grid issues, but the procurement takes place in other timeframes than the centralized AS market. Table 7 summarizes the market design and main responsibilities for each system operator (i.e. TSO and DSO).

Table 7: Centralized AS market model

Characteristics	
Market design	There is one common market for ancillary services, operated by the TSO, for both resources connected at transmission and distribution level. There is no separate local market.
TSO role	The TSO is responsible for the operation of its own market for ancillary services. The TSO does not take DSO constraints actively into account. A separate process (system prequalification) could be installed to guarantee that the activation of resources from the distribution grid by the TSO does not cause additional constraints at the DSO-grid (e.g. congestion).
DSO role	The DSO is not involved in the procurement and activation process of AS by the TSO, except in the case that a process of system prequalification13is installed to guarantee that the activation of resources from the distribution grid by the TSO does not cause additional constraints at the DSO-grid (e.g. congestion). The DSO is not procuring local flexibilities in real-time or near to real-time.

Figure 10 illustrates the role played by relevant stakeholders. Additionally, the figure shows a high-level view of the market architecture and interactions among players.

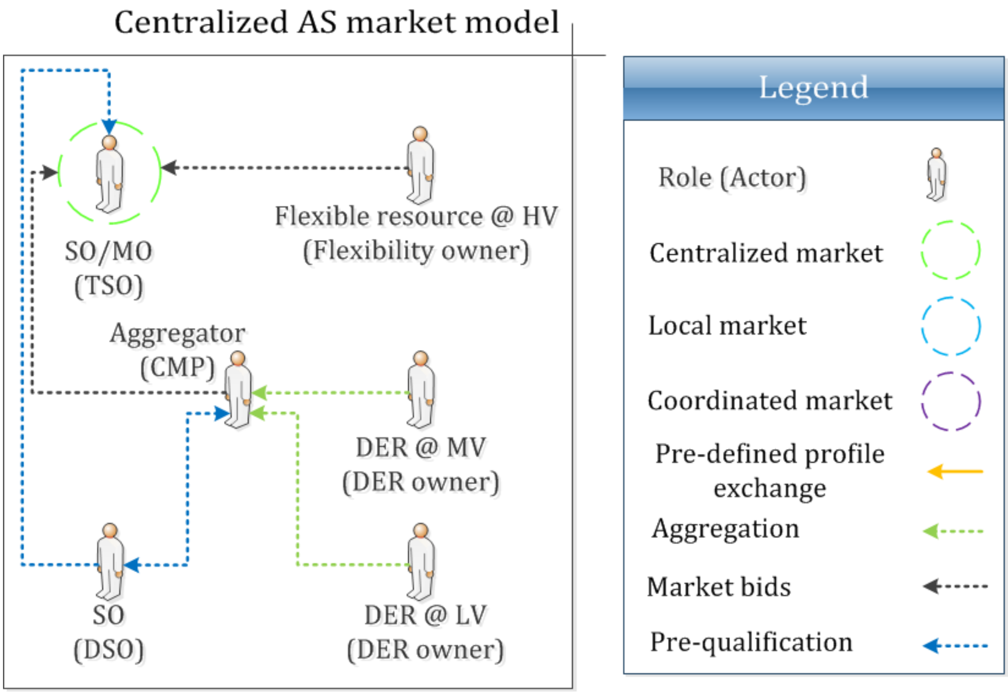

Figure 10: Centralized AS market model: high-level view of roles, market architecture and stakeholder Interactions [60]

In summary, this scheme limits the involvement of the DSO to a possible role in the system prequalification process (Figure 10). To note that in exceptional cases, the DSO might want to include DSO grid constraints in the TSO market clearing process. Consequently, the DSO will need to provide the necessary data to the TSO or the TSO should have full observability of the DSO-grid.

Local AS market model

The main principle of this scheme is the operation of a local market by the DSO. The TSO can contract DER indirectly via a local market, after the DSO has aggregated these resources and has transferred them to the TSO AS market. Table 8 summarizes the market design and main responsibilities for each system operator (i.e. TSO and DSO).

Table 8: Local AS market model

	Characteristics
Market design	There is a separate local market managed by the DSO. Resources from the DSO grid can only be offered to the TSO via the DSO/local market and after the DSO has selected resources needed to solve local congestion. The DSO aggregates and transfers bids to the AS market, operated by the TSO. The DSO assures that only bids respecting the DSO grid constraints can take part in the AS market.
TSO role	The TSO is responsible for the operation of its own market for ancillary services, where both resources from the transmission grid and resources from the distribution grid (after aggregation by the DSO) can take part.
DSO role	The DSO is the operator of a local market for flexibility. The DSO clears the market, selects the necessary bids for local use and aggregates and transfers the remaining bids to the TSO-market. The DSO has priority to use the flexible resources from the local grid.

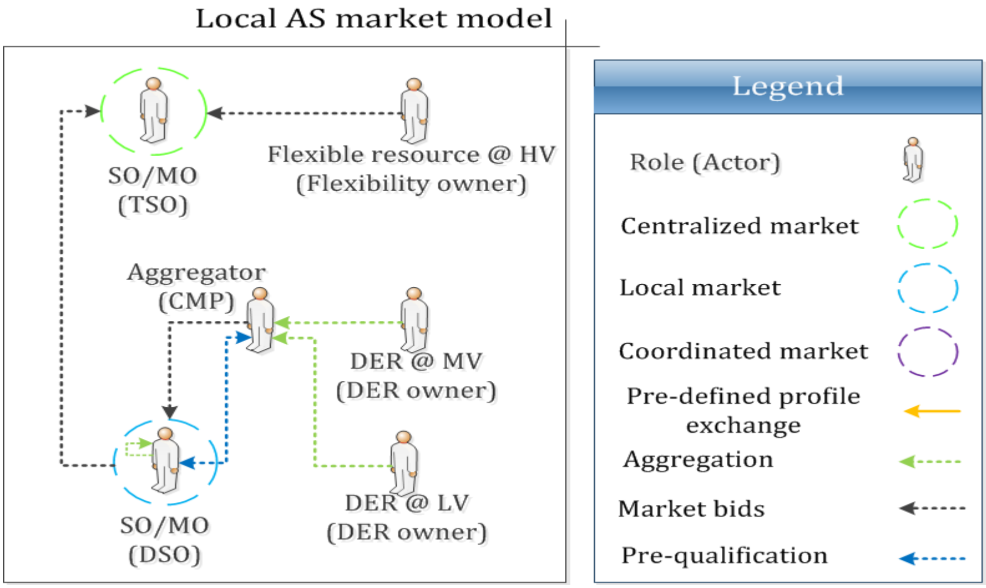

Figure 11: Local AS market model: high-level view of roles, market architecture and stakeholder Interactions [60]

In sum, the *Local AS market model* deviates from the *Centralized AS market* model by promoting a local market. The implementation of such a market shifts priority towards the DSO. All flexibility not needed/procured at the local market (where the DSO is the market operator) is sent to the central market (where the TSO acts as the market operator) in an aggregated form, taking into account that the distribution network constraints are respected (e.g. some local market bids could possibly not be transferred to the TSO if that would jeopardize the distribution grid operation). In this scheme, the DSO contracts and aggregates (already) aggregated bids.

Shared balancing responsibility model

For this scheme, the TSO transfers the "balancing" responsibility for the (local) distribution grid to the DSO. The DSO has to respect a pre-defined schedule15 and uses local DER (obtained via a local market) to fulfill its balancing responsibilities. The pre-defined schedule is based on the nominations of the BSPs (for the entire DSO-area), possibly in combination with historical forecasts at each TSO-DSO interconnection point. In case the pre-defined schedule is based on the outcome of the energy-only markets, TSOs and DSOs do not make any modifications to this schedule. This means that the pre-defined schedule is determined at the level of the entire DSO-area and not at the level of the TSO-DSO interconnection point, due to the fact that today, nominations are not exclusively made for each TSO-DSO interconnection point.

Alternatively, TSOs and DSOs could determine the pre-defined schedule, using historical forecasts for each TSO-DSO interconnection point, together with congestion constraints for both the transmission and distribution grid. In this second option, the pre-defined schedule is determined for each individual TSO-DSO interconnection point. Table 9 summarizes the market design and main responsibilities for each system operator (i.e. TSO and DSO).

Table 9: Shared balancing responsibility model

Characteristics	
Market design	There is an AS market for resources connected at the TSO-grid, managed by the TSO. There is a separate local market for resources connected at the DSO-grid, managed by the DSO. Resources from the DSO-grid cannot be offered to the TSO grid. DSO constraints are integrated in the market clearing process of the local market.

TSO role	The TSO is the operator of the AS market, limited to resources connected at the transmission level. The TSO is responsible for the balancing of the transmission grid.
DSO role	The DSO is the operator of a local market. The DSO contracts local flexibility for both local congestion management and balancing of the DSO-grid. The DSO is responsible for the balancing of the DSO-grid, i.e. respecting the pre-defined schedule.

Figure 12 illustrates the role played by relevant stakeholders. Additionally, the figure shows a high-level view of the market architecture and interactions among players.

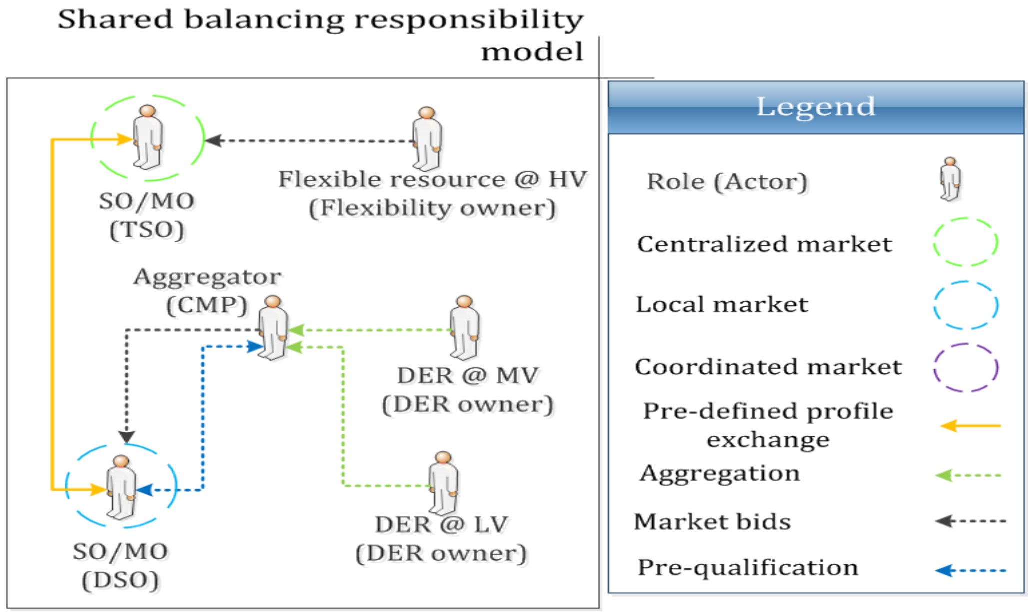

Figure 12: Shared balancing responsibility model: high-level view of roles, market architecture and stakeholder interactions [60]

The Shared balancing responsibility model is the only coordination scheme where the TSO has no access to resources connected at the distribution grid. Flexibility from the distribution grid is reserved exclusively for the DSO, in order to fulfil its responsibilities with respect to local grid constraints and local grid balancing.

Common TSO-DSO AS market model

The Common TSO-DSO AS market model promotes a common flexibility market for system operators (SO). The procurement of resources made under this coordination scheme has as main goal to minimize total procurement costs of flexibilities. This idea is also supported by the recent position paper issued by CEER which states that it is essential that controls on revenue recovery for DSOs and TSOs create incentives to optimize outcomes for the system as a whole, rather than focusing on minimizing the DSO's and TSO's costs in isolation [14]. Table 10 summarizes the market design and main responsibilities for each system operator (i.e. TSO and DSO).

Table 10: Common TSO-DSO market model

Characteristics	
Market design	There is an AS market for resources connected at the TSO-grid, managed by the TSO. There is a separate local market for resources connected at the DSO-grid, managed by the DSO. Resources from the DSO-grid cannot be offered to the TSO grid. DSO constraints are integrated in the market clearing process of the local market.

TSO role	The TSO is the operator of the AS market, limited to resources connected at the transmission level. The TSO is responsible for the balancing of the transmission grid.
DSO role	The DSO is the operator of a local market. The DSO contracts local flexibility for both local congestion management and balancing of the DSO-grid. The DSO is responsible for the balancing of the DSO-grid, i.e. respecting the pre-defined schedule.

Figure 13 illustrates the role played by relevant stakeholders. Additionally, the figure shows a high-level view of the market architecture and interactions among players.

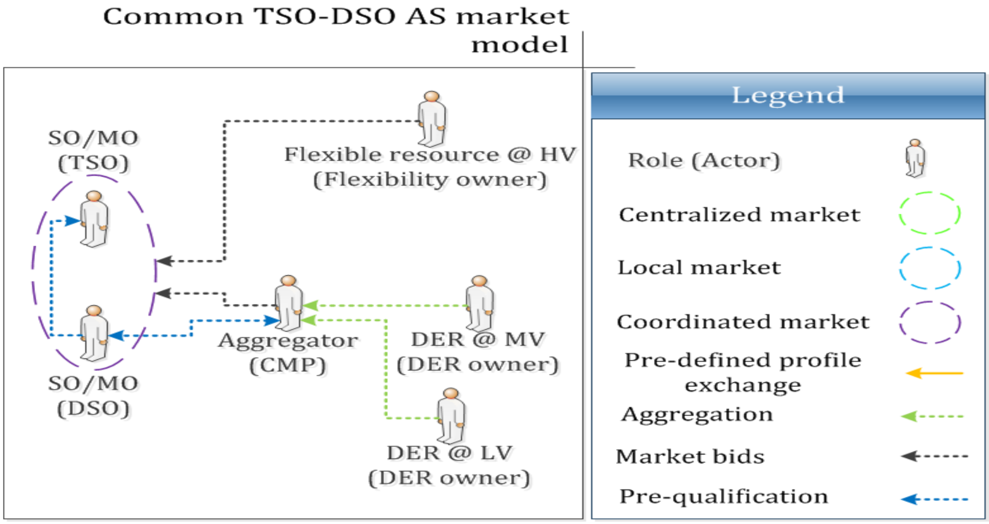

Figure 13: Common TSO-DSO AS market model: high-level view of roles, market architecture and stakeholder interactions [60]

In summary, the Common TSO-DSO AS market model could be seen as an extension of the Centralized AS market model (for the centralized variant) and the Local AS market model (for the decentralized variant). In the centralized variant, the optimization is still organized by aggregating both resources connected at transmission grid and distribution grid, but in this scheme, not only TSO grid constraints are integrated but also DSO grid constraints and possible local needs for flexibility are part of the common market. The decentralized variant differs from the Local AS market model in such a way that the DSO has no priority to use flexible resources from the distribution grid.

Integrated flexibility market model

The Integrated flexibility market model promotes the introduction of a market where regulated (TSO and DSO) and commercial market parties (CMPs) procure flexibilities in a common market. Table 11 summarizes the market design and main responsibilities for each system operator (i.e. TSO and DSO).

Table 11: Integrated flexibility market model

Characteristics	
Market design	The common market for flexibilities is organized according to a number of discrete auctions and is operated by an independent/neutral market operator. There is no priority for TSO, DSO or CMP. Resources are allocated to the party with the highest willingness to pay. There is no separate local market. DSO constraints are integrated in the market clearing process.
TSO role	TSOs are contracting AS services in a common market. TSOs can sell previously contracted DER to the other market participants.
DSO role	DSOs are contracting flexibilities for local purposes in a common market. DSOs can sell previously contracted DER to the other market participants.

Figure 14 illustrates the role played by relevant stakeholders. Additionally, the figure shows a high-level view of the market architecture and interactions among players.

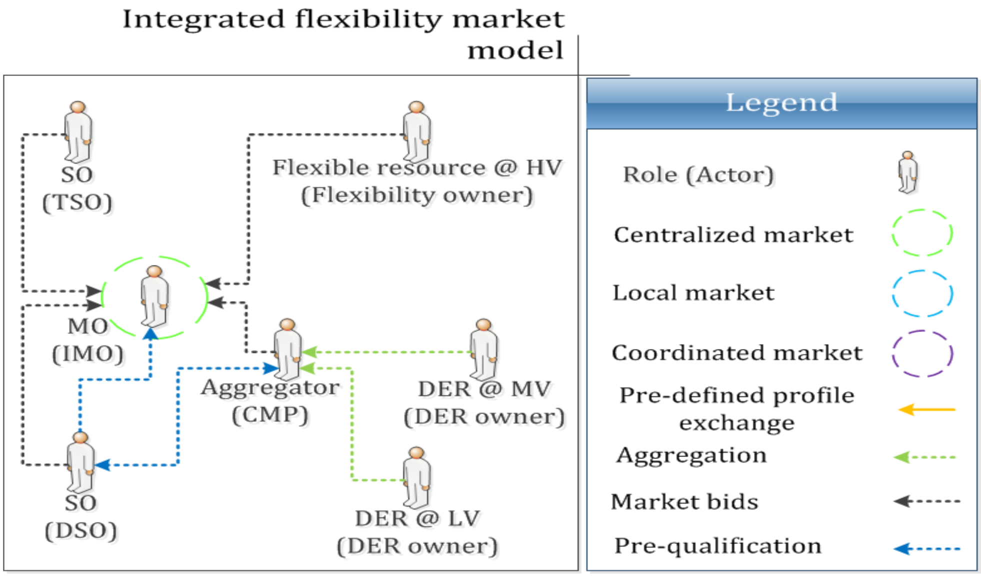

Figure 14: Integrated flexibility market model: high-level view of roles, market architecture and stakeholder interactions [60]

In sum, the Integrated flexibility market model proposes a market mechanism where available flexibility can be procured by system operators and commercial market parties under the same conditions. There is no distinction between regulated and liberalized actors. Market forces dictate how flexibility will be allocated. This allocation, however, will respect grid constraints at all voltage levels.

4.2. Mapping of roles and coordination schemes

In each coordination scheme, the DSO will be responsible for system prequalification, i.e. the process where the impact of a certain flexibility source is assessed on the DSO-grid. The technical prequalification, where the technical capabilities of the flexibility source are verified, could be done by a verified independent actor, which should not necessarily be a system operator. A certification from this verified body is than sufficient to make a request for system prequalification.

The DSO is the only entity that can be responsible for system prequalification. As data manager (DM) and system operator (SO) of the distribution grid, the DSO is capable, without third-party intervention, to analyze scenarios and assess potential impacts. Alternatively, if the DSO is not involved in the process of system prequalification, the TSO could perform the assessment on behalf of the DSO, under condition that all relevant data are available and communicated to the TSO. This might be optimal in case of a large number of small DSOs. However, the implications of the latter option would have to be further investigated. This in order to avoid potential situations that may impact distribution grid operation costs and dynamics (e.g. non-coordinated actions from TSO and DSO, duplication of data,…).

The role of buyer and seller of flexibility-based services, provided by DER, changes across coordination schemes.

In the Centralized AS market model, only the TSO is actively buying resources in short-term (dayahead, intraday and real-time). The DSO is not buying flexibility-based services in the same timeframe as the TSO. However, the DSO might buy some flexibility resources in the longer term to solve e.g. structural grid congestion or to postpone certain grid reinforcements.

In the Local AS market model, the Shared balancing responsibility model, the Common TSO-DSO AS market model, and the Integrated flexibility market model, both TSO and DSO are buying flexibility-based services provided by resources directly connected to the distribution grid in the same time frame. In the

Local AS market model, resources from the distribution grid are allocated with priority to the DSO while in the Common TSO-DSO AS market model, the allocation of resources is based on a global minimization of the costs for concerned system operators. In the Shared balancing responsibility model, the TSO has no access to resources connected at the distribution grid, only the DSO can use these resources. In the Integrated flexibility market model, commercial market parties are also allowed to compete on an equal base with the regulated parties.

In most coordination schemes, commercial market parties (CMPs) are the sole sellers of flexibility resources. Only in the Integrated flexibility market model, system operators could, via the independent market platform, resell back to the market previously contracted flexibility. This could be done to increase liquidity and reduce grid costs.

In none of the coordination schemes, CMPs can make a trade-off between different flexibility markets, i.e. the location of a certain flexibility resource, in combination with the chosen coordination scheme, determines where the CMP could offer the flexibility. This means that for example in the Local AS market model, CMPs can only offer flexibility to the TSO, via the local market operated by the DSO. Also in the Shared balancing responsibility model, CMPs cannot offer flexibility, connected at the distribution grid, to the TSO.

The role of market operator is directly linked with the market design and is different for each coordination scheme. In the Centralized AS market model, the TSO operates both the AS market for resources connected at the distribution grid and for resources connected at the transmission grid. In the Local AS market model and the Shared balancing responsibility model, TSO and DSO are each responsible for the respective operation of the flexibility market of their grid. In the Common TSO-DSO AS market model, dependent on the market design, TSO and DSO operate together one common platform, or alternatively, operate each their respective markets, optimizing the outcome of both markets in mutual agreement. In the Integrated flexibility market model, the IMO takes over the role of market operator to guarantee neutrality as commercial market players are now competing with regulated entities.

The aggregation of flexibility resources is done by flexibility service providers or aggregators. Small individual DER are combined and offered in an aggregated way to the market. In addition, it is also possible for the DSO to aggregate individual bids, offered to the local market, and to send them to the TSO in an aggregated form, taking into account specific constraints from the DSO-grid. By doing this, the DSO guarantees that the bids coming from the DSO-grid and used by the TSO, respect all DSO grid constraints. The DSO carries out this activity of DSO-aggregation in the Local AS market model and the Common TSO-DSO AS market model (decentralized variant). In the former, the DSO aggregates after the resources needed to solve local constraints are taken out. In the latter, the DSO performs the aggregation, using all resources offered to the local market, combined in such a way that local constraints are not only respected but also solved, independent of the selection of bids made by the TSO.

After the clearing of the market, the most adequate resources are selected and can be activated. In the case of a capacity market, the buyer has received a capacity and should explicitly send an additional activation signal to the market operator, in case the buyer needs to activate the resource. In the situation of an energy only market, the activation is implicit in the confirmation of the bid (i.e. market clearing), given by the market operator. The activation involves a cascading process, starting with a signal sent from the market operator to the relevant CMP (seller of contracted flexibility). Next, the CMP sends an activation signal to the DER unit(s) required for service provision.

The responsibility for the meter readings to verify the activation could go done by the DSO, via the official DSO-meter or alternatively, in case approved by regulation, via an independent commercial player with an independent meter, only meant for measuring the activation of a flexibility resource.

4.3. Important design parameters

When designing a market for the distribution grid operator, several parameters need to be defined. Especially the following three are important design parameters [61] [62]:

- Technology neutrality: It is important to enable on the one hand side a market that allows for a level playing field for all technologies, but on the other side it is also important to allow the DSO to get the security for the grid that the DSOs nee to operate a grid safely.
- Product standardisation: Product standardisation allows more liquidity on the markets, but technologies with special characteristics are not enabled to bring in the full technological potential.
- Locational tagging: The size of a market highly influences the liquidity of the market, but the problems in the distribution grid are very local.

Table 12: Overview about relevant design parameters for DSO markets

Parameters	Options	Description	Recommendation for FlexGrid
Technology neutrality	Long-term procurement	Better to plan for grid operators	Design a market with long-term capacity reservation as well as allowing short-term bidding of energy bids
	Short-term procurement	Easier for flexible load and renewable energies to participate	
Product standardisation	Standardised products	High liquidity, possibility to build merit order	Standardize the products as much as possible for usual problems in the grids, but non-standardized products will be allowed in a continuous pay-as-bid market clearing.
	Non-standardised products	Special incentives	
Locational tagging	Location-based	The more local the more effective	This will be analysed in detail by considering the costs of the flexibility and the location.
	(Dynamic) zones or postal	The larger the area, the more competition	

4.4. Coordination schemes and the constraints of the Distribution grid

The use of flexibility from DER, connected at the DSO-grid, may have an impact on the grid imposing constraints to its operation. For instance, the activation of DER might violate voltage limits and/or overload distribution lines (leading to an increase in losses). It is therefore important to assess how DSO grid constraints should be integrated in the processes of procurement and activation of ancillary services in order to safeguard security of supply and quality of service. DSO constraints may be taken into account according to four (4) scenarios:

- ***Scenario 1:*** DSO constraints are not considered. This is currently the case in most European countries. It is clear that this is a scenario that could only be acceptable in case the share of resources connected from the distribution grid is below a certain threshold. This threshold may vary across MS and should take into account the state of the grid. Also in distribution grids that are heavily over- dimensioned, it could be agreed that it is not necessary to involve the DSO in any of the processes where the TSO contracts resources from the distribution grid.

- ***Scenario 2:*** The DSO is involved in a process of system prequalification. During this process, DER assets are analysed and approval is given by the DSO to the DER owner to participate to the flexibility market. The process of system prequalification differs from a more technical prequalification. During the process of technical prequalification, the technical requirements of a certain resource are assessed to make it eligible to deliver a specific service. During the process of system prequalification, the DSO assesses the impact of the delivery of a specific service by a certain resource on the grid. In case the delivery of the service in that specific area would violate grid constraints, the DSO could forbid the delivery of the service by that specific resource.

- ***Scenario 3:*** The DSO is not only involved during system prequalification (before procurement), but also after the clearing of the market. The DSO has the possibility to block the activation of a flexible resource (if selected by the clearing of the market), in case DSO constraints might be violated. Blocking a specific resource is a manual and iterative process. The market operator (in case it is not the DSO) will inform the DSO about the market results, the DSO will make an internal assessment and approves or blocks the selected resources. In case of blocking of certain resources, the market is cleared again, and the updated results are again sent to the DSO. It is clear that this manual check of DSO constraints might be operationally heavy as it could require multiple iterations within a very short time frame in case constraints of the distribution grid in a specific market are easily violated.

- ***Scenario 4:*** The DSO is not only involved during prequalification (before procurement), but DSO constraints are also integrated in the market clearing algorithm. This assures that the outcome of the market clearing will not violate DSO grid constraints. The advantage of this scenario compared to scenario 3 is that it is operationally much easier as no manual actions from the DSO are required after market clearing and no iterations are needed. Nevertheless, integrating physical grid constraints in the market algorithm might be heavy from a mathematical point of view. Also, this requires that the DSO provides the necessary data to the party responsible for the operation of the market. In case the DSO is the market operator, this is trivial, however, in case an external party operates the market, concerns related to privacy and confidentiality of data might need to be addressed.

The first scenario where DSO constraints are not taken into account, illustrates the current situation in most countries. As it can be seen, this scenario does not encourage the implementation of an active distribution system management. Moreover, it is only relevant for very specific conditions. This scenario will not be discussed in detail for the coordination schemes because such scenario does not require any interaction between TSO and DSO.

In case the DSO is the operator of a local market, which is the case in the Local AS market model, the Shared balancing responsibility model and the Common TSO-DSO AS market model, it is logic that DSO constraints are always taken into account in an automated way. This is operationally less heavy, and privacy and confidentiality of data are guaranteed.

In a market set-up where the DSO is not the operator of the market, which is the case in the Centralized AS market model and the Integrated flexibility market model, the choice between different scenarios depends on several aspects such as the state of the distribution grid, the requirements for data protection and confidentiality, the national organization of DSOs,… in order to determine which is the most optimal set-up. In the case of the Centralized AS market model, DSOs are only to a limited level involved in the processes for flexibility procurement and activation, carried out by the TSO. As a result, DSO involvement will be mostly limited to system prequalification. However, in some cases, DSOs might want to include DSO grid constraints automatically in the TSO market clearing. Therefore, DSOs will need to provide the necessary data to the TSO or alternatively, should allow the TSO to access directly certain DSO data.

In the Integrated flexibility market model, the market is operated by an independent market operator. This IMO could be responsible for the 'blocking' of certain bids, in order to guarantee neutrality. This is in particular relevant for the Integrated flexibility market model as DSOs are allowed to resell previously contracted DER. If DSOs are simultaneously a seller themselves and responsible for the acceptance of new sellers in the market (prequalification) and the acceptance of selected bids, this could create potential conflicts of interest. It is important that processes are in place to ensure appropriate justification and transparency around restrictive actions taken by the DSO or TSO [14].

The process of system prequalification is not always necessary in case DSO grid constraints are integrated in the clearing process in a manual or automated way. This could possibly result in a higher participation of DER to the market, but also a higher probability of bids not selected during or after the market clearing.

The advantage of the process of system prequalification is that it gives an indication to flexibility providers in case they might be located in a constrained area. It is important to highlight that the process of system prequalification should also be a dynamic process. It should give the right incentives to DSOs to invest in certain areas to unlock the potential of flexibility. As a result, a request for system prequalification, in case of a negative result, could be repeated after a certain period of time. Table 13 summarizes the main benefits and risks of a specific choice for handling DSO grid constraints.

Table 13: Benefits and risks across scenarios

	Benefits	Risks
Scenario 1 (distribution constraints not considered)	•No additional cost	•Constraints might not be respected
Scenario 2 (DSO involved in system prequalification)	•Implementation costs might be low • DSO grid constraints are taken into account • Provides more information to the DSO (enhancing grid observability)	• Constraints might not be respected • Need for accurate forecasts of future grid load • In order to secure the grid, safety margins taken by the DSO might be very conservative
Scenario 3 (DSO also involved after market clearing)	•DSO grid constraints are always respected • Provides more information to the DSO (enhancing grid observability)	• Heavy operational process (manual and iterative)

	• Mathematically not difficult to implement	• Deadline of finishing the market clearing process might be endangered by this process • Could create uncertainty in the market as it is unclear on which base DSOs might block activations • Issues with transparency
Scenario 4 (Constraints integrated in market clearing)	• DSO grid constraints are always respected • Provides more information to the DSO (enhancing grid observability) • Operational process is relatively light • No issues related to 'neutrality' of the DSO	• Heavy mathematical process to integrate all constraints in the clearing • Need for sharing data between DSO and market operator (discussions on security and privacy of data)

In case no DSO constraints are taken into account, flexible resources could be aggregated across several DSO areas without any problems. In case DSO grid constraints should be taken into account, aggregation of bids across several areas might need to reflect the locality aspect of the bid. Market products will need to decide if this means that aggregation will only happen at the level of the individual node or if aggregation could still happen over a larger area. In the second case, there could be e.g. market products that will only be partially cleared (dependent on the locality) in case of violation of constraints.

4.5. Minimization of network investments for the DSO

Research motivation and novel FLEXGRID contributions

Observing the current trends in the domain of power supply, few general observations are nonnegligible:

- Penetration of the intermittent energy resources [63]
- Distributed paradigm opposed to the centralized [64]
- Greater usage of modern energy storage solutions [65] due to:
    - Advancement in technology
    - Lower costs / economies of scale
    - Orientation from fossil fuels towards greener solutions
- Demand seasonality in some regions (e.g. touristic attractions) [66]
- Increasing share of EVs (thus greater power supply demand) [67]

Above mentioned facts, together with others that are not explicitly written, present potential problems for the distribution system operators as they may be demand growth catalysators, occasional or even constant. Those demand peaks may be greater than the nominal capacity of respective network segments, having for consequence partial inability to meet the requirements of consumers.

All questions regarding network infrastructure are generally under the respective DSO's jurisdiction [68]. Historically, DSO's primary concern was to always ensure stable and reliable power supply with regards to possible contingencies [69]. Although efficiency and rational economic solutions were also considered factors, but stable and reliable power supply was in most cases achieved firstly by oversizing network dimension plans for some region and, with the future demand growth, existing network would be reinforced and expanded. Such actions are above all capital intensive (both oversizing of the future network and expansion of the existing one), and, generally speaking, most of the time some parts of the distribution network remain heavily under-capacity as plans are always done according to the worst-case scenario predictions. Although, this is a viable solution strategy, and it has been proven effective regarding power supply safety and reliability, it presents great financial burden which, for instance, may result with postponing or even canceling of some other potential investment plans.

Considering major advancements in utilizing various energy storage systems (both technical and economic), introduction of distributed energy storage systems (with emphasize on renewable energy sources) and dynamic evolvement of electricity markets (and consequently appropriate business models) in general, we argue that DSOs may adopt more efficient and more rational strategies to ensure system's safety and reliability.

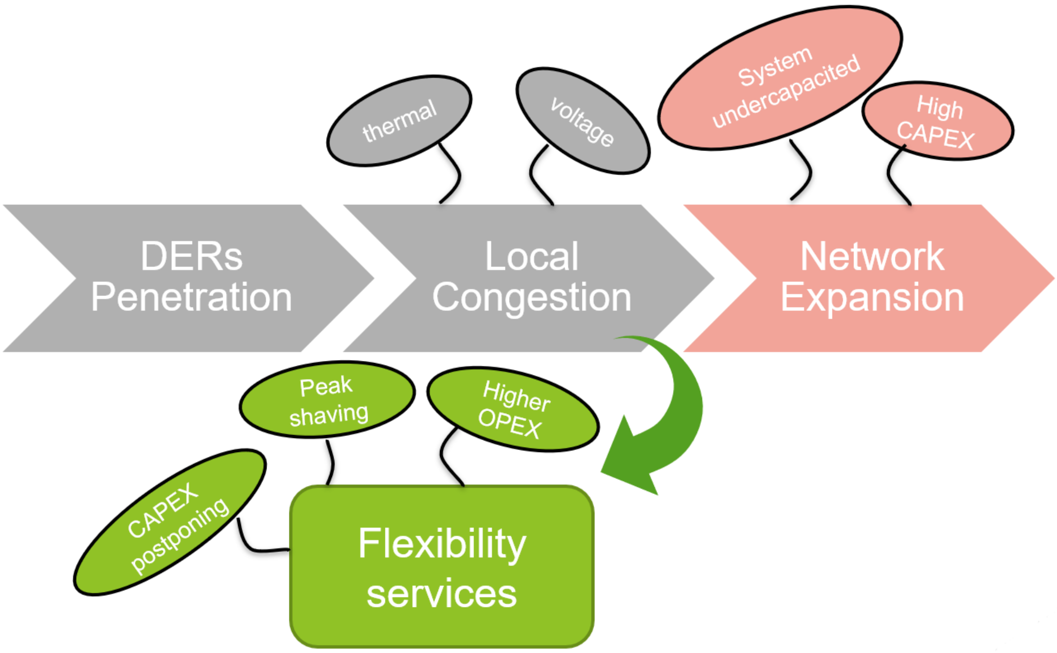

Figure 15: Ensuring system safety and reliability

The main motivation for this research case is the opportunity to ensure system safety and reliability but in a more efficient way. The opportunity itself stems from the traditional capital-intensive way of managing the network. Meaning that the aim is to postpone network investments when possible, reduce total amount of time when the system is in a heavily under-capacity state, and consequently reduce CAPEX. Reducing CAPEX, at least in scope of this research problem, will inevitably increase OPEX. It is precisely the trade-off between CAPEX and OPEX that will be one of the crucial factors when developing a model and creating efficient and profitable business strategies.

Novel FLEXGID contributions in scope of this research problem may be listed in three separate points that together form novel network managing strategy for DSOs:

- Bilevel optimization to minimize (and postpone) network investments
- OPEX rather than CAPEX for satisfying network needs
- Stackelberg competition (DSO and ESPs)

To encompass all the relevant factors for the successful development of novel network expansion postponing strategies, it is of crucial importance to understand both the needs of the DSOs and profit-oriented ESPs which need to be motivated to provide such service. Bilevel optimization alongside with the Stackelberg competition between DSO and respective ESPs are to model DSOs network cost minimization efforts and ESPs' profit maximization efforts. Such holistic approach should create a clear picture when (under what price and in what duration) procuring FlexServices makes sense both from the DSO's and ESP's perspective. Moreover, the model itself will generate appropriate price signals for the purpose of procurement of FlexServices opposed to capital intensive network expansion activities.

All in all, all above mentioned ongoing processes in the electricity power markets present challenges, but also opportunities for DSOs to treat network problems in a novel and (presumably) more efficient manner.

Survey on related work in the international literature

Various papers investigate how different technics may help in:

- Achieving peak shaving
- Solving congestions
- Postponing network reinforcements

In [70] authors argue that battery storage systems could help avoid expensive and unnecessary investments in grid reinforcement. Furthermore, as DSO is regulated system entity, authors claim that the most transparent way is to rent a battery (in some capacity). As batteries are still expensive, such model should also help investors in batteries to construct viable financial construction when planning future battery investments. Bilevel model proposed in the article (solved separately, where output of one level becomes an input parameter in the other one) compares conventional approach and battery storage integration trough voltage improvement and cost savings. Authors have showed potential benefits both for DSO (postponing network reinforcements) and aggregator (incentives to invest in battery storage).

Furthermore, Aguado et al. [71] focus on battery energy storage systems' role in transmission network expansion planning. Market-driven optimization models proposal for further network expansion and/or installation of battery storage system with the goal of maximizing social welfare. Results show increase in the net social welfare when batteries are included in network expansion process and in some cases storage system even delays the construction of some lines. Similarly, authors in [72] use Benders composition to model transmission network expansion and energy storage planning and argue that energy storage system installation is an efficient solution for the transmission upgrade deferral.

On the other hand, Moradijoz et al. in [73] observe increased penetration of the electric vehicles and consequently spread of parking lots for EV which can provide energy service to the grid and influence on possible network expansion deferral. Sbordone et al. [74] introduce the role of an aggregator and emphasize the importance of Information and Communications Technology (ICT) in order to incorporate scattered bids (of DERs) and offer services such as load shedding in the critical situations. Hu, Zhang and Li have formulated in [75] transmission expansion planning considering both addition of new circuits and installation of energy storage systems. Mixed-integer linear programming model is developed to decide whether it is better (in financial terms) to invest in energy storage or to conventionally reinforce the network. What this study lacks is the inclusion of multiple stakeholders which are in reality involved in such process, each with its own interest. This case study focuses primarily on DSOs. The same "one-dimensional" approach to the problem was noticed in [76], where stochastic optimization model co-plans investment in network expansion and battery storage systems.

Following similar principle, authors in [77] also optimize together network expansion and energy storage investment but using robust optimization model with the emphasize on the worst case scenario combinations concerning power output of intermittent energy sources (wind farm) and load demands. In addition to the energy storage systems, authors in [78] plan network expansion considering not only future storage (hydrogen-storage in this case), but also incorporate wind energy. Same as in previous examples, it lacks the other actors besides the DSO and its expansion deferral policy.

Some articles, like [69] propose also methods like demand response utilization for postponing network reinforcement. Authors elaborate how such principle enables to push the network limits beyond traditional planning standards. Furthermore, they conclude that the proposed solution is attractive from the perspective of investment costs only whenever traditional investments are significant and demand side response costs are competitive. Dvorkin et al. in [79] investigated the problem from a bit different perspective. Their opening argument states that network expansion plans may significantly impact merchant's profit opportunities. In their proposed tri-level model, upper level deals with the merchant storage problem (profit maximization), middle level problem with the transmission expansion problem (minimization of the transmission expansion decision cost and the expected system operating cost over representative days) and lower level with the market-clearing problems (maximization of social welfare). Results suggest that the most profitable locations for the storage systems are near the renewable energy resources, congested lines and bulk conventional generation and potential transmission expansion may impact expected profit. Moreover, co-planning of storage and transmission expansion achieves greater OPEX savings than solely the deployment of storage.

Authors in [80] also use trilevel as Dvorkin et al. [79] model but in a manner where upper level problem optimizes the SO's transmission line and energy storage investments (please notice that in this model even the SO may invest in the storage facilities), the middle problem deals with the merchant energy storage investment decisions and the lower level problem deals with the market clearing process over the set of representative days. It is important to emphasize that in the model energy storage may be operated both by SO and a merchant, but with significantly different roles. SO operates transmission lines and energy storage in the same manner, it uses lines to transfer electricity in space and energy storage to transfer electricity in time, and SO owned energy storage may be used only for non-market services. Au contraire, a merchant is profit seeking owner of a storage and isn't entitled to any rate-based payments. The results suggest that SO prefers transmission line rather than energy storage investments even at low cost of energy storage because they have longer expected lifetime. While merchant energy storage investments aim for the most volatile parts of the network in terms of LMP and points where SO cannot increase the social welfare sufficiently to justify investments in transmission lines.

In [81], authors argue that contracting demand flexibility might limit the need for physical expansion of the lines. Their model can calculate the optimal combination of physical grid expansions, demand flexibility and curtailment of the PV installations output. Throughout the text, local flexibility market is advocated as promising solution for the challenges that high RES penetration and DERs introduce. Ramos et al. in [82] also propose local market designs as viable solutions to accommodate local flexibility trading and provide DSOs with a new approach to system management. They specify following three main roles for such markets:

- Balancing local demand to match varying renewable supply under conditions of congestion
- Managing constraints in transmission and distribution network
- Optimizing portfolios for market agents, considering network needs at specific times and locations in the grid
- Deferring grid investment if flexibility can be effectively used as part of the DSO's grid planning

Authors in [83] primarily consider market-based initiatives to deal with the problems in the distribution network and consequently possible expansion deferral strategies. They emphasize the role of the aggregator in the proposed local flexibility market and thoroughly explain principles in such market. Particularly the interactions between DSO-BSP-aggregator-prosumer have been described.

Above stated short summary of the literature reviewed concerning the topic of this use case, it is noticeable that there is a lot of research regarding the possible alternatives to the physical network expansion. In the recent times, even novel concepts of flexibility markets are being researched as one of the viable solutions. Best to our knowledge, there isn't available models concerning bargaining between DSO expansion deferral goals and profit-oriented flexibility service providers. Precisely in this direction the research of this use case is pointed. With special regards to the research progress efforts in terms of the local flexibility markets such as those mentioned in the research and literature reviews: [84], [32].

Basic system model to be followed

DSO has the responsibility to maintain secure and stable power supply throughout distribution network in its jurisdiction using the most efficient method to do so. Traditionally, DSO dealt with possible voltage problems and network congestions with network upgrades and general network oversizing when planning new or upgrading existing cables. Having in mind increased penetration of renewable energy sources and DERs in general, distribution system faces new challenges among which are bi-directional power flows, intermittent nature of RES and uncertainty in general.

Basic system model for this use case considers all the factors above mentioned and approaches the DSO's problem of voltage control and congestion management trough market-oriented lenses. In that manner, the goal is to model a game between DSO and ESPs. DSO and ESP have somewhat opposite interests, but they are forced to cooperate in order to achieve them (at least partially). First one looks for the alternatives to the physical network expansion and seeks the lowest price possible for procuring flexibility services as a strategy to postpone network expansion and high CAPEX. The latter one is a profit-oriented subject that offers flexibility services with the sole motive of increasing earnings. Both entities have in mind their opposing interests, thus game-theory algorithms are researched and used to model the behavior of players and formation of the acceptable price for the flexibility services.

DSOs duty is to consider whether in a long run the better solution is to procure flexibility services or to upgrade the grid. On the other hand, ESP acts not only on the flexibility market, but it has the ability to access multiple markets (e.g. intraday, day-ahead, reserve markets etc.) and offer its services accordingly. That is the reason why ESP needs to perform its own optimization before offering its capacity to different players. The big role in the model plays the formulation and design of the flexibility market, so the discussion about this aspect will also be conducted, but mostly in other use cases that are part of the FLEXGRID's research goals in general, and further business modelling adjusted accordingly.

All above mentioned will be encompassed in a model trough following submodules developed as part of FLEXGIRD's Flex Suppliers' Toolkit (FST):

- Forecasting engine
- Optimal bidding algorithm
- FlexAsset sizing/siting algorithm
- Optimal scheduling algorithm

With the following assumptions:

- Network congestion really occurs
- At first only one ESP is considered, in later stages perhaps competition between more of them

In the end, the model should be somewhat of an advisory toll for a DSO, as the main object of interest in this use case, with numerically and graphically listed pros and cons between capital intensive network upgrade strategy and procuring flexibility service from profit-oriented ESPs. With the important fact that the same algorithm will model the bargaining between the DSO and respective ESPs to calculate price acceptable for everybody if there really is one. Depending on frequency that the voltage and/or thermal congestion occur, assumption is that procuring flexibility services will make sense when congestion happen during relatively small number of hours in a year.

Basic problem formulation and algorithmic solutions

As stated in previous sub-chapters, the problem is considered as a bargaining game between the DSO and ESP (at first only one, later perhaps more of them). To model the process in which price and quantity acceptable for both interested parties are determined, bi-level optimization model is used.

Bi-level model is suitable for representation of the Stackelberg competition, which is assumed as appropriate for this use. Stackelberg competition is a model of imperfect competition based on a non-cooperative game. DSO is a leader in the game, and ESP(s) is(/are) follower(s). Leader bases its moves with the insight what will be follower's response. This is formulated trough bi-level optimization model, which in a nutshell consists of one optimization problem in whose constraints is nested the other one.

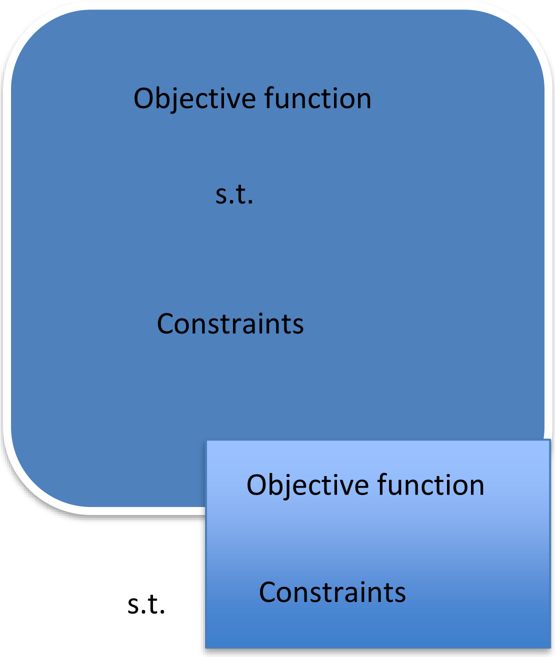

Figure 16: Bi-level model structure

To solve the optimization problem in a commercial solver, lower level problem must be translated to the upper level as set of constrains. This is done by using Karush-Kuhn-Tucker (KKT) optimality conditions [85].

Upper level problem represents DSO's problem. It consists of an objective function which includes DSO's costs caused by network congestion problems. That includes possible network expansion costs, possible flexibility services procurement, balancing costs, etc. DSO is network-aware entity, moreover the whole process is about events (disturbances) happening in the network, thus the objective function is network constrained. Objective function in the lower level describes ESP's profit maximization goal. That goal may be achieved acting on multiple markets (e.g. day-ahead, intraday, reserve market and flexibility provision), while constraints model ESP's FlexAssets.

The most important variables for the whole problem are price and quantity of the flexibility services that will: i) DSO procure, ii)ESP offer. Other variables in the upper level are those concerning network characteristic states (all relevant for the AC-OPF which is part of the upper-level calculations) while variables in the lower-level describe FlexAssets' characteristic states – for example:

- state-of-energy (SOE)
- DA charging/discharging power
- Capacity reserved for the reserve markets

Parameters in the upper level are ones describing network characteristics (resistance, conductance, length, topology) while in the lower level input parameters are prices for the all available markets, charging/discharging efficiency of energy storage systems and other FlexAssets related characteristics.

Datasets to be used for simulation setup and most important KPIs

Table 14 summarizes the data to be used for the simulation setup:

Table 14: Dataset

Distribution network technical data	Generation	Market data (intraday, day-ahead, balancing markets)	Consumption data	Storage	Cost of network upgrade investments
Topology	Locations (nodes)		Historical consumption data	Location (nodes)	
Admittance	Min./max. power	Historical prices			
Capacity	Costs				
Tap ratios	Type (PV, solar,..)	Historical volumes	Dispatched consumption	Capacity per asset	
Shunt capacities	Dispatched generation				
Loads	RES production curves	Forecasted market prices	Forecasted consumption		
Voltage Constraints					

The most important KPIs to understand how the model is performing are those concerned with overall costs and power balances. Overall costs are divided into two categories: CAPEX and OPEX, sensitivity analysis will provide insight how different setups and strategies affect those two main categories. Furthermore, overall costs (including both CAPEX and OPEX) will be calculated for some (longer) observed period producing comparable numerical results to perform meaningful economic analysis of different strategies. On the other hand, balancing costs and value of lost loads are somewhere between overall costs and power balance categories, and they provide glimpse whether respective strategies have been precise (balancing costs) and have they secured reliable and stable power supply (lost load).

Curtailment of RES will also be monitored, as the intention is to integrate renewables to the greatest extent possible, both for financial and ecological reasons.

Chapter 5. Flexibility Market Clearing Toolkit – FMCT

In this chapter, the operation of the Flexibility Market Clearing Toolkit (FMCT) is described. It shows how the research algorithms will be integrated in the toolkit. It also describes in a high-level of abstraction the structure of the graphical user interface (GUI) associated with the FMCT.

So far, in FLEXGRID, we have done the following work with respect to the FMCT:

- A requirements' analysis work (see more details in D2.1 [86]).
- An initial business and market analysis (see more details in D8.1 [12]).
- The internal FMCT S/W architecture has been described together with technical specifications and a draft data model to be followed regarding FMCT's algorithmic inputs/outputs (see more details in D2.2 [1]).

5.1. FMCT requirements' analysis

Different types of users will have access to the FMCT platform:
- The FMO
- The DSO
However, they will not all have access to the same functionalities and information.

The requirements of the FMCT are:

- FMCT's intelligence will be an open-source S/W and modular-by-design in order to be easily integrated as a module of a more complex S/W platform such as FLEXGRID ATP.
- FMCT will have a user-friendly GUI in ATP and a backend system where all WP5 algorithms' intelligence will reside.
- FMCT will have a bi-directional API with the central FLEXGRID database in order to: i) acquire ("pull") input data required for algorithms' execution, and ii) send ("push") algorithms' output data to the database in order to be stored and be retrievable at any time in the future.
- FMCT will support DSO for the creation of FlexRequests.
- FMCT will be able to setup, operate and clear flexibility markets
- FMCT will have a bi-directional API with the core FLEXGRID ATP in order to: i) acquire related ("pull") data once new FlexOffer or FlexRequest are published in ATP, and ii) send ("push") the algorithmic results of the creation of FlexRequest and of the flexibility market clearing (dispatch and payments) for all participants to be able to visualize them.

5.2. FMCT as an exploitable commercial asset

The FMCT has been designed in a way that can be commercially exploitable as a standalone S/W toolkit, which can be integrated as S/W "plug-in" in other S/W either for market clearing by a FMO or for evaluation of flexibility needs by a DSO. Within the FLEXGRID's context, FMCT will be integrated in the FLEXGRID S/W platform (ATP) and its operation will be tested via extensive lab experimentations and pilot tests within WP7. The main target groups of FMCT are:

- Individual researchers and research groups, who want to use FMCT for research and experimentation purposes.
- Market Operators who would like to develop a new flexibility market platform.
- DSOs for the evaluation of flexibility needs and the optimal participation in future flexibility markets, by the creation of the proper FlexRequests.

5.3. FMCT S/W architecture, interaction with other subsystems and algorithms' integration

In technical terms, the internal FMCT S/W architecture comprises of the following S/W modules, which will be developed within WP6:

- Web REST API for bi-directional data exchange between the central FLEXGRID database and the FMCT
- Web REST API for bi-directional data exchange between the core FLEXGRID ATP and the FMCT
- Data Acquisition Module
- Identification of Flexibility Needs Module
- Market Clearing Module (Price Determination and Flexibility Schedule)
- Internal Database

Regarding the first web REST API, one server-side REST API will be implemented at the central FLEXGRID database and one client-side REST API will be implemented at the FMCT side. Once a new FMCT algorithm needs to be executed, the Data Acquisition Module (client-side) will request for required input datasets in an appropriate data structure. Then, the server-side REST API will prepare/retrieve the requested datasets from the central database and will send them back to the FMCT's Data Acquisition Module (DAM). The final step will be for the DAM to forward the datasets to the appropriate Algorithm Module, so that the algorithm can run. Once the algorithm's execution has been finished, its results/output datasets will be stored in FMCT's internal database.

As of the ATP-FMCT web REST API, one server-side REST API will be implemented at the FMCT side and one client-side REST API will be implemented at the core FLEXGRID ATP side. When an algorithm is triggered through the FMCT, the ATP REST client will automatically construct the necessary datasets in a fine-grained JSON format and send them to the FMCT REST API server. Once the algorithm's execution is finished, its results/output datasets will be stored in FMCT's internal database. The ATP REST client will also forward FlexRequests and FlexOffers to the FMCT once those are generated and published in the ATP. Subsequently, the FMCT REST API server will use these as input data to clear the market.

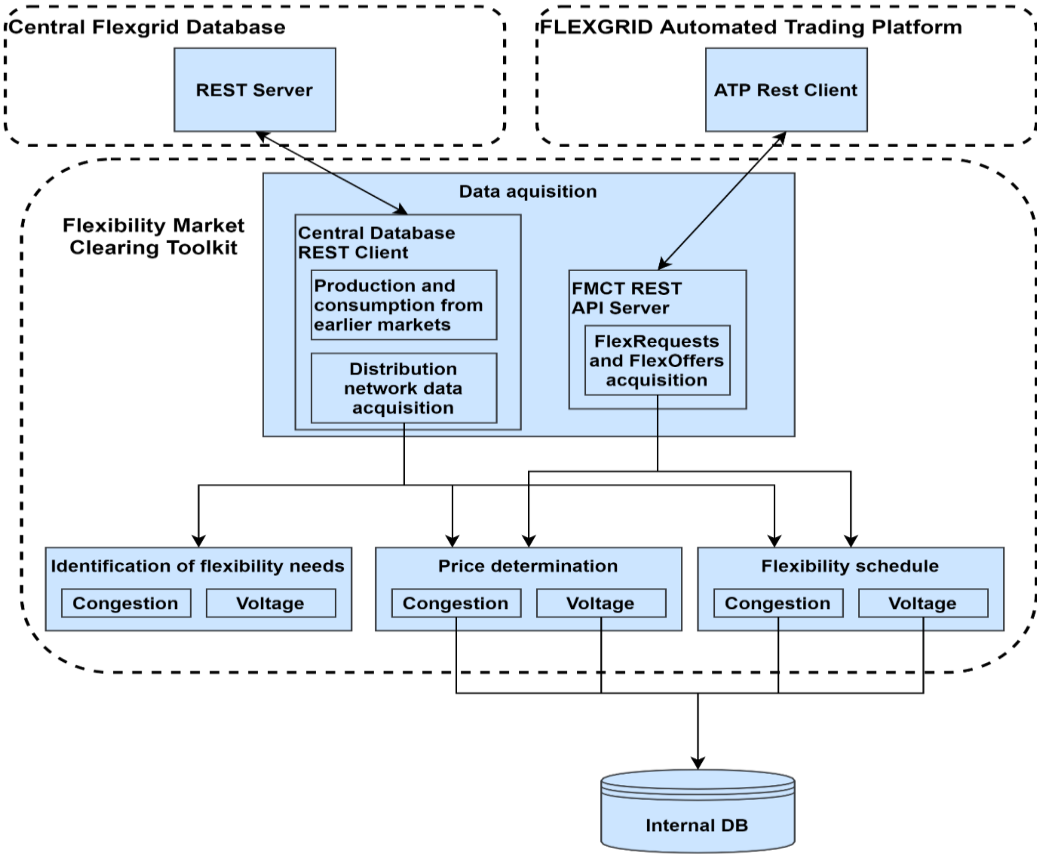

Figure 17: The Flexibility Market Clearing Toolkit (FMCT) internal architecture (taken from [1])

The "Identification of Flexibility Needs Module" will integrate the relaxed AC-OPF algorithms described in chapter 3. This module will be used by the DSO to identify possible line congestions and voltage deviations, and to formulate FlexRequests. The algorithm is triggered by the DSO. Once line congestions or voltage deviations have been identified, he has the possibility of translating them (or a part of them) into FlexRequests.

The "Market Clearing Module" will integrate all the algorithms performing market clearing, that have been described in chapter 3. Every time the FMO will want to clear a flexibility market, this will be done through this module (automatically triggered). In this module are contained the "Price Determination" and "Flexibility Schedule". Several algorithms can be applied, depending on the type of market: auction based (with the relaxed AC-OPF) or continuous.

Note: In chapter 7 of D2.2 [1], there is an extensive list of the required input and output data per algorithm category that will be created and exchanged among the above-mentioned S/W modules. The final version of the data models will be developed within Task 6.1 and will be officially delivered in Month 18 through D6.1.

5.4. Draft structure of the DSO's Graphical User Interface (GUI)

This section provides a tentative list of web pages that the DSO user will be able to visualize and use:

- DSO dashboard
- Network data
- Network overview
- Create a FlexRequest

The "DSO dashboard" web page will contain general information for the DSO user:
- Accepted FlexRequests
- Pending FlexRequests
- Line congestions and voltage deviations avoided

- Savings compared to network reinforcement

The “Network data” web page will show all the network parameters as they were set by the DSO and will allow for modification of its network data.

The “Network overview” web page will show a representation of the DSO network at a chosen point in time, with potential line congestions and voltage deviations standing out. For those, it will be possible to generate a FlexRequest from there.

The “Create a FlexRequest” will list all the potential future line congestions and voltage deviations in the DSO network and will offer the possibility to create a corresponding FlexRequest. It will also allow the creation of a FlexRequest from scratch. A “Recalculation” button will trigger the algorithm for the identification of future line congestions and voltage deviations and update the list.

5.5. Draft structure of the FMO’s Graphical User Interface (GUI)

This section provides a tentative list of web pages that the FMO user will be able to visualize and use:

- FMO dashboard
- Market management
- Support

The “FMO dashboard” web page will contain general information for the FMO user:
- Evolution of flexibility market prices
- Last matching offers
- Total volume of exchanges on the different markets
- Bids in the Shared Order Books (submitted bids waiting to be matched)

The “Market management” web pages (one per market) will allow the FMO to have access to the market settings and modify them if necessary. From there, he will also be able to publish important messages for the market users. Note that the market clearing algorithms are triggered automatically, following the market settings entered in this page.

The “Support” web page will allow the FMO to have access to all the issues reported by the market users and to address them.

Chapter 6. Conclusions

FLEXGRID introduces the novel concept of "Distribution Level Flexibility Market - DLFM" which is operated in an efficient manner by an independent company (e.g. NODES) in collaboration with the DSO. The ultimate goal of FLEXGRID is to propose optimal trade-offs between optimal market and network operations (or else economic efficiency vs. reliability under future high RES penetration scenarios). The DLFM operated by the FMO is the central architectural proposition of FLEXGRID project. Within WP5 work, we will design, develop and evaluate (via system-level simulations) various energy market architectures investigating the impact that the proposed DLFM could have in existing markets' and network' operations.

Three different market architectures are selected highlighting their advantages and disadvantages and will be further investigated and developed in the project.

- ***Reactive distribution level flexibility market (R-DLFM)***. FMO may run the day-ahead energy market at the DN level right after the respective TN-level market clearing results are available .The main advantage of the proposed R-DLFM model is that it is compatible with the existing energy market architecture and respective regulatory framework. This is mainly due to the fact that all existing TN-level market clearing processes (i.e. day-ahead energy, intra-day energy, reserve, ancillary services and balancing energy markets) remain unaffected and perform in a business-as-usual manner. R-DLFM model may also have several disadvantages that need to be taken into consideration. Firstly, all markets are operating in a sequential manner (i.e. each market takes as input the results of the previous market without being able to change anything in the dispatch schedule that has been decided), so social welfare results are expected to be sub-optimal. Furthermore, no actual TSO-DSO and MO-FMO coordination may take place because the energy resources at TN and DN levels are not pooled together.

- ***Proactive distribution level flexibility market (R-DLFM)***. Here the sequence of markets starts with market #3 operated by the FMO, which is a day-ahead energy market at the DN level (i.e. 3 → 4 → 1 → 2 → 6 → 5). Right afterwards, the day-ahead reserve market at DN level is operated by the DSO. These two markets should publish their results before the gate closure of the traditional day-ahead wholesale energy market (TN-level). The main architectural assumption is that the FMO and the DSO clear their day-ahead energy/reserve markets before MO/TSO. The main advantage of P-DLFM model is that DN constraints are taken into consideration in a proactive way and thus local congestion and voltage control issues in high DER/RES penetration scenarios at the DN level can be proactively solved with low cost. A main drawback is that the TSO may experience high re-dispatch costs, because it can only use the most expensive reserve capacity from the DN-level resources. Another major drawback is that social welfare results may be much worse than optimal because pre-qualification process is based on stochastic RES, consumption modeling and confidence intervals.

- ***Interactive distribution level flexibility market (I-DLFM).*** A main advantage of I-DLFM model is that it can maximize the social welfare and thus provide optimal network operation and market efficiency outcomes. Moreover, the proposed model adopts a decentralized scheme (via decomposition algorithms), which can achieve results similar or very close to the ideal case of centralized optimization market model (cf. section 2.3.1 above). Moreover, it can also be a practical and scalable solution as the complex MO-FMO and/or TSO-DSO coordination problem is decomposed in sub-problems, which can be solved more easily and within the timing constraints set by the regulatory framework and today's real business. One of the main drawbacks of the proposed I-DLFM model is that it is incompatible with the existing regulatory framework and assumes several advancements regarding the ICT infrastructure needed to support the proposed advanced coordination schemes.

The AC-OPF is an optimization problem aiming to determine the best dispatch of generators and loads in an electrical network, so that all the physical and operational constraints are respected. It is the most accurate representation of such a system, but it is a non-linear and non-convex problem and as a consequence, there is no guarantee that a solution can be found. To the best of our knowledge, market clearing with a convex relaxation of the AC-OPF is a novelty. An important challenge is to be able to retrieve meaningful locational marginal prices (LMPs) for active and for reactive power.

One way to obtain a solution to the AC-OPF is to use a convex relaxation. The idea is to solve the problem on a larger, convex space, by relaxing the constraints responsible of the non-convexity. If the solution obtained is feasible for the original, non-convex AC-OPF, then it is the optimal solution. This is the approach chosen here. With such a model, it will be possible to:

- Represent the power flows in a distribution network
- Identify possible voltage deviations
- Identify possible line congestions
- Assist the DSO with the formulation of FlexRequests to avoid line congestions and voltage deviations
- Perform market clearing in a flexibility market
- Integrate the network model in bilevel problems, which require convex low-level problems

A part of the flexibility market clearing could be auction based such as day-ahead flexibility market, using the AC-OPF as presented in section 3.1. However, moving closer to real-time, it could become more relevant to have a continuous market. Instead of a market clearing considering all bids and clearing once and for all, this model would be continuously matching bids. This is often the case for intraday markets. The difference and novelty here are that we need to take the distribution network constraints into account and make sure that two bids would only match if their activation would not deteriorate the situation of the network, in terms of line congestions and voltage deviations.

In order to test the continuous market clearing algorithms, the following inputs are necessary:

- Parameters of the tested distribution network (topology, operating limits…)
- Sets of FlexRequests and FlexOffers for this network
- Planned production and consumption of the assets in this network

The following KPIs will be studied to evaluate the performance of the algorithms:

- Total computational runtime
- Social Welfare
- Cost reduction achieved (compared to grid reinforcement)
- Number of transactions
- Volume of transactions
- Market utilization factor

It is very important for treatment of new bids to happen fast, in order to avoid a long latency when many offers are submitted in a short amount of time.

In this deliverable, the operation of the Flexibility Market Clearing Toolkit (FMCT) was described. It shows how the research algorithms will be integrated in the toolkit. It also describes in a high-level of abstraction the structure of the graphical user interface (GUI) associated with the FMCT.

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