Deliverable D6.4

Scalability and replicability analysis of the market platform and standardized products

V1.0

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D6.4 – Scalability and replicability analysis of the market platform and standardised products

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Executive summary

Deliverable D6.4 presents the methodology followed to perform the Scalability and Replicability Analysis (SRA) of the CoordiNet Business Use Cases (BUCs) and, more importantly, the main results and conclusions obtained from this analysis. Following the Description of the Action, the SRA includes two distinct components:

i. A quantitative analysis focusing on the functional aspects of the BUCs which analyses how changes in certain technical and market boundary conditions affect the results obtained, as measured by the relevant Key Performance Indicators (KPIs) - particularly those related to flexibility activation amount and costs. The most relevant technical and market conditions include, among others, the following: number/size/type of Flexibility Service Providers (FSPs) providing the services, grid characteristics, TSO-DSO coordination schemes, or type/frequency/amount of flexibility requirements.

ii. A qualitative analysis that identifies the key barriers for upscaling and replication that may be found in current power system regulation.

The quantitative analysis is divided into three different Modeling Workstreams. Each Workstream considers different coordination schemes, demo sites, services, and voltage levels. Different modelling techniques are also employed, depending on the characteristics of the study.

Modelling workstream	Countries/sites[1]	Modelling approach	Coordination schemes
1-Balancing + congestion management including transmission and HV distribution grids[2]	ES (T + Cádiz and Albacete), SE (Uppsala)	Economic dispatch with DC power flow equations in GAMS	Common, central, multi-level + joint and separate procurement of balancing and congestion management in the 3 coordination schemes.
2 - Congestion management in MV grids	ES (Málaga-Cádiz Road and Murcia), GR (Argostoli)	PTDF[3]-linearized local market model in Python	Local
3 - Voltage control in T+D grids (or D only)	ES (T+Cádiz, Murcia), GR (Kefalonia area+Argostoli)	Sensitivity factors-linearized local market model in Python and Matlab	Common, multi-level, fragmented, local

Description of the three modelling workstreams part of the quantitative SRA

Workstream 1 relies on a combined TSO-DSO model for the procurement of flexibility, including flexibility from DERs. This model aims to provide an assessment tool for different TSO-DSO coordination schemes, considering that both SO may utilize resources connected at the distribution grid for the purposes of solving congestions in the grids and imbalances of the system. Therefore, this modelling workstream focuses exclusively on these two products, namely balancing and congestion management. This model is applied to two CoordiNet demo countries: Spain (Cadiz and Albacete regions) and Sweden (Uppsala). In each case

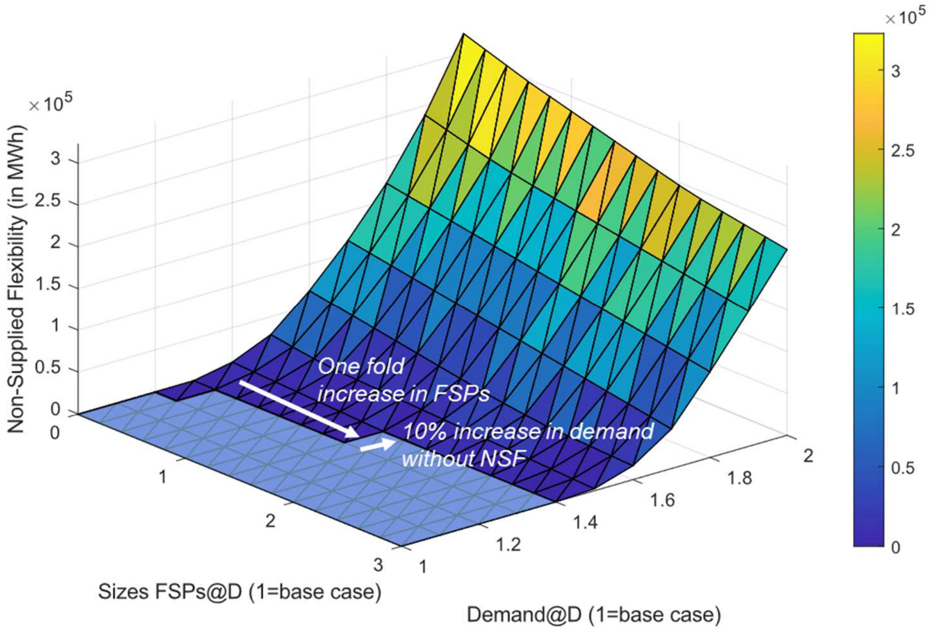
[1] Data from the demonstrations were used together with synthetic data when necessary.
[2] Congestion management services are procured by both TSO and DSO, while balancing services are procured by the TSO.
[3] Power Transfer Distribution Factor.

study, different scalability and replicability scenarios were tested, having the CoordiNet demonstration as a base case. Among the different scenarios tested are different coordination schemes (replicability), different types of FSPs in each demo (replicability), availability of flexibility (scalability), and demand growth (scalability).

The results from workstream 1 revealed that grid and FSPs characteristics play an important role in the outcomes of flexibility usage by system operators. Firstly, different types of grid topology were observed, such as meshed DSO grids (subtransmission) and power-exporting DSO grids, characterized by high penetration of distributed generation, besides more typical load-driven distribution grids. This diversity of grid topologies is also accompanied by a variety of FSP types. While the Swedish demonstration was characterized by demand response flexibility and storage, the Spanish demonstration counted primarily on renewable sources (e.g. wind and solar) as FSPs. The replicability scenarios, in which types of FSP from one demonstration are simulated in another demo, showed the potential benefits arising from the complementarity of the different types of FSPs and their capability. On the one hand, a grid with the characteristics of the Swedish demonstration could benefit from the distributed generation from renewables to avoid surpassing subscription limits. In this case, the study shows that the benefits from the added renewables capacity come not only from having them as flexibility providers but the fact they are distributed generators in the first place. In Sweden, renewables in the future could be complemented with storage (so-called hybrid parks) and then have the capability to provide capacity during dimensioning hours. On the other hand, a grid similar to the Spanish demonstration would benefit from the demand response and storage capability of providing upward flexibility, something limited to renewables. Therefore, replication scenarios show that the types of FSPs available for the TSO and DSO play an important role in determining the possibility for SOs to use flexibility. A system dominated by renewables as FSPs will be able to provide downward capacity for an extended period but will be limited in providing upward capacity. Therefore, a mix of different types of FSPs could be most beneficial to system operators.

Scalability scenarios attested to the effectiveness of the use of flexibility in different situations, considering the assumptions made[4]. Firstly, considering the Swedish scenarios characterized by the possibility of subscription penalty costs for the DSO, an increase of 60% over the base case flexibility could already lead to a situation in which the DSO does not incur subscription penalties. The use of flexibility also proved to be effective in the face of demand growth scenarios. Results suggest that a one-fold increase in FSP availability could lead to an increase of 10% in demand without the occurrence of Non-Supplied Flexibility (NSF) for the DSO. The NSF concept is introduced by this deliverable and presents the idea of a flexibility need by the system operator that cannot be supplied by the available FSPs, either by a lack of providers in the market, or their technical limitation to solve the need in question.

[4] Scenarios are built having the demonstration as a base case. However, assumption and synthetic data were used when necessary (e.g. simplification of the whole national transmission grid). For this reason, conclusions present the result of studies based on the demonstrations and cannot be considered as forecasts for the actual grids.



Sensitivity to demand connected to distribution and size of FSPs connected at the distribution grid. Non-Supplied Flexibility for DSO in Multi-level LFM in the Swedish case study.

Concerning Workstream 2, it examines the SRA performance of the local congestion management solutions proposed within CoordiNet, which aim to procure flexibility from resources connected at the DSO networks to solve transitory congestions that can occur at MV grids. This modelling workstream is applied to two CoordiNet demo countries, namely Spain (Malaga and Murcia) and Greece (Kefalonia). Furthermore, the Workstream 2 methodology is based on a simulation analysis of a local congestion management model under different SRA scenarios, which are defined considering the maximum net load, demand growth, N-1 conditions of the network, and availability of flexibility, among others. These scenarios assess the effect of the parameters that comprise the technical boundary conditions of the BUCs of Workstream 2. In addition, a set of KPIs is computed, including the flexibility activation cost, criticalities reduction index, and the volume and number of transactions of the local flexibility market.

It is relevant to highlight that the Workstream 2 results reveal that for some SRA scenarios, the congestion criticalities were not entirely solved even after procuring the maximum available flexibility of FSPs. Since more flexibility is needed in these scenarios, other flexibility options could be considered, such as network reconfiguration, control of on-load tap-changers, new FSPs, etc. Therefore, DSOs can choose between using their own flexible resources or procuring flexibility from third parties, or a combination of both to solve potential operational and planning problems related to congestion. On the other hand, this workstream also implements an ex-post validation process to ensure that the clearing solution does not violate the limits exposed by the DSO. According to the SRA results the proposed linearized local flexibility market using Power Transfer Distribution Factors (PTDFs) does not lead to new congestion problems after the market-clearing.

Workstream 3 focused on the different market models for procuring voltage support from FSPs involving both TSO and DSO and a great variety of HV, MV, and LV grids. Radial and meshed grids were studied considering different DG penetration levels to investigate the conditions that determine voltage issues and study the effectiveness of FSPs in providing reactive power support for voltage control. In SRA workstream 3, the considered FSP technology are distributed generators (PV and wind) interfaced with power electronics. Hence, the adopted FSPs model is general and describes a future scenario in which network codes require distributed generators to fully control the power exchange. Scalability scenarios assessed the effectiveness of the use of flexible reactive power support from distributed generators in different situations characterized by demand growth, loss of dispatchable generators, and increase of generation from DERs.

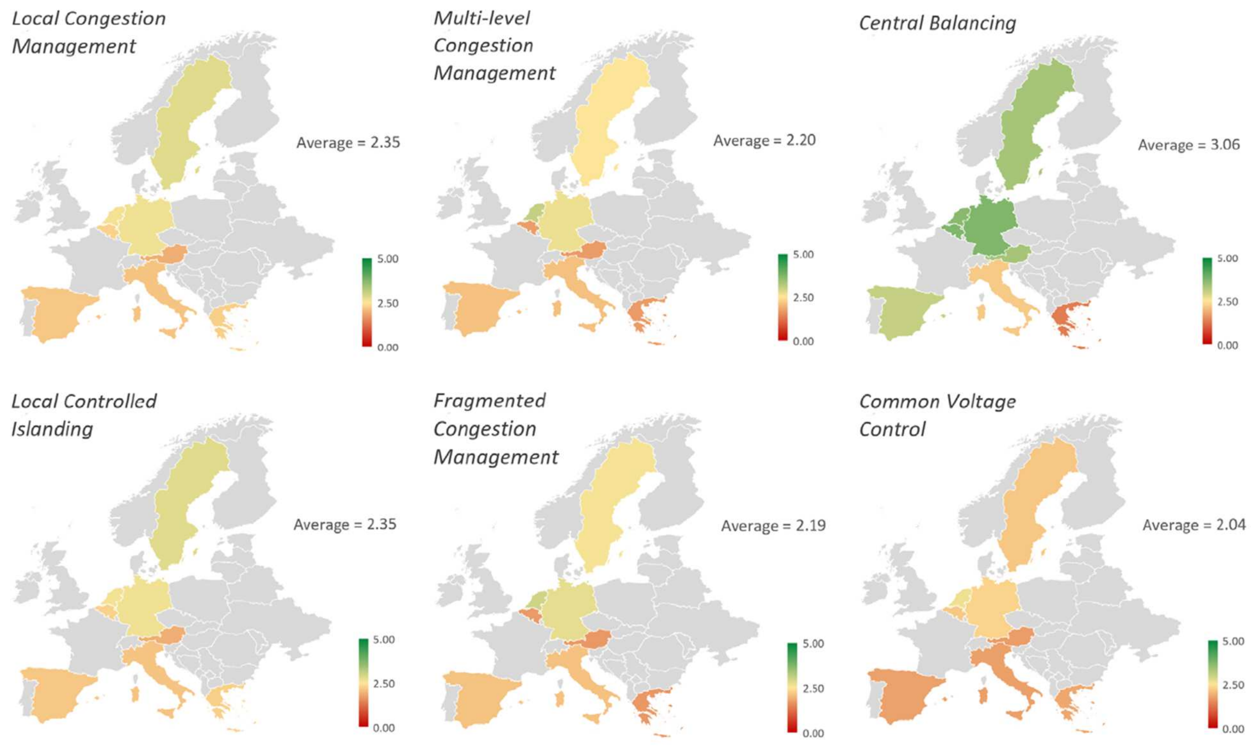
Voltage control effectiveness increases if the FSPs are properly located in the network with respect to the bus with voltage violations, rather than having a larger reactive power capacity in less effective buses. Hence, sufficiently high participation of potential FSPs is fundamental to increasing the probability of having well located FSPs and avoiding market distortions. The SRA studies of workstream 3 highlighted that a sub-transmission grid like the one in the Cadiz demo site could benefit from distributed generation from RES participating as FSPs to voltage control especially if operated using a closed loop topology. A transmission system like the one in the Greek demo site can benefit from the voltage support available from distributed generators as FSPs to clear voltage violations caused by the loading conditions of long feeders and submarine cables. As highlighted in the SRA of the Murcia demo site, the growth of demand expected due to the electrification of the energy uses will determine undervoltages in the distribution grids that fed urban areas that can be resolved resorting the reactive power capability of power electronic interfaced distributed generators. Nevertheless, the addressed SRA analysis point out the need for complementary FSPs technologies (i.e. FSPs whose reactive power capability is not constrained by the active power production from renewables) and measures (i.e. network equipment operation, network reconfigurations, active power support) to resolve all voltage violations that may occur in the network.

Topology is the key aspect of voltage control effectiveness; the local peculiarity of voltage control influences the effectiveness of the adopted market model. As highlighted in the study of the Greek demo site, a multi-level market model with sequential DSO-TSO optimization can lead to the implicit resolution of voltage violations expected in the TSO network.

Finally, apart from the three modelling workstreams, a regulatory SRA was also conducted, in which the main focus was on the regulatory replicability of the different coordination schemes and the provision of DER flexibility for different services. The aim of the regulatory SRA was to identify barriers and drivers for replicating the selected BUCs posed by existing regulation. Barriers are rules, found in all or some of the countries considered, that potentially constrain the implementation and operation of the BUCs. On the contrary, a regulatory driver is found when certain solutions are enabled and incentivized by regulation. The countries analysed are the three demo countries, namely Greece, Spain and Sweden, and five additional countries: Austria, Belgium, Germany, Italy, and the Netherlands.

The country analyses showed that an important gap exists before CoordiNet's solutions can be deployed and replicated. First, it was verified that the congestion management and voltage control services are very unharmonized among countries, and a common market-oriented definition is lacking even at the European level. Second, DER provision of flexibility to DSOs is still a challenge. The economic regulation of DSOs is still mostly CAPEX-biased, with little incentive for the procurement of flexibility. Additionally, no country has yet implemented a regulatory framework for the cost recognition or output incentives for the use of flexibility. Finally, different market models will require different levels of coordination between TSO-DSO. It was found that most of the studied countries already have TSO-DSO coordination in most timeframes of operational planning and real-time operation of the system. However, enhanced coordination will be needed for the market models proposed in CoordiNet, which is still a barrier to replicability. Among the drivers identified in the different countries is the opening of balancing markets to the participation of distributed energy resources. Another driver is aggregation. Several countries have already implemented regulations that recognize the aggregator as a market actor, and some also provide the necessary framework for the independent aggregator to share responsibilities with other parties (e.g. balance responsible parties).

In order to illustrate the potential compatibility of different generic use cases (a pair of service and market model), a compatibility index is proposed. The index goes from zero to five, where zero represents a national regulatory framework that prevents the development of the use case, and five a regulation that not only allows it but also provides the necessary conditions for its development. Although a numerical exercise, these values are computed based on a qualitative assessment, and therefore serve as a stylized illustration of how compatible the regulation in each country is to the different use cases. The figure below illustrates the compatibility index for six use cases in the eight countries analysed. A green colour (high index) means that the current national regulation is more welcoming to the development of that use case. Conversely, a red colour (low index) means that regulation still prevents the development of that use case. Colours/indexes in between (yellow colour) mean that regulation may allow the use case to be developed, but it is incomplete and does not provide the necessary conditions for the different actors.



Regulatory Compatibility of Selected Generalized Use Cases

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Notations, abbreviations and acronyms

Table 1: Acronyms list

ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
AS	Ancillary Service
B	Balancing
BRP	Balancing Responsible Party
BSP	Balancing Service Providers
BUC	Business Use Case
CACM	Capacity Allocation and Congestion Management
CAPEX	Capital Expenditures
CCGT	Combined cycle gas turbine
CEER	Council of European Energy Regulators
CEP	Clean Energy Package
CHP	Combined Heat and Power
CM	Congestion Management
CM + B	Congestion Management and Balancing
CRI	Criticalities Reduction Index
CS	Coordination Scheme
DA	Day-ahead
DER	Distributed Energy Resource
DG	Distributed Generation
DoA	Description of Action
DR	Demand Response
DSO	Distribution System Operator
EBGL	Electricity Balancing Guideline
ESS	Energy Storage System
EU	European Union
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
FSP	Flexibility Service Provider
HV	High Voltage
HVDC	High Voltage Direct Current
ICT	Information and Communication Technology
ID	Intra-Day
IPTO	Independent Power Transmission Operator [Greek TSO]
KPI	Key Performance Indicator
LFM	Local Flexibility Market
LMP	Locational Marginal Pricing
LV	Low Voltage
MARI	Manually Activated Reserves Initiative
mFRR	Manuel Frequency Restoration Reserve
MIP	Mixed Integer Programming
MM	Market Model
MO	Market Operator

MV	Medium Voltage
NSF	Non-Served Flexibility
NTC	Net Transfer Capacity
OLTC	On-Load Tap Changer
OPEX	Operational Expenditures
OPF	Optimal Power Flow
P2P	Peer-to-Peer
PF	Power Flow
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PTDF	Power Transfer Distribution Factor
PV	Photovoltaic
RAB	Regulatory Asset Base
RES	Renewable Energy Source
RNM	Reference Network Model
RR	Restoration Reserve
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
SoC	State of Charge
SRA	Scalability and Replicability Analysis
T&D	Transmission and Distribution
TERRE	Trans European Replacement Reserves Exchange
TIEPI	Tiempo de Interrupción Equivalente de la Potencia Instalada (Systam Average Interruption Duration Index – SAIDI as defined in Spanish regulation)
ToE	Transfer of Energy
TOTEX	Total Expenditure
TSO	Transmission System Operator
UC	[Generic] Use Case
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WP	Work Package

1. Introduction

1.1. The Coordinet project

The CoordiNet project is a response to the call LC-SC3-ES-5-2018-2020, entitled "TSO – DSO – Consumer: Large-scale demonstrations of innovative grid services through demand response (DR), storage and small-scale generation" of the Horizon 2020 programme. The project aims at demonstrating how Distribution System Operators (DSO) and Transmission System Operators (TSO) shall act in a coordinated manner to procure and activate grid services in the most reliable and efficient way through the implementation of three large-scale demonstrations. The CoordiNet project is centred around three key objectives:

1. To demonstrate to which extent coordination between TSO/DSO will lead to a cheaper, more reliable and more environmentally friendly electricity supply to the consumers through the implementation of three large-scale demonstrations, in cooperation with market participants.
2. To define and test a set of standardized products and related key parameters for grid services, including the reservation and activation process for the use of the assets and finally the settlement process.
3. To specify and develop a TSO-DSO-Consumers cooperation platform starting with the necessary building blocks for the demonstration sites. These components will pave the way for the interoperable development of a pan-European market that will allow all market participants to provide energy services and opens up new revenue streams for consumers providing grid services.

In total, ten demonstration activities will be carried out in three different countries, namely Greece, Spain, and Sweden. In each demonstration activity, different products will be tested, in different time frames, relying on the provision of flexibility by different types of Distributed Energy Resources (DERs). Figure 1 presents an approach to identify (standardized) products, grid services, and coordination schemes on which the CoordiNet project focuses.

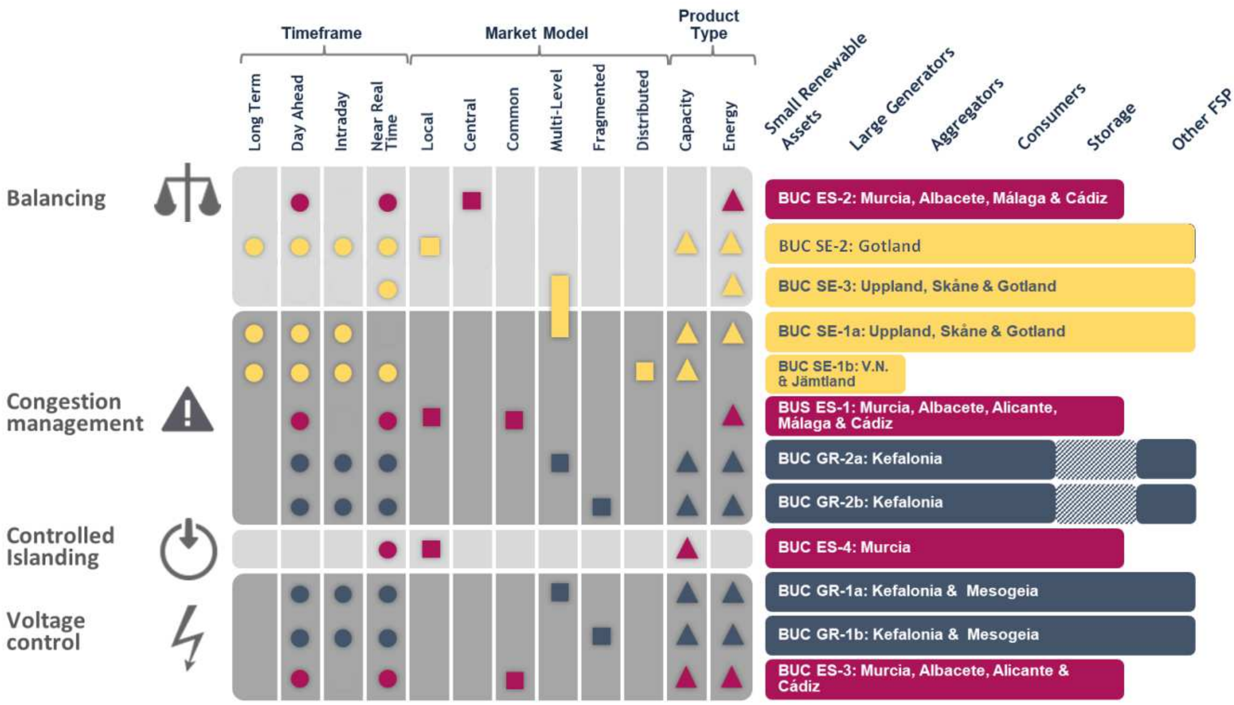

Figure 1. Overall CoordiNet approach: Services, timeframes, coordination schemes and products that will be demonstrated in different countries (Spain in pink, Sweden in yellow, and Greece in grey)

1.2. Aims and scope of the document

Deliverable D6.4 presents the methodology followed to perform the Scalability and Replicability Analysis (SRA) of the CoordiNet Business Use Cases (BUCs) and, more importantly, the main results and conclusions obtained from this analysis. Following the DoA, the SRA includes two distinct components:

iii. A quantitative analysis focusing on the functional aspects of the BUCs which analyse how changes in certain technical and market boundary conditions affect the results obtained, as measured by the relevant Key Performance Indicators (KPIs) (particularly those related to flexibility activation amount and costs). The most relevant technical and market conditions include, among others, the following: number/size/type of Flexibility Service Providers (FSPs) providing the services, grid characteristics, TSO-DSO coordination schemes, or type/frequency/amount of flexibility requirements.

iv. A qualitative analysis that identifies the key barriers for upscaling and replication that may be found in current power system regulation.

This report is linked to task 6.4.

1.3. Structure of the document

The remainder of this report is organized as follows. After this introductory chapter, chapter 2 presents an overview of the different elements that make up the CoordiNet SRA that has been carried out as well as a high-level description of the methodology implemented. Next, chapters 3 to 5 respectively provide detailed information on the modelling framework used in each of the three workstreams (introduced in chapter 2) that are part of the quantitative SRA, together with the main optimization/simulation results and conclusions drawn. In turn, chapter 6 addresses the other main component of the SRA, i.e., the qualitative regulatory analysis where barriers to upscaling and replication on a set of target countries are discussed. Lastly, chapter 7 presents some general conclusions and final remarks about the SRA results.

2. CoordiNet SRA scope and methodology

This chapter provides a high-level overview of the SRA scope and methodology as well as a description of the process carried out in preparation of the SRA execution. In this regard, the SRA follows the guidelines provided in the DoA which states that the SRA will include a technical analysis (quantitative) which ought to analyze different scenarios characterized by changes in technical boundary conditions, regulatory framework, market conditions or coordination schemes. This analysis is done through simulations considering real aspects of demonstrations. Likewise, a non-technical analysis (qualitative) should assess barriers to replication due to existing regulatory conditions and market rules. The assessment of the Information and Communications Technology (ICT) topics (architecture, communications links, software scalability, etc.) is explicitly out of the scope of the task, as this subject is covered the CoordiNet deliverable D6.5.

2.1. Quantitative SRA: analysis of use cases, KPIs and modelling requirements

This section aims to describe the key steps of the preparatory work for the quantitative SRA. Firstly, it is necessary to state that the minimum unit of analysis considered is the BUC (combination of service and coordination scheme), i.e. the SRA will assess the outcomes of replicating or upscaling a BUC considered as a whole. Moreover, it was necessary to define the geographical scope of the SRA. Given the high number of demo sites in the project, it was deemed sufficient to analyze regions located within the three demo countries: Greece, Spain and Sweden.

The subsections ensuing describe the different steps followed for the preparation of the SRA, including: selection of BUCs and demo sites to evaluate, identification of modelling needs, shortlist KPIs to quantify, and definition of data requirements.

2.1.1. Selection of BUCs and definition of modelling workstreams

As stated above, the SRA is oriented towards the BUC as a unit of analysis. Therefore, it is firstly needed to select the BUCs that will be addressed within the simulation studies. Based on the information presented in Figure 1, it can be seen that BUCs are already clustered into four distinct categories, namely balancing, congestion management, islanding, and voltage control. The BUC selection thus starts from this classification and adapts it to the requirements and limitations of the analysis.

The goal of this selection is to select the BUCs that are more central to the TSO-DSO coordination topic, offer a larger scope for replicability, and can be bundled in clusters for modelling purposes. From the eleven BUCs shown above, two were discarded from the SRA for similar reasons:

- BUC ES-4 (islanding operation) was excluded from the quantitative SRA due to: i) islanded operation as a service is only tested in one demo site, ii) it does not include any TSO-DSO coordination scheme, iii) it would require a completely different simulation environment, unrelated to the other modelling workstreams.
- BUC SE-1b (congestion management with a distributed Peer-to-Peer [P2P] market model) was not included in the SRA due to: i) it is being tested in only two demo sites in one country, ii) it is the only use case relying on a P2P model which is completely different to the other market models, iii) it would require a completely different simulation environment.

The remaining 9 BUCs were clustered into three groups or workstreams:

- **Workstream 1: balancing + congestion management**. Balancing and congestion management are two services that are tightly coupled (particularly close to the T-D interface) and for which some form of TSO-DSO coordination is more relevant. Therefore, it was decided to analyze both jointly. Many different coordination schemes can be found across the BUCs, hence all of them were replicated and compared in the simulations.

This workstream comprises the following BUCs: ES-1a[5], ES2, SE1a, SE3.

The BUCs under this workstream require modelling the complete transmission system of a given country to account for the balancing needs, even if in a simplified manner, as well as the HV subtransmission grid (owned and operated by the DSO in Spain and Sweden, but not in Greece where the boundary is set at the 150kV/20kV substations).

In order to capture (partly) the complexities of balancing markets, some form of economic dispatch model able to capture the market sequence whilst considering grid constraints (Optimal Power Flow [OPF] or equivalent) is necessary.

- **Workstream 2: local congestion management markets.** Contrary to the aforementioned need for TSO-DSO coordination in terms of congestion management in higher voltage levels, needs at Medium Voltage (MV) or Low Voltage (LV) may be addressed with a purely local market model.

  This workstream comprises the following BUCs: ES-1b, GR2a, and GR2b[6]. We have as the base the BUC-ES-1b (Local Congestion Management), which aims to procure flexibility from resources connected at the DSO networks to solve transitory congestions that can occur at DSO grids. This BUC is tested in the demo sites of Malaga and Murcia of the Spanish demo, thus this workstream will perform an SRA for these two demonstrators. Furthermore, to assess the SRA performance of GR2a and Gr2b the Kefalonia demo site of the Greek demonstrator is considered.

  Contrary to the previous workstream, this group only requires modelling the distribution system, with focus on the MV and LV grids. For the sake of simplicity, and because LV flexibility markets find a lot of liquidity limitations, only congestions in the MV grid and upstream transformers will be considered. LV grid users and FSPs will be aggregated at the corresponding secondary substations if relevant.

  Given that decoupled power flow methods are not accurate in MV systems to the R/X ratio[7] of the lines, the market model is linearized using PTDFs (further details can be found in section 4).

- **Workstream 3: voltage control**. The three coordination schemes tested in the Spanish and Greek demos will be simulated in the demos sites selected, together with the purely local voltage control market model when MV voltage constraints are considered.

  This workstream comprises the following BUCs: ES3, GR1a, GR1b.

  The grid models considered in this workstream will include both categories, i.e. Transmission + High Voltage (HV) distribution or MV only, depending on the demo site analyzed.

  Similarly, to workstream 2, the market model will be linearized through the computation of voltage sensitivity factors that reflect the impact of the nodal power injection (reactive or active) of FSPs on the voltage magnitudes to be controlled (further details can be found in section 5).

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[5] For the BUC ES-1, the Workstream 1 considers only the "Common Market Model" implementation, also referred as the BUC ES-1a. The "Local Market Model" (ES-1b) implementation of this BUC is modeled and analysed in Workstream 2.
[6] Regards to BUC GR-2a and GR-2b, the congestion events are only foreseen in the transformers located in the boundary between transmission and distribution and in the distribution lines. Therefore, a local market downstream of the congested transformer is equivalent to the TSO-DSO coordination schemes considered in the BUC GR-2a and GR-2b (and in any case, the fragmented market model is equivalent to running two independent local congestion markets).
[7] The amount of reactance X divided by the amount of resistance R.

2.1.2. Selection of demo sites to be considered in the analysis

Overall, the CoordiNet project has a total of 12 demo sites located in the three demo countries. Due to limited time and the volume of data that would have to be collected, it was necessary to select a subset of these sites. The following criterion was used for this selection: all workstreams should be modelled and replicated in at least two countries. On the ensuing, further details on this selection are presented.

2.1.2.1. Spanish demo

The Spanish demo has a total of 6 demo sites. The sites of Cádiz, Alicante and Albacete focus on the HV subtransmission grid (operated by the DSO) and the coordination with the TSO. On the other hand, the two sites within Málaga (Cádiz Road and Guadalhorce) and the one in the city of Murcia consider FSPs and constraints located in the MV and LV distribution network. Table 2 shows which BUCs are tested in which demo sites.

BUC	Description	Demo site				
		Málaga (2 sites)	Cádiz	Murcia	Alicante	Albacete
BUC ES-1a	**Congestion management - Common market**	X	X	X	X	X
BUC ES-1b	**Congestion management - Local market**	X		X		
BUC ES-2	**Balancing services for TSO**		X		X	X
BUC ES-3	**Voltage control**		X	X		X

Table 2: BUCs tested in the different demo sites in the Spanish demo

In order to simulate all BUCs, at least one demo site from the two groups mentioned before should be selected. Concerning sites comprising HV plus transmission grids, the site of Alicante was excluded as it includes a single industrial consumer, thus prioritizing the areas of Albacete and Cádiz where a high number of FSPs were located. In both of these demo sites, there is a high penetration of intermittent Renewable Energy Source (RES) generation levels. On the other hand, concerning MV grids, the sites of Málaga-Cádiz Road and Murcia were selected as they cover distinct regions and two different DSOs (e-distribución and i-DE, respectively). The only demo site not simulated is the Alicante area.

2.1.2.2. Swedish demo

As shown in Figure 2, the Swedish demo has a total of 4 demo sites. In this case, the site selection was mostly determined by the BUC selection presented in section 2.1.1. The final BUCs selected are tested only in Skåne and Uppland.

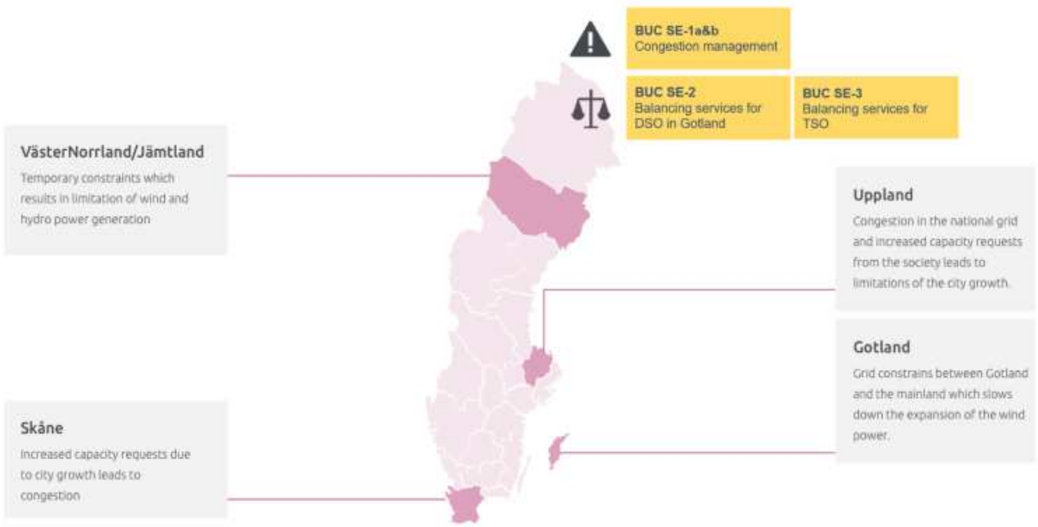

Figure 2: Demos sites and BUCs in the Swedish demo. Source: CoordiNet D4.4 (Bjarup & Isendahl, 2020).

In both cases, there is a growing demand, but insufficient capacity at transmission level that has led to the denial of an increase in the subscription level for regional DSOs, who own and operate the HV subtransmission network. This subscription level is the maximum power that DSOs may draw from the transmission grid at each boundary point (see Figure 3). Using flexibility to avoid surpassing this subscription level can reduce penalties or subscription costs for DSOs and facilitate their capability to meet the growing demand in these areas. Therefore, the type of “congestion” modelled in the Swedish case is not a physical congestion (thermal limit), but the subscription level contracted by the regional DSO. The learnings can in the future be applied on physical congestion.

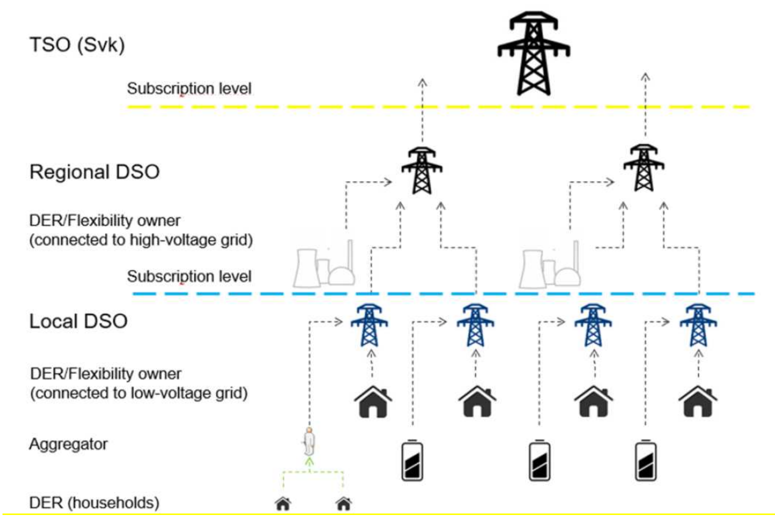

Figure 3: Subscription levels at the boundaries between different grid operators in Sweden. Source: CoordiNet D4.5 (Etherden et al., 2020).

The Uppsala demo site was eventually selected among these two as all relevant use cases are tested in this site and it includes more flexibility products and coordination schemes. Moreover, it is the largest flexibility market in the Swedish demo in terms of volume of activations and flexibility costs.

2.1.2.3. Greek demo

The Greek demo comprises two demo sites, Kefalonia and Mesogeia areas, which are shown in Figure 4. Voltage control BUCs are tested in both sites, whereas congestion management BUCs are only demonstrated in Kefalonia.

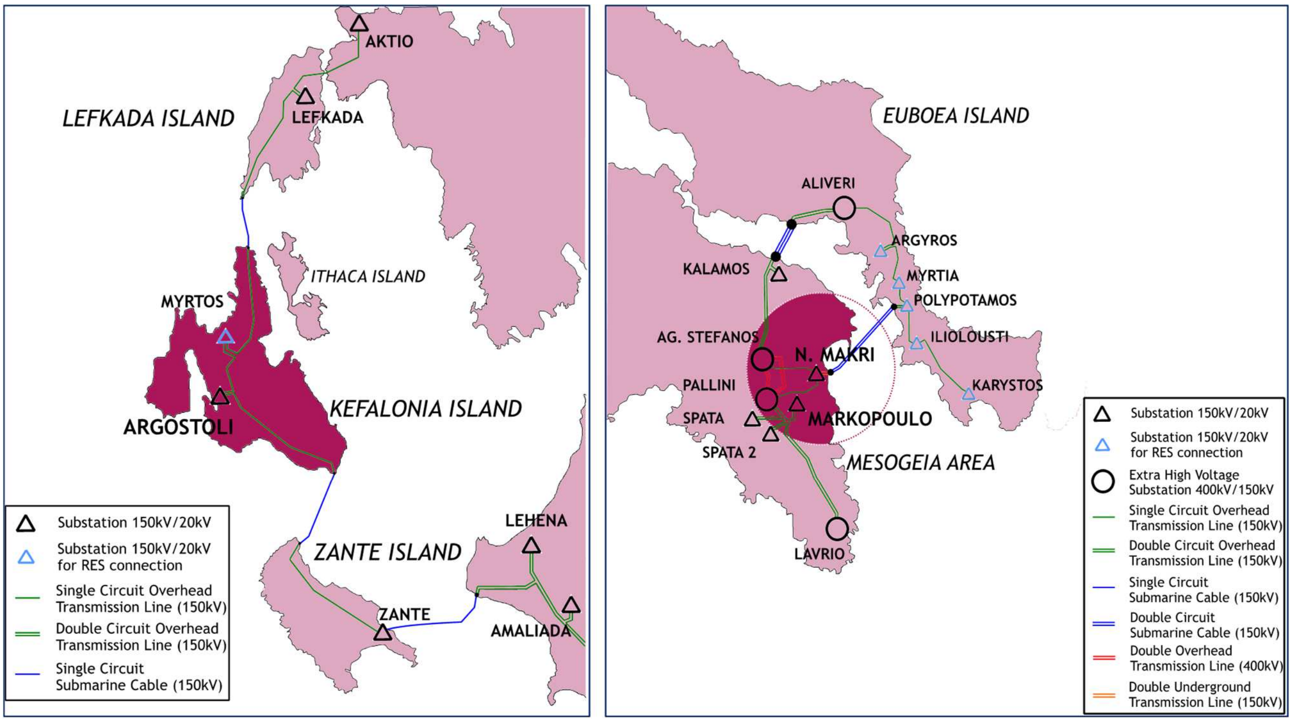

Figure 4: Demo sites in the Greek demo

In this case, the quantitative SRA focused on the demo site of Kefalonia for the following reasons:

- All demo BUCs were tested at this demo site (both voltage control and congestion).
- The site presents a higher number of FSPs participating in the demo.
- It shows some distinct features, i.e. several islands connected through submarine cables.

Concerning the distribution grid, the MV network downstream of the main substation of the island will be considered, i.e. Argostoli substation, where potential local congestions have been detected.

2.1.3. Selection of KPIs to quantify in the SRA

Deliverable D1.6 identified a list of 39 KPIs to be taken into account in the CoordiNet demos. However, not all of them were considered equally relevant to the quantitative SRA. Hence, a shortlist of KPIs to quantify in the SRA was obtained through a selection process. The following list enumerates the main types of KPIs excluded from the analysis:

- KPIs related exclusively to the BUC ES-4 on islanding operation which, as mentioned above, was not included in the quantitative SRA (e.g. islanding duration or the continuity of supply index TIEPI[8]).
- KPIs mostly oriented to monitor the demo implementation rather than the functional performance of the BUCs (e.g. participant recruitment, percentage of tested products).
- KPIs related to the ICT or software performance during the demo (e.g. forecasting accuracy, total computation runtime).
- KPIs whose main purpose is the economic evaluation of the demos (e.g. increase in network hosting capacity or ICT costs). These KPIs are calculated and monetized in the CoordiNet deliverable D6.3.

Figure 5 presents the final list of KPIs considered in the quantitative SRA. These KPIs are mostly related to the amount of flexibility that is contracted/activated in each scenario, the costs corresponding to this volume of flexibility, and the effect of the BUCs on grid constraints.

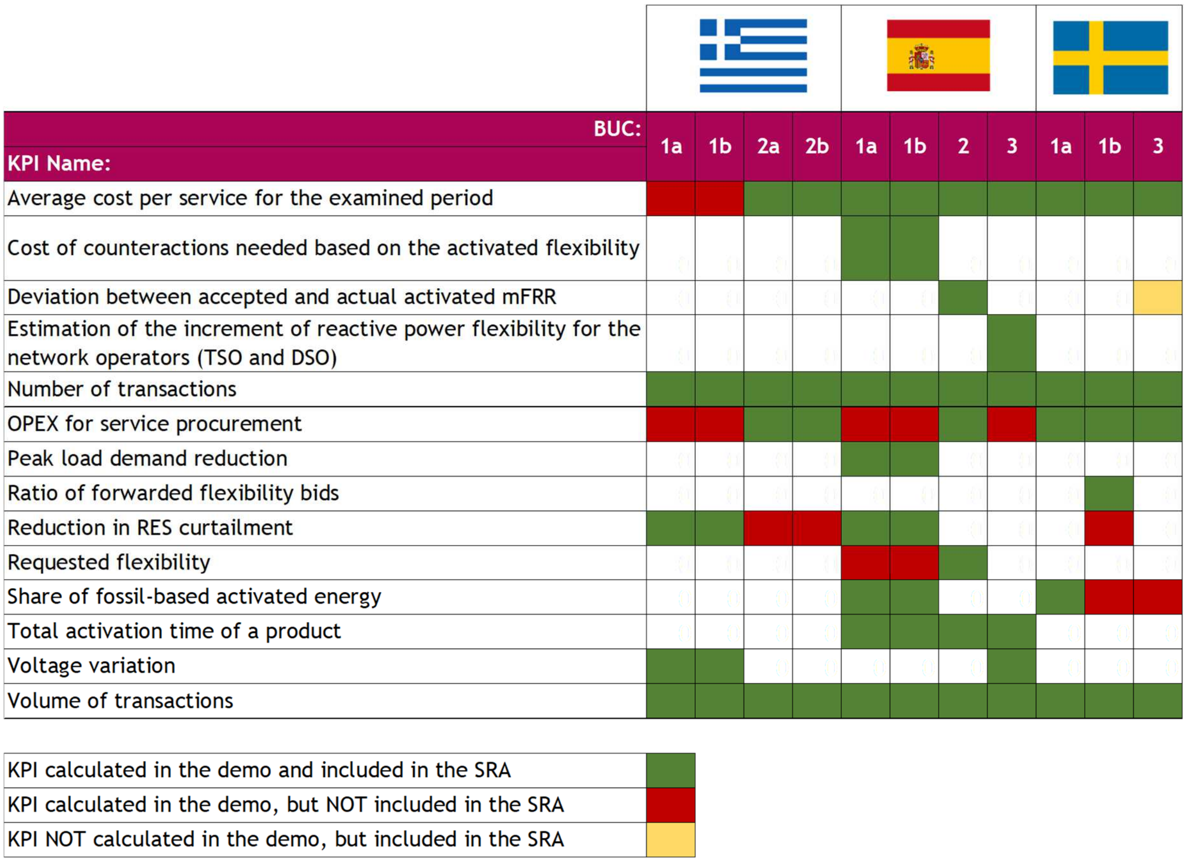

Figure 5: Selection of demo KPIs to be considered in the quantitative SRA

[8] In Spanish: *Tiempo de Interrupción Equivalente de la Potencia Instalada*. It is in practice similar to the Average System Interruption Duration Index (ASIDI) defined by the IEEE standard 1366-2003, although instead of using the kVA served, the MV/LV transformation capacity and the power contracted by MV consumers are considered as weighting factors.

2.1.4. Input data requirements

The simulation and quantification of the aforementioned KPIs required collecting and treating an extensive amount of input data, with the support of demo partners. The main types of input data required are the following:

- Network data: as mentioned above the simulations required running power flows or computing sensitivity factors linearizing the power flow equations around a certain operating point. This inevitably requires having the network data to build a complete grid model. The approach followed differed for transmission and distribution systems.
    - Transmission grids: using a complete model of the national transmission system would not be practical due to their size and complexity, or even feasible due to confidentiality or security constraints. Therefore, in order to keep the models manageable, a balance between a simple network model that could be easily analyzed, and a model that adequately reflects the main congestions in the system to be solved with the FSPs was sought.

      In practice, this was achieved through two alternative approaches. In the cases of Spain and Sweden, we relied on simplified transmission models developed and validated in previous EU projects or research works based on the actual transmission system. On the other hand, in the case of Greece, the TSO (IPTO) provided a detailed transmission grid model for the selected demo area and a simplified equivalent circuit representing the rest of the Greek transmission system.
    - Distribution grids: in this case it was possible to use the actual grid model provided by the DSO, although in some cases it was necessary to rely on synthetic or modified networks (lengths or impedances) due to confidentiality concerns. Nonetheless, all these networks were validated by the corresponding DSO to ensure they reflect the main characteristics of real grids.
- Others data required:
    - Load/generation profiles at the level of the national system and each of the distribution areas. It is relevant to note that the simulations where both transmission and distribution networks are modelled, some assumptions should be made in order to allocate in a consistent manner the load/generation at system level per transmission bus and, at the same time, allocate the load at the transmission substation among each of the buses of the distribution network located downstream.
    - Individual load profiles: in order to perform distribution grid analyses, load/generation profiles for individual users are needed. These may be actual profiles, or, in order to observe data protection constraints, standardized or averaged profiles.
    - Voltage control strategies at distribution level: what DSO-owned resources are used for voltage control (on-load tap changers (OLTCs), capacitor banks, voltage regulators), where (voltage levels, regions, overhead/underground) and how (automatic, manual).
    - Type of flexibility providers in the demos, technical characteristics (flexible power, availability of upwards and downwards flexibility, reservation/activation costs, etc.).

2.1.5. Summary of workstreams and scope of quantitative SRA

Based on the previous discussions, Table 3 summarizes the key information for each of the three modelling workstreams: grids/voltage levels considered, countries and demo sites for replication, modelling tools, and coordination schemes tested.

Modelling workstream	Countries/sites	Modelling approach	Coordination schemes
Balancing + congestion management including transmission and HV distribution grids[9]	ES (T + Cádiz and Albacete), SE (Uppsala)	Economic dispatch with DC power flow equations in GAMS	Common, central, multi-level + joint and separate procurement of balancing and CM in the 3 CSs.
Congestion management in MV grids	ES (Málaga-Cádiz Road and Murcia), GR (Argostoli)	PTDF-linearized local market model in Python	Local
Voltage control in T+D grids (or D only)	ES (T+Cádiz, Murcia), GR (Kefalonia area+Argostoli)	Sensitivity factors-linearized local market model in Python	Common, multi-level, fragmented

Table 3: Description of the three modelling workstreams part of the quantitative SRA

2.2. Regulatory SRA aim and approach

The aim of the regulatory SRA is to identify barriers (and drivers) for upscaling and replicating the selected BUCs posed by existing regulation. Barriers are rules, found in all or some of the countries considered, that potentially constrain the implementation and operation of the BUCs. On the contrary, a regulatory driver is found when certain solutions are enabled and incentivized by regulation.

Regulation includes all the rules about which services can be provided, the different roles of actors, the remuneration of certain activities, etc. With respect to replicability, the regulatory SRA studies whether the use case tested in one country can be replicated in another country under the existing regulation in that country. The regulatory topics covered are based on deliverable D1.1 which already analyzed the regulatory conditions in a set of target countries (Lind & Chaves Ávila, 2019a). These topics are the following: DER provision of services for TSOs and DSOs, aggregation, allocation of balancing responsibility, existing TSO-DSO interactions, and market design and access rules.

The target countries covered in D1.1 included the three demo countries, plus a set of additional EU countries. In this case, given the fast evolution of power system regulation nowadays, the regulatory information collected at the beginning of the project and presented in D1.1 has been updated by project partners and linked third parties in order to reflect the latest status of regulation possible. The final list of countries covered in this SRA are the following: Spain, Sweden, Greece, Germany, Italy, Netherlands, Austria, and Belgium.

Once the relevant regulatory topics and geographical scope were defined, the regulatory SRA has been carried out according to the following steps:

- Collect the updated regulatory information from each target country.

[9] Congestion management services are procured by both TSO and DSO, while balancing services are procured by the TSO.

- Map the regulatory topics and associated drivers/barriers against the BUC analyzed, i.e. define what barriers/drivers are related to what regulatory topics and how relevant they are to each BUC.
- Perform a comparative country analysis of the status and relevance of the different barriers, i.e. assess how important or active each barrier is in each country.
- Carry out a maturity assessment for each BUC and country depending on the relevance of each barrier to each BUC as well as the status of each barrier per country.

3. Quantitative SRA - Workstream 1: TSO-DSO coordination for the procurement of balancing and congestion management services

The main purpose of this chapter is to describe the SRA methodology and analyze the SRA results for the modelling Workstream 1. This workstream focuses on different Coordination Schemes as well as the procurement of flexibility for both balancing and congestion management services. In this context, both demo and synthetic data were used in the modelling process. For the transmission grids, synthetic networks were used in order to keep the model tractable. Distribution-related data was mostly gathered from the demonstrations and supplemented with synthetic data when needed, as described in the following sections. Together with the SRA parameters for the different scenarios, this data serves as an input for the different optimization models used in workstream 1. These models are described in the following section. As an output, different analyses are made based on KPIs also used in the demonstrations. Figure 6 provides an overview of the SRA methodology for workstream 1.

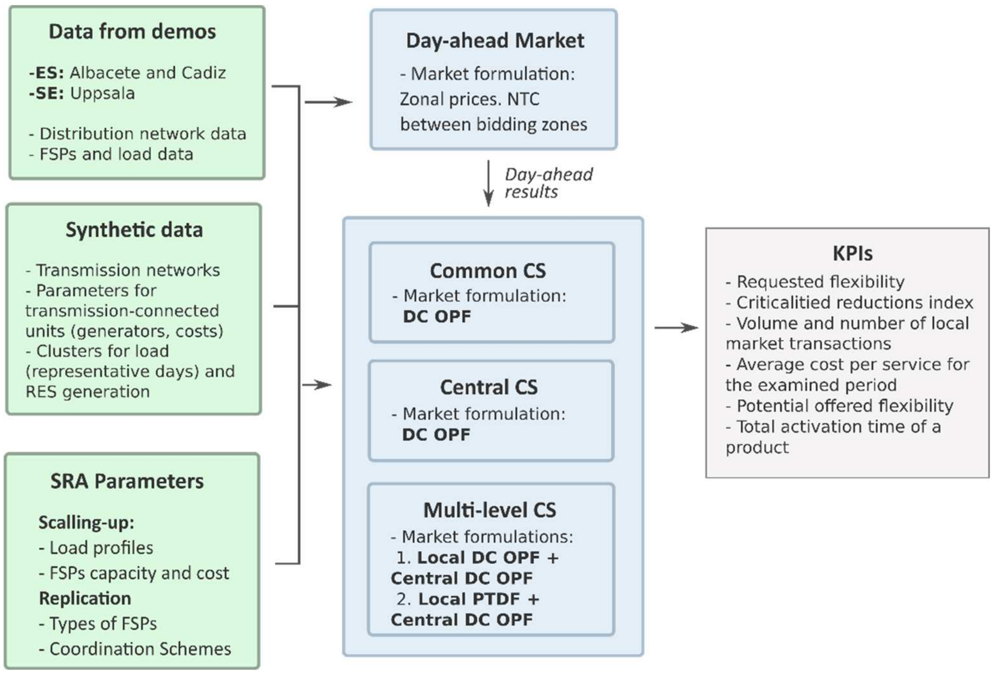

Figure 6: Overview of SRA Methodology for workstream 1

3.1. Modelling approach

In this section, the optimization models used in this SRA workstream are presented, including their rationale and mathematical formulation.

3.1.1. Linear TSO-DSO coordination model for transmission and sub-transmission grids

In this modelling workstream, a combined TSO-DSO model for the procurement of flexibility, including flexibility from DERs, is presented. This model aims to provide an assessment tool for different TSO-DSO coordination schemes, considering that both System Operators (SOs) may utilize resources connected at the distribution grid for the purposes of solving congestions in the grids and imbalances of the system. Therefore, this modelling workstream focuses exclusively on these two products, namely balancing and congestion management. Therefore, this model is composed of three building blocks, namely a wholesale energy market, a congestion management market and a balancing market. The two latter are organized in different coordination schemes as explained below.

Firstly, however, it is important to understand what is understood by each product. We model what aims to describe a generic European market sequence, as described in CEDEC et al. (2019) and illustrated in Figure 7. This means that firstly, a wholesale market is operated, clearing offers from buyers and producers for a 24h period. This market is here referred to as the DA market, in reference to when it takes place in relation to the energy delivery (real-time). This market, however, does not consider any network constraints other than those between bidding zones, limited by their Net Transfer Capacity (NTC). In this generic European market sequence, the results from the DA market are passed onto the SO, in this case, the TSO and/or the DSO, which checks for the feasibility of that market-clearing. In case of network violations, the SO solves them using congestion management markets. These markets act as corrective markets[10,11], considering the results from the DA market, the offers from flexibility providers in the congestion management markets and the network limits and characteristics. This clearing process varies according to the different CSs proposed. This market takes place in between the DA and near to real-time timesteps. Finally, near real-time, another type of market is cleared by the TSO, namely the balancing market[12]. The purpose of this market is to compensate for possible imbalances between generation and consumption in real-time. In this deliverable, these imbalances are input data of the model, calculated using assumptions for each country under study, as described in sections 3.2 and 3.3.

The red boxes in Figure 7 illustrate the market sequence considered in this modelling workstream. First, the DA market, second, the congestion management market, and third, the balancing market.

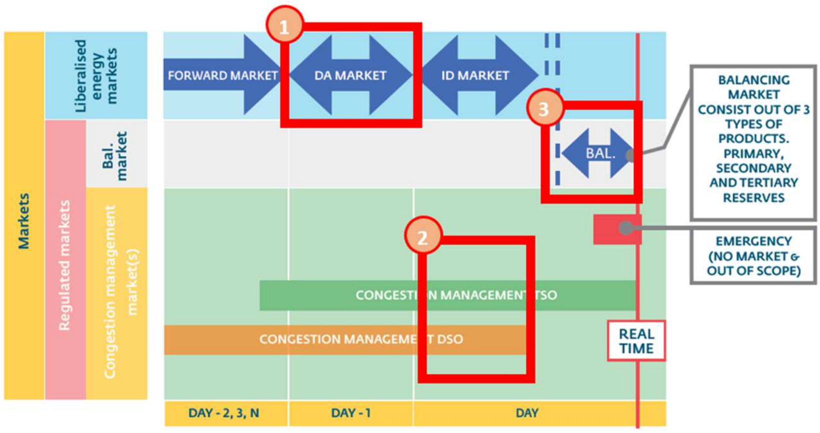

Figure 7: The sequence of electricity markets in Europe. Adapted from: (CEDEC et al., 2019)

[10] Corrective markets are here understood as the markets used to solve congestion in the network caused by the DA schedule. These markets can also be called redispatch markets (mostly in the context of transmission), or flexibility markets (distribution context) (Meeus, 2020).

[11] This approach is a general representation for a European market sequence. However, this is not the case for every European country. In Sweden, for instance, local flexibility markets take place before the DA market. This difference is discussed in section 3.2.

[12] It is important to notice that the markets here referred are energy markets. Capacity markets for balancing may have different market sequence.

The way congestion management and balancing are organized between TSO and DSO are hereafter referred to as CSs, following what has been produced in the TSO-DSO coordination literature (Gerard et al., 2016, 2018; Givisiez et al., 2020; Lind et al., 2019a). In the current formulation of the different CSs, we use as a basis for interpretation the work conducted at the beginning of the CoordiNet project, published in the deliverable D1.3, that defined the different market models to be considered in the project, and the recently published CoordiNet deliverable D6.2, which evaluated different coordination schemes under a theoretical approach (Delnooz et al., 2019; Sanjab et al., 2022).

Three main CSs are analysed in this modelling workstream, namely the Common CS, the Central CS and the Multi-level CS. The Common CS is defined by a single market in which both congestions and imbalances (jointly or in sequence). It can be assumed that this market is run by a single entity (e.g. an independent market operator; the TSO) and that both TSO and DSO procure flexibility in this market, in accordance with the definition used in the CoordiNet project (Delnooz et al., 2019). However, it is not modelled how TSOs and DSOs will share the cost of the market clearing. For this analysis, we refer the reader to CoordiNet's deliverable D6.2 (Sanjab et al., 2022).

The Central CS is similarly defined as the Common CS, however this time the TSO is the single buyer. The TSO can procure flexibility also from the resources connected at the distribution grid. However, the TSO does not have observability over the distribution grid. Therefore, only the power limits at the substation connecting the DSO (hereafter referred as interface) are considered by the TSO. It is assumed that the distribution grid can handle the flexibility activations from the TSO, assuming that the prequalification process ensures that no activation leads to further congestion at distribution.

Finally, the Multi-level CS considers that firstly, the DSO is responsible to run a local congestion management market to solve congestions at the distribution grid, followed by the TSOs markets. In this sequence of markets, unused bids by the DSO are then passed on to the TSO market(s), if they do not create additional constraints.

From the TSO perspective, there are always two different needs to be met, namely congestions and balancing. These two needs can be procured in different markets (the typical approach in Europe), or jointly, as proposed in (CEDEC et al., 2019). Therefore, for each CS, two variations exist. First, the one in which the TSO runs the redispatch market and then the balancing market in a sequential way. Second, the one in which the TSO procures both products in one single market session. Figure 8 presents an overview of the modelling approach described. Each blue box represents one market session, all modelled as Mixed Integer Programming (MIP) optimization problems.

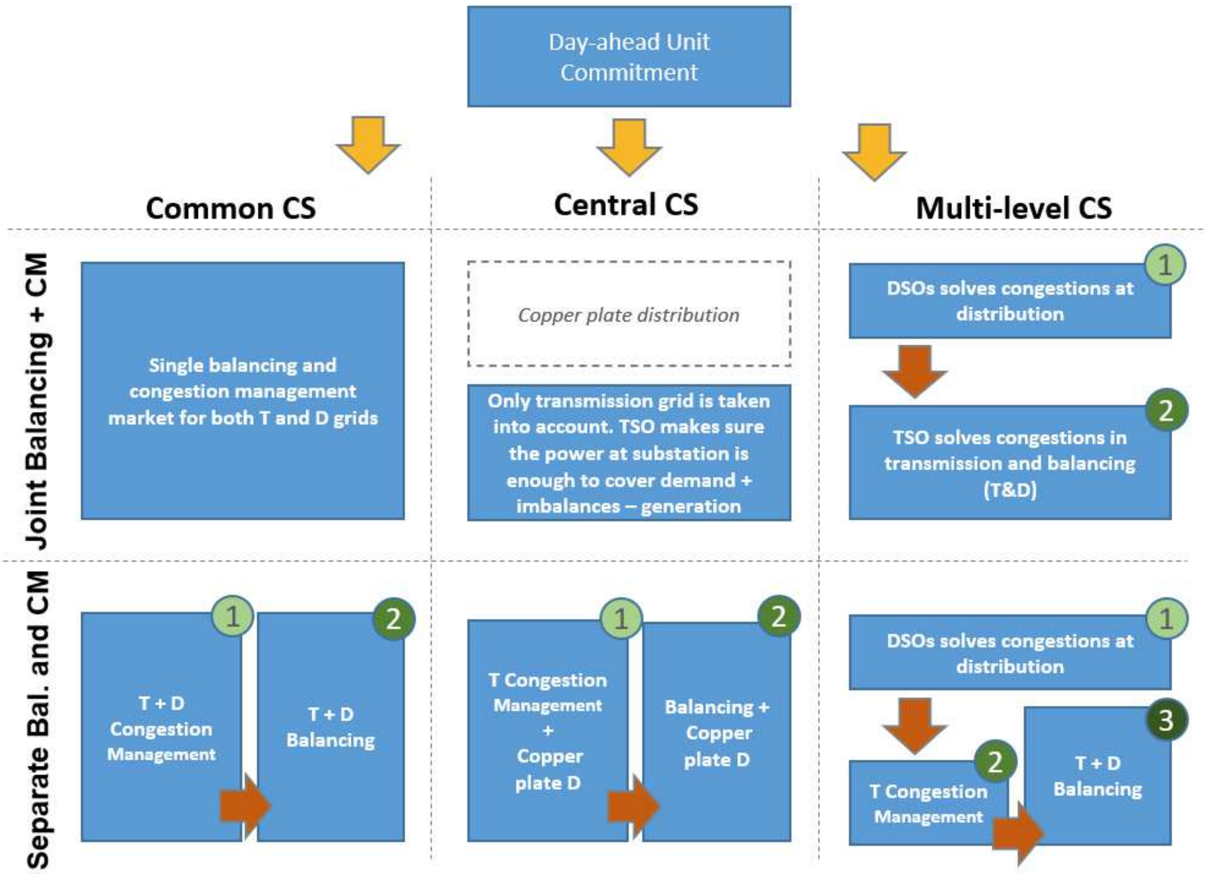

Figure 8: Overview of the Linear TSO-DSO Coordination Model

In their general form, the ancillary service markets in all coordination schemes (congestion management and balancing) are modelled as OPFs. However, in order to capture the different market design choices made by the demonstrations in CoordiNet, additional implementations of the Common and the Multi-level CS are proposed.

Firstly, a variation on the Multi-level CS is implemented based on the Swedish Local Flexibility Market (LFM). In this variation, the DSO procures flexibility not based on an OPF implementation but considering the impact of each individual FSP over the power flows at the interfaces with the TSO. In this market design, the DSO is mostly concerned with the power flow at the substation, considering that in Sweden the DSO faces a financially imposed constraint at the interface. At each interface, a subscription level is granted to the DSO, which is usually below the normal technical power limits of the substation. Surpassing the subscription level would mean a penalty for the DSO, in case a temporary subscription is not granted by the TSO. Therefore, the subscription level-based Multi-Level CS tries to replicate this logic in order to model what was actually tested in the Swedish demonstration as a market design for local flexibility.

Secondly, the Spanish understanding of the Common CS also differs from the generalized single-OPF problem. In the Spanish demonstration, the BUCs ES-1a (Common Congestion Management) and ES-2 (Common Balancing) were implemented in a way that the DSO is able to check if the FSPs being activated in these markets are causing congestion in the distribution or not (Lind et al., 2022). This CS is characterized by a first TSO-run market for congestion management, balancing or both. Secondly, the DSO receives the market results and runs a power flow of those results. If congestions are identified, the DSO can impose limitations to the FSPs connected at the distribution grid. These limitations are sent back to the TSO that re-runs the original market, but now including the limitations from the DSO.

Finally, a third implementation of the Multi-level CS is modelled. This variation is a combination of the Swedish variation and the general OPF implementation, as it uses the impact factor in the form of the PTDF, but it considers needs not only at the interface with the TSO, but in any element of the distribution grid. This CS starts by the DSO running a Power Flow (PF) and identifying potential needs. Following that, a local flexibility market is run based on the PTDF of each participating FSP over the constrained assets. This implementation is modelled here as it is the basic version of the local flexibility market proposed in the Workstream 2 of this SRA. Table 4 summarizes all the CS and their essential characteristics.

Table 4: List of Coordination Schemes modelled and their characteristics

Coordination Scheme	Market Operator	Joint-Separate	Service / Market Session[13]	Underlying Model Technique
Common	TSO	Joint	CM+B	DC-OPF
		Separate	B	DC-OPF
			CM	DC-OPF
Central	TSO	Joint	CM+B	DC-OPF
		Separate	B	DC-OPF
			CM	DC-OPF
Multi-level (OPF)	DSO	Separate (Local Market)	CM	DC-OPF
	TSO	Joint	CM+B	DC-OPF
		Separate	B	DC-OPF
			CM	DC-OPF
Multi-level (Subscription) *(Swedish case)*	DSO	Separate (Local Market)	CM	PTDFs
	TSO	Joint	CM+B	DC-OPF
		Separate	B	DC-OPF
			CM	DC-OPF
Common (Limit.) *(Spanish case)*	TSO	Joint	CM+B	PF / DC-OPF
		Separate	B	PF / DC-OPF
			CM	PF / DC-OPF
Multi-level (PTDFs)	DSO	Separate (Local Market)	CM	PF / PTDFs
	TSO	Joint	CM+B	PF / PTDFs
		Separate	B	PF / PTDFs
			CM	PF / PTDFs

The different coordination schemes of Workstream 1 are applied to two case studies, namely the Swedish and Spanish case studies (sections 3.2 and 3.3, respectively). One characteristic of these case studies is the necessity to obtain yearly results. For that purpose, case studies are assembled using a variety of

[13] CM: Congestion Management; B: Balancing; CM+B: Congestion Management plus Balancing.

representative days throughout the year in terms of demand and RES profiles. The methodology to generate these representative days is the k-means clustering. With this technique, for example, all 365 24h-load curves can be clustered in a set of tractable representative days (usually eight, two per season).

3.1.2. Formulation of a linear TSO-DSO coordination model for transmission and sub-transmission grids

3.1.2.1. Nomenclature

INDICES

$h \in H$	Hour
$i,j \in N$	Node
$g \in G$	Generator
$f \in F$	flexibility service provider (FSP)
$s \in S$	system operator (SO)
$t \in T$	type system operator
$z, zz \in Z$	bidding zones
lv	levels of subscription of the interface (multi-level cs)

SETS

H	Set of hours
N	Set of nodes
$L(i,j)$	Set of lines from node i to node j
G	Set of generators participating in the Day-Ahead market
F	Set of FSPs participating in the Ancillary Service (AS) markets
S	Set of system operators ($= \{T1 \dots Tn, D1 \dots Dn\}$)
T	Set of types of system operators ($= \{TSO, DSO\}$)
Z	Set of bidding zones
$TS(t,s)$	Set of correspondence between t and s
$SUBS$	Set of substations nodes ($SUBS \subset N$)
$INTER$	Set of interface nodes ($FRONT \subset SUBS$)
$IS(i,s)$	Set of nodes i belonging to System Operator s
$IG(i,g)$	Set of generators g connected at node i
$IF(i,f)$	Set of FSPs f connected at node i
$ZN(i,z)$	Set of nodes i in bidding zone z
$ZG(g,z)$	Set of generators g belonging to bidding zone z
$IZ(z,zz)$	Set of interconnections between bidding zones
$RES(g)$	Subset of generators g that are RES
$ESS(f)$	Subset of FSPs that are ESS

PARAMETERS

Q_g^+	Maximum output of generator g in MW
D_{ih}	Demand at node i in hour h in MW
Q_f^+	Maximum output of FSP f in MW
Q_f^-	Minimum output of FSP f in MW
X_{ij}	Reactance of line (i,j) in p.u.
P_{ij}^+	Maximum power flow of line (i,j) in MW
P_{ij}^-	Minimum power flow of line (i,j) in MW ($= pP_{i,j}^+ * -1$)
θ_i^+	Maximum angle θ for node i in p.u.
θ_i^-	Minimum angle θ for node i in p.u.
Bid_g	Bid of generator g in the DA market in €/MWh
Bid_f	Bid of FSP f in the AS market(s) €/MWh
$DispatchDA_{ih}$	Total generation cleared in the DA market produced in node i during hour h in MW

QDA_{fh}	Quantity dispatched in the DA for FSP f in hour h
Imb_{gh}	Imbalance of generator g in hour h in MW
SB	Base Power in MW
Cyc_{g}	Cycling cost of generator g. In €/MW
$ResProfile_{g}$	RES profile
$MinDispatch_{g}$	Minimum technical dispatch of generator g. In p.u.
$NTC^{+}_{z,zz}$	Upper bound for Net Transfer Capacity between bidding zones
$NTC^{-}_{z,zz}$	Lower bound for Net Transfer Capacity between bidding zones
$MaxFlex^{+}_{g}$	Maximum upward flexibility capacity in relation to the DA dispatch
$MaxFlex^{-}_{g}$	Maximum downward flexibility capacity in relation to the DA dispatch
$SoC^{init}_{f,h=1}$	Initial SoC of ESS f in hour 1
EF	ESS efficiency
$DRMaxh$	Number of hours that a DR FSP can provide flexibility
$MinBidSize$	Minimum bid size. In MW.
$Impact_{i}$	Average of PTDFs for substation i
$CNSF$	Cost of non-served flexibility
$CSubs_{i,lv}$	Cost per subscription level lv in substation i
$DispatchFSP_{fh}$	Parameter that captures the activation of FSP in the LFM
$DSONeed_{sijh}$	Overloads in elements to be solved in the LFM with PTDFs
$PTDF_{ij,ii}$	PTDF of node ii over line i,j

VARIABLES

p_{ijh}	Power flow in line connecting nodes i and j during hour h in MW
θ_{ih}	Angle θ at node i in hour h in radians
qda_{gh}	Quantity cleared in the DA market for generator g in hour h in MW
dda_{ih}	Total generation cleared in the DA market produced in node i during hour h in MW
q_{fh}	Quantity cleared in the AS market for FSP f in hour h in MW
$psubs_{ih}$	Power leaving or entering substation i in hour h ($i \in SUBS$) in MW
su_{gh}	Start-up of generator g in hour h. $\in \{0,1\}$
sd_{gh}	Shutdown of generator g in hour h. $\in \{0,1\}$
uc_{gh}	Unit commitment status of generator g in hour h. $\in \{0,1\}$
$tc_{z,zz,h}$	Transfer capacity between bidding zones z and zz in hour h
$qmax_{gh}$	Auxiliary variable for the unit commitment problem
nsf^{p}_{ih}	Non-served upward flexibility in node i in hour h
nsf^{n}_{ih}	Non-served downward flexibility in node i in hour h
soc_{fh}	State of Charge of ESS f in hour h
$pdis_{f,h}$	Power being discharged from ESS f in hour h in p.u.
$pcha_{f,h}$	Power being charged from ESS f in hour h in p.u.
$flexess^{dw}_{fh}$	Auxiliary variable for the implementation of the ESS logic
$bcha_{fh}$	Binary variable for the charging of ESS
$bdis_{fh}$	Binary variable for the discharging of ESS
uc^{up}_{fh}	Binary variable for the upward activation of FSP f in hour h
uc^{dw}_{fh}	Binary variable for the downward activation of FSP f in hour h
vd_{sh}	Virtual demand of DSO so in hour h
$pimport_{ih}$	Power imported by the distribution grid from the transmission grid (central cs)
$pexport_{ih}$	Power exported from the transmission grid to the distribution grid (central cs)
$psubs_{ih}$	Power demanded at the interface (multi-level cs)
$qsubs_{i,lv,h}$	Level of use of subscription power at the substation

3.1.2.2. Day-ahead market

The day-ahead market is characterized by a clearing of the total demand in each hour and the merit order list of generation bids. At this market phase, the network is not taken into account, except for the limits between bidding zones. Therefore, the Market Operator (MO) minimizes the generation cost (3-1), ensuring that the total demand within the bidding zone is supplied while accounting for imports from and exports to other bidding zones (3-2). Eq. (3-3) computes the day-ahead dispatch that will later be passed on to the following CSs. Eq. (3-4)-(3-6) are responsible for the unit commitment logic (based on Tejada-Arango et al. 2020)). Eq. (3-7) accounts for any minimum up time if applicable to the generator g (e.g. nuclear or thermal power plants), while eq. (3-8) accounts for the minimum technical dispatch. Finally, eq. (3-10) and (3-11) limit transfer capacity between bidding zones and power output per generator to their bounds.

$$\min \sum_{gh} ((Bid_g * qda_{gh}) + (su_{gh} * Cyc_g * Q_g^+)) \tag{3-1}$$

s.t.

$$\sum_{g \in ZG} qda_{gh} - \sum_{zz \in IZ} tc_{z,zz,h} + \sum_{zz \in IZ} tc_{zz,z,h} = \sum_{i \in ZN} D_{ih}, : (\lambda_{zh}) \ \forall zh \tag{3-2}$$

$$dda_{ih} = \sum_{g \in IG} qda_{gh} \qquad \forall ih \tag{3-3}$$

$$uc_{g,h-1} = uc_{gh} - su_{gh} + sd_{gh} \quad \forall gh \tag{3-4}$$

$$qmax_{gh} = uc_{gh} * Q_g^+ \quad \forall gh \tag{3-5}$$

$$qda_{gh} \leq qmax_{gh} \quad \forall gh \tag{3-6}$$

$$su_{gh} * minup_g \leq \sum_{h}^{h+minup_g} uc_{gh} \ \forall gh \tag{3-7}$$

$$uc_{gh} * Q_g^+ * MinDispatch_g \leq qda_{gh} \tag{3-8}$$

$$q_{gh} \leq Q_g^+ * ResProfile_g \quad \forall g \in RES \tag{3-9}$$

$$NTC_{z,zz}^- < tc_{z,zz,h} < NTC_{z,zz}^+ \tag{3-10}$$

$$qda_{gh} < Q_g^+ \qquad \forall gh \tag{3-11}$$

Following the DA market, the AS market(s) take place based on the results of the DA market. Therefore, notice the optimal dispatch for all generators is passed on as a parameter to all subsequent AS markets. The dispatch is passed on aggregated per node (3-12).

$$DispatchDA_{ih} = dda_{ih}^* \tag{3-12}$$

3.1.2.3. Common Joint CS

In this Common Joint CS, the market solves all imbalances and network congestions using resources connected at both the transmission and the distribution networks. In this case, a single minimization problem is solved. Equation (3-13) minimizes the total cost of the FSPs' activation during 24h. Considering that both congestion management and balancing markets are centrally run, the modelling of this CS can be seen as a single DC OPF. However, the demand balance equations (3-14)-(3-15) and the power flow equations are split according to the type of SO (3-16)-(3-17)[14]. In addition, equations (3-18) and (3-19) ensure that the power at the substation (the interface between TSO and DSO) is consistent. Eq. (3-20)-(3-21) limit the maximum number of hours (in an equivalence of power output) that DR FSPs can provide flexibility, in order to account for comfort limitations in flexibility provision. Eq. (3-22)-(3-23) limit the upward and downward provision of flexibility from RES in relation to their DA dispatch, given that these types of FSP may only have a limited capacity upward, especially (e.g. due to forecasting errors). Eq. (3-24)-(3-29) are an implementation for the Energy Storage System (ESS) logic (based on Niewiadomski & Baczyńska (2021)). According to ESS, two binary variables are included to define the state of the battery, namely $bcha_{fh}$ and $bdis_{fh}$. Table 5 presents the state of the ESS depending on the state of each binary variable. Notice that $bcha_{fh}$ and $bdis_{fh}$ cannot be 1 at the same time, as this behavior is constrained by equation (3-27).

Table 5: State of ESS according to binary variables

$bcha_{fh}$	$bdis_{fh}$	ESS State
1	0	Charging
0	1	Discharging
0	0	Storing energy

Eq. (3-30)-(3-35) implement the unit commitment equivalent for the FSPs. Finally, Eq. (3-36), (3-37) and (3-38)-(3-39) limit the power flow over the lines, the angles in each node, and the maximum output per FSP, respectively.

$$\min \sum_{s\in TS\wedge t=TSO,ifh} \left(\left(Bid_f * q^{up}{}_{fh}\right) + \left(Bid_f * q^{dw}{}_{fh}\right)\right) + \sum_{s\in TS\wedge t=DSO,ifh} \left(\left(Bid_f * q^{up}{}_{fh}\right) + \left(Bid_f * q^{dw}{}_{fh}\right)\right) + \sum_{ih} \left(nsf_{ih}^{up} + nsf_{ih}^{dw}\right) * CNSF \tag{3-13}$$

s.t.

$$DispatchDA_{ih} + \sum_{f\in IF} q_{fh} - \sum_{j} p_{ijh} + \sum_{j} p_{jih} - Imb_{ih} = D_{ih} + nsf_{ih}^{p} - nsf_{ih}^{n} \qquad \forall i \in IS, s \in TS \wedge t = TSO, h \tag{3-14}$$

$$DispatchDA_{ih} + \sum_{f\in IF} q_{fh} - \sum_{j} p_{ijh} + \sum_{j} p_{jih} - Imb_{ih} = D_{ih} + nsf_{ih}^{p} - nsf_{ih}^{n} \qquad \forall i \in IS, s \in TS \wedge t = DSO, h \tag{3-15}$$

$$p_{ijh} = SB * \frac{\theta_{ih} - \theta_{jh}}{X_{ij}} \qquad \forall (i \in IS, j \in IS) \in L, (s \in TS) \wedge (t = TSO), h \tag{3-16}$$

$$p_{ijh} = SB * \frac{\theta_{ih} - v\theta_{jh}}{X_{ij}} \qquad \forall (i \in IS, j \in IS) \in L, (s \in TS) \wedge (t = DSO), h \tag{3-17}$$

[14] From a mathematical formulation perspective, TSO and DSOs are differentiated through different sets. For example, the demand balance equation (3-14) applies to all nodes associated to a SO ($\forall i \in IS$), for all SOs associated to a type of SO ($s \in TS$) and to which the type of system operator is a TSO ($\wedge\, t = TSO$).

$$p_{ijh} = pSB * \frac{v\theta_{ih} - v\theta_{jh}}{pX_{ij}} \qquad \forall (i,j) \in L \wedge \big((i \in SUBS) \vee (j \in SUBS)\big), h \tag{3-18}$$

$$\sum_{j} vP_{jih} = \sum_{j} vP_{ijh} \qquad \forall (i,j) \in SUBS, h \tag{3-19}$$

$$\sum_{h} q_{fh}^{up} \leq Q_f^{+} * DRMaxh \quad \forall f \in DR \tag{3-20}$$

$$\sum_{h} q_{fh}^{dw} \leq Q_f^{-} * DRMaxh \quad \forall f \in DR \tag{3-21}$$

$$q_{fh}^{up} \leq QDA_{fh} * MaxFlex_g^{+} \quad \forall f \in RES \tag{3-22}$$

$$q_{fh}^{dw} \leq QDA_{fh} * MaxFlex_g^{-} \quad \forall f \in RES \tag{3-23}$$

$$soc_{fh} = SoC_{f,h=1}^{init} + soc_{f,h-1} - \left(pdis_{f,h} * Q_{fh}^{+} * EF + q_{fh}^{up}\right) + \left(pcha_{f,h} * Q_{fh}^{-} * EF + q_{fh}^{dw}\right) \forall f \in ESS, h \tag{3-24}$$

$$q_{fh}^{dw} = \ flexess_{fh}^{dw} * Q_{fh}^{+} * EF \quad \forall f \in ESS, h \tag{3-25}$$

$$q_{fh}^{up} = \ flexess_{fh}^{up} * Q_{fh}^{+} * EF \quad \forall f \in ESS, h \tag{3-26}$$

$$bcha_{fh} + bdis_{fh} \leq 1 \ \forall f \in ESS, h \tag{3-27}$$

$$pdis_{f,h} + flexess_{fh}^{dw} \leq bdis_{fh} \ \forall f \in ESS, h \tag{3-28}$$

$$pcha_{fh} + flexess_{fh}^{up} \leq bcha_{fh} \ \forall f \in ESS, h \tag{3-29}$$

$$q_{fh}^{up} \leq Q_{fh}^{+} * uc_{fh}^{up} \ \forall fh \tag{3-30}$$

$$q_{fh}^{up} \leq Q_{fh}^{+} * uc_{fh}^{up} \ \forall fh \tag{3-31}$$

$$uc_{fh}^{up} * MinBidSize \leq q_{fh}^{up} \ \forall fh \tag{3-32}$$

$$q_{fh}^{dw} \leq Q_{fh}^{-} * uc_{fh}^{dw} \ \forall fh \tag{3-33}$$

$$uc_{fh}^{dw} * MinBidSize \leq q_{fh}^{dw} \ \forall fh \tag{3-34}$$

$$uc_{fh}^{up} + uc_{fh}^{dw} \leq 1 \ \forall fh \tag{3-35}$$

$$P_{ij}^{-} < p_{ijh} < P_{ij}^{+} \qquad \forall ijh \tag{3-36}$$

$$\theta_i^{-} < \theta_{ih} < \theta_i^{+} \qquad \forall ih \tag{3-37}$$

$$q_{fh} = q_{fh}^{\mathrm{up}} - q_{fh}^{dw} \qquad \forall fh \tag{3-38}$$

$$Q_f^{-} < q_{fh} < Q_f^{+} \qquad \forall fh \tag{3-39}$$

3.1.2.4. Common CS with Separate CM and Balancing

This CS is characterized by a central MO, in this case, the TSO, solving congestions and balancing. Resources connected to the distribution and transmission grid are used for that purpose. The difference with respect to the previous CS lies in the fact that first, a congestion management market is run, followed by a balancing market.

3.1.2.4.1. Congestion Management Market

The congestion management market is characterised by a DC OPF, similar to the Common Joint CS, differing by the fact that the demand balance equations (3-40)-(3-41) do not include the imbalances.

Min (3-13)

s.t.

(3-16), (3-17), (3-18), (3-19), (3-20)-(3-21), (3-22)-(3-23), (3-24)-(3-29), (3-30)-(3-35), (3-36), (3-37), (3-38), (3-39),

$$DispatchDA_{ih} + \sum_{\substack{f \in IF \\ = TSO,h}} q_{fh} - \sum_{j} p_{ijh} + \sum_{j} p_{jih} = D_{ih} + nsf_{ih}^{p} - nsf_{ih}^{n} \qquad \forall i \in IS, s \in TS \wedge t \tag{3-40}$$

$$DispatchDA_{ih} + \sum_{\substack{f \in IF \\ = DSO,h}} q_{fh} - \sum_{j} p_{ijh} + \sum_{j} p_{jih} = D_{ih} + nsf_{ih}^{p} - nsf_{ih}^{n} \qquad \forall i \in IS, s \in TS \wedge t \tag{3-41}$$

Following the congestion management market, minimums and maximums are adjusted and passed on to the balancing market, as demonstrated in equations (3-42)-(3-47).

$$Q_f^{new+} = Q_f^{+} - q_{fh}^{*} \qquad \forall fh \tag{3-42}$$

$$Q_f^{new-} = Q_f^{-} - q_{fh}^{*} \qquad \forall fh \tag{3-43}$$

$$P_{ij}^{new+} = P_{ij}^{+} - p_{ijh}^{*} \qquad \forall (i,j) \in L, h \tag{3-44}$$

$$P_{ij}^{new-} = P_{ij}^{-} - p_{ijh}^{*} \qquad \forall (i,j) \in L, h \tag{3-45}$$

$$\theta_i^{new+} = \theta_i^{+} - \theta_{ih}^{*} \qquad \forall ih \tag{3-46}$$

$$\theta_i^{new-} = \theta_i^{-} - \theta_{ih}^{*} \qquad \forall ih \tag{3-47}$$

3.1.2.4.2. Balancing Market

In the balancing phase, another DC OPF is run by the TSO, this time including only the imbalances in demand balance equations (3-48)-(3-49) and considering the new limits received from the congestions management market (3-50)-(3-52). Although the balancing market could be modelled without considering the network (replicating what happens in several balancing markets), the network is included here. It is assumed that the TSO has full observability of the distribution network from the previous congestion management market.

This helps to ensure the feasibility of the final result, as this is the last market in the sequence. The DC OPF for the balancing market serves as a proxy for what could be a longer market sequence in this setting, composed of another congestion management market very close to real-time.

Min (3-13)

s.t.

(3-16), (3-17), (3-18), (3-19), (3-20), (3-21), (3-22), (3-23), (3-24)-(3-29), (3-30)-(3-35),

$$\sum_{f \in IF} q_{fh} - \sum_{j} p_{ijh} + \sum_{j} p_{jih} = \sum_{g \in IG} Imb_{gh} \qquad \forall i \in IS, s \in TS \wedge t = TSO, h \tag{3-48}$$

$$\sum_{f \in IF} q_{fh} - \sum_{j} p_{ijh} + \sum_{j} p_{jih} = \sum_{g \in IG} Imb_{gh} \qquad \forall i \in IS, s \in TS \wedge t = DSO, h \tag{3-49}$$

$$P_{ij}^{new-} < p_{ijh} < P_{ij}^{new+} \qquad \forall ijh \tag{3-50}$$

$$\theta_{i}^{new-} < \theta_{ih} < \theta_{i}^{new+} \qquad \forall ih \tag{3-51}$$

$$Q_{f}^{new-} < q_{fh} < Q_{f}^{new+} \qquad \forall fh \tag{3-52}$$

3.1.2.5. Central Market Model[15]

In the Central CS, the TSO is still the only buyer. However, in this CS the TSO does not have the observability over the distribution grid. This means that the TSO must deliver/absorb the power at the interface with the DSO according to the expectation of total demand, generation, imbalances and flexibility activations at the distribution grid. Therefore, Eq. (3-53) computes the “virtual demand” that the TSO has to deliver to the DSO. Considering that we focus on HV distribution grids and those can be meshed, there could be multiple TSO-DSO interfaces for a single distribution grid. In this context, the virtual demand must be distributed to the different TSO-DSO interfaces. To do that, it is considered that the power flow on the interfaces will follow a typical impact factor for each substation. This impact factor is an average of the PTDFs of the nodes in the distribution grid in relation to the interface substations. This method intends to account for what in reality, would be the forecasting process of the TSO. This process of allocating the virtual demand to the interface substations is done in Eq. (3-54)-(3-57).

Min (3-13)

s.t.

(3-14), (3-16), (3-18), (3-19), (3-20)-(3-21), (3-22)-(3-23), (3-24)-(3-29), (3-30)-(3-35), (3-36), (3-37), (3-38), (3-39),

[15] For the remaining CSs, only the joint version is presented. The separate version, in which balancing, and congestion management is split by the TSO is done in a similar fashion as the Common market model.

$$-\sum_{i} DispatchDA_{ih} + \sum_{i} D_{ih} + \sum_{i} Imb_{ih} - \sum_{i\in IF} q_{fh} + \sum_{i} nsf_{ih}^{up} - \sum_{i} nsf_{ih}^{dw} = vd_{sh} \ \ \forall i \in IS, s \in TS \wedge t = DSO, h \tag{3-53}$$

$$\sum_{j\in(L,SUBS)} p_{jih} = pimport_{ih} \ \forall i \in (IS, SUBS), s \in TS \wedge t = DSO, h \tag{3-54}$$

$$pimport_{ih} = vd_{sh} * Impact_{i} \ \ \forall i \in (IS, SUBS), s \in TS \wedge t = DSO, h \tag{3-55}$$

$$pimport_{ih} = pexport_{ih} \ \forall i \in SUBS, h \tag{3-56}$$

$$-\sum_{j} p_{ijh} + \sum_{j} p_{jih} = \ pexport_{ih} \ \forall i \in (IS, SUBS), s \in TS \wedge t = TSO, h \tag{3-57}$$

3.1.2.6. Multi-level CS

In this Multi-level implementation, firstly, the DSO runs a local congestion management market, followed by the TSO market(s). With regards to the bids of FSPs, it could be assumed that they bid independently in each market and that bids are not passed on as modelled here. However, in order to model the independent bidding, aspects such as FSP bidding strategy would have to be considered, which lies outside the scope of this deliverable. In the following subsections, we focus on the formulation of the local flexibility markets. The subsequent TSO market follows a similar approach to the Central CS presented in section 3.1.2.5.

3.1.2.6.1. Local Flexibility Market (OPF)

In the LFM, the DSO minimizes the cost of activating resources connected at the distribution grid to solve local congestions only. The demand balance equations for this market consider the results of the day-ahead market in terms of generation and demand for each node of the DSO's grid, plus the power expected at the interface with the TSO. Similarly to the Central CS, in the Local Market of the Multi-level, the DSO expects to receive (or export) a certain power through the interface. In this case, the same virtual demand variable is used in the Central CS (section 3.1.2.5). Eq. (3-59)-(3-60) compute and allocate the power at the interfaces. Eq. (3-61)-(3-62) calculate the subscription levels and the subscription costs incurred by the DSO.

$$min \sum_{s\in TS\wedge t=DSO,ifh} \left(\left(Bid_{f} * q_{fh}\right) + \left(Bid_{f} * q^{dw}{}_{fh}\right) + subscost_{sh} + \left(nsf_{ih}^{up} + nsf_{ih}^{dw}\right) * CNSF \right) \tag{3-58}$$

s.t.

(3-15), (3-17), (3-18), (3-19), (3-20)-(3-21), (3-22)-(3-23), (3-24)-(3-29), (3-30)-(3-35), (3-36), (3-37), (3-39), (3-41),

$$psubs_{ih} = + \sum_{j\notin SUBS} p_{ijh} - \sum_{j\notin SUBS} p_{jih} \ \forall i \in (IS, SUBS), s \in TS \wedge t = DSO, h \tag{3-59}$$

$$psubs_{ih} = vd_{sh} * Impact_i \quad \forall i \in (IS, SUBS), s \in TS \wedge t = DSO, h \tag{3-60}$$

$$psubs_{ih} = \sum_{lv} qsubs_{i,lv,h} \; \forall i \in (IS, SUBS), s \in TS \wedge t = DSO, h \tag{3-61}$$

$$subscost_{sh} = \sum_{i,lv} qsubs_{i,lv,h} * CSubs_{i,lv} \tag{3-62}$$

After the LFM, unused bids and the information on the activated FSPs are passed on to the TSO, like Eq. (3-42)-(3-47). Unused bids, however, are passed on so that no congestions can be created. It is to say that the TSO cannot activate FSPs in the direction opposite to the direction they were activated by the DSO. Moreover, the information on the activated FSPs must be sent to the TSO (Eq. (3-63)), so this SO can consider it when forecasting the necessary power to be delivered at the interface (Eq. (3-64)).

$$DispatchFSP_{fh} = q^*_{fh} \; \forall fh \tag{3-63}$$

$$\begin{aligned} -\sum_i DispatchDA_{ih} + \sum_i D_{ih} + \sum_i Imb_{ih} - \sum_{i \in IF} q_{fh} - \sum_f DispatchFSP_{fh} \\ + \sum_i nsf^{up}_{ih} - \sum_i nsf^{dw}_{ih} = vd_{sh} \;\; \forall i \in IS, s \in TS \wedge t = DSO, h \end{aligned} \tag{3-64}$$

3.1.2.6.2. Local Flexibility Market (PTDFs)

In this LFM implementation, two steps are taken by the DSO. Firstly, the DSO runs a power flow analysis on the distribution grid based on the results of the DA market. This PF analysis will identify overloads in the elements of the grids in order to be solved by the LFM. The equations of the PF analysis are here omitted, as they follow the typical DC PF formulation (e.g. Van den Bergh et al., 2014). Overloads in MW terms per element are captured in the parameter $DSONeed^{up,dw}_{sijh}$[16]. The DSO then resolves these congestions by procuring flexibility according to the impact this flexibility will have on the congested asset(s). These impacts are given by the PTDF of the nodes where the FSPs are connected to the congested lines/transformers. This is computed in Eq. (3-66) and (3-67).

$$min \sum_{s \in TS \wedge t = DSO, ifh} \left(\left(Bid_f * q_{fh} \right) + \left(Bid_f * q^{dw}{}_{fh} \right) + \left(nsf^{up}_{ih} + nsf^{dw}_{ih} \right) * CNSF \right) \tag{3-65}$$

s.t.

(3-19), (3-20)-(3-21), (3-22)-(3-23), (3-24)-(3-29), (3-30)-(3-35), (3-36), (3-37), (3-39), (3-41),

[16] DSO needs are computed always for a pair of nodes i,j, as all grid elements are modelled as either lines or buses, given the linearized characteristics of the modelled. For example, a substation is modelled as a line between the HV bus and the LV bus with a certain impedance.

$$\sum_{f \in IG(ii)} q_{fh}^{up} * PTDF_{ij,ii} - \sum_{f \in IG(ii)} q_{fh}^{dw} * PTDF_{ij,ii} \geq DSONeed_{sijh}^{up} - nsf_{ijh}^{up} \; \forall ii \in IS, s \in TS \wedge t = DSO, (i,j) \in L, h \tag{3-66}$$

$$- \sum_{f \in IG(ii)} q_{fh}^{up} * PTDF_{ij,ii} + \sum_{f \in IG(ii)} q_{fh}^{dw} * PTDF_{ij,ii} \geq DSONeed_{sijh}^{dw} - nsf_{ijh}^{dw} \; \forall ii \in IS, s \in TS \wedge t = DSO, (i,j) \in L, h \tag{3-67}$$

3.1.2.6.3. Local Flexibility Market (Subscription)

The final implementation of the LFM aims at replicating the Swedish understanding over the LFM. In this implementation, a similar approach is used as the previous CS. However, only the impact over the substation is considered. In addition, no power flow analysis is done primarily. The DSO considers the impact of each demand, generation, and FSP activation over the substation using PTDFs. This computation is done in Eq. (3-68).

Min (3-58)

s.t.

(3-19), (3-20)-(3-21), (3-22)-(3-23), (3-24)-(3-29), (3-30)-(3-35), (3-36), (3-37), (3-39), (3-41),

$$\sum_{ii} D_{ii,h} * PTDF_{ij,ii} - \sum_{ii} DispatchDA_{ii,h} * PTDF_{ij,ii} + \sum_{f \in IG(ii)} q_{fh}^{up} * PTDF_{ij,ii} - \sum_{f \in IG(ii)} q_{fh}^{dw} * PTDF_{ij,ii} \geq DSONeed_{sijh}^{up} - nsf_{ijh}^{up} \; \forall ii \in IS, s \in TS \wedge t = DSO, (i,j) \in L, h \tag{3-68}$$

3.1.2.7. Common (limitation)

The final CS modeled is the Common market model with limitations by the DSO. This CS is based on the Spanish interpretation of the Commom approach. In this implementation, the TSO is responsible for solving both congestion and balancing, including the use of flexibility located at the distribution grid. However, instead of doing it in one single step, additional intermediary steps are included in order to allow the DSO to identify potential congestions being created by the original market clearing by the TSO. Therefore, after the TSO market run, results are passed on to the DSO. The DSO then conducts a PF analysis and identifies potential congestions being created. If that is the case, the DSO may impose limitations on the FSPs causing the congestions. These limitations are then sent to the TSO, which re-runs the common market(s) considering the limitations imposed by the DSO.

Formulations here are omitted as they are very similar to the ones presented in subsection 3.1.2.5, followed by a PF analysis, followed by the re-run of formulations in subsection 3.1.2.5.

3.2. Swedish Case Study

For the purpose of studying the scalability and replicability in Sweden, a simplified test-case network was built, considering both a simplified transmission model for the whole country and a medium-voltage model for the Uppsala region, in which demonstration activities of the CoordiNet project are taking place. In this study, Skåne and Gotland are not included.

3.2.1. Business Use Cases Considered

In this case study, we have as the base case the BUCs SE-1a&b and SE-3. The former relates to a multi-level implementation for congestion management markets for the DSO, while the latter demonstrates balancing services for the TSO.

3.2.2. Network, Generation and Demand

The Swedish transmission grid is an adapted version of the Nordic 32 (Van Cutsem et al., 2015). This 32-node test system is a fictitious but similar grid to the Swedish one, with connections to the Nordic system. Therefore, additional modifications and inclusions were necessary in order to make this test system a more robust representation of the actual Swedish system. For this purpose, the works of (Müller, 2019; Thorslund, 2017) were used.

The original Nordic 32 test system, as presented in (Van Cutsem et al., 2015, 2020), is divided into four areas, namely North, Central, South, and Equiv., the latter being a representation of the connection of Sweden with the rest of the Nordic System. Figure 9 presents the original implementations of the Nordic 32 with the representation of the four mentioned zones.

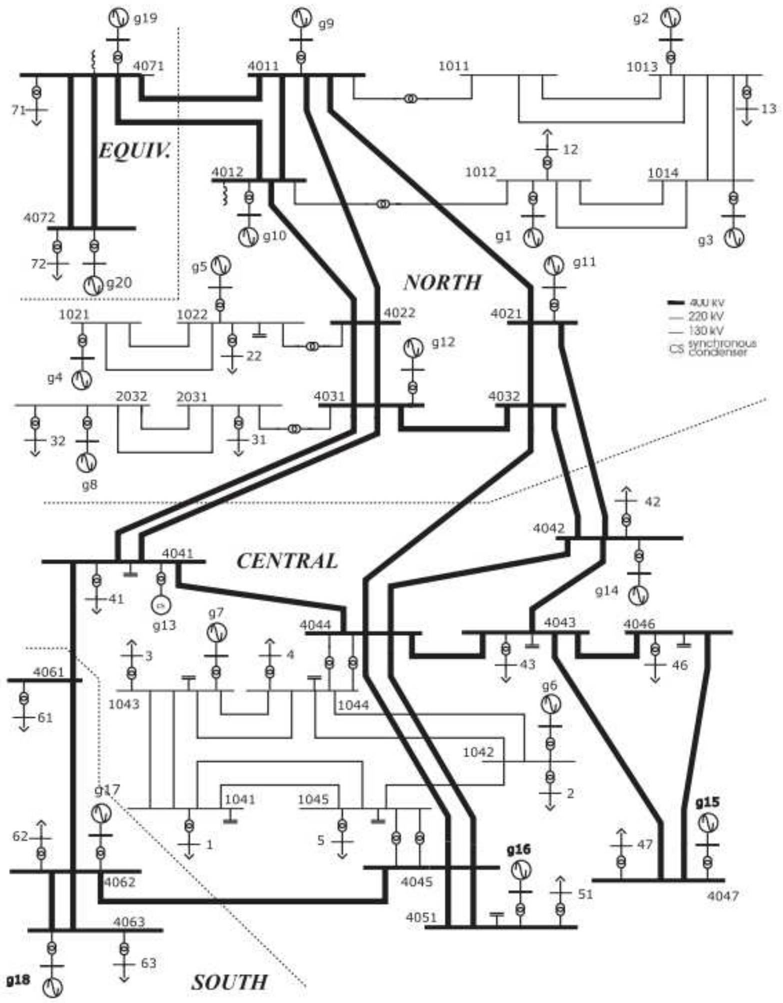

Figure 9: One-line diagram of the Nordic 32 test system as presented in (Van Cutsem et al., 2020).

The works of Thorslund (2017) and Müller (2019) have adapted both network parameters as well as the case study inputs in terms of generation and demand in order to better represent the Swedish case. These adaptations, especially in terms of generation and demand and separation of bidding zones, are also used in this study, as they serve as a reference point for the DA market model, together with the profiles in terms of representative days.

The networks based on the Nordic 32 test system, however, do not include the distribution network necessary for the TSO-DSO CSs. For that purpose, a sub-transmission grid is incorporated into the transmission network. This sub-transmission grid is a representation of the 70 kV network of the Uppsala site, one of the demonstration sites of the Swedish demo. The network data, as well as some demand and FSP parameters for this sub-transmission grid, were provided by the demonstration partners[17]. Figure 10 provides an illustration of the distribution grid considered. One aspect being considered is that this network is connected to the TSO grid by two interfaces (substations). All nodes depicted are at the 70 kV voltage

[17] Data for this sub-transmission grid was provided under a non-disclosure agreement. Therefore, only limited data and diagrams regarding this network are shared in this report.

level. Downstream to these nodes, 10 kV radial feeders are found, followed by the LV grids. However, these MV and LV networks are not considered in these models. The loads and FSPs eventually connected to these lower voltage levels are aggregated at the 70 kV nodes.

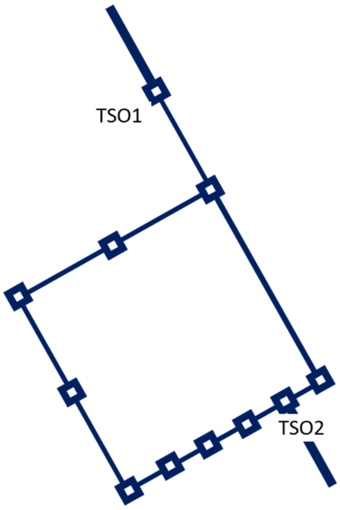

Figure 10: Representation of 70 kV distribution grid in Uppsala

The 70 kV distribution grid is then located and incorporated into the transmission grid. Of the two actual substations of the Uppsala grid, only one is originally modelled in the Nordic 32 test system. Therefore, the necessary adaptations were made to accommodate another transmission node. Modifications were also necessary in terms of the load allocated to each node. The load of the sub-transmission grid was subtracted from the loads in the two transmission nodes to which the sub-transmission grid is connected to.

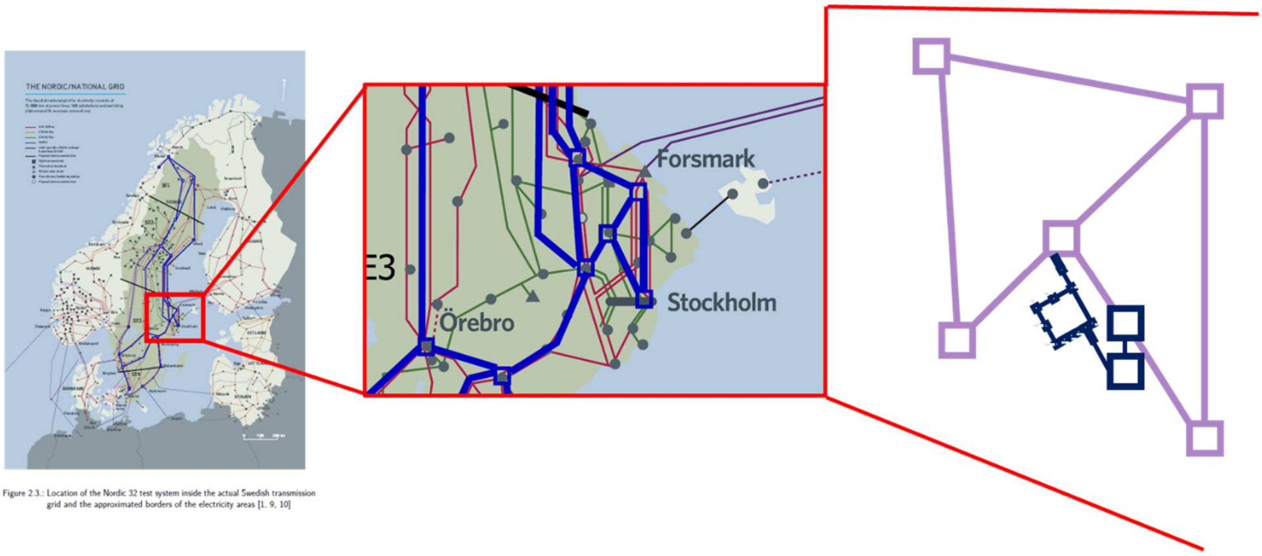

Figure 11: Location and representation of the 70 kV Uppsala grid

With regards to the load and generation parameters, the year 2020 serves as the base year. The load profiles for the whole year are gathered and clustered into eight representative days. Two representative days are calculated per season. For the winter and summer seasons, the correlation between the "high" cluster and the weekdays, as well as the correlation between the "low" cluster and the weekends is high. However, for autumn and spring, the correlation is low. Figure 12 presents the different profiles for the different representative days. Each representative day is associated with several days per year.

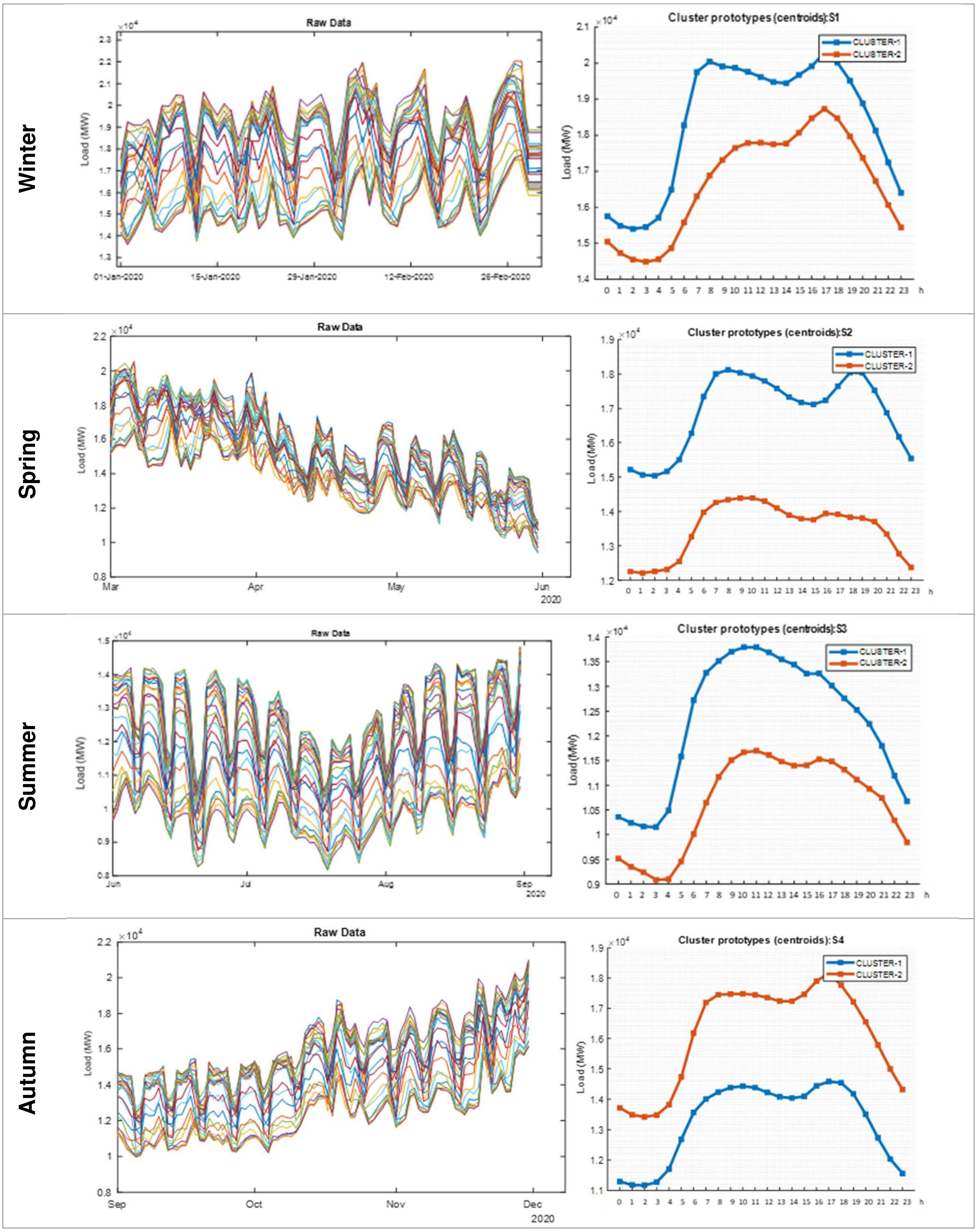

Figure 12: Load clustering for Sweden

The generation of renewables is aggregated into clusters per bidding zone. For this aggregation process, wind generation in 2020 is used. One relevant characteristic of the Swedish wholesale market is the existence of four different bidding zones. The NTC between bidding zones considered is the maximum NTC calculated by ENTSO-e and published by Nord Pool (ENTSO-E, 2021a).

The cost information per type of technology considered is obtained from the work of (Jensen & Pinson, 2017), presented in Figure 13. For wind farms and solar power plants, the variable cost considered is close to 1 €/MWh, as no fuel costs exist. Additionally, the cycling costs from (Jensen & Pinson, 2017) are also used. Values for the individual generators are multiplied by a random factor between 95% and 105% of the reference technology values in order to avoid numerical issues in the optimization problems. It is important to highlight that the objective of the analyses in this modelling workstream is not to forecast actual costs for SOs, but rather to study the rate of change under the different scalability and replicability scenarios. Therefore, although costs per technology could be calibrated to try to better represent national realities in relation to different markets and years, this study opts to use the fixed set of variable costs per technology in order to ensure comparability between the different scenarios analysed.

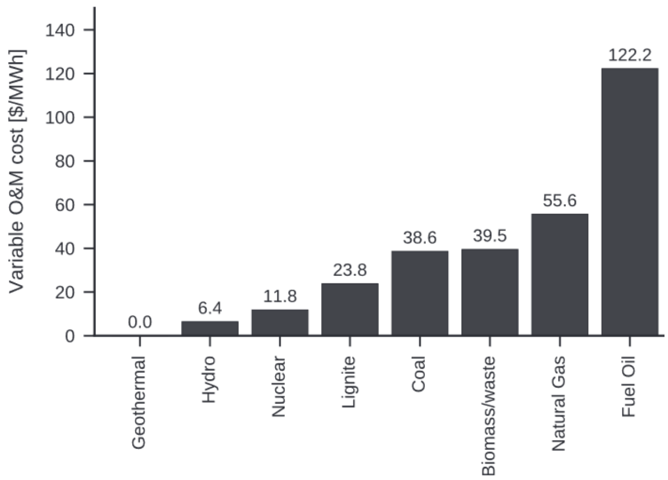

Figure 13: Variable cost per technology. Adapted from: (Jensen & Pinson, 2017).

3.2.2.1. Results from the Day-Ahead Market

As described in section 3.1, the results from the day-ahead market will determine the congestion needs later considered in the individual CSs. For this reason, the obtained results from the DA market for one year are compared with the actual DA market results in terms of the energy mix and average price. Technologies such as nuclear and thermal generators will have a minimum dispatch associated to them, also obtained from (Jensen & Pinson, 2017). For nuclear technology only, a "must-run" option is added, considering that the model runs eight individual representative days without constraints connecting them. Additionally, one may notice that no hydro reservoir constraints are included in the model. In order to calibrate the hydro generation, it was verified that the total hydro generation in Sweden in the year 2020 was, on average, 50% of their installed capacity. Therefore, the parameter $ResProfile_g$ was set to 50% for hydro power plants, meaning that hydro power plants can be dispatch up to 50% of their installed capacity at any given time. It is observed that the model reaches satisfactory comparability with the actual generation in Sweden in the year 2020, as shown in Table 6.

Table 6: Comparison between model output and actual generation mix in Sweden in 2020

Technology	Model Output		Actual Generation Mix in 2020	
	TWh	% Mix	TWh	% Mix
Thermal	3	2%	6	4%
Hydro	68	48%	72	47%
Nuclear	43	31%	47	31%
Wind	27	19%	28	18%
Total (TWh)		141		153

The difference in total energy generated by the model (141 TWh) against the actual generation (152 TWh) is due to the higher export of energy to the connecting systems. Although the network model considers an external grid, representing the interconnection with other systems, the amount of imports/exports with those grids is not calibrated, as their relevance for the congestion management needs is lower. It is worth noting that the objective of the DA market modelling is not to replicate with precision the results of the actual wholesale market, but to generate a representative dispatch of the system analysed that serves as an input for the CSs under analysis.

In addition to the energy mix, the average price for the energy is compared. The DA price is computed based on the marginal price per bidding zone. Therefore, the total cost of the DA is computed as $\sum_{gzh}(\lambda_{zh} * qda_{gh})$. According to (DG Energy - EC, 2021), the average wholesale baseload electricity price in Sweden in the year 2020 was between 12.3 €/MWh (Q2) to 24.5 €/MWh (Q3). The average price computed by the model is 27 €/MWh. Although this result is 10% higher than the average in Sweden for Q3, it is within an acceptable range given the various simplifications posed by the model and considering current instability in wholesale energy prices[18]. In addition to that, it is important to highlight that the objective of this simulation activity is not to reach a value that could approximate with precision the ones observed in Sweden, but rather to capture the correct generation mix in the DA, as this generation mix will be the basis for the subsequent services and CSs. Therefore, considering the good fit of generation mix results showed in Table 6 and the approximation of the average wholesale baseload energy price, the DA model is considered suitable for the simulation of the different CSs.

3.2.2.2. Imbalances and Congestion Management needs

In order to evaluate the different CSs, appropriate scenarios of congestion management and balancing needs are required. As mentioned above, the overall need for congestion management is generated by the DA dispatch and the network capability.

According to (ACER, 2021), the total volume of remedial actions[19] in 2020 in Sweden was 69.2 GWh, and the total cost was 1.14 million euros. These values are taken as a reference. However, it is important to notice

[18] It is important to notice that, at the time of writing, recent wholesale energy prices have been affected by extraordinary scenarios. In the year 2020, base year for this analysis, prices were influenced by the COVID-19 pandemic. In contrast, in the year 2019, the average price for the Q3 in Sweden was 36 €/MWh. In the subsequent year of 2021, on the other hand, prices were affected by raising fuel costs, increasing the average electricity wholesale price in Sweden to 69.7 and 81.2 €/MWh in Q3 and Q4, respectively. (Source: DG Energy Quarterly Reports on European Electricity Markets)

[19] Remedial actions definition: "the remedial actions relate to the measures taken by TSOs to address the congestions remaining after the market gate closure time, i.e. after day-ahead and intraday market coupling. Some remedial measures, such as changes in grid topology, do not lead to significant costs. Others, like re-dispatching, countertrading and curtailment of allocated capacity, come at a cost to the system or to TSOs." (ACER, 2021).

that these values are informed by the Member States to ACER, and a big range of values is observed. While some countries reported volumes in the order of tens of GWh per year (e.g. Belgium, Sweden, Finland), others reported tens of TWh (e.g. Germany, Italy, Poland).

The balancing needs are included as an input of the model assigned per node of the grid based on the results of the DA clearing. In order to calculate the amount of balancing needs and in which direction, data from the ENTSO-E transparency platform is used (ENTSO-E, 2022b). It is observed that imbalances in Sweden totaled approximately 3 TWh in 2020. Imbalances are equally distributed among deficit and surplus hours, as shown in the histogram of Figure 14. For modelling purposes, a total of 3 TWh is allocated per representative day and node in proportion to the DA load and generation in each node.

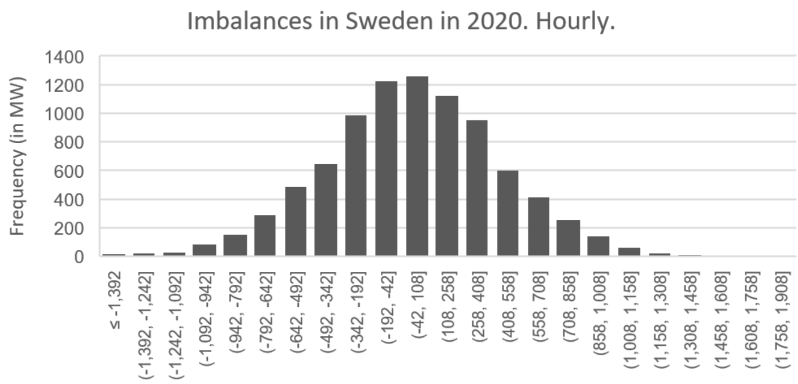

Figure 14: Histogram of imbalances in Sweden in the year 2020. Calculated based on (ENTSO-E, 2022b).

3.2.3. Scenarios

The base case scenarios for the evaluation of the different scalability and replicability scenarios consider the results from the DA clearing in terms of demand and generation, as well as the associated needs in terms of balancing and congestion management. The flexibility available for the different market sessions presented in section 3.1.1 is offered by resources connected at both the transmission and the distribution grids, in accordance with the different CSs. The FSPs connected to the transmission grid are the same generators that participate in the DA market. Their capability to offer flexibility will depend on their cleared volume in the DA market and their technology. The thermal generators, if dispatched by the DA model, can offer downward[20] flexibility down to their technical minimum while being able to offer upward flexibility[21] up to their installed capacity. We assume that wind farmscan only offer 5% of their DA schedule upwards, considering that there are differences between their DA forecasts and the real-time generation. Solar power plants cannot offer upward flexibility, only downward. In terms of bidding, these units bid the same variable cost as they offered to the DA market. In this context, we assume that the FSPs are participating under perfect competition and act as naïve agents and therefore bid their true short-term variable cost.

With regards to the market sequence simulated, it should be noticed that it differs from the one tested in the demonstration. In the Swedish demo, the CoordiNet Flex Markets (both for the local and for the regional DSO's) are placed before the DA market, while in the simulations carried out for this SRA they come after.

[20] Reduction of active power output. Equivalent to an increase of consumption.
[21] Increase in active power generation. Equivalent to a reduction in consumption.

The placement of the local flexibility market can suppose important differences for the FSPs and for the DSOs. When the LFM is placed before the wholesale energy market and considering that the clearing of the LFM happens before the gate closure time of the DA market, allows for the FSP to bid (or alter the existing bid) to the DA market in accordance with the result of flexibility market. In this case, the FSP mitigate the risk of being unbalanced after the LFM clearing. From the DSO perspective, the total flexibility need is computed based on the information available to the network operators at the moment of market clearing (e.g. demand forecasting, PF analysis, etc). Having the DA market before the LFM could provide the DSO with additional information with regards to the scheduling of units. However, from a practical perspective, this information would provide less value to the calculation of flexibility needs than the burden generated by a market sequence in which markets interfere to each other. From the modeling perspective of this SRA, however, having the flexibility market after the DA does not impose important changes to the expected results, considering that the objective of the model is to compute the results for the SOs rather than the individual FSPs. In fact, imbalances are not considered for each FSP, but rather aggregated for the whole network. This is also done considering that the retailer's BRP might aggregate consumers in a wider area than just the demonstration site. For the DSO, having the DA before the flexibility market serves the purpose of simulating the information available to the local market operator. It can be seen as a proxy to the forecasting and other sources of information available to the DSO at the time of running the LFM. This holds true specially to the simulated Swedish distribution network, considering that the grid is demand-driven. In this case, the result of the DA market (e.g. supply of the demand in the distribution grid) is a good approximation for the what the DSO would use to set flexibility needs (e.g. demand forecasting). Therefore, although the market sequence considered in these simulations for the SRA is not the same as in the Swedish demonstrations, the results should not be affected by this aspect.

In the Swedish case, the FSPs connected to the distribution grid are based on the FSPs participating in the demonstration. Table 7 lists the type of FSP and their capacity to offer upward and downward flexibility. Bid prices offered are the same in both directions and are calculated based on observations from the demonstration. This simplification aims at ensuring better comparability among the different options. One battery is included, with an energy capacity of 20 MWh[22]. This battery has a flexible capacity of 5 MW, having to comply with the state of charge (SoC) formulations presented in section 3.1.2.3. The round-trip efficiency considered is 80% (EIA, 2021).

Table 7: FSPs connected to the Uppsala grid in Sweden

FSP identification	FSP type	Downward capacity (in MW)	Upward Capacity (in MW)	Bid prices (both up and down; in €/MWh)
Fsp1	Battery (20 MWh)	5	5	8
Fsp2	Office buildings	0	0.5	10
Fsp3	Multi-family housings	0	0.5	16
Fsp4	Commercial building	0	0.5	12
Fsp5	District heating	5	30	20
Fsp6	Multi-family housings	0	0.5	16
Fsp7	Industry	0.5	1	16
Fsp8	Industry	0.5	1	16

[22] https://www.power-technology.com/marketdata/uppsala-battery-energy-storage-system-sweden/

The base case for the scalability and replicability scenarios is the “multi-level (subscription)” CS considering the FSPs connected at the distribution grid. This scenario aims at reaching the best approximation possible for the demonstration in Sweden in the year 2020.

For the scalability and replicability analysis, different scenarios are tested. For scalability purposes, a sensitivity analysis is used. Sensitivity factors are applied to selected parameters of the optimization models, as presented in Table 8. The sensitivity range shows the values to which parameters are multiplied to in the sensitivity analysis.

Table 8: Sensitivity factors for scalability analysis

Parameter	Parameter description	Considerations	Sensitivity range
$\boldsymbol{Q_f^+}, \boldsymbol{Q_f^-}$	Maximum and minimum flexibility of FSP f. (in MW)	Sensitivities applied only to FSPs connected at the distribution grid	$[0 \quad 0.2 \quad \cdots \quad 2.8 \quad 3]$
$\boldsymbol{Bid_f}$	Bid of FSP f in the AS market(s). (in €/MWh)	Sensitivities applied only to FSPs connected at the distribution grid	$[0 \quad 0.2 \quad \cdots \quad 2.8 \quad 3]$
$\boldsymbol{D_{ih}}$	Demand at node i in hour h	Sensitivities applied only to the load connected at the distribution grid	$[0.8 \quad 0.9 \quad \cdots \quad 1.9 \quad 2]$

The replication scenarios considered for the Swedish case are two, namely the different CSs and the types of FSPs. Considering that the Swedish demonstrations were done under a multi-level CS, other CSs are also tested for the Swedish case study. The latter proposes an exercise in connecting types of FSPs not observed in the Swedish demonstration but do participate in the Spanish demonstration. The opposite exercise is done for the Spanish case study. In this case, two wind farms are connected to the distribution grid, namely WindCAD1 and WindCAD2, as depicted in Figure 15. The characteristics of the wind farms are the same as those presented in section 3.3.3.

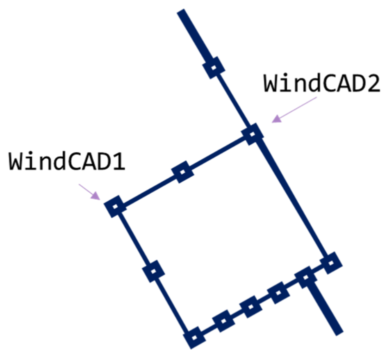

Figure 15: Replication scenario in Sweden.

3.2.4. Results

Table 9 presents the results in terms of energy activated for the base case scenario in the Swedish case study. This base case scenario considers the “Multi-level (subscription)” CS with the FSPs connected to the distribution grid. Values presented are in GWh/year[23]. It is possible to observe that activations due to congestion management needs do occur, but only during the winter representative days. The DSO does activate 10 GWh of flexibility in its LFM, which represents 0.69% of the total energy supplied by the DSO. The TSO activates approximately 3.6 TWh, of which 3 TWh are due to balancing needs, and 0.6 are due to congestions.

Table 9: Base case scenario for Swedish case study: Energy activated. In GWh/year.

SO Market / Product / Direction	Winter High	Winter Low	Spring High	Spring Low	Summer High	Summer Low	Autumn High	Autumn Low	Total Year
DSO Market: LFM	**9**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**10**
CM	*9*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*10*
Up.	9	1	0	0	0	0	0	0	10
TSO Markets	**1,008**	**368**	**338**	**427**	**438**	**320**	**326**	**420**	**3,645**
B	*400*	*341*	*337*	*427*	*438*	*320*	*326*	*420*	*3,009*
Down.	189	175	132	98	153	138	154	164	1,203
Up.	211	166	206	329	285	182	172	256	1,807
CM	*608*	*27*	*0*	*0*	*0*	*0*	*0*	*0*	*635*
Down.	308	14	0	0	0	0	0	0	323
Up.	300	13	0	0	0	0	0	0	313

Table 10 presents the results in terms of the cost of activation in thousands of euros. For the DSO, the total cost is 802 k€ per year. This cost includes not only the procurement of flexibility (10 GWh) but also the payment of subscription penalties. In fact, the subscription penalties account for 645 k€, while the remaining 157 k€ refer to the procurement of flexibility. The TSO costs for balancing plus congestion management totaled 12,769 k€. If divided by the activated energy, one may notice that the average congestion management cost is approximately 6.30 €/MWh, while the average balancing cost is 2.81 €/MWh. There are different reasons why these values are lower than what is observed in actual markets. First, as mentioned above, we consider naïve agents that bid their short-term variable costs, the same as the DA market, and flexibility is primarily provided by hydro and wind units. Second, the objective functions in the different CSs compute the summation of payments for flexibility in a pay-as-bid manner. For most CSs relying on an OPF formulation, a Locational Marginal Pricing (LMP) clearing cost could be formulated, which would mean having a nodal marginal price. However, several other CSs rely on other and new clearing methods, such as the Multi-level (Subscription) and the Multi-level (PTDF), in which marginal prices would have different meanings. Therefore, a comparison between different CSs would also suppose comparing different pricing methods. For this reason, we opt for computing all costs as prices as bids, considering that strategic behavior of agents is not within the scope of these simulations.

Moreover, balancing markets, for instance, could be designed as zonal markets but having a network check to avoid new congestions. Modelling the TSO markets as OPFs can be seen as a simplification of a more complex sequence of markets and network checks. For these reasons, costs from all markets and CSs are computed in their pay-as-bid form, even if agents bid their variable cost. Although this approach may lead to less representative total costs for the TSO, it ensures better comparability between CSs. Finally, it is

[23] Meaning that the results per representative day are already multiplied by the number of times the representative day takes place in one year.

worth noticing that the LFM in Sweden was designed as a pay-as-bid market and that bids from distributed FSPs are based on observations from the demos, leading to more representative total costs for the DSO.

Table 10: Base case scenario for Swedish case study: Objective value[24]. In k€/year.

SO Market Product	Winter		Spring		Summer		Autumn		Total
	High	Low	High	Low	High	Low	High	Low	Year
DSO Obj. Value	**790**	**10**	**2**	**0**	**0**	**0**	**1**	**0**	**802**
CM	790	10	2	0	0	0	1	0	802
TSO Obj. Value	**5,293**	**1,063**	**936**	**1,360**	**1,260**	**855**	**836**	**1,166**	**12,769**
B	1,171	882	935	1,360	1,260	855	836	1,166	8,465
CM	4,122	181	0	0	0	0	0	0	4,304

When comparing the total cost for a scenario with no flexibility being provided by the FSPs at the distribution grid with the base case scenario, it is possible to verify a significant reduction for the DSO from 1,674 k€ per year to 802 k€. In a scenario with no flexibility, the totality of the cost would be related to surpassing subscription levels. With regards to that type of cost, it is important to clarify that only the penalties associated to surpassing subscription levels are considered, and not the eventual temporary subscription that can be granted by the TSO. This approach is like what was used to calculate and analyse the KPIs of the Swedish demonstration[25]. When comparing the cost for the DSO with the KPIs calculated by the demo for both the “No-flexibility scenario” as well as the “CoordiNet scenario”, it is possible to observe that the costs calculated by the model are within ±25% of the calculated KPIs. Table 11 presents the results for both scenarios, as well as the replication scenario comparing different CSs.

Table 11: Comparison between the "No-flexibility" and the "CoordiNet" scenarios in Sweden. In k€/year.

Market Model	No-Flexibility Scenario	CoordiNet Scenario
Common		
Joint	13,095	11,658
Separate	13,793	12,481
Multi-level (OPF)		
Local	**1,674**	**713**
Joint	11,913	11,937
Separate	12,751	12,767
Multi-level (Subscription)		
Local	**1,817**	**802**
Joint	11,913	11,937
Separate	12,751	12,769

When comparing the results from the different CSs, it is possible to observe that the common market model would lead to the least total cost of flexibility procurement, considering that for both implementations of the multi-level CS, the LFM cost had to be added to either the joint or separate TSO markets in order to make costs comparable. The costs from the Multi-level (OPF) are also lower than the Multi-level

[24] In the Swedish case, Objective Value is equal to flexibility procurement costs plus subscription overrun penalties.
[25] The analysis of the KPIs will be published in the upcoming CoordiNet deliverable D6.1.

(Subscription), as it considers a full representation of the grid at the expense of being a more complex and perhaps less transparent market formulation.

Figure 16 below presents the results for the scalability scenario in which sensitivity factors are applied to the sizes and bids of the FSPs connected to the distribution network. The costs shown in Figure 16 are for the DSO in the LFM. The sensitivity factor in the x and y axes of the graph are those defined in Table 8, where a sensitivity factor of 1 represents the base case (or "CoordiNet") scenario. In the curve of the graph, it is possible to identify the "no-flexibility" and the "CoordiNet" scenarios discussed above and presented in Table 11. Moreover, this scalability scenario reveals that if the capacity of the FSPs in the demo is scaled up to a factor of 1.6, subscription penalties are eliminated by the procurement of local flexibility. Figure 17 isolates the sensitivity to the size of the FSPs (considering the sensitivity factor of bids = 1) in order to show the effect of the increase of flexibility available to the DSO on the subscription cost and the total cost incurred by the DSO in the Multi-level LFM.

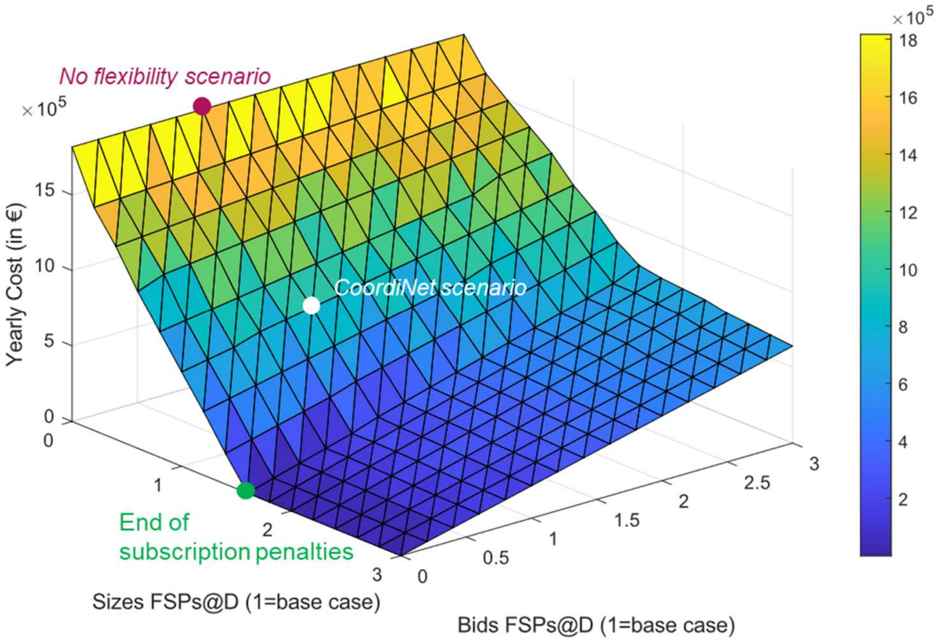

Figure 16: Sensitivities to size and bids of FSPs@D. DSO costs in the Multi-level (subscription) LFM.

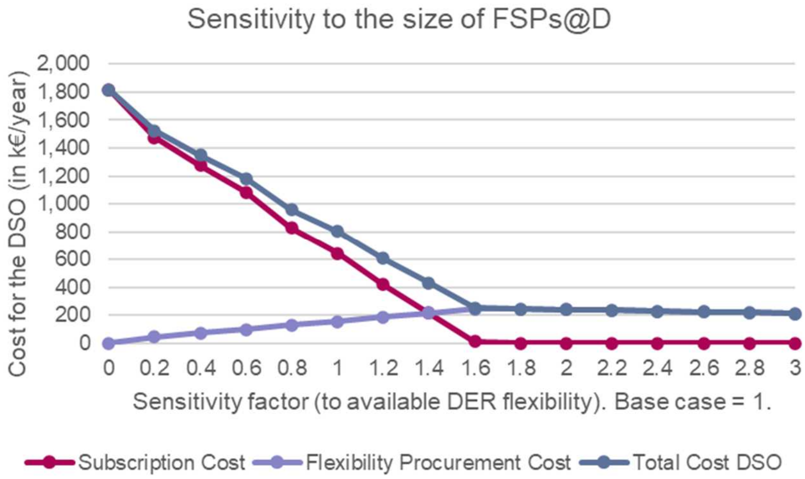

Figure 17: Sensitivity to the size of FSPs@D. Costs for the DSO in the Multi-level LFM

When looking at the whole system, considering balancing and congestion management costs for both transmission and distribution grids, the effect of the FSPs in the Uppsala grid is much lower, as expected, as shown in Figure 18. The highest effect is observed when the sizes of FSPs approach their maximum over the established range (x3) and prices offered by these FSPs are below the sensitivity factor of 0.4, in which the FSPs connected at the distribution grid (e.g. DR, battery, district heating) become cheaper than hydro and wind units typically providing balancing and central congestion management services.

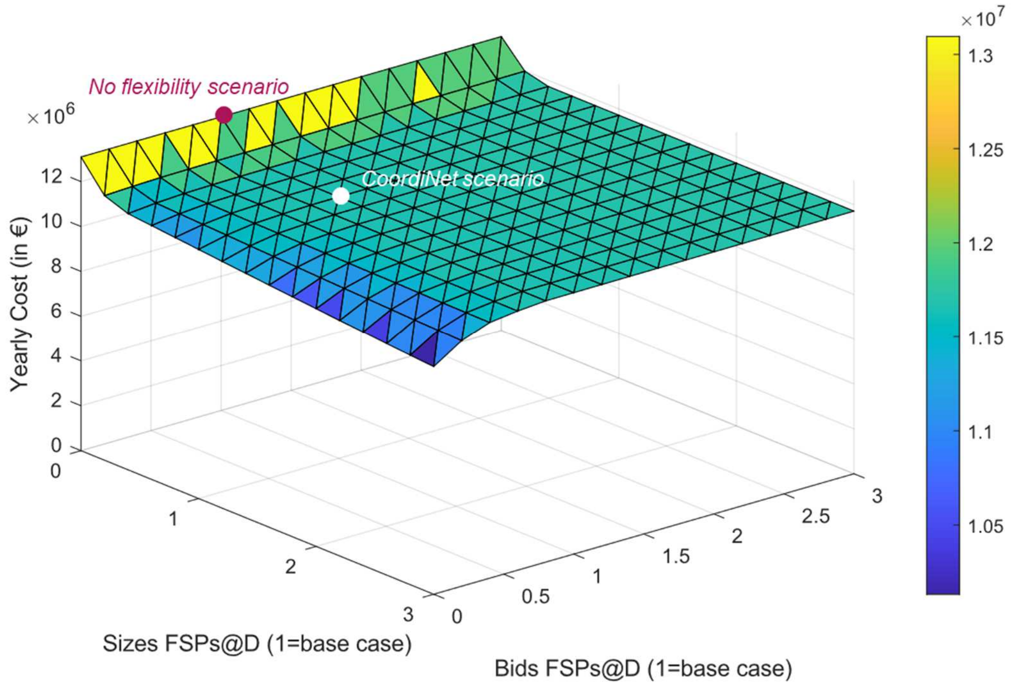

Figure 18: Sensitivities over size and bids of FSPs@D. Total costs in the Common-Joint CS.

The second scalability scenario explores the effects of increasing the demand connected at the distribution grid. In this scenario, we run a sensitivity factor over the demand and the size of FSPs in the distribution grid and explore the concept of the "non-supplied flexibility" (NSF). The non-supplied flexibility is the position in which the DSO has congestions in its grid, wants to procure flexibility to solve these congestions, but the flexibility available in the market is not sufficient or not effective for that purpose. In that case, the DSO would have to resort to mechanisms other than the flexibility market to ensure the secure operation of the grid (e.g. change in topology, curtailment of selected units). Figure 19 presents the result of this scalability scenario.

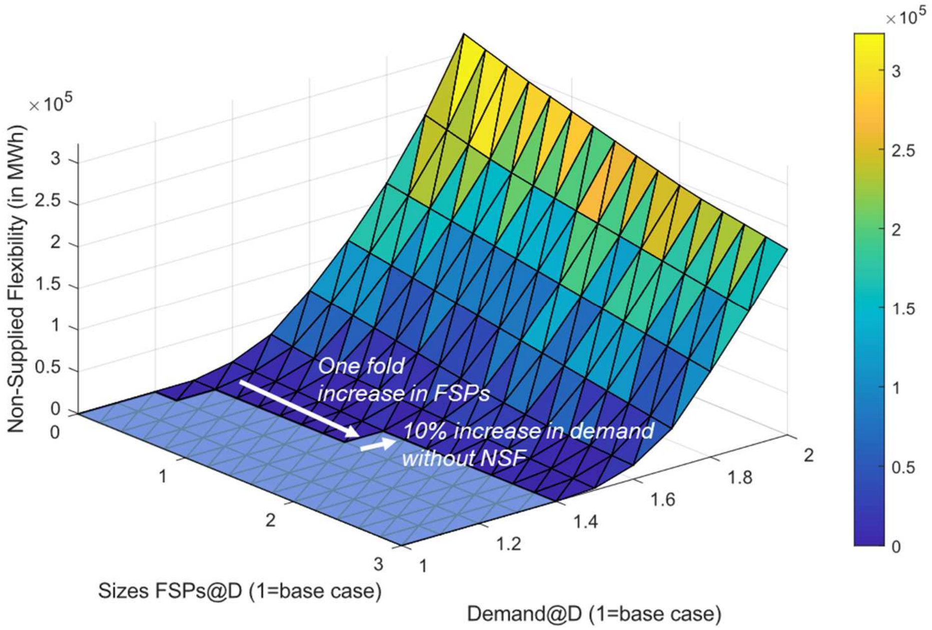

Figure 19: Sensitivity to demand connected to distribution and size of FSPs@D. Non-Supplied Flexibility for DSO in Multi-level (OPF) LFM.

The flat light-blue area on the graph represents the region in which either the DSO does not have any congestion in the network or, if congestions exist, they can be solved by the available flexibility in the LFM. Outside the flat area is the region in which the DSO observes some amount of non-supplied flexibility. It is important to note, though, that this analysis considers only congestions due to thermal limit violations and not needs due to subscription penalties (which already exist at the current load level). For this reason, this scalability scenario considers the CS Multi-level (OPF), which also accounts for the power flow in every line in the grid, and not only the power flow at the substation as the Multi-level (subscription).

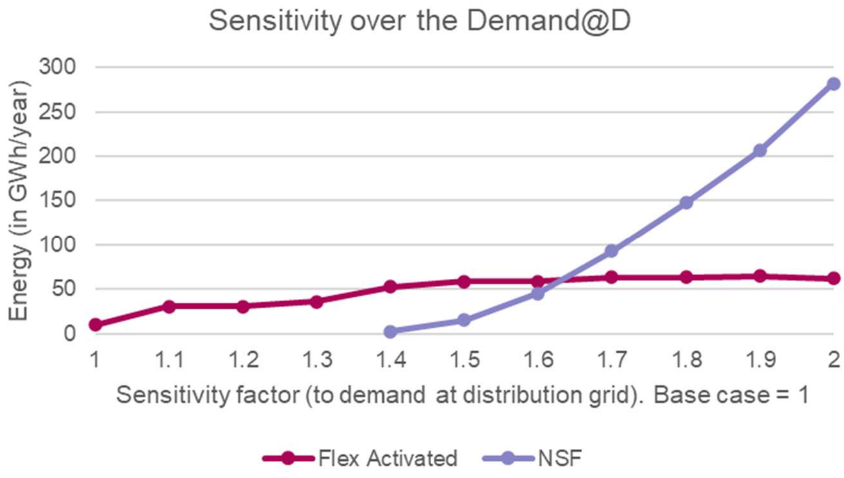

Figure 20: Sensitivity over the demand at distribution. Sizes of FSPs=1.

This analysis reveals that a one-fold increase in the available FSPs capacity from 0.2 to 1.2 would allow the DSO to incorporate another 10% of demand without entering into the non-supplied flexibility region. In energy terms, this means that an increase of 10 GWh of activated flexibility per year would allow the incorporation of 145 GWh of demand without leading to an NSF situation. For the DSO, this could mean that grid reinforcement needed in the face of demand growth could be deferred using local flexibility, for instance.

Finally, the replication case is presented, in which two wind farms with the characteristics of those found in the Spanish case study are incorporated into the Swedish case study. The addition of the two wind farms consistently reduces the total costs for the TSO by approximately 2%. For the DSO, however, the costs can be reduced by up to 98%. This is due to the fact that incorporating the two new DERs in the DSO's grid not only increases the flexibility available but also means that distributed generation (DG) is included in this grid. The DG helps to offset the need for importing energy from the TSO through the TSO-DSO interfaces, which leads to a significant reduction in subscription penalties.

Table 12: Replication scenario. Wind Farms incorporated to Sweden case study. In k€/year.

Coordination Scheme	Base Case	Replication Scenario	%
Central			
Joint	11,913	11,657	-2.2%
Separate	12,751	12,501	-2.0%
Common			
Joint	11,658	11,369	-2.5%
Separate	12,481	12,197	-2.3%
Multi-level (OPF)			
Local	**713**	**12**	**-98.3%**
Joint	11,937	11,674	-2.2%
Separate	12,767	12,514	-2.0%
Multi-level (Subscription)			
Local	**802**	**23**	**-97.2%**

Joint	11,937	11,683	-2.1%
Separate	12,769	12,521	-1.9%

3.2.5. Interim conclusions

From the analysis of the Swedish case study, it can be concluded that:

- In the Swedish context, in which DSOs may be subject to penalties if subscription levels are surpassed, the use of flexibility can be an effective way to reduce total costs for the DSO. It is shown that, for the analysed case study, an increase of only 60% over the base case flexibility could already lead to a situation in which the DSO does not incur subscription penalties.
- Considering that the grid studied was load-driven, the increase in FSPs availability could also be beneficial when coping with the increase in demand. The study suggested that a one-fold increase in FSP availability could lead to an increase of 10% in demand without occurrence of NSF for the DSO.
- The replication scenario in which wind farms are incorporated into the distribution grid shows that this type of DER could help the DSO to mitigate the surpassing of subscription levels, as the incorporation of DG offsets the need for imports from the TSO through the TSO-DSO interface.

3.3. Spanish Case Study - Common Congestion Management and Balancing

For the purpose of studying the scalability and replicability in Spain, a simplified test-case network was built, considering both a simplified transmission model for the whole country and a high-voltage model for both the Cadiz and the Albacete regions, in which demonstration activities of the CoordiNet project are taking place.

3.3.1. Business Use Cases Considered

This case study covers two BUCs, namely ES-1a (common congestion management) and the ES-2 (common balancing).

3.3.2. Network, Generation and Demand

The simplified transmission network used in this study is the 11-node "small Spanish system" developed for use with the openTEPES model (Ramos & Alvarez, 2022). The openTEPES is an open-source optimisation model for transmission and generation expansion planning. Together with the model, the authors also publish the complete data set for the small Spanish system, a case study focused on the transmission expansion planning for the 2030 scenario. Therefore, this case study had to go through the necessary adaptations in order to better reflect the current Spanish power system. The adaptations made were mostly related to the installed capacity mix, as the 2030 scenario considers a higher penetration of RES and lower installed capacity of thermal generators. In relation to the network, two adaptations were made. First, candidate lines for the transmission expansion problem were disregarded. Second, the model considered a double circuit from nodes T8 to T10. This double circuit was split into one double circuit from T8 to T10 and another from T8 to T6, in order to accommodate the Albacete sub-transmission grid. The Cadiz network is directly connected to node T5 of the transmission grid. Figure 21 provides an illustration of the final Spanish test system used in this study.

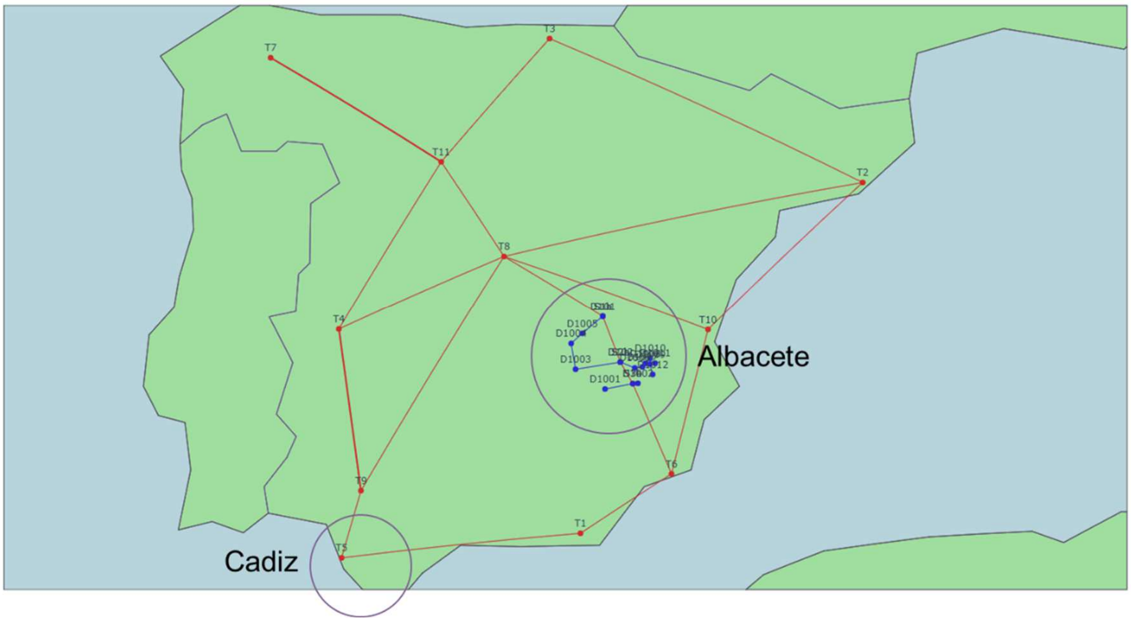

Figure 21: Spanish test system

3.3.2.1. Albacete grid

The Albacete sub-transmission grid consists of two 132 kV networks connected to the transmission grid. These networks were produced based on the network maps published by the Spanish TSO and typical electrical parameters for the lines provided by the demo partners. Figure 22 depicts the complete network map (on the left) and the modelled section of the grid (on the right). The first network (upper network) consists of a ring with two interfaces with the DSO to which load and generation are connected, together with a radial network exclusively used by wind farms. The second grid (lower on the figure) consists of only two nodes plus the substation. These lines connect RES generators.

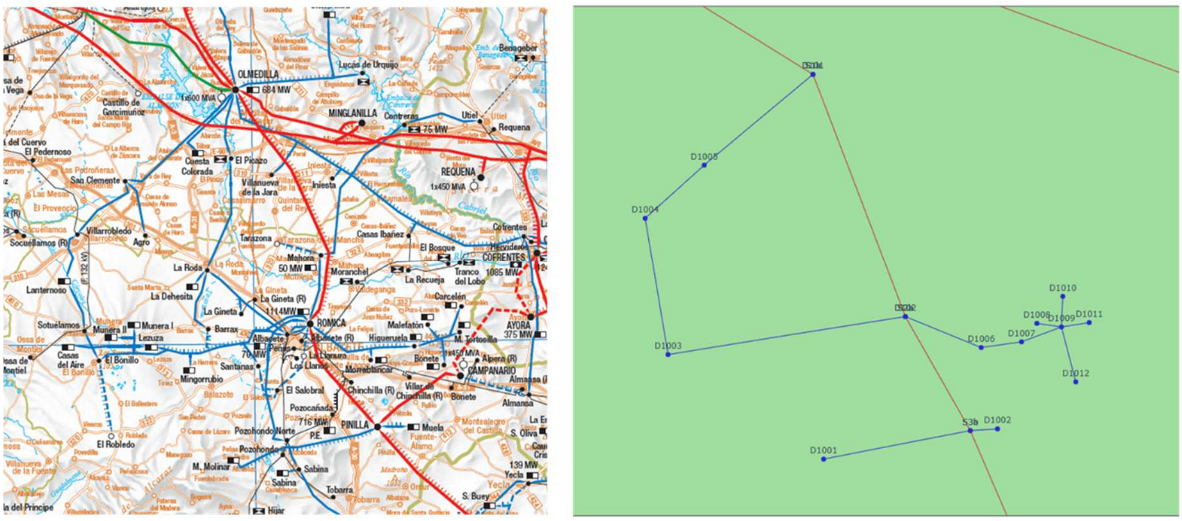

Figure 22: Albacete sub-transmission network. Source (map on the left): (Red Electrica de España, 2015)

3.3.2.2. Cadiz network

The information on the Cadiz network used in this study was provided by the DSO e-DI. Considering that the network data did not contain georeferencing of its elements, it is not plotted in Figure 21. However, Figure 23 presents a simplified version of the single line diagram of this network[26]. Figure 23 also provides the illustration of the FSPs participating in the demonstration and therefore considered in this SRA. In order to incorporate this network into the transmission network, the external grid seen in the picture connected to the substation "Pinar del Rey" becomes the node T5 depicted in Figure 21. The line connecting the 66 kV busbar of the substation "Puerto de la Cruz" to the node in which the wind farm PESUR is connected is considered open for the purposes of this study, in line with the actual operation in the demonstration (Chaves-Ávila et al., 2020).

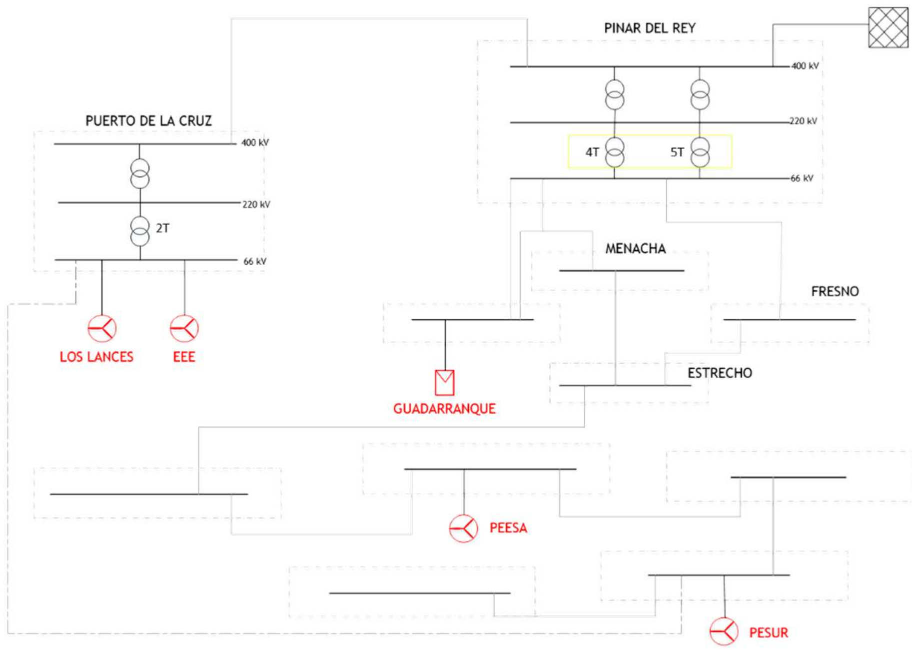

Figure 23: Cadiz network. Source: (Ivanova et al., 2021)

[26] Details are omitted as the data for this network was provided under an NDA.

3.3.2.3. Generation and Demand

Similarly to the Swedish case study, eight representative days are created for the demand using the k-means clustering technique, two for each season[27], as shown in Figure 24. Profiles for wind and solar generation are also created based on 2020 data.

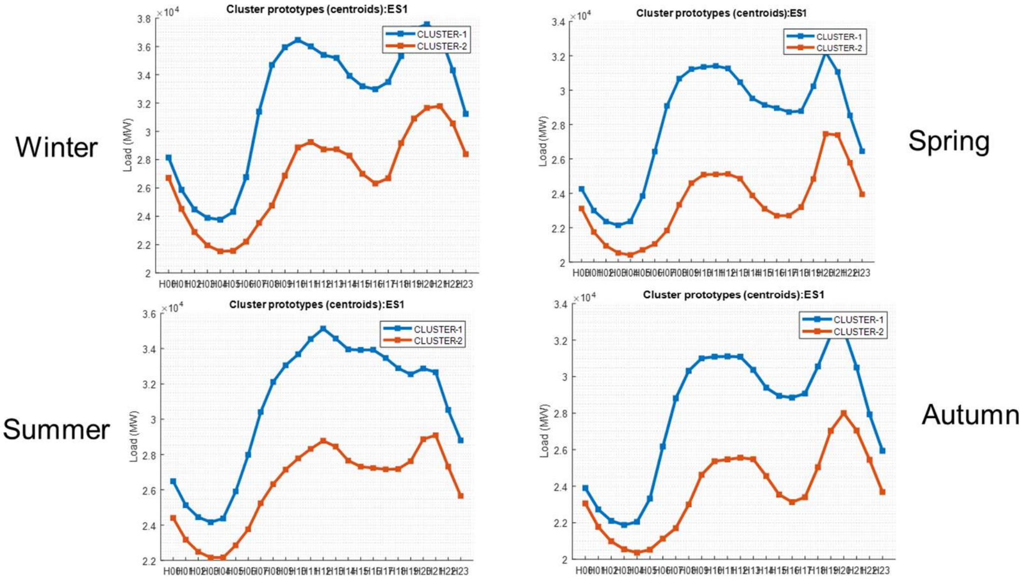

Figure 24: Representative days for the Spanish case study

The volume of the demand generation at the transmission grid, however, had to be scaled up from the original data set from the openTEPES, as this data set considers values one order of magnitude lower than the actual figures from the Spanish system.

Once the demand and the installed capacity are calibrated according to the actual figures from 2020, the results for the DA market are analysed in terms of the energy mix and average price per MWh. As shown in Table 13, and when compared to the actual generation mix in Figure 25, the values obtained are representative of the Spanish system.

Table 13: DA results from the Spanish case study

	Representative Day (Yearly Values - in GWh)									
	Winter		Spring		Summer		Autumn		*Total*	*Gen. Mix*
Technology	High	Low	High	Low	High	Low	High	Low		
CCGT[28]	9,026	4,339	5,242	3,264	8,737	3,461	4,826	3,471	42,367	18%
Cogeneration	3,323	2,849	2,781	2,806	3,595	2,645	2,713	2,933	23,645	10%
Hydro	4,324	3,706	3,618	4,500	4,677	3,441	3,529	4,500	32,294	13%
Nuclear	6,697	5,740	5,603	6,945	7,243	5,330	5,467	6,970	49,995	21%

[27] The original "small Spanish case" from openTEPES does provide data for all 8760h of the year. However, considering the time involved in running the sensitivities, it was chosen to use the representative day approach for the Spanish case study as well.

[28] Combined cycle gas turbine.

Solar	3,406	2,920	2,850	3,545	3,685	2,711	2,781	3,545	25,444	11%
Thermal	3,503	1,127	1,347	0	3,178	1,039	1,545	0	11,739	5%
Wind	7,374	6,320	6,170	7,675	7,975	5,869	6,019	7,675	55,076	23%
Total									**240,562**	

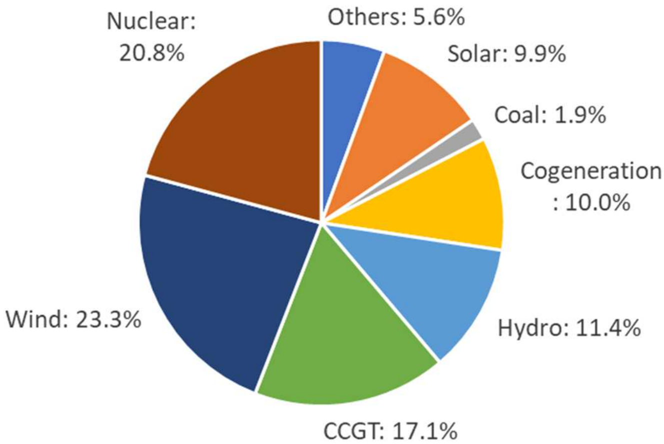

Figure 25: Actual generation mix in Spain in 2021. Adapted from: (Statista, 2022)

The average price computed by the model is 58.24 €/MWh, which is higher than the average computed in (DG Energy - EC, 2021), at 40.2 €/MWh (Q4 - 2020).

3.3.2.4. Imbalances and Congestion Management needs

Imbalances and congestion management were also calibrated for the Spanish case study. For this purpose, a similar approach to the Swedish case study was used. First, balancing needs for 2020 were gathered from the information published by the Spanish TSO Red Eléctrica. According to their monthly reports, the tertiary reserve energy activated upwards in 2020 totalled 1.7 TWh, while the downward totalled 1.2 TWh. These values were used as reference values and assigned to nodes in proportion to the demand and the DA clearing result.

The congestion management reference volume considered comes from (ACER, 2021). According to this report, the total volume for remedial action in Spain in 2020 was 10.6 TWh at a total cost of 435 M€. In order to reach similar volumes, the transmission network was calibrated in such a way that the volume of congestion management needs would be compatible with the reference values obtained from (ACER, 2021). This calibration process was done by scaling up the thermal limits of the transmission lines up to the point where volumes are compatible. The scaling-up process was necessary considering that the original openTEPES network was also dimensioned one order of magnitude lower compared to the actual Spanish values.

3.3.3. Scenarios

The scenarios for the Spanish case consider the FSPs participating in the demonstration, both in Cadiz and Albacete. For the base case, the Common (limitation) CS is considered in the separate form, as this most closely resembles the implementation of the BUCs ES-1a and ES-2 in the Spanish demonstration

Table 14: FSP characteristics for the Spanish case study

FSP identification	Grid	FSP type	Installed Capacity	Downward capacity	Upward Capacity	Bid price (both up and down; in €/MWh)
WindALB1	Albacete 1	Wind	38	100% of the DA	5% of DA	1
WindALB2	Albacete 1	Wind	49.5	100% of the DA	5% of DA	1
WindALB3	Albacete 1	Wind	13.2	100% of the DA	5% of DA	0.99
WindALB4	Albacete 1	Wind	37	100% of the DA	5% of DA	1.02
WindALB5	Albacete 1	Wind	23	100% of the DA	5% of DA	1.02
WindALB6	Albacete 1	Wind	24	100% of the DA	5% of DA	0.98
WindALB16	Albacete 2	Wind	49.5	100% of the DA	5% of DA	0.99
WindALB17	Albacete 2	Wind	45.5	100% of the DA	5% of DA	1.01
Cogen1	Albacete 1	Cogeneration Plant	10	2	2	39.9
WindCAD2	Cadiz 2	Wind	32	100% of the DA	5% of DA	0.98
WindCAD1	Cadiz 2	Wind	10.68	100% of the DA	5% of DA	1.01
SolarCAD1	Cadiz 1	Solar	12.3	100% of the DA	0	1
WindCAD3	Cadiz 1	Wind	42	100% of the DA	5% of DA	1.01
WindCAD4	Cadiz 1	Wind	6	100% of the DA	5% of DA	1.02

The scalability scenarios considered are the same as those used for the Swedish demonstration and are presented in Table 8. Regarding the replicability analysis, a similar approach to the one in the Swedish case was used. First, the results from the different CSs serve as one replication scenario. Second, a scenario in which FSPs types from the Swedish demonstration are brought to the Spanish context is built. This second replication scenario consists of DR and storage types of FSPs being deployed in both Cadiz and Albacete networks. In addition, a third scenario is tested, considering congestions in selected elements of the grid. Figure 26 illustrates the allocation of the Swedish types of FSPs on the Cadiz network.

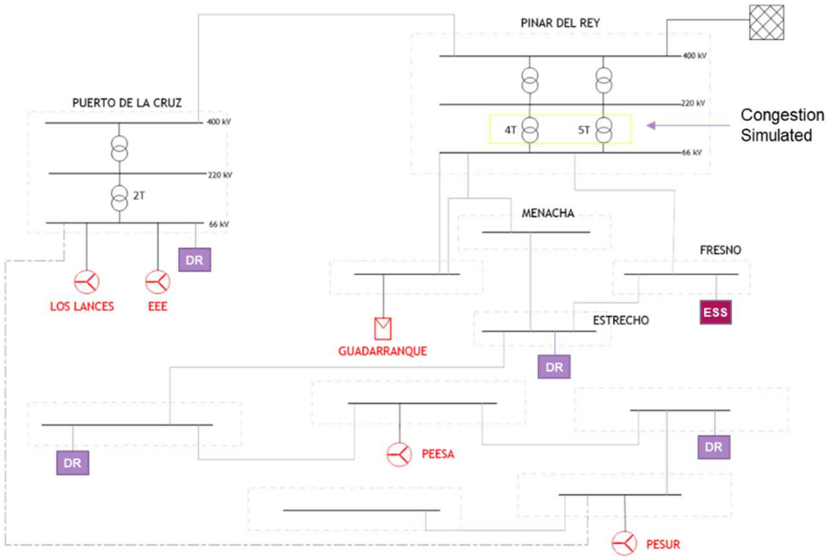

Figure 26: Cadiz network with Swedish types of FSPs

3.3.4. Results

Table 15 presents the energy activated for the Spanish base case. In total, the Spanish TSO activates approximately 8.9 TWh, from which 3.5 TWh are for balancing, and 5.4 TWh are for congestion management purposes. The results also show that congestion management needs are mostly concentrated in the winter months.

Table 15: Base case scenario for Spanish case study: Energy activated. In GWh/year.

CS / Product / Direction	Winter		Spring		Summer		Autumn		Total
	High	Low	High	Low	High	Low	High	Low	Year
Common (Limit.)	**5,363**	**536**	**470**	**571**	**605**	**432**	**468**	**496**	**8,941**
Balancing	395	463	316	563	554	383	364	459	3,497
Down.	209	174	161	160	199	164	181	245	1,493
Up.	186	289	155	402	355	219	183	214	2,004
C.M.	4,967	73	154	9	51	49	104	37	5,444
Down.	2,484	36	77	4	25	24	52	18	2,722
Up.	2,484	36	77	4	25	24	52	18	2,722

Table 16 presents the total cost data for the base case (common limitation CS) and the other CSs modelled under this study. The results from the multi-level CS implementations reveal that the distribution network is not constrained in the base case scenario.

Table 16: Objective value for different CSs[29]. Spanish case study. In k€/year

Market Model	Winter		Spring		Autumn		Summer		Yearly Cost
	High	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	
Central									
Joint	152,262	3,124	4,811	2,516	3,498	1,945	3,154	1,473	172,783
Separate	144,389	3,065	4,870	2,522	3,446	1,886	3,193	1,413	164,785
Common									
Joint	152,255	3,123	4,810	2,515	3,498	1,944	3,152	1,472	172,770
Separate	152,577	3,063	4,896	2,522	3,448	1,886	3,192	1,412	172,997
Common (Limit.)									
Joint	152,262	3,124	4,811	2,516	3,498	1,945	3,154	1,473	172,783
Separate	144,389	3,065	4,870	2,522	3,446	1,886	3,193	1,413	164,785
Multi-level (OPF)									
Local	0	0	0	0	0	0	0	0	0
Joint	152,262	3,124	4,811	2,516	3,498	1,945	3,154	1,473	172,783
Separate	152,584	3,065	4,897	2,522	3,448	1,886	3,193	1,413	173,009
Multi-level (PTDF)									
Local	0	0	0	0	0	0	0	0	0
Joint	152,262	3,124	4,811	2,516	3,498	1,945	3,154	1,473	172,783
Separate	152,584	3,065	4,897	2,522	3,448	1,886	3,193	1,413	173,009

The first scalability scenario to be simulated is the one with sensitivities over the size of FSPs and the bids offered by the FSPs. Results are presented in the chart in Figure 27. In this case, however, the increase in the size of the FSPs leads to an increase in the overall system cost. This happens because the FSPs considered in this case study are mostly wind farms. Therefore, increasing the size of FSPs also means increasing the penetration of RES and its generation in the DA. After a certain sensitivity factor (2), the increased RES generation leads to the need for additional redispatch measures, increasing the overall cost.

[29] Differently from the Swedish case, the Spanish case does not consider any form of subscription penalties. Therefore, the objective value here includes only the flexibility procurement cost.

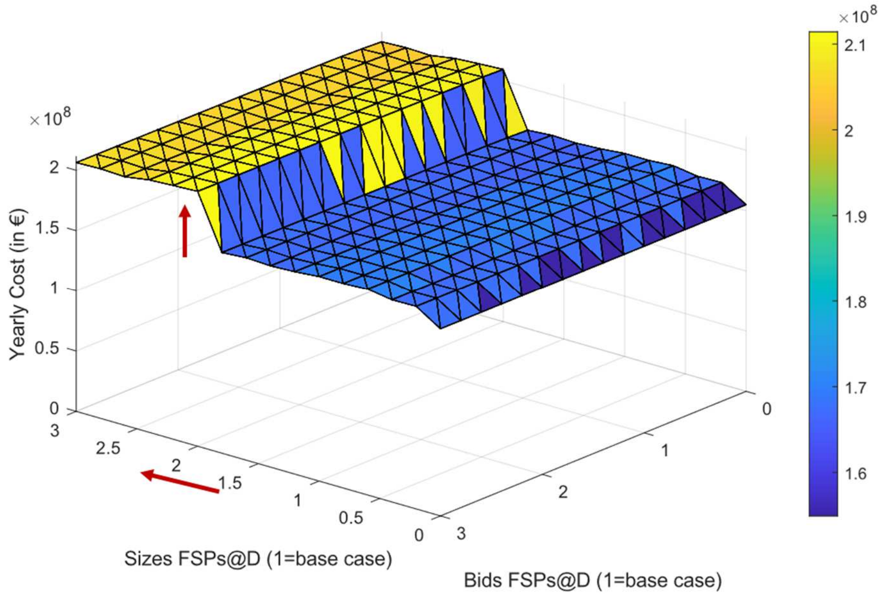

Figure 27: Sensitivities over size and bids of FSPs@D. TSO costs in the Common-Joint CS in the Spanish case study.

Figure 28 presents the results for the second scalability scenario, in which sensitivity factors are applied to the demand connected to the distribution grids and the sizes of FSPs. These results are only for the LFM portion of the multi-level CS. For this scalability scenario, results are similar to the Swedish case study, although to a lower extent.

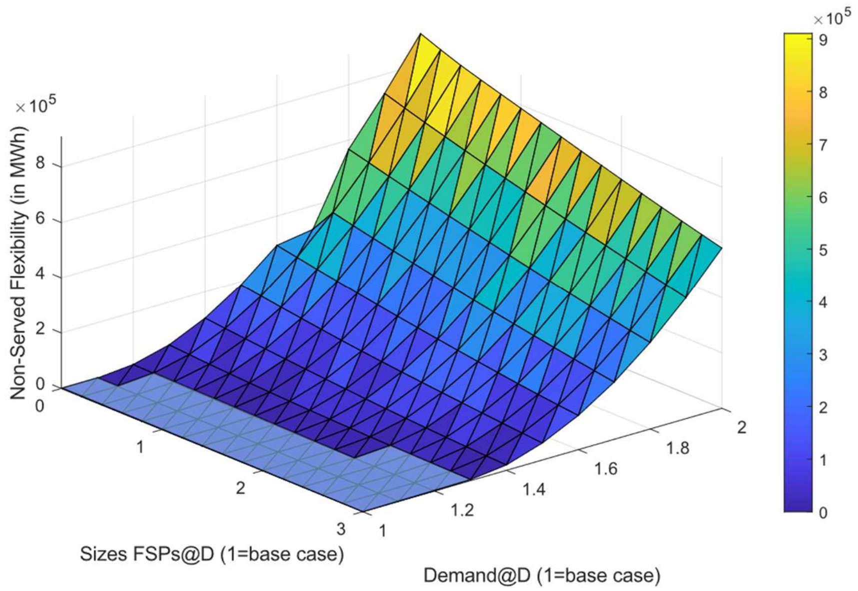

Figure 28: Sensitivity of demand at distribution and size of FSPs@D. Non-Supplied Flexibility for DSO in Multi-level (OPF) LFM in ES.

Finally, Table 17 presents the results of the replication scenario of the Spanish case study. In this scenario, two aspects are analysed. First, the Swedish types of FSPs are incorporated in the analysis. Both DR and batteries are considered in the grid of Cadiz and Albacete. Second, congestion is simulated in two different elements of the grids. One congestion in the line between nodes D1006 and D1007 at the Albacete grid, and one congestion in the substation Pinar del Rey. Table 17 presents the results of this replication scenario. The most relevant finding from this scenario is the fact that, in the base case, when congestions are simulated, the existing resources are not capable of solving the congestions. This happens because the congestion creates a need for upward flexibility in the Cadiz network. As wind farms cannot provide the necessary upward flexibility, the DSO enters the NSF state. In the replication scenario, including the resources from the Swedish case study, the congestions created can be solved without NSF for the DSO.

Table 17: Replication Scenarios in the Spanish case study

Market Model	Base Case		Replication Scenario	
	No Cong.	With Cong.	No Cong.	With Cong.
Central				
Joint	169,284	169,284	169,005	169,005
Separate	161,445	161,445	161,192	161,192
Common				
Joint	169,271	NSF	168,993	170,546
Separate	169,493	NSF	169,223	170,242
Common (Limit.)				
Joint	169,284	169,703	169,005	169,437
Separate	161,445	161,768	161,192	161,527
Multi-level (OPF)				
Local	0	NSF	0	**258**
Joint	169,284	170,208	169,005	170,061
Separate	169,505	169,871	169,232	169,736
Multi-level (PTDF)				
Local	0	NSF	0	**258**
Joint	169,284	170,208	169,005	170,064
Separate	169,505	169,880	169,232	169,747

3.3.5. Interim conclusions

From the analysis of the Spanish case study, it can be concluded that:

- Diverse grids can be observed in the context of TSO-DSO coordination with HV grids. In the Spanish case study, not only meshed grids with multiple interfaces are seen both in Cadiz and Albacete, but DSO grids are often exporters of energy, not importers as are generally assumed for distribution grids.
- Increasing the presence and size of certain types of FSP also increases their participation in the DA market. This could lead to increases in overall costs.
- The types of FSPs available for the TSO and DSO play an important role in determining the possibility for SOs to use flexibility. A system dominated by RES type of FSP will be able to provide downward capacity for an extended period but will be limited in providing upward capacity. Therefore, a mix of different types of FSPs could be most beneficial to the SO.

4. Quantitative SRA - Workstream 2: Local congestion management in MV distribution grids

The main purpose of this chapter is to describe the SRA methodology and analyze the SRA results for the modelling workstream 2, which comprises the following BUCs: ES-1b, GR-2a, and GR-2b. Since this modelling workstream focuses on the SRA for congestion in MV grids, we have as the base the BUC-ES-1b – Local Congestion Management, which aims to procure flexibility from resources connected at the DSO networks to solve transitory congestions that can occur at DSO grids. This BUC is tested in the demo sites of Malaga and Murcia of the Spanish demo, thus this workstream will perform an SRA for these two demonstrators.

Furthermore, to assess the SRA performance of the GR-2a and GR-2b BUCs the Kefalonia demo site of the Greek demonstrator is also considered. In this case, the analysis focuses on the MV distribution network of Argostoli. An overview of workstream 2 is presented in Table 18.

The remainder of this chapter is organized into three main sections. First, Subchapter 4.1 describes the SRA methodology for this workstream. Subsequently, Subchapters 4.2 and 4.3 apply this methodology and analyse the SRA results for the Greek case study (Kefalonia) and the Spanish case study (Malaga and Murcia), respectively.

Table 18: Workstream 2 Overview

Workstream 2 Specifications	
BUCs	BUCs ES-1b, GR-2a, and GR-2b[30] focused on congestion management of MV grids
Coordination scheme	Local
Countries, demo sites for the SRA	• Spanish demonstrator: Malaga and Murcia MV distribution networks. • Greek demonstrator: Argostoli MV distribution network of Kefalonia.
Modelling approach	PTDF-linearized local market

4.1. Modelling approach

4.1.1. Overview of the SRA methodology applied in workstream 2

Figure 29 summarizes the proposed SRA methodology for workstream 2. This methodology is divided into three main blocks, the SRA inputs (green colour) and the SRA outputs (grey colour) that will be introduced in this subchapter, and the BUC modelling and simulation approach (blue colour) will be further explained in the following subchapter.

[30] Regards to BUC GR-2a and GR-2b, the congestion events are only foreseen in the transformers located in the boundary between transmission and distribution and in the distribution lines. Therefore, a local market downstream of the congested transformer is equivalent to the TSO-DSO coordination schemes considered in the BUC GR-2a and GR-2b (and in any case, the fragmented market model is equivalent to running two independent local congestion markets).

Regarding the SRA inputs, some parameters that comprise the technical boundary conditions (network characteristics and technical constraints) of the BUCs are selected. For example, the parameters related to load profiles, DG size and penetration may affect the scalability of the BUC. In addition, the parameters associated with FSPs, such as their number, location, capacity and cost, may be related to both scaling-up and replication. Moreover, the SRA requires running extensive simulations using power flow studies and optimization problems. Therefore, different input data must be gathered for each demonstration location to perform these simulations. This data is mainly composed of network models, load and generation profiles, and FSPs' location, capability, and bidding cost.

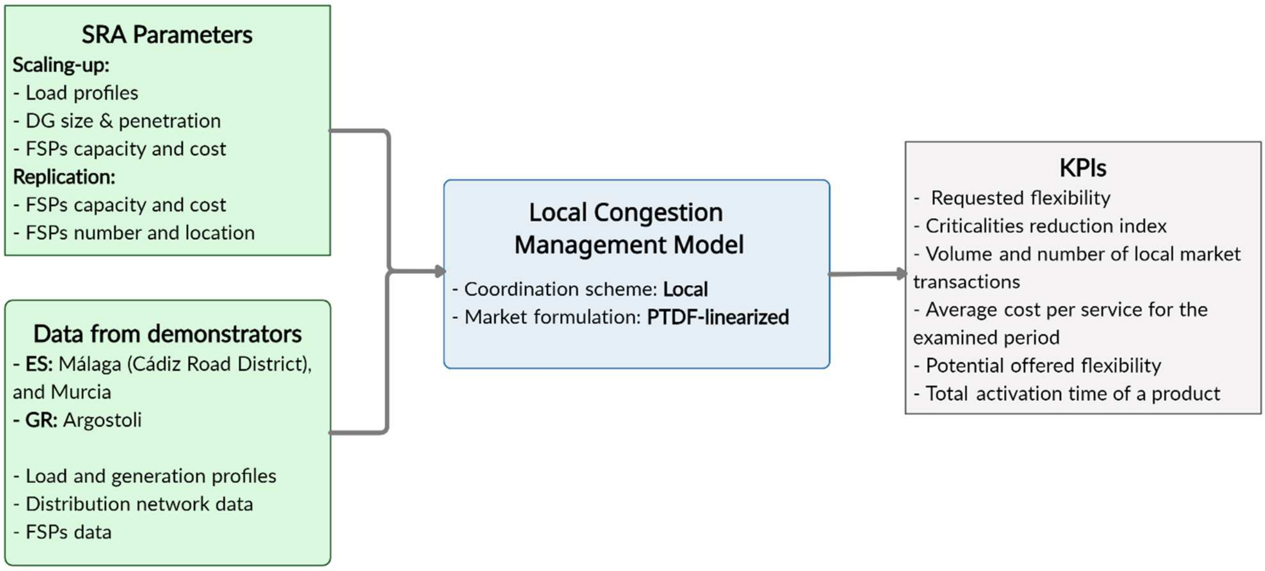

Figure 29: Overview of SRA Methodology for Workstream 2

Concerning the SRA outputs, these will be computed based on the KPIs identified and defined in the deliverable D1.6 of CoordiNet (Trakas, D., & Kleftakis, V., 2020). Among these indicators, a set of KPIs was selected for the SRA of workstream 2, according to Table 19. The calculation of these KPIs allows quantitative evaluations and comparisons of the local congestion management BUC. Finally, it is important to highlight that the final SRA parameters, the data from the demonstrators, and KPIs for each case of study will be detailed in Subchapters 4.2 and 4.3.

Table 19: Workstream 2 KPIs selected

SRA KPI Name	KPI Description	KPI Category	Related KPI-ID in D1.6
Flexibility activation cost	This indicator computes the flexibility activation cost for the total market horizon (24 hours).	Economic	KPI 6
Total cost of local market clearing	This KPI considers the summation between the flexibility activation cost and the not-supplied flexibility[31] cost for the total market horizon (24 hours).	Economic	KPI 6

[31] The not-supplied flexibility concept is introduced in Section 3.2.4.

Criticalities reduction index	This KPI measures the reduction of the number of criticalities on the network under consideration in terms of overload of the lines and transformers	Technical	KPI 13
Potential offered flexibility	This KPI contains the potential flexibility that is available to the market	Technical	KPI 16
Volume and Number of transactions	This indicator measures the volume and/or the number of transactions in the local flexibility market.	Economic	KPI 18 and KPI 19
Requested flexibility	The amount of flexibility requested by the DSO for the total market horizon	Technical	KPI 22

4.1.2. Local Congestion Management Model

Since the Local congestion management modelling and simulation process is considered a key part of the methodology presented previously, Figure 30 shows further details of this process according to the below description.

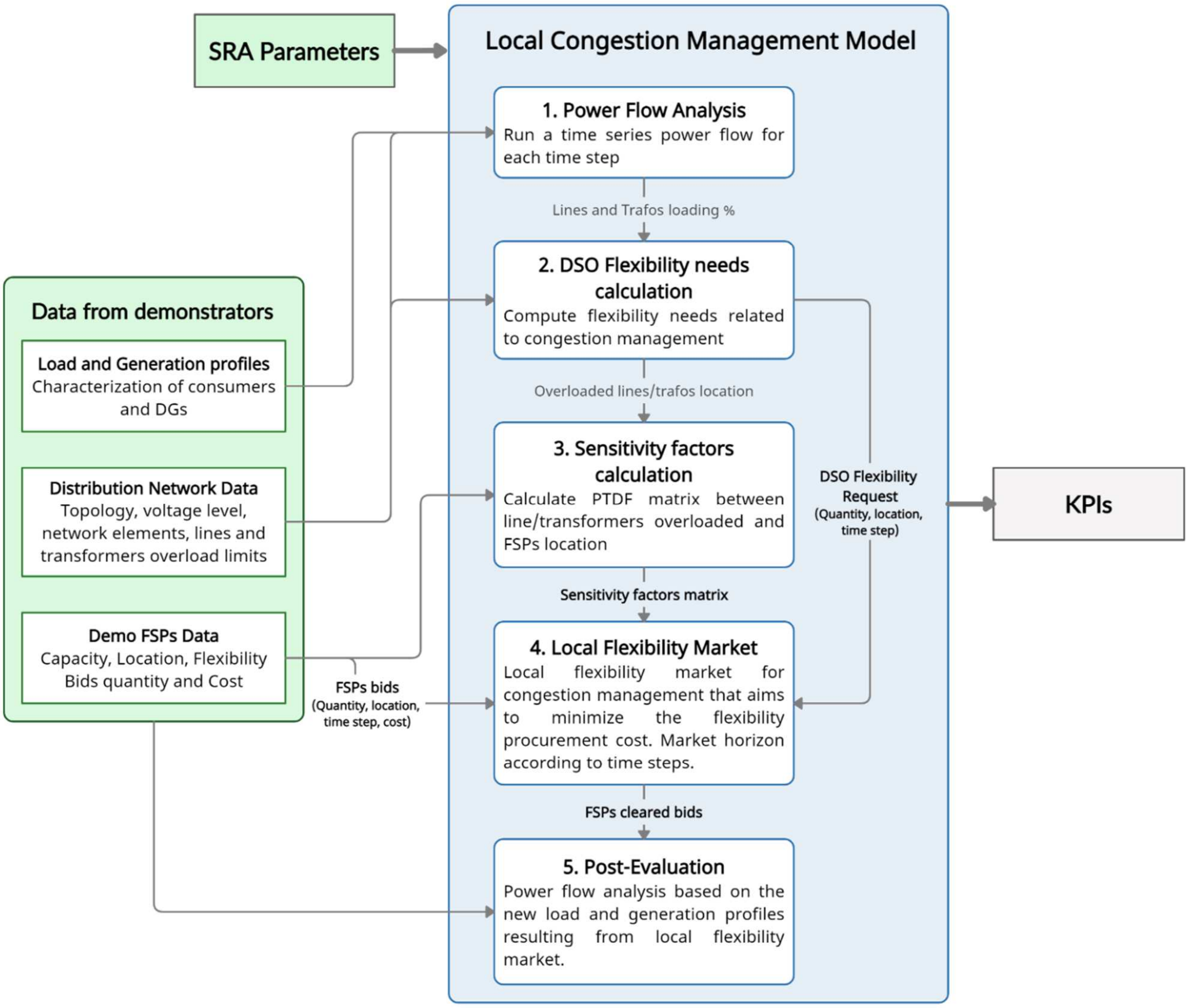

Figure 30: Local Congestion Management Model for the Workstream 2

- **Power flow analysis (Step 1):** For workstream 2, the local congestion management BUC is based on the assumption that grid congestions (overloading of lines or transformers) can be forecasted in terms of location and quantity. Therefore, the first step is to perform a power flow analysis for each time step to detect eventual constraints. To do this, the distribution network data and load and generation profiles mentioned previously are utilized for this analysis. Moreover, the time series module of Pandapower (Thurner et al., 2018) was used to perform the power flow analysis.

- **DSO flexibility needs calculation (Step 2):** In this second step, the DSO calculates its flexibility needs related to congestion management in MW based on the power flow results. A DSO flexibility need is defined when a line or transformer has a loading greater than 100%, and then this overload in percentage is transformed in terms of MW for each congestion event. These DSO needs are inputs for the local flexibility market-clearing described in Step 4, where DSOs submit a bid as FlexRequest for active power in either upward or downward direction considering the quantity.

- **Sensitivity factors calculation (Step 3):** A local flexibility market-clearing could be solved with or without considering the network data. There are different solutions to incorporate network data and flow constraints in market models for distribution systems, such as second-order cone programming formulations (Papavasiliou, A., 2018), quadratically constrained programming (Baldick, R., 2003), or linearization proposals of the power flow constraints (Sanjab, A. et al., 2021). However, these solutions can still pose challenges for implementation in practice, particularly with networks of thousands of nodes, as in the case of the CoordiNet demonstrators. Therefore, the sensitivity factors could be a solution for linear market representations when considering grid information in the market-clearing.

  Within the workstream 2 SRA approach, the DSO calculates the sensitivity factor for each FSP relative to the flexibility need. They are computed depending on the locations of the FSP assets, their impact on solving grid constraints, and their potential bid limitations. To compute the sensitivity factors for congestion management, it is necessary to analyze the sensitivity of the power flow of the critical branches to the FSPs' power injections. This sensitivity is based on the PTDF matrix (Baldick, R., 2003), where the change in the flow of line ij associated with a power injection at node k and equivalent withdrawal at node m is:

$$\Delta P_{ij} = PTDF_{ij,km} \Delta P_{km} \tag{4-1}$$

  To calculate the total flow over a line, this is given by:

$$P_{ij} = \sum_{m} PTDF_{ij,km} P_m \tag{4-2}$$

  Where node k is the slack bus, and all the PTDFs are calculated with respect to this node. In this step, the PTDF matrix is built using an internal function of the Pandapower called "makePTDF" for a given choice of slack. This matrix is nbr x nb, where nbr is the number of branches or lines, and nb is the number of buses.

- **Local flexibility market-clearing (Step 4):** In the local flexibility market-clearing, the most efficient flexibility bids from FSPs are selected to mitigate the identified DSO needs at minimum cost. As highlighted in Figure 30, the inputs of the market-clearing are:

  - DSO flexibility needs for congestion management as computed in step 2 (FlexRequest).
  - Flexibility bids from FSPs (FlexOffer): These bids are composed of their quantity, location, price, and direction. Here, the direction indicates i) Volumes of increase and reduction of generation (upward and downward flexibility, respectively) connected at a distribution node, and ii) Volumes of reduction and increase of demand (i.e., upward and downward flexibility) at a distribution node. The cost for the flexibility activation is also included in the bid because the FSPs are considered as active traders deciding on their flexibility price.
  - Sensitivity factors: The sensitivity factors calculated in Step 3 will affect the merit order on the market since the combination of the bid price, quantity, and location in the form of sensitivity factor together will decide which order bids will be cleared.

– The market formulation is introduced in the following subsection.

- **Post-evaluation (Step 5):** In addition to previous steps, the workstream 2 SRA simulation approach includes an ex-post validation process to ensure that the clearing solution does not violate the limits exposed by the DSO. Therefore, a new power flow analysis is executed based on the new load and generation profiles resulting after the market clearing.

4.1.3. Formulation of the Local Flexibility Market model

As the local congestion management BUC aims to resolve congestion issues at minimum cost, a linear programming (LP) market-clearing formulation is proposed for workstream 2. The nomenclature used in the optimization problem is described by the following indices, sets, parameters, and variables. The details of the formulation are presented below.

INDICES AND SETS

$h \in H$	Hour
$f \in F$	flexibility service provider (FSP)
$r \in \mathrm{R}$	flexibility request from the DSO
H	Set of hours
F^U	Set of FSPs that offers upward flexibility
F^D	Set of FSPs that offers downward flexibility
R^U	Set of upward flexibility requests from the DSO
R^D	Set of downward flexibility requests from the DSO

PARAMETERS

$C_{f,h}^U$	Cost of upward flexibility for each FSP bid in period h
$C_{f,h}^D$	Cost of downward flexibility for each FSP bid in period h
$VOLL$	Value of not-supplied flexibility
$P_{r,h}^{U\_DSO}$	Upward flexibility DSO request in period h
$P_{r,h}^{D\_DSO}$	Downward flexibility DSO request in period h
$PTDF_{f,r}$	Sensitivity factor between FSP location (node) and DSO request location (line/transformer)
$P_{f,h}^{Umin}$	Lower limit of the FSP upward flexibility bid in period h
$P_{f,h}^{Umax}$	Upper limit of the FSP upward flexibility bid in period h
$P_{f,h}^{Dmin}$	Lower limit of the FSP downward flexibility bid in period h
$P_{f,h}^{Dmax}$	Upper limit of the FSP downward flexibility bid in period h

VARIABLES

$p_{f,h}^U$	Cleared upward flexibility bid from an FSP in period h
$p_{f,h}^D$	Cleared downward flexibility bid from an FSP in period h
$\alpha_{r,h}^U$	Upward not-supplied flexibility in period h and DSO requested r
$\alpha_{r,h}^D$	Downward not-supplied flexibility in period h and DSO requested r

As stated in Step 4 of the methodology, the local flexibility market clearing for congestion management is used to determine the most efficient flexibility bids from FSPs to mitigate the DSO flexibility needs at minimum cost. The objective function of this day-ahead local flexibility market is defined by (4-3), and it can be divided into two parts: the first and the second terms represent the upward and downward flexibility activation cost, and the last term represents the cost of the expected not-supplied flexibility.

The constraints (4-4) and (4-5) match flexibility requests from the DSO with flexibility offers from FSPs, respectively for upwards and downwards bids. It is relevant to mention that in these equations, each FSP bid is multiplied by its respective sensitivity factor ($PTDF$) which will affect the merit order on the market. Constraints (4-6) and (4-7) capture the limits of the submitted bids from FSPs, and constraint (4-8) ensures that the variable corresponding to the not-supplied flexibility is positive.

$$min \sum_{h\in H} \left[\sum_{f\epsilon \mathrm{F}^U} C^U_{f,h} p^U_{f,h} \ + \sum_{f\epsilon \mathrm{F}^D} C^D_{f,h} p^D_{f,h} \ + VOLL(\alpha^U_{r,h} + \alpha^D_{r,h}) \right] \tag{4-3}$$

s.t.

$$P^{U\_DSO}_{r,h} - \sum_{f\epsilon \mathrm{F}^U} PTDF_{f,r} p^U_{f,h} - \alpha^U_{r,h} \leq 0\,, \qquad \forall_r\in R^U, \forall_h\in H \tag{4-4}$$

$$P^{D\_DSO}_{r,h} - \sum_{f\epsilon \mathrm{F}^D} PTDF_{f,r} p^D_{f,h} - \alpha^D_{r,h} \leq 0\,, \qquad \forall_r\in R^D, \forall_h\in H \tag{4-5}$$

$$P^{Umin}_{f,h} \leq p^U_{f,h} \leq P^{Umax}_{f,h}\,, \qquad \forall_f\in \mathrm{F}^U, \forall_h\in H \tag{4-6}$$

$$P^{Dmin}_{f,h} \leq p^D_{f,h} \leq P^{Dmax}_{f,h}\,, \qquad \forall_f\in \mathrm{F}^D, \forall_h\in H \tag{4-7}$$

$$\alpha^U_{r,h}\,, \alpha^D_{r,h} > 0 \ \ \forall_r\in R, \forall_h\in H \tag{4-8}$$

4.2. Greek Case Study

To study the scalability and replicability of Workstream 2 in Greece, the Kefalonia demo site was selected. Therefore, the details of the input data for the SRA are introduced in Sections 4.2.1 and 4.2.2, such as the Kefalonia MV distribution network characteristics, load and generation profiles, and FSPs information. Then the three SRA scenarios are defined in Section 4.2.3 to examine the congestion events and the SRA performance for this demo site. Subsequently, the results of each SRA scenario are analyzed in Sections 4.2.4, 4.2.5, and 4.2.6. Last, section 4.2.7 provides concluding remarks about the SRA for MV local congestion management applied to the Greek case study.

4.2.1. Network characteristics and Load and Generation profiles

As illustrated in the single diagram of Figure 31, the distribution network in Kefalonia consists of twelve MV feeders (20 kV) that start from Argostoli HV/MV substation and serve several locations in the area (Bachoumis et al., 2020). Five feeders (22-26) start from HV/MV transformer Tr1 with a 50 MVA nominal capacity, and the rest of the feeders (27-96) start from HV/MV transformers Tr2 and Tr2a. Tr2 and Tr2a operate in parallel and have a nominal capacity of 25 MVA each. Regarding the network elements, this grid consists of 389 buses, 25 lines, 219 load points, 23 Photovoltaic (PV) plants, and 2 wind farms.

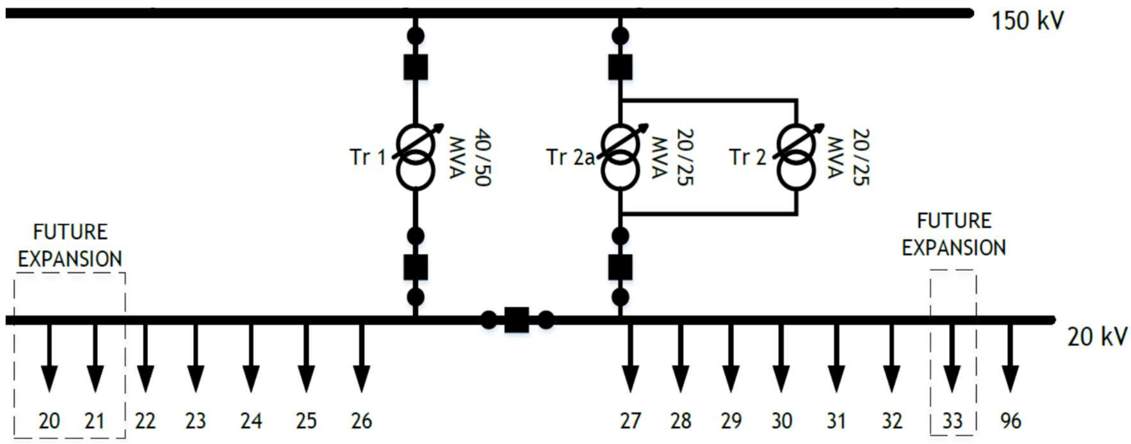

Figure 31: Single line diagram of Argostoli substation – Kefalonia demo site (Bachoumis et al., 2020)

With regards to the load and generation profiles, the year 2018 serves as the base year. The load profiles for the whole year were analyzed, and the demand peak occurs during the evening of August 14th. Thus, it was selected as the representative day for the SRA. Figure 32 shows the different MV load profiles for the representative day. Furthermore, Figure 33 and Figure 34 depict the profiles for wind and PV generation, which were also created based on the 2018 data. It is important to highlight that the information about load and wind profiles was provided by the Greek demo, and the PV profiles were computed using the database available in (Pfenninger and Staffell, 2016), considering the location of PV plants.

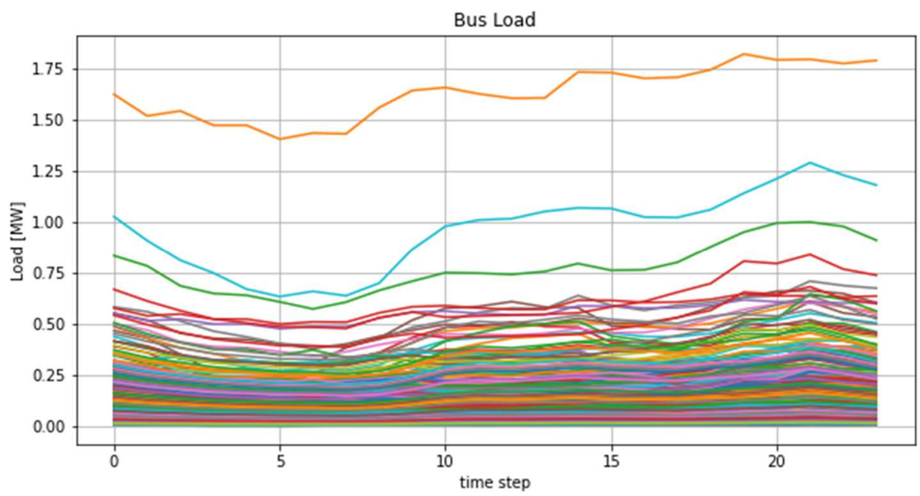

Figure 32: Representative day load profiles for the 219 load points of the Kefalonia MV distribution network

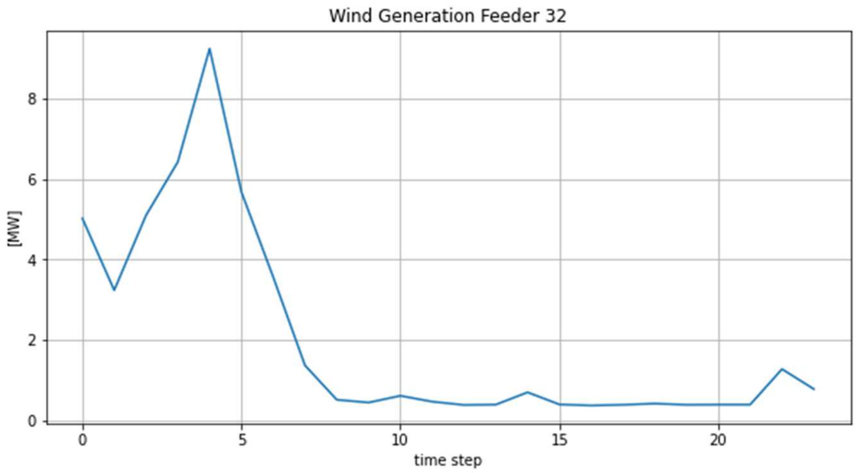

Figure 33: Representative day wind generation profile for the wind farm connected in Feeder 32 of the Kefalonia MV distribution network

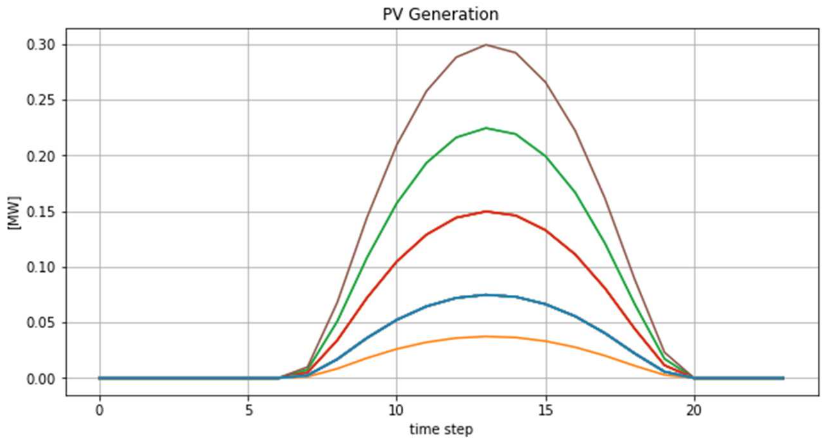

Figure 34: Representative day PV plants profiles of Kefalonia distribution network. There are 22 PV plants in the Kefalonia MV network categorized into five profiles according to their maximum capacity: orange (0.05 MW), blue (0.1 MW), red (0.2 W), green (0.3 MW), and brown (0.4 MW).

4.2.2. FSPs characteristics

Table 20 lists the FSPs considered in the Greek case study and their characteristics for the MV local congestion management. The information related to the FSP type and capacity was obtained from CoordiNet D5.3 (Leonidaki et al., 2020), and the remainder data was derived from available information within the project. Moreover, it should be noted that the FSPs offer only upward flexibility for this analysis, and their available flexibility is equal to 10% of the FSP capacity (base case).

Table 20: FSP characteristics for the Greek case study

FSP ID	Feeder ID	Node ID	FSP type	FSP Capacity [MW]	Upward Flex Capacity [%]	Upward Flex Cost [EUR/MWh]
Fsp1	25	129	Prefecture building	0.1332	10	87.57
Fsp2	25	135	Municipal building	0.1215	10	87.57
Fsp3	25	164	Municipal building	0.243	10	87.57
Fsp4	25	164	Municipal building	0.1485	10	87.57
Fsp5	25	164	Municipal building	0.09	10	87.57
Fsp6	25	166	Municipal building	0.27	10	87.57
Fsp7	24	96	Irrigation pumps	0.2125	10	81.35
Fsp8	24	98	Irrigation pumps	0.34	10	81.35
Fsp9	24	101	Irrigation pumps	0.34	10	81.35
Fsp10	24	105	Irrigation pumps	0.34	10	81.35

4.2.3. Kefalonia SRA scenarios

For the scalability and replicability analysis of the local congestion management in the Greek case study, different scenarios are tested according to Table 21. This table also summarizes the SRA parameters and the KPIs to be calculated for each scenario.

Three scenarios are defined. Scenario 0 analyses the Kefalonia MV distribution network under the conditions of the representative day (peak demand), which was selected previously. Scenario 1 examines the congestion events in the network under the same representative day of Scenario 0, but the load of Feeders 24 and 25 is increased by 25%. Since the FSPs are connected to these two feeders, this scenario will allow to implement a local market in case of congestion events because of the radiality of the network. Finally, Scenario 2 examines the network under the loss of one of the HV/MV transformers (Tr1) of the Argostoli substation considering the representative day of Scenario 0. The SRA methodology defined in Subchapter 4.1 is applied for each of these scenarios, and the results are further analyzed in the following subsections.

Table 21: SRA scenarios for the Greek case study

<table>
<tr><th>Scenario ID</th><th>Description</th><th>SRA parameters</th><th>KPIs calculated</th></tr>
<tr><td>Scenario 0</td><td>Analysis considering peak demand profiles (August 14th of 2018)</td><td colspan="2">No congestion events</td></tr>
<tr><td>Scenario 1</td><td>Scenario 0 + Increase 25% of the load in Feeders 24 and 25 where the FSPs are connected</td><td>FSPs size
FSPs bid cost</td><td rowspan="2">KPI 6: Total flexibility activation cost
KPI 13: Criticalities reduction index
KPI 16: Potential offered flexibility
KPI 18: Volume of transactions in LFM
KPI 19: Number of transactions in LFM
KPI 22: Requested flexibility</td></tr>
<tr><td>Scenario 2</td><td>Scenario 0 + N-1 conditions (Loss of 50 MVA rated power transformer Tr1)</td><td>FSPs size
FSPs bid cost
FSP number and location</td></tr>
</table>

4.2.4. Kefalonia Scenario 0

As highlighted before, the SRA methodology described in Subchapter 4.1 is applied for Scenario 0. Therefore, this section describes the results of each of the five steps of the methodology:

- **Power flow analysis (Step 1):** The first step is to perform a power flow analysis for 24 hours (market horizon) to detect eventual constraints. This step considers the distribution network data and load and generation profiles described in section 4.2.1. The profiles refer to the selected representative day, August 14th, 2018 (peak demand). The results of step 1 are illustrated in Figure 35 for the lines and in Figure 36 for the transformers. These results show that congestion problems (lines and transformers overloading events) do not occur under Scenario 0 in the Kefalonia MV distribution network. Even during the peak demand hours (19h-22h), the thermal limits of the lines and transformers are not violated.

This is the reason why congestion problems are examined under the conditions of Scenario 1 and 2 in the next subsections of the Greek case of study.

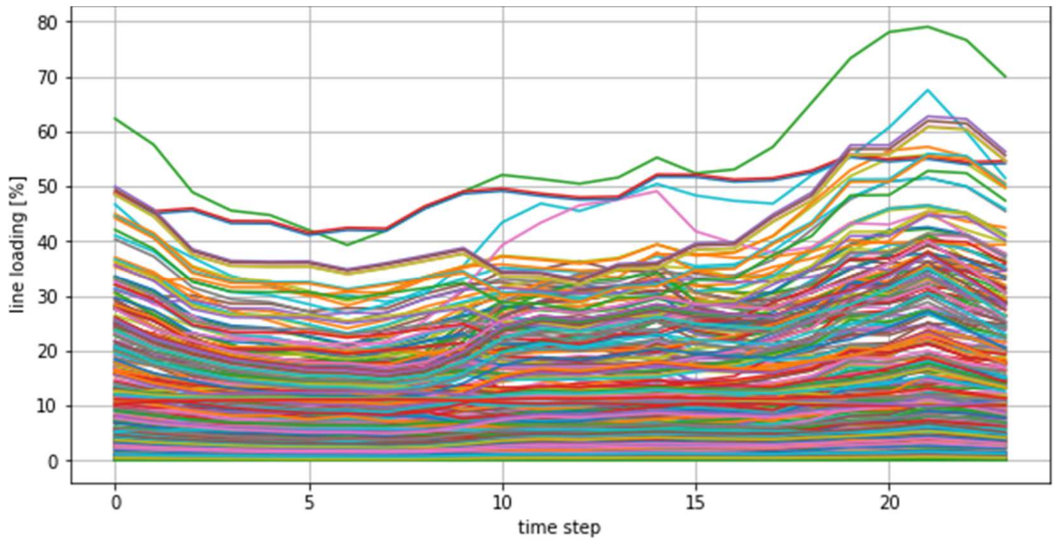

Figure 35: Line loading [%] for the Scenario 0, Greek case study

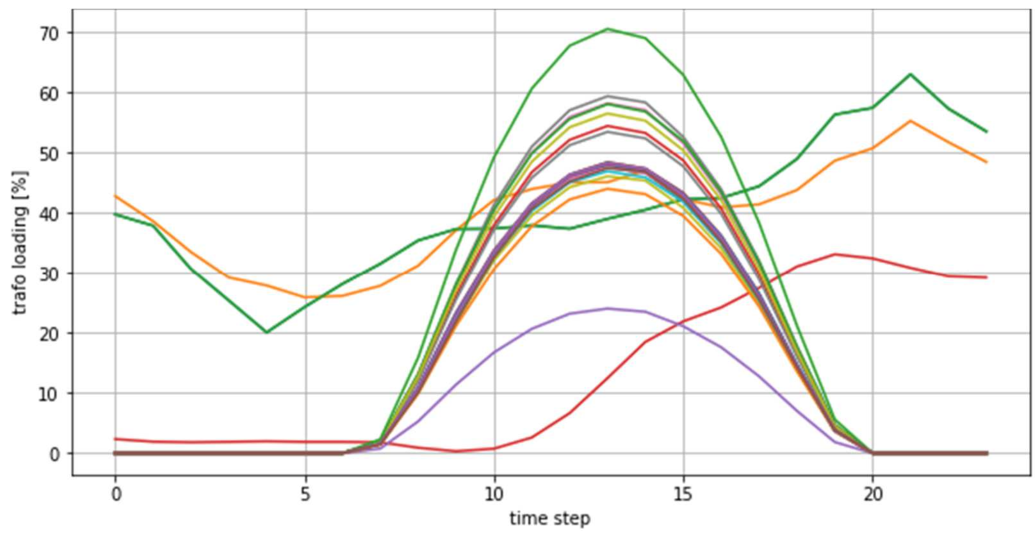

Figure 36: Transformers loading [%] for the Scenario 0, Greek case study

4.2.5. SRA for Kefalonia Scenario 1

This section describes the results of applying the SRA methodology defined for Workstream 2 in Scenario 1. The Scenario 1 analysis is based on the representative day of Scenario 0, except for the load profiles of the Feeders 24 and 25, which are increased by 25% according to the scenario definition. The results of the SRA methodology are further described below.

- **Power flow analysis (Step 1):** Considering the new load profiles, a power flow analysis is run for 24 hours (market horizon) to detect eventual constraints. The results of the power flow are depicted in Figure 37 for the lines, from this figure we notice that one of the MV distribution lines is congested at hours 20, 21, and 22. This line is part of the Feeder 24 and it is identified with index 122. Furthermore, it is important to highlight that the thermal limits of the transformers were not violated in Scenario 1.

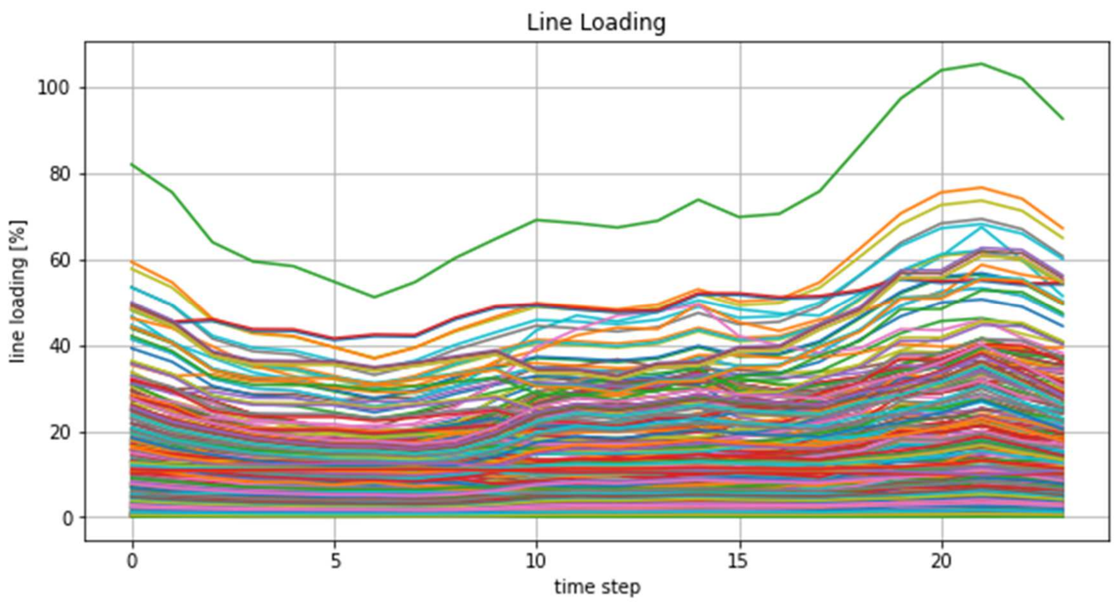

Figure 37: Line loading [%] for the Scenario 1, Greek case study

- **DSO flexibility needs calculation (Step 2):** In this second step, the DSO calculates its flexibility needs related to the congested line #122. Table 22 summarizes the flexibility needs in terms of MW for the three criticalities (congested events) identified in the previous step for line # 122.

Table 22: DSO flexibility needs for Scenario 1 – Greek case study

Line ID	Hour	Loading [%]	Flexibility need [%]	Upward Flexibility need [MW]
122	20	104.028	4.028	0.285865
122	21	105.527	5.527	0.392253
122	22	102.026	2.026	0.143765

- **Sensitivity factors calculation (Step 3):** In this step, the sensitivity factors (PTDF) are computed for each FSP participating in the local market relative to the DSO flexibility needs of step 2. Table 23 sums up the PTDFs obtained. It is interesting to note that although there are 10 FSPs on the demo site, only four of them directly impact the congested line # 122, as only FSPs 7, 8, 9, and 10 are connected downstream of line #122. The rest of the FSPs are connected to the Feeder 25, and their sensitivity factors with respect to line # 122 are equal to zero.

Table 23: Sensitivity Factors for Scenario 1 - Greek demo

FSP ID	Sensitivity factors FSPs/ Line 122
Fsp1 - Fsp6	0
Fsp7 – Fsp10	1

- **Local flexibility market-clearing (Step 4) and post-evaluation (Step 5):** In step 4, a day-ahead local flexibility market-clearing is carried out to solve the criticalities identified in step 2 using the most efficient flexibility bids from FSPs 7, 8, 9, and 10 at minimum cost. To evaluate the SRA performance of scenario 1, sensitivities are applied to selected parameters of the local flexibility market-clearing model, as presented in Table 24. Therefore, steps 4 and 5 of the SRA methodology are executed according to the sensitivities of Table 23 and the results are reported in the following subsection. Furthermore, it is relevant to mention that a cost of 4240 (EUR/MWh) is considered for the $VOLL$ parameter according to the report in (ACER/ CEPA, 2018).

Table 24: Sensitivities to the SRA parameters for scalability - Scenarios 1 and 2

Parameter	Parameter description	Considerations	Sensitivity range
$\boldsymbol{P_{f,h}^{Umin}}, \boldsymbol{P_{f,h}^{Umax}}$	Maximum and minimum available flexibility of FSP f in period h. (MW)	Sensitivities are applied only to upward flexibility bids from FSPs because the DSO request is related to upward flexibility	Scenario 1: $[0 \;\; 0.2 \;\; \cdots \;\; 4.8 \;\; 5]$ Scenario 2: $[0 \;\; 0.2 \;\; \cdots \;\; 9.8 \;\; 10]$
$\boldsymbol{C_{f,h}^{U}}$	Bid cost of the FSP f in the local market in period h. (€/MWh)		Scenarios 1 and 2: $[0 \;\; 0.2 \;\; \cdots \;\; 4.8 \;\; 5]$

4.2.5.1. SRA Results Scenario 1

First, the results for the scalability analysis on the KPI-13 Criticalities Reduction Index (CRI) are examined, which measures the reduction of the number of criticalities by comparing the results before and after the local flexibility market-clearing. The number of criticalities correspond to the number of congestion events, i. e. overload of the lines and transformers. Figure 38 below presents the results for this KPI in which the sensitivities in the x and y axes of the graph are those defined in Table 24, where a sensitivity value of 1 represents the base case (or “CoordiNet case”). For the base case, we can see that only 33.33% of the criticalities are solved using a local flexibility market solution. However, the scalability scenario reveals that if the capacity of the FSPs in the demo is scaled up to a factor of 3.2, the three criticalities identified for line # 122 are completely solved by the procurement of local flexibility.

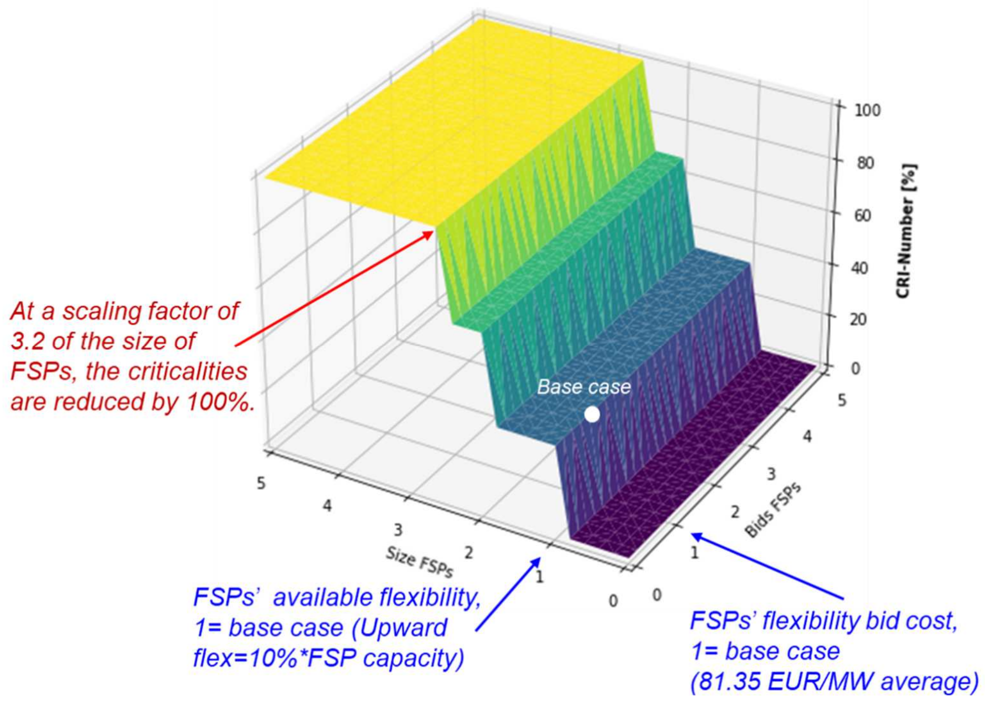

Figure 38: Sensitivity analysis on the KPI 13: Criticalities Reduction Index, Scenario 1 Greek demo

The second scalability analysis uses the same sensitivities of the previous KPI, the same size of FSPs, and the same bids offered by the FSPs. In this case, the effect of the sensitivities on two relevant costs terms are analysed, 1) The flexibility activation cost (upward and downward), and 2) The total cost of the local market-clearing, which was defined in Section 4.1.3 as the sum of the cost of flexibility activation plus the cost of the expected not-supplied flexibility. As shown in Figure 39, both cost terms are not sensitive to the size of the FSPs as from a factor of 3.2. These findings confirm the results of the KPI-13, where the total number of criticalities were solved from the same factor value. Moreover, we observe from the left side plot of Figure 39 that after this factor (3.2 size of FSPs), the cost related to the flexibility not supplied is zero. Thus, the total cost is only sensitive to the bid cost of the FSPs.

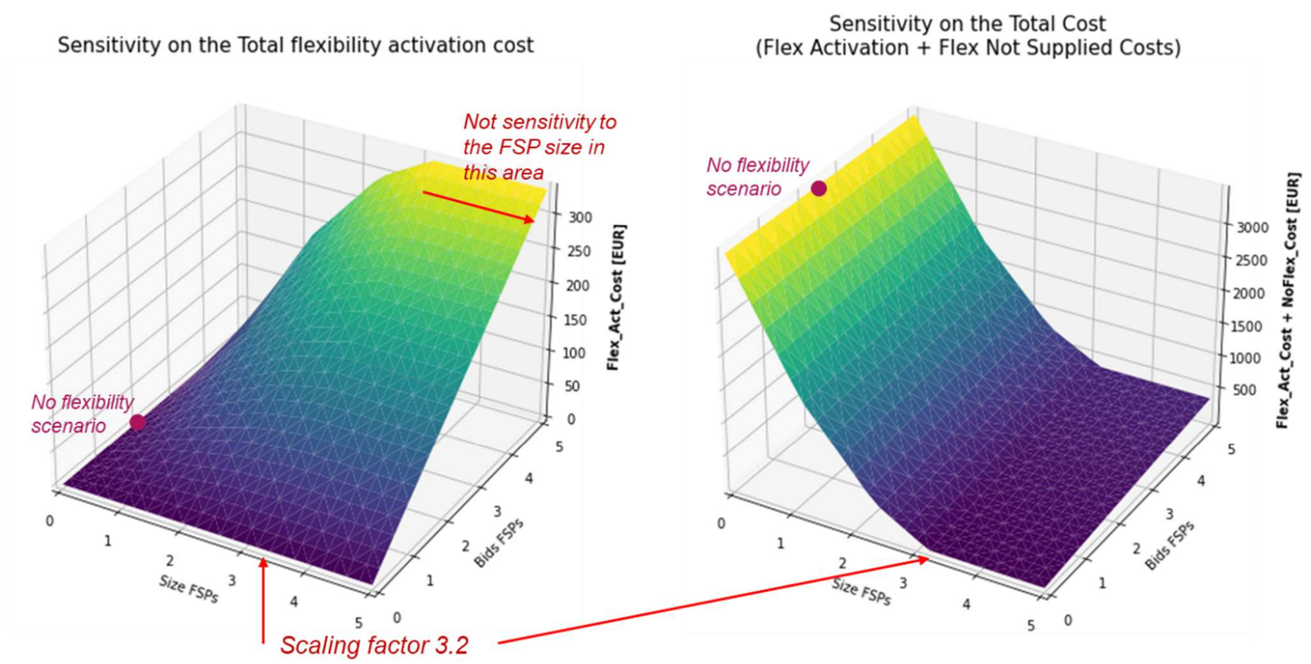

Figure 39: Sensitivity analysis on the Flexibility Cost, Scenario 1 Greek demo

Finally, the results for the scalability analysis on the KPI-18 are studied, which measures the volume of transactions of the local flexibility market in terms of MW. The sensitivities of Scenario 1 previously defined are applied, and Figure 40 displays the results for this KPI. For the three criticalities of line # 122, 0.8221883 MW of flexibility is needed, therefore, Figure 40 indicates that at a scaling factor of 3.2 of the size of the FSPs, the total DSO flexibility request is solved by the local flexibility market.

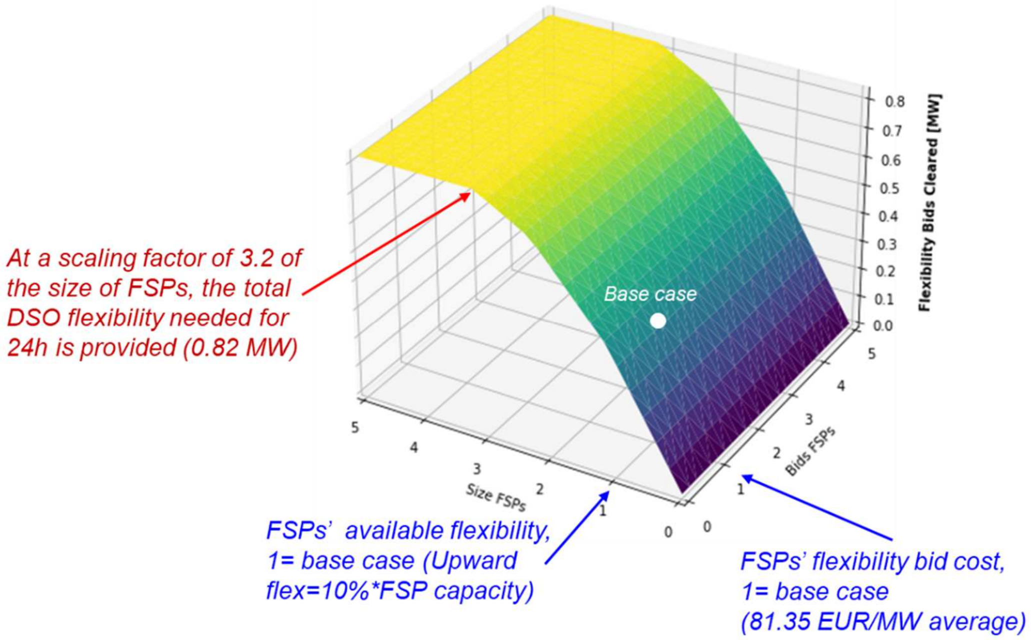

Figure 40: Sensitivity on KPI 18: Total Volume of Transactions in the Market, Scenario 1 Greek demo

4.2.6. SRA for Kefalonia Scenario 2

This section describes the results of applying the SRA methodology defined for Workstream 2 in Scenario 2. This scenario is based on the representative day of Scenario 0, and it also considers the N-1 conditions according to the scenario definition of Section 4.2.3. The N-1 conditions mean the loss of the Tr1 transformer of the Argostoli MV distribution network, which has a capacity of 50 MVA. The results of the SRA methodology are further described below.

- **Power flow analysis (Step 1):** Considering both the load and generation profiles defined in the Scenario 0 of high peak demand and the N-1 conditions, a power flow analysis is run for 24 hours to detect eventual constraints. The power flow results are illustrated in Figure 41 for the transformers. From this figure, we can observe that the two parallel HV/MV transformers Tr2 and Tr2a are congested from hour 18 to hour 23. Particularly, the loading of these two transformers reaches a value of 140 % in hour 21. Furthermore, it is important to highlight that the thermal limits of the lines were not violated in Scenario 2.

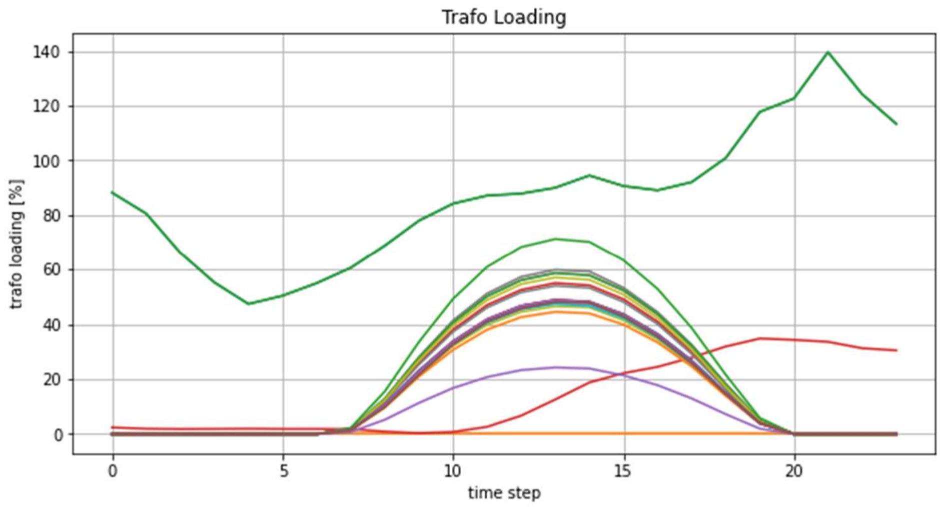

Figure 41: Transformers loading [%] for the Scenario 2, Greek case study

- **DSO flexibility needs calculation (Step 2):** In this step, the DSO calculates its flexibility needs related to the congested transformers Tr2 and Tr2a. Table 25 lists the flexibility needs in terms of MW for the twelve criticalities identified in the previous step. We note from this table that the amount of MW needed to solve the criticalities identified in Scenario 2 exceed the current capacity of the FSPs participating in the demo site, see Section 4.2.2. Therefore, we scale up the number of FSPs from 10 to 26. Since the current FSPs are connected at the feeders 24 and 25, two new FSPs were placed for each of the other feeders. Table 26 lists the current and the new FSPs considered for Scenario 2.

Table 25: DSO flexibility needs for Scenario 2 - Greek case study

Trafo ID	Hour	Loading [%]	Flexibility need [%]	Upward Flexibility need [MW]
Tr2	18	100.896	0.896	0.190410
Tr2	19	117.763	17.763	3.774678
Tr2	20	122.665	22.665	4.816400
Tr2	21	139.638	39.638	8.423068
Tr2	22	124.284	24.284	5.160426
Tr2	23	113.423	13.423	2.852396
Tr2a	18	100.896	0.896	0.190410
Tr2a	19	117.763	17.763	3.774678
Tr2a	20	122.665	22.665	4.816400
Tr2a	21	139.638	39.638	8.423068
Tr2a	22	124.284	24.284	5.160426
Tr2a	23	113.423	13.423	2.852396

Table 26: New FSPs for Scenario 2 - Greek case study

FSP ID	Feeder ID	Node ID	FSP type	FSP Capacity [MW]	Upward Capacity [%)]	Downward Flex Cost (EUR/MW)	Upward Flex Cost (EUR/MW)
Fsp1	25	129	Gen	0.1332	10	109.013	87.5704
Fsp2	25	135	Gen	0.1215	10	109.013	87.5704
Fsp3	25	164	Gen	0.243	10	109.013	87.5704
Fsp4	25	164	Gen	0.1485	10	109.013	87.5704

Fsp5	25	164	Gen	0.09	10	109.013	87.5704
Fsp6	25	166	Gen	0.27	10	109.013	87.5704
Fsp7	24	96	Load	0.2125	10	102.284	81.3576
Fsp8	24	98	Load	0.34	10	102.284	81.3576
Fsp9	24	101	Load	0.34	10	102.284	81.3576
Fsp10	24	105	Load	0.34	10	102.284	81.3576
Fsp11	22	49	Load	0.415	10	102.284	81.3576
Fsp12	22	46	Load	0.345	10	102.284	81.3576
Fsp13	23	62	Load	0.57	10	102.284	81.3576
Fsp14	23	84	Load	0.25	10	102.284	81.3576
Fsp15	26	172	Load	0.215	10	102.284	81.3576
Fsp16	26	173	Load	0.245	10	102.284	81.3576
Fsp17	27	199	Load	0.905	10	102.284	81.3576
Fsp18	27	204	Load	0.32	10	102.284	81.3576
Fsp19	28	220	Load	0.245	10	102.284	81.3576
Fsp20	28	245	Load	0.205	10	102.284	81.3576
Fsp21	29	288	Load	0.33	10	102.284	81.3576
Fsp22	29	296	Load	0.2	10	102.284	81.3576
Fsp23	30	309	Load	0.34	10	102.284	81.3576
Fsp24	30	325	Load	0.42	10	102.284	81.3576
Fsp25	31	342	Load	0.225	10	102.284	81.3576
Fsp26	31	356	Load	0.295	10	102.284	81.3576

- **Sensitivity factors calculation (Step 3):** In this step, the PTDFs are computed for each FSP listed in Table 26 relative to the DSO flexibility needs of step 2. Table 27 summarizes the PTDFs obtained, where it is relevant to highlight that although all FSPs participating in this SRA scenario can contribute to solve congestions in Tr2 and Tr2a, the sensitivity factors between the FSPs and these two transformers are equal to 0.5 because Tr2 and Tr2a operate in parallel.

Table 27: Sensitivity Factors for Scenario 2 - Greek demo

FSP ID	Sensitivity factors FSPs/ Trafo Tr2	Sensitivity factors FSPs/ Trafo Tr2a
FSP1 – FSP16	0.5	0.5

- **Local flexibility market-clearing (Step 4) and post-evaluation (Step 5):** Step 4 runs a day-ahead local flexibility market-clearing to solve the criticalities identified in step 2 using the most efficient flexibility bids from FSP 1 to FSP 16. To evaluate the SRA performance of Scenario 2, steps 4 and 5 of the SRA methodology are executed according to the sensitivities of Table 24, and the results for scenario 2 are reported in the following subsection. Furthermore, this scenario also considers a cost of 4240 (EUR/MWh) for the $VOLL$ parameter according to the report in (ACER/ CEPA, 2018).

4.2.6.1. SRA Results for Scenario 2

Similar to scenario 1, the results for the scalability on the KPI-13 Criticalities Reduction Index (CRI) are analysed in the first place. Figure 42 reports the results for this KPI in which the sensitivities in the x and y axes of the graph are those defined in Table 24, where a sensitivity value of 1 represents the base case (or "CoordiNet case"). The figure is revealing in several ways. First, from a factor of 0.5 to 4.5 of the FSPs size, the CRI remains at 16.6%. However, as soon as this sensitivity is greater than 5 the CRI increases again until it reaches a rate of 80% when the FSP size is equal to 10. Therefore, it is important to note that using all available flexibility from the FSPs (FSP size = 10), the twelve criticalities identified for the transformers Tr2 and Tr2a are not completely solved by the procurement of local flexibility. As expected, even using the maximum available flexibility from the FSPs leads to a not-supplied flexibility of 13.5 MW, see Figure 43.

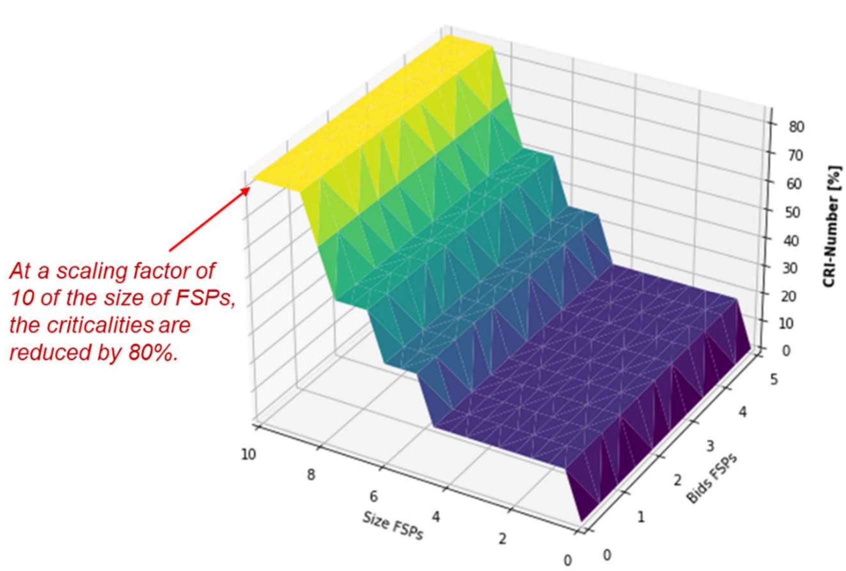

Figure 42: Sensitivity analysis on the KPI 13: Criticalities Reduction Index, Scenario 2 Greek demo

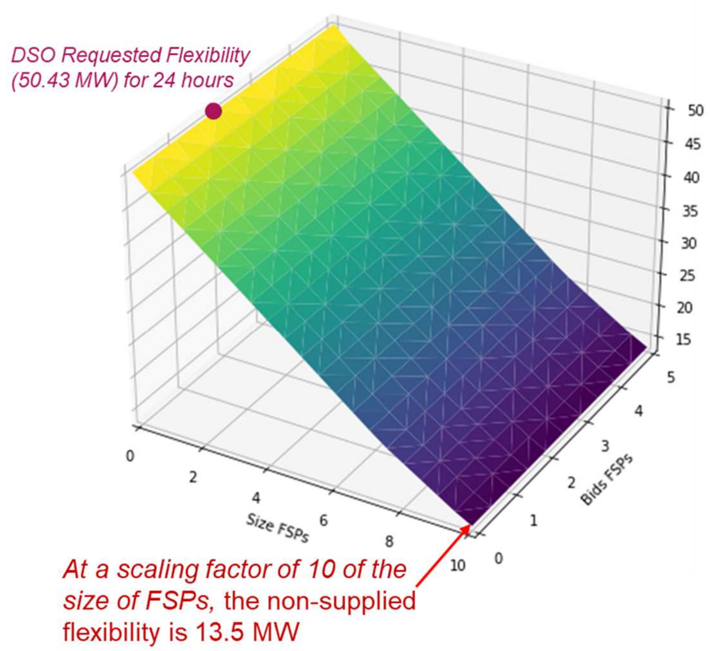

Figure 43: Sensitivity analysis on the not-supplied flexibility, Scenario 2 Greek demo

Turning now to the second scalability analysis of this scenario, the effect of the sensitivities is examined on 1) The flexibility activation cost (upward and downward) and 2) The total cost of the local market-clearing (sum of the cost of flexibility activation plus the cost of the expected not-supplied flexibility). From Figure 44, we can observe that both cost terms are sensitive to the size of the FSPs. The flexibility activation cost continues to rise as more flexibility is being purchased in the local market to solve the criticalities. By contrast, the total cost decreases because we have less not-supplied flexibility by increasing the FSP size parameter.

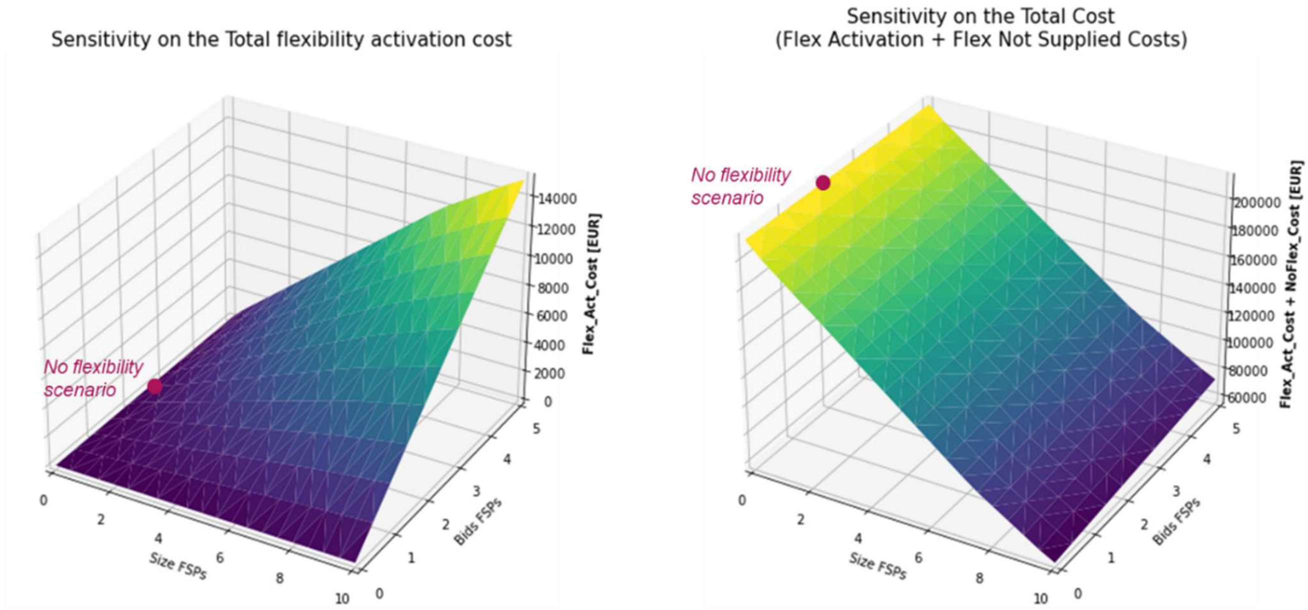

Figure 44: Sensitivity analysis on the Flexibility Cost, Scenario 2 Greek demo

4.2.7. Interim Conclusions

From the analysis of the Greek case study for the workstream 2, it can be concluded that:

- Under scenario 2 (N-1 loss of Tr1-50MVA), the congestion criticalities are reduced by 80% using the maximum available flexibility of FSPs. Since more flexibility is needed to solve the total criticalities in this scenario, other flexibility options could be considered, such as network reconfiguration, control of the OLTC, new FSPs, etc. Therefore, DSOs can choose between using their own flexible resources or procuring flexibility from third parties, or a combination of both to solve potential operational and planning problems related to congestion. In this regard, it could be beneficial to propose a framework for analyzing the interaction between flexibilities from DSO and local flexibility markets to determine which solutions are the most attractive from the point of view of economic efficiency, implementation cost, information asymmetry, and other criteria to be explored.

- The FSPs' engagement is key to the local flexibility market for congestion management in the Greek demo. As highlighted in the results, for both scenario 1 and scenario 2, the current flexibility capacity of FSPs does not solve the total DSO flexibility request.

- The proposed linearized local flexibility market using PTDF does not lead to new congestion problems after the market-clearing, according to the post-evaluation process and under the scenarios analyzed.

4.3. Spanish Case Study

To study the scalability and replicability of Workstream 2 in Spain, the Malaga and Murcia demo sites were selected because a local congestion management market is tested in these locations. Therefore, this subchapter is divided into three main parts. First, Sections 4.3.1 to 4.3.6 describe the inputs, scenarios, and results for the Malaga SRA. Similarly, Sections 4.3.7 to 4.3.11 present the inputs, scenarios, and outcomes related to the Murcia SRA. Last, section 4.3.12 provides concluding remarks about the SRA for MV local congestion management applied to Malaga and Murcia.

4.3.1. Malaga Network characteristics and Load and Generation profiles

The Malaga demo site comprises four MV separated networks (Ivanova et al., 2022). However, as illustrated in Figure 45, the network related to the Industrial park of Guadalhorce together with the Cadiz road district area, is selected for the SRA because most of the FSPs considered in the demo are connected there. This 20 kV network is formed by the substations of Visos, Poligono, and San Sebastian. Regarding the network elements, this grid consists of 1984 buses, 515 lines, 268 load points, 17 PV plants, and 2 natural gas generation plants.

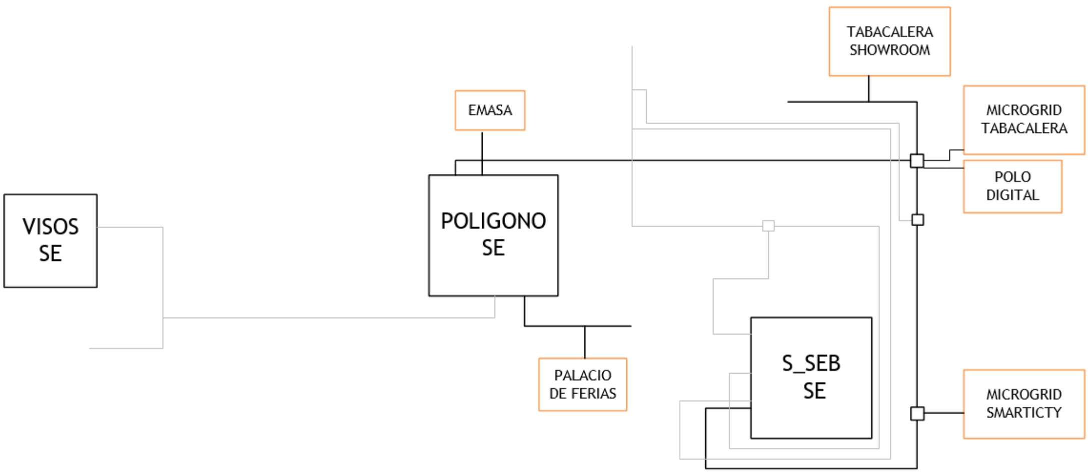

Figure 45: Industrial Park of Guadalhorce & Cadiz Road District area, source (Ivanova et al., 2022)

Furthermore, the Malaga network parameters and the yearly profiles available in (Red Eléctrica España, 2022) and (Pfenninger and Staffell, 2016) are used to obtain the load and generation profiles. As a first step, two representative days were calculated corresponding to the maximum and the minimum net load of the network, then the PV profiles for the maximum and minimum representative day were obtained (Figure 46). In addition, as illustrated in Figure 47, eight different load profiles were computed according to the consumers' power capacity in place of the maximum (blue) and minimum (red) representative days. It is relevant to point out that the profiles related to the maximum representative day are considered for the SRA in the next sections of this subchapter since this workstream is focused on the analysis of congestion management for lines and transformers. The minimum representative day could be used to study other network issues such as voltage control.

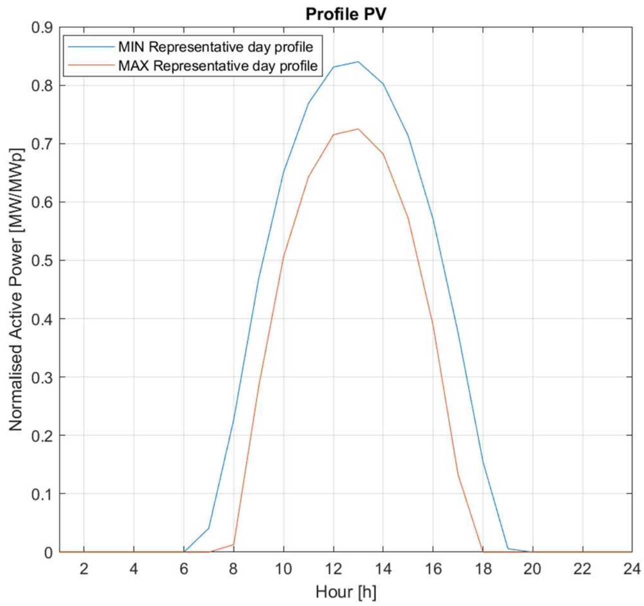

Figure 46: PV profiles for the Malaga demo site - Workstream 2

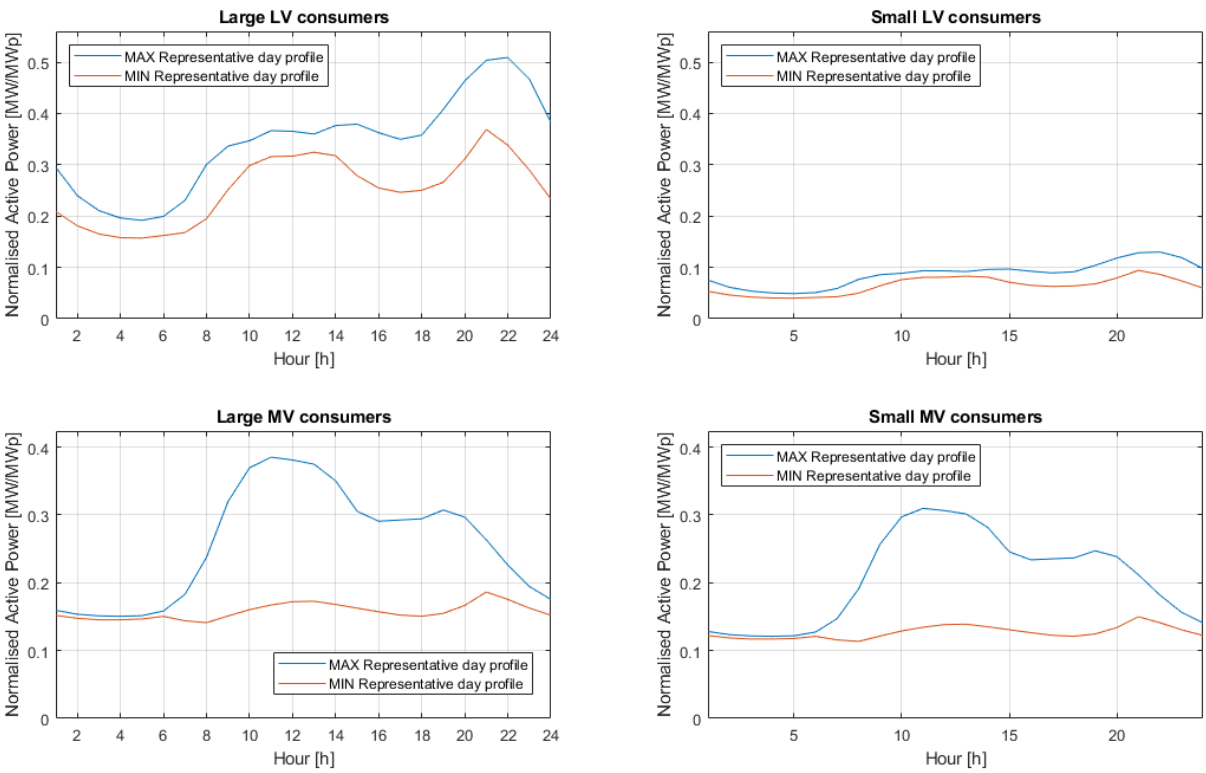

Figure 47: Load profiles for the Malaga demo site - Workstream 2

4.3.2. Malaga FSPs characteristics

Table 28 lists the FSPs considered in the Malaga demo site for local congestion management. The information related to the FSP type and capacity was obtained from CoordiNet D3.1 (Chaves-Ávila et al., 2020), and the remaining data was derived from the project. The five FSPs considered in this SRA are also represented in the simplified scheme of Figure 45.

Table 28: FSPs characteristics for the Malaga case study

FSP ID	Feeder ID	Node ID	FSP type	FSP Capacity [MW]	Down. Flex Cap. [%]	Upward Flex Cap. [%]	Down. Flex Cost [EUR/MWh]	Upward Flex Cost [EUR/MWh]
Fsp1: Polo Digital	Tabacalera	1783	Consumption/ Buildings	0.316	0	10	-	54.41
Fsp2: Microgrid Tabacalera	Tabacalera	1790	Microgrid	0.035	10	10	84.91	121.31
Fsp3: Microgrid Smart City	Pacifico	908	Microgrid	0.055	10	10	66.09	94.42
Fsp4: Tabacalera Showroom	Tabacalera	1920	Consumption, Storage, and Solar PV	0.11	10	10	64.79	90
Fsp5: Palacio de Ferias	Palacio de las ferias	975	Solar PV	0.10	10	10	64.79	90

4.3.3. Malaga SRA scenarios

For the local congestion management SRA in the Malaga demo site, three different scenarios are tested according to Table 29. Scenario 0 analyses the Malaga distribution network under the maximum representative day (peak net load) conditions, which was selected previously. Scenario 1 examines the congestion events in the network under the same representative day as Scenario 0, but the load of feeders Pacifico, Palacio de las Ferias, and Tabacalera is increased by 300% since the FSPs of the demo are connected to these feeders. Finally, in Scenario 2, considering the representative day of Scenario 0, we analyse the network under the reduction of the maximal thermal current of the lines 398 (Palacio de las Ferias), and 481 (Tabacalera/Pacifico). The SRA methodology defined in Subchapter 4.1 is applied for each of these scenarios, and the results are further analysed in the following subsections. Table 29 also summarizes the SRA parameters and the KPIs to be calculated for each scenario.

Table 29: SRA scenarios for the Malaga case study

<table>
<tr><th>Scenario ID</th><th>Description</th><th>SRA parameters</th><th>KPIs calculated</th></tr>
<tr><td>Scenario 0</td><td>Analysis considering maximum net load representative day profiles</td><td colspan="2">No congestion events</td></tr>
<tr><td>Scenario 1</td><td>Scenario 0 + Increase 300% of load in Feeders Pacifico, Palacio de las Ferias, and Tabacalera.</td><td>FSPs size
FSPs bid cost</td><td rowspan="2">KPI 6: Total flexibility activation cost
KPI 13: Criticalities reduction index
KPI 16: Potential offered flexibility
KPI 18: Volume of transactions in LFM
KPI 19: Number of transactions in LFM
KPI 22: Requested flexibility</td></tr>
<tr><td>Scenario 2</td><td>Scenario 0 + Reduction of Imax of lines 398, and 481 which are part of feeders Palacio de las Ferias, and Tabacalera/Pacifico respectively.</td><td>FSPs size
FSPs bid cost</td></tr>
</table>

4.3.4. Malaga Scenario 0

This section describes the results of Scenario 0 applying the SRA methodology for the Workstream 2:

- **Power flow analysis (Step 1):** As a first step, a power flow analysis is performed for 24 hours to detect eventual constraints. This step considers the distribution network data and load and generation profiles described in section 4.3.1, and these profiles correspond to the maximum net load representative day. Figure 48 and Figure 49 show the outcomes of step 1 in terms of loading percentage for lines and transformers, respectively. From these figures, we can notice that there are no thermal limit violations for the lines and transformers of the Malaga MV network under the conditions of Scenario 0. Therefore, the congestion problems are examined under scenarios 1 and 2 in the next subsections of the Malaga case study.

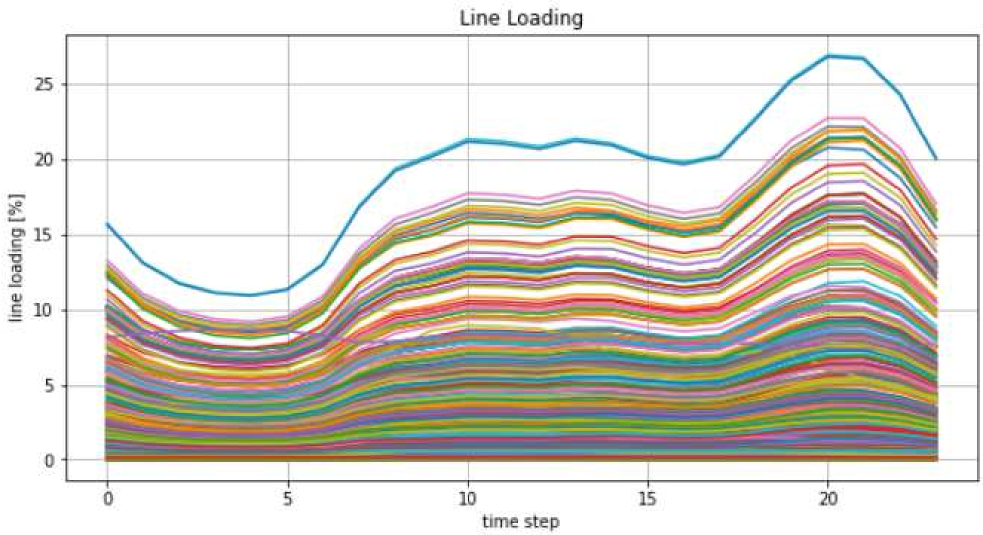

Figure 48: Line loading [%] for the Scenario 0, Malaga case study

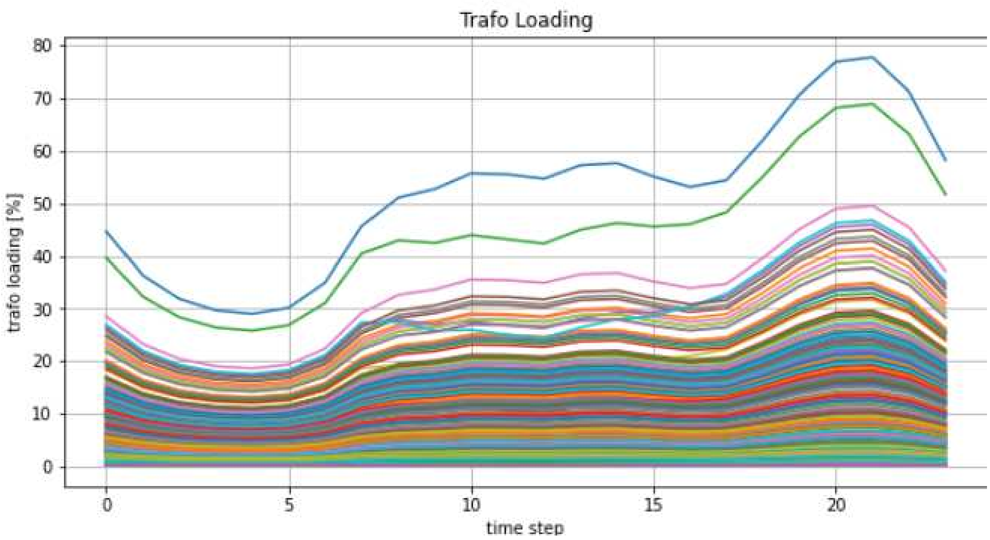

Figure 49: Transformers loading [%] for the Scenario 0, Malaga case study

4.3.5. SRA for Malaga Scenario 1

This section analyses the results of applying the SRA methodology defined for Workstream 2 in Malaga Scenario 1. This scenario is based on the representative day of Scenario 0, except for the load profiles of the Feeders Pacifico, Palacio de las Ferias, and Tabacalera, which are increased by a factor of 3 according to the scenario definition. The outcomes of the SRA are further described below.

- **Power flow analysis (Step 1):** Considering the new load profiles, a power flow analysis is run for 24 hours to detect eventual congestions. Figure 50 shows the new loading percentage for the transformers after power flow analysis, where we identified two 20/0.4 kV transformers congested at hours 19, 20, 21, and 22. They are located in the Tabacalera feeder and identified with indices 170 and 171. Furthermore, it is important to highlight that the thermal limits of the lines were not violated under Scenario 1, the maximum loading of the lines was around 35%.

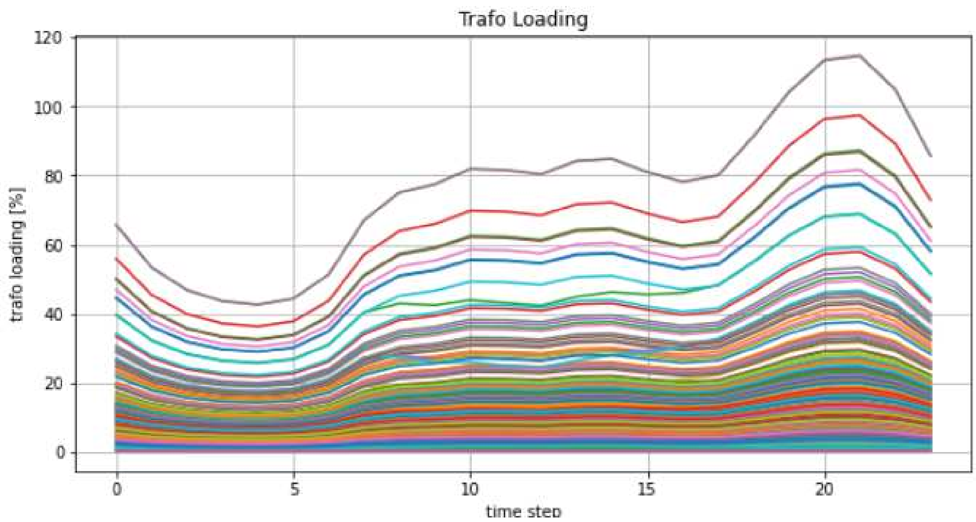

Figure 50: Transformers loading [%] for the Scenario 1, Malaga case study

- **DSO flexibility needs calculation (Step 2):** In this step, the DSO calculates its flexibility needs related to the congested transformers 170 and 171. Table 30 summarizes the flexibility needs in terms of MW for each of the eight criticalities, which add up to 0.449 MW for 24 hours.

Table 30: DSO flexibility needs for Scenario 1 – Malaga case study

Trafo ID	Hour	Loading [%]	Flexibility need [%]	Upward Flexibility need [MW]
170	19	104.358	4.358	0.026088
170	20	113.582	13.582	0.081292
170	21	114.849	14.849	0.088876
170	22	105.132	5.132	0.030716
171	19	104.174	4.174	0.024987
171	20	113.385	13.385	0.080115
171	21	114.651	14.651	0.087688
171	22	104.946	4.946	0.029606

- **Sensitivity factors calculation (Step 3):** Table 31 presents the sensitivity factors (PTDF) computed for each FSP of the demo relative to the DSO flexibility needs of step 2. Since FSPs 1 and 2 are connected downstream of the transformers 170 and 171, they have a direct impact on solving these congested transformers.

Table 31: Sensitivity Factors for Scenario 1 – Malaga case study

FSP ID	Sensitivity factors Trafo 170	Sensitivity factors Trafo 171
Fsp1	1	0
Fsp2	0	1
Fsp3-Fsp5	0	0

- **Local flexibility market-clearing (Step 4) and post-evaluation (Step 5):** Step 4 runs a day-ahead local flexibility market-clearing to solve the criticalities identified in step 2 using the most efficient flexibility bids from FSPs 1 and 2. This step and the post-evaluation analysis (step 5) are executed according to the sensitivities of Table 32, and the results are reported in the following subsection. Furthermore, it is relevant to mention that for the Spanish case studies, a cost of 7880 (EUR/MWh) for the $VOLL$ parameter is considered according to the report in (ACER/ CEPA, 2018).

Table 32: Sensitivities to the SRA parameters for scalability - Scenarios 1 and 2 Malaga

Parameter	Parameter description	Considerations	Sensitivity range
$\boldsymbol{P_{f,h}^{Umin}}, \boldsymbol{P_{f,h}^{Umax}}$	Maximum and minimum available flexibility of FSP f in period h. (MW)	Sensitivities are applied only to upward flexibility bids from FSPs because the DSO request is related to upward flexibility	Scenarios 1 and 2: $[0 \;\; 0.5 \;\; \cdots \;\; 9.5 \;\; 10]$
$\boldsymbol{C_{f,h}^{U}}$	Bid cost of the FSP f in the local market in period h. (€/MWh)		Scenarios 1 and 2: $[0 \;\; 0.5 \;\; \cdots \;\; 4.5 \;\; 5]$

4.3.5.1. Malaga SRA Results Scenario 1

This section aims to analyse the SRA results for Scenario 1 of the Malaga case study based on the KPIs defined in Table 19 of Section 4.1. In the first place, Figure 51 depicts the scalability performance on the KPI-13 Criticalities Reduction Index (CRI), where the sensitivities in the x and y axes of the graph are those defined in Table 32. From this figure, we can note that 2 of the 8 criticalities are solved when the sensitivities are equal to one, which means that only 25% of criticalities are solved by procuring flexibility through a local market and considering the base case. However, when the flexibility capacity of the FSPs is greater than 8.5, the CRI increases at a higher rate up to 75%. Furthermore, we can observe that even procuring all available flexibility from the FSPs (FSP size = 10), the 8 criticalities identified in this scenario are not entirely solved. As expected, in this case, the not-supplied flexibility is 0.0963 MW, see Figure 52.

In addition, Figure 53 shows the SRA on the flexibility activation cost (left side) and the total objective function cost (right side) of the local flexibility market clearing. These results are in conformity with the outcomes obtained for the CRI and not-supplied flexibility since the flexibility activation cost continues to rise as more flexibility is being purchased in the local market to solve the criticalities. On the other hand, the total cost decreases because by increasing the FSP size, we have less not-supplied flexibility.

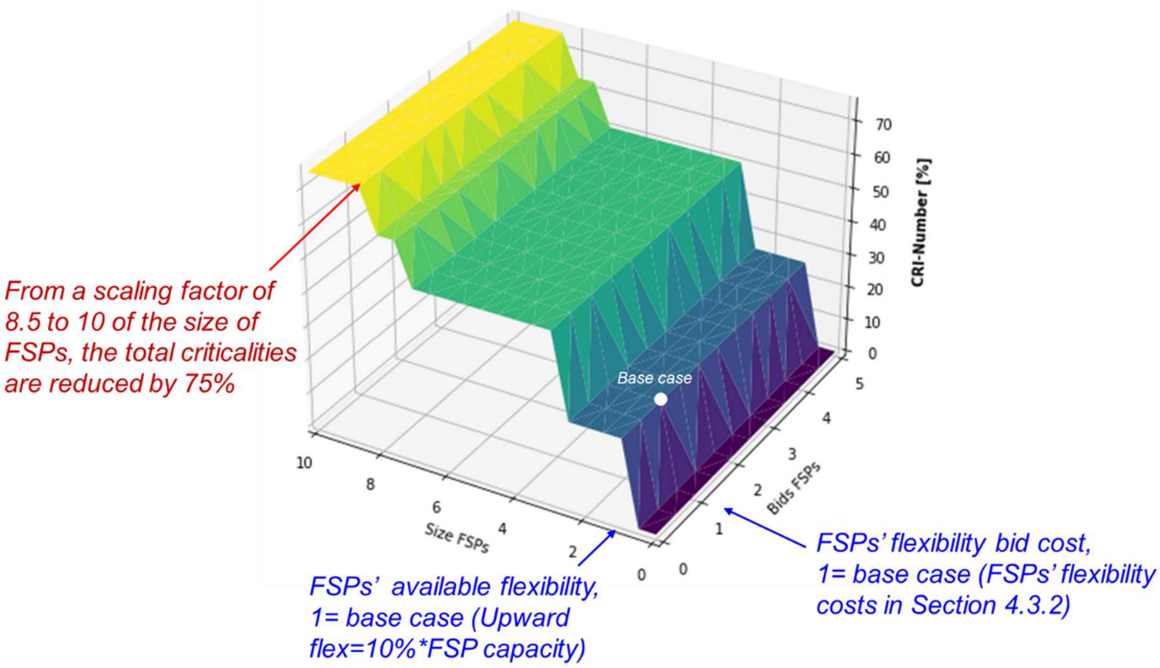

Figure 51: Sensitivity analysis on the KPI 13: Criticalities Reduction Index, Scenario 1 Malaga demo

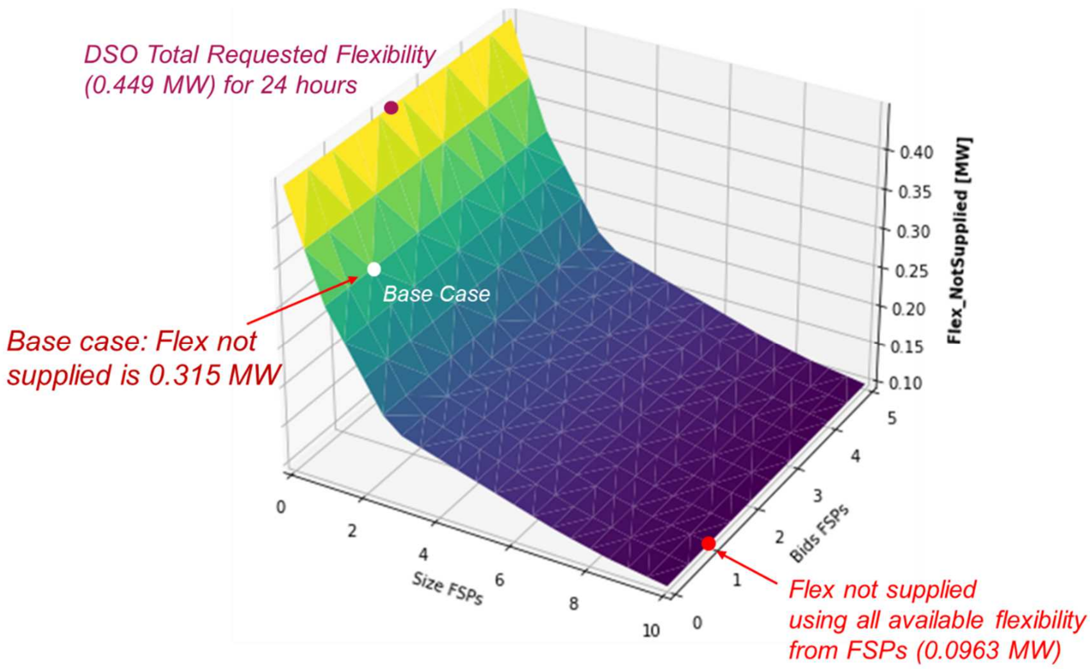

Figure 52: Sensitivity analysis on the not-supplied flexibility, Scenario 1 Malaga demo

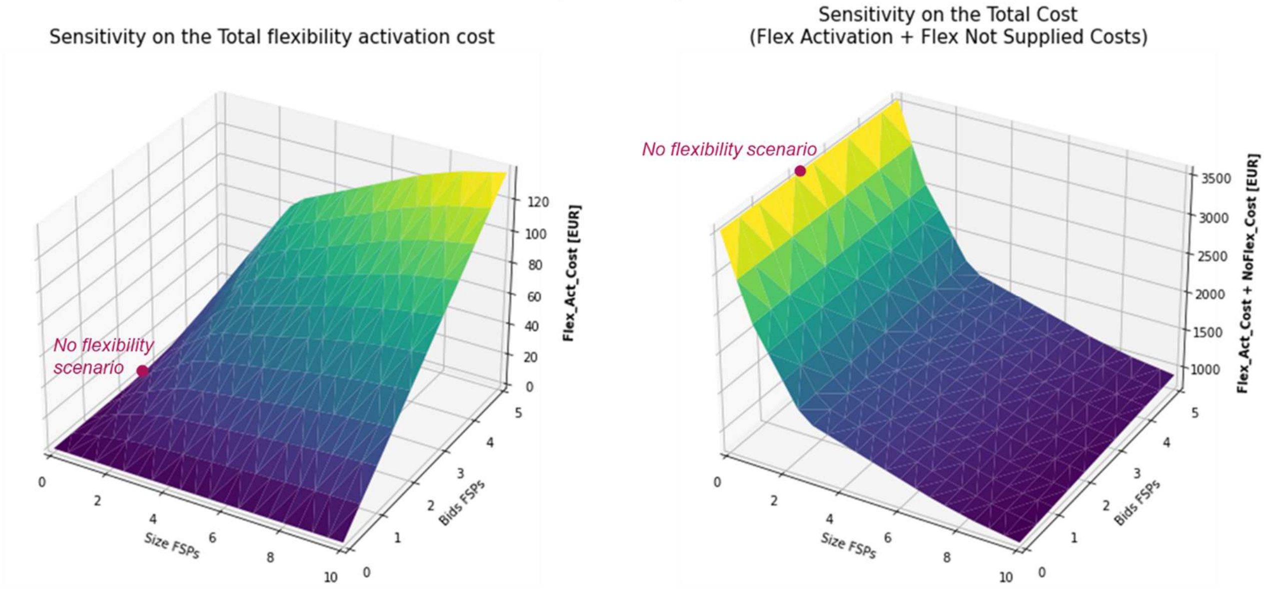

Figure 53: Sensitivity analysis on the Flexibility Cost, Scenario 1 Malaga demo

4.3.6. SRA for Malaga Scenario 2

This section examines the results of the SRA scenario 2 for the Malaga demo site. This scenario is based on the representative day of Scenario 0 and considers a reduction of the maximum thermal current (Imax) of lines 398 and 481. These lines were selected because they are part of feeders Palacio de las Ferias and Tabacalera/Pacifico, where most of the FSPs are connected. The initial Imax of these lines was 0.421 kA, and this value was reduced to 10% for the SRA. The choice of the 10% of Imax is because these lines are not congested for higher percentage factors. The outcomes of the SRA are further described below.

- **Power flow analysis (Step 1):** Considering the Scenario 2 conditions, a power flow analysis is run for 24 hours to detect eventual congestions. The outcomes of this step are depicted in Figure 54, where we can observe that the line 398 is congested at hours 9-12, and the line 481 is overloaded at hours 20 and 21. Furthermore, it is important to highlight that the thermal limits of the transformers were not violated under Scenario 2 conditions.

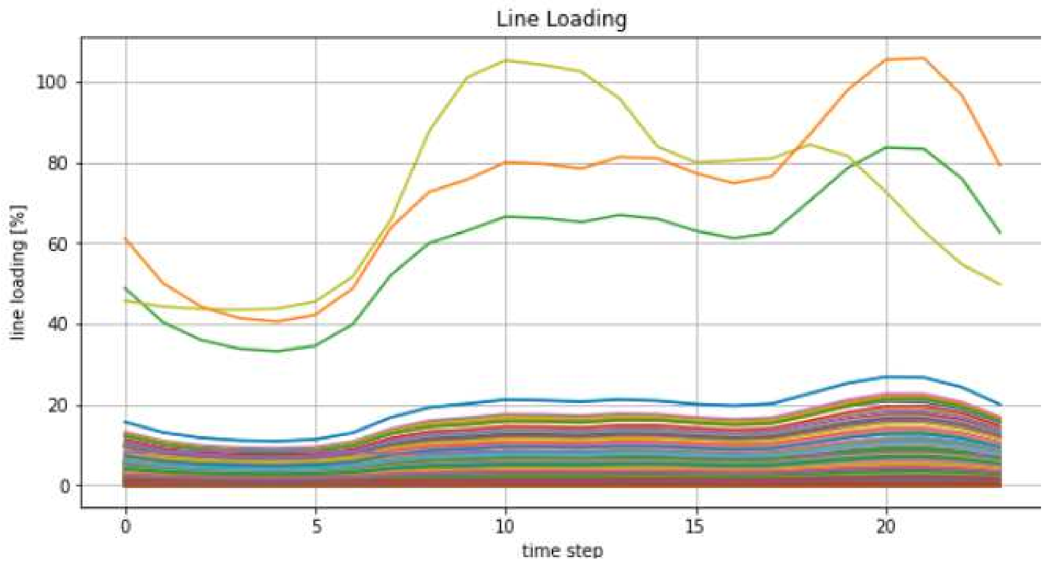

Figure 54: Line loading [%] for the Scenario 2, Malaga case study

- **DSO flexibility needs calculation (Step 2):** Table 33 presents the flexibility needs in terms of MW for the two congested lines, in total we have six criticalities to be solved with a flexibility need of 0.338089 MW for 24 hours.

Table 33: DSO flexibility needs for Scenario 2 - Malaga case study

Trafo ID	Hour	Loading [%]	Flexibility need [%]	Upward Flexibility need [MW]
398	9	101.060	1.060	0.012489
398	10	105.231	5.231	0.061598
398	11	104.103	4.103	0.048323
398	12	102.444	2.444	0.028777
481	20	105.429	5.429	0.090260
481	21	105.813	5.813	0.096642

- **Sensitivity factors calculation (Step 3):** Table 34 summarizes the sensitivity factors (PTDF) computed for each FSP of the demo relative to the DSO flexibility needs of step 2. The sensitivity factors between the FSPs 1-4 and line 481 are less than 1, which indicates that the Tabacalera and Pacifico feeders are connected in a meshed network. On the other hand, the FSP 5 directly impacts line 398 because it is connected downstream of this line.

Table 34: Sensitivity Factors for Scenario 2 - Malaga case study

FSP ID	Sensitivity factors Line 398 – Palacio de las Ferias	Sensitivity factors Line 481 – Tabacalera/Pacifico
Fsp1	0	0.906772
Fsp2	0	0.906772
Fsp3	0	0.315565
Fsp4	0	0.778991
Fsp5	1	0

- **Local flexibility market clearing (Step 4) and post-evaluation (Step 5):** The local flexibility market clearing (step 4) and the post-evaluation analysis (step 5) of Scenario 2 are executed according to the same sensitivities of Malaga Scenario 1, see Table 32. Furthermore, a cost of 7880 (EUR/MWh) for the $VOLL$ parameter is considered in this scenario. The SRA outcomes of this scenario are further described in the following section.

4.3.6.1. Malaga SRA Results Scenario 2

This section evaluates the SRA results for the Malaga case study under the conditions of Scenario 2. This analysis begins by examining the scalability performance on the KPI-13 Criticalities Reduction Index (Figure 55), where the sensitivities in the x (FSP size) and y (FSP bid cost) axes of the graph are those defined in Table 32. From this figure, we can observe that 36.8% of the criticalities are solved when the sensitivities are equal to one (base case). However, if the capacity of the FSPs is increased by a factor of 7 the CRI reaches up to 96.24%, and this value remains constant from an FSP size factor of 7 to 10. A further important implication is that the amount of flexibility procured in the local market to solve 96.34% of the criticalities (0.39304 MW) is higher than the amount of flexibility requested by the DSO (0.338089 MW), this is because the sensitivity factors are less than one for this scenario, see Figure 56. Moreover, the results of the Figure

57 support the previous outcomes since the Flexibility activation cost and the Total cost of the market clearing are not sensitive to the size of the FSPs from a factor of 7.

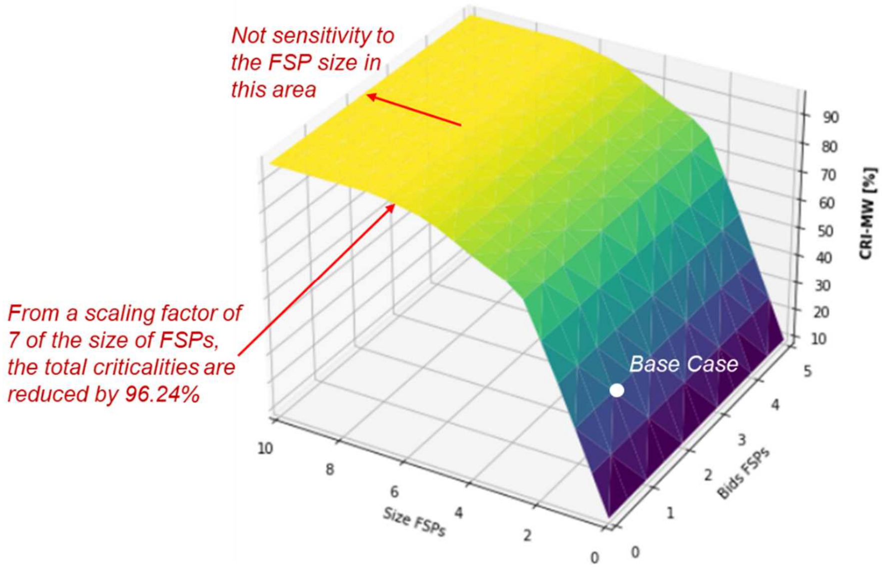

Figure 55: Sensitivity analysis on the KPI 13: Criticalities Reduction Index, Scenario 2 Malaga demo

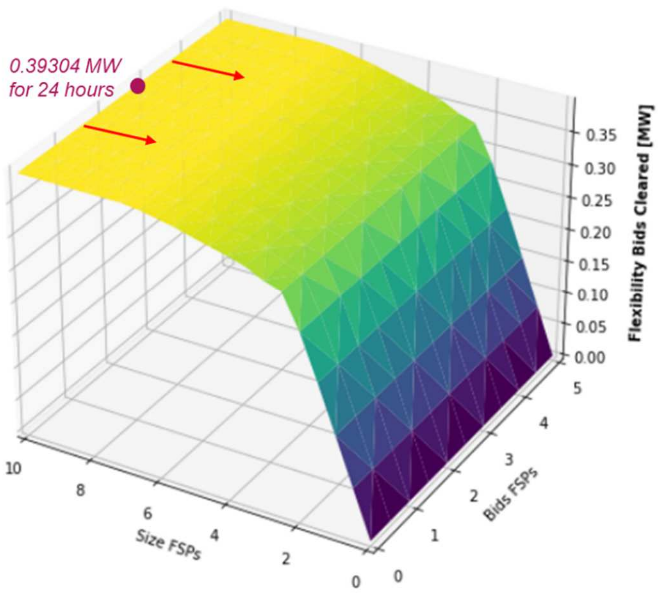

Figure 56: Sensitivity on KPI 18: Total Volume of Transactions in the Market, Scenario 2 Malaga demo

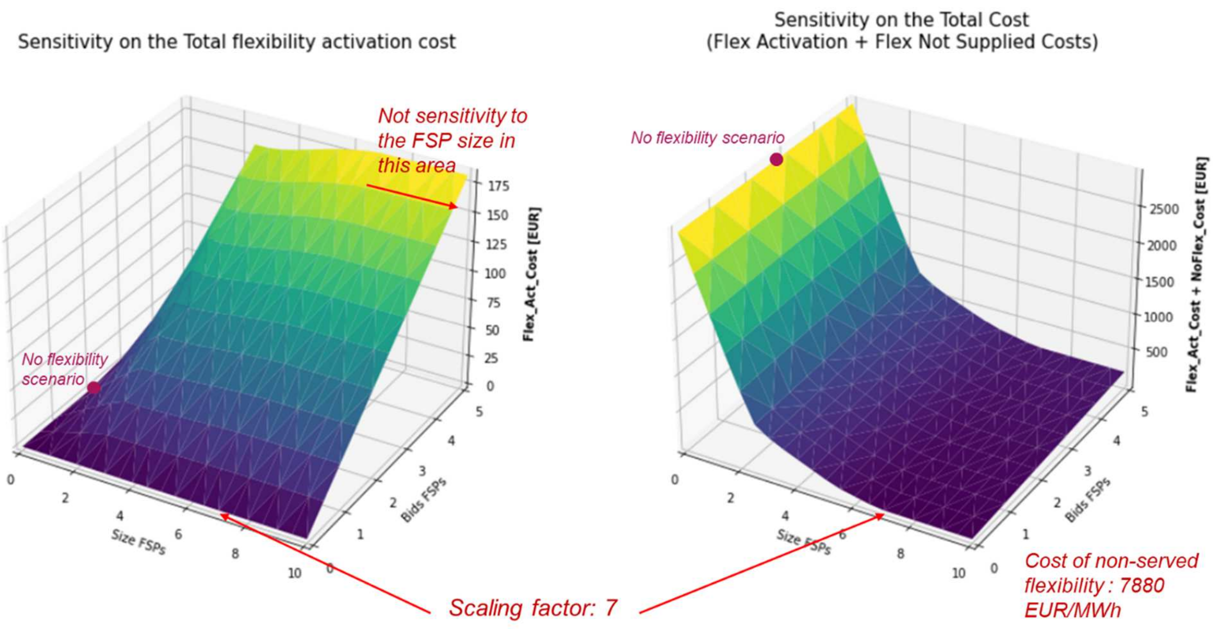

Figure 57: Sensitivity analysis on the Flexibility Cost, Scenario 2 Malaga demo

4.3.7. Murcia Network characteristics and Load and Generation profiles

As stated in Sections 4.2.1 and 4.3.1, the Greek and Malaga MV networks were formed using the anonymized grids provided by the DSOs. However, for the Murcia demo site, a synthetic grid is built with similar characteristics to the real one. In this sense, the Reference Network Model (RNM) was used to build an MV network for the urban area of Murcia city. The RNM is a large-scale planning tool that plans the electrical distribution network using GPS coordinates and power of every customer and DER (Institute for Research in Technology, 2022). This tool has been used for different applications and research studies, such as DiNeMo (Joint Research Centre, 2022), which is an online platform that allows the development of distribution network models based on RNM.

Figure 58 illustrates the approach of the RNM greenfield version, which builds the network from scratch using a street map image as input to the model. After that, the RNM automatically selects the consumers' location and builds the synthetic network using general statistical information from consumers and a standard library of network components. Once the synthetic network has been obtained, structural network indicators are calculated and compared with the indicators of the actual network provided by DSOs.

The resulting MV synthetic network is depicted in Figure 59, and this network starts from the 400/132 kV transformer T0, which serves two 132/20 kV Transformers T301 and T302, from which different 20 kV feeders are derived. Furthermore, it is relevant to highlight that only one FSP is considered to participate in the local congestion management BUC of Murcia. This FSP is also indicated in Figure 59.

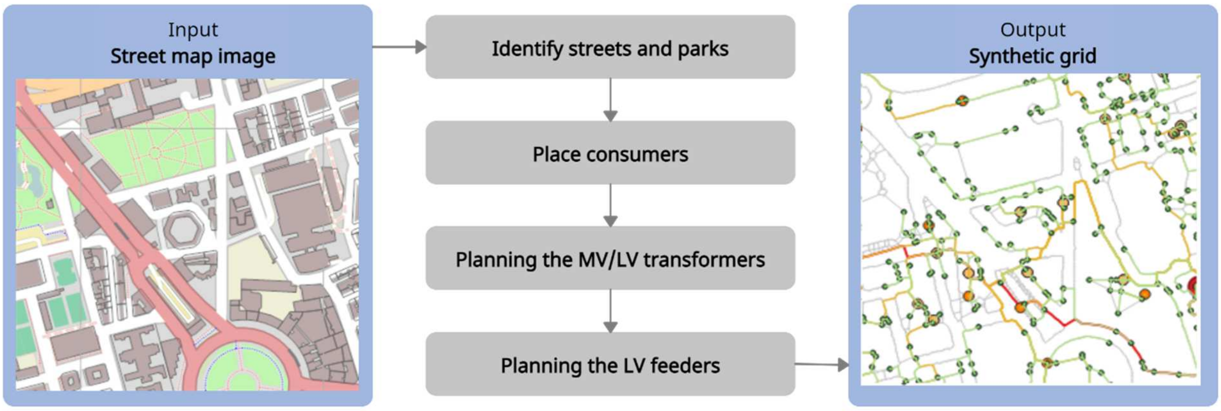

Figure 58: RNM approach for the distribution grid modelling (greenfield version)

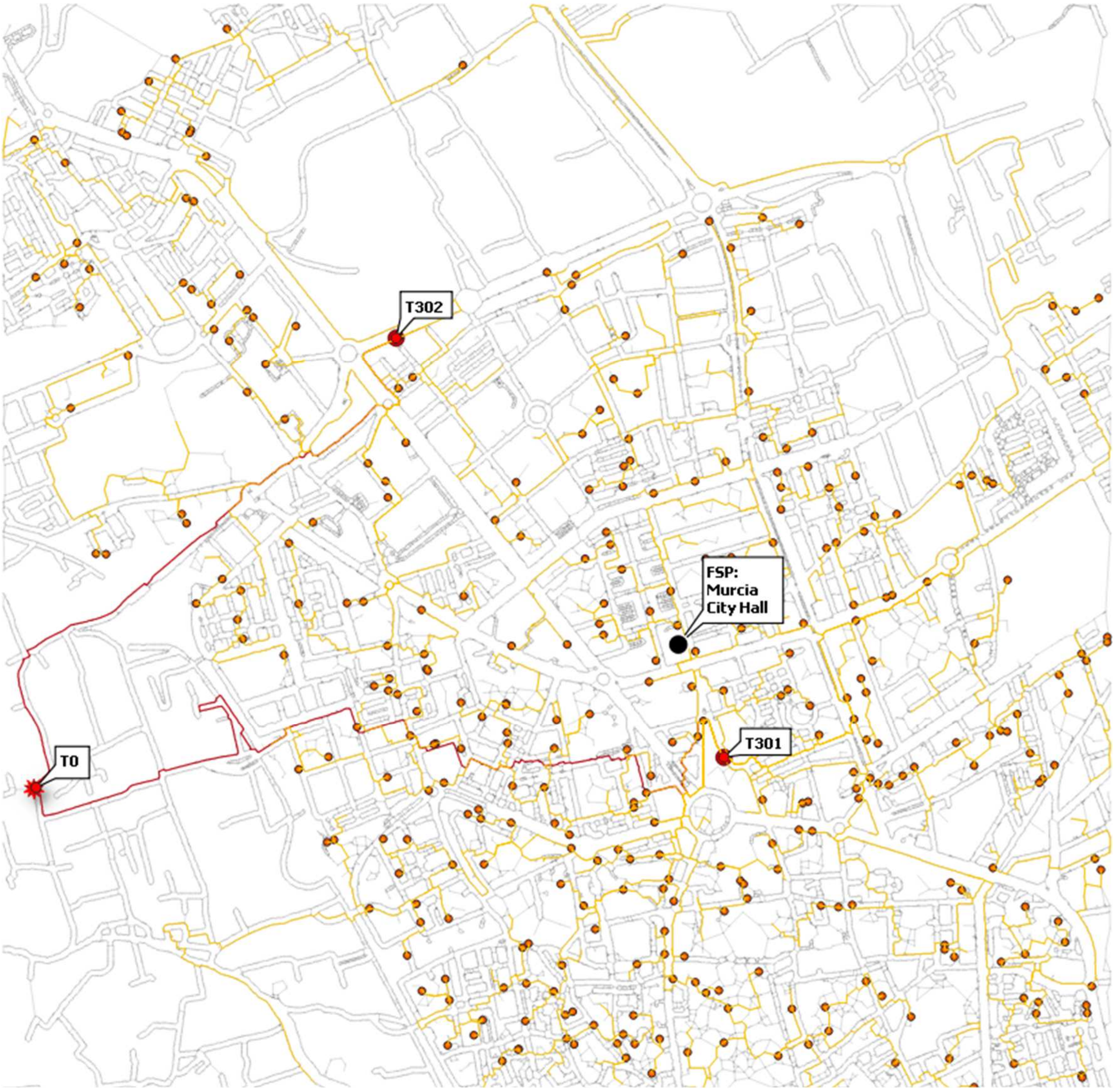

Figure 59: Murcia MV synthetic network, HV lines: red colour, MV lines: yellow colour

To obtain the load and generation profiles for the Murcia demo site, the same procedure described in Section 4.3.1 is followed to compute the Malaga profiles. Therefore, we use the information related to the Murcia network data and the yearly profiles for the load and PV available in (RED Eléctrica España, 2022) and

(Pfenninger and Staffell, 2016), respectively. Then two representative days were selected corresponding to the maximum and the minimum net load of the network, and Load profiles (Figure 60) and PV profiles (Figure 61) were calculated. In the last step, four different load profiles were computed according to the power capacity of the consumers, see Figure 60. As stated before, the profiles related to the maximum representative day are considered for the SRA since this workstream is focused on the analysis of congestion management for lines and transformers.

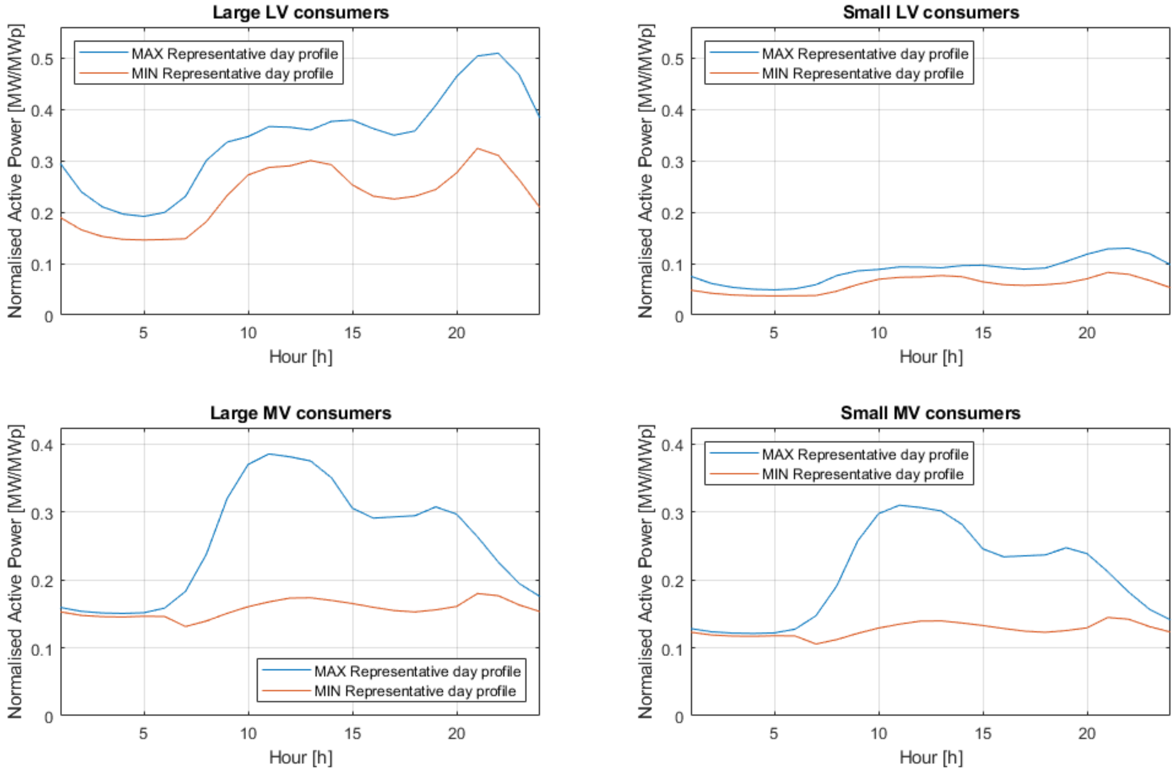

Figure 60: Load profiles for the Murcia demo site - Workstream 2

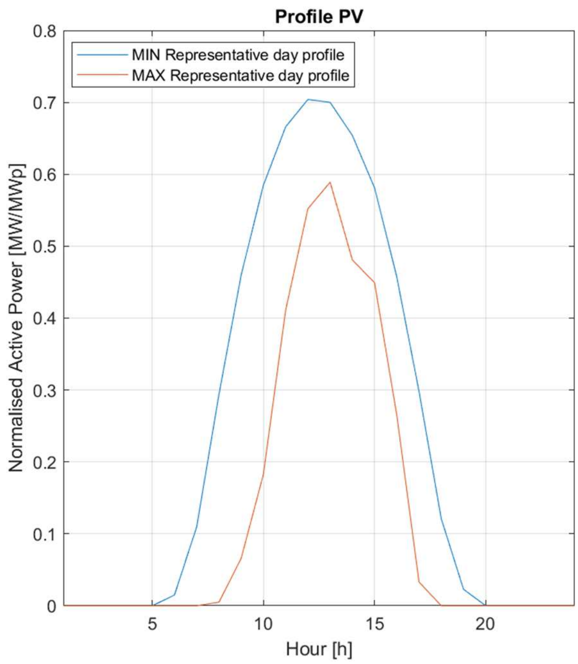

Figure 61: PV profiles for the Murcia demo site - Workstream 2

4.3.8. Murcia FSPs characteristics

Table 35 details the information related to the only FSP considered in the Malaga demo for local congestion management. The flexibility cost and capacity data were obtained from CoordiNet D3.6 (Ivanova, A. et al., 2022), and the remainder data was derived from the project. The location of this FSP is illustrated in Figure 59.

Table 35: FSPs characteristics for the Murcia case study

FSP ID	Feeder ID	Node ID	FSP type	FSP Capacity [MW]	Down. Flex Cap. [%]	Upward Flex Cap. [%]	Downward Flex Cost [EUR/MWh]	Upward Flex Cost [EUR/MWh]
Fsp1: Murcia City Hall	T301	6574 and 6582	Consumption	0.76	0	83.3	-	25

4.3.9. Murcia SRA scenarios

Table 36 presents the description, SRA parameters, and the KPIs to be calculated for the two scenarios tested for the SRA workstream 2 in the Murcia demo. Scenario 0 studies the Murcia distribution network under the conditions of the maximum representative day (peak net load), which was described in Section 4.3.7. Moreover, Scenario 1 examines the congestion problems under the same representative day as Scenario 0, but the load of all feeders is increased by a factor of 2.13. It is important to highlight that there are no congestion events if we multiply the load by a factor less than 2.13. The SRA methodology defined in Subchapter 4.1 is applied for the two scenarios, and the results are further analysed in the following subsections.

Table 36: SRA scenarios for the Murcia case study

Scenario ID	Description	SRA parameters	KPIs calculated
Scenario 0	**Analysis considering maximum net load representative day profiles**	**No congestion events**	
Scenario 1	Scenario 0 + ***Increasing the load by a factor of 2.13 in all feeders.***	**FSPs size** **FSPs bid cost**	KPI 6: Total flexibility activation cost KPI 13: Criticalities reduction index KPI 16: Potential offered flexibility KPI 18: Volume of transactions in LFM KPI 19: Number of transactions in LFM KPI 22: Requested flexibility

4.3.10. Murcia Scenario 0

This section details the outcomes of the SRA methodology applied to Scenario 0 of the Murcia demo:

- **Power flow analysis (Step 1):** In this step, a power flow analysis is performed for 24 hours to detect eventual congestion issues. Therefore, the distribution network parameters and load and generation profiles (maximum representative day) described in section 4.3.7 are considered as input information. Regarding the results of step 1, Figure 62 and Figure 63 show the loading percentage for lines and transformers, respectively. From these figures, we can observe that there are no thermal limit violations for these elements under the conditions of Scenario 0. Therefore, the congestion problems are examined under the conditions of scenario 1 through the next subsections of the Murcia case study.

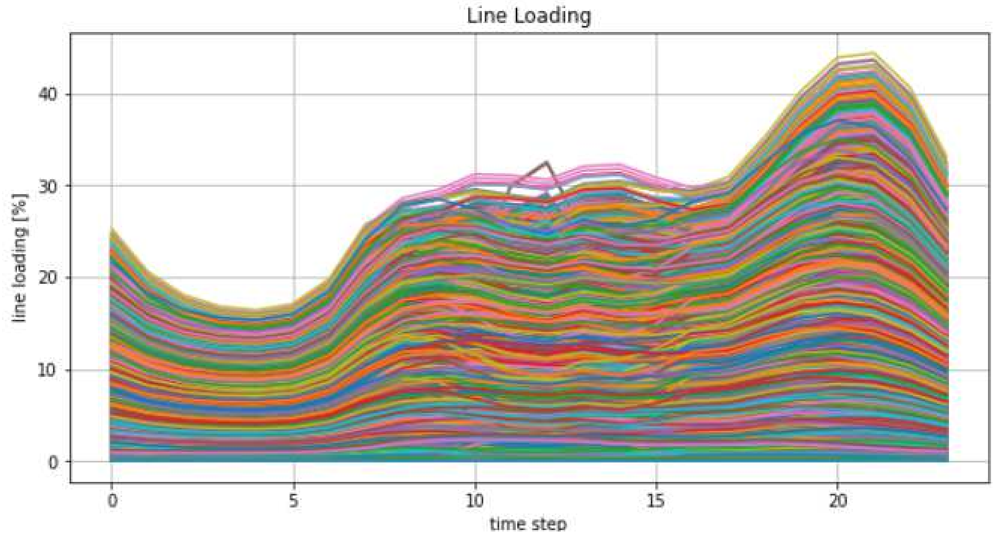

Figure 62: Line loading [%] for the Scenario 0, Murcia case study

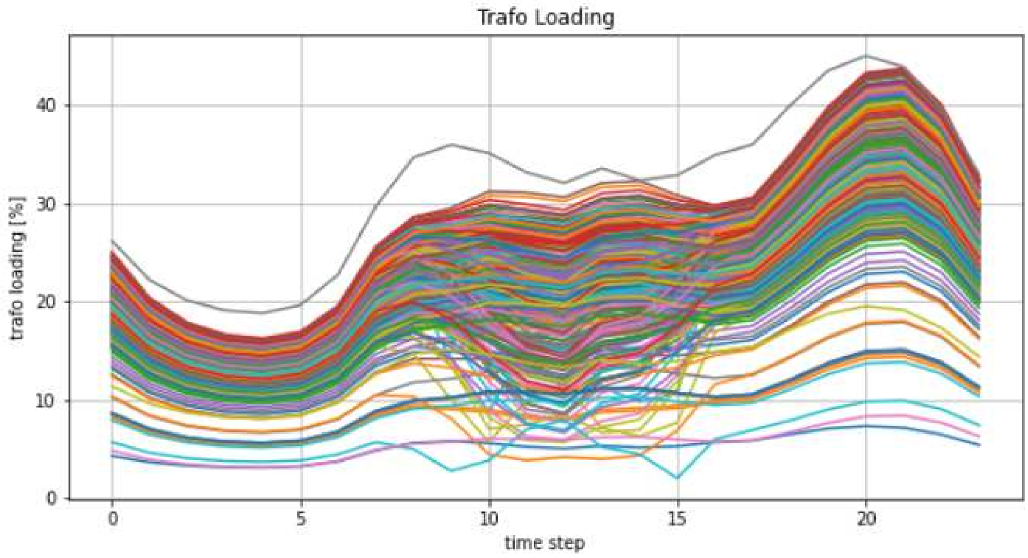

Figure 63: Transformers loading [%] for the Scenario 0, Murcia case study

4.3.11. SRA for Murcia Scenario 1

This section analyses the SRA results for Scenario 1 of the Murcia demo. This scenario is based on the same representative day of Scenario 0, but the load of all feeders is increased by a factor of 2.13 according to the scenario definition. As stated before in section 4.3.9, there are no congestions events if we multiply the load by a factor less than 2.13. Of course, if this factor is greater than 2.13 the number of criticalities identified will be greater, but this case is not analysed since the demo has only one FSP. The outcomes of the SRA are further described below.

- **Power flow analysis (Step 1):** First, a power flow analysis is run for 24 hours to detect eventual congestions considering the new profiles of Scenario 1, and Figure 64 shows the new loading percentage for the transformers. From these results, we identified that one of the two 132/20 kV Transformers (T301) is congested at hour 20. Furthermore, it is relevant to mention that the thermal limits of the lines were not violated under this scenario.

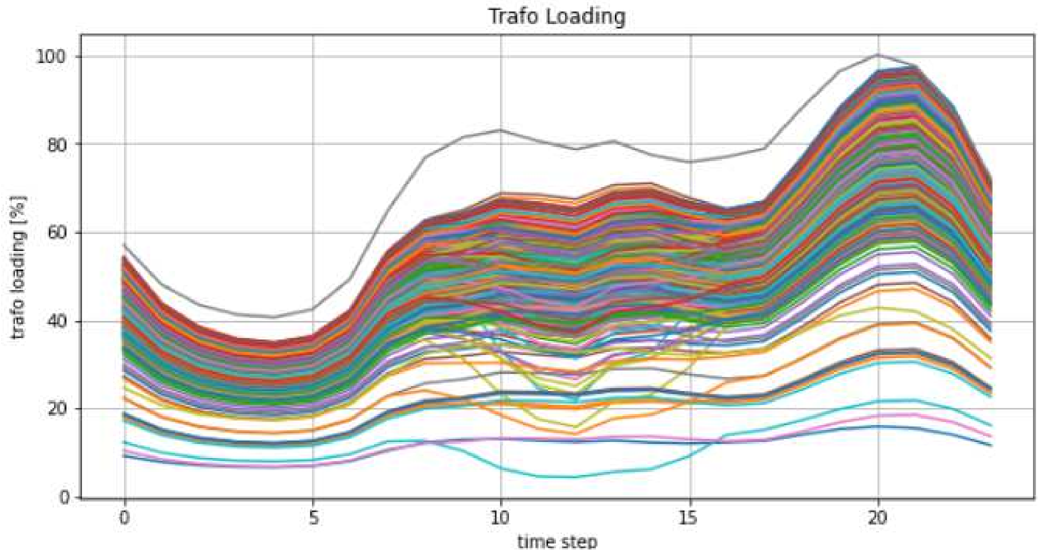

Figure 64: Transformers loading [%] for the Scenario 1, Murcia case study

- **DSO flexibility needs calculation (Step 2):** Table 37 details the loading percentage of the transformer T301 and its flexibility need in terms of MW (0.219883 MW).

Table 37: DSO flexibility needs for Scenario 1 – Murcia case study

Trafo ID	Hour	Loading [%]	Flexibility need [%]	Upward Flexibility need [MW]
301	20	100.1913	0.1913	0.219883

- **Sensitivity factors calculation (Step 3):** Since the FSP (Malaga city Hall) is connected downstream of the T301. It has a sensitivity factor equal to 1 concerning the congested transformer, see Table 38.

Table 38: Sensitivity Factors for Scenario 1 – Murcia case study

FSP ID	Sensitivity factor Trafo 301
Fsp1	1

- **Local flexibility market-clearing (Step 4) and post-evaluation (Step 5):** The local flexibility market clearing (step 4) and the post-evaluation analysis (step 5) are executed according to the sensitivities of Table 39, and the results are reported in the following subsection. Furthermore, a cost of 7880 (EUR/MWh) is considered for the $VOLL$ parameter, which is reported in (ACER/ CEPA, 2018) for Spain, which was also used in the SRA for the Malaga demo site.

Table 39: Sensitivities to the SRA parameters for scalability – Scenarios 1 Murcia case study

Parameter	Parameter description	Considerations	Sensitivity range
$P_{f,h}^{Umin}$, $P_{f,h}^{Umax}$	Maximum and minimum available flexibility of FSP f in period h. (MW)	Sensitivities are applied only to upward flexibility bids from FSPs because the DSO request is related to upward flexibility	Scenario 1: $[0 \;\; 0.2 \;\; \cdots \;\; 9.8 \;\; 10]$
$C_{f,h}^{U}$	Bid cost of the FSP f in the local market in period h. (€/MWh)		Scenario 1: $[0 \;\; 0.2 \;\; \cdots \;\; 4.8 \;\; 5]$

4.3.11.1. Murcia SRA Results Scenario 1

This section evaluates the SRA results for the Murcia Scenario 1 considering the scenario definition in Table 36 and the sensitivities of Table 39. The KPI-13 Criticalities Reduction Index (CRI) is analysed first, and Figure 65 shows its performance in terms of the scalability of the size of the FSP and the flexibility cost. It is interesting to note that by multiplying the FSP size by a factor of 0.4, the congestion in the transformer T301 is completely solved, which means that procuring 40% of the flexible capacity of the Murcia City Hall solves all criticalities for this scenario. Figure 66 confirms previous findings since the amount of DSO requested flexibility is zero after procuring 40% of the flexible capacity of the FSP.

Furthermore, the scalability performance is examined under the flexibility activation cost and the total cost of the local market-clearing (sum of the cost of flexibility activation plus the cost of the expected not-supplied flexibility) using the same sensitivities of the previous KPIs. As illustrated in Figure 67, both cost terms are not sensitive to the size of the FSPs from a factor of 0.4, which corroborates preceding findings for Scenario 1.

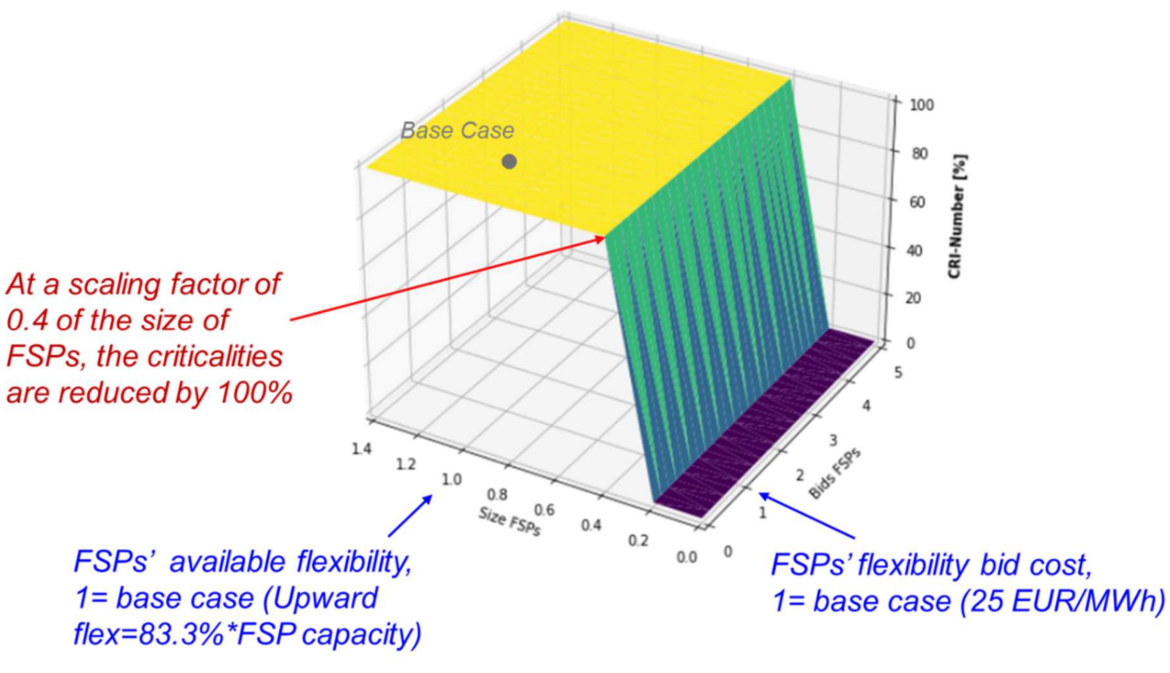

Figure 65: Sensitivity analysis on the KPI 13: Criticalities Reduction Index, Scenario 1 Malaga demo

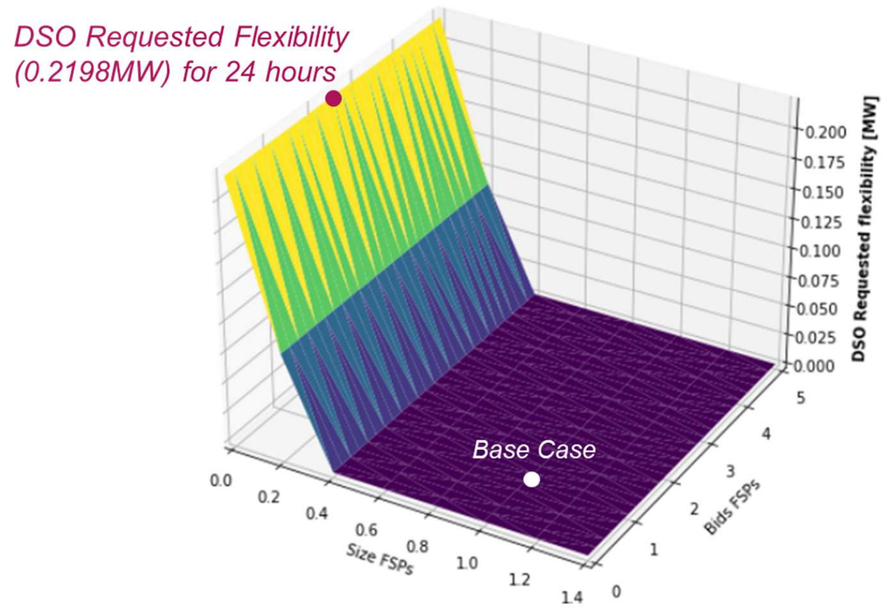

Figure 66: Sensitivity analysis on the KPI22, Scenario 1 Malaga demo

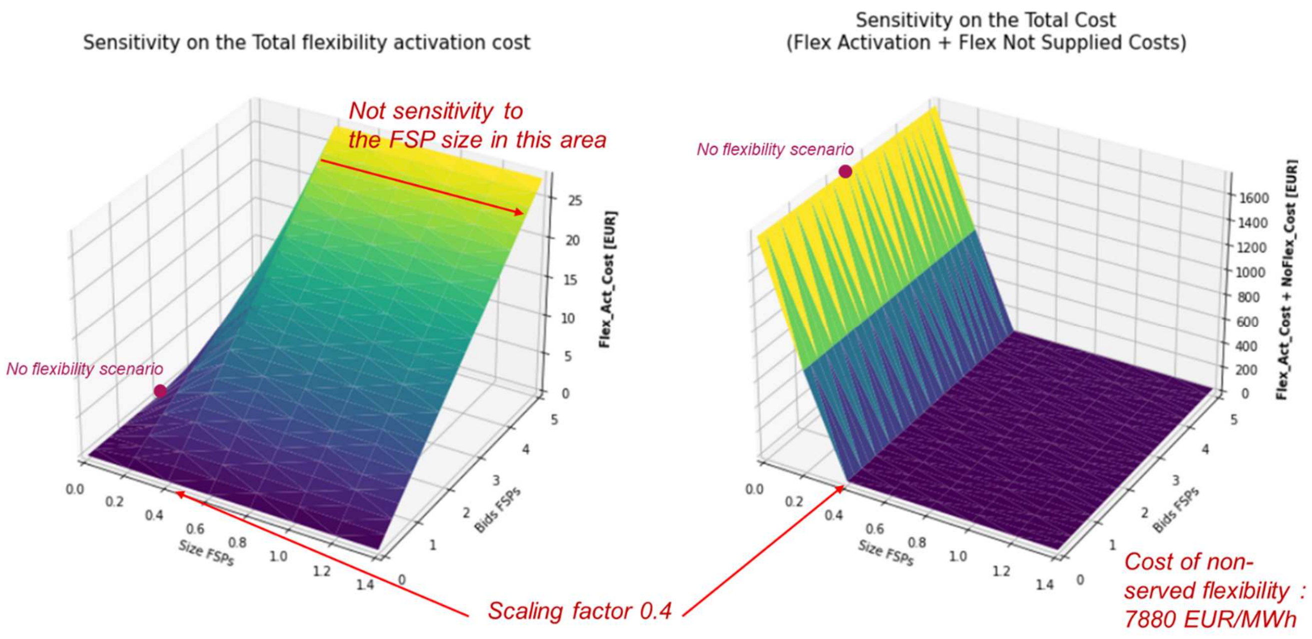

Figure 67: Sensitivity analysis on the Flexibility Cost, Scenario 1 Malaga demo

4.3.12. Interim Conclusions

From the SRA results of the Spanish case study, it can be concluded that:

- Concerning the results of the Malaga demo, we have confirmed that there are no thermal limit violations for the lines and transformers under the conditions of the selected representative day (maximum net load). However, when the load is increased by a factor of 3 in scenario 1, it results in two congested 20/0.4 kV transformers. From the SRA for this scenario, it is found that the eight criticalities identified were not entirely solved even after procuring all available flexibility from the FSPs. This suggests that the FSPs' engagement in the Malaga LV network is relevant for the congestion management of the secondary substations.

- Furthermore, since the resulting loading of the MV lines under scenarios 0 and 1 of the Malaga demo was less than 35%, scenario 2 (lines 398 and 481 maximum thermal current reduction) was proposed to test the SRA performance for congestion management in MV lines. Under this scenario, sensitivity factors with values less than one were obtained because the feeders Tabacalera and Pacifico are connected in a meshed network. This implied that the amount of flexibility procured in the local market was higher than the total DSO flexibility request. Therefore, for installing new FSPs, the FSP's location is a relevant parameter to be selected based on the expected congested lines.

- On the other hand, the SRA results of the Murcia demo site have highlighted that by procuring 40% of the flexible capacity of the Murcia City Hall, the total criticalities are solved for scenario 1 (an increase of demand by a factor of 2.13). However, if we increase the total demand by a higher value, the number of criticalities will rise in different network locations. Therefore, more flexibility is needed since the demo currently has only one FSP participating in local congestion management.

- Finally, the previous points have shown that more flexibility is needed to solve congestion events for future scenarios in the Malaga and Murcia demo sites. Therefore, other flexibility options could be considered, for example, DSOs can use their own flexible resources such as network reconfiguration, control of the OLTC, etc. These flexibility resources from the DSO could interact with the local market to resolve congestion events more effectively.

5. Quantitative SRA - Workstream 3: Market-based procurement of voltage control services with different TSO-DSO coordination schemes

The main purpose of this chapter is to describe the SRA methodology and analyze the SRA results for the modelling workstream 3, which comprises the following BUCs, GR-1a, GR-1b, ES-3. This modelling workstream focuses on the SRA for voltage control in transmission and distribution grids by procuring reactive power support from flexibility service providers. Different coordination schemes are adopted for procuring the necessary voltage support from the resources.

To assess the SRA performances concerning GR-1a and GR-1b the Kefalonia demo site, the MV distribution network of Argostoli, and the relevant portion of the Greek transmission system are considered. In GR-1a and GR-1b both steady state active and reactive power products are used to provide voltage support. In SRA workstream 3 described in this section, only the reactive power product is considered. The SRA performances concerning ES-3 are evaluated considering the Murcia and Cadiz demo sites. An overview of workstream 3 is presented in Table 40.

The remainder of this chapter is organized into three main sections. First, Subchapter 5.1 describes the SRA methodology for this workstream. Subsequently, Subchapters 5.2 and 5.3 apply this methodology and analyse the SRA results for the Greek case study (Kefalonia Area) and the Spanish case study (Cadiz and Murcia), respectively.

Table 40: Workstream 3 Overview

Workstream 3 Specifications			
BUCs	GR-1a	GR-1b	ES-3
Coordination scheme	Multi-level	Fragmented	Common
Countries, demo sites for the SRA	• Argostoli MV distribution network of Kefalonia. • Transmission network of Kefalonia Area	• Argostoli MV distribution network of Kefalonia. • Transmission network of Kefalonia Area	• Murcia MV and LV distribution networks. • Cadiz transmission and distribution networks
Modelling approach	Q-linearized local market	Q-linearized local market	Q-linearized local market

5.1. Modelling approach

5.1.1. Overview of the SRA methodology applied in workstream 3

Figure 68 summarizes the proposed SRA methodology for workstream 3. This methodology is divided into three main blocks, the SRA inputs (green colour) and the SRA outputs (grey colour) that will be introduced in this subchapter, and the BUC modelling and simulation approach (blue colour) will be further explained in the following subchapter.

Regarding the SRA inputs, some parameters that comprise the technical boundary conditions (network characteristics and technical constraints) of the BUCs are selected. For example, the parameters related to load profiles, DG size and penetration may affect the scalability of the BUC. In addition, the parameters associated with FSPs, such as their number, location, capacity and cost, may impact scaling-up and replication. Moreover, the SRA requires running extensive simulations using power flow studies and optimization problems. Therefore, different input data must be gathered for each demonstration location to perform these simulations. This data is mainly composed of network models, load and generation profiles, and FSPs' location, capability, and bidding cost.

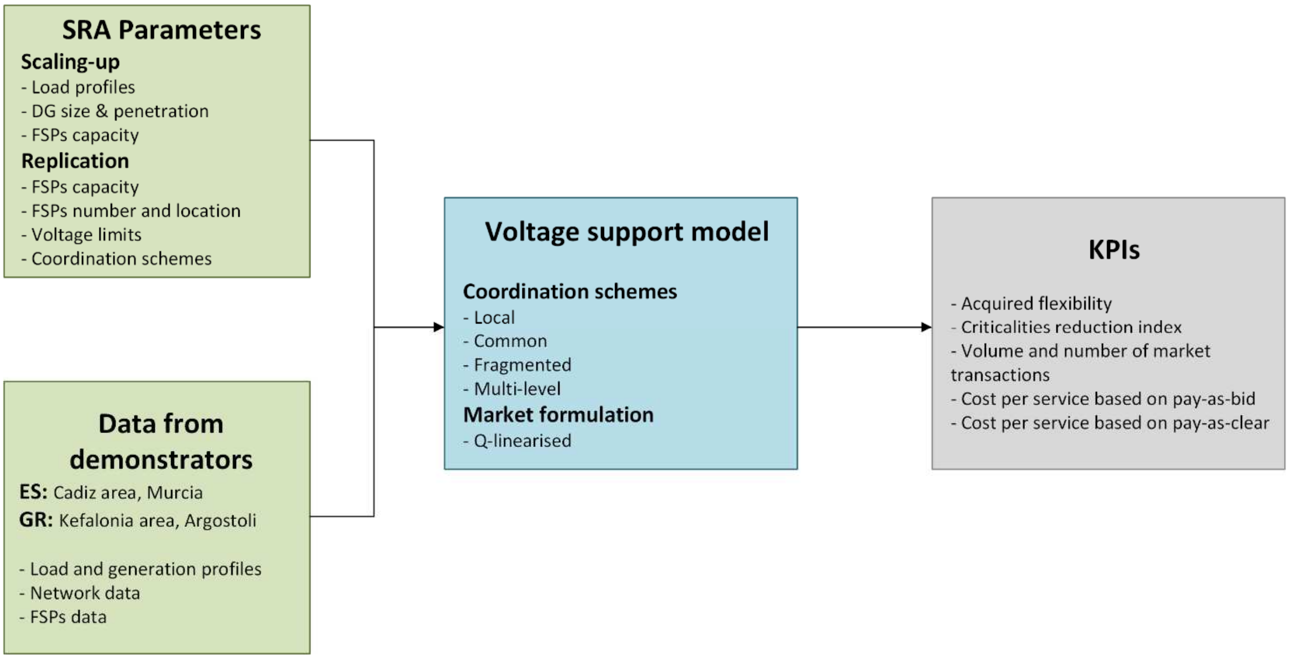

Figure 68: Overview of SRA Methodology for Workstream 3

Concerning the SRA outputs, these will be computed based on the KPIs identified and defined in the deliverable D1.6 of CoordiNet (Trakas, D., & Kleftakis, V., 2020). Table 41 shows the KPIs calculated in workstream 3, several indicators are adopted from deliverable D1.6, while other are proposed by the described workstream activities. The calculation of these KPIs allows quantitative evaluations and comparisons of the voltage support BUCs. Finally, it is important to highlight that the final SRA parameters, the data from the demonstrators, and KPIs for each case study will be detailed in Subchapters 5.2 and 5.3.

Table 41: Workstream 2 KPIs selected

SRA KPI Name	KPI Description	KPI Category	Related KPI ID in D1.6
Flexibility activation cost (pay as bid)	This indicator computes the flexibility activation cost for the total market horizon (24 hours). Value calculated using the pay as bid approach.	Economic	KPI 6
Flexibility activation cost (pay as clear)	This indicator computes the flexibility activation cost for the total market horizon (24 hours). Value calculated using the pay as clear approach.	Economic	KPI 6
Criticalities reduction index	This KPI measures the reduction of the number of criticalities on the network under consideration in terms of violation of voltage magnitude constraints	Technical	KPI 13
Acquired flexibility	Volume of reactive power acquired for the total market horizon (24 hours).	Technical	KPI 22

5.1.2. Voltage Support Management Model

Since the voltage support management modelling and simulation process is considered a key part of the methodology presented previously, Figure 69 shows further details of this process according to the below description.

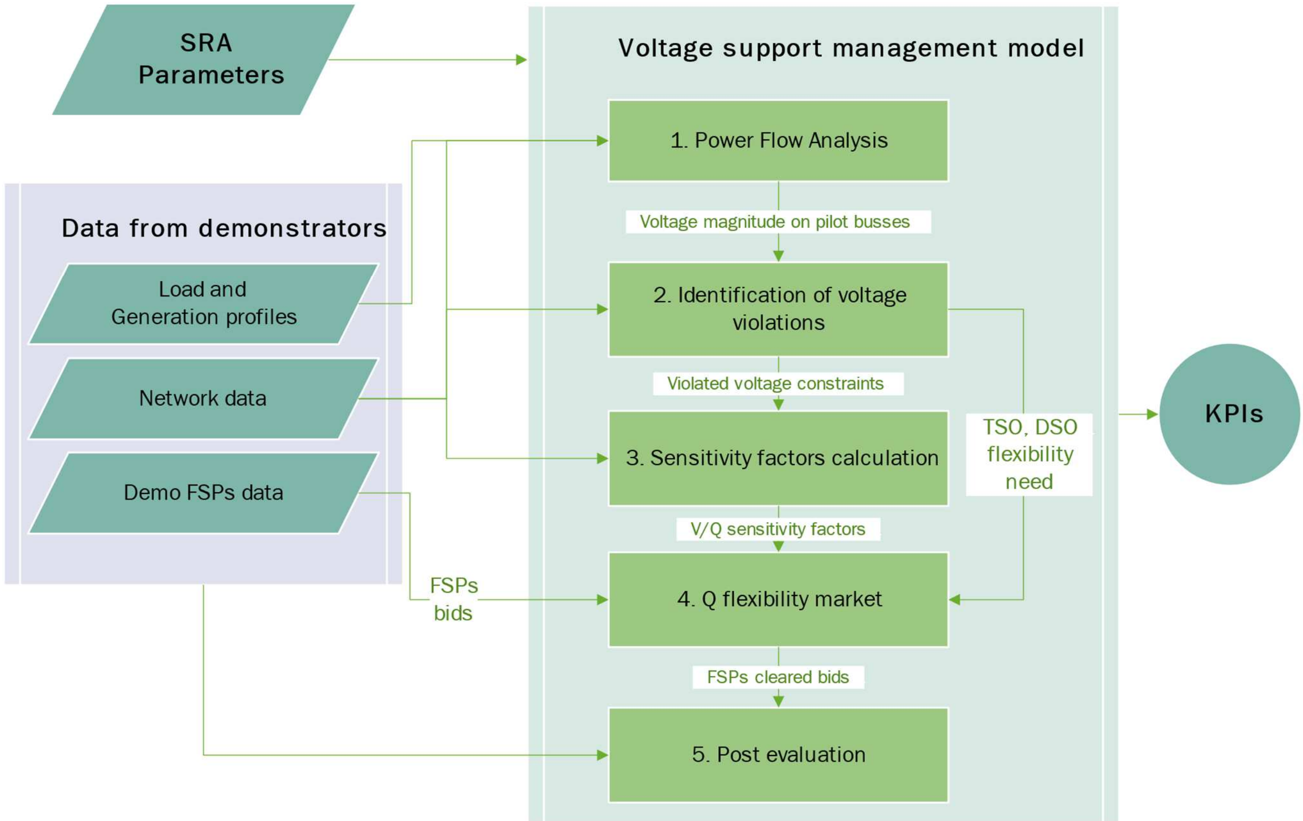

Figure 69: Voltage support management model for the Workstream 3

- **Power flow analysis (Step 1):** For workstream 3, the voltage support management BUC assumes that voltage violations (overvoltages and undervoltages on pilot busses) are forecasted in terms of location and quantity on a day-ahead basis. Therefore, the first step is to perform a power flow analysis for each time step to detect eventual constraint violations. To do this, the network data and load and generation profiles are utilized for the power flow analysis. Moreover, the Python and Matlab environments with the Pandapower tool (Thurner et al., 2018) were used to perform the power flow analysis.
- **Identification of voltage violations (Step 2):** In this second step, the TSO and/or the DSO calculate their flexibility needs related to voltage support based on the power flow results. A flexibility need is defined when a pilot bus shows a voltage magnitude outside the admissible range [V_{min}, V_{max}]. The system operation needs are represented by the voltage variation required for each pilot bus to restore the nominal voltage magnitude range. As inputs for the flexibility market-clearing (Step 4), these voltage values drive the procurement of the necessary reactive power support from FSPs.

- **Sensitivity factors calculation (Step 3):** As in Workstream 2, Workstream 3 considers a linearised network representation for the formulation of the market clearing algorithm. Within the workstream 3, the system operator calculates the sensitivity factor for each FSP relative to the flexibility need. They are computed depending on the locations of the FSP assets, their impact on solving grid constraints, and their potential bid limitations. To compute the sensitivity factors for voltage control, it is necessary to analyse the sensitivity of the voltage magnitude of each bus to the FSPs' reactive power exchange variations. This sensitivity is based on the inverse of the Jacobian matrix of the power flow equations according to the Newton Raphson method (Federico Milano, 2010; Naik et al., 2011; Rodríguez-Montañés et al., 2022). As shown in (5-1), the voltage variation in a i-th node

(ΔV_i) can be obtained by the sum of the contributions of the reactive power variations (ΔQ_j) in all N_{Bus} of the networks by means of the sensitivity coefficient $K_{i,j}$.

$$\Delta V_i = \sum_{j=1}^{N_{Bus}} K_{i,j} \Delta Q_j \tag{5-1}$$

The matrix $[K]$ of sensitivity coefficients is the IV quadrant of the inverse of the Jacobian matrix. The linearized power flow equations consider the interdependence between the reactive power and voltage magnitudes and assumes that no variation of active power injections and withdrawals occur.

- **Local flexibility market-clearing (Step 4):** In the flexibility market-clearing, the most efficient flexibility bids from FSPs are selected to mitigate the identified voltage violations at minimum cost. As highlighted in Figure 30, the inputs of the market-clearing are:
  - DSO flexibility needs for voltage control as computed in step 2.
  - Flexibility bids from FSPs: These bids are composed of their quantity, location, and price. The quantity offered by the FSPs correspond to the available reactive power margin considering the actual active power exchange and the nominal apparent power of the resources. The price for the flexibility activation is also included in the bid as the FSPs are considered as active traders deciding on their flexibility price. It is assumed that the price for flexibility provision depends on the cost related to the additional active power losses due to reactive power provision.
  - Sensitivity factors: The sensitivity factors calculated in Step 3 will affect the merit order on the market since the combination of the bid price, quantity, and location in the form of the sensitivity factor will decide which bids will be cleared.
  - The market formulation is introduced in the following subsection.
- **Post-evaluation (Step 5):** In addition to previous steps, this workstream includes an ex-post validation process to check whether the clearing solution solved all network constraints. Therefore, a new power flow analysis is executed based on the new load and generation profiles resulting after the market clearing.

5.1.3. Formulation of the reactive power market clearing model

As the local voltage BUC aims to resolve voltage issues at minimum cost, a linear programming (LP) market-clearing formulation is proposed for workstream 3. The nomenclature used in the optimization problem is described by the following indices, sets, parameters, and variables. The details of the formulation are presented below.

INDICES AND SETS

Symbol	Definition
N_T	Set of day-ahead horizon periods
N_{Bus}	Number of busses
N_{BFSP}	Number of busses with FSPs, where ($N_{BFSP} \leq N_{Bus}$)
Z	Number of busses with voltage problems, where: ($Z \leq N_{Bus}$)
F_B	Number of FSPs
${F_{B,i}}^{BUS}$	Number of FSPs – generators in bus i-th

PARAMETERS

Symbol	Definition	u.m.
${R_i}^{(0)}{}_t$	initial value of reactive power exchange for the i-th FSP (before the market) in the t-th period	[MVAr]
C_{i_t}	Unitary cost of activating the i-th FSP in the t-th period	[€/MVArh]
$C^{\alpha}_{i\,t}$	Unitary cost related to the i-th auxiliary variable in the t-th period	[€/MVArh]
${Q_i}^{(0)}{}_t$	initial value of reactive power exchange for the i-th bus in the t-th period (before the market)	[MVAr]
${V_i}^{(0)}{}_t$	initial value of voltage magnitude for the i-th bus in the t-th period (before market clearing)	[V]

K_{i,j_t}	Voltage magnitude sensitivity coefficient in the t-th period, obtained from the inverse of the reduced Jacobian matrix	[V/MVAr]
S_i	Nominal apparent power of the i-th FSP	[MVA]
$P_{i,t}$	Active power exchange of the i-th FSP in the t-th period	[MW]

VARIABLES

Symbol	Definition	u.m.
ΔR_{i_t}	Reactive power activation of the i-th FSP in the t-th period $\Delta R_{i_t} \stackrel{\text{def}}{=} R_i{}^{(1)}{}_t - R_i{}^{(0)}{}_t$	[MVAr]
$R_i{}^{(1)}{}_t$	final value of reactive power exchange for the i-th FSP (after the market) in the t-th period	[MVAr]
α_{i_t}	Auxiliary variable for the i-th node in the t-th period	[MVAr]
ΔV_{i_t}	Voltage variation (magnitude) at the i-th bus in the t-th period $\Delta V_{i_t} \stackrel{\text{def}}{=} V_i{}^{(1)}{}_t - V_i{}^{(0)}{}_t$ where:	[V]
$V_i{}^{(1)}{}_t$	final value of voltage magnitude for the i-th bus in the t-th period (after market clearing)	[V]

REACTIVE POWER MARKET CLEARING

As stated in Step 4 of the methodology, the flexibility market clearing algorithm for voltage control is used to determine the most efficient flexibility bids from FSPs to mitigate the voltage control issues at minimum cost. The objective function of this day-ahead flexibility market is defined by (5-2), the first term is the reactive power activation cost, the second term represents the cost of the expected not-served flexibility.

$$\min\left\{\sum_{t=1}^{T}\left[\left(\sum_{i=1}^{F}\left|\Delta R_{i_t}\right| C_{i_t}\right)+\left(\sum_{j=1}^{Z}\left|\alpha_{j_t}\right| C_j^{(\alpha)}{}_t\right)\right]\right\} \tag{5-2}$$

The constraint (5-3) represents the flexibility requirement the linearized power flow equation that matches, for each pilot bus, the voltage magnitude variation with the variation of the reactive power exchange of the FSPs. It is relevant to mention that in equation (5-3), each FSP bid is multiplied by its respective sensitivity factor ($K^B{}_{i,y_t}$) which affects the merit order on the market. Constraint (5-4) imposes that the voltage magnitude on pilot busses respects the admissible voltage range. Constraints (5-5), (5-6), and (5-7) capture the limits of the submitted bids from FSPs.

$$V_i{}^{(1)}{}_t - V_i{}^{(0)}{}_t = \left[a_{i_t} + \left(\sum_{y=1}^{F_B{}^{BUS}} K^B{}_{i,y_t} \Delta R_{i,y_t}\right)\right] \qquad \forall_t \in [1,\dots,N_T], \forall_i \in [0,\dots,Z] \tag{5-3}$$

$$\begin{cases} V_i{}^{(1)}{}_t - V^{(Min)} \geq 0 \\ V_i{}^{(1)}{}_t - V^{(Max)} \leq 0 \end{cases} \qquad \forall_t \in [1,\dots,N_T], \forall_i \in [0,\dots,Z] \tag{5-4}$$

$$\begin{cases} \Delta R_{i_t} \geq R_{lead}^{(max)}{}_{i_t} - R_i^{(0)}{}_t \\ \Delta R_{i_t} \leq R_{lead}^{(min)}{}_{i_t} - R_i^{(0)}{}_t \end{cases} \qquad \forall_t \in [1,\dots,N_T], \forall_i \in [0,\dots,F_B] \tag{5-5}$$

$$\begin{cases} \Delta R_{i_t} \geq R_{lag}^{(min)}{}_{i_t} - R_i^{(0)}{}_t \\ \Delta R_{i_t} \leq R_{lag}^{(max)}{}_{i_t} - R_i^{(0)}{}_t \end{cases} \qquad \forall_t \in [1, \dots, N_T], \forall_i \in [0, \dots, F_B] \tag{5-6}$$

$$\begin{cases} R_{lag,i}^{(max)}{}_t = -\sqrt{S_i - P_{i,t}} \\ R_{lead,i}^{(max)}{}_t = \sqrt{S_i - P_{i,t}} \end{cases} \qquad \forall_t \in [1, \dots, N_T], \forall_i \in [0, \dots, F_B] \tag{5-7}$$

Figure 70 depicts the generalised flexibility characteristic considered as flexibility bid in the presented reactive power market formulation.

Availability interval for FSP reactive power exchange (R_i):

$$R_{lead}^{(max)} \leq R_{lead}^{(min)} \leq R_i \leq R_{lag}^{(min)} \leq R_{lag}^{(max)}$$

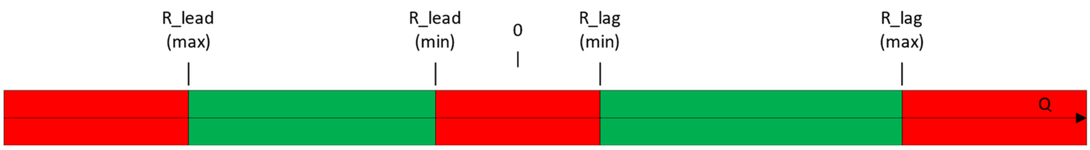

Figure 70: FSP characteristic - reactive power support capability

The reactive power market clearing model is formulated according to the active sign convention, also knwn as generation convention (Lukman, 2002). Table 42 summarises the relationship between the sign of the reactive power and the effect on voltages. If the reactive power exchange is positive, it means that the FSP is injective reactive power that determines an increase of bus voltages. The FSP behaves as a capacitor. On the contrary, If the reactive power exchange is negative, it means that the FSP is adsorbing reactive power that determines an decrease of bus voltages. The FSP behaves asinductor.

Table 42. Convention adopted to the reactive power market clearing model

Q sign	Effect on voltage
Q>0	$\frac{\partial V}{\partial Q} > 0$
Q<0	$\frac{\partial V}{\partial Q} < 0$

5.1.4. Formulation of the voltage control market model

The reactive power market formulation described in section 5.1.3 represents the core of the voltage control market algorithm that implements different TSO-DSO coordination schemes. In fact, the formulation of the reactive power market clearing model (section 5.1.3) can be easily integrated in more complex algorithms. The TSO-DSO coordination schemes developed for voltage control are depicted in Figure 71 (local reactive market model), Figure 72 (common reactive market model), Figure 73 (multi-level reactive market model), and Figure 74 (fragmented market model).

The local reactive market model for voltage control depicted in Figure 71 is proposed for solving voltage violations on pilot buses in the distribution network by using FSPs locally connected. No interaction with the

TSO, the TSO network, or the FSPs connected to the transmission system occurs. The voltage magnitude of the interface bus between TSO and DSO network is invariant. The DSO has access to the FSPs connected to its network.

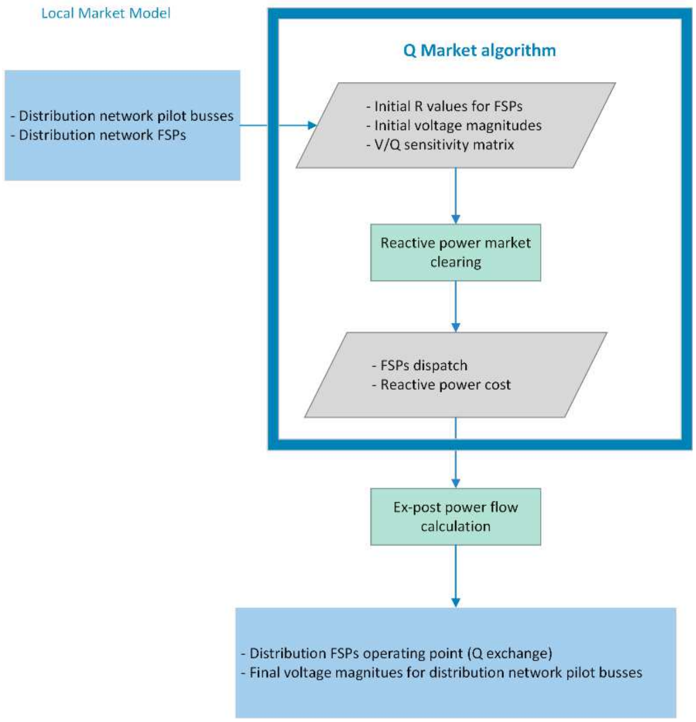

Figure 71. Local reactive market model for voltage control

The common reactive market model for voltage control depicted in Figure 72 is proposed for simultaneously solving voltage violation on pilot buses in both the transmission and distribution networks by using FSPs connected to both networks. The DSO has access to the FSPs connected to its network. The TSO has access to the FSPs connected to the transmission network and the FSPs connected to the distribution network. The voltage magnitude of the interface bus between the TSO and DSO network is free to change within the admissible voltage limits.

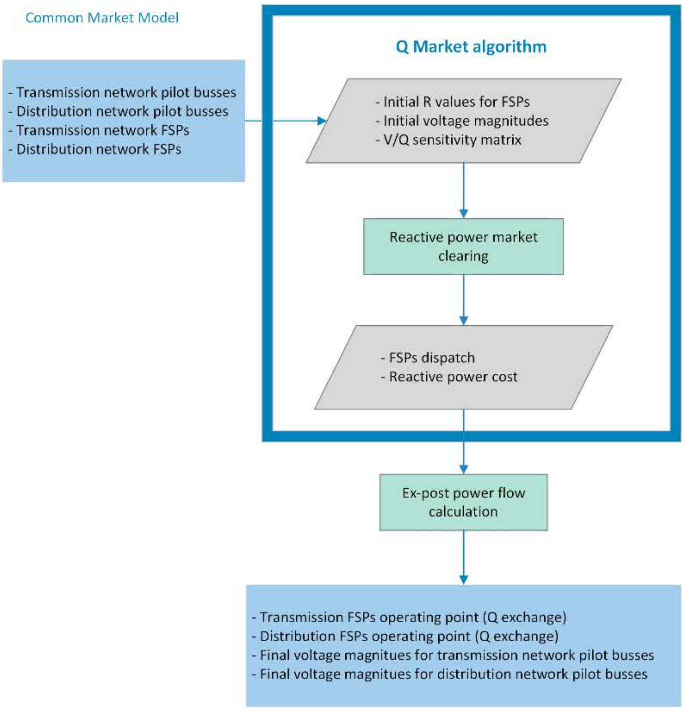

Figure 72. Common reactive market model for voltage control

The multi-level reactive market model for voltage control depicted in Figure 73 is proposed for sequentially solving voltage violation on pilot buses in the distribution and the transmission networks by using FSPs connected to both networks. In the multi-level market model, the distribution network market and the transmission network market are coordinated. The DSO has access to the FSPs connected to its network. The TSO has access to the FSPs connected to the transmission network and the FSPs connected to the distribution network. As shown in Figure 73, the adopted implementation concerns first the distribution network market clearing, and then, the remaining voltage violations in the transmission network pilot busses are addressed by the transmission network market clearing that also involves the FSPs connected to the distribution network. These FSPs participate in the transmission network market by offering the residual reactive power capacity after the distribution market clearing. For the sake of simplicity, the same offered price is considered in both markets. The voltage magnitude of the interface bus between TSO and DSO network is free to change within the admissible voltage limits.

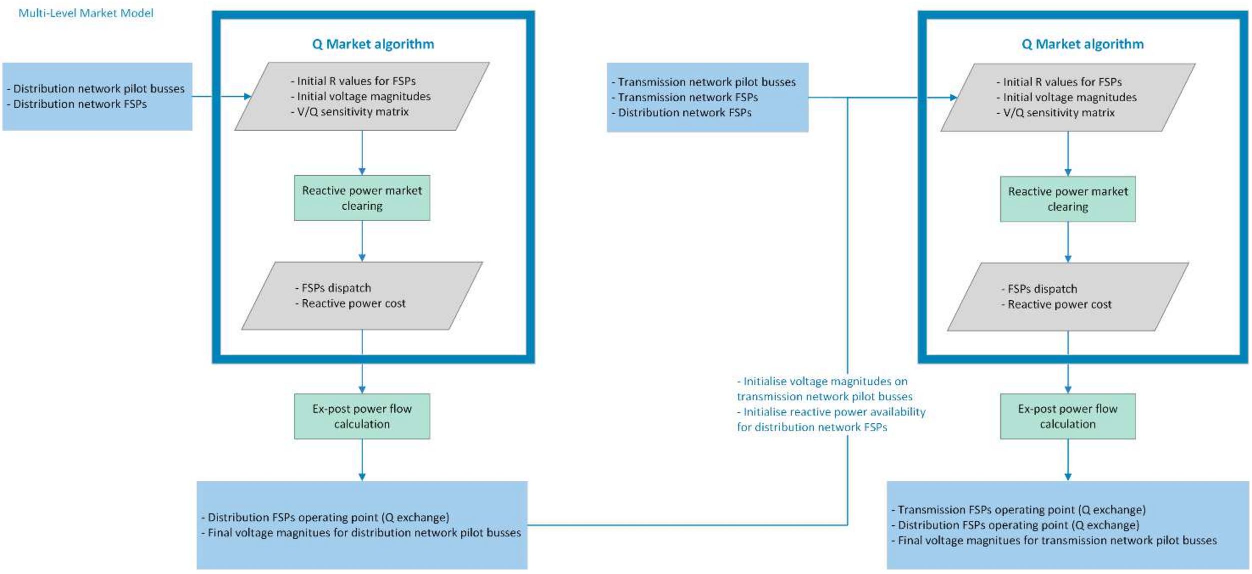

Figure 73. Multi-level reactive market model for voltage control

The fragmented reactive market model for voltage control depicted in Figure 74 is proposed for sequentially solving voltage violation on pilot buses in the distribution and the transmission networks by using FSPs connected to both networks. In the fragmented market model, the distribution network market and the transmission network market are not coordinated, the two markets are cleared independently considering a different set of FSPs. The DSO has access to the FSPs connected to its network. The TSO has access to the FSPs connected to the transmission network. The voltage magnitude of the interface bus between TSO and DSO network is free to change within the admissible voltage limits. As shown in Figure 74, the adopted implementation concerns first the distribution network market clearing, and then, the remaining voltage violations in the transmission network pilot busses are addressed by the transmission network market clearing that involves only the FSPs connected to the transmission network.

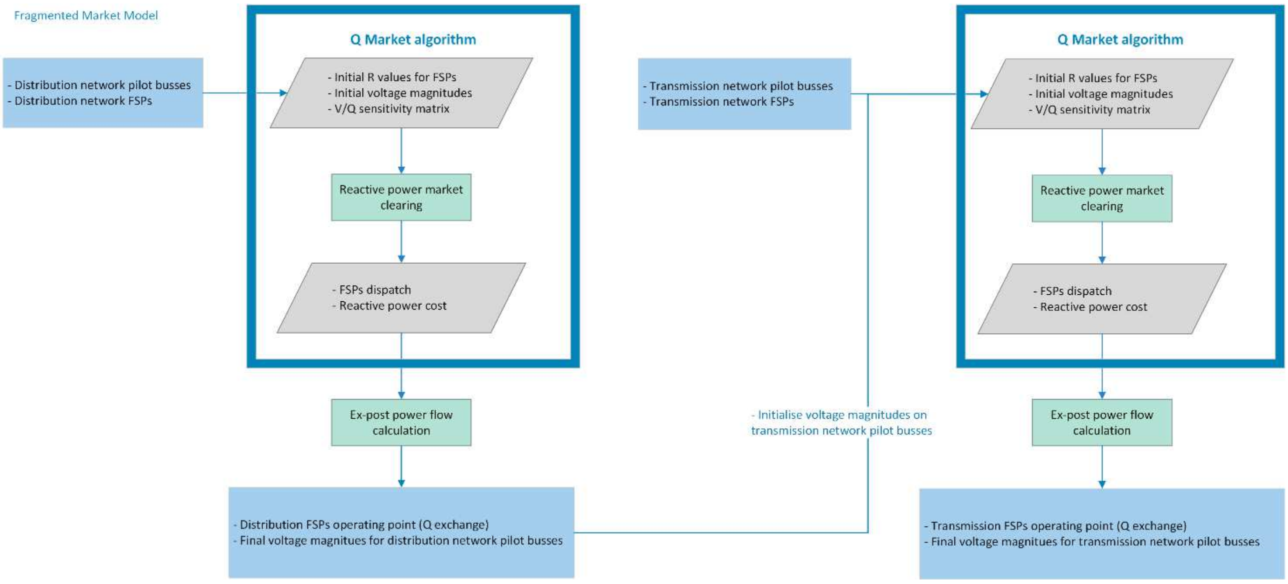

Figure 74. Fragmented market model for voltage control

5.1.5. FSP characteristic – reactive power support cost

From the providers' perspective, voltage control costs can be classified in terms of investment (CAPEX) and operational expenditures (OPEX) (Rueda-Medina & Padilha-Feltrin, 2013):

- Investment costs are the CAPEX related to the equipment required for enabling the reactive power provision.
- Invariable operational costs depend on the minimum reactive power for the normal operation of the source (internal losses) and the share of maintenance cost allocated to the reactive power provision.
- Variable operational costs relate to equipment internal energy losses for providing the reactive power support and the lost opportunity in case of active power activation (Barquín et al., 1998).

CAPEX for pure reactive providers equals the total investment cost. For the mixed active-reactive power providers, CAPEX for voltage control is a share of the total CAPEX plus the investment for the auxiliary equipment needed for enabling the reactive power exchange. The OPEX related to internal active power losses caused by the reactive power support depends on the device's operational point through the loss curve. The loss curve of synchronous generators, inverter-based DERs, DFIGs, and STATCOMs can be approximated by a second-order polynomial function symmetrical considering positive and negative reactive power outputs (Barquín et al., 1998; Braun, 2008, 2009; Gil et al., 2000; Koeppe et al., 2018; Troncia et al., 2021).

The current analysis assumes that the FSPs bid at their marginal cost considering the variable operational costs related to the equipment's internal energy losses. The formula for calculating the unitary cost of activating the i-th FSP in the t-th period is reported in (5-8). For the technology considered, an energy loss coefficient (L_i) has been used considering the information available in literature (Barquín et al., 1998; Braun, 2008, 2009; Gil et al., 2000; Koeppe et al., 2018; Troncia et al., 2021). A reference energy cost (E_t) has been considered to price the energy losses. Moreover, to add variability to the analysis, the FSPs behaviour has been modelled by applying to each single FSP a random coefficient (A_i) normally distributed in the interval [0.95 1.05].

$$C_{i_t} = L_i \cdot E_t \cdot A_i \qquad \forall_t \in [1, \dots, N_T], \forall_i \in [0, \dots, F_B] \qquad [\text{€/MVArh}] \tag{5-8}$$

5.2. Greek case study

The scalability and replicability study of Workstream 3 considers in Greece the Kefalonia demo site. Section 5.2.1 introduces the network characteristics and the load and generation profiles, section 5.2.2 describes the characteristics of the FSPs considered, section 5.2.3 introduces the SRA scenarios considered for the study of the Kefalonia demos site, section 5.2.4 discusses the analysis of the scenarios considered and section 5.2.5 presents the results obtained.

5.2.1. Network characteristics and Load and Generation profiles

Workstream 3 for Greece considers the Kefalonia MV distribution network connected at the Argostoli substation and the transmission network of the Kefalonia Area, as shown in Figure 75.

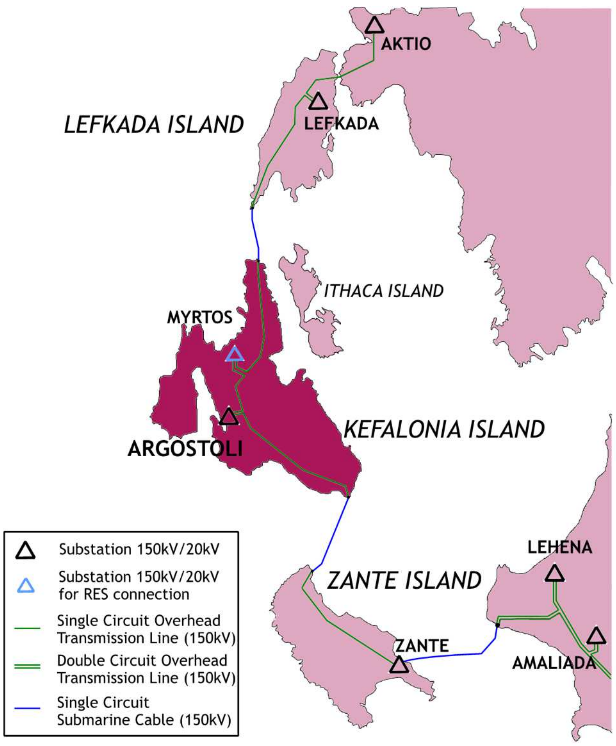

Figure 75. Transmission network considered in Workstream 3 for the Greek demonstrator

Load and generation profiles and the Kefalonia MV distribution network characteristics are described in section 4.2. The power system of Kefalonia is part of the Greek interconnected system. There are two substations on the island, one in Argostoli and one in the area of Myrtos. The second substation works exclusively for wind farms connected to the HV system, while the substation of Argostoli serves the load of the whole island. Both substations have HV to MV transformers (150kV/20kV). The Greek Demonstration takes place mainly in the grid connected to the Argostoli substation (Bachoumis et. al, 2019).

A single circuit overhead transmission line extends to the island. This HV line (150kV) starts at the south-eastern part of the island (near Zante), is connected with the two HV/MV substations of the island and ends at the north side of the island. The total length of the high-voltage line is approximately 65km. On its north side, the island is connected to the rest of the Greek TS by a single circuit submarine cable with Lefkada island. The rated voltage of this line is 150kV and its rated transmission capacity is 125MVA. On the southern side of the island there is a single circuit submarine cable in order to connect Kefalonia's system with Zante. This line also has a rated voltage of 150kV and its rated transmission capacity is 125MVA (Bachoumis et. al, 2019).

Kefalonia's power system is a small part of the western Greek interconnected power system and its load is served mainly by the plants of this area, where the biggest part of its power fleet consists of hydro plants. Moreover, the large-scale wind potential of the island is the reason why there are a lot of wind farms. Specifically, on the island of Kefalonia wind farms with a total established rated power of 101.5MW are operating today, while connection offers with an aggregated power of 46.7MW on Kefalonia and Lefkada islands, have already been granted. As a consequence, the total established rated power of wind farms in this region is expected to reach 148.2MW (Bachoumis et. al, 2019).

The Kefalonia transmission network model considers as generators imposing a fixed voltage magnitude on the related bus the ones located in Myrtos, Peloponnisos, Zante, Leukada, and Aktio. Hence the voltage magnitude on the corresponding bus is fixed and determined by the set-point of the generator. The generation profiles considered for these generators in workstream 3 are depicted in Figure 76. These profiles relate to the maximum generation scenario, the synthetic profile of the Peloponnisos equivalent generator assumes a plant dispatch that follows the load, according to the load profiles shapes described in 4.2.1. The nominal voltage value is imposed to the busbar to which each generator is connected.

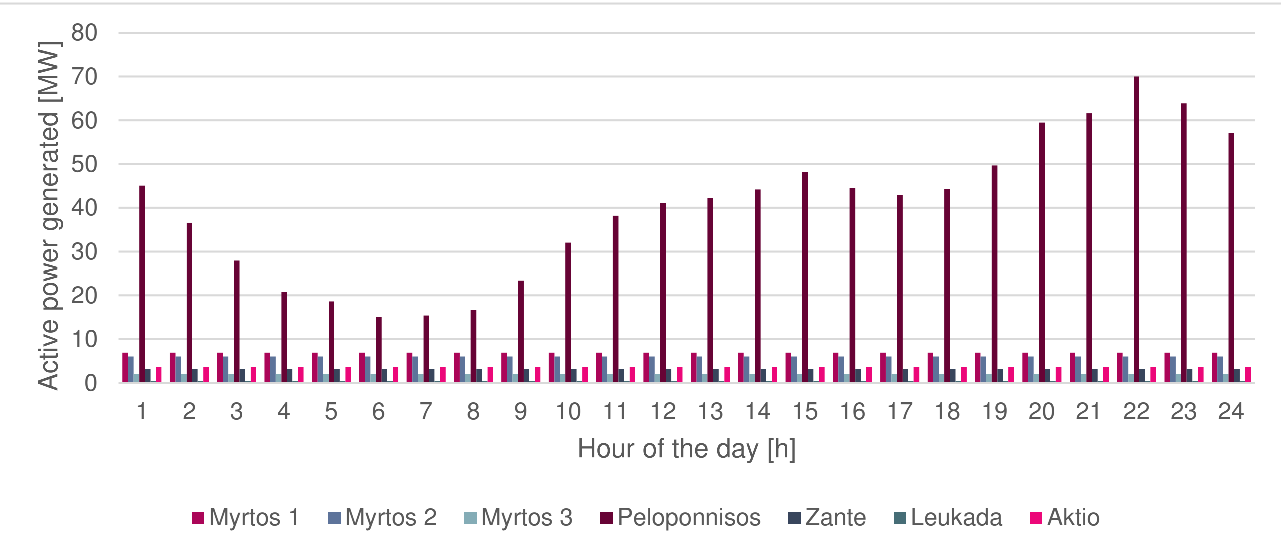

Figure 76. Generation profile for generators connected at the Kefalonia area transmission network

The loads connected to the transmission network model are located in Zante, Lefkada, Argostoli, and Aktio. The load demand at transmission system busses is represented in Figure 77 in terms of active power and in Figure 78 in terms of reactive power. These synthetic profiles are obtained considering the information available on the maximum and minimum value of the demand for each bus and the load profile shape of the

MV network described in 4.2.1. The maximum generation scenario is considered for workstream 3 studies, the load in the Argostoli network is represented by the load of the Kefalonia MV network described in 4.2.1. The considered scenario neglects the Aktio load profile.

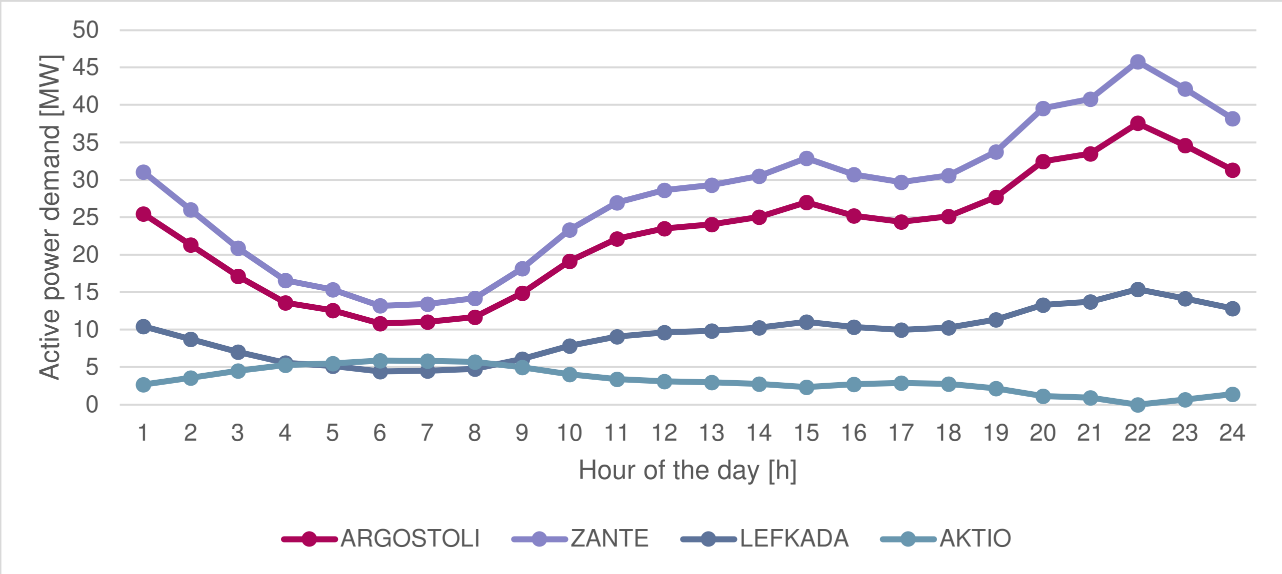

Figure 77. Active power demand at transmission system busses

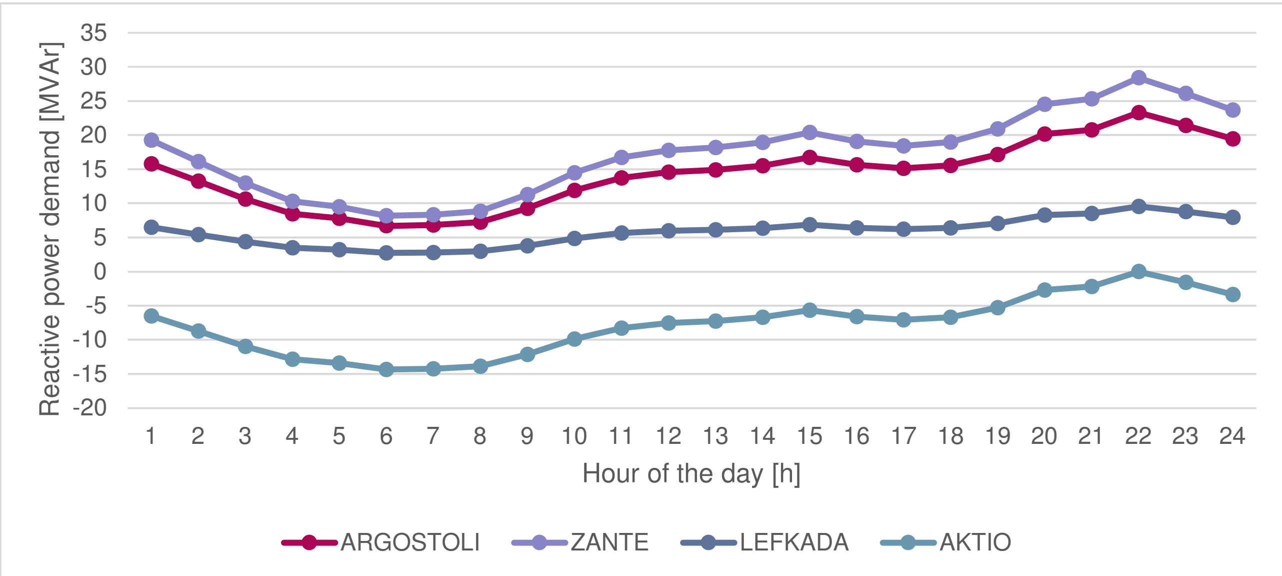

Figure 78. Reactive power demand at transmission system busses

The adopted generation profiles for RES connected to the distribution network are described in section 4.2.1. The generation profiles for RES connected to the transmission network assume the same shape as the generation profile of the RES of the same type (i.e. wind or solar) connected to the distribution network, described in section 4.2.1. A power factor equal to one is considered.

5.2.2. FSPs characteristics

Table 43 lists the FSPs considered in the Greek case study for workstream 3. The capability to contribute to voltage support follows the approach described in section 5.1.3 considering $R_{lead}^{(min)} = R_{lag}^{(min)} = 0$.

Table 43: FSP characteristics for the Greek case study in workstream 3

FSP ID	Zone	FSP type	FSP Capacity [MVA]	FSP bid price [€/MVArh]
Fsp0	Aktio transmission	Wind generator	26.8	9.9
Fsp1	Argostoli distribution	Wind generator	13.6	14.56
Fsp2	Argostoli distribution	Wind generator	2.7	14.7
Fsp3	Argostoli distribution	PV plant	0.1	14.14
Fsp4	Argostoli distribution	PV plant	0.05	13.44
Fsp5	Argostoli distribution	PV plant	0.2	13.44
Fsp6	Argostoli distribution	PV plant	0.2	13.58
Fsp7	Argostoli distribution	PV plant	0.1	14.56
Fsp8	Argostoli distribution	PV plant	0.1	13.58
Fsp9	Argostoli distribution	PV plant	0.1	14.42
Fsp10	Argostoli distribution	PV plant	0.1	13.58
Fsp11	Argostoli distribution	PV plant	0.1	14.7
Fsp12	Argostoli distribution	PV plant	0.3	13.72
Fsp13	Argostoli distribution	PV plant	0.1	13.58
Fsp14	Argostoli distribution	PV plant	0.2	13.58
Fsp15	Argostoli distribution	PV plant	0.3	14.14
Fsp16	Argostoli distribution	PV plant	0.2	14
Fsp17	Argostoli distribution	PV plant	0.1	13.72
Fsp18	Argostoli distribution	PV plant	0.4	14.56
Fsp19	Argostoli distribution	PV plant	0.1	14.14
Fsp20	Argostoli distribution	PV plant	0.1	14.14
Fsp21	Argostoli distribution	PV plant	0.1	14.7
Fsp22	Argostoli distribution	PV plant	0.1	13.72
Fsp23	Argostoli distribution	PV plant	0.1	14.42
Fsp24	Argostoli distribution	PV plant	0.1	14.42

5.2.3. Kefalonia SRA scenarios

For the scalability and replicability analysis of voltage control in the Greek case study, different scenarios are tested according to Table 44. The four scenarios in this table differ in terms of the adopted coordination scheme, voltage support availability, FSP number and location, and RES impact on voltage baseline values. In all scenarios the minimum and maximum voltage limits considered for safe operation are respectively 0.95 and 1.05 (values expressed in per unit). The pilot busses in the distribution network are all busses having a nominal voltage of 20 kV, while the pilot busses in the transmission network are all busses having a nominal voltage of 150 kV.

Table 44: SRA scenarios for the Greek case study in workstream 3

Scenario ID	Description	Coordination scheme	SRA parameters	Quantities calculated
Scenario 0	Set up described in sections 5.2.1 and 5.2.2	Fragmented market model	Coordination scheme FSP number and location	Total flexibility activation cost Criticalities reduction index Volume of transactions in LFM
Scenario 1	As scenario 0	Multi-level market model	Coordination scheme FSP number and location	
Scenario 2	As scenario 0	Common market model	Coordination scheme FSP number and location	
Scenario 3	Scenario 0 + but with FSPs with doubled converter size	Multi-level market model	FSPs size FSP number and location	
Scenario 4	Scenario 0 + but with FSPs with doubled power size and doubled converter size (i.e., for PV plants it corresponds to doubling the surface covered by solar panel, for wind plants, it corresponds to doubling the power that can be generated by a turbine)	Multi-level market model	FSPs size and increased RES impact	

For each scenario in Table 44, three cases are considered, as shown in Table 45. The three selected cases allow to investigate the impact of the number and location of the FSPs on the performance of voltage control and the related market procurement.

Table 45: Cases for SRA scenarios for the Greek case study in workstream 3

Case ID	FSPs participation
Case 0	Fsp0, Fsp1
Case 1	Fsp0, Fsp1, Fsp2, Fsp3, Fsp4
Case 2	All FSPs

5.2.4. Analysis of scenarios for workstream 3 - Greek demo

The analysis of scenario 0 in the context of workstream 3 adopts the approach presented in section 5.1. The first step is to perform a power flow analysis for 24 hours (market horizon) to detect eventual constraints. The distribution network data and load and generation profiles described in sections 5.2.1 and 5.2.2 are considered. The results of step 1 are illustrated in Figure 79. In total 6147 voltage violations are detected in the pilot busses of the network, 6144 are detected in the distribution network pilot busses while 3 voltage violations refer to the pilot busses of the transmission network. Voltage violations are detected in all 24 hours of the selected representative day to study. As shown in Figure 79, voltage violations concern both over-voltages and under-voltages.

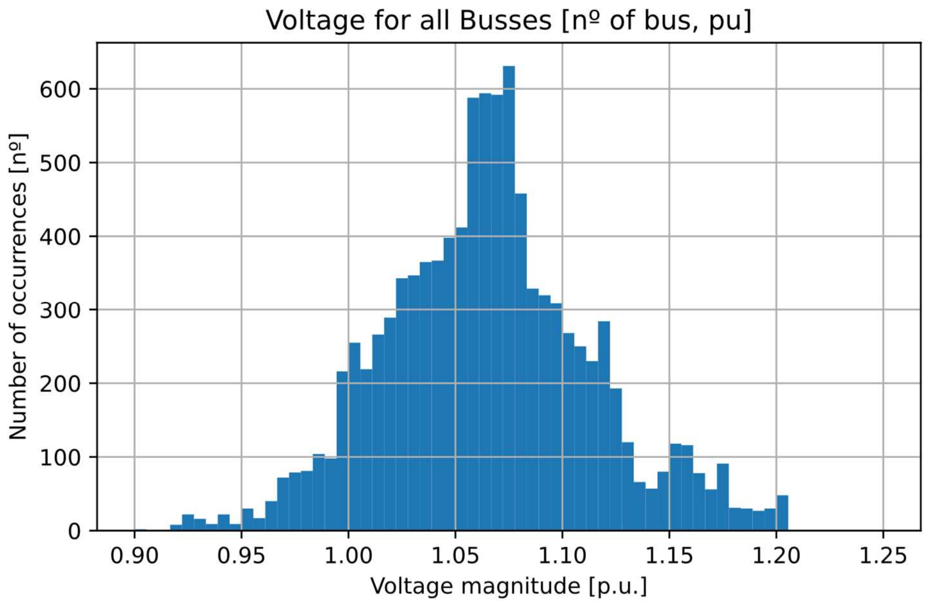

Figure 79. Distribution of voltage magnitudes for all pilot busses in the considered representative day (24 samples per bus)

The flexibility need can be quantified by identifying the voltage violations and subsequently quantifying the voltage variations required to comply with the operational limits.

For each FSP participating in the market the corresponding the voltage sensitivity factors are computed for each hour as described in 5.1.

A day-ahead flexibility market-clearing is carried out to solve the voltage violations identified using the most efficient flexibility bids from FSPs at minimum cost according to the approach described in sections 5.1.3, 5.1.4, and 5.1.5. Once the market is cleared, the evaluation of the market result is done by running a power flow to check the technical performance of the market.

5.2.5. SRA results for the workstream 3 – Greek demo

The SRA results for the workstream 3 for the Greek demo are described in this section and reported in Table 46, Table 47, Table 48, and Table 49. The scenario analysis is provided in relative terms to highlight the differences and allow a comparison among the different scenarios. Scenario 2 is used as a reference since it relates to the common market model which represents the best solution from the theoretical perspective (Sanjab, A., et al., 2022). The reference values are reported in Table 46.

Table 47 gives the comparison of the different coordination schemes in terms of daily acquisition costs. The acquisition cost is calculated considering pay as bid (PaB) and pay as clear (PaC) pricing. The overall daily acquisition cost is calculated and a distinction is made between the acquisition cost for FSPs connected to the distribution system (DS) and the transmission system (TS). Table 47 highlights that the fragmented and multi-level market models coincide since, given the market architecture described in section 5.1.4, the distribution system market clearing solves the voltage issues on the transmission system pilot bus, hence, the market for the transmission system do not occur.

Considering the overall procurement cost, the common market model reaches the highest cost, the multi-level and fragmented market models reach an overall daily cost that is about half of the procurement cost for the common market model. However, as depicted in Figure 80, the common market model is technically more effective.

Table 46. Reference scenario values – SRA for the Greek demonstrator

Scenario			Scenario 2	Scenario 2	Scenario 2
Case			0	1	2
Daily cost	Pay as Bid	[€]	7380.08	8376.79	8699.85
Daily cost	Pay as Clear	[€]	9238.72	10570.07	10715.55
Daily cost	Pay as Bid Distribution System FSPs	[€]	3431.46	3925.77	4684.46
Daily cost	Pay as Bid Transmission System FSPs	[€]	3948.62	4451.02	4015.39
Daily cost	Pay as Clear Distribution System FSPs	[€]	3431.46	3960.99	4753.30
Daily cost	Pay as Clear Transmission System FSPs	[€]	5807.26	6609.08	5962.25
Reactive power	Support acquired (Q) Distribution System FSPs	[MVArh]	235.68	269.46	323.35
Reactive power support acquired (Q)	Support acquired (Q) Transmission System FSPs	[MVArh]	398.85	449.60	405.60
Reactive power support acquired (Q)	Overall support acquired (Q)	[MVArh]	634.53	719.05	728.95
Residual violations		[%]	30.63	23.52	19.52

The common market model achieves a share of residual voltage violations of 19.52%, conversely, the best performance of the fragmented and multi-level market models is 32.73%. Hence, the higher overall cost of the common market model relates to the higher number of voltage issues solved. The fragmented and multi-level market models do not procure reactive power support from the FSPs connected to the transmission system since the support procured from the FSPs connected to the distribution system already solve the voltage violations in transmission system pilot buses. As reported in Table 47, the common market model shows a similar cost for the procurement of reactive power support from FSPs connected to the distribution system and to the transmission system. However, the allocation of costs between distribution and transmission system FSPs diverges if the pay as clear remuneration mechanism is considered since all providers are remunerated considering the most expensive bid cleared in the market. With respect to the common market model, the cost related to the FSPs connected to the distribution system in the fragmented and multilevel coordination schemes lies between the 51% and the 58% (Pay as bid mechanism).

Table 47. Workstream 3 - Greek demo - comparison of the coordination schemes in terms of relative acquisition cost compared to the reference scenario

Coordination scheme	Scenario	Case	Cost Pay as Bid	Cost Pay as Clear	Cost Pay as Bid (DS)	Cost Pay as Bid (TS)	Cost Pay as Clear (DS)	Cost Pay as Clear (TS)
Fragmented	Scenario 0	0	0.51	0.41	1.10	0.00	1.10	0.00
Fragmented	Scenario 0	1	0.54	0.43	1.15	0.00	1.15	0.00
Fragmented	Scenario 0	2	0.58	0.48	1.08	0.00	1.08	0.00
Multi-level	Scenario 1	0	0.51	0.41	1.10	0.00	1.10	0.00
Multi-level	Scenario 1	1	0.54	0.43	1.15	0.00	1.15	0.00
Multi-level	Scenario 1	2	0.58	0.48	1.08	0.00	1.08	0.00
Common	Scenario 2	0	1.00	1.00	1.00	1.00	1.00	1.00
Common	Scenario 2	1	1.00	1.00	1.00	1.00	1.00	1.00
Common	Scenario 2	2	1.00	1.00	1.00	1.00	1.00	1.00

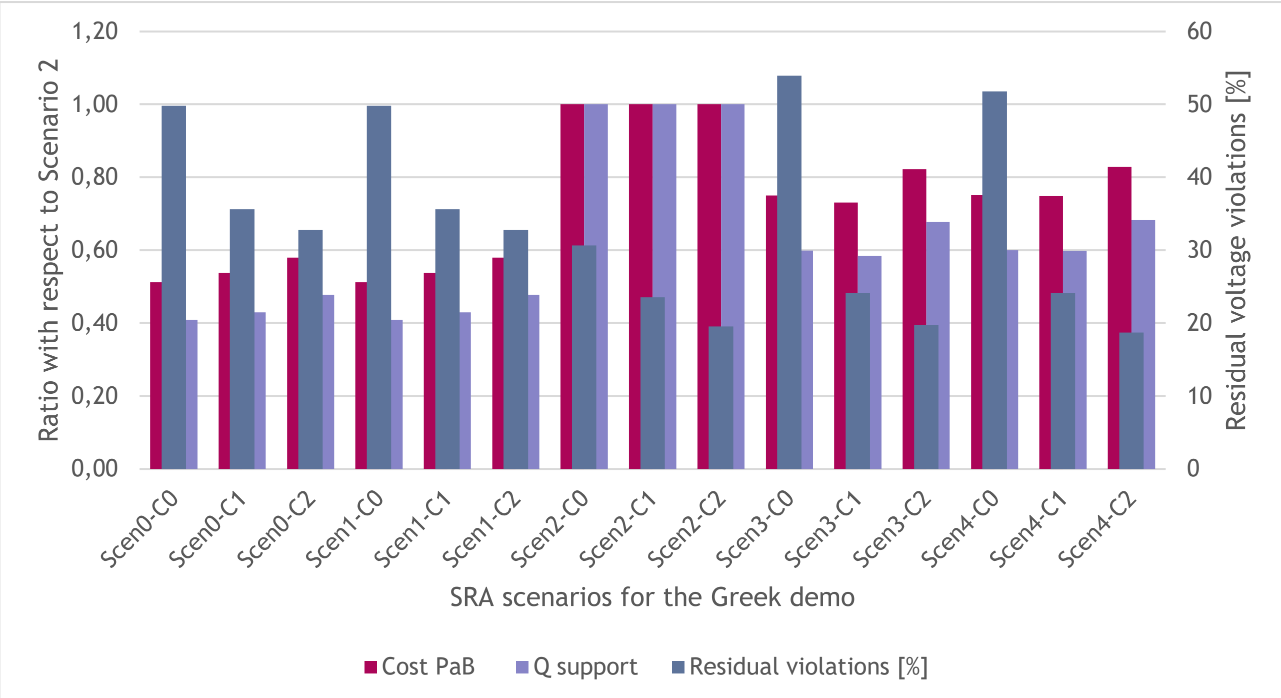

Figure 80. Workstream 3 - Greek demo - comparison of the coordination schemes in terms of acquisition costs and residual voltage violation

Table 48 compares the three considered coordination schemes in terms of reactive power support acquired. The common market model leads to the acquisition of the highest share of reactive power support, compatibly with the highest number of voltage violations solved. The fragmented and multi-level market models procure an overall reactive power support that lies between 41% and 48% of the quantity acquired by the common market model. Fragmented and multi-level market model lead to a higher percentage of residual voltage violations than the common market model. The average cost for solved violations is higher in the case of common market model; however, the three scenarios are not comparable in these terms since the different performance in terms of residual voltage violations. As depicted in Figure 42, all coordination schemes procure a similar amount of reactive power support from the FSPs connected to the distribution system. However, the common market model also procures reactive power support from the FSP connected to the transmission system which offers a large reactive power capacity at the lowest cost. The reactive power support acquired from this FSPs is larger than the overall quantity procured form FSPs connected to the distribution system allowing to solve a larger number of voltage violations.

Table 48. Workstream 3 - Greek demo - comparison of the coordination schemes in terms of reactive power support acquired

Coordination scheme	Scenario	Case	Q DS	Q TS	Q	Residual violations [%]	Average cost for solved violations [€/n°]
Fragmented	Scenario 0	0	1.10	0.00	0.41	49.77	1.22
Fragmented	Scenario 0	1	1.15	0.00	0.43	35.60	1.14
Fragmented	Scenario 0	2	1.08	0.00	0.48	32.73	1.22
Multi-level	Scenario 1	0	1.10	0.00	0.41	49.77	1.22
Multi-level	Scenario 1	1	1.15	0.00	0.43	35.60	1.14
Multi-level	Scenario 1	2	1.08	0.00	0.48	32.73	1.22
Common	Scenario 2	0	1.00	1.00	1.00	30.63	1.73
Common	Scenario 2	1	1.00	1.00	1.00	23.52	1.78
Common	Scenario 2	2	1.00	1.00	1.00	19.52	1.76

Figure 42 introduces the technical performances of SRA scenarios 3 and 4. These scenarios concerns a multi-level market model with augmented FSP size (scenario 3: the size of the converted is doubled) and RES impact (scenario 4: the power rate of the generator corresponding to the FSP is doubled). In all scenarios, the considered FSPs are RESs (i.e., PV and wind generators). Comparing scenario 3 with scenario 1 it is worth noting that, even doubling the available reactive power capacity, the procured reactive power support does not increase with the same factor. However, the performance in terms of residual voltage violations improves in the cases 1 and 2 getting closer to the common market model values. Considering scenario 4, even if the production from RES is doubled, the availability of reactive power capability for voltage control leads to performances similar to scenario 3.

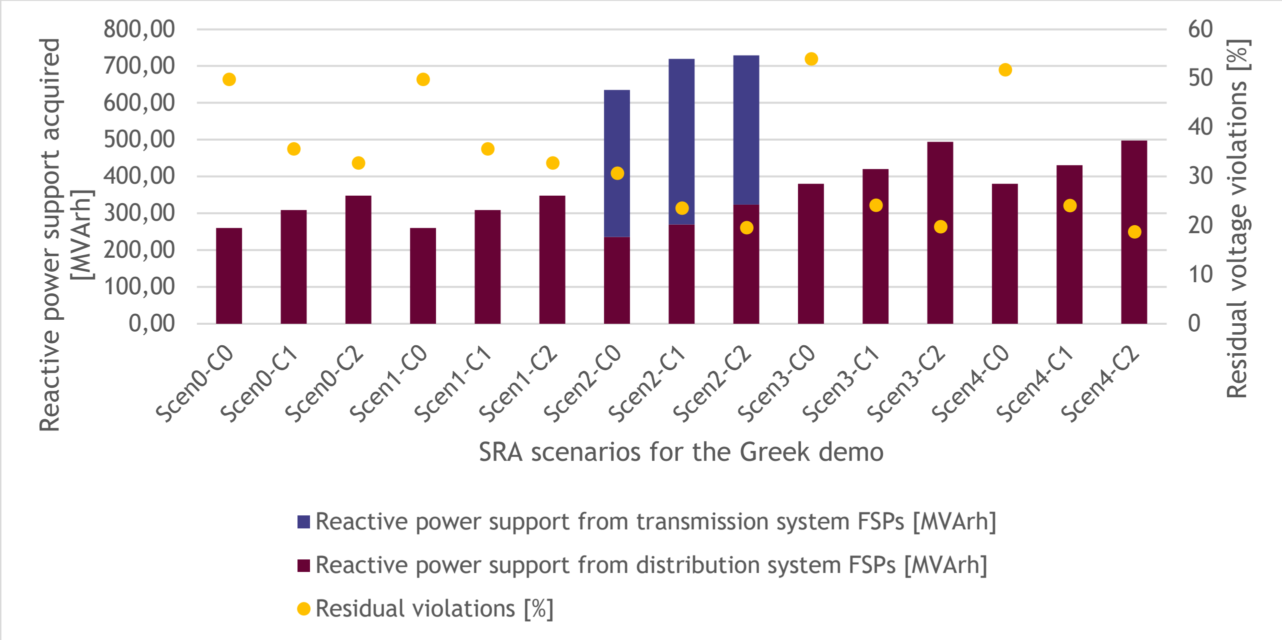

Figure 81. Workstream 3 - Greek demo - comparison of the coordination schemes in terms of acquired reactive power support and residual voltage violation

Figure 82 compares the studied scenarios in terms of procurement cost and the allocation of these costs among the FSPs. On the left side Figure 82 shows the procurement costs calculated according to the pay as bid mechanism, on the right side, Figure 82 displays the procurement costs calculated according to the pay as clear mechanism. Figure 82 highlights that the procurement cost for scenarios 3 and 4 is higher than the procurement cost of scenarios 1, while lower of the overall procurement cost occurred in the case of the common market model (scenario 2). Table 49 compares the scenarios in terms of procurement costs in relative terms with reference to the common market model (scenario 2) costs.

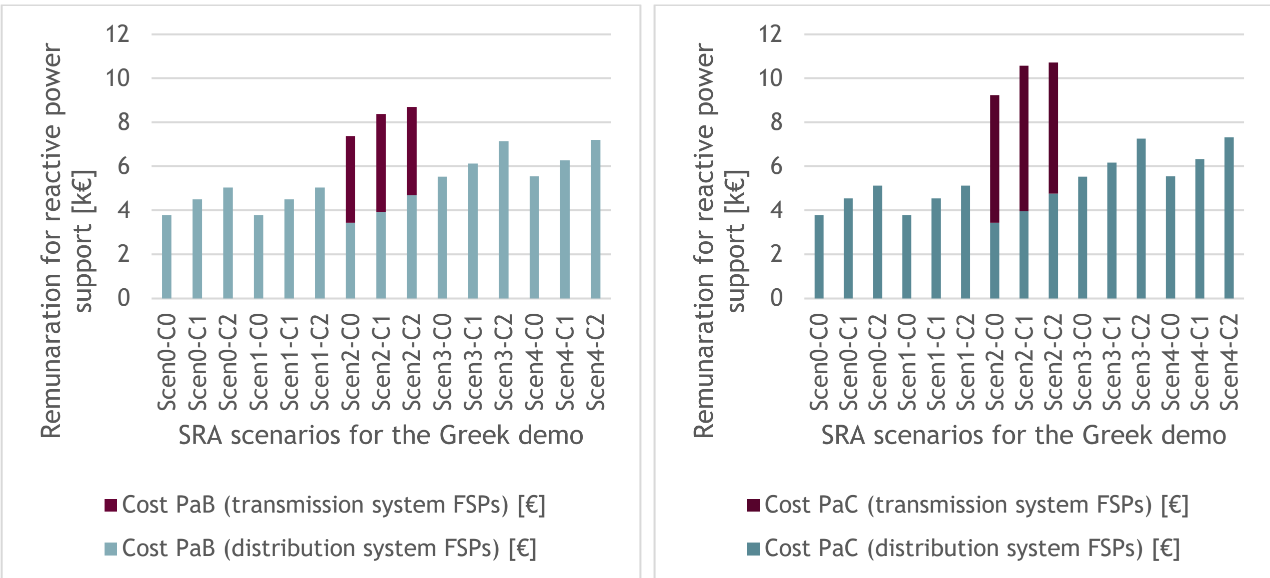

Figure 82. Workstream 3 - Greek demo - comparison of the considered scenarios in terms of procurement cost

Table 49. Workstream 3 - Greek demo - sensitivity considering the increased FSP size - cost comparison

Scenario	Case	Cost PaB	Cost PaC	Cost PaB (DS FSPs)	Cost PaB (TS FSPs)	Cost PaC (DS FSPs)	Cost PaC (TS FSPs)	Average cost for solved violations [€/n°]
Scenario 0	0	0.51	0.41	1.10	0.00	1.10	0.00	1.22
Scenario 0	1	0.54	0.43	1.15	0.00	1.15	0.00	1.14
Scenario 0	2	0.58	0.48	1.08	0.00	1.08	0.00	1.22
Scenario 1	0	0.51	0.41	1.10	0.00	1.10	0.00	1.22
Scenario 1	1	0.54	0.43	1.15	0.00	1.15	0.00	1.14
Scenario 1	2	0.58	0.48	1.08	0.00	1.08	0.00	1.22
Scenario 3	0	0.75	0.60	1.61	0.00	1.61	0.00	1.95
Scenario 3	1	0.73	0.58	1.56	0.00	1.56	0.00	1.31
Scenario 3	2	0.82	0.68	1.53	0.00	1.53	0.00	1.45
Scenario 4	0	0.75	0.60	1.61	0.00	1.61	0.00	1.82
Scenario 4	1	0.75	0.60	1.60	0.00	1.60	0.00	1.31
Scenario 4	2	0.83	0.68	1.54	0.00	1.54	0.00	1.41

5.2.6. Interim Conclusions

From the SRA results of the Greek case study in workstream 3, it can be concluded that:

- The SRA scenarios of the Greek demo highlights the effectiveness of the common market model in procuring reactive power support from FSPs to solve voltage violations. In fact, considering the analysed scenarios, the common market model lead to the lowest share of residual voltage violations after the market.

- The fragmented and multi-level coordination schemes considered for SRA concern a sequential optimisation in which the distribution system market is solved first, while the transmission system market follows. This approach solved the voltage violations on transmission system pilot buses thanks to the redispatch of the FSPs in the distribution system driven by the distribution system market clearing. This can be seen as a distortion in the allocation of costs between the transmission and distribution systems, since the former benefits from the solution of the distribution system market without participating to it.

- The network scenarios studied for the Greek demo highlight the impossibility of solving all voltage violations exploiting only reactive power. The increased penetration of RES leading to an increased availability of reactive power capacity due to the power electronic converter relieves the problem allowing solving a higher share of voltage violations; however, the effectiveness of reactive power support is limited. The oversizing of the power electronic converters of inverter-based RES to increase the reactive power capacity available for reactive power support do not achieve a comfortable level of performances in terms of avoided voltage violations in reference to the to the scenario of increased RES size (i.e. the scenario in which not only the converter size is doubled but also the active power generated).

5.3. Spanish case study

The scalability and replicability study of Workstream 3 considers the Spanish sites of Cadiz and Murcia. Section 5.3.1 describes the SRA addressed for the Cadiz demo site, section 5.3.7 focuses on the SRA for the Murcia demo site.

5.3.1. Voltage control for Cadiz

Workstream 3 for the Spanish demo site of Cadiz considers the transmission and distribution network presented in sections 3.3.2.2 and 3.3.2.3. Two scenarios are considered for the load and generation profiles. The MAX scenario describes the maximum load (Figure 83) and the corresponding maximum generation (Figure 84) from dispatched generators. Conversely, the MIN scenario describes the minimum load (Figure 86) and the corresponding minimum generation (Figure 87) from dispatched generators. The RES profiles are the same in both the MAX (Figure 85) and MIN (Figure 88) scenarios. Additionally, a synthetic profile for RES generators (Figure 89) is devised and used in the MIN scenario to study the effects of a higher contribution of distributed generators. In that case, this synthetic scenario is labelled as MINS.

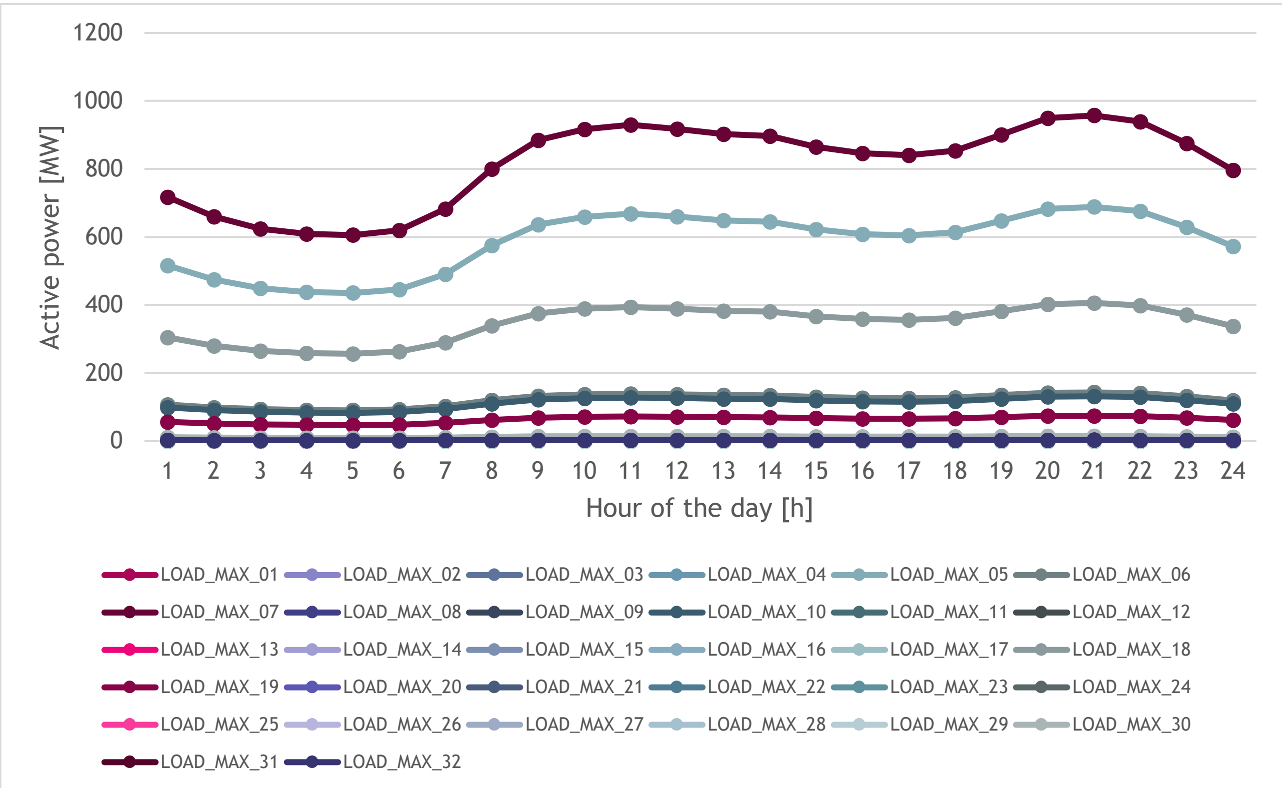

Figure 83. Load profiles in MAX scenario - Workstream 3 - Cadiz

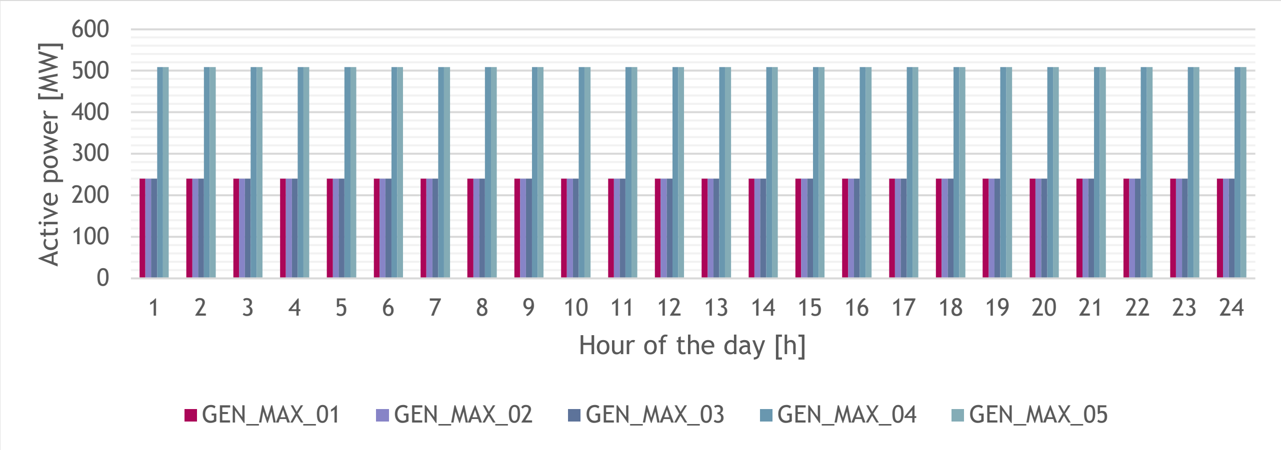

Figure 84. Generation profile for dispatched generators in MAX scenario - Workstream 3 - Cadiz

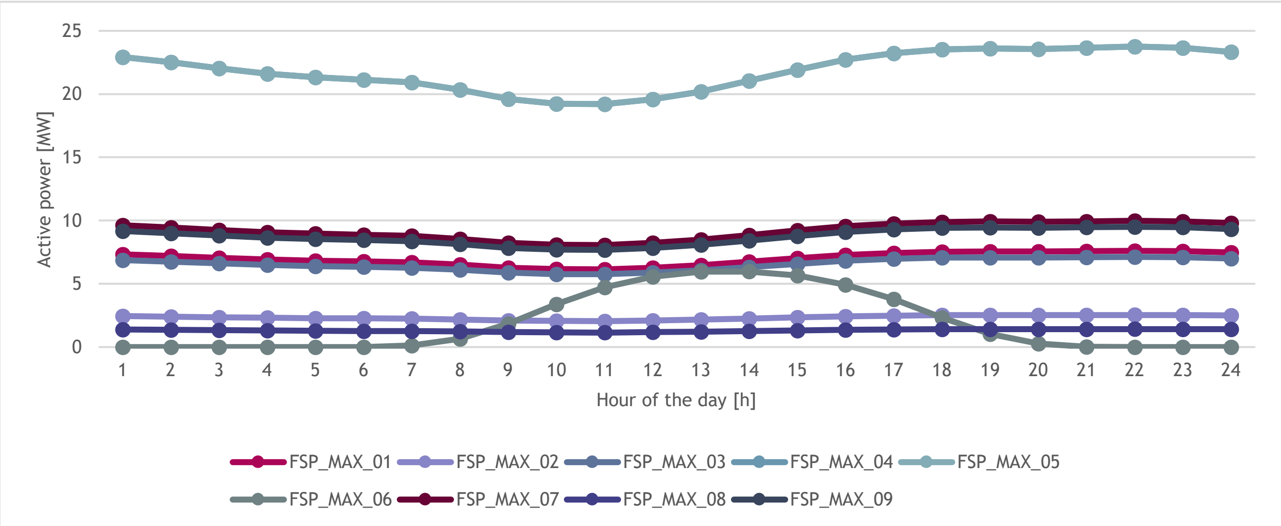

Figure 85. Generation profiles for RES in MAX scenario - Workstream 3 - Cadiz

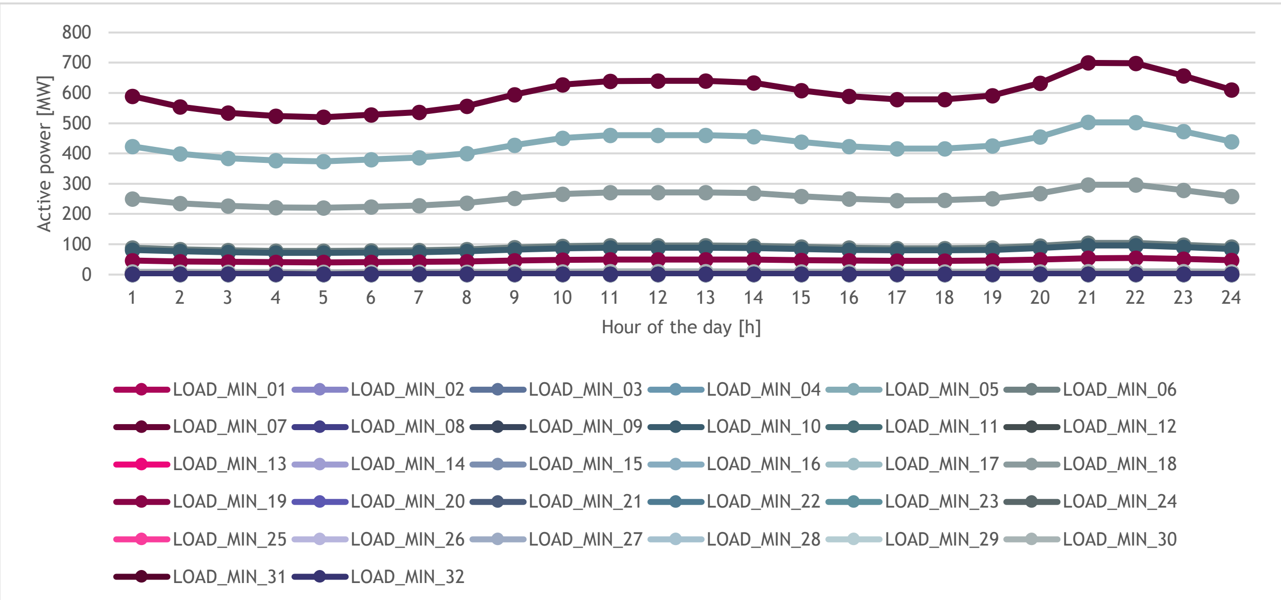

Figure 86. Load profiles in MIN scenario - Workstream 3 - Cadiz

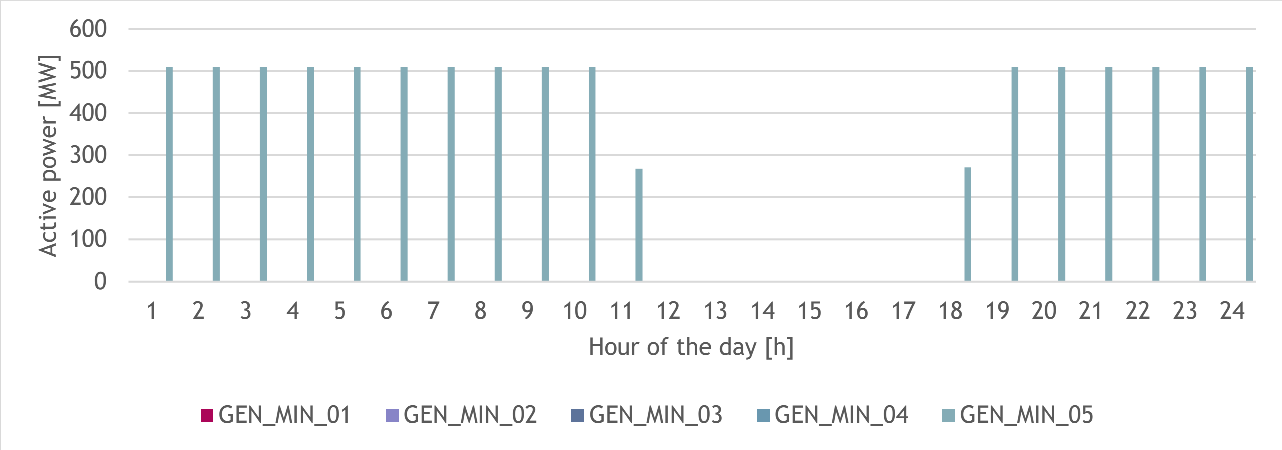

Figure 87. Generation profile for dispatched generators in MIN scenario - Workstream 3 - Cadiz

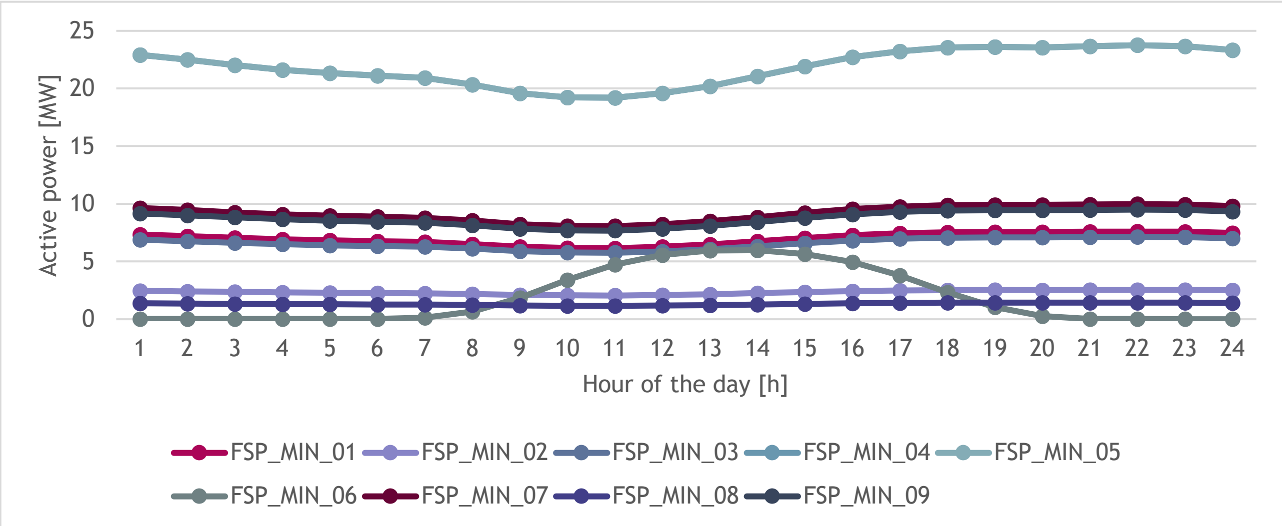

Figure 88. Generation profiles for RES in MIN scenario - Workstream 3 - Cadiz

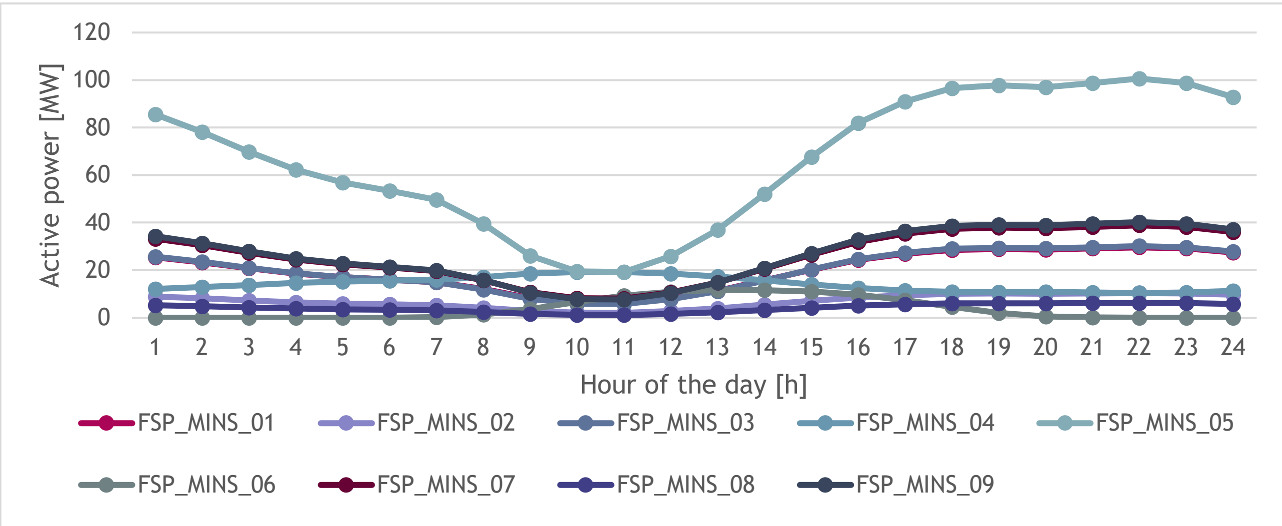

Figure 89. Synthetic generation profiles for RES in MINS scenario - Workstream 3 - Cadiz

5.3.2. FSPs characteristics

Table 50 enumerates the FSPs connected to the transmission grid in the demo site of Cádiz.

Table 50: Transmission-connected FSP characteristics for the Spanish case study - Cádiz site in workstream 3

Generator ID	Zone	Type	Capacity [MVA]
Gen0	Pinar del Rey	Dispatchable generator	447.2
Gen1	Puerto de la Cruz	Dispatchable generator	447.2
Gen2	Puerto de la Cruz	Dispatchable generator	447.2
Gen3	Pinar del Rey	Dispatchable generator	600
Gen4	Pinar del Rey	Dispatchable generator	600

On the other hand, Table 51 lists the FSPs considered in the Spanish case study for workstream 3 connected to the distribution grid. The capability to contribute to voltage support follows the approach described in section 5.1.3 considering $R_{lead}^{(min)} = R_{lag}^{(min)} = 0$.

Table 51: Distribution-connected FSP characteristics for the Spanish case study - Cádiz site in workstream 3

FSP ID	Zone	FSP type	FSP Capacity [MVA]	FSP bid price [€/MVArh]
Fsp0	Puerto de la Cruz	Wind generator	33.0	13.44
Fsp1	Puerto de la Cruz	Wind generator	11.6	14.70
Fsp2	Pinar del Rey	Wind generator	33.5	14.70
Fsp3	Pinar del Rey	Wind generator	111.8	14.00
Fsp4	PEESA-PESUR	Wind generator	111.8	14.42
Fsp5	Guadarranque	PV plant	12.9	13.44
Fsp6	PESUR	Wind generator	43.3	13.86
Fsp7	PEESA	Wind generator	6.9	14.70
Fsp8	PEESA	Wind generator	44.7	14.14

5.3.3. Cadiz SRA scenarios

For the scalability and replicability analysis of voltage control in the Cadiz case study, different scenarios are tested according to Table 52. These scenarios differ in terms of the adopted coordination scheme, grid topology, resources availability, FSP number and location. The pilot busses in the distribution network are all busses having a nominal voltage of 66 kV, while the pilot busses in the transmission network are all busses having a nominal voltage of 220 kV. In all scenarios the minimum and maximum voltge limits considered for safe operation are respectively 0.95 and 1.05 (values expressed in per unit). No voltage violations have been detected in the baseline scenarios (AC0 and AM0) considering as minimum and maximum voltage limits the values 0.93 and 1.07. The open loop topology refers to the network operation status in which the line that connects the two HV substations is open; hence the two HV substations are not directly connected. Conversely, in closed loop scenarios the two HV substations are directly connected by a dedicated line.

Table 52: SRA scenarios for the Cadiz case study in workstream 3

Scenario ID	Coordination scheme	SRA parameters
AC0	Common	Topology: Open loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators off: None
AM0	Multi-level	
AC1	Common	Topology: Open loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators off: n° 2
AM1	Multi-level	
AC2	Common	Topology: Open loop Scenario profiles: MIN Voltage limits: [0.95, 1.05] Generators off: n° 2
AM2	Multi-level	
AC3	Common	Topology: Open loop Scenario profiles: MINS Voltage limits: [0.95, 1.05] Generators off: n° 2
AM3	Multi-level	
AC4	Common	Topology: Open loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators off: n° 0
AM4	Multi-level	
AC5	Common	Topology: Open loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators off: n° 1
AM5	Multi-level	
AC6	Common	Topology: Open loop Scenario profiles: MINS Voltage limits: [0.95, 1.05] Generators off: n° 0
AM6	Multi-level	
AC7	Common	Topology: Open loop Scenario profiles: MINS Voltage limits: [0.95, 1.05] Generators off: n° 1
AM7	Multi-level	
BC1	Common	Topology: Closed loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators off: n° 2
BM1	Multi-level	
BC2	Common	Topology: Closed loop Scenario profiles: MINS Voltage limits: [0.95, 1.05] Generators off: n° 2
BM2	Multi-level	
BC3	Common	Topology: Closed loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators off: n° 0
BM3	Multi-level	
BC4	Common	Topology: Closed loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators off: n° 1
BM4	Multi-level	
BC5	Common	Topology: Closed loop Scenario profiles: MINS Voltage limits: [0.95, 1.05] Generators off: n° 0
BM5	Multi-level	

For each scenario, three cases are considered, as shown in Table 53. The three selected cases allow to investigate the impact of the number and location of the FSPs on the performance of voltage control and the related market procurement.

Table 53: Cases for SRA scenarios for the Greek case study in workstream 3

Case ID	FSPs participation	SRA parameters
Case 0	Fsp6	Coordination scheme FSP number and location
Case 1	Fsp0, Fsp1, Fsp5, Fsp6	
Case 2	All FSPs	

5.3.4. Analysis of scenarios for workstream 3 – Spanish demo (Cadiz)

The power flow analysis for the Cadiz SRA scenarios introduced in Table 52 allows to identify the relevant scenarios in terms of occurrence of voltage violations. Table 54 provides an overview of the result of the power flow analysis of the Cadiz SRA scenarios. Only in some of the simulated scenarios voltage violations occur; thence, the market performance assessment focus on the scenarios that show voltage violations to be solved by running the reactive power support market.

The flexibility need can be quantified by identifying the voltage violations and subsequently quantifying the voltage variations required to comply with the operational limits. The analysis of the scenarios highlights the occurrence of voltage violations in the MAX scenarios, while no voltage violations occur in the case of the MIN scenarios. Nevertheless, for some network configurations, voltage issues occur in the case of the synthetic MIN profiles.

Moreover, in the network scenarios characterized by the open loop topology the voltage violations are more likely to occur. In network scenarios characterized by the closed loop topology, the two HV busbars that characterize the grid of the Cadiz demo site are directly connected. In the closed loop topology voltage violations are less possible due to the higher interconnection of busses that enhances the voltage support effects among the network busses.

For each FSP participating in the market the voltage sensitivity factors are computed for each hour as described in 5.1.

A day-ahead flexibility market-clearing is carried out to solve the voltage violations identified using the most efficient flexibility bids from FSPs at minimum cost according to the approach described in sections 5.1.3, 5.1.4, and 5.1.5. Once the market is cleared, the evaluation of the market result is done by running a power flow to check the technical performance of the market.

The analysis of the scenarios highlights the occurrence of voltage violations in the MAX scenarios, while no voltage violations occur in the case of the MIN scenarios. Nevertheless, for some network configurations voltage issues occur in the case of the synthetic MIN profiles.

Moreover, in the open loop topology scenarios, voltage violations are more likely to occur. In closed loop topology scenarios, the HV busbars are directly connected, which lowers the occurrence of voltage violations.

As for the analysis of the Greek demo site described in section 5.2, the voltage sensitivity factors are computed for each hour for each FSP participating in the market relative, as described in 5.1.

According to the approach described in sections 5.1.3, 5.1.4, and 5.1.5, the day-ahead flexibility market-clearing is carried out to solve the voltage violations at minimum cost using the most efficient FSPs. After market clearing, market evaluation is done running a power flow to check the technical performance.

Table 54. Identification of the voltage violations for Cadiz SRA scenarios

Scenario ID	Coordination scheme	Presence of voltage violations [Hours of the day]	Voltage violations type
AC0	Common	10 11 19 20 21 22	Undervoltage
AM0	Multi-level		
AC1	Common	10 11 19 20 21 22	Undervoltage
AM1	Multi-level		
AC2	Common	No Voltage violations	No Voltage violations
AM2	Multi-level		
AC3	Common	No Voltage violations	No Voltage violations
AM3	Multi-level		
AC4	Common	10 11 12 13 18 19 20 21 22	Undervoltage
AM4	Multi-level		
AC5	Common	9 10 11 12 13 14 15 16 17 18 19 20 21 23	Undervoltage
AM5	Multi-level		
AC6	Common	3 4 5	Overvoltages
AM6	Multi-level		
AC7	Common	No Voltage violations	No Voltage violations
AM7	Multi-level		
BC1	Common	No Voltage violations	No Voltage violations
BM1	Multi-level		
BC2	Common	No Voltage violations	No Voltage violations
BM2	Multi-level		
BC3	Common	10 11 19 20 21 22	Undervoltage
BM3	Multi-level		
BC4	Common	No Voltage violations	No Voltage violations
BM4	Multi-level		
BC5	Common	No Voltage violations	No Voltage violations
BM5	Multi-level		

5.3.5. SRA results for the workstream 3 – Cadiz demo

The SRA results for workstream 3 for the Cadiz demo are described in this section to highlight the differences and similarities existing between the performance achieved by the common and multi-level market models if applied to different network scenarios. Among the scenarios in Table 52, this section discusses only the scenarios that in Table 54 show voltage violations since only in these cases the need for a reactive power market exists.

Figure 90 compares the SRA scenarios for the Cadiz demo in terms of residual voltage violations; it highlights that the reactive power market is not able to solve all voltage violations in all scenarios. The market is not able to solve all voltage congestions in scenarios AC4, AM4, BC3-C0, and BM3-C0. Scenarios AC4 and AM4 are characterized by the loss of Generator nº 0, also scenarios BC3-C0 and BM3-C0 describe the case in which Generator nº 0 is off, however in BC3-C0, and BM3-C0 line nº16 is closed and the only FSP available is PESUR. Hence, Figure 90 highlights the scenarios in which the available resources for voltage support are not sufficient for solving all expected voltage violations. Moreover, Figure 90 points out that the common and the multi-level market models have the same effectiveness in solving voltage violations. It is worth noting that in this case the multi-level market model is limited to the distribution system market clearing since no voltage violations are detected in the transmission system pilot busses (Table 54), hence no transmission system market clearing occurs.

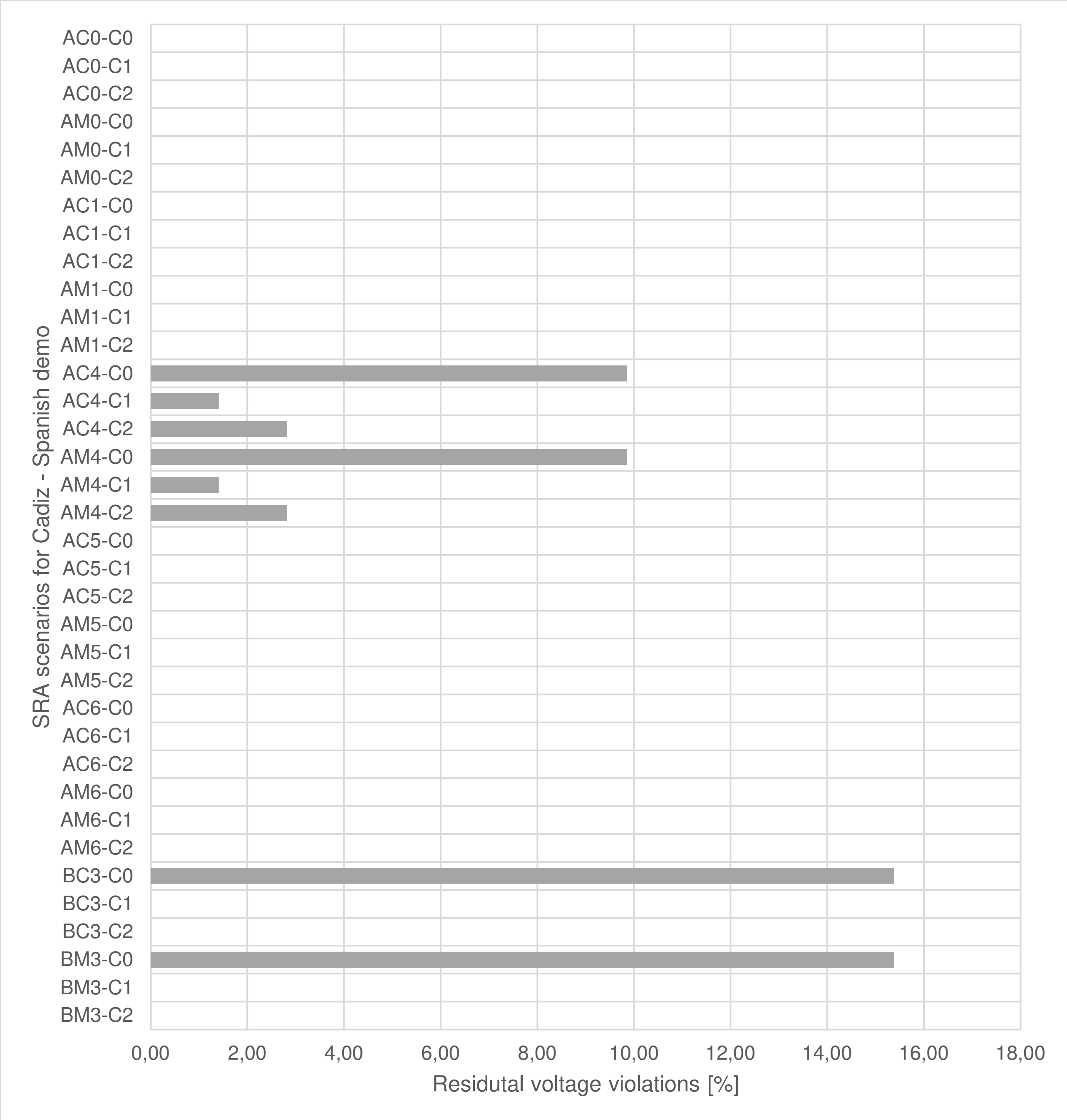

Figure 90. Comparison of SRA scenarios for the Cadiz demo – residual voltage violations - workstream 3

Figure 91 and Figure 92 compare the SRA scenarios for the Cadiz demo in terms of daily procurement cost (calculated according to the pay as bid mechanism) and reactive power support acquired from FSPs. Figure 91 depicts the scenarios with no residual voltage violations while Figure 92 concerns the scenarios with nonzero residual voltage violations. In both charts, the first two metrics are reported in relative terms to the result achieved by scenario AC0, which values are reported in Table 55. Since the absence of voltage violations on transmission system pilot busses and FSPs connected to the transmission system, the performance achieved by the common market and multi-level market models overlap.

Figure 91 and Figure 92 highlight the impact on the voltage support to be acquired depending on the availability of the dispatchable generators connected to the two HV busbars. Considering the topology characterised by no interconnection between the two HV busbars, the most severe scenario occurs when the generator n° 0 is not available (connected to Pinar del Rey) since the majority of FSPs is connected closer to the Puerto de la Cruz HV busbar. Accordingly, in the scenarios AC4 and AM4 characterised by the unavailability of generator n°1 (connected to Pinar del Rey), all voltage violations (undervoltages) are solved by the market that procures the highest amount of reactive power support. In the case of the closed loop topology, the most severe scenario also occurs when generator n° 0 is not available; however, this scenario is characterised by the emergence of overvoltages due to the high distributed generation peak. In this scenario, the voltage violations are not solved by the market in the cases in which only FSP n° 0 is available. Hence, as shown in Figure 91 and Figure 92, the augmented availability of potential FSPs located in different nodes is beneficial for solving the voltage problems as it leads to a smaller overall amount of reactive power support to be acquired through the market since FSPs located in more effective busses are available; as a consequence the operating expenses for voltage control are reduced.

Table 55. Reference scenario values - SRA for the Greek demonstrator

Scenario			AC0	AC0	AC0
Case			0	1	2
Daily cost	Pay as Bid	[€]	248.74	259.11	178.63
Daily cost	Pay as Clear	[€]	248.74	259.11	187.95
Daily cost	Pay as Bid Distribution System FSPs	[€]	248.74	259.11	178.63
Daily cost	Pay as Bid Transmission System FSPs	[€]	0.00	0.00	0.00
Daily cost	Pay as Clear Distribution System FSPs	[€]	248.74	259.11	187.95
Daily cost	Pay as Clear Transmission System FSPs	[€]	0.00	0.00	0.00
Reactive power	Support acquired (Q) Distribution System FSPs	[MVArh]	18.51	18.51	12.79
Reactive power support acquired (Q)	Support acquired (Q) Transmission System FSPs	[MVArh]	0.00	0.00	0.00
Reactive power support acquired (Q)	Overall support acquired (Q)	[MVArh]	18.51	18.51	12.79
Residual violations		[%]	0	0	0
Initial violations		[n°]	25	25	25

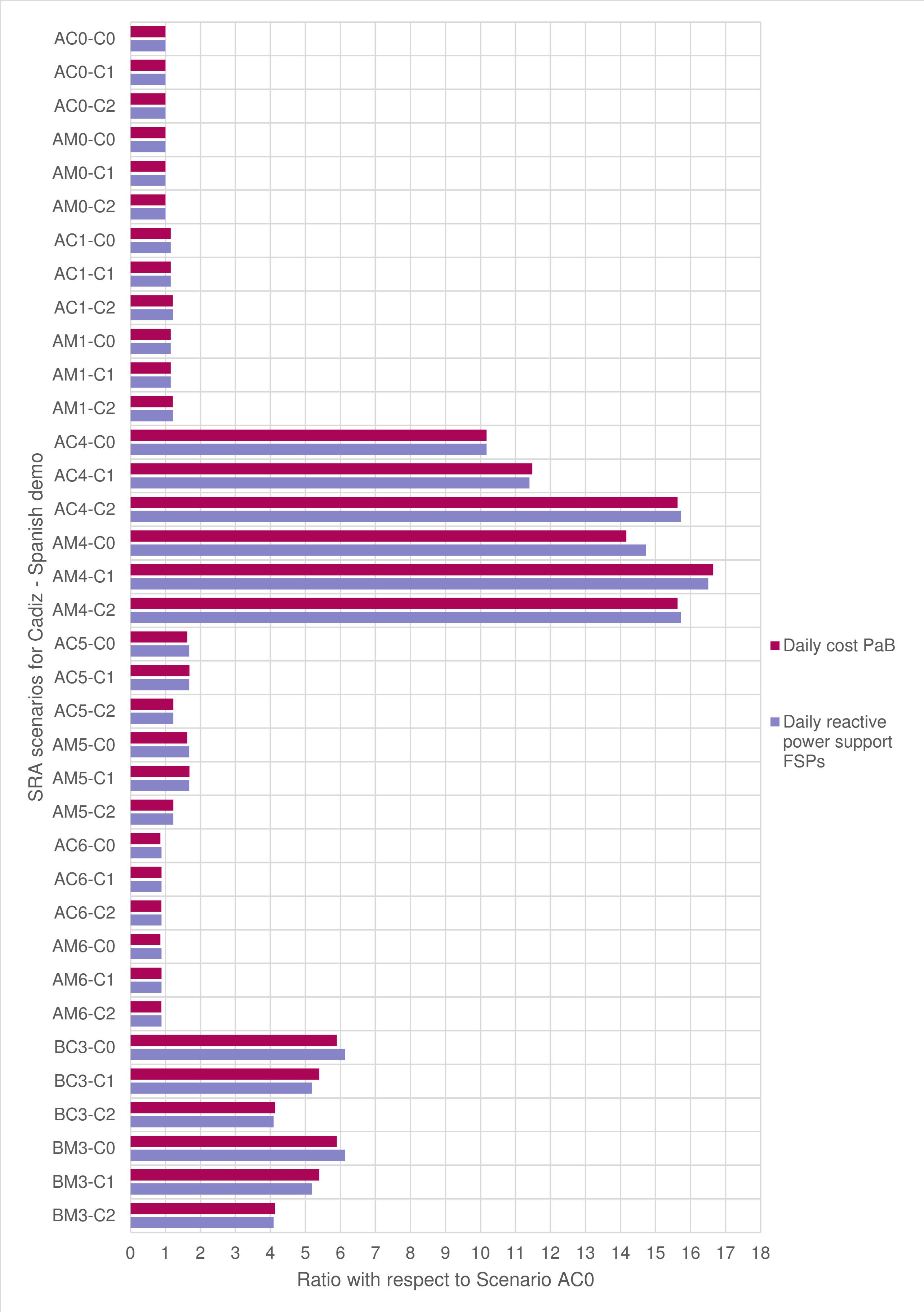

Figure 91. Comparison of SRA scenarios for the Cadiz demo - workstream 3

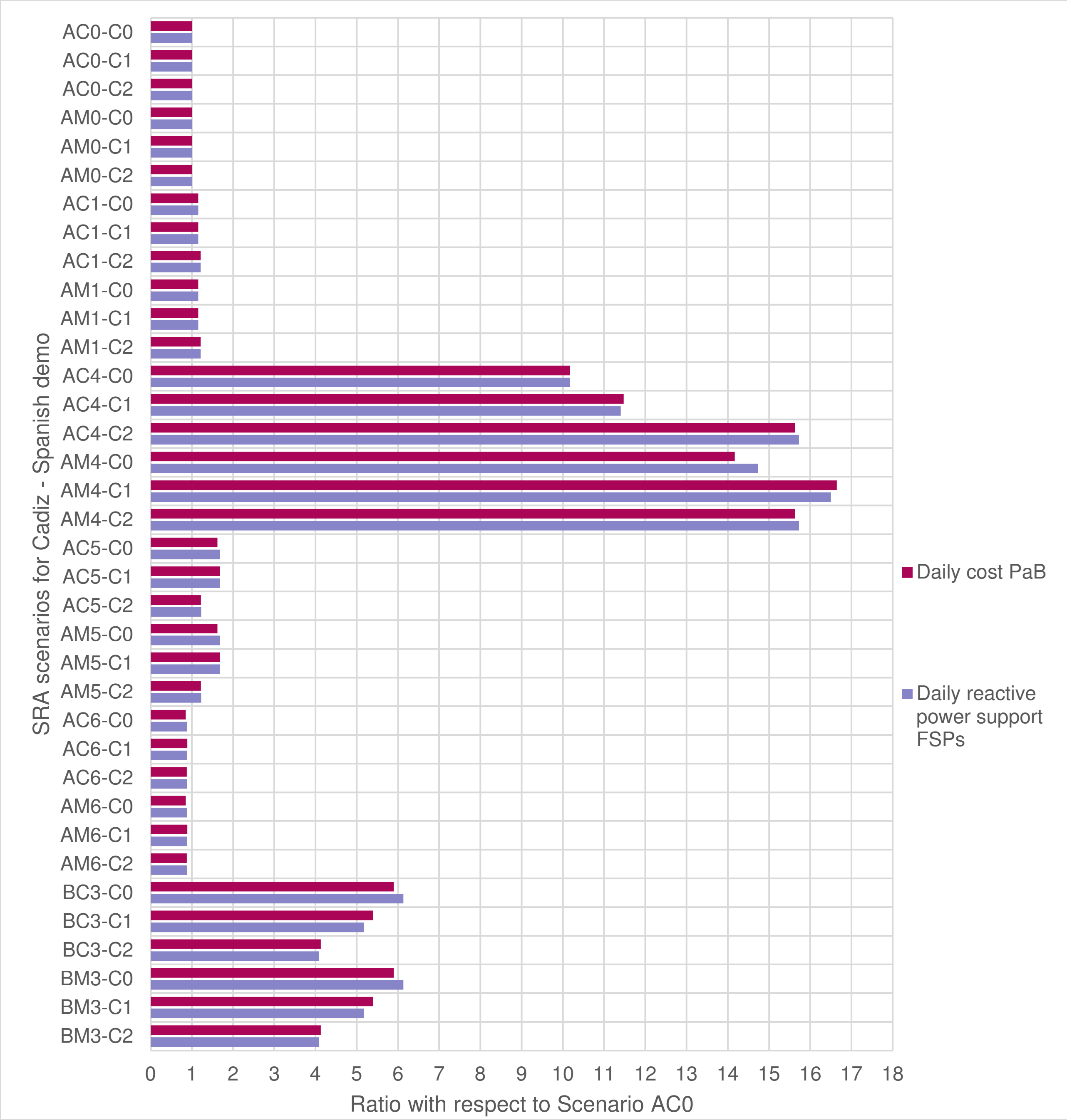

Figure 92. Comparison of SRA scenarios for the Cadiz demo - workstream 3

Figure 93 compares the SRA scenarios for the Cadiz demo site defined in Table 52 in terms of the remuneration for the FSPs calculated according to the pay as bid and pay as clear mechanisms and the share of residual voltage violations after the market clearing. Figure 94 allows the comparison of the SRA scenarios for the Cadiz demo in terms of reactive power support procured from FSPs and the corresponding residual voltage violations.

Figure 93 highlights that the studied scenarios lead to a small difference between the amount of remuneration for the FSPs calculated using the two remuneration mechanisms since voltage problems are solved by resorting to the FSPs that offer lower priced bids. The difference between the remuneration calculated through the two different mechanisms increases in the scenarios characterized by nonzero residual voltage violations. In these scenarios, the market aims to procure a larger amount of reactive power support (see also Figure 94) hence clearing bids with a higher price.

Figure 93. Comparison of SRA scenarios for the Cadiz demonstrator in terms of FSP remuneration and residual voltage violations.

Figure 94 shows that, given the same topology and availability of dispatchable generators, an increased number of potential FSPs located in the various busses of the network allows the market to procure a smaller amount of reactive power support to solve the voltage violations. Figure 94 points out that, in some scenarios even with a higher amount of reactive power support procured from the available resources, not all voltage violations can be solved.

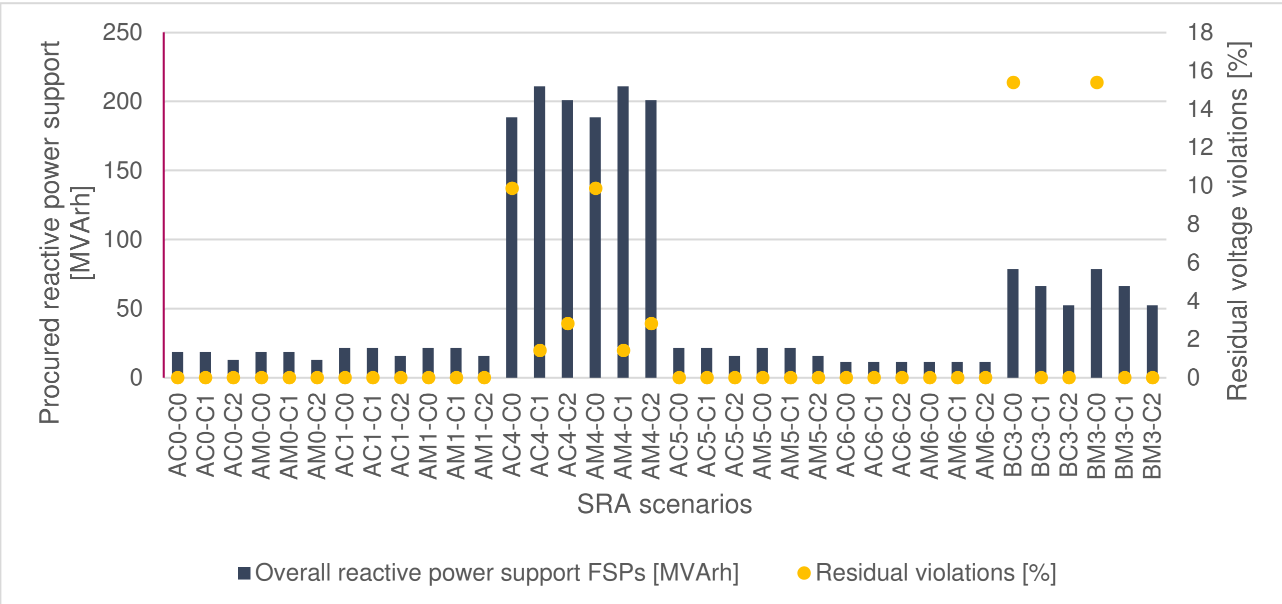

Figure 94. Comparison of SRA scenarios for the Cadiz demonstrator in terms of reactive power support from FSPs and residual voltage violations.

Table 56 compares the Cadiz SRA scenarios in terms of the average cost for solved voltage violations. Multi-level and common market model show the same average cost for solved violations since the absence of voltage violations in transmission system pilots nodes make the two market models functioning equivalent.

Table 56. Comparison of Cadiz SRA scenarios in terms of residual voltage violations and average cost for solving the voltage issues

Scenario ID	Residual violations [%]	Average cost for solved violation [€/nº]
AC0-C0	0.00	9.95
AC0-C1	0.00	10.36
AC0-C2	0.00	7.15
AM0-C0	0.00	9.95
AM0-C1	0.00	10.36
AM0-C2	0.00	7.15
AC1-C0	0.00	10.65
AC1-C1	0.00	11.09
AC1-C2	0.00	8.04
AM1-C0	0.00	10.65
AM1-C1	0.00	11.09
AM1-C2	0.00	8.04
AC4-C0	9.86	19.77
AC4-C1	1.41	21.24
AC4-C2	2.82	20.23
AM4-C0	9.86	19.77
AM4-C1	1.41	21.24
AM4-C2	2.82	20.23
AC5-C0	0.00	10.71
AC5-C1	0.00	11.15
AC5-C2	0.00	8.10
AM5-C0	0.00	10.71
AM5-C1	0.00	11.15
AM5-C2	0.00	8.10
AC6-C0	0.00	8.98
AC6-C1	0.00	9.35
AC6-C2	0.00	9.26
AM6-C0	0.00	8.98
AM6-C1	0.00	9.35
AM6-C2	0.00	9.26
BC3-C0	15.38	47.90
BC3-C1	0.00	37.07
BC3-C2	0.00	28.39
BM3-C0	15.38	47.90
BM3-C1	0.00	37.07
BM3-C2	0.00	28.39

5.3.6. Dual Cadiz Voltage control scenarios

In addition to the scenarios described in Table 54, Workstream 3 considers extreme scenarios where only one dispatchable generator is available in the Cadiz demo grid. As shown in Table 57, these additional scenarios are dual to some of scenarios in Table 54. Since only one dispatchable generator is available for each scenario, the burden related to the reactive power support that needs to be acquired through the market is higher than in the case of the scenarios described in Table 54.

Table 57: Dual SRA scenarios for the Cadiz case study in workstream 3

Scenario ID	Coordination scheme	SRA parameters
Dual-AC1	Common	Topology: Open loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators ON: n° 2 Generators OFF: n° 0,1,3,4
Dual-AM1	Multi-level	
Dual-AC4	Common	Topology: Open loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators ON: n° 0 Generators OFF: n° 1,2,3,4
Dual-AM4	Multi-level	
Dual-AC6	Common	Topology: Open loop Scenario profiles: MINS Voltage limits: [0.95, 1.05] Generators ON: n° 0 Generators OFF: n° 1,2,3,4
Dual-AM6	Multi-level	
Dual-BC3	Common	Topology: Closed loop Scenario profiles: MAX Voltage limits: [0.95, 1.05] Generators ON: n° 0 Generators OFF: n° 1,2,3,4
Dual-BM3	Multi-level	

For the analysis of the additional scenarios, three cases are considered for each scenario, as shown in Table 54. The three selected cases allow investigating the impact of the number and location of the FSPs on the performance of voltage control and the related market procurement.

Table 58: Cases for SRA scenarios for the Spanish case study in workstream 3

Case ID	FSPs participation	SRA parameters
Case 0	Fsp6	Coordination scheme FSP number and location
Case 1	Fsp0, Fsp1, Fsp5, Fsp6	
Case 2	All FSPs	

Figure 95 compares the dual scenarios in terms of the technical performances achieved: the overall reactive power support acquired from the FSPs and the share of residual voltage violations.

The scenarios Dual-AC1and Dual-AM1 are characterized by the highest share of residual voltage violations. In the maximum loading conditions and open loop topology the unavailability of all dispatchable generators except generator n°2 determines the impossibility of solving all voltage violations that occur even after acquiring a large amount of reactive power. The share of residual voltage violations decreases from 86% to 23% if all FSPs are available. Figure 95 shows that the share of residual voltage violations in the other dual scenarios is zero. In the case of the multi-level market model, this result is achieved already after the distribution system market clearing; hence the voltage violations on transmission system busses are solved indirectly thanks to the reactive power support acquired from FSPs to solve the distribution system voltage violations; no transmission system reactive power market is necessary.

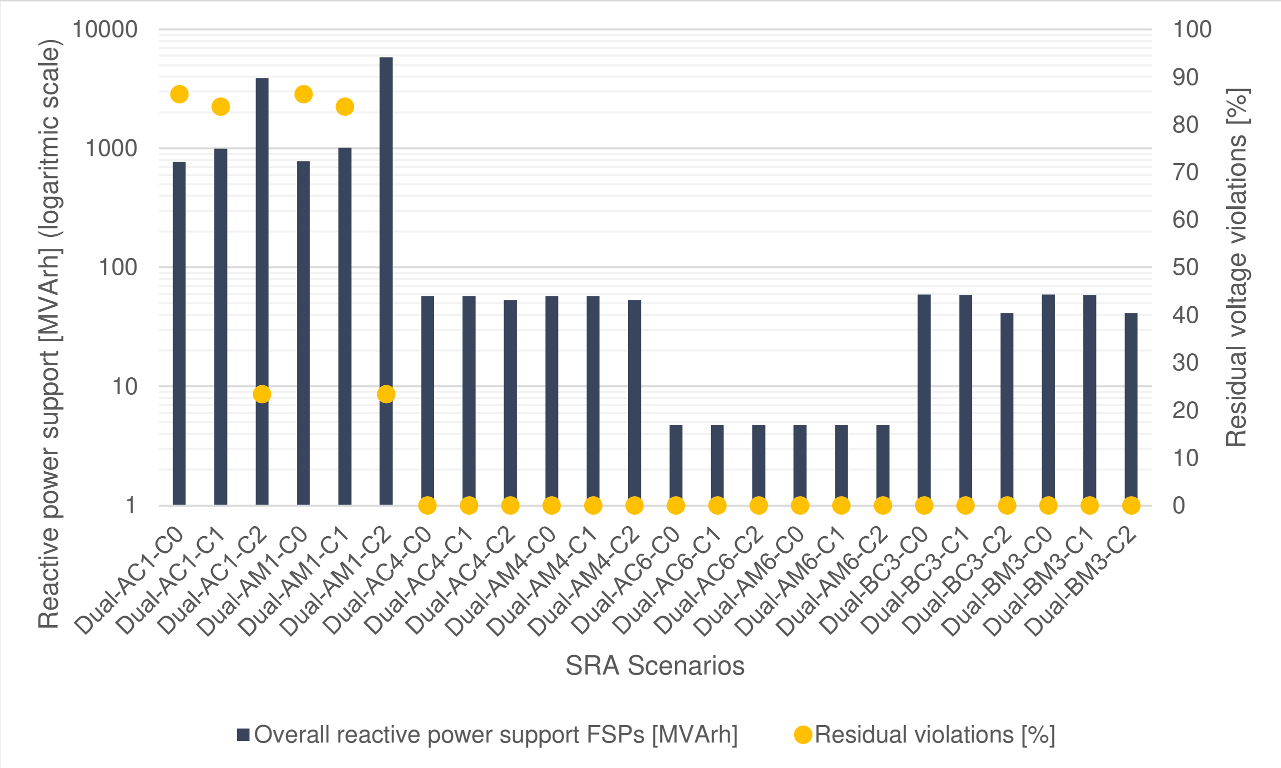

Figure 95. Comparison of dual SRA scenarios for the Cadiz demonstrator in terms of reactive power support from FSPs and residual voltage violations.

Figure 96 depicts for each dual scenario the cost for acquiring the reactive power support calculated considering the pay as bid and the pay as clear mechanisms, and the share of residual voltage violations. The scenarios characterized by the resolution of all voltage violations show the equivalence of the costs that occurred for acquiring reactive power support for both adopted market models. Considering scenarios Dual-AC1and Dual-AM1, the common market model determines the reactive power support procurement cost to be lower than the cost achieved in the case of the multi-level market model. The cost difference between the two market models reaches its maximum in the case in which all FSPs participate in the market. The analysis of the dual scenarios highlights that the common market model reaches better technical and economic performance than the multi-level market model in cases in which residual voltage violation occurs after the overall market clearing. The two market models are equivalent in the scenarios in which no voltage violations occur after the overall market clearing.

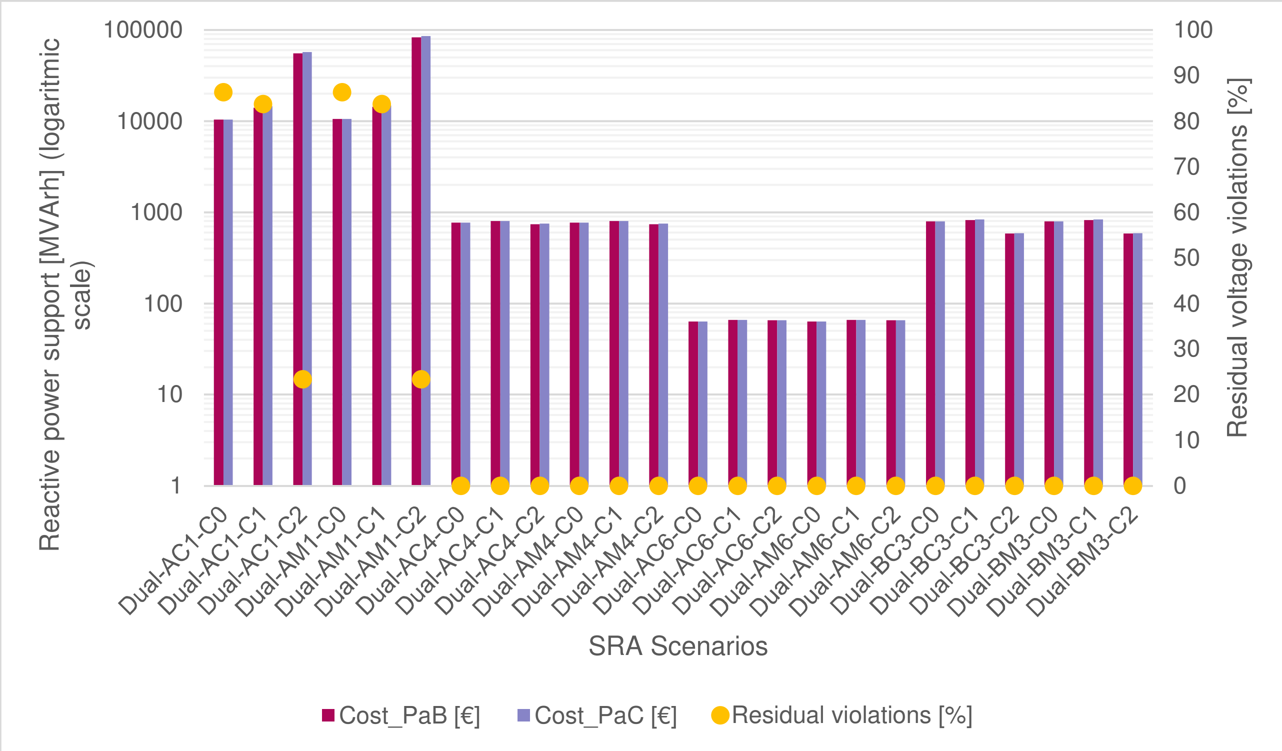

Figure 96. Comparison of dual SRA scenarios for the Cadiz demonstrator in terms of FSP remuneration and residual voltage violations

Table 59 compares the Cadiz SRA dual scenarios in terms of residual voltage violations and average cost for solving the voltage issues. Table 59 highlights that in scenarios in which the common and the multi-level market model achieve the same percentage of residual voltage violations the common market model determines a lower average cost for solved voltage violations. In scenarios in which there are no residual voltage violations the two market models determine the same average cost since the sequential distribution system market solves the voltage issues in transmission system. Hence, the market model functioning coincides.

Table 59. Comparison of Cadiz SRA dual scenarios in terms of residual voltage violations and average cost for solving the voltage issues

Scenario ID	Residual violations [%]	Average cost for solved violation [€/n°]
Dual-AC1-C0	86.36	246.98
Dual-AC1-C1	83.77	280.90
Dual-AC1-C2	23.38	233.89
Dual-AM1-C0	86.36	250.62
Dual-AM1-C1	83.77	286.36
Dual-AM1-C2	23.38	350.74
Dual-AC4-C0	0.00	11.68
Dual-AC4-C1	0.00	12.17
Dual-AC4-C2	0.00	11.23
Dual-AM4-C0	0.00	11.68
Dual-AM4-C1	0.00	12.17
Dual-AM4-C2	0.00	11.23
Dual-AC6-C0	0.00	7.05
Dual-AC6-C1	0.00	7.35
Dual-AC6-C2	0.00	7.27
Dual-AM6-C0	0.00	7.05
Dual-AM6-C1	0.00	7.35
Dual-AM6-C2	0.00	7.27
Dual-BC3-C0	0.00	23.45
Dual-BC3-C1	0.00	24.15
Dual-BC3-C2	0.00	17.23
Dual-BM3-C0	0.00	23.45
Dual-BM3-C1	0.00	24.15
Dual-BM3-C2	0.00	17.23

5.3.7. Voltage control for Murcia

Workstream 3 for the Spanish demo site of Murcia considers the distribution system formed by the MV and LV networks as presented in section 4.3.7. The Reference Network Model (RNM) was used to build the distribution network for the urban area of Murcia city. In addition to the MV synthetic network depicted in Figure 59 used in workstream 2, workstream 3 also considers the downstream LV subnetworks connected at the 20/0.4 kV transformers. The characteristics of the distribution network considered in workstream 3 are resumed in Table 60.

Table 60. Characteristics of the distribution network of Murcia considered in workstream 3

Feature	Values
Voltage levels	Medium voltage (132 kV and 20 kV) and low voltage (0.4 kV)
Nº of busses	7373 (6733 at 0.4 kV, 636 at 20 kV)
Nº of loads	6768
Overall load capacity	337 MVA
Nº of MV/LV transformers (20/0.4 kV)	300
Nº of MV/MV transformers (132/20 kV)	3
Nº of lines	7083

The representation of the MV network is provided in Figure 59, the representation of one of the 300 LV grids connected to the MV/LV transformers is given in Figure 97. The bus colored in red represents the secondary of the MV/LV transformer.

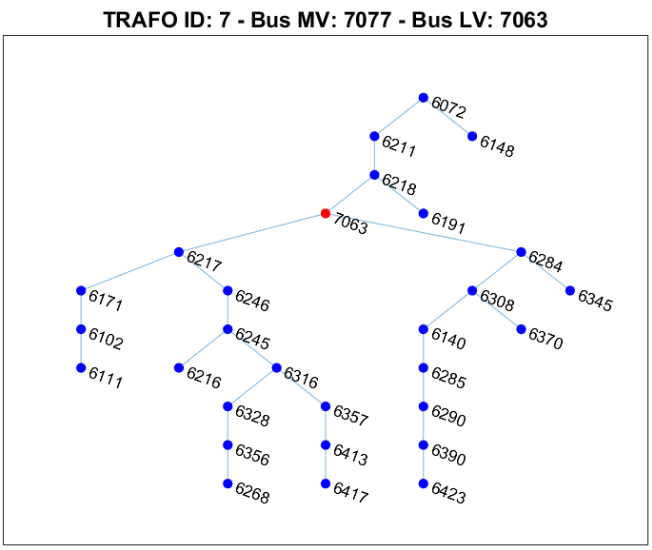

Figure 97. Representation of one of the LV grids of the distribution system of Murcia considered in workstream 3. The bus coloured in red represents the secondary of the MV/LV transformer.

The scenarios considered for the load and generation profiles are two, the MAX scenario describes the maximum net load scenario; conversely, the MIN scenario describes the minimum net load scenario. The approach for determining the representative profiles for loads and generators in the MAX and MIN scenarios and the corresponding plots are described in section 4.3.7.

Only PV generators are considered as DERs, the initial network configuration is passive (i.e. no PV generation connected to MV or LV busses). To build the baseline scenario for SRA workstream 3 it is assumed that the 10% of LV nodes and the 10% of MV nodes have a PV plant connected (676 PV plants in total). PV plants are randomly assigned to busses considering the predefined size and size distribution quota reported in Table 61.

Table 61. Predefined size and size distribution quota of PV plants - workstream 3

Generator Class	Generator type	Size [MVA]	Size quota
PV in MV busses	Small	**0.1**	**50%**
	Large	**0.3**	**50%**
PV in LV busses	Small	**0.01**	**75%**
	Large	**0.06**	**25%**

5.3.8. FSPs characteristics

The FSPs characteristics for the SRA of the Murcia demo site considered in workstream 3 follow the same assumptions described in sections 5.2.2 for the Greek and Cadiz demo sites. The potential FSPs are the PV plants since interfaced with power electronics inverters, the reactive power bid quantity is the remaining apparent power capability as described in section 5.1.3. Moreover, the lower bounds are set as $R_{lead}^{(min)} = R_{lag}^{(min)} = 0$. The reactive power bid price is the estimated amount of internal energy losses due to reactive power provision. The reactive power bid price calculation assumes an active power cost of 200 €/MWh. It is assumed that the internal power losses are lower for larger size converters (Braun, 2008, 2009); hence two different loss coefficients are considered for the two classes of FSPs (Table 61), the loss coefficient is 0.07 MWh/MVArh for PV plants in LV grid and 0.05 MWh/MVArh for PV plants connected to the MV grid. Workstream 3 assumes that the FSPs behave bidding at their marginal cost, no strategic behaviour is considered; hence, all FSPs belonging to the same category offer the reactive power support at the same price, as reported in Table 62.

Table 62. Predefined size and size distribution quota of PV plants - workstream 3

Generator type	Unitary bidding price for reactive power support
PV in MV busses	**14 €/MVArh**
PV in LV busses	**10 €/MVArh**

5.3.9. Murcia SRA scenarios

For the scalability and replicability analysis of the voltage control in the Murcia case study, different scenarios are tested. Since only the distribution system is involved, the coordination scheme considered for procuring reactive power support is the local market model. The system service need is local; hence, the scenario simulates the DSO's need of procuring reactive power support to solve the local voltage violations. The pilot busses are the MV network busses (20 kV nominal voltage magnitude), in all scenarios, the minimum and maximum voltage limits considered for safe operation are respectively 0.95 and 1.05 (values expressed in per unit).

The power flow analysis of the synthetic distribution network of Murcia was addressed to identify scenarios characterized by voltage violations. Table 63 provides an overview of the outcome of the scenario-based power flow analysis. In the baseline scenarios (S0_MAX and S0_MIN) no voltage violations are observed; hence, new scenarios have been investigated by imposing SRA parametric variations concerning load and generator size and profile shapes. Besides the baseline scenarios, Table 63 reports the derived scenarios relevant to the scope of the described SRA. Moreover, as SRA parameter is considered the share of LV and

MV nodes that host a PV plant, as shown in Table 63. Each of the scenarios in Table 63 characterized by voltage violations is studied considering six different sub-scenarios in terms of FSPs' participation as additional SRA parameters to evaluate the efficiency of the market-based procurement of reactive power for voltage support, as reported in Table 64.

Hence, the SRA parameters considered for the study of the Murcia demo site are load and generation size, load and generation profile shape, presence of DERs fed by renewables, and availability of FSPs.

Table 63. SRA scenarios for the Murcia case study in workstream 3

Sim	PV LV rate	PV MV rate	Load growth	Gen grow	Case Profile	Voltage violations
S0_MAX	0.1	0.1	1	1	MAX	No
S0_MIN	0.1	0.1	1	1	MIN	No
S01_MAX	0.1	0.1	2.34	1	MAX	19,20,21,22,23
S01_MIN	0.1	0.1	2.34	1	MIN	No
S02_MAX	0.5	0.5	2.34	1	MAX	19,20,21,22,23
S02_MIN	0.5	0.5	2.34	1	MIN	No
S03_MAX	0.9	0.9	2.34	1	MAX	19,20,21,22,23
S03_MIN	0.9	0.9	2.34	1	MIN	No

Table 64. SRA sub-scenarios for the Murcia case study in workstream 3

Sub-scenario	Share of LV PV available as FSPs	Share of MV PV available as FSPs
a	10%	10%
b	10%	50%
c	10%	100%
d	50%	10%
e	100%	10%
f	100%	100%

5.3.10. Analysis of scenarios for workstream 3 – Murcia demo site

The analysis of scenario 0 in the context of workstream 3 adopts the approach presented in 5.1. The first step is to perform a power flow analysis for 24 hours (market horizon) to detect eventual constraints. The distribution network data and load and generation profiles described in section 4.3.7 and the scenarios in section 5.3.9 are considered.

In this section, the analysis of the most relevant scenarios for SRA is described, hence scenarios S01_MAX, S02_MAX, and S03_MAX. For these scenarios, the results of step 1 are illustrated respectively in Figure 98, Figure 99, and Figure 100. In all these scenarios 1253 voltage violations are detected in the pilot busses of the network in the hours 19, 20, 21, 22, and 23 of the studied representative day. Therefore, even increasing the presence of DERs, the number of voltage magnitude criticalities in the observed network does not change, as depicted in Figure 98, Figure 99, and Figure 100, the voltage violations are undervoltages which occur during the period of the day in which PV power plants do not inject active power into the network.

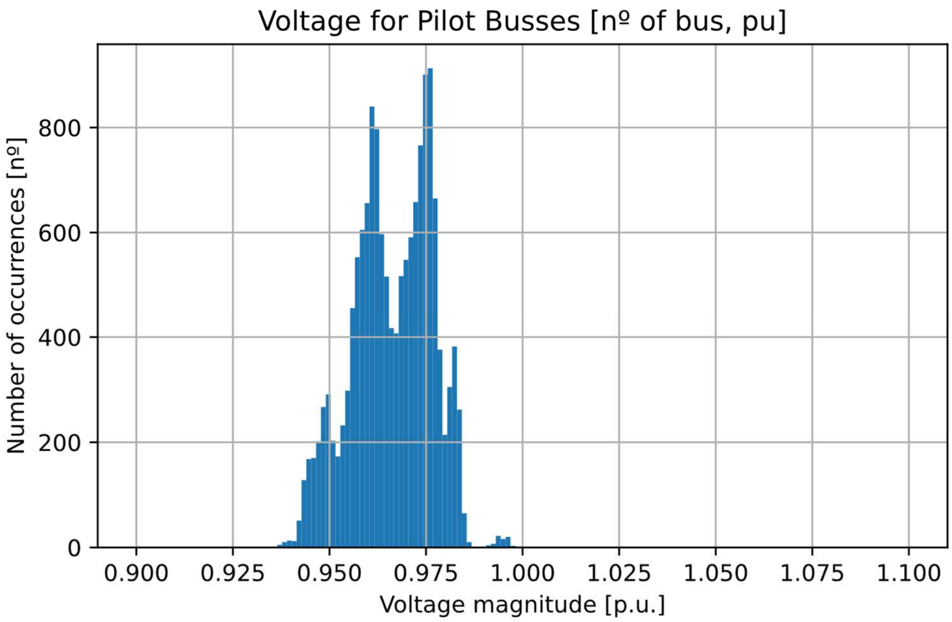

Figure 98. Distribution of voltage magnitudes for all pilot busses in the considered representative day (24 samples per bus) - scenario S01_MAX

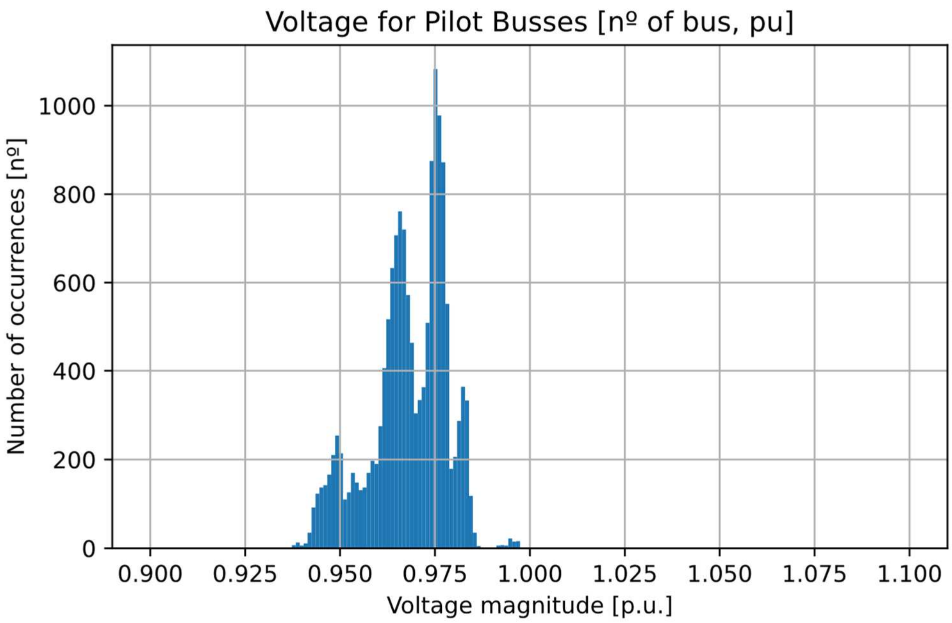

Figure 99. Distribution of voltage magnitudes for all pilot busses in the considered representative day (24 samples per bus) - scenario S02_MAX

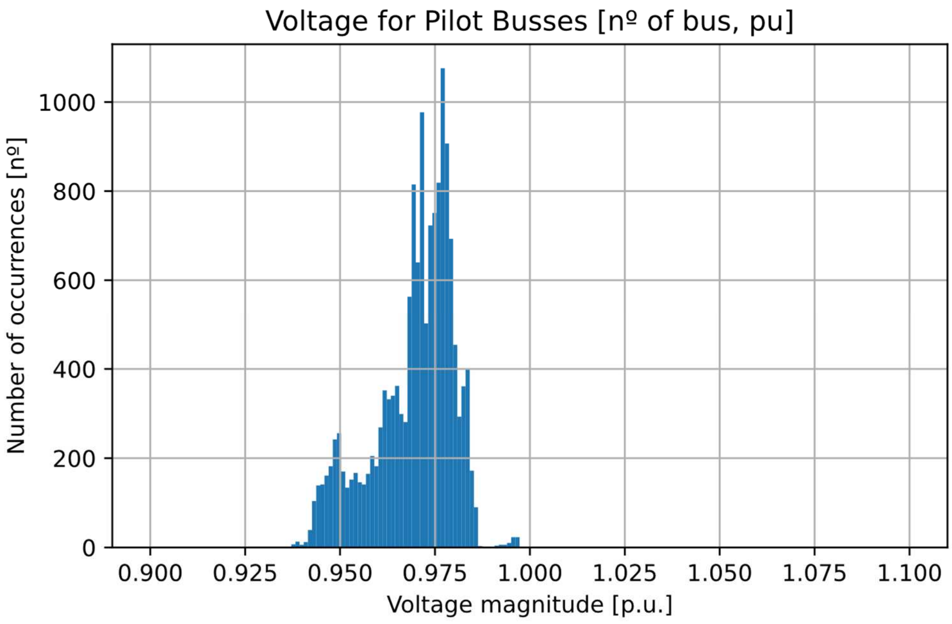

Figure 100. Distribution of voltage magnitudes for all pilot busses in the considered representative day (24 samples per bus) - scenario S03_MAX

The identification of the voltage violations and the quantification of the voltage variations required to meet the operational limits quantify the flexibility needs. For each FSP participating in the market, the voltage sensitivity factors are computed for each hour as described in section 5.1.

A day-ahead flexibility market-clearing is carried out to solve the voltage violations identified using the most efficient flexibility bids from FSPs at minimum cost according to the approach described in sections 5.1.3, 5.1.4, and 5.1.5. Once the market is cleared, the evaluation of the market result is addressed by running a power flow to check the technical performance of the market.

5.3.11. SRA results for the workstream 3 – Murcia demo site

The SRA results for workstream 3 for the Murcia demo site are described in this section and reported in Figure 101 and Figure 102. Figure 101 compares the result obtained for SRA scenarios of the Murcia demo site considering the reactive power support acquired from the FSPs and the residual voltage violations. Figure 102 compares the same scenarios in terms of the acquired reactive power support and the corresponding cost calculated considering the pay as bid and pay as clear mechanisms.

Figure 101 points out how the FSPs' location impacts the effectiveness of the voltage support acquired through the market. In the analysis of the case study of Murcia, the pilot busses considered for the voltage control belong to the MV network; hence Figure 101 allows to understand the effectiveness of the FSPs connected to the MV and LV grids. Among the studied scenarios, the class of scenarios S01_MAX are characterized by the lowest share of PV plants connected to the distribution system busses (i.e., 33 PV plants connected to the MV grid and 643 PV plants in the LV grid), hence the lowest share of the potential FSPs. As described in Table 64, in scenarios from S01_MAXa to S01_MAXc the share of PV plants connected to the MV that represent a potential FSP rises from 0.1 to 1 while the share of PV plants acting as FSPs in the LV grid is 0.1. In this set of scenarios, the reactive power support acquired from FSPs is not sufficient to solve all voltage violations, the percentage of unsolved violations is the highest among all studied scenarios. This behavior is not observed for scenarios S01_MAXd and S01_MAXe characterized by a higher share of FSPs connected to the LV network (Table 64). The reactive power support acquired from the FSPs connected to the LV network is more effective in solving the existing voltage violations than the support acquired from MV FSPs in scenarios S01_MAXb and S01_MAXc. Since for each scenario the FSP role is randomly assigned to the existing PV plant, this behavior is due to many LV FSPs that makes more likely the case of having FSPs close to the voltage violation to solve; contrariwise, the small number of MV FSPs reduces the probability of having an MV FSPs close to the voltage violations. In scenario S01_MAXf all PV plants connected to the studied distribution network act as FSP, almost all existing voltage violations are solved by the reactive power support procured from both the FSPs connected to the two considered voltage levels. The reactive power support acquired from LV FSPs is about 4/3 of the reactive power support acquired from MV FSPs. The bid price of MV FSPs is lower hence their reactive power contribution determines a reduction of the overall procurement cost with respect to the cost related to the scenario S01_MAXe, as depicted in Figure 102.

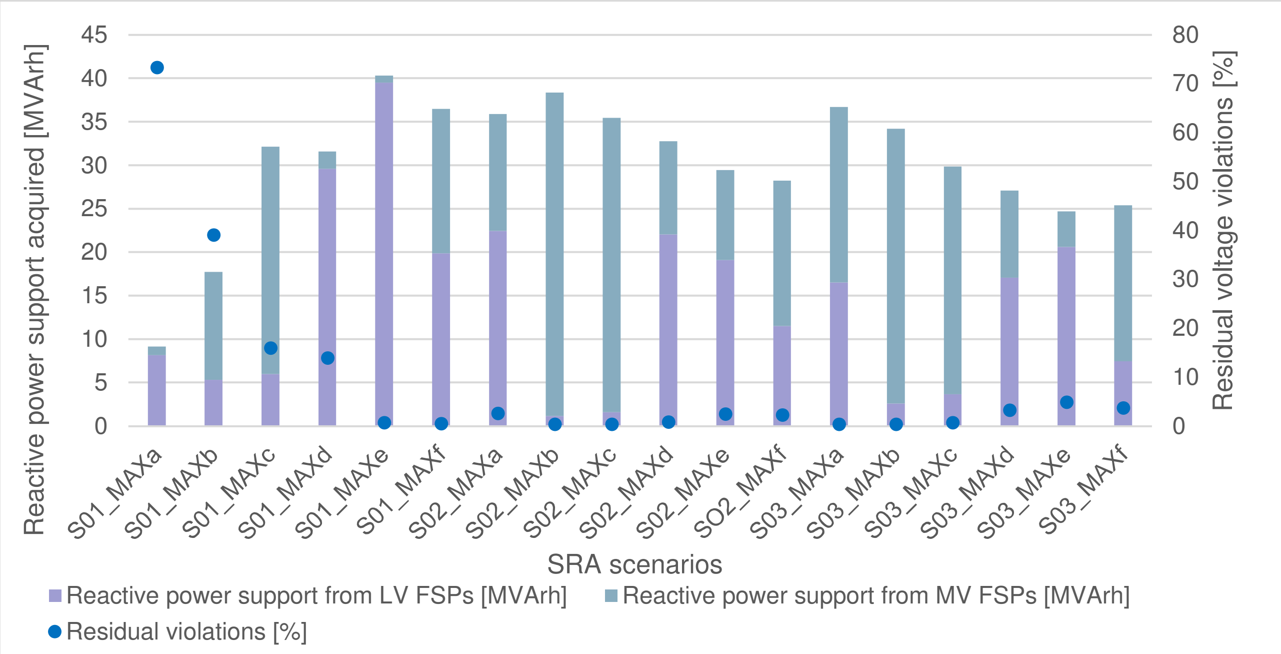

Figure 101. Comparison of SRA scenarios for the Murcia demo site considering the reactive power support acquired from the FSPs and the residual voltage violations

The classes of scenarios S02_MAX and S03_MAX are characterized by a share of PV plants in the distribution busses of 0.5 and 0.9 respectively. In S02_MAX, 3217 PV plants are connected to the LV grids while the number of PV plants connected to the MV grid is 167. In S03_MAX, the number of PV plants connected to the LV and MV grid is 5790 and 301 respectively. As depicted in Figure 101, the behavior of these two classes of scenarios is similar. The increased share of PV connected to the MV grid allows the market to activate MV FSPs able to solve the voltage violations. In the class of scenarios S02_MAX and S03_MAX, the sub-scenarios characterized a higher share of MV FSPs than the availability of LV FSPs are more effective in terms of solved voltage violations; however, the amount of reactive power procured is higher than the amount procured in the scenarios characterized by many LV FSPs. The sub-scenarios characterized by the totality of PV available as FSP show a percentage of residual voltage violations that lies between the values obtained in the sub-scenarios characterized by the majority of FSPs connected to the MV grid and the LV grids. Finally, Table 65 compares the Murcia SRA scenarios in terms of residual voltage violations and average cost for solving the voltage issues

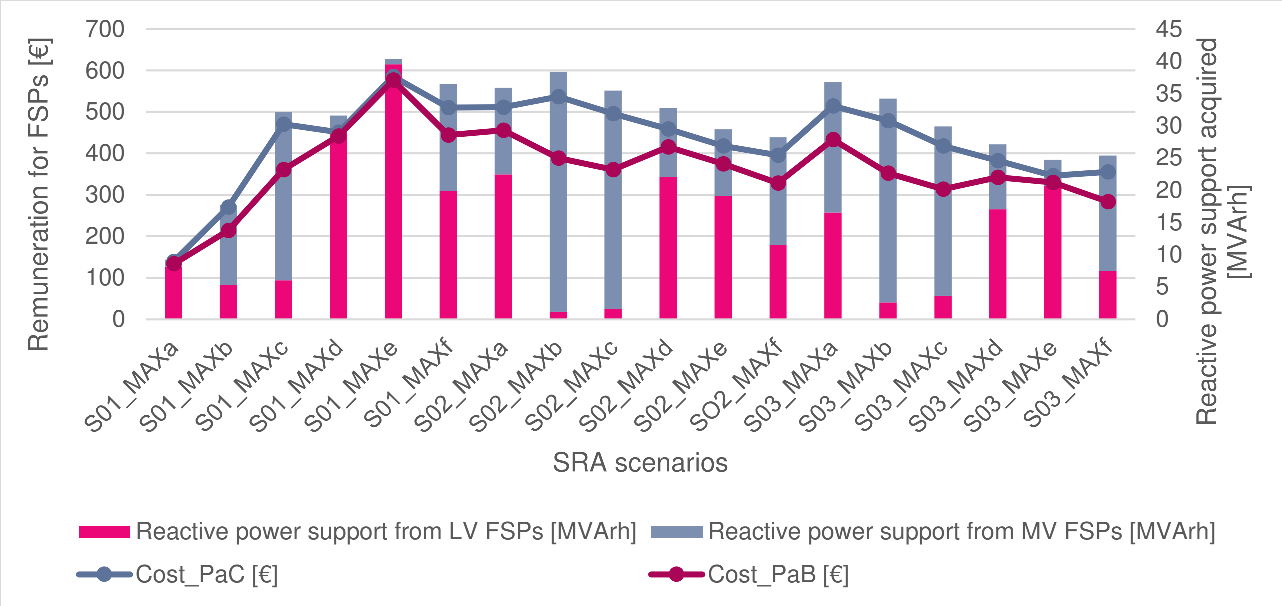

Figure 102. Comparison of SRA scenarios for the Murcia demo site considering the reactive power support acquired from the FSPs and the remuneration for the acquired reactive power calculated according to the pay as bid and pay as clear mechanisms

Table 65. Comparison of Murcia SRA scenarios in terms of residual voltage violations and average cost for solving the voltage issues

Scenario ID	Residual violations [%]	Average cost for solved violation [€/n°]
S01_MAXa	73.34	0.40
S01_MAXb	39.11	0.28
S01_MAXc	15.96	0.34
S01_MAXd	13.97	0.41
S01_MAXe	0.72	0.46
S01_MAXf	0.56	0.36
S02_MAXa	2.63	0.37
S02_MAXb	0.40	0.31
S02_MAXc	0.40	0.29
S02_MAXd	0.88	0.33
S02_MAXe	2.47	0.31
SO2_MAXf	2.31	0.27
S03_MAXa	0.40	0.35
S03_MAXb	0.40	0.28
S03_MAXc	0.72	0.25
S03_MAXd	3.27	0.28
S03_MAXe	4.95	0.28
S03_MAXf	3.75	0.24

5.3.12. Interim Conclusions

From the SRA results of the Spanish case study, it can be concluded that:

- The SRA addressed for the Cadiz demo site highlighted the impact of grid topology on the occurrence of voltage violations and the effectiveness of voltage support from FSPs. Furthermore, the presented SRA points out the effects on grid voltage magnitudes caused by the unavailability of the dispatchable generators that contribute to the voltage regulation of the HV busbars of the studied network. The addressed analysis highlighted the scenarios in which the loss of one or more dispatchable generator determines voltage violations that cannot be solved by exploiting the reactive power support of the available FSPs.
- The scenarios characterized by a radial topology present a higher share of voltage violations than the scenarios characterized by a meshed topology in which the two HV substations are connected. Moreover, undervoltages occur in the case of maximum loading conditions for radial scenarios, while overvoltages are less likely to occur. Overvoltages appear only in the case of extreme generation levels from DERs. Scenarios characterized by a closed loop topology are less prone to develop voltage issues, however, some criticality can occur under high loading conditions due to the unavailability of dispatchable generating units.

- In the studied scenarios the reactive power capacity available for voltage support is adequate to solve the observed voltage violations, also in the case in which only one unit is available (i.e. the scenarios related to the cases 0). However, grid topology influences the effectiveness of the voltage control measures. In the scenarios in which the network is operated as an open loop, fsp0 alone is not able to solve all voltage problems in the studied scenarios in which the unavailable dispatchable generator refers to the HV busbar far from the busbar to which the fsp0 is connected (i.e., due to the poor interconnection existing between the nodes, the FSP capability of solving the voltage problems is jeopardised).

- Considering every single scenario, all things being equal in terms of topology and availability of dispatchable generators, the increased availability of potential FSPs connected to different nodes allows the market to reduce the overall amount of reactive power to be procured from FSPs to achieve the same rate of resolution of the voltage violations. For some scenarios, the availability of FSPs better located in the network to the voltage issues is crucial for solving the voltage problems, providing evidence of the strict locational characteristic of voltage control. Hence, sufficiently high participation of potential FSPs is fundamental to avoid market distortions and achieving efficient procurement mechanisms.

- The results obtained for the SRA of the Murcia demo site highlight the effectiveness of reactive power for supporting voltage control in MV and LV grids. In fact, in most scenarios, the percentage of residual voltage violations is lower than 5%. Therefore, reactive power support can represent an effective means for supporting voltage control activities also in the distribution grid of urban areas.

- The SRA of the Murcia demo site underlines the extreme relevance for radial grids of the relative location between the FSPs and the voltage violations to solve. The FSPs connected to both the MV and the LV network can effectively solve the voltage issues on the MV grid if close to the pilot bus that shows a voltage magnitude outside the acceptable limits. The scenarios studied are devised relying on a random definition of the busses with FSPs availability, in the scenarios in which the randomly selected FSP busses are not electrically close to the voltage violations, the voltage support effectiveness is compromised. Therefore, even if the market is characterized by a high level of competition among sellers, the technical performance of the solution found by the market clearing can be not adequate. Addressing voltage control in radial networks by involving third parties requires approaches that foster investments in voltage support capability at the buses electrically close to the ones more likely to experience a voltage violation.

6. Qualitative SRA - Regulatory barriers to scaling-up and replication

This chapter presents the results of the regulatory SRA, performed according to the steps enumerated in section 2.2.

In order to provide a more generalized view of the BUCs in CoordiNet, instead of analyzing each individual BUC, the analysis is conducted per service and Market Model (MM). As shown in Figure 1, each BUC is generally associated to one service and one market model in one demo country[32]. One exception to this rule is the Swedish demonstration as both congestion management and balancing are combined in the multi-level MM. However, this regulatory SRA considers only a generalized matrix of services and market models, as shown in Table 66. In Table 66, each BUC in CoordiNet is linked to a service and a MM. Other possible associations of service-MM are identified, even if they are not demonstrated in CoordiNet. The remaining service-MM are market as “not applicable”, as the procurement of that service under the specific MM does not seem to be feasible. This is the case for balancing services in fragmented or distributed MMs, for example. Considering that balancing services are frequency-related, it seems less probable that this service can be procured and operated in a decentralized way (e.g. fragmented or distributed MMs). One exception to this general rule is the local balancing implementation in Sweden. In this demonstration, the physical island of Gotland, connected by a High Voltage Direct-Current (HVDC) cable, is managed by the regional DSO, reason why balancing services may be required by the distribution operator. However, considering that the replicability analysis will focus on the general case of each service-MM pair for different countries, fragmented and distributed MM for balancing are not considered. Likewise, controlled islanding is defined as a DSO-exclusive service, having as a reference the BUC developed in CoordiNet. Other controlled islanding services could be envisioned for the TSO. However, this would lead to a different BUC, not the one proposed in CoordiNet. Finally, we identify the voltage control service in a distributed MM (e.g. peer-to-peer) needs additional research, given the lack of literature and demonstrations in this field.

Table 66: Mapping of services and market models in CoordiNet

Market Model / Service	Local	Central	Common	Fragmented	Multi-level	Distributed
Balancing	SE-2	ES-2	*Not demonstrated but applicable*	*Not applicable*	SE-3	*Not applicable*
Congestion Management	ES-1b	*Not demonstrated but applicable*	ES-1a	GR-2b	SE-1a, GR-2a	SE-1b
Controlled Islanding	ES-4	*Not applicable*	*Not applicable*	*Not applicable*	*Not applicable*	*Not applicable*
Voltage Control	*Not demonstrated but applicable*	*Not demonstrated but applicable*	ES-3	GR-1a	GR-1a	*Application needs further investigation*

Different regulatory topics can have an impact on the replicability potential of the different services and market models. The identification of these topics is done in two steps. First, the relevant topics are identified for the different services, focusing on their provision by DERs, as this is the focus of CoordiNet. Second, specific topics concerning the different market models are also identified, focusing particularly on the TSO-DSO coordination aspects.

Regulatory topics concerning replicability are organized in four big groups. First, topics related to the provision of flexibility by DER to TSOs are considered. In case of the TSO, markets and procedures for the

[32] In Figure 1, the BUC ES-1 is shown as having two possible market model. However, later into the project, this BUC is referred as ES-1a and ES-1b for the common and local implementations, respectively.

provision of flexibility of transmission-connected units are already established. For the CoordiNet solutions to be replicated, these TSO mechanisms and markets would have to allow for the participation of DER. In some cases, this is already foreseen by the European regulation. Second, the provision of flexibility by DER to the DSO is analysed. As established by the Clean Energy Package, DSOs should be able to procure flexibility as a means of possibly deferring investments. For that to be possible, DSOs should be able to recover costs involved in the local flexibility procurement and have appropriate incentives to do so. Third, aggregation rules are looked upon, as aggregators (including independent aggregators) are expected to be an important enabler for flexibility provision by DERs. Finally, the current TSO-DSO coordination is considered, as a means to understand how advanced current coordination mechanisms are, and how far they are from the ones proposed in the CoordiNet project.

For each regulatory topic, a set of sub-topics is identified. For each sub-topic, a set of guiding questions are identified. These guiding questions will help steer the country assessment. Table 67 presents the final set of regulatory topics, sub-topics and guiding questions.

Table 67: Regulatory topics and guiding questions for the regulatory SRA.

Topic	Sub-topic	Question ID	Guiding questions
DER provision of services to TSOs	DER in Balancing	Q1	Can DER participate in balancing markets?
		Q2	Are there practical limitations to DER participation (e.g. min. bid size, symmetrical bidding)?
		Q3	Are all types of DERs allowed to participate in balancing markets?
	DER in Congestion Management	Q4	Can DER participate in congestion management markets?
	Voltage Control Mechanisms	Q5	Is voltage control a market-based service?
		Q6	Can DER provide voltage control?
DER provision of services to DSO	DSO economic regulation and incentives	Q7	Does regulation provide cost recovery for flexibility procurement?
		Q8	Does regulation incentivize the use of flexibility (e.g. as an alternative for grid reinforcement)?
		Q9	Are there incentives for continuity of supply?
	Market-based procurement of flexibility by DSOs	Q10	Can DER provide services to the DSO is any form (e.g. non-firm connection agreement)?
		Q11	Is there regulation for market-based procurement of flexibility?
Aggregation rules	DER aggregation rules	Q12	Can DER be aggregated in the different markets (both TSO and DSO)?
		Q13	Is the independent aggregator recognized?
		Q14	Is there a comprehensive framework for independent aggregation (e.g. adequate rules on allocation of balancing responsibility)?
Current TSO-DSO coordination	TSO-DSO planning and operation coordination	Q15	What are the coordination measures in grid operation?
		Q16	Which is the information exchanged for grid operation? In which timeframes?

In order to assess the different regulatory topics in the different countries, a regulatory survey was answered by partners of the CoordiNet project and external stakeholders. This survey is in fact an update on the survey first used at the beginning of the CoordiNet project, analyzed and published in the CoordiNet

Deliverable D1.1 (Lind & Chaves Ávila, 2019a). Considering that several regulatory frameworks have changed since the beginning of the project, an update on the original questionnaire was provided to serve as a basis not only for this regulatory replicability analysis, but also other deliverables within the WP6 of CoordiNet. In addition to the regulatory questionnaires produced in CoordiNet, other sources also helped complement the information necessary for the analysis. In particular, the latest Survey on Ancillary Service Procurement and Balancing Market Design, by ENTSO-e and the Report on Regulatory Frameworks for European Energy Networks, by CEER (CEER, 2022; ENTSO-E, 2021b).

It is important to mention that the sources used as the basis for the analysis (both the CoordiNet questionnaire and the reports by CEER and ENTSO-e) have some caveats to their methodology. Firstly, they are a relatively high-level exercise, and not all details may be captured. Secondly, as mentioned by ENTSO-e (2021b), concepts used in different countries vary, posing a difficulty in the analysis when questionnaires are answered using a single set of definitions. Finally, answers are provided by individuals to the best of their knowledge. Answers cannot always be verified for correctness and/or completeness.

Following the identification of topics to be assessed in the different countries, a mapping of regulatory topics and both services and market models is conducted. This mapping will serve to weight the assessment of countries in the different topics, providing the level of compatibility of services and MMs. Regulatory topics are mapped against the different services, as shown in Table 68. The assessment is carried out by sub-topic and uses a rating from 0 to 5. This rating system aims at capturing the level of importance of one sub-topic to one service. Although the rating system is numerical, this remains a qualitative analysis, and the rating is a product of the discussion presented in the following paragraphs.

Table 68: Mapping of regulatory topics and services. Assessment: 0-no relevance; 5-higher relevance.

Topic	Sub-topic	Balancing	Congestion Management	Controlled Islanding	Voltage Control
DER provision of services to TSOs	DER in Balancing	5	0	0	0
	DER in Congestion Management	0	5	0	0
	Voltage Control Mechanisms	0	0	0	5
DER provision of services to DSO	DSO economic regulation and incentives	0	5	5	5
	Market-based procurement of flexibility by DSOs	0	5	5	5
Aggregation rules	DER aggregation rules	2	2	2	2
Current TSO-DSO coordination	TSO-DSO planning and operation coordination	1	1	1	1

The provision of flexibility by DER to both TSO and DSO will have a high and direct impact whenever that SO is procuring the service in question. Therefore, when analyzing the provision of DER flexibility to balancing services, it is clear that “DER in Balancing” sub-topic has a high relevance, therefore being rated “5”. The relevance of the remaining “DER provision of services” sub-topics are rated low at “0”, as they should not impact balancing directly. Also, it is important to mention that the impact of the DSO sub-topics is zero for balancing, as in this regulatory SRA we are not considering the procurement of balancing services by DSOs[33]. For congestion management, the “DER in (TSO) congestion management” is rated high, as well as the two sub-topics for the DSO. As most DSOs do not have local congestion management markets organized yet, we also consider the underlying requirements for DSOs to start procuring that service (e.g. economic incentives, cost recovery). In the case DSOs are already procuring local congestion management services, this is identified in the sub-topic “Market-based procurement of flexibility by DSOs”. The service “controlled islanding” is primarily a DSO service, and therefore it is rated high for the DSO and zero for the TSO, as the impact on the TSOs activity will depend on the market model. For this service, it is important the existence of output incentives on continuity of supply, as the islanding operation will contribute to the improvement of the DSO’s indexes. Lastly, the “voltage control” is analyzed similarly to the congestion management service. It is a service that could be procured by both TSO and DSO, and therefore topics affecting its procurement are rated high for both SOs.

With regards to aggregation, this is rated “2” for all services, as aggregation can be considered an enabler for local flexibility provision and should affect them in a more homogeneous way. For some services, a higher or lower relevance rating could be debatable. Balancing markets, for example, usually have minimum bid sizes and technical requirements that limit the participation of smaller DER, making aggregation more relevant. However, as these aspects are already assessed in the “DER in Balancing” sub-topic, aggregation is also rated at “2” for balancing.

Finally, the topics related to TSO-DSO coordination are rated “1”. These aspects will impact the markets models, discussed below. In isolation, considering only the services without a specific market model, the considerations on coordination schemes become less clear.

In Table 69, a similar exercise to the one presented in Table 68 is conducted. This time, the assessment is done for regulatory topics and market models. This assessment is mostly guided by two main questions. First, who procures the service? Second, how independent is this procurement and activation by the DSO from the procurement/activation by the TSO (and vice versa)? The answer to the first question comes from the definition of market models presented in CoordiNet deliverable D1.3 (Delnooz et al., 2019). Therefore, it is safe to say that the local market model will be impacted more by DSO-related regulation than TSO-related ones. Conversely, the central market model will be impacted mostly by TSO regulation. For the common, fragmented and multi-level market model, both TSO and DSO could procure flexibility[34].

[33] One may notice that the procurement of balancing by the DSO is in fact tested in the CoordiNet project under the BUC SE-2. However, this BUC considers a particular physical feature, namely the need for balancing on an island operated by the DSO and connected by an HVDC link. Taking into consideration that the regulatory SRA is a high-level study considering the general regulatory framework in the different countries, and considering that balancing is normally a TSO’s responsibility, we focus only on the latter in this analysis.

[34] Nevertheless, for this first question (who procures the service), ratings are kept as 1 or 0, as the biggest impact will be on given by the TSO-DSO regulation topics. This way, when calculating the compatibility indexes in section 6.2, we avoid “double counting”, considering the weights of regulatory topics by service.

Table 69: Mapping of regulatory topics and market models. Assessment: 0-lower relevance; 5-higher relevance.

Topic	Sub-topic	Local	Central	Common	Fragmented	Multi-level
DER provision of services to TSOs	DER in Balancing	0	1	1	1	1
	DER in Congestion Management	0	1	1	1	1
	Voltage Control Mechanisms	0	1	1	1	1
DER provision of services to DSO	DSO economic regulation and incentives	1	0	1	1	1
	Market-based procurement of flexibility by DSOs	1	0	1	1	1
Aggregation rules	DER aggregation rules	1	1	1	1	1
Current TSO-DSO coordination	TSO-DSO planning and operation coordination	2	3	5	2	4

The answer to the second question is less straightforward. One could argue that all market models require a high degree of coordination between TSO-DSO. However, in order to find a common evaluation criterion, we look at the independence to which TSO and/or DSO can procure and activate DER flexibility in the respective MMs. Starting with the local market model, it could be assumed that the DSO could procure local flexibility with less interactions with the TSO than in other MMs. This could be especially true if the flexibility markets take place at the lower voltage levels in the distribution grid, leading to a small impact at the TSO-DSO interface. The central market model would require a higher degree of coordination and/or information exchange. As the TSO procures flexibility connected at the distribution grid, the DSO could be impacted. To mitigate this, several options could be adopted. One example is to provide the TSO with the observability over the parts of the grid to which FSPs are connected (higher information exchange). Another option is to allow the DSO to double-check the foreseen flexibility activations, imposing limitations when needed (higher coordination). In the common market model, the coordination and information could be even higher, as both TSOs and DSOs are procuring services through the same platform. This is also true for the multi-level market model, in which flexibility markets are linked to each other. The fragmented market model is the one in which coordination needs could be lower, even though both DSO and TSO are procuring flexibility. The reason for this is that the TSO does not have access to DER. Therefore, each SO only procures flexibility from resources connected at their respective grids. As mentioned in D1.3, "there is no need for a very elaborate communication between the TSO and DSO [for the fragmented MM]. Coordination would mostly be limited to certain agreements on the exchanges between the TSO/DSO interconnections." (Delnooz et al., 2019). With regards to the aggregation topics, the same rationale from Table 68 applies, and therefore it is rated "1" for all market models.

6.1. Country Assessment

In this section, eight countries are assessed based on the regulatory topics and guiding questions listed in Table 67. The list of countries is composed by the three demo countries, namely Greece, Spain and Sweden, and five additional countries: Austria, Belgium, Germany, Italy, and the Netherlands. The additional countries were selected based on the participation of external stakeholders to the consultation process carried out at the beginning of the project and the update of answers conducted within WP6 of CoordiNet. Their answers allow for a harmonized assessment, complemented when necessary by other sources as mentioned at the beginning of this chapter. Nevertheless, it worth mentioning that the information collected is not always complete or comparable. When this is the case, a certain topic may be excluded from the analysis for certain countries. The only countries in which completeness is achieved are the demo countries, for which a more comprehensive questionnaire was answered and updated, following the methodology presented in the CoordiNet deliverable D1.1 (Lind & Chaves Ávila, 2019a).

This country assessment is organized by regulatory sub-topic. For each sub-topic, first an introductory section is presented, highlighting the importance of that sub-topic for the replicability of the CoordiNet BUCs. Following the introduction, a brief country description is made, presenting the status of the sub-topic in each country of the analysis. Finally, Table 70 to Table 78 propose a rating of the sub-topic in each country, also presenting a short rationale for the choice in terms of rating.

The rating scale used for the country assessment goes from 0 to 5. In general terms, a rating of 5 means that the status of the sub-topic in the specific country is completely compatible to what is needed for the replication of the CoordiNet's BUCs. For example, a country would be rated high for "DER participation in balancing markets" if balancing markets are already open to DER participation and if no practical barriers exist to their participation. This would mean low minimum bid sizes, no requirement for symmetrical bidding, facilitated pre-qualification process, and possibly a high share of DER already participating in those markets, showing that markets are indeed already open for DER participation. Conversely, a country would be rated zero if current regulation does not allow the participation of DER in any form. In between these extremes, a gradient would exist, in which countries maybe allow for participation, but there are practical limitations to the actual participation.

6.1.1. DER participation in balancing markets

On the one hand, balancing services are procured in what can be considered liquid and well-implemented markets in most countries. Products for this type of service are harmonized across Europe by the Electricity Balancing Guideline (EBGL - EB Guideline, 2017), and are now starting to be traded cross-border with the implementation of the European platforms for the exchange of balancing energy (ENTSO-E, 2022a). The different balancing products have different characteristics in terms of activation time and automatization, limiting the potential for DER participation. However, the EBGL established that TSOs should allow the participation of DER[35] in balancing markets.

The Frequency Containment Reserve (FCR) is the fastest type of reserve, and therefore critical for the system. For this reason, several countries do not trade this service in an organized market, but rather consider it as a mandatory service for generation units able to provide it. The automatic frequency restoration reserve (aFRR) is the second reserve to be activated. It is a fast reserve, and therefore units must comply with more complex requirements to be prequalified for the provision of this service. The manual frequency restoration reserve (mFRR) is the reserve that follows, which substitutes the aFRR. This reserve has less strict communication requirements. Finally, the replacement reserve (RR) product, intended to serve as a replacement for the mFRR, is not in place in all countries. Therefore, it is not considered in this regulatory replicability analysis. Therefore, the focus of this section will be placed on the design of balancing markets for the provision of aFRR and mFRR products.

As of today, balancing markets across Europe are not fully harmonized, and therefore, specificities in every country matter in terms of replicability. Nevertheless, a harmonization effort is taking place as a consequence of the implementation of the Network Codes and Guidelines. The Electricity Balancing Guideline calls for standardization of balancing products to a certain extent. The main goal of the EBGL is to reach an integration of balancing markets across Europe. Within the scope of the EBGL are the pan-European balancing platforms that will trade the balancing products across borders, namely the PICASSO

[35] The EB Guideline mentions demand facilities, energy storage facilities and generation facilities, and the aggregation of these units.

(for aFRR trading), the MARI (mFRR), and TERRE (RR) (ENTSO-E, 2019a). It is important to note though, that the standardization proposed by the EBGL does not aim to be complete, but rather sufficient to allow cross-country trading between the different balancing markets. In practice, balancing markets will still differ among countries, and therefore, this regulatory replicability analysis is still relevant for the future scenario in which the EBGL will be fully implemented.

In addition to the definition of product harmonization, the EBGL also provides additional instructions on market design aspects that are relevant for replicability. More precisely, the EBGL provides important guidelines for the participation of resources connected to the distribution grid in balancing markets. (Schittekatte et al., 2019) shows that the recital (8) of the EBGL calls for a level-playing field for all market participants, including demand-response aggregators and assets connected to the distribution grid in the provision of balancing services. These two are precisely the two key open questions regarding the balancing market design affecting the replicability of CoordiNet's solutions, namely:

- Are balancing markets open for demand-response participation?
- Are balancing products and conditions suitable for demand/DER participation?

The review of the current situation in the abovementioned countries shows that some relevant steps have been taken in order to adapt national balancing markets. However, it also revealed that further efforts would be required to ensure a level playing field for all potential participants in these markets. This review shows that simply enabling DER and demand response to participate is not enough unless additional requirements and market conditions change as well. On the ensuing, a summary of the current situation in these countries is provided:

Greece: As of writing, there is no regulatory framework which allows the participation of DER in ancillary services markets. Only conventional units are responsible for ancillary services and participate in AS market. Nevertheless, according to ENTSO-E guidelines and the Greek energy market Target Model, ancillary service markets are foreseen to be open to DER in the near future.

Spain: Until recently, Spain could be considered a country closed for DER participation in balancing markets. The only exception was the "interruptible contract", in which the TSO tenders a certain flexible capacity from large industrial consumers. However, in December of 2019, a new resolution was approved by the regulatory authority as consequence of the directives established by the EBGL. The Resolution 18423/2019 now recognizes four types of balancing providers, namely generation units, demand agents, units with storage, and representatives of the former three types (aggregators) (Cossent et al., 2020). Minimum bid size is set to 1 MW (Resolución 18423 de 11 de diciembre de 2019, de la Comisión Nacional de los Mercados y la Competencia, 2019). The DER units can now participate in aFRR, mFRR and RR provision. Besides having a 1 MW minimum bid size, units have to be able to comply with the required information exchange (both structural data as well as real-time data) through a control centre. Aggregation of units is allowed.

Sweden: The Swedish regulatory framework is very much linked with the ones in Norway, Finland, and Denmark, as the Nordic countries share a single market and regulation (despite having different TSOs). In principle, regulation in the Nordics allows the participation of demand response in ancillary service markets. Sweden does allow the participation of DR and aggregation, including the FCR, aFRR, mFRR products. However, a minimum bid size of 5 MW in SE4 and 10 MW in the rest of the country may be a barrier to DER participation. (Ribó-Pérez et al., 2021). Prequalification for certain products can also be challenging. Units participating in mFRR, for instance, are required to go through physical tests regarding response time and have a real-time sampling rate of 36 seconds. The units should be able to start within 15 minutes and be active for one hour (Simon Färegård & Marko Miletic, 2021). There is a Strategic Reserve service in Sweden, for which the rules state that 25% of this service is to be provided by demand response, even though its efficacy is arguable (smartEn, 2021).

Austria: Demand response and aggregation have progressively been accepted in balancing markets, starting in the year 2013 (Cossent et al., 2020). Demand response can participate in all balancing markets, as long as they fulfil the prequalification process (smartEn, 2018). In practice though, the prequalification process is still complex and imposes several limitations for certain types of demand response participation. Starting with FCR, this product has to be offered in a symmetrical way, and therefore is limited to generation. For aFRR, procured in weekly tenders, the minimum bid size is 1MW. However, pooling is allowed, provided that individual consumers maintain a communication (phone contact) with the TSO. On the prequalification process, balancing service providers (BSPs) can perform the tests in a centralized way, but they need to measure and store data on individual users/consumers. One proactive measure in Austria is the fact network charges are differentiated in case of balancing provision, being charged at a lower rate by DSOs. Also, consumers are not penalized for changing their consumption profile when providing demand response (Bertoldi, Zancanella, & Boza-Koss, 2016).

Belgium: Balancing markets open for DER participation include the FCR, aFRR and mFRR markets. Minimum bid size for mFRR is 1MW, but aggregation is allowed, and therefore this requirement is not restrictive for DR participation. Residential consumers can currently only participate in FCR markets and, recently, some first activations with residential flexibility for the FCR market have taken place. Apart from that, there is an Interruptible Service for load curtailment, a Strategic Reserve and a newly introduced Capacity remuneration mechanism in which DER can participate.

Germany: All technologies may provide frequency control services. For few big size industrial consumers in EHV grid or close to it, DR (reducing consumption) is possible. FCR, aFRR and mFRR are open to DER participation. The minimum bid size is 1 MW for most cases, and pooling is allowed. There are no limitations for technologies[36], if they can go through the prequalification process, including low voltage connected resources (Cossent et al., 2020).

Italy: Aggregated DER can participate in the provision of some ancillary services through the UVAM (translated to 'virtually aggregated mixed assets'). This participation takes place in experimental projects. According to (Murley & Mazzaferro, 2022), as of December 2021 this was extended to aFRR (energy payments only). However, high metering and testing requirements still present a barrier to DER participation.

The Netherlands: According to the assessment of smartEn (2018), The Netherlands has a reasonable amount of DR participation in balancing markets. All FCR, aFRR and mFRR are open to DER participation, but practical limitations exist. For FCR, symmetrical bids are required. For mFRR, minimum bid size is 20 MW.

Table 70 displays the rating attributed to each country for each question on the "DER participation in balancing markets" sub-topic based on the findings above. A short rationale for the rating is also provided.

[36] Some exceptions may exist. RES cannot be aggregated in the aFRR market for instance.

Table 70: Assessment table for "DER in Balancing" sub-topic

Q1	Can DER participate in balancing markets?			
Q2	Are there practical limitations to DER participation (e.g. min. biz size, symmetrical bidding)?			
Q3	Are all types of DERs allowed to participate in balancing markets?			
	Q1	*Q2*	*Q3*	*Short rationale*
Greece	1	0	0	DER cannot provide ancillary services. Updates to regulation are foreseen.
Spain	4	3	5	DER can participate in balancing markets (aFRR, mFRR and RR). DR, DG, ESS and aggregators can participate. Minimum bid size and technical requirements may limit participation.
Sweden	5	3	5	DER can participate in balancing markets. However, requirements (e.g. bid size) and prequalification requirements may limit participation. One product is set to have a minimum DR provision (the Strategic Reserve service).
Austria	5	3	5	Balancing markets are open to DER and incentives exists for their participation. Prequalification process can be complex and communication requirements can be a barrier.
Belgium	5	5	4	DER can participate in FCR, aFRR and mFRR, Interruptible Service (DR exclusive), Strategic Reserve and the Capacity Remuneration Mechanism.
Germany	5	4	5	DER can provide most balancing services and minimum bid sizes is 1 MW for most cases
Italy	2	2	2	DER can participate in experimental projects for balancing provision. Only aggregated units can participate. High metering and testing requirements still present a barrier to DER participation.
The Netherlands	4	3	4	Balancing markets are open to DER participation, but practical limitations exist, such as symmetrical bids and high minimum bid sizes.

6.1.2. DER participation in congestion management markets

On the contrary of balancing markets, congestion management markets are considerably less harmonized across European countries with regards to internal congestions. The European electricity markets are based on bidding zones. While capacity between bidding zones is limited, power transmission within bidding zones should be, in principle, unrestricted. From a European regulatory perspective, cross-border congestion management is a harmonized process, guided by the Guideline on Capacity Allocation and Congestion Management (*CACM Guideline*, 2015). Internal congestions, however, are managed through different mechanisms by each TSO. The congestion management markets defined and demonstrated in CoordiNet are one type of remedial action at the disposal of the TSO to solve internal congestions. A remedial action is defined in Article 2(13) of CACM Guideline as “any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security.” According to ENTSO-E, remedial actions may include redispatching, countertrading, topology changes, use of reactive power devices (e.g. tap-changers, capacitor banks etc), request (or control if available) additional voltage/reactive support from power plants, among others (ENTSO-E, 2015). This list of possible mechanisms is also in line with the definitions from the System Operation Guideline, Articles 20 to 23 (*SO Guideline*, 2017).

The list of possible remedial actions includes options that do not impose significant costs to the TSO, such as topology changes (ACER, 2021). Others are expected to generate costs to the TSO such as redispatching or countertrading. With regards to costly remedial actions, TSOs may use different mechanisms to solve internal congestions, one of them is a dedicated congestion management markets, as considered in the CoordiNet project. Apart from that, the TSO could also solve internal congestions by countertrading in the intraday (ID) markets, meaning that the TSO procures energy in one location to sell the same amount in another location (Meeus, 2020). Finally, TSOs could use balancing bids to solve congestions. This could be considered a way of redispatching, as the TSO could activate one upward balancing bid in one location and a downward balancing bid in another location. In fact, the annual ENTSO-E survey on ancillary services and balancing market design shows that most countries use mFRR activations for purposes other than balancing, as illustrated in Figure 103.

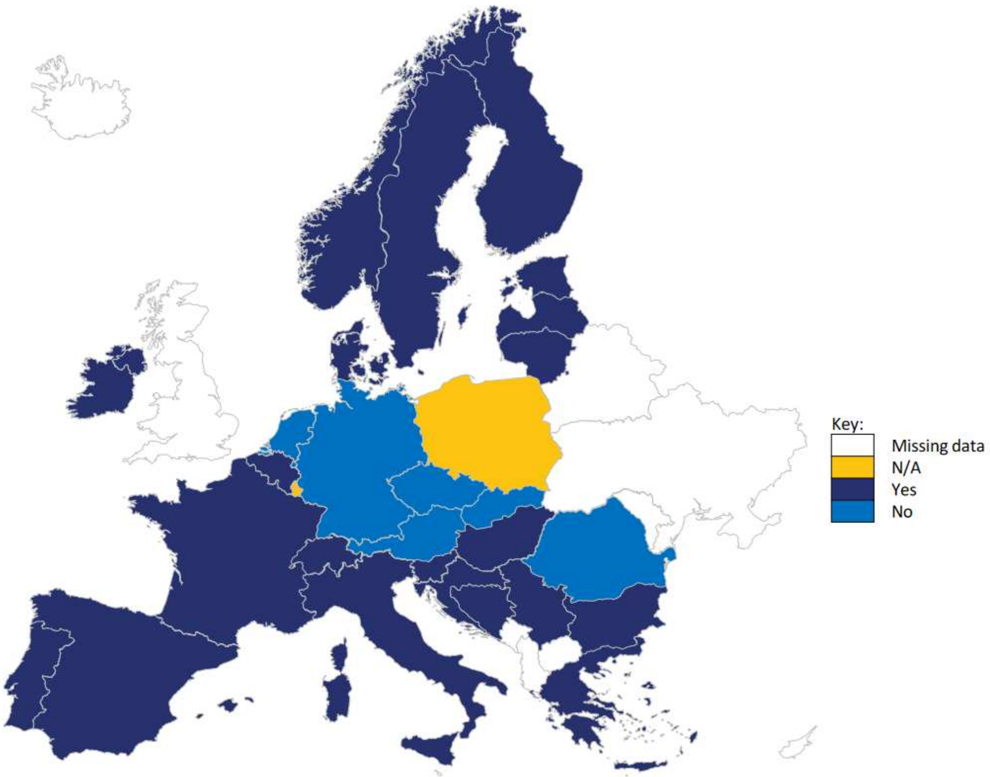

Figure 103: Answer to question "Are activations [*mFRR*, *energy*] for other purposes than Balancing (e.g. congestion management) possible?". Source: (ENTSO-E, 2021b)

Therefore, the lack of clarity in congestion management procedures is already an important barrier for the replicability of the CoordiNet BUCs that consider the use of DER by TSOs in specific congestion management markets.

For the purposes of this SRA, it is important to mention that no consolidated European assessment of how internal remedial actions are done in the different member states was found. Therefore, we consider the answers provided by respondents in the CoordiNet survey to the question "is DER allowed to provide ancillary services (congestion management) to the Transmission System Operator (TSO)?", but it must be considered that congestion management mechanisms may vary among countries.

Greece: DERs cannot provide ancillary services to the TSOs yet.

Spain: The congestion management market in Spain is a mandatory market for those units scheduled in the DA market. Therefore, DER units connected to the HV grid of distribution systems that participate in the wholesale market must bid in the existing congestion management market. However, participation of other types of DER (demand response, aggregated DER) is not allowed (*P.O. 3.2 - Restricciones Técnicas*, 2022).

Sweden: Bids for congestion management are ordered from the same marketplace as mFRR, the Nordic Regulating Power Market. If disturbances such as electricity production outages or transmission grid faults occur, and the bids on the regulating power market are not able to solve the disturbance, the "disturbance reserve" ("Störningsreserv") is used[37].

Austria: In case of grid instability DER flexibility could be used for congestion management purposes.

Belgium: DER cannot provide congestion management services in Belgium.

Germany: DER can, in principle, provide congestion management services, depending on local requirements.

Italy: DER can, in principle, provide congestion management services under experimental projects (see DER in balancing section).

The Netherlands: DER can provide congestion management services to the TSO through the GOPACS platform. GOPACS is not a market platform itself, but it is connected to other market platforms. It helps manage congestion at all voltage levels, increasing the available flexibility for re-dispatch and improving DSO/TSO coordination (Valarezo et al., 2021).

Table 71 displays the rating attributed to each country for each question on the "DER in Congestion Management" sub-topic based on the findings above. A short rationale for the rating is also provided.

Table 71: Assessment table for "DER in Congestion Management" sub-topic

Q4	Can DER participate in congestion management markets?	
	Q4	*Short rationale*
Greece	0	DER cannot provide congestion management services
Spain	2	Only DER scheduled in the DA market (in principle connected to the HV grid)
Sweden	2	DER can provide congestion management services, but mFRR bids are used
Austria	1	Only for emergency purposes
Belgium	0	DER cannot provide congestion management services
Germany	3	DER can provide congestion management depending on local requirements
Italy	2	DER can provide congestion management under pilot projects
The Netherlands	4	DER can provide congestion management services to the TSO through the GOPACS platform.

6.1.3. TSO's Voltage Control Mechanisms and DER participation

Under the EU regulation terminology, the voltage control mechanisms are also a part of the remedial actions taken by the TSO to ensure secure operation of the grid. The SO Guideline classifies "control voltage and manage reactive power" as one of the categories of remedial actions. The possible means for the TSO to do so are:

(i) tap changes of the power transformers;
(ii) switching of the capacitors and reactors;

[37] Text provided by questionnaire respondent.

(iii) switching of the power-electronics-based devices used for voltage and reactive power management;
(iv) instructing transmission-connected DSOs and significant grid users to block automatic voltage and reactive power control of transformers or to activate on their facilities the remedial actions set out in points (i) to (iii) if voltage deterioration jeopardises operational security or threatens to lead to a voltage collapse in a transmission system;
(v) requesting the change of reactive power output or voltage setpoint of the transmission-connected synchronous power generating modules;
(vi) requesting the change of reactive power output of the converters of transmission-connected non-synchronous power generating modules;

The SO Guideline includes options that are not costly to the TSO (options (i) to (iii) if part of the transmission grid) and others that could be organized as a remunerated service.

The ENTSO-E's survey on ancillary services shows that for the countries under analysis, only Belgium and The Netherlands declared to have some sort of mart-based procurement of voltage control-related services. With regards to which types of providers can participate in this market, only Germany mentioned RES and storage, which could be a DER. No country allows the participation of DR or independent aggregators. When asked about the settlement rules, Austria, Belgium and The Netherlands mentioned a concrete type of remuneration settlement, suggesting that voltage control in other countries could be unremunerated (Germany clearly states that). Table 72 provides an excerpt of the voltage control-related questions in the ENTSO-E survey.

Table 72: Excerpt from ENTSO-E survey on Voltage Control. Source: (ENTSO-E, 2021b)

Country	Voltage control procurement scheme	Who are the providers of the voltage control service?								Settlement Rule
		Conventional power plants	RES	Demand Side	Storage	HVDC links	Indep. Aggregator	Distribution system operators	Transformers of the transmission grid	
Austria	Mandatory service	Yes	No	No	No	No	No	No	No	Marginal pricing
Belgium	Market based procurement	Yes	No	No	No	No	No	No	No	Hybrid
Germany	Mandatory service	Yes	Yes	No	Yes	Yes	No	No	Yes	Free
Greece	Mandatory service	Yes	No	No	No	No	No	No	No	N/A
Italy	Mandatory service	Yes	No	No	No	No	No	No	Yes	N/A
Netherlands	Hybrid	Yes	Yes	No	No	Yes	No	No	Yes	Pay as bid
Spain	Mandatory service	Yes	No	No	No	No	No	No	No	N/A
Sweden	N/A[38]	Yes	Yes	No	No	No	No	No	No	N/A

Table 73 displays the rating attributed to each country for each question on the "Voltage Control" sub-topic based on the findings above. A short rationale for the rating is also provided.

[38] In the ENTSO-e survey, the "NA" is given for the "voltage control procurement scheme" in Sweden. However, Elia's study clarifies that in Sweden the provision of voltage control services is mandatory and not remunerated (ELIA, 2018).

Table 73: Assessment table for the "Voltage Control" sub-topic

Q5	Is voltage control a market-based service?		
Q6	Can DER provide voltage control?		
	Q5	*Q6*	*Short rationale*
Greece	1	0	Voltage control is mandatory. No DER participation. No settlement mentioned.
Spain	1	0	Voltage control is mandatory. No DER participation. No settlement mentioned.
Sweden	1	0	Voltage control is mandatory. No DER participation. No remuneration to providers.
Austria	2	0	Voltage control is mandatory. No DER participation. Marginal pricing used (remuneration in place).
Belgium	4	0	Voltage control is a market-based service. No DER participation. Remuneration in place.
Germany	1	2	Voltage control is mandatory. RES and storage can provide voltage control. No settlement mentioned.
Italy	1	0	Voltage control is mandatory. No DER participation. No settlement mentioned.
The Netherlands	3	1	Voltage control is a "hybrid" service. RES can provide voltage control. Pay-as-bid used (remuneration in place).

6.1.4. DSO economic regulation and incentives

Several CoordiNet BUCs consider the use of local flexibility to support distribution grid operation. This is in line with the recently adopted Clean Energy Package, which states that DSOs shall procure flexibility services in a market-based manner from resources such as distributed generation, demand response or storage, when such services are less costly than grid expansion (CEP Electricity Directive, 2019a). The main goal is therefore to achieve lower grid costs by reducing expansion expenditures in the long-term.

However, it will not be possible to completely replace network expansion (reinforcement) by flexibility. In some cases, network expansion/reinforcement will be necessary to ensure security of supply, whereas, in other situations, temporary procurement of flexibility could help to overcome existing constraints during the time required to complete expansions/reinforcements. Therefore, DSO regulation should create the necessary conditions for DSOs to decide on what is the most suitable solution for each case, including long-term costs and reliability. By incentivizing DSOs to operate efficiently, regulation would thus benefit end consumers through, for instance, lower network charges.

Nowadays, most European countries have implemented some form of incentive regulation (e.g. RPI-X[39]), which intends to promote cost reductions whilst ensuring adequate levels of security of supply. In spite of the many differences in the details of the national regulatory frameworks that can be found, some general features that discourage the use of flexibilities are widespread. These create a situation where current regulation is generally still poorly adapted to this upcoming paradigm.

[39] RPI minus X refers to the form of incentive regulation commonly used in many countries. The allowed price or revenue of the regulated company is adjusted for the previous year's Retail Price Index (RPI) and for expected efficiency improvements (X) during the time period the price adjustment formula is in place. This time period is often called a regulatory period. At the end of each regulatory period, the baseline price/revenue of the regulated company might be reviewed, as well as the efficiency term X.

The way the incentive regulation is set also matters. It is traditionally set either over the Operational Expenditure (OPEX) alone (letting the Capital Expenditure (CAPEX) be a pass-through component), or over the Total Expenditure (TOTEX). Historically, the former setting was firstly adopted, providing the signal to DSOs to build a strong network (investments were incentivized, as they are the ones remunerated) and providing an incentive to reduce inefficiencies in the management of the companies. However, in the perspective of a high penetration of DER and the possibility of such resources providing flexibility as a means to avoid reinforcement, this CAPEX-biased type of regulation ends up providing an incentive in the opposite direction.

In addition to the CAPEX/OPEX treatment, economic regulation may also include additional components to the DSO's revenue formula in order to provide target-specific incentives. A widely used example is the incentive to reduce losses. This can be done by including a bonus (or penalty) to the remuneration, by obliging the DSO to buy their own losses. Additionally, quality of supply can be incentivised, also by providing bonus/penalties based on pre-established indicators (e.g. SAIFI[40], SAIDI[41]). The latter can be especially important for the controlled islanding service in CoordiNet.

Greece: The regulatory framework in Greece recently transitioned from a cost-of-service scheme to an incentive regulation with a 4-year regulatory period. The first regulatory period goes from 2021 to 2024 (CEER, 2022). Within the new regulation, CAPEX and OPEX are regulated separately. According to the recent law on the methodology of DSO's revenue calculation, there are also separate incentive mechanisms in order to increase the efficiency of controlled OPEX and perform projects of major importance. A premium weighted average cost of capital (WACC) is provided for these major importance projects, including those that contribute to the facilitation of increase in DER penetration and smart grid implementation. There are no incentives for continuity of supply in the first regulatory period. It is not defined yet if they will be implemented in the second regulatory period.

Spain: DSOs in Spain are under a revenue cap regulation with six-year periods, being the current one 2020-2025. CAPEX and OPEX remuneration are calculated separately considering the information reported by DSOs and a set of tables of standard costs for different asset categories. Deviations between standard and actual costs are capped and these must be justified if they exceed a certain threshold. The remuneration is therefore largely proportional to the volume of investments made by the DSO. New distribution investments are included into the Regulatory Asset Base (RAB) and start to be remunerated with a delay of two years, i.e. assets put into service in year n-2 start are included in the remuneration of year n. The rate of return is determined following the WACC approach. Spanish DSOs are subject to a bonus-malus incentive on continuity of supply.

Sweden: The Swedish economic regulation for DSOs is set as an incentive regulation with a revenue cap in a 4-year regulatory period. The CAPEX and OPEX are calculated separately. OPEX is based on the company's own historical cost and with an efficiency target. Efficiency targets are based on national benchmarking. On the CAPEX side, calculation is based on standard cost for all assets, this gives incentives to invest to a lower cost than the standard cost. Apart from that, it is important to mention that Swedish DSOs (regional and local) are subject to subscription limits at the substations connecting to the next SO. Therefore, an incentive for flexibility procurement exists. In Sweden, the DSOs are responsible for buying the losses, and

[40] System Average Interruption Frequency Index.

[41] System Average Interruption Duration Index.

a symmetric bonus-malus for continuity of supply indexes exists (SAIDI, SAIFI and LV ENS, both planned and unplanned).

Austria: a price cap incentive regulation is in place. Currently in the 4th regulatory period[42] (five-year periods), Austria treats OPEX and CAPEX separately, with efficiency targets (X-factor) applied to the former. However, before every regulatory period, in order to establish the efficiency factor, a TOTEX benchmarking is carried out. On continuity of supply, Austria does not have a financial incentive, but minimum standards are mandated by law.

Germany: Germany is known for the large number of DSOs, approximately 850. The DSOs are submitted to an incentive regulation scheme with a revenue cap. Germany is currently in its 3rd regulatory period after moving from a cost-plus regulation to the incentive regulation in 2009, and each regulatory period lasts for 5 years. For the first two regulatory periods, Germany adopted a TOTEX revenue cap approach with a yearly efficiency X-factor. However, for the 3rd regulatory period, starting in 2019, a reform of the incentive regulation was made. Now, efficiency targets are applied only to "generally controllable costs", while CAPEX can be considered a pass-through component. In order to adjust the revenue cap before the start of a new regulatory period, benchmarking techniques are used. Also, for very efficient DSOs, according to the benchmarking process, a bonus can be introduced, being distributed equally over the regulatory period. Also, a bonus-malus for quality of supply exists.

Table 74 displays the rating attributed to each country for each question on the "DSO economic regulation" sub-topic based on the findings above[43]. A short rationale for the rating is also provided.

Table 74: Assessment table for "DSO economic regulation" sub-topic

Q7	Does regulation provide cost recovery for flexibility procurement?			
Q8	Does regulation incentivize the use of flexibility (e.g. as an alternative for grid reinforcement)?			
Q9	Are there incentives for continuity of supply?			
	Q7	*Q8*	*Q9*	*Short rationale*
Greece	2	2	0	Incentive regulation, but with a traditional OPEX/CAPEX differentiation. Some incentives exist to promote the use of flexibility. No incentives for continuity of supply.
Spain	2	1	4	Incentive regulation, traditional OPEX/CAPEX differentiation. No clear incentives to use flexibility yet. Bonus-malus incentive over continuity of supply indexes.
Sweden	3	3	4	CAPEX regulation provides some incentive to cost reduction. Incentives exists for flexibility usage (subscription limits). Bonus-malus incentive over continuity of supply indexes.
Austria	3	1	3	Separate OPEX/CAPEX regulation, but with a TOTEX benchmark before every regulatory period. No clear incentives for the procurement of flexibility. Limited financial incentives on continuity of supply.
Germany	4	1	4	TOTEX incentive regulation is used. No clear incentives for the procurement of flexibility. Bonus-malus incentive over continuity of supply indexes.

[42] Since the begging of the incentive regulation regime in Austria.

[43] For this sub-topic, not enough information was collected for Belgium, Italy and The Netherlands. For these countries, a score of 2.5 was attributed for the purposes of the calculation of the compatibility indexes calculated in section 6.2. This number is slightly below the average of the other countries and is chosen in other no to pollute the calculations while still ensuring that the scores can be calculated for all use cases.

6.1.5. Market-based procurement of flexibility by DSOs

In this section we analyse the existence of specific regulation on the possibility for DSOs to procure local flexibility, in line with the definition brought forward by the Clean Energy Package. These local flexibility mechanisms can take different forms depending on the procurement method, the participating technologies, whether participation is mandatory or voluntary, etc. According to (CEER, 2018), four general types of flexibility mechanisms can be found:

i. Rule-based: Mandatory requirements set by regulation.
ii. Network Tariffs: incorporating flexibility incentives (Time-of-Use, dynamic charges, etc.).
iii. Connection Agreements: DSOs reach an agreement with new grid users who provide flexibility in exchange for some sort of compensation (e.g. lower connection charges).
iv. Market-Based Procurement: DSOs explicitly procure flexibility from local markets.

In this section we focus on specific implementations on the “Market-Based Procurement” type.

Greece: The regulatory basis for the DSO to procure DER flexibility for local grid management exists, however there is no implementation yet of DER flexibility for local grid management purposes. A regulatory basis for the activation of distributed Demand Response by the DSO has already been established under Article 28 of the Hellenic Electricity Distribution Network Code. This article foresees the possibility for the Hellenic Electricity Distribution Network Operator (HEDNO/DEDDIE) to conclude “Demand Control Contracts” with individual electricity consumers in network areas that are considered as congested. The Demand Control Contracts allow HEDNO to set limits or even to interrupt at its own initiative the supply of the facilities of the contracted consumers, after their notification, in the periods specified in the contracts. The details of this DR mechanism are supposed to be described in the Access Manual of the Hellenic Electricity Distribution Network Code which is currently under preparation. Thus “Demand Control Contracts” have not been implemented yet.

Only consumers with telemetering infrastructure can conclude “Demand Control Contracts”. The DSO defines additional requirements in case there is a remote controlled or automated demand response.

According to the Hellenic Electricity Distribution Network Code, the DSO will be able to directly conclude Demand Control Contracts with Consumers (bilateral contract). A standard contract will be included in the Access Manual of the Hellenic Electricity Distribution Network Code which is currently under preparation.

For distributed generators, a different regulation exists. According to the Hellenic Electricity Distribution Network Code, the DSO has the right to request from distributed generators to contribute to voltage control by controlling injected/absorbed reactive power by including these requirements in the Connection Agreement (Article 77 of the Hellenic Electricity Distribution Network Code). Also, active power of a distributed generator can be limited by the DSO if this is included in its connection agreement (Article 78 and Article 68 of the Hellenic Electricity Distribution Network Code). It must be noted though that the above provision of the network code has not yet been implemented in the Greek distribution network. Regarding technical requirements, these are included in their Connection Agreement.

The DSO has the right to directly request the contribution of generators connected to the distribution network to voltage control by absorbing/injecting reactive power or by curtailing active power, according to their Connection Agreement. There is no compensation to the producers in that case.

Spain: DSOs use DER to solve congestions (only with generation units) in the same way the TSO does. However, once those congestions are identified as well as the generation units that have an impact on the congestion, these needs are sent to the TSO who accesses the bids and calculates the necessary redispatch to ensure solving the detected constraints (*P.O. 3.2 - Restricciones Técnicas*, 2022).

DSOs may also request a change to the TSO in the power factor range instructions sent to generation units with an installed capacity larger than 5 MW.

DG is remunerated for the energy redispatched in the same way as all other generation units, including large power plants.

As of today, no comprehensive new regulation on the use of flexibility by the DSO has been published. However, a few initiatives have been initiated towards this goal. First, a public consultation was held for a regulation on sandboxes in the electricity sector[44]. Second, the Spanish NEMO (OMIE) together with the Spanish Ministry has also opened a public consultation on Local Flexibility Markets[45].

Sweden: The DSOs can have bilateral agreements with DER for load reduction and increase of DG production (Lind & Chaves Ávila, 2019a). Nevertheless, there is no specific regulation defining the characteristics of these bilateral agreements, being the DSOs the responsible for setting the terms of these agreements.

Swedish DSOs are subject to subscription limits on the substation connecting to the upstream SO (either regional DSO or TSO). Subscription limits can be raised temporarily by request of the DSO. When subscription cannot be raised, a penalty cost applies. These penalty costs are regarded as pass-through in the next regulatory period, meaning that the DSO would be able to recover this cost from the tariff. However, an uncertainty exists with regards to what the regulator will regard as reasonable remuneration. Therefore, the DSO has an incentive to avoid penalty costs by either reinforcing the grid or using local flexibility.

Some initiatives already exist for the DSO to procure local flexibility in Sweden. The most mature one is the SthlmFlex market, which included all of Stockholm municipality and is, in fact, a spinoff from the CoordiNet project. The platform was jointly created by Svk (Swedish TSO), Ellevio (DSO) and Vattenfall. Although still a pilot project, the platform has activated more than 2 GWh in its first pilot run (Simon Färegård & Marko Miletic, 2021). It is worth mentioning that SthlmFlex operates two platforms, namely SWITCH and NODES. The former is the platform created within the CoordiNet project, and the latter is a consolidated flexibility platform owned by Nord Pool and which is also active in Norway and Germany (Valarezo et al., 2021).

Austria: Resources connected at the distribution grid cannot provide any local service to the DSO. There is an expectation on forthcoming regulation on the topic.

Belgium: There is no actual product today where DER flexibility is procured by the DSO for local grid management purposes (no commercial flexibility). A regulatory framework does exist that allows for the possibility of a connection with flexible access ("Aansluiting met Flexibele Toegang") for network reinforcements with a longer lead time, but in this case there is no compensation for modulation. A connection with flexible access can be used by the DSO in case of risks for congestions. The idea behind this

[44] https://energia.gob.es/es-es/Participacion/Paginas/DetalleParticipacionPublica.aspx?k=438
[45] https://www.omie.es/sites/default/files/2019-12/webinar_idae_omie_140619.pdf; https://energia.gob.es/es-es/Participacion/Paginas/DetalleParticipacionPublica.aspx?k=438

flexible access is that each type of RES should be allowed to connect to the grid in the future. However, in the short term, networks cannot always be reinforced immediately. As such, DER can inject energy through these connections with flexible access, but they can be curtailed in case of congestion. In principle, this flexible access is a temporary measure, pending the implementation of a planned grid reinforcement. It is only applicable to distributed generation.

Other possibilities for local grid management purposes are under discussion. Within this respect, VREG, the Flemish regulator, has formulated some basic principles for commercial flexibility that should be taken into account in future regulations.

Germany: Several pilot projects are testing local flexibility markets in Germany. Most of these projects are supported by a large-scale government-funded research program called "SINTEG". This program also grants DSOs with regulatory exceptions. The NODES platform is also operational in Germany (Valarezo et al., 2021).

Italy: As of today, no specific regulation has been published for the DSO's procurement of local flexibility. Nevertheless, a new regulation (resolution 352/2021) has introduced a preliminary framework allowing DSOs to propose pilot projects for the procurement of local flexibility.

The Netherlands: Although no new regulation has been published for the use of local flexibility by DSOs, the GOPCAS platform has been deployed and used in large demonstration activities (Anaya & Pollitt, 2021; Valarezo et al., 2021).

Table 75 displays the rating attributed to each country for each question on the "Market-based procurement of flexibility by DSOs" sub-topic based on the findings above. A short rationale for the rating is also provided.

Table 75: Assessment table for "Market-based procurement of flexibility by DSOs" sub-topic

Q10	Can DER provide services to the DSO in any form (e.g. non-firm connection agreement)?		
Q11	Is there regulation for market-based procurement of flexibility?		
	Q10	*Q11*	*Short rationale*
Greece	3	3	A new regulation was published recently, although not yet applied.
Spain	2	2	No regulation specifically on local flexibility. Pilots and a sandbox regulation published. DSOs can request large DER flexibility in some cases.
Sweden	4	1	No regulation specifically on local flexibility. A large pilot project exists besides CoordiNet. A natural incentive to use flexibility by DSOs exists (subscription levels)
Austria	1	1	No regulation specifically on local flexibility.
Belgium	2	1	Local flexibility can be used, although not remunerated.
Germany	3	1	No regulation specifically on local flexibility. Large scale projects are testing local flexibility provision to DSOs.
Italy	2	1	No regulation specifically on local flexibility. A sandbox regulation was recently published.
The Netherlands	3	1	No regulation specifically on local flexibility. Large scale projects are testing local flexibility provision to DSOs.

6.1.6. DER aggregation rules

The independent aggregator is a new agent defined by the Clean Energy Package as a "market participant engaged in aggregation who is not affiliated to the customer's supplier" (CEP Electricity Directive, 2019b). In this context, DERs, including demand response, can enter in an agreement with an independent aggregator besides already having an agreement with a retailer. Moreover, the CEP also determines "the right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without the consent of other market participants” (CEP Electricity Directive, 2019b). That means that, in principle, an independent aggregator does not have to enter into an agreement with the consumers’ retailer, and that can lead to distortive situations if a proper regulatory framework is not in place. For instance, the independent aggregator can create an imbalance on the retailer’s portfolio by activating their customer’s flexibility. If there is no compensation in place, the retailer is worse off. On the contrary, if there is a mandatory compensation in place, that may put the independent aggregator in a position of uncertainty regarding the retailer’s profile and the baseline for the deviations, leaving the independent aggregator business model at risk (Lind et al., 2019b).

On the ensuing, the questions of whether aggregation is permitted, particularly considering DER, and whether regulatory conditions are suitable for the development of independent aggregators will be explored for the countries considered in this report.

Greece: The regulatory basis for the establishment of RES aggregators already exists according to law 4414 /2016. More specific, RES that will be developed with a Feed-In Premium contract will be able to participate in energy markets via an aggregator. However, the wholesale market in Greece is operated as a mandatory pool and currently the day-ahead market is the only one operating. Greece is committed towards the EU target model, which consist of four markets (day-ahead, intraday, forward and balancing markets). In the new electricity market model aggregated RES will be able to participate in DA/ID and balancing markets.

In the case an Aggregator is interested in participating in the Balancing Market operated by the TSO, then the Aggregator is obliged to assign a Balance Responsible Party (BRP), which will in turn conclude a BRP Contract with the TSO. However, no comprehensive framework exists for the aggregator-BRP conditions.

Spain: As of today, aggregation of distributed resources in Spain is still a very immature activity. It is important to notice the concept of aggregation is already present in balancing markets in Spain. In the aFRR market, generating units of one technology from a same company are aggregated within a regulation zone. The aggregation of different types of DER is, however, not in place yet. For instance, aggregation is not allowed in the “interruptibility contracts” of the TSO. However, a new regulation has just been approved, introducing the aggregator as a possible provider of balancing services. According to the new regulation, aggregated demand, generation or storage will be allowed to offer balancing services, but in a separated fashion[46]. In other words, demand and generation could not be aggregated together, potentially limiting the compatibility of the Virtual Power Plant (VPP) concept.

Sweden: Retailers are allowed to become aggregators in Sweden. In principle, independent third-party aggregation is also possible if the agent registers as a BRP. In this case, besides paying an annual cost and installing the required electronic reporting system, the independent aggregator would have to sign an agreement with the consumer’s BRP (Bertoldi et al., 2016). Independent aggregators can, however, act on behalf of retailers, acting as a subcontracted agent.

Austria: Aggregation from the retailer’s side is legal, as well as independent aggregation. However, independent aggregators have to inform and contract with the BRP/retailer in order to use the consumer’s flexibility. There are however no compensation mechanisms in place for retailers to recover potential losses

[46] Resolution 18423 of December 11, 2019. Article 8(3).

created by aggregation activity. Nevertheless, this situation shows that in Austria, the independent aggregator still lacks a framework that eliminates the need for contracting the consumer's BRP and that sets possible compensations between aggregator and retailer.

Belgium: Aggregation regulation is well developed in Belgium as compared to other EU Member States. Independent aggregation is allowed and already explored in Belgium. Prior to 2018, independent aggregators had to enter into an agreement with the customers' BRP. However, the "Energy Pact" removed this obligation in 2018 (Bray & Woodman, 2019). As of today, independent aggregators can participate in balancing independently from the BRP (smartEn, 2018). In order to enable the participation of the independent aggregator, an innovative regulation was put in place, based on the concept of Transfer of Energy (ToE) (Elia, 2019). The independent aggregator and the supplier can enter in a bilateral agreement to decide how to settle possible costs from imbalances (the "opt-out" arrangement). However, if not a bilateral agreement is made, a standard ToE framework applies (Dam, 2019). This ToE is calculated by the Belgian TSO Elia. This mechanism provides a predictable framework for independent aggregators in Belgium, including VPPs, already present in the Belgium balancing markets (Next Kraftwerke, 2019).

Germany: Until recently, independent aggregation suffered with several barriers in Germany. Third-party aggregators had to enter into several bilateral agreements with the consumer, the TSO, the DSO and the consumers' BRP (Bray & Woodman, 2019). Since 2018, with the introduction of the new aggregation framework, these contracts are no longer required (smartEn, 2018). The concept of the VPP is also already in use in Germany (Next Kraftwerke, 2017).

Italy: According to the smartEn report (2018), aggregation takes place in Italy in the tertiary control market, equivalent to the mFRR. In this market, that is operated under the UVAM[47] project, aggregation of demand-side resources, mostly medium of large industrial consumers, could be carried out.

The Netherlands: Aggregation in the Netherlands is already regulated and independent aggregation is allowed. In principle, the Independent Aggregator does not have to enter into an agreement with the customers' BRP. However, the customer that delivers the flexibility may have to, depending on his contract with its BRP.

Table 76 displays the rating attributed to each country for each question on the "DER aggregation rules" sub-topic based on the findings above. A short rationale for the rating is also provided.

Table 76: Assessment table for DER aggregation rules sub-topic

Q12	Can DER be aggregated in the different markets (both TSO and DSO)?			
Q13	Is the independent aggregator recognized?			
Q14	Is there a comprehensive framework for independent aggregation (e.g. adequate rules on allocation of balancing responsibility)?			
	Q12	*Q13*	*Q14*	*Short rationale*
Greece	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place.
Spain	3	3	1	Aggregation (including independent) is possible. However, aggregation cannot include different types of DER. No comprehensive framework in place.

[47] in Italian: *Unità Virtuali Abilitate Miste. i.e.,* virtually aggregated mixed units

Sweden	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place.
Austria	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place.
Belgium	4	4	4	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. A comprehensive framework exists.
Germany	4	4	4	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. A comprehensive framework exists.
Italy	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place.
The Netherlands	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place.

6.1.7. Current TSO-DSO coordination for grid operation

The TSO-DSO coordination is at the core of the solutions developed and demonstrated in the CoordiNet project. Enhanced coordination is a key requirement for the implementation of the different market models. This enhanced coordination means that TSOs and DSOs will have to exchange more information, in a more efficient way, they will have to share and coordinate responsibilities while maintaining the security of the system. The following paragraphs present the current status of the TSO-DSO coordination measures and information exchange for the purpose of operation planning and real-time operation of the system, as well as eventual ex-post communications and responsibilities. For this SRA, the coordination for grid planning and reinforcement is not discussed.

Greece: TSO and DSO are cooperating with regards to system operation. The scope of the coordination is the secure, reliable and economic operation of the power system. Coordination between TSO and DSO in Greece is mainly focused on the following areas:

- Load Shedding, which is performed by the DSO after request of the TSO, under critical System conditions. When the TSO issues an alert state the DSO shall be well prepared to perform load shedding if requested.
- Information exchange and TSO-DSO cooperation in power system restoration procedures.
- Active power output limitation of DGs, when requested by the TSO.
- Maintenance Scheduling. DSO is notified with regard to the maintenance schedule of TSO. DSO takes into account the maintenance schedule of TSO in order to schedule distribution network maintenance. DSO can also request modifications of the TSO's maintenance schedule.
- Protection coordination and interlocking arrangements. TSO may request complementary protection on the distribution network
- With regard to Under Frequency Load Shedding, there is a coordination between the TSO and the DSO to set up the thresholds
- The DSO can also request the contribution of the TSO in the maintenance and repair of high voltage distribution lines and HV/MV substations.
- When the DSO is about to perform reconfiguration that can lead to load reduction of more than 10 MW on a connection point of the distribution network to the transmission system, then the TSO must be informed.

In case of load curtailment, the TSO has priority over the DSO.

Spain: the TSO and DSO exchange data on a regular basis for operational purposes. The TSO informs to the DSO the daily operation plan, and the DSO can request changes when needed. The TSO also informs the DSO on the schedules for DER providing balancing services. Moreover, the TSO communicates the schedule of generation unit tests on a weekly basis. Units of more than 50MW connected to the distribution network have to be tested by the TSO. In this case, the TSO informs the DSO on a weekly basis on the schedule for these tests with units in the distribution network. Also, structural data is sent by the DSO to the TSO for units of more than 1 MW. DGs above 5 MW are monitored real-time by the TSO (Lind & Chaves Ávila, 2019b).

TSO and DSO do cooperate in Spain, with a focus on different information exchanges for operational planning and in real-time. The Spanish regulation includes structural, scheduled and real-time data exchange between all involved parties (TSO, DSOs, power exchange, market parties) (*P.O 9.0 - Información Intercambiada Por El Operador Del Sistema*, 2019). Information is shared between TSO and DSOs on a regular basis for operational purposes. These information exchange include (but are not limited to):

- Communication of the Daily Operation Plan (PDBF, in Spanish). In the case the DSO realizes a problem may occur in the distribution network due to the PDBF, the DSO may request the adaptation of the PDBF by the TSO. (Frequency: daily)
- Data of generating units (of more than 1MW). The TSO keeps a database of generating units of more than 1MW connected to the distribution network with data that these units are mandated to provide to the TSO. The DSO can request this information in case needed. (Frequency: on demand)
- Real time data of generating units or aggregations with an installed capacity greater than 1 MW. This data is currently received by the TSO from the generation control centers and it is sent in real-time as well from the TSO to the DSO to which the generator is connected. (Frequency: continuous)

The DG above 5MW is connected to the Control Centre of Renewable Energies, which manages technical constraints of connected renewable sources.

Sweden: In the long-term, TSO-DSO coordination occurs for outage planning coordination. Also, yearly communication between respective operational planning units occurs. The TSO enters into a dialogue with DSO representatives about consequences for different operational modes and outages.

In the mid-term, TSO and DSO exchange information on switching schedules of common interest.

In the DA, ID, near real timeframe: TSO is in dialogue with relevant DSOs about consequences for various operational modes and outages, overloads and disturbances. In short term there is communication between grid control centres.

The organizational arrangements for grid operation in Sweden create additional complexities for this coordination. In Sweden, the power grid is divided into transmission, regional and local distribution systems. The regional power system is formed by concessions of lines that connect transmission and local DSOs. Some large customers and generation (wind farms mainly) are connected to the regional system (Wallnerström et al., 2016). In this case, the TSO-DSO coordination could potentially involve three different stakeholders, increasing complexity of coordination and information exchange.

Austria: It is recognized in research projects, that the TSO and DSOs must cooperate more in the context of flexibility-Markets, which will not be integrated in the frequency balancing markets. This cooperation will be the Load-Flow-Calculation in "parallel" grid segments in the different voltage levels of TSO and DSOs. For decision on flexibility offers permission, TSO and DSOs will exchange grid system security results.

Belgium:

As of today, the DSO needs to inform the TSO on new connections. In addition, there are some additional requirements in place before the TSO can procure flexibility from sources connected to the distribution grid. The flexibility provided via a FSP to the TSO must be part of a contractual relationship between the FSP and the DSO. In particular, a DSO/FSP agreement is needed in order to include a flexible resource from the distribution grid in an FSP portfolio to provide FCR, aFRR and mFRR. In addition, a Network Flexibility Study, needs to be done for flexible resources from the distribution grid for aFRR and mFRR (not for FCR) to ensure that the activation of the flexibility, does not compromise the stability of the grids or cause congestion or voltage issues.

In the future, an intensified collaboration is foreseen. An example is the current IO.Energy ecosystem which is set up by all Belgian DSOs and TSO, which aims to implement new energy services through a consumer-centric approach.

Germany: RES/CHP curtailment is supposed to be integrated into the TSO's ReDispatch: Thus, TSOs need more data from the DSO DA being able to judge which generation resource, conventional or RES or Combined Heat and Power (CHP), needs to be adjusted. TSO and DSO also exchange information in the DA, ID and real-time, as shown in Table 77.

Italy: There is a coordination but without hierarchy of decisions. In particular, technical coordination in planning activities is focused on TSO-DSO interconnection facilities. Information exchange takes place in the long-term, DA, and near real-time.

Generally speaking, the Commission Regulation (EU) 2017/1485 "SOGL" guidelines apply.

The Netherlands: DSOs and TSO are coordinating on congestion bids through the GOPACS platform. Grid operators notify if the connection limits are being reached, the GOPACS platform takes these limits into account when accepting bids for congestion management for other grid operators.

Informants were asked to provide details on the information exchanged between TSO and DSO in the different time-steps of the operational horizon, going from the long-term (e.g. months ahead) to the real-time operation, and the eventual ex-post exchanges. The data collected is presented in Table 77. It is important to remark that this data was provided by the questionnaire respondent who might have provided different levels of detail on the actual exchanges between TSO-DSO.

Even if the data collected might be incomplete for different countries, it is possible to verify that within most countries[48], data is exchanged between TSOs and DSOs in all timesteps of the operational horizon. They can be classified in three different categories, namely forecasts and schedules, grid operation, and measurements:

- Forecasts and schedules: includes results from different markets and forecasts of the power in the TSO-DSO interface substations. These information exchange takes place in the long-term, DA, ID and near real-time, including the modification on previous forecasts.

[48] Considering those that provided details in the questionnaire regarding the information exchanged.

- Grid operations: Information is shared related to switching that may impact the connecting SO, reactive power management and requests for load/generation shedding from one SO to the other. This can take place from the DA to near to real-time.
- Measurement: includes mostly the power flows at the TSO-DSO interfaces. This can take place in the real-time or ex-post.

Table 77: TSO-DSO information exchange in different countries according to questionnaire respondents.

Timeframe	Greece	Sweden	Spain	Netherlands	Austria	Germany
Long-term	Load Profiles, Load Projections, DER Measurements, Network Topology, Network Development Plan of DSO, Ten-year development plan of TSO, Maintenance Schedules, Ex-ante shares of suppliers (every month) Protection coordination and interlocking arrangements. TSO may request complementary protection on the distribution network With regard to Under Frequency Load Shedding, there is a coordination between the TSO and the DSO to set up the thresholds	Outage planning coordination: yearly communication between respective operational planning unit (TSO/DSO). TSO dialogue with DSO representatives about consequences for different operational modes and outages. Exchange of switching schedules of common interest.	The TSO will inform the structural data of installations that participate in balancing services.	Maintenance and grid planning	Forecast and schedules for the interchange substations.	
Day-ahead	When the DSO is about to perform reconfigurations that can lead to load reduction more than 10 MW on a connection point of the distribution network to the transmission system, then the TSO must be informed.	Exchange of switching schedules of common interest. TSO in dialogue with relevant DSO about consequences for various operational modes and outages, overloads and disturbances. In the short-term, there is communication	The TSO sends to the DSO the daily schedule. The DSO can evaluate and request modifications due to congestion in the distribution network. The TSO will inform the DSO the schedules for DER providing balancing services.	Transportation prognosis from DSO-> TSO Congestion Limits	Forecast and schedules for the interchange substations.	Forecast of schedules at grid connection points and electrical values of grid assets within observability area.

Intraday	When the DSO is about to perform reconfigurations that can lead to load reduction more than 10 MW on a connection point of the distribution network to the transmission system, then the TSO must be informed.	between grid control centers.	The schedules (PDVP) after the ID market session are published as soon as they are available	Congestion Limits		Reactive power management (only if necessary), RES curtailment, update of schedules etc. if applicable
Near Real-time	Request for load/generation shedding under critical situation. Information exchange and TSO–DSO cooperation in power system restoration procedures Active power output limitation of DGs, when requested by the TSO. When the DSO is about to perform reconfigurations that can lead to load reduction more than 10 MW on a connection point of the distribution network to the transmission system, then the TSO must be informed .		Real time schedules (P48) are published as soon as they are available			
Real-time	Request for load/generation shedding under critical situation Information exchange and TSO –DSO cooperation in power system restoration procedures		Installations that are not obliged to be attached to generation control centre can be monitored by the DSO control centre. The units must be connected to the	Emergency restoration services	Measured values for the interchange substations. SCADA-to-	Reactive power management, RES curtailment, update of schedules etc. if applicable

	Active power output limitation of DGs, when requested by the TSO.		observable network of DSOs. The information must be provided by physical unit.		SCADA[49] coupling for the generation units in question.	
Ex-post	DSO provides every month the ex-post shares of suppliers.		Three days after real time, balancing schedules (aggregated per type of generation) are published. 3 months after real time, all information is public.	Energy Settlement and measuring data	Measured values for the interchange substations.	

[49] Supervisory control and data acquisition.

Table 78 displays the rating attributed to each country for each question on the "Current TSO-DSO coordination" sub-topic based on the findings above. A short rationale for the rating is also provided.

Table 78: Assessment table for "Current TSO-DSO coordination" sub-topic

Q15	What are the coordination measures in grid operation?		
Q16	Which is the information exchanged for grid operation? In which timeframes?		
	Q15	*Q16*	*Short rationale*
Greece	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post.
Spain	2	2	TSO and DSO exchange information in all timesteps of the operational planning, real-time and ex-post. DSO can limit activations by the TSO.
Sweden	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post.
Austria	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post.
Belgium	2	1	Coordination and information exchange takes place mainly during prequalification.
Germany	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post.
Italy	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post.
The Netherlands	4	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post. Advanced TSO-DSO coordination takes place through the GOPACS platform.

6.2. Compatibility of Use Cases

Considering the evaluation of each sub-topic and the mapping of relevance for the different services and market models, a final compatibility assessment is made for the different countries and for different Generic Use Case (UC hereafter; composed of a pair of service-MM). In order to do that, the scoring attributed to each guiding question is weighted according to the coefficients presented in Table 68 and Table 69. The formula for the calculation of the compatibility index is shown below. The Compatibility Index is a measurement (from zero to five) that helps understand how compatible the current national regulatory framework is to a determined UC. An index closer to five means that the current national regulation is more welcoming to the development of that use case. Conversely, an index closer to zero means that regulation still prevents the development of that use case. Colors/indexes in between mean that regulation may allow the use case to be developed, but it is incomplete and does not provide the necessary conditions for the different actors. However, as mentioned at the beginning of this Chapter 6, the Compatibility Index is a tool for the qualitative analysis, and not a quantitative evaluation for the different countries. This remains a qualitative analysis, and the Compatibility Indexes calculated next are a product of the discussion presented in the previous sub-sections.

$$Compatibility_{country,UC} = \frac{\sum_{question}(Score_{subtopic}^{country} * Weight_{subtopic}^{service} * Weigh_{subtopic}^{MM})}{\sum_{subtopic}(Weight_{subtopic}^{service} * Weigh_{subtopic}^{MM})} \quad (6\text{-}1)$$

, where

$Compatibility_{country,UC}$ is the compatibility index calculated for $country$ in the Generic Use Case UC,

$Score_{subtopic}^{country}$ is the average score given to the regulatory $subtopic$ in the specific $country$ (Table 70 to Table 78), and

$Weight_{subtopic}^{service}$ is the weight for the specific $service$ and $Weigh_{subtopic}^{MM}$ is the weight for the Market Model MM (Table 68 and Table 69, respectively).

For this compatibility analysis, six UCs were chosen. Each UC is composed of one service and one specific market model (MM). The UCs are:

- Local (MM) Congestion Management (Service)
- Multi-level (MM) Congestion Management (Service)
- Central (MM) Balancing (Service)
- Local (MM) Controlled Islanding (Service)
- Fragmented (MM) Congestion Management (Service)
- Common (MM) Voltage Control (Service)

Figure 104 shows that among the different countries, a consistency exists on the potential for replicability of the different UC. This is mostly driven by how open markets are to DER participation and the levels of incentives and possibilities for the TSO and DSO to procure that flexibility. Among the different UCs, slight differences exist, either driven by the service or the MM chosen. The most replicable UC seems to be the "Central Balancing" (average 3.06). The balancing service is highly harmonized across Europe, and the opening of this service to DER is mandated by the Network Codes and implemented in many countries. On the opposite side, with the lowest average index, is the "Common Voltage Control" (average 2.04). Although the MM is still the same, the service is far less harmonized, and for several of the countries analysed, it is not a market-based service, but a mandatory one provided by conventional units, often not remunerated. Other UCs capture differences in the MM implementation, as is the case for the UC on local congestion management and multi-level congestion management. It is possible to observe that the overall compatibility index is slightly lower for the multi-level when compared to the local MM, due to higher need for TSO-DSO coordination.

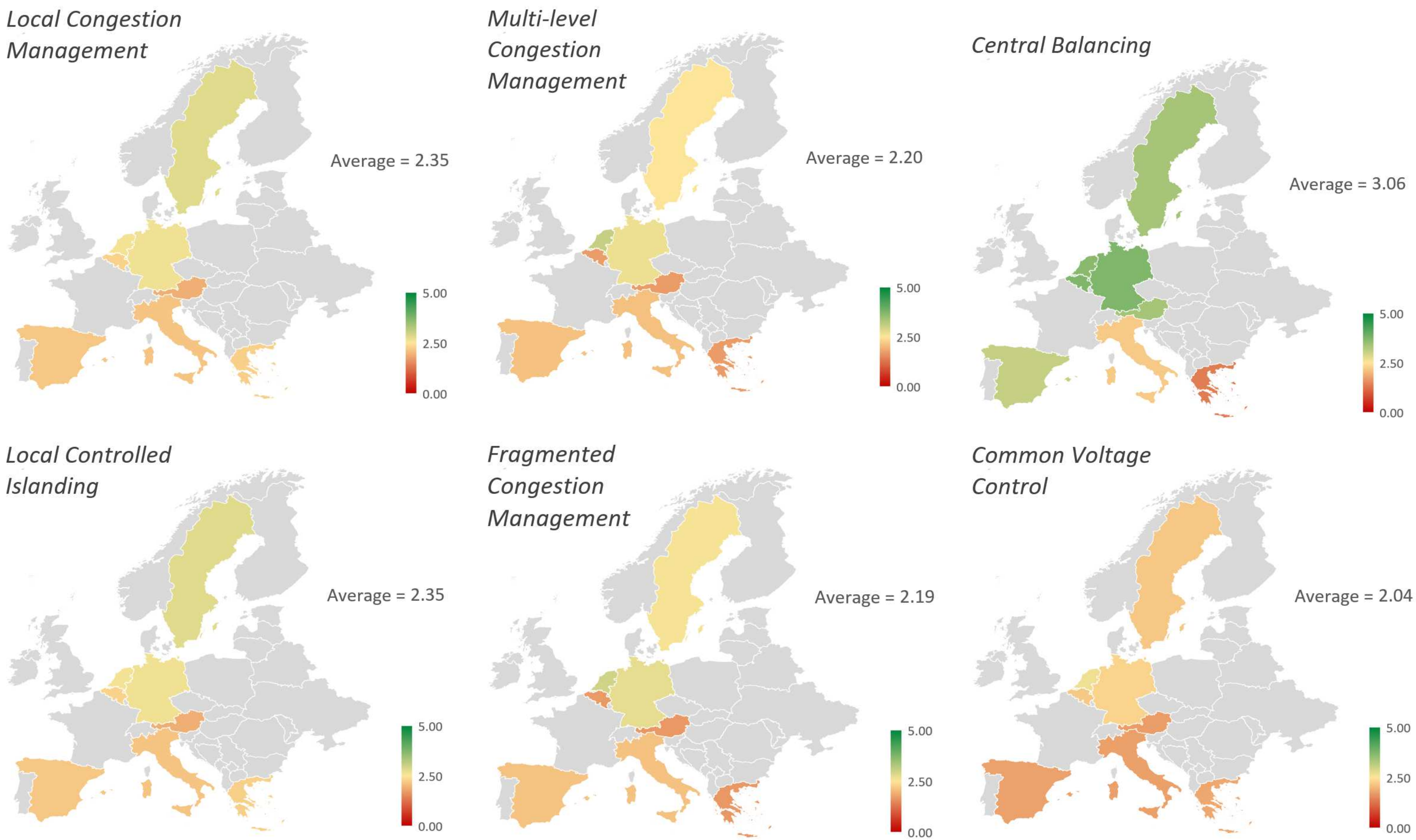

Figure 104: Regulatory Compatibility of Selected Generalized Use Cases. Green: Regulation allows and promotes UC. Red: Regulation prevents/prohibits the UC.

6.3. Interim Conclusions

In this chapter, a regulatory replicability analysis was carried out. Seven regulatory sub-topics were analysed in the three CoordiNet demo countries and five additional EU Member States. From this analysis, it can be concluded that:

- A driver for regulatory replicability of use cases involving the balancing service is that several countries already have balancing markets open to DER, and practical limitations for their participation are being reduced.
- Another driver is aggregation. Several countries have already implemented regulations that recognize this actor, and some also provide the necessary framework for the independent aggregator to share responsibilities with other entities (e.g. BRPs).

Several barriers to replicability were also identified:

- It was verified that the congestion management service is very unharmonized among countries. In addition, the EU regulation does not set specific rules for congestion management markets for solving internal congestions. Countries may adopt specific congestion management markets (as proposed in CoordiNet) or not. Besides relying on non-costly mechanisms to solve congestions (e.g. changes in topology), countries can use countertrading or even balancing markets to solve congestions without using redisptach-specific markets.
- Voltage control is in a similar situation as congestion management, in which countries have different mechanisms to solve this problem, often being non-remunerated mandatory provision, which is a clear barrier to the replicability of the voltage control UCs.
- DER provision of flexibility to DSOs is still a challenge. The economic regulation of DSOs is still mostly CAPEX-biased, with little incentive for the procurement of flexibility. Additionally, no country has yet implemented a regulatory framework for the cost recognition or output incentives for the use of flexibility. Nevertheless, most countries have continuity of supply incentives, which would already provide an incentive to the controlled islanding service.
- Different market models will require different levels of coordination between TSO-DSO. It was found that most countries already have TSO-DSO coordination in most timeframes of operational planning and real-time operation of the system. However, enhanced coordination will be needed for most market models, which is still a barrier to replicability.

7. Conclusions

In this deliverable D6.4, the scalability and the replicability of solutions proposed in the CoordiNet project were analysed from a quantitative and qualitative perspective. The former focused on the techno-economic aspects of the different BUCs, while the latter looked at the national regulatory frameworks not only in the demo countries but also in the additional EU Member States. The quantitative analysis was based on the simulations of different scenarios, having the demonstration activities as a base case. These simulations, organized in three different modelling workstreams, covered a wide range of scenarios, including different market models (or coordination schemes), types of FSPs, and network characteristics.

The modelling activities were focused on trying to reproduce what the CoordiNet project had developed and demonstrated in the different demo sites, both from a market model perspective as well as from a network perspective. In this context, this work serves as a complement to other studies carried out in the project, such as the evaluation of coordination schemes presented in D6.2 (Sanjab et al., 2022).

The results from the first modelling workstream focused on different market models for the procurement of both balancing and congestion management involving the TSO and the HV grid of DSOs, revealing that grid and FSPs characteristics play an important role in the outcomes of flexibility usage by SOs. Firstly, different types of grid topology were observed, such as meshed DSO grids (subtransmission) and power-exporting DSO grids, characterized by high penetration of DG, besides more typical load-driven distribution grids. This diversity of grid topologies is also accompanied by a variety of FSP types. While the Swedish demonstration was characterized by demand response flexibility and storage, the Spanish demonstration counted primarily on RES as FSPs. The replicability scenarios, in which types of FSP from one demonstration are simulated in another demo, showed the potential benefits arising from the complementarity of the different types of FSPs and their capability. On the one hand, a grid with the characteristics of the Swedish demonstration could benefit from distributed generation from RES to avoid surpassing subscription limits. In this case, the study shows that the benefits from the added renewables capacity come not only from having them as flexibility providers but as distributed generators in the first place. In Sweden, renewables in the future could be complemented with storage (so-called hybrid parks) and then have the capability to provide capacity during dimensioning hours. On the other hand, a grid similar to the Spanish demonstration would benefit from the demand response and storage capability of providing upward flexibility, something somewhat limited to RES. Therefore, replication scenarios show that the types of FSPs available for the TSO and DSO play an important role in determining the possibility for SOs to use flexibility. A system dominated by RES type of FSP will be able to provide downward capacity for an extended period but will be limited in providing upward capacity. Therefore, a mix of different types of FSPs could be most beneficial to the SO.

Scalability scenarios attested to the effectiveness of the use of flexibility in different situations. Firstly, considering the Swedish scenarios characterized by subscription penalty costs, an increase of only 60% over the base case flexibility could already lead to a situation in which the DSO does not incur subscription penalties. The use of flexibility also proved to be effective in the face of demand growth. Results suggest that a one-fold increase in FSP availability could lead to an increase of 10% in demand without the occurrence of NSF for the DSO. The NSF concept is introduced by this deliverable and presents the idea of a flexibility need by the DSO that cannot be supplied by FSPs, either by a lack of providers in the market, or their technical lack of effectiveness to solve the need in question.

The simulations could test the limits of the proposed markets, showing that for some situations, criticalities can only be partially solved by using flexibility. For instance, in Workstream 2 which focuses on congestion management in MV grids, some SRA scenarios from the Greek and Spanish case studies showed that the congestion criticalities were not entirely solved even after procuring the maximum available flexibility of FSPs. Since more flexibility is needed in these scenarios, other flexibility options could be considered, such as network reconfiguration, control of OLTC, new FSPs, etc. Therefore, DSOs can choose between using their own flexible resources or procuring flexibility from third parties, or a combination of both to solve potential operational and planning problems related to congestion. In this regard, it could be beneficial to propose a framework for analyzing the interaction between flexibilities from DSO and local flexibility markets to determine which solutions are the most attractive from the point of view of economic efficiency, implementation cost, information asymmetry, and other criteria to be explored. This highlights once more the grid dependence of results and the need for FSPs' engagement to the local flexibility market for congestion management.

Workstream 3 focused on the different market models for procuring voltage support from FSPs involving both TSO and DSO and a great variety of HV, MV, and LV grids. Radial and meshed grids were studied considering different DG penetration levels to investigate the conditions that determine voltage issues and study the effectiveness of FSPs in providing reactive power support for voltage control. In SRA workstream 3, the considered FSP technology are DGs (PV and wind) interfaced with power electronics, since in principle this technology allows controlling the reactive power exchange without affecting the active power injection by exploiting the apparent power bandwidth available depending on the actual DG operating point. Hence, the adopted FSPs model is general and describes a future scenario in which network codes require DGs to fully control the power exchange. Scalability scenarios assessed the effectiveness of the use of flexible reactive power support from DG in different situations characterized by demand growth, loss of dispatchable generators, and increase of generation from DERs.

The augmented availability of FSPs in terms of size and location is beneficial for increasing the effectiveness of the market-based procurement of voltage support. Increasing the probability of having FSPs electrically close to the voltage issue is crucial for control effectiveness. An increased FSP size, and then, an increased reactive power support capacity, is beneficial for voltage control if the considered FSP is well located with respect to the voltage issue. Grid topology is the main feature influencing voltage control effectiveness, in meshed grids the number of busses that can effectively contribute to clear a voltage issue may be higher than in radial grids, determining a higher efficiency of the corresponding market-based procurement. Grid topology influences the benefits of adopting a common market model over a multi-level; in general, voltage sensitivities must be part of the market formulation to avoid procuring reactive power support from FSPs that do not effectively contribute to resolving the voltage issue.

The SRA studies of workstream 3 highlighted that a sub-transmission grid like the one in the Cadiz demo site could benefit from distributed generation from RES participating as FSPs to voltage control especially if operated using a closed loop topology. A transmission system like the one in the Greek demo site can benefit from the voltage support available from DG FSPs to clear voltage violations caused by the loading conditions of long feeders and submarine cables. Generally, the availability of FSPs both in the transmission and distribution system is crucial for minimizing the risk of residual voltage violations. As highlighted in the SRA of the Murcia demo site, the growth of demand expected due to the electrification of the energy uses will determine undervoltages in the distribution grids that fed urban areas. The availability of FSPs well distributed on the network helps relieve the voltage issues during the peak load periods. However, in the case of radial topologies, the analyzed reactive power support is effective only if the FSPs are well located with respect to the pilot bus to be controlled. The SRA of the Cadiz demo site encompass scenarios modelling the effects of decarbonization policies which determine the lack of dispatchable generators; the studies highlight the effectiveness of FSPs to support voltage control. However, some criticality can occur under high loading conditions, and scenarios characterized by a closed loop topology are less prone to residual voltage issues. Hence, reactive power support from FSPs has to be coordinated with other measures to ensure the resolution of all possible voltage violations.

Voltage control effectiveness increases if the FSPs are properly located in the network with respect to the bus with voltage violations, rather than having a larger reactive power capacity in less effective buses. Hence, sufficiently high participation of potential FSPs is fundamental to increasing the probability of having well located FSPs and avoiding market distortions. The reactive power support capability considered in

Workstream 3 is limited to the hours of low active power production since the availability of a larger apparent power bandwidth to be used for reactive power provision. Hence, as demonstrated by the SRA analysis of the Murcia and Greek demo sites, considering reactive power support, FSPs based on DG are more likely to contribute to resolving voltage problems caused by peaks of demand or Ferranti effects. Nevertheless, the addressed SRA analysis point out the limit of this kind of voltage support that requires to be complemented by other FSPs technologies (i.e. FSPs whose reactive power capability is not constrained by the active power production from RES) and measures (i.e. network equipment operation, network reconfigurations, active power support) to resolve all voltage violations that may occur in the network. Therefore, a mix of different types of FSPs to complement the already available voltage control measures could be most beneficial to the SOs.

Topology is the key aspect of voltage control effectiveness, the local peculiarity of voltage control influences the effectiveness of the adopted market model. As highlighted in the study of the Greek demo site, a multi-level market model with sequential DSO-TSO optimization can lead to the implicit resolution of voltage violations expected in the TSO network, determining a situation that can be seen as a distortion in terms of cost allocation.

One important technical outcome of the studies conducted, both in Workstreams 1 and 2, is the demonstration of the effectiveness of the PTDF local market formulation. The proposed linearized local flexibility market does not lead to new congestion problems after the market-clearing, according to the post-evaluation process and under the scenarios analyzed. The studies in workstream three provide evidence of the effectiveness of the proposed linearized reactive power market in procuring effective voltage support by minimizing the overall procurement expenses.

Therefore, from a quantitative perspective, simulations suggested the viability of usage of flexibility usage under different scalability and replicability scenarios. From a regulatory perspective, however, the country analyses showed that an important gap exists before CoordiNet’s solutions can be replicated to different countries.

A qualitative SRA was also conducted, in which the main focus is on the regulatory replicability of the different coordination schemes and the provision of DER flexibility for different services. The aim of the regulatory SRA is to identify barriers and drivers for replicating the selected BUCs posed by existing regulation. Barriers are rules, found in all or some of the countries considered, that potentially constrain the implementation and operation of the BUCs. On the contrary, a regulatory driver is found when certain solutions are enabled and incentivized by regulation. The countries analysed are the three demo countries, namely Greece, Spain and Sweden, and five additional countries: Austria, Belgium, Germany, Italy, and the Netherlands.

The country analyses showed that an important gap exists before CoordiNet’s solutions can be replicated to different countries. First, it was verified that the congestion management and voltage control services are very unharmonized among countries, and a common market-oriented definition is lacking even at the European level. Second, DER provision of flexibility to DSOs is still a challenge. The economic regulation of DSOs is still mostly CAPEX-biased, with little incentive for the procurement of flexibility. Additionally, no country has yet implemented a regulatory framework for the cost recognition or output incentives for the use of flexibility. Finally, different MMs will require different levels of coordination between TSO-DSO. It was found that most countries already have TSO-DSO coordination in most timeframes of operational planning and real-time operation of the system. However, enhanced coordination will be needed for certain MMs, which is still a barrier to replicability.

Among the drivers identified in the different countries, it is important to highlight that replicability of use cases involving the balancing service is more feasible in several countries, as they already have balancing markets open to DER, and practical limitations for their participation is limited. Another driver is the fostering of aggregation activity. Several countries have already implemented regulations that recognize this agent, and some also provide the necessary framework for the independent aggregator to share responsibilities with other entities (e.g., BRPs).

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