Deliverable D6.3

Economic assessment of proposed coordination schemes and products for system services

V1.0

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D6.3 – Economic assessment of proposed coordination schemes and products for system services

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Executive summary

This deliverable aims at analyzing the economic implications of the proposed coordination schemes (CSs) and products for system services within CoordiNet.

The analysis in this deliverable focuses on the demonstration activities performed in CoordiNet in Spain, Sweden and Greece for the coordinated procurement of system services by Distribution System Operators (DSOs) and Transmission System Operators (TSO) from flexibility service providers (FSPs) and other Distributed Energy Resources (DER).

For that purpose, it builds upon the experience of the CoordiNet demonstrators, but also on the analyses and simulations performed in WP6. This way, the costs for the implementation and operation of the required platforms that enable the exploitation of flexibility for the operation of the system are based on the analysis of the Key Performance Indicators (KPIs) in (Trakas et al., 2022). Moreover, the CSs originally proposed in (Delnooz et al., 2019), which included four main classification dimensions (where the need is located, who the buyer is, the number of markets, and whether the TSO has access to DER) have been further detailed in (Sanjab et al., 2022), by adding four additional classification dimensions (agreement on the interface flow – if applicable, sharing of resources, how network information sharing is considered, and whether bids can be forwarded and how). Additionally, the scalability and replicability analysis (Cossent et al., 2022) provided different simulations, which were the basis for the estimation of the case studies considered in this deliverable.

The evaluations of the CSs, services and products are performed with different levels of detail and for different scopes. As an initial step, this deliverable presents a qualitative analysis of the coordination schemes, services and products considered in the CoordiNet demonstrators, by analyzing the key parameters, the activation process and the settlement process, with the aim of extracting conclusions on their suitability both for TSOs and DSOs, and for FSPs and DER. For products and service, aspects such as active vs reactive power products, capacity vs energy products, timing aspects, product distinction per quantity, symmetry, possibility to aggregate, locational information, automatic vs manual activation, etc. are analyzed and compared among the three countries. For coordination schemes, the analysis focused on the type of FSPs participating the provision of services, the number of markets demonstrated, the potential combination of the procurement of balancing and congestion management (CM), timing aspects, maturity of the services and sharing of network information between system operators.

One of the conclusions of this analysis, in particular regarding maturity, and which is also in line with the findings of D6.2 (Sanjab et al., 2022), is that the balancing markets are well established (as they are already existing markets), while the markets for the other services (such as voltage control or controlled islanding) are less developed. Therefore, a lot of attention has been paid to the definition of markets for CM in CoordiNet and, hence, the procurement of that service is the main focus of this deliverable.

Once the focus is on congestion management, different key aspects must be taken into account in order to evaluate the most efficient way to procure and use flexibility. These aspects are discussed in this deliverable and result in the three pillars described below. In particular, the methodology described here aims at **answering the following four core questions**:

1. Under which conditions is the use of flexibility more suitable than the Business-as-Usual option (i.e., reinforcing the grid or ask for temporary subscription tariffs)?
2. Which is the most cost-effective way of coordinating the procurement (including the cost of developing the platforms necessary to do so) of system services between TSOs and DSOs?
3. Is the provision of flexibility a profitable business model for both FSPs and DERs?

4. Do local flexibility markets provide a cost-effective solution for solving specific needs of the DSO? If so, can they facilitate and incentivize the participation of both small FSPs and DERs?

It is important to bear in mind that flexibility may or may not be more cost-efficient than reinforcing the grid or using other traditional solutions (grid reconfiguration, increase in the subscription level by regional and local DSOs, etc.). Therefore, the conditions under which the use of flexibility is more effective (or provides a solution with a similar cost, but with a much faster commissioning time) must be determined. This analysis is one of the first of three pillars identified in this deliverable for the success of the flexibility use.

The second pillar refers to the selection of the most cost-effective coordination scheme between the TSO and DSO. When the needs of the TSO and the DSO must be satisfied in a coordinated manner, three main alternatives arise (Delnooz et al., 2019), (Madina et al., 2020):

- *Common Market Model (CMM)*: both local and central needs coming from DSO and TSO are considered in a single market and, thus, the TSO can use assets connected to the distribution grid to solve all system needs.
- *Multi-level Market Model (MMM)*: it is a variation of the CMM, in which each system operator uses its own market in a sequential order, rather than through a single market. Two alternatives can be considered in this case: The unused bids in the market operated at distribution level are forwarded automatically to the market operated at transmission level (which is the market model is considered in the analysis) or, alternatively, aggregators and other FSPs are allowed to submit new bids for their unused flexibility after the market operated at distribution level to the market operated at transmission level.
- *Fragmented Market Model (FMM)*: it is split as in the MMM, but the TSO has no access to DERs. Hence, resources connected to the distribution grid can only offer their flexibility to solve the DSO needs and, hence, has low coordination between TSO and DSOs. Therefore, this third option is not included in the analysis in this deliverable.

Additionally, it is also important to evaluate whether the provision of flexibility is a profitable business for FSPs, which is the core of the third pillar of the analysis. Consequently, while the first two pillars assessed the coordination schemes for the procurement of congestion management services at system level (as a macro analysis), the third pillar evaluates the business case performance (at micro level).

Since the participation in flexibility markets, where needs of both TSOs and DSOs are satisfied, is not an easy task for small-scale FSPs, but their inherent flexibility which can still be very useful to solve other kind of issues in the system, such as local needs at distribution level, and the Internal Electricity Market Directive (European Commission, 2019a) sets up a framework that enable DSOs to use local flexibility to procure congestion management services, local markets will also be considered within this deliverable.

Therefore, the analysis for pillars 1 and 3 is split between two different application scopes: pillars 1.a and 3.a analyze the provision of flexibility for solving joint TSO and DSO needs, while pillars 1.b and 3.b look at the use of flexibility for solving DSO-specific needs (with little or no impact on the TSO) at the lowest voltage levels of the power system. This division of scope is also in line with the analysis of products, services and coordination schemes presented in this deliverable, where the definition of different products per bid size or the use of different coordination schemes per size of FSP is already studied.

Pillar 1.a answers the core question #1 *"under which conditions is the use of flexibility more suitable than the Business-as-Usual option (i.e., reinforce the grid or ask for temporary subscription tariffs)?"* by comparing the procurement of flexibility services versus the Business as Usual (BaU) alternative for addressing joint TSO and DSO needs, focusing on the implemented CS in each demo-country. Based on (Cossent et al., 2022), this analysis compares the common and multi-level market models for the procurement of flexibility with the BaU alternative, which is a grid reinforcement in the Spanish case and overcoming the subscription level in the Swedish case (more details about subscription levels can be found in subsection 3.1.2). As presented in Figure 1, the accumulated costs for both alternatives are evaluated along a variable flexibility procurement period, with the objective of supporting the decision-making process of the medium-term grid expansion plans. On the flexibility solution side, the costs related to the software (SW) platform and the costs of Information and Communication Technologies (ICTs) for all actors are included, as well as the cost for the CM service procurement (both at distribution and transmission level) and the cost of the temporary subscription (if needed) in the case of Sweden. On the BaU grid alternative, both capital expenditures (CAPEX) and operational expenditures (OPEX) for new grid assets (if needed in distribution and/or transmission network) are included in Spain, and the cost of the temporary subscription tariff cost is quantified in Sweden). Although the DSO may use a BaU alternative to solve its needs, the TSO may still need to procure flexibility to solve the needs at transmission level.

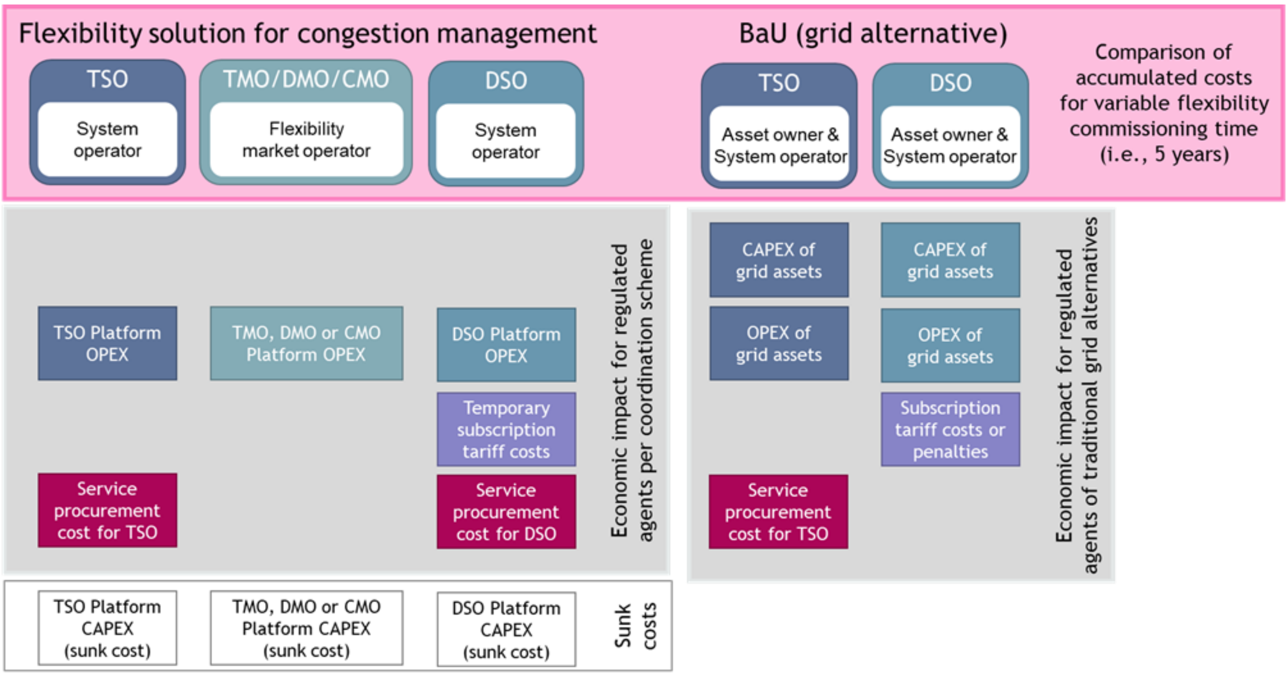

Figure 1: Cost components for regulated agents in the flexibility and BaU alternatives for joint TSO and DSO needs (Pillar 1.a)

It is important to note that the desired functionalities for the DSO's flexibility platform are not location-specific (maybe except the ones related to grid monitoring, but the increased complexity in the operation of the distribution system requires the installation of the appropriate equipment for DSOs to improve the observability of the grid and, hence, it is expected that these grid monitoring functionalities would become widespread in the future). As a result, once that the consideration of the flexibility markets as a potential means to solve system needs is granted, those platforms will be implemented and, thus, the cost of their implementation (i.e., CAPEX for the ICT infrastructure and SW platforms to enable new flexibility markets) has already been borne at system level (it is considered in Pillar 2) and, hence, it becomes a sunk cost and it must not be taken into account when evaluating whether flexibility or grid reinforcement is the best solution for a given system need in a specific location.

The flexibility solution has demonstrated to be a faster, more effective, temporary mechanism to avoid or postpone grid reinforcements (i.e., reinforced line, new substation), while the grid-based solution is commissioned and comes into service and before congestions appear due to vegetative increase of demand. In Sweden, the flexibility solution may also be interesting to avoid the payment of high temporary subscription usage fees, or even further, the penalties for overcoming the subscription level. The flexibility solution will reduce the need to ask for higher subscription level (and the risk to have it denied) and enable the connection of new customers to a higher extent. Moreover, it has proven to be a faster and efficient solution, until the TSO reinforces the transmission grid and is able to provide higher subscription levels.

Pillar 1.b assesses whether *"local flexibility markets provide a cost-effective solution for solving specific needs of the DSO instead of other Business-as-Usual alternatives (i.e., reinforce the grid or take remedial actions)"*, i.e., the first half of question #4, by evaluating the conditions under which the use of flexibility can postpone or temporarily replace traditional, grid-based solutions to solve DSO-specific needs, especially in Spain (Málaga and Murcia) and Greece (Kefalonia network) local distribution grids. In the short term, the flexibility solution may be compared to the cost of a remedial action when congestions are already appearing, in which avoiding not supplying energy to final customers must be a DSO concern. In the medium term, the use of flexibility for a given commissioning time may be compared to the cost of traditional grid reinforcement when the DSO should take decisions for the upcoming distribution grid planning period. Since it is the DSO who should decide whether to use flexibility or the BaU alternative, Pillar 1.b is focused on the DSO economic impact as seen in Figure 2. On the flexibility solution side, OPEX terms related to the SW platform and ICT costs and the cost for the CM service procurement at distribution level are included, while CAPEX for the development of the platforms for the local market operator (LMO) and the DSO are not (as in the case of pillar 1.a). Additionally, there may be some "flexibility" not supplied (FNS) when there is not enough flexibility to completely solve the congestion. The FNS is only considered in local needs, while in joint TSO and DSO needs it is assumed that there is enough liquidity and available flexibility to solve the simulated needs. On the other hand, the DSO, as distribution asset owner, should consider CAPEX and OPEX of the traditional grid reinforcement (i.e., repowered line, new transformer, new generation asset, etc.).

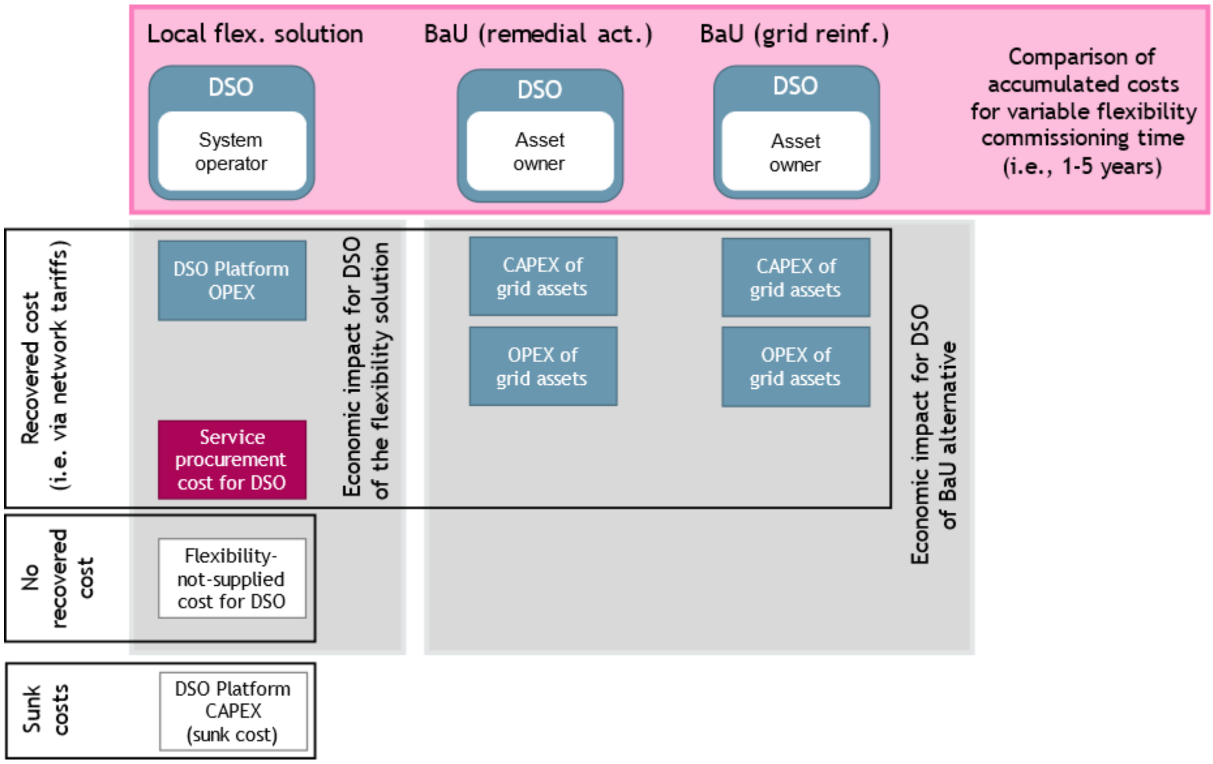

Figure 2: Cost components for the DSO in the flexibility and BaU alternatives for local needs (Pillar 1.b)

In case of occasional congestions, flexibility may be more cost-efficient than reinforcing the grid or take costly remedial actions (i.e., the use of a diesel generator). In the case of structural congestions, DSOs must procure flexibility more frequently or the amount of flexibility needed is higher than in the case of occasional congestions. Specially, there is a special concern in structural congestions at local level, in which the security of supply might be at risk for the DSO, due to potential non-supplied energy. In each case and location, the DSO must decide the best way to procure and activate the flexibility (via short-term markets or long-term contracts) by evaluating the flexibility needs, market liquidity, and flexibility availability from FSPs.

Table 1 below summarizes the main economic implications for the DSO, either when the flexibility solution or the Business-as-Usual alternative is selected, for each simulated scenario in Spain, Sweden and Greece (joint TSO and DSO needs and/or local DSO needs). It must be stressed that these results are based on the scenarios considered in the scalability and replicability analysis (Cossent et al., 2022), which are evaluated under some specific market and technical conditions and, hence, should not be generalized and extrapolated to other potential scenarios.

Table 1: Summary of main economic implications for the DSO for the simulated scenarios in Spain, Sweden and Greece

	Albacete + Cádiz	Uppsala	Málaga	Murcia	Kefalonia
Type of CM need	Joint TSO and DSO needs	Joint TSO and DSO needs + temporary subscription	Local DSO need	Local DSO need	Local DSO need
Flexibility need	163 GWh/year	10 GWh/year	143 MWh/year	80 MWh/year	605 MWh/year
Weighted price	1.5 €/MWh	16 €/MWh	92.5 €/MWh	25 €/MWh	82 €/MWh
Flexibility solution cost for the DSO	279 k€/year	920 k€/year	29 778 €/year	18 506 €/year	81 583 €/year
Threshold flexibility scenario vs BaU	41 000 MWh/year at 7.4 €/MWh	n/a	1 004 MWh/year at 46 €/MWh	682 MWh/year at 50 €/MWh	1 234 MWh/year at 41 €/MWh
BaU 1 type	Grid-based (Reinforcement)	High temporary subscription usage fees	Grid-based (Reinforcement)	Grid-based (Reinforcement)	Grid-based (Reinforcement)
BaU 1 cost	350 k€/year	1 816 k€/year	65 438 €/year	52 695 €/year	84 597 €/year
BaU 2 type	-	Subscription level penalties	Remedial action (diesel gen.)	Remedial action (diesel gen.)	Remedial action (diesel gen.)
BaU 2 cost	-	4 070 k€/year	81 632 €/year	49 645 €/year	1 158 k€/year

Pillar 2 addresses the core question #2 *"which is the most cost-effective way of coordinating the procurement (including the cost of developing the platforms necessary to do so) of system services between TSOs and DSOs"*. Consequently, it focuses on the evaluation and comparison of the economic efficiency of the common and multi-level CSs for providing CM for solving needs of both the TSO and the DSO, by comparing the costs for regulated agents, i.e., TSOs, DSOs and market operators (MOs) in the simulation scenarios considered for Spain and Sweden. In this deliverable, it is assumed that the specific role of the MO is on the one hand, independent from system operators and, on the other, a regulated party. Regarding the first assumption, the MO platforms to provide these services may be operated and/or hosted by the TSO

and/or the DSO, or the MO role may be performed by an independent agent (Valarezo et al., 2021), but, to account for all potential regulatory options, the role of market operator is considered to be taken up by an agent which is external to the respective system operator. As for the second assumption, it is important to mention that it does not mean that we recommend that this platform shall be owned and managed by third independent parties, such as Nominated Electricity Market Operator (NEMOs), and that, hence, other existing business models are not addressed here for the flexibility market operator (i.e., non-regulated flexibility market platforms, which may be operated by private market operators, as it was the case in the Swedish demonstrator).

From the results obtained in the analysis presented in this deliverable, it can be concluded that there is no one-size-fits-all coordination scheme. The existing market structure and legacy systems have a strong impact on the efficiency of the different coordination schemes, together with other issues such as the local and regional needs, the role of each agent, the maturity levels of services and products, and type of FSPs among countries. From the pure service procurement cost perspective, both common and multi-level markets seem to be equally efficient, by clearing the most competitive flexibility bids in short-term market mechanisms to achieve a cost-efficient service. Based on the particular conditions in Sweden, the multi-level market model seems to better address the challenges resulting from the subscription tariffs framework and to better promote the access of FSPs connected at distribution level to flexibility markets.

Pillar 3.a addresses core question #3 *"is the provision of flexibility is a profitable business model for both FSPs and DERs, both at solving joint TSO and DSO needs and at solving specific DSO needs at local level"*, and the second half of core question #4 *"can the DSO facilitate and incentivize the participation of both small FSPs and DERs"*, by evaluating the profitability of the provision of flexibility services by FSPs and DERs for joint TSO and DSO needs under the common and multi-level coordination schemes in Spain and in Sweden. Non-regulated agents, such as aggregators and other FSPs, will only participate in flexibility markets if they can see an attractive business model for providing services. That is, the remuneration that they receive for participating in those markets must be higher than the cost of providing them. As shown in Figure 3, FSPs and aggregators receive market incomes for the provision of flexibility services (from the TSO, from the DSO or from both in the case of the common market model), but they must deal with additional costs associated to this business activity, including the costs of developing, deploying and operating the necessary ICT systems (CAPEX and OPEX terms), flexibility market fee to access the market, and other costs linked to the activation of flexibility. In addition, if those FSPs are aggregators (either independent or not) which represent and optimize the use of the flexibility from multiple types of flexible DERs and end-users connected to the distribution grid (e.g., the ones participating at demo sites), they should consider both the cost of the aggregation platform and other costs associated to the DERs they represent, while it is assumed that FSPs who manage their own resources already have the required infrastructure to provide flexibility services and they do not require any aggregation platform. The market incomes of the FSPs will vary depending on the pricing scheme (pay-as-bid, pay-as-clear, etc.), the bid prices, the adopted coordination scheme, the features of competitors (demand response, generation units, etc.) and the amount of flexibility required.

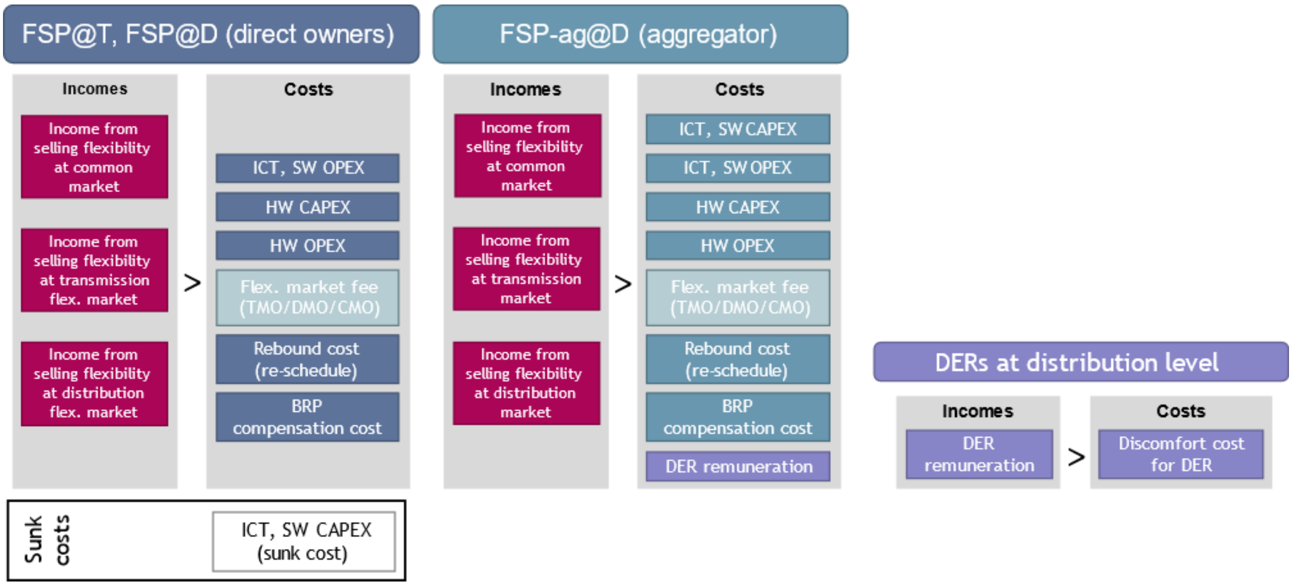

Figure 3: Incomes and costs for non-regulated actors (Pillar 3)

The participation in flexibility markets, where needs of both TSOs and DSOs are satisfied, is not an easy task for small-scale DERs or energy aggregators with limited resources and infrastructure, because technical and economic requirements are tailored to ensure the overall power system security and are suitable for large-scale players, but not necessary for small DERs at distribution level, such as energy storage, demand response, and distributed generators. However, these small units have an inherent flexibility which can still be very useful to solve other kind of issues in the system, such as local needs at distribution level.

Therefore, **Pillar 3.b** takes again core question #4 *"can the DSO facilitate and incentivize the participation of both small FSPs and DERs"* and evaluates the profitability of the provision of flexibility services by FSPs and small DERs in the local markets in Spain and in Greece.

Both in pillars 3.a and 3.b, the business model seems to be still uncertain and risky under the simulated cases in all demonstrators, especially when the solution is only implemented in a specific location. The high entry costs (platform development, communication infrastructure and maintenance, prequalification, market participation fee or other linked costs to the flexibility activation) and demanding technical and communication requirements disincentive the participation, especially when solving joint TSO and DSO needs. The scalability of the business model will make it more attractive and cost-efficient in case of more widespread congestions. As presented above, DSOs could also establish local market models to exploit the flexibility of small DERs to solve congestion issues at distribution level. These local markets seem to be more accessible and attractive for small DERs, as the communications and reliability requirements (and, thus, costs) may be lower, while, at the same time, they can provide a highly valuable service for the DSO at local level.

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Notations, abbreviations and acronyms

Table 2: Acronym list

API	Application Programming Interface
BAU	Business as usual
BRP	Balance Responsible Party
BUC	Business Use Case
CAPEX	Capital Expenditures
CBA	Cost Benefit Analysis
CHP	Combined Heat and Power
CM	Congestion Management
CMM	Common Market Model
CMO	Common Market Operator
CS	Coordination Scheme
DC	Direct Current
DER	Distributed Energy Resource
DMO	Distribution Market Operator
DSO	Distributed System Operator
EHV	Extra high voltage
ESB	Enterprise Service Bus
EU	European Union
FMM	Fragmented Market Model
FNS	Flexibility not supplied
FSP	Flexibility Service Provider
FSP-ag@D	Flexibility Service Providers (aggregators)
FSPs@D	Flexibility Service Providers (owners of resources connected at distribution network)
FSPs@T	Flexibility Service Providers (owners of resources at transmission network)
GCT	Gate Closure Time
HV	High Voltage
HVDC	High-Voltage Direct Current
HW	Hardware
ICT	Information and communications technology
KPI	Key Performance Indicator
LMM	Local Market Model
LMO	Local Market Operator
LV	Low Voltage
mFRR	Manual Frequency Restoration Reserves
MMM	Multi-level Market Model
MO	Market Operator
MV	Medium Voltage

NEMO	Nominated Electricity Market Operator
NRA	National Regulatory Authority
O&M	Operation and Maintenance
OPEX	Operational Expenditures
OPF	Optimal Power Flow
P2P	Peer-to-peer
PTDF	Power Transfer Distribution Factors
RES	Renewable Energy Sources
RR	Replacement Reserves
RT	Real time
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SW	Software
T&D	Transmission and Distribution
TMO	Transmission Market Operator
TOTEX	Total Expenditures
TSO	Transmission System Operator
VOLL	Value of Lost Load
WACC	Weighted average cost of capital

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 system services through demand response, 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 system services in the most reliable and efficient way through the implementation of three large-scale demonstration campaigns or demonstrators. The CoordiNet project is centred on 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 demonstrators at large scale, in cooperation with market participants.
2. To define and test a set of standardized products and the related key parameters for system 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 system services and opens up new revenue streams for consumers providing system services.

In total, ten demonstration activities have been carried out in three different countries, namely Spain, Sweden and Greece. In each demo activity, different products have been tested, in different time frames and relying on the provision of flexibility by different types of Distributed Energy Resources (DER). Figure 4 presents the standardized products, system services, and coordination schemes implemented in the CoordiNet demonstration activities for Spain (pink), Sweden (yellow) and Greece (grey). More details about the process to define the business use cases (BUCs) which have been tested in CoordiNet can be found in D1.5 (Gürses-Tran et al., 2019).

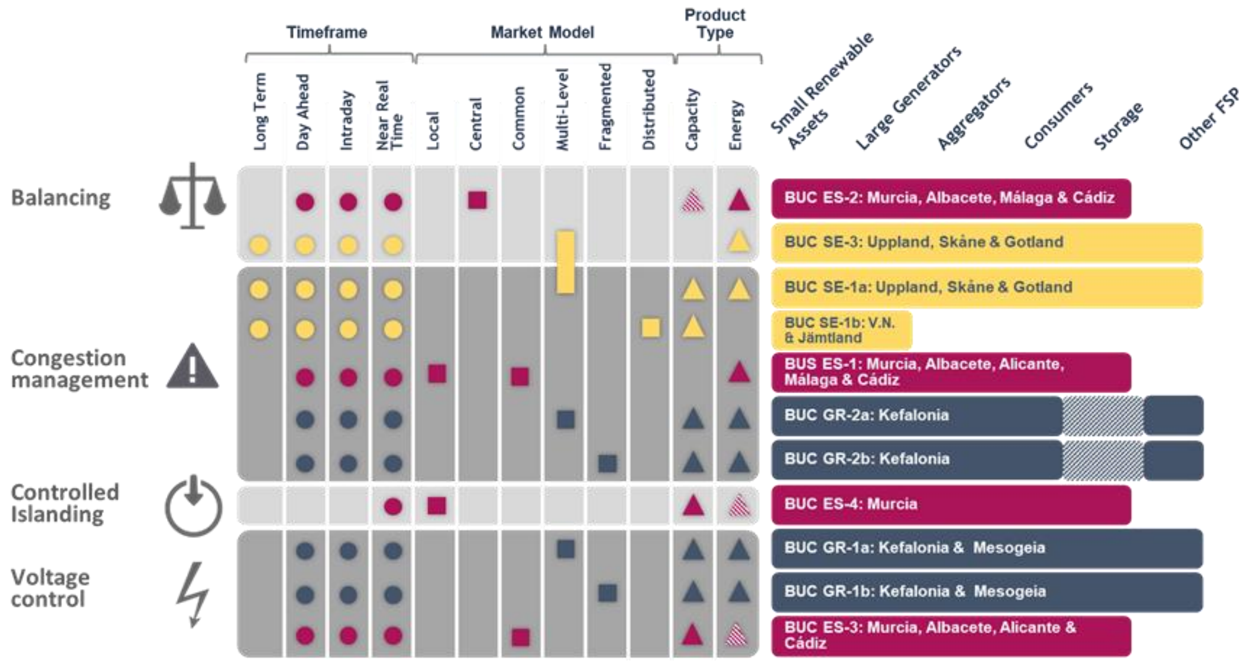

Figure 4: Services, timeframes, coordination schemes and products demonstrated in different countries

1.2 Scope of the document

The objective of this deliverable is to perform an economic assessment of the proposed coordination schemes (CSs) and products for system services within CoordiNet.

The economic assessment of the different CSs is performed at two levels. On the one hand, this deliverable evaluates the overall efficiency of the different CS alternatives at system level. On the other hand, it covers the economic implications for all market agents in the value chain, i.e., TSOs, DSOs, flexibility market operator (MO), flexibility service providers (FSPs) (including aggregators) and DERs. In particular, the economic assessment in this deliverable aims at answering the following four core questions:

1. Under which conditions is the use of flexibility more suitable than the Business-as-Usual option (i.e., reinforcing the grid or ask for temporary subscription tariffs)?
2. Which is the most cost-effective way of coordinating the procurement (including the cost of developing the platforms necessary to do so) of system services between TSOs and DSOs?
3. Is the provision of flexibility a profitable business model for both FSPs and DERs?
4. Do local flexibility markets provide a cost-effective solution for solving specific needs of the DSO? If so, can they facilitate and incentivize the participation of both small FSPs and DERs?

As discussed in D6.2 (Sanjab et al., 2022), market-based procurement of some system services (congestion management, voltage related services, inertial response, black start services, controlled islanding) is currently under discussion, while, for balancing services, there are already well-established markets and the European regulation (European Commission, 2017) gives the responsibility of ensuring system balance on TSOs. Specially, the economic evaluation of the congestion management through market-based procurement has drawn the attention and tested in several demos.

As the procurement of flexibility for congestion management and balancing services are not addressed jointly within the CoordiNet project, this deliverable is focused on the evaluation of the different CSs for providing congestion management (CM) services (for joint TSO and DSO needs, and for DSO-specific local need). A detailed analysis of the implications of the products, services and coordination schemes implemented in the demonstrators is provided in chapter 3.

The economic efficiency of the different coordination schemes at system level can be measured by comparing the costs for regulated agents (i.e., TSOs, DSOs and MOs[1]), which will need to be recovered either through transmission and distribution fees or other regulated charges, in each case. These costs include both the cost of procuring system services and the cost of developing and deploying the Information and Communication Technologies (ICTs) or software (SW) platforms required for such procurement. ICT costs comprise both capital expenditures (CAPEX) and operational expenditures (OPEX). Meanwhile, non-regulated agents, such as aggregators and other kind of FSPs, will only participate in flexibility markets if they can see an attractive business model for doing so, i.e., the remuneration that they receive for participating in those markets must be higher than the cost of providing the flexibility, including the costs of developing and deploying the necessary ICT systems.

[1] In order to account for all potential regulatory options, the role of market operator is considered to be played by an agent which is external to the respective system operator. This is not the case in existing balancing markets and in markets for solving congestions at transmission level, although it might be the case for new flexibility markets to be operated at distribution level. In this deliverable, it is assumed that the MO is a regulated agent.

Participation in flexibility markets, where needs of both TSOs and DSOs are satisfied, is not an easy task for small-scale DERs at distribution level, such as energy storage, demand response, and local generators. Technical and economic requirements of system services are very often tailored to ensure the overall power system security and are typically suited for large players, but not for small DERs. However, these small units have an inherent flexibility which can still be very useful to solve certain issues in the system, including local needs. The Internal Electricity Market Directive (European Commission, 2019a) sets up a framework that mandates DSOs to use local flexibility to procure congestion management services, as long as they use transparent, non-discriminatory and market-based procedures and when "*such services cost effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system*" [Art. 32, (European Commission, 2019a)].

As a result, DSOs can also establish local markets to exploit the flexibility of small DERs to solve congestion issues at distribution level. Moreover, there may be cases where the appearance of congestions may hinder economic development or the connection of new users to the system, as the commissioning times of grid-based solutions may be too long. Therefore, the use of these local markets may allow for not only postponing the need to reinforce the grid, but also provide a temporary solution cope with the vegetative increase of demand during the commissioning time of the new grid elements. Consequently, the evaluation of local flexibility use versus grid reinforcement is made with a medium-term vision, by comparing the costs of both alternatives over a certain time span, e.g., from 1 to 5 years.

In order to be able to use flexibility-based solutions locally, DSOs must develop, deploy and integrate several ICT-based platforms and install new monitoring devices in the Medium Voltage (MV) and Low Voltage (LV) grids. Such platforms require massive investments, but they are easily scalable and replicable. In fact, their implementation does not only solve one specific issue in the system at a certain location, but it can also be used to solve many issues in many different locations.

Thus, once that the consideration of flexibility solution as a potential means to solve system needs (both joint TSO and DSO, and local needs) is granted, the cost of their implementation becomes a sunk cost and, hence, it must not be taken into account when evaluating whether flexibility or grid reinforcement is the best solution for a given system need (the functionalities that the DSO's flexibility platform should have are shown in Table 3). Both grid alternatives are evaluated along a given time span (i.e., a variable flexibility procurement period), which enables to compare the accumulated costs (i.e., CAPEX for grid assets, OPEX for grid assets, ICT or software platforms' maintenance, flexibility procurement costs, in each case) along the upcoming years and select the most cost-effective solution under given specific grid conditions. In case of flexibility solution convenience, grid-based alternative can be postponed or delayed.

The economic analysis described in this deliverable D6.3 is fed by the outputs of the CoordiNet demonstrators and several market simulations with different coordination schemes. The scenarios for the market simulations have been designed to consider the different coordination schemes, products, voltage levels, network models, and demo sites with the existing DERs in each country under analysis, i.e., Spain, Sweden, and Greece. Specifically, the market simulations are described in D6.4 (Cossent et al., 2022), while the estimates about CAPEX and OPEX are based on the data provided by the demonstrators in several deliverables and collected in D6.1 (Trakas et al., 2022).

1.3 Document structure

This report is structured in nine chapters and three annexes. Chapter 1 provides an introduction to the CoordiNet project and to the scope of the document. Chapter 2 provides an overview of the scope and the background information required in order to understand the economic assessment presented in this deliverable.

Next, chapter 3 gives an overview of the services, products and coordination schemes of the different demonstrators, and the different approaches between the different demonstrators are compared.

Chapter 4 describes the methodology followed to evaluate the proposed coordination schemes and products both at system and business levels, including the main characteristics of the methodology and the three pillars on which the assessment is based.

Chapters 5, 6 and 7 show the economic assessment carried out for Spain, Sweden, and Greece, respectively. All three chapters are equally structured. First, the main features of the country-specific scenarios considered for the analysis are explained. Then, the obtained results are detailed and analyzed for the three pillars. Last, the main conclusions of the flexibility solution in each country are drawn.

Finally, chapter 8 gathers the main general conclusions and recommendations. Then, chapter 9 provides the references used in the preparation of this deliverable.

In addition, three annexes are included at the end of the report: Annex I provides a detailed definition of the products for system services tested in each demonstrator, Annex II shows the sequence diagrams of some coordination schemes to address joint TSO and DSO needs which are not investigated in detail in this deliverable, and Annex III explains the current regulatory mechanisms and legal framework for market actors in the three countries.

2 Scope and background for the economic assessment

This chapter provides an overview of the scope and the required background to perform the economic assessment at system and business level of the proposed coordination schemes and products within the CoordiNet project.

2.1 Context and scope of the economic assessment

The **Energy Transition** will raise important challenges to shift from a fossil-based to zero-carbon energy sector in a cost-efficient way, in which power system operations becomes more complex. Higher shares of renewable energy sources are challenging the capability of the system to both accommodate the massive connection of generation facilities to the distribution grid and to ensure the balance between generation and demand. In addition, the electrification of the transport, heating, and industrial sectors, entails an increased electricity demand, which is putting a strain on both the transmission and distribution systems.

The shift to renewables and increased electrification is crucial to achieve carbon neutrality by 2050 (European Commission, n.d.). The Electricity market design, as a key part of the "*Clean energy for all Europeans package*" (European Commission, 2019b) and the "*The Fit for 55*" legislative proposals (European Council, 2022) and the recent Repower EU (European Commission, 2022) contribute to the European Union's goal of fostering renewable production and, it is highly aligned to the scope of the CoordiNet project. In fact, the **use of flexibility markets** can offer more efficient solutions than just reinforcing the grid or applying temporary solutions, when:

a) power consumption increases due to the electrification of heating or mobility sectors,
b) DERs cause local congestion events,
c) increasing renewable energy should be accommodated in the grid, and
d) the access of new electrified consumers (such as fossil-based industries, electric transport) should be enabled as far as possible (Vattenfall, 2022) in distribution networks with an already quite limited capacity.

The casuistry of the problem is diverse and highly country specific.

This Electricity market design initiative thus pursues the *"adaptation of the current market rules to new market realities, by allowing electricity to move freely to where it is most needed when it is most needed via undistorted price signals, whilst empowering consumers, reaping maximum benefits for society from cross-border competition and providing the right signals and incentives to drive the necessary investments to decarbonise our energy system"* (European Commission, 2019b).

DSOs should act as market facilitators of the energy transition and, thus, they shall play new roles as a buyer of local flexibility, as an interlocutor with the TSO for system-wide ancillary services, and at the same time, it should enable non-discriminatory access to active consumers and other agents in the markets. With the Clean Energy Package in place (European Commission, 2019b), DSOs now shall investigate if the use of **market-based solutions for flexibility** are more cost-efficient than other grid alternatives to optimize network investment decisions.

In this sense, a closer cooperation between TSOs and DSOs is essential for enabling TSOs and DSOs to fulfil their duties in a manner that minimizes societal cost (CEDEC et al., 2015), maximizes sustainability and ensures affordable security of supply of our power system, balances the grid and manages congestions cooperatively at transmission and/or distribution level (progressively to a higher degree at distribution level). For such increased cooperation, regulation should evolve in order to clearly define the coordination schemes between the DSOs and TSO, the standardized products and the flexibility services. In order to identify the most efficient way of such TSO-DSO coordination, the CoordiNet project has investigated the economic implications of the selection of different coordination schemes or alternatives, especially for the procurement of different services in the involved European countries.

2.2 Market actors in flexibility markets

As presented in section 1.2, this Deliverable D6.3 covers the **economic implications of all involved market agents** in the value chain, i.e., TSOs, DSOs, MOs, FSPs, and DERs.

According to the Directive (EU) 2019/944 (European Commission, 2019a), the TSO is a "*natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity*". Whilst, in a manner similar, the DSO is the natural or legal person responsible of the distribution system in a given area.

According to Article 2(7) of the Regulation (EU) 2019/943 (European Commission, 2019c), market operator means an "*entity that provides a service whereby the offers to sell electricity are matched with bids to buy electricity*". Particularly, a flexibility market operator is oriented to flexibility products and services.

Both the DSO and the TSO buy flexibility needs via a market-based mechanism within CoordiNet. Depending on the coordination scheme, a single or multiple markets can be used to meet local, central or both needs of DSOs and TSOs. Likewise, separate markets for different products (CM, balancing, etc.) could be considered.

Additionally, the MO platforms to provide these services may be operated and/or hosted by the TSO and/or the DSO, or the MO role may be performed by an independent agent (Valarezo et al., 2021). In order to account for all potential regulatory options, the role of market operator is considered to be taken up by an agent which is external to the respective system operator. Although this is not the case in existing balancing markets and in markets for solving congestions at transmission level, it might be the case for new flexibility markets to be operated at distribution level. Consequently, three roles will be evaluated independently from the system operators:

- Transmission market operator (TMO), who is responsible for matching the TSO needs with the offers received from the FSPs connected to transmission grids (in fragmented market model) or the FSPs connected to transmission and distribution grids (in multi-level market model).
- Distribution market operator (DMO), who is responsible for matching the DSO needs with the offers received from the FSPs connected to distribution grids (in multi-level and fragmented markets).
- Common market operator (CMO), who is responsible for matching both TSO and DSO needs with the offers received from the FSPs connected to transmission and distribution grids (in common market).
- Local market operator (LMO), who is responsible for matching the DSO-specific local needs with the offers received from the FSPs connected to LV distribution grids (in local markets). In this deliverable, it is assumed that the LMO operates a market which is aimed at solving DSO-specific needs in LV or MV grids, where only small FSPs (e.g., below 1 MW) participate, and which has little impact on the TSO.

Likewise, a FSP represents one or more flexible resources connected to the transmission or distribution grids with the capability to provide flexibility services, being a potential market participant to operate in flexibility markets for TSOs and/or DSOs. The FSP can *be a direct owner of flexible resources participating* *in the provision of the grid services or an intermediary, such as independent aggregator or a retailer, that represents flexible resources and coordinates their response* (Gürses-Tran et al., 2019). Therefore, these flexible resources include DERs at distribution networks, as well as centralized resources connected at transmission network.

As defined in the CoordiNet deliverable D1.1 (Lind and Chaves, 2019), DER is a concept used to encompass the multiple types of end-users connected to the distribution grid, capable of providing energy and/or services to the grid by mobilizing the flexibility they have available. Afterwards, an energy aggregator is a party that aggregates resources for usage by a service provider for energy and/or services markets.

In the following economic analysis, the sellers of the flexibility markets would be classified according to the voltage level of the distribution grid that the resources are connected:

- FSPs at transmission network are direct owners of flexible resources and potential participants in the provision of system services. Hereafter, the set of FSPs at transmission network will be designated with the acronym FSP@T.
- FSPs at distribution network may be direct owners of flexible resources and potential participants in the provision of system services (which will be designated with the acronym FSP@D) or may be aggregators (either independent or not) which encompass the multiple types of flexible DERs and end-users connected to the distribution grid (e.g., the ones participating at demo sites) (which will be designated with the acronym FSP-ag@D).

In this context, an independent aggregator is a market participant engaged in aggregation who is not affiliated to the customer's supplier (European Commission, 2019a). The introduction of independent aggregators operating as FSPs allow that they can resell an amount of energy that a supplier has already paid for in the existing market(s), or refrain from using it. Thus, the FSP (or the aggregator in this case) should be economically responsible for the imbalances due to unmatched positions they cause to balance responsible parties (BRPs) for the activation of that flexibility. In this regard, it could be necessary to establish different financial compensation mechanisms to ensure that BRPs are not significantly affected by their activity (CEER, 2020).

The relationship and agreement conditions regarding the compensation mechanism between aggregators, BRPs, and suppliers, is still under discussion at European and national level (Bray and Woodman, 2019):

- There is no standardized role for independent aggregators: Germany, Great Britain, and Spain.
- Independent aggregators must bilaterally contract with the consumers' BRP and retailer through a prior agreement: Denmark, Finland, and Belgium.
- Aggregators do not need prior agreement from BRPs: France, Switzerland, and Ireland.

Figure 5 shows the BUC overview for CM in a multi-level CS, where the relationship between the agents is presented: TMO, DMO, FSP@T (in the form of a direct owner of flexible resources, in the diagram named as *"service provider (transmission)"*), FSP@D (in the form of a direct owner of flexible resources, in the diagram named as *"service provider (distribution)"*), the FSP-ag@D (in the diagram named as *"aggregator/flexibility operator"*), and DERs (in the diagram named as *"flexibility provider (DER owner - distribution)"*).

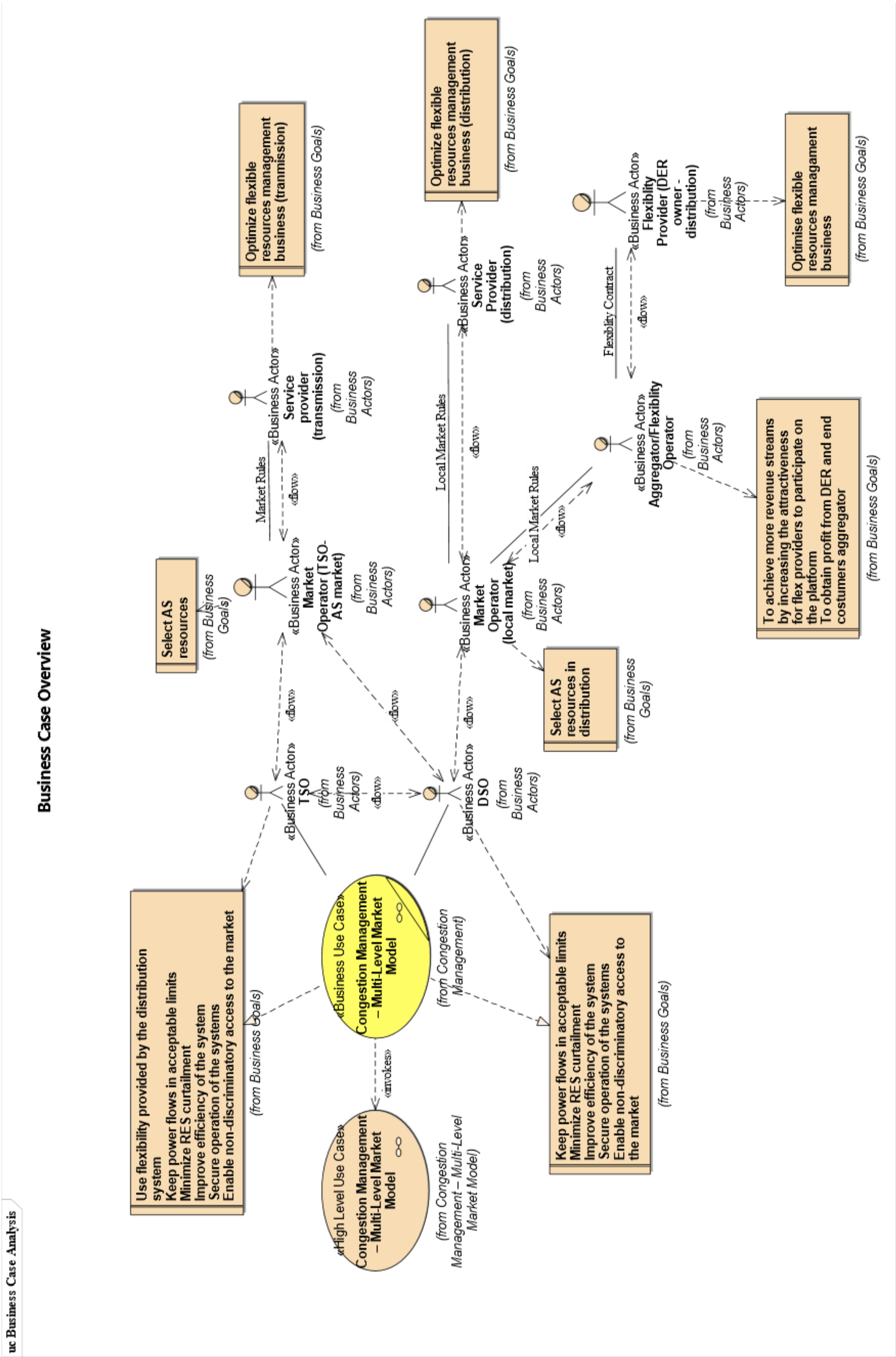

Figure 5: Business case overview for congestion management in a multi-level coordination scheme (Gürses-Tran et al., 2019)

2.3 Flexibility platform costs towards a commercial solution

The costs to be considered in the analysis carried out in this report are based on the costs related to the implementation of ICT systems in each market model developed within the CoordiNet project. The term implementation, as explained in (Trakas et al., 2022), includes the work in designing, specifying, coding, testing, validating and documenting software. The term ICT cost comprises the communications and information technologies, including the software for the aggregation and market clearing process.

These costs have been selected as one of the Key Performance Indicators (KPIs) in the CoordiNet project. In particular, the one called KPI20_ICT costs (which refers to the CAPEX for the deployment of the required platforms) and KPI4_OPEX (which reflects the recurrent OPEX required to operate and maintain the installed equipment) have been calculated by each demonstrator and their values have been evaluated in detail in (Trakas et al., 2022). It must be noted that KPI20_ICT costs only considers the costs for upgrading existing systems or developing new ones that are necessary for the implementation of the new markets tested in CoordiNet. Hence, the costs of the already existing systems are not considered (Trakas et al., 2022). Likewise, it is generally difficult to individually specify the actual costs incurred for one specific BUC, instead of providing a common value joining several BUCs. The information provided by the partners taking part in the demonstration activities is based on their own experiences within the CoordiNet project, so the incurred costs may be common for the development and deployment of all BUCs at each specific demonstration site.

The ICT cost estimation involves a lot of uncertainties, since both energy markets and technologies are under continuous evolution. As stated in (Gómez et al., 2019), market opportunity, cost estimate uncertainty, contractual terms, requirements diversity and financial health are listed as main factors affecting software pricing. Therefore, the quantification of the final ICT costs requires predictions and estimation of development, other related ICT costs, and several assumptions have to be made. Moreover, these ICT costs estimated by the partners involved in the demonstrators are the ones needed to launch a pilot demonstrator and, thus, are not based on the real implementation and do not include the necessary arrangements to provide an industrialized solution, nor the costs for integrating them into the existing ICT systems of the different agents, such as the TSO, DSO and MO. When integrating these new tools in existing systems, TSOs and DSOs will indeed require updating and changing other tools in order to communicate with the new datasets and implement the new functionalities. Moreover, the Coordinet project has not tested all the necessary functionalities to fully implement flexibility at the DSO. For example, flexibility involves very different processes, such as the long-term grid planning or the real-time grid operation, which is controlled by a Supervisory Control and Data Acquisition (SCADA) system, and payment tools directly related to the metering and billing processes.

As an example of the different components that an industrialized and fully integrated solution may have, in comparison to the costs required to launch a demonstrator, like the ones in CoordiNet,

Table 3 presents the functionalities that a DSO platform would require and whether those functionalities have been developed for the demonstrator within CoordiNet (P) or not (-). In particular, it presents the case of the DSO platforms developed by e-distribución and i-DE for the operation of the common and local congestion management markets (BUC ES-1a and BUC ES-1b), the balancing market (BUC ES-2) and the voltage control market (BUC ES-3) (Chaves et al., 2020) as part of the execution of the Spanish demonstrator in CoordiNet.

Table 3: Example of functionalities needed for a commercial solution of a DSO platform and the development for CoordiNet

Block	Functionality	Tested in CoordiNet
Long-term grid planning with flexibility resources	Definition of scenarios (y+1, y+5, y+10) integrating flexibility resources	-
	Long-term flexibility needs calculation for network development planning	-
	Definition of flexibility areas to make the flexibility procurement	-
	Cost Benefit Analysis (CBA) of alternatives (grid reinforcement vs long-term flexibility procurement)	-
	Definition of flexibility areas to make the long-term flexibility procurement	-
	Grid prequalification and product prequalification process for long-term flexibility products or bilateral agreements	-
Distributed Energy Resources Management Systems (DERMS)	Grid prequalification and product prequalification process for short-term flexibility products or bilateral agreements (common & local CM and voltage markets)	✓
	Receive scheduling data from generators, consumers through TSO (D-1)	✓
	Forecasting high-voltage (HV), MV and LV flows using scheduling data (D-1)	✓
	Calculation of flexibility needs, both day-ahead and in real-time (RT)	✓
	Long-Term flexibility activation (D-1 and RT)	-
	Procurement of short-term flexibility (D-1 and RT)	✓
	Short-term flexibility activation (D-1 and RT)	✓
	RT grid monitoring	✓
	Receive RT data from FSP and DER (through TSO or on-site controllers, e.g., energy boxes)	✓
	CBA of alternatives (remedial actions vs short-term flexibility procurement), especially for unforeseen events	✓
DSOs - FSP Data hub - FSP Register (SIORD)	Information exchange between DSO and FSP (i.e., RT data, setpoints)	✓
	Database of prequalified FSP for each flexibility service	-
DSO Market interface	Interface between DSO and the external market platforms	✓
	Selection of the best procurement strategy (auction / market)	✓
	Definition of baselines based on market data	✓
	Validation of external market data vs metering data (ex-post)	-
DSO metering tool	Verification of baselines sent by FSPs based on past metering data	✓
	Communication with smart meters (in the point of connection with the grid) to perform the (ex-post) validation of the delivered flexibility	(i-DE)
DSO payment tool	Billing	-
	Calculation of economic compensation or economic penalties based on delivered flexibility vs market clearing	-
	Settlement of flexibility services	-
Grid monitoring	Communication with grid-monitoring devices	✓
	Installation of grid-monitoring devices	✓
	Location selection for grid monitoring devices within a congested area	✓
	RT grid monitoring	✓

3 Analysis of products and coordination schemes in the CoordiNet demonstration campaigns

This chapter gives an overview and an analysis of the services, products and coordination schemes of the different demonstrators. In addition, the different approaches between the different demonstrators are compared. This will allow for drawing conclusions on the level of product standardization that could be recommended and on the preferred coordination schemes when procuring these products (which can be country-specific). This way, the foundations for answering core questions #2 (*Which is the most cost-effective way of coordinating the procurement (including the cost of developing the platforms necessary to do so) of system services between TSOs and DSOs?*) and #4 (*Do local flexibility markets provide a cost-effective solution for solving specific needs of the DSO? If so, can they facilitate and incentivize the participation of both small FSPs and DERs?)* are provided here.

A coordination scheme (CS) is defined as "*the relation between TSO and DSO, defining the roles and responsibilities of each system operator, when procuring and using system services provided by the distribution grid*" (Gerard et al., 2018). A closer cooperation between TSOs and DSOs is essential for enabling TSOs and DSOs to fulfil their duties in a manner that minimizes societal cost at system level.

3.1 Challenges addressed by the CoordiNet demonstration campaigns

3.1.1 Spanish demonstrator

Currently, in Spain, congestions at distribution level are not frequent, because DSOs invest in grid assets to continue providing system security and quality of service to their customers prior to reaching technical limits according to planning criteria, as stablished in the current regulation. However, currently DSOs have limited possibility to directly use flexibility from resources connected to the distribution network (i.e., this activation is possible, although it is done through the TSO). With the foreseen massive connection of renewable energy sources (RES) both at transmission and distribution levels, it is expected that congestions could also increase at the distribution level (Chaves et al., 2020). From a TSO's perspective, balancing and congestion management (CM) services are procured from resources connected both at the transmission and the distribution networks, as most HV networks (e.g., 132 kV) are operated by DSOs in Spain[2]. In this context, the activation of flexibility connected to the distribution grid could lead to unforeseen congestions in the future. Therefore, the Spanish demonstration aims at providing solutions for such future scenarios in which flexibility at the distribution system can help system operators cope with network violations (Trakas et al., 2022). In addition, the Spanish demonstrator aims at proving the technical and economic viability of a system that enables FSPs, regardless of their size and connection voltage level, to provide system services to both DSOs and the TSO, which will procure these services in a coordinated manner (CoordiNet project, n.d.).

3.1.2 Swedish demonstrator

The objective of the Swedish demonstration lies in relieving the existing and growing large-scale network constraints in the regional DSO grid and on DSO/TSO interfaces, allowing the integration of RES, urbanization and industrialization (Hugner et al., 2020).

[2] The TSO operates the extra high voltage (EHV) network, which includes 220 kV and 400 kV, as well as some other networks at 150 kV, 132 kV and 110 kV.

In Sweden, distribution networks are organized into two levels: the local network (up to 50 kV) managed by the local DSO, and the regional network (normally between 70 kV-130 kV) managed by the regional DSO. The regional DSOs have a contract with a specific subscription level towards the TSO. The subscription level is the annually contracted level of power that is allowed to be drawn by the regional grid from the TSO, without further agreement (Ruwaida and Etherden, 2022). Until recently, it was also possible to apply for a temporary subscription in addition to the annual subscription. Historically, there has not been any problem for the regional DSOs to get subscription raise or temporary subscriptions. However, in recent years, the regional DSOs in Uppland and Skåne have been denied subscription raises, while awaiting completion of TSO's grid enforcements. The denial of subscription requests is especially problematic given the long planning time for HV levels of the grid. Also, the local DSOs have a subscription level with the regional DSO (Etherden et al., 2020).

Thus, there is an increasing need for flexibility for the TSO and, also the DSOs have an urgent need for flexibility for local needs. Since the challenges for the DSOs differ in each area, the demonstration campaigns are developed in four different locations (Ruwaida and Etherden, 2022):

- Uppland and Skåne have similar problems: There is an increase of power demand, as the cities are growing, and a local combined heat and power (CHP) facility has been closed. Moreover, the TSO is not able to increase subscription level for the local and regional DSOs without grid reinforcement. Therefore, the TSO has had to deny the increase of the subscription level to the local/regional DSOs. The grid reinforcements can last about ten years, while customers need to be connected as soon as possible.
- Gotland has a large share of RES, providing 50% of the island's electricity consumption. The island is connected to mainland Sweden through an aging high-voltage direct current (HVDC) link. The connection of new RES installations threatens the operational security of the system, and additionally, the power demand is also expected to increase. Consequently, it is feared that it will not be possible to electrify large industrial sites.
- In Västernorrland/Jämtland and Gotland, maintenance on power lines result in temporary capacity limitations which imply that wind and hydro power generation must be reduced.

In the Swedish demonstrator, new and innovative local flexibility markets, next to the centralized market for ancillary services, are established in order for DSOs to use flexibility services to lower peak demand in the grid during the winter season from November to March. In addition to these local markets, new and innovative peer-to-peer (P2P) markets are also deployed. Prerequisites for these markets are improved cooperation between the DSO and the TSO, suitable CSs for the different markets, necessary market tools and a thorough understanding of both customer and grid operator user conditions (Hugner et al., 2020).

The combination of the new local flexibility market and the existing central markets for ancillary services will achieve a more integral approach, with a cost-efficient utilization of the grid, considering also the regional constraints as a pricing factor (Hugner et al., 2020). Vattenfall, E.ON (the DSOs in the Swedish demonstrator) and Svenska Kraftnät (the Swedish TSO) intend to look at the Swedish energy market, not just from a technical perspective, but also considering the cultural, political and financial aspects (Hugner et al., 2020).

For the achievement of the mentioned objectives, several activities have been developed (Ruwaida and Etherden, 2022):

- Definition of a process of large-scale customer engagement in the sub-demonstration sites.
- Change management to achieve acceptance and utilization of local flexibility markets in DSO and TSO organizations.

- Development of a well-accepted market design with products and coordination schemes.
- Definition of business models and future planning and operation models able to benefit and value the increased efficiency resulting from the coordination between TSO-DSO-customers.
- Design and development of a well-accepted market platform for all users, considering user experience, robustness, and data availability.
- Integration of the marketplace into existing systems, applications and data, and into field devices (smart meters).

3.1.3 Greek demonstrator

The overall objective of the Greek demonstration is to prepare the consumers and RES producers to obtain a more active role in the management and operation of the power system at national and regional level. This new role and the associated technological solutions will allow the creation of new products and services, providing a reduced cost of energy and improved quality of supply to the consumers (Dimeas et al., 2020).

Currently, HEDNO (the Greek DSO) does not allow the connection of users (producers and consumers) to the distribution network if their connection leads to network issues, such as congestions and voltage violations. The connection of the users in these cases requires the reinforcement of the network, leading to delays and high costs. Also, the requirement for reinforcement excludes areas as possible connection points, reducing the potential connection points. Additionally, IPTO (the Greek TSO) faces network issues in some network areas due to the increased penetration of RES (Trakas et al., 2022).

In the future, the RES penetration in the distribution system will increase significantly, so, congestions and voltage violations will appear with high renewable generation and low demand, but also with low renewable generation and high demand. In order to improve quality of supply and avoid the curtailment of RES generation and the investments required to alleviate the networks issues, different TSO-DSO coordination schemes and the use of flexibility through market-based mechanisms are evaluated as possible solutions in the Greek demonstrator (Trakas et al., 2022).

The Greek demonstrator focuses on overriding the existing network restrictions in certain areas of the grid, by means of voltage support and CM. The aim of the Greek demonstrator is to determine how the flexibility from the distribution level could be used by both TSO and DSO to address these issues. With that purpose, the Greek pilot requires a strength cooperation between DSO-TSO, which will utilize consumers and other assets in the distribution network, such as DER, buildings, etc. Therefore, this demonstration applies a suitable CS between the two system operators and other market participants while creating the necessary market tools (Dimeas et al., 2020).

The implementation of a real flexibility market for CM and voltage control in Greece is not feasible, since the relevant regulation is not in place yet. A local market and the relevant platform were developed to allow the DSO to buy flexibility from the DERs connected to the distribution level. The objective of the Greek demonstrator is to test the specific developed market platform and that the required communications work properly to identify the advantages and drawbacks of such market platform (Trakas et al., 2022).

In the Greek demo, two services are tested, CM and voltage control, under two CSs. When the multi-level market model is implemented, the unused bids of the local market are forwarded to the TSO market. When the fragmented market model is implemented, each system operator can buy flexibility only from the resources connected to its own system.

3.2 Services and products tested in the CoordiNet demonstration campaigns

3.2.1 Spanish demonstrator

In the Spanish demonstrator, four system services (i. e. CM, balancing, voltage control and controlled islanding) were tested under different coordination schemes. The system services and the BUCs considered in the Spanish demonstrator and the corresponding demo site are listed below (Ivanova et al., 2021):

- **BUC ES-1a**: Common CM. This BUC is used to solve congestions at both HV and MV grids and, so, the requirements from both the TSO and the DSO are considered when clearing the corresponding market. In this case, resources connected both at transmission and distribution level can be providers of flexibility. This BUC is tested in different demo sites, located in distribution grids owned and operated by either e-distribución (Cádiz and Málaga) or i-DE (Albacete and Murcia).
- **BUC ES-1b**: Local CM. This BUC is used by the DSO to solve congestions at LV distribution networks, by means of flexibility from resources connected at the lowest voltage levels and with capacities below 1 MW. This BUC is tested in Málaga and Murcia. In comparison with BUC ES-1a, the main differences of this BUC are that: 1) congestions at distribution level are a local issue, happening in the distribution network, where there may not be enough observability or monitoring capabilities, 2) the requirements established for the participation in the common congestion market could be quite restrictive for small FSPs, and 3) the local product is simpler.
- **BUC ES-2**: Balancing. This BUC is deployed through a central coordination scheme, being its main objective to reduce the balancing cost from the TSO’s perspective, while avoiding congestions or voltage issues at distribution level. This BUC is tested in Cádiz, Albacete, and Alicante (where i-DE is the responsible DSO).
- **BUC ES-3**: Voltage control, with a common market approach. A new product for voltage control has been developed in order to solve voltage problems arisen both at transmission and distribution levels. This BUC is tested in Cádiz and Albacete, and the flexibility providers of this service can be connected at HV or MV.
- **BUC ES-4**: Controlled islanding. This BUC tests a local market in order to operate part of the distribution network in an islanding mode during outages or programmed maintenance. This BUC is only deployed in Murcia.

Table 4: Products tested in the Spanish demonstrator

BUC	Product name	System service	Capacity/Energy
ES-1a	Non-reserved CM (Common market)	Congestion management	Energy
ES-1b	Non-reserved CM (Local market)	Congestion management	Energy
ES-2	Manual Frequency Restoration Reserves (mFRR)	Balancing	Energy
ES-2	Replacement Reserves (RR)	Balancing	Energy
ES-3	Steady-state reactive power	Voltage control	Capacity
ES-4	Programmed island	Controlled islanding	Capacity
ES-4	Outage island	Controlled islanding	Capacity

Table 52 in Annex I: Product definitions provides further insights on the design of the seven products through standard attributes for product definition (see (Delnooz et al., 2019) for more details on product attributes). When looking in detail to the product definition, the following observations can be made:

Active vs reactive power products: All BUCs, apart from the voltage control BUC, focused on active power. For voltage control, reactive power injection or consumption can be used at transmission level. At distribution level both active and reactive power can be used. However, in case active power is used for voltage control, the CM BUC will be used (Gürses-Tran et al., 2019). Furthermore, at distribution level, reactive power is not as useful as at transmission level (Gürses-Tran et al., 2019). As a result, the voltage control BUC mostly focused on reactive power services provided by FSPs at the highest voltage of the distribution network and on FSPs connected to the transmission system.

Capacity vs energy products: In the Spanish demo, *energy-based products* are used for the BUCs focusing on CM and balancing. With regard to grid congestions, the possibility to have a *capacity product* could also be explored in the future. For controlled islanding, capacity could be contracted beforehand and energy delivery would be rewarded in addition. A distinction is made between the Programmed islanding and the Outage islanding product. In the case of Programmed islanding, the FSP will automatically control the frequency and the voltage according to the setpoints sent by the DSO. In case of an outage, a command will be sent from the DSO for the formation of the preselected island and the FSP will form the island similarly to a black start. Once this is done, the FSP will control the frequency and the voltage according to the setpoints sent by the DSO, in the same way as in programmed islands. In the programmed islanding case, only activation would be compensated, while in the case of outage islanding both availability and activation would be renumerated. The Steady State reactive power product is a capacity-based product.

Timing aspects: The *minimum duration* of the delivery period is typically 15 minutes. In addition, for some products, a *maximum duration* is defined: 6 hours for the non-reserved CM product (which is procured from small FSPs via the local market), 4 hours for the RR product (60 minutes in the future) and 96 minutes for the products to deliver the controlled islanding service. The *full activation time* is defined for non-reserved CM for the local market (30 minutes), for mFRR (15 minutes), for RR (30 minutes), while for these services no distinction is made between the preparation and ramping period. For steady state reactive power, full activation time is not specified. For outage islanding, full activation time is only 3 minutes, while for programmed islanding it is 1.6 hours before the island, in the worst case, to allow for recovery after previous activations. The *recovery period* for these two products is thus also 1.6 hours. The deactivation and recovery period for the non-reserved CM product for the local market is set at 15 minutes and 2 hours, respectively.

Quantity and symmetry: For CM, a distinction is made between products for small FSPs (having a *maximum quantity* of 1 MW) and other FSPs (where no *maximum quantity* is defined). Other products do not have maximum specified quantities, apart from the islanding cases (1.2 MW and 2 MW for generating or consuming). The *minimum quantities* are 1 MW for balancing products, and for steady state reactive power, this is defined as an area 1 MW x Mvar. Other products have smaller minimum quantities, typically 0.1 MW, except for the CM product for the local market which focuses on small FSPs as from 1 kW. All products are *asymmetric*, implying that both upward and downward regulation can be provided separately, and *divisible bids* are only not allowed for steady state reactive power.

Other: *Aggregation* is allowed for CM and balancing products. For reactive power and for programmed islanding and outage islanding, no aggregation is allowed due to the local character of the service. Furthermore, *locational* information is needed for all the different products with different degree of detail depending on the service. *Manual activation* is considered for all active power products and for Outage islanding, while the reactive power product is activated automatically by the DSO. In case of programmed islanding, automatic activation could be considered aside from manual activation.

3.2.2 Swedish demonstrator

The BUCs tested in the Swedish demonstrator are the following:

- BUC-SE1a: CM - Multi-level market model. This BUC is tested in Uppland, Skåne and Gotland.
- BUC-SE1b: CM – P2P market model. This BUC is tested in Västernorrland/Jämtland.
- BUC-SE3: Balancing service - Multi-level market model. This BUC is tested in Uppland, Skåne.

Table 5: Products tested in the Swedish demonstrator

Product name	System service	Capacity/Energy	BUC
Reserved CM (long-term bids)	Congestion management	Capacity	SE-1a
Non-reserved CM (free bids)	Congestion management	Energy	SE-1a
Congestion management P2P	Congestion management	Energy	SE-1b
mFRR	Balancing	Energy	SE-3

Table 53 in Annex I: Product definitions provides further insights on the design of the four products through standard attributes for product definition (see (Delnooz et al., 2019) for more details on product attributes). When looking in detail to the product definition, the following observations can be made:

Capacity vs energy products: The BUC SE-1a, which focuses on CM, distinguishes between capacity and energy products. During the first winter season, solely energy-only products were available and, although relatively high volumes of flexibility were cleared on the CoordiNet markets, the vast majority of the volume were from one or a few significant grid users. Capacity products with an availability remuneration allow FSPs to recover some fixed cost that may be independent of traded volume. As the volumes depend on weather and can be very low in a mild winter, the incentives for FSPs to participate can be too low and the risk associated with not getting back cost for setting up processes to supply flexibility is too high (Ruwaida and Etherden, 2022). To increase liquidity and competition during the next winter seasons, the capacity product (reserved CM product) was added. This also ensured that FSP bid when the flexibility was most needed, i.e., during times of high congestion, which typically occurs during cold periods lasting over several days (Ruwaida and Etherden, 2022). For the reserved CM product, depending on the type of contract and resource type, a remuneration for availability can be foreseen. The mFRR product is also an energy product. For all products, a remuneration for activation is provided. For the reserved CM product, this is a fixed price (according to contract), while for the other products, FSPs can freely determine their bid prices. Throughout the different demo runs, several alternative availability compensations were tested (Ruwaida and Etherden, 2022). An example for the Skåne demo site is given below.

Example of the use of capacity and energy products in Skåne (Ruwaida and Etherden, 2022)

The Skåne flexibility markets for CM only used free bids at first. Afterwards, availability products were added with certain requirements on availability (e.g., available for flexibility provision 33%, 50% or 66% of the time during weekdays from 06:00-20:00) with a fixed availability price (in [SEK/MW/winter]) and an activation price (in [SEK/MW]) with a pre-determined component and cost-reflective part negotiated with the DSO at the time of contract signing. In the next season, three different capacity products were considered: one product where the FSP commits to be available all weekdays 07-20 during the whole season and receives an availability and activation price pre-set in the contract, a second similar product but with a pre-agreed volume per week which is supplied during peak load hours and, finally, a third weekly availability product with a compensation for availability and activation.

Timing aspects: The CM products have a minimum *duration* of 60 minutes, but the duration can be longer (multiple hours or as long as the maintenance period in case of the P2P product), while the mFRR product has a minimum duration of 15 minutes, which can be extended up to 60 minutes. The *full activation time* has not been defined for the CM products; for the mFRR product a *full activation time* of maximum 15 minutes is set, according to the current applicable product definitions. The *validity period* is typically defined by the agreed period of delivery. For the reserved CM product, this is defined by the contract, several alternatives exist such as all hours of the year, all hours or specified orders during the winter season (November-March). Several attributes related to the timing have not been used and are not considered as relevant for the product definitions in the Swedish CoordiNet demo. This is the case for: *preparation period, ramping period, deactivation period* and the *recovery period*. For the latter, it should be noted that in the case of the non-reserved CM product, the FSP has the option to configure the recovery period in the CoordiNet market platform.

Quantity and symmetry: A *minimum quantity* of 1 MW is used in the Swedish CoordiNet demo, except for the P2P product, for which a minimum quantity of 0.1 MW is used. It should be noted that the current mFRR product in Sweden has a minimum quantity of 10 MW, except for the bidding zone of Skåne. By harmonizing the minimum quantities of the balancing product with the reserved and non-reserved CM products, bid forwarding can be made possible, as will be explained in subsubsection 3.3.2.1. *Maximum quantity* is not defined. The granularity of the CM product is 0.1 MW, while the mFRR product has a granularity of 1 MW. This means that only bids with a size of 1 MW or multiple MW can in effect be forwarded. The CM bids can be partly accepted, while in the case of mFRR, bids are indivisible and, thus, need to be fully accepted. For BUC SE-1, only upward regulation is procured (load reduction), as the goal of the use case is to decrease the load on the interface flow between the local DSO(s) and regional DSO, and between the regional DSO and TSO. Both upward and downward mFRR is procured separately, but in the case of CoordiNet, only upward regulation is considered, as these are the only bids offered to the local CM and which can thus be forwarded to the mFRR market.

Other: *Aggregation* is allowed for all the considered products and *locational* information is needed. *Manual activation* is considered for all products; The requests of the regional and local DSOs are sent by Application Programming Interface (API), text message and email, while in the case of the TSO, electronic ordering is used via the CoordiNet platform. Aside from the attributes defined in D1.3 (Delnooz et al., 2019), an additional attribute has been defined for the Reserved CM product by the Swedish demo, i.e., the availability. An availability of 99% is targeted for the reserved CM product[3].

3.2.3 Greek demonstrator

The BUCs tested in the Greek demonstrator are the following ones (Dimeas et al., 2020):

Table 6: Products tested in the Greek demonstrator

BUC	Product name	System service	Capacity/Energy
GR-2a&b	Reserved CM	Congestion management	Capacity
GR-2a&b	Non-reserved CM	Congestion management	Energy
GR-1a&b	Steady state reactive power	Voltage control	Energy
GR-1a&b	Active power	Voltage control	Capacity & Energy

[3] One winter period corresponds to 151 days or 3 624 hours. Therefore, unavailability may not be more than 36 hours for a winter period.

- BUC GR-1a: Voltage control – Multi-level market model
- BUC GR-1b: Voltage control – Fragmented market model
- BUC GR-2a: CM – Multi-level market model
- BUC GR-2b: CM – Fragmented market model

Table 54 in Annex I: Product definitions provides further insights on the design of the four products through standard attributes for product definition (see (Delnooz et al., 2019) for more details on product attributes). When looking in detail to the product definition, the following observations can be made:

Active vs reactive power products: For the voltage control use case, both an active and reactive power product is proposed. All other products are active power products.

Capacity vs energy products: The BUC GR-2a&b which focuses on CM, distinguishes between capacity and energy products; The voltage control cases have an energy product in case of the reactive power product, while for the active power product, capacity and energy products are proposed. FSPs can thus offer both energy and capacity products. Energy products can be procured in the day-ahead, intraday and near real-time markets, while capacity products can only be purchased in the day-ahead and intraday market (Leonidaki et al., 2021). As such, real-time markets can procure additional energy-based products in case already reserved capacity cannot cover the requirements. Block energy products have also been considered in the day-ahead and intraday market to capture the technical constraints of the participants (Leonidaki et al., 2021). They have not been implemented in the demonstrator, as they are currently not compatible with the TSO market and, therefore, they cannot not be forwarded to the TSO market in the multi-level market model. The proposed capacity products only have a renumeration for availability, while the energy products have a renumeration for the amount of activated flexibility.

Timing aspects[4]: The timing aspects of the different active power products proposed in the Greek demo have between harmonized: *full activation time* of 12.5 minutes (*preparation period* of 2.5 minutes and a *ramping time* of 10 minutes), a *fixed duration* of 15 minutes (or multiple quarter hours) and a *deactivation period* of 10 minutes. A *recovery period* is not defined, nor is a *validity period*. The reactive power product also has a *full activation time* of 12.5 minutes. All other timing aspects are not relevant, since the product can be constantly activated.

Quantity and symmetry: The *minimum quantity* and the *granularity* are the same in the Greek demonstrator: a value of 0.01 MW is used for the active power products and 0.01 MVAr for the reactive power products. A *maximum quantity* is not defined. For the reactive power product, the maximum quantity is determined by the technical limits of the installation or the sum of different installations capable of being grouped at the same connection point. *Divisible and indivisible bids* are allowed for the active power products, while the reactive power bids are *indivisible*. All products are *asymmetric* so upward and downward regulation can be provided separately.

[4] The timing aspects have been defined considering the technical characteristics of the FSPs and discussions with the TSO and DSO in the Greek demo, so that they can be considered in their future market operation strategies. However, they have not been tested, so they can be seen as current recommendations from the system operators.

Other: *Aggregation* is allowed for all the considered products and *locational* information is needed. Moreover, within the Multi-level market model, the TSO receives the non-activated bids from the DSO after the local market clearing and aggregates them to the corresponding HV substation in order to include the bids in the TSO market clearing. *Manual activation* is considered for all active power products, while the reactive power product is *activated automatically* by the DSO.

3.2.4 Conclusions and lessons learnt

Some reflections related to the demo choices and lessons learnt from the different demos are summarized below:

- **Active vs reactive power products:** The main focus of the CoordiNet demonstrators was on active power products. For voltage control, active and reactive power can be used. Reactive power products have been tested in the Spanish and Greek demo. At the distribution level, reactive power is not as useful as at transmission level, particularly at the LV grid level (Gürses-Tran et al., 2019). In addition, there is a bigger interdependency between reactive and active power at the demand side as a combination of active power and reactive power can solve the DSO needs and active power and reactive power delivery is also often linked at the flexibility provider side. Moreover, in RES, the reactive power capacity can depend on the active power production (depending on the technology considered), which clearly constraints the provision of this service by these types of generators. Further investigation on these interlinkages is needed and the effect on the product and market design needs to be considered, but this was not in scope of the CoordiNet demonstrators, which mainly focused on the technical aspects of reactive power delivery.
- **Capacity vs Energy products:** Some resources require long notification time to deliver flexibility, while other resources are more suitable for near real time delivery (Ruwaida and Etherden, 2022). In addition, some types of FSPs would prefer an availability price aside from an activation price. As a result, both energy and capacity products have been considered in the Swedish and Greek demonstrators. This also allows both TSOs and DSOs to reserve some capacity beforehand and acquire additional flexibility when needed, shorter to the delivery time. In the Spanish demo, mostly energy products are procured for CM and balancing. The possibility to have a capacity product could however also be explored in the future. There seems to be consensus that the co-existence of capacity and energy products could be targeted, certainly for markets which are still rather immature.
- **Timing aspects:** The timing aspects of the different active power products proposed in the Greek demo have between harmonized and all attributes as proposed in (Delnooz et al., 2019) have been used. Both in the Spanish and Swedish demonstrators, several proposed product attributes related to the timing have not been defined in detail. These less strict requirements could benefit the participation of FSP and, thus, be a good strategy to increase liquidity. This might however limit the potential of bid forwarding.
- **Quantity:** In the Spanish demo, a distinction is made between products for small FSPs (up to 1 MW) and other FSPs. The other demonstrators do not make such a distinction. The minimum bid size within the Swedish multi-level market has been standardized to 1 MW and to 0.01 MW in the Greek demo. The Spanish demo did not standardize the minimum bid size of the different products, as bid forwarding is not considered. A detailed analysis of the effect of the minimum bid size has not been the focus of the CoordiNet demonstrators, but there is a trend towards lowering the threshold.
- **Symmetry:** All demonstrators allow asymmetric products to allow more FSPs to participate in the service. In the Swedish demonstrator, only upward regulation is procured due to the nature of the congestions, i.e., the goal of the use case is to decrease the load on the interface flows between the local DSO and the regional DSO, and between the regional DSO and the TSO.

- **Other:** Aggregation is allowed for all CM and balancing products and for the voltage control products in the Greek demo. Furthermore, locational information is needed for all the different products, with different degree of detail depending on the service. For reactive power products automatic activation is considered, while for the active power products considered in the demonstrations manual activation was mostly proposed. Some FSPs, however, asked for automated processes, so the option for bidding and calling trough automated interfaces was also foreseen in some of the cases.

Within D1.3 (Delnooz et al., 2019), one or more standard products for each of the system services were defined, with some commonly defined product attributes and some ranges of values for some attributes. The Greek demonstrator has adopted a high level of standardization of the different products, with common attribute values for the different services. Also, the Spanish non-reserved CM product for BUC ES-1a considers CM for both the TSO and DSO and, thus, provides a standardized product for the TSO and DSO. For the other BUCs and products tested in the different demos, the standardization level is lower, and products are adapted to the needs considered. It therefore seems that a high level of standardization across the different demonstrators is not possible at this stage, but rather standardization is to be sought, to the extent possible, at member state level. Agreement on a common list of attributes to be used to define products, which is very often referred to as “product harmonization” (Drivakou et al., 2021), however seems realistic.

3.3 Coordination schemes tested in the CoordiNet demonstration campaigns

The aim of this section is to summarize the CSs applied to the different demo BUCs. To do so, the classification developed in D6.2 (Sanjab et al., 2022) is used as a starting point and further classification dimensions are added to describe the market design in more detail. Originally, D1.3 used four classification dimensions to describe coordination schemes (Delnooz et al., 2019):

- **Need**, describes which system operator’s needs will be addressed and, thus, where the flexibility need is located in the system (central = TSO, local = DSO).
- **Buyer**, describes who is the primary buyer of flexibility (DSO, TSO, or DSO and TSO)
- **# markets**, describes how many different markets are set up to purchase flexibility and, thus, how many market layers are considered.
- **TSO access to DER**, describes whether the TSO has direct access to flexibility resources connected to the distribution grids (see below), which means that the TSO can buy flexibility from DER. This dimension, however, does not reveal whether the DSO or TSO has priority access or not.

In D6.2, based on further analyses, four additional classification dimensions are added, which are summarized as follows (Sanjab et al., 2022):

- **Agreements on the interface flow if applicable,** this describes whether certain agreements are made between system operators on the interface flows between connecting grids. The interface flow will play a key role as it creates the main power flow link between different grids operated by different system operators.[5]

[5] TSO-DSO interface flow pricing (and absence thereof) could play a major role in the market outcomes of Fragmented Market Models (Sanjab et al., 2022). This is however not considered in the CoordiNet demonstration. More information on interface flow pricing can be found within deliverable D6.2 (Sanjab et al., 2022).

- **Sharing of resources**, a distinction can be made between a common order book, direct, indirect or no sharing of resources. In case of direct sharing, the TSO or DSO can procure flexibility from resources connected to another operator's grid. In case of indirect sharing, one TSO or DSO cannot procure flexibility from resources at another operator's grid but can indirectly benefit from its connection with the grid of another TSO or DSO by modifying the interface flow to meet its needs, while in the case resources are not shared the interface flow should stay constant.
- **How network information sharing is considered,** this describes whether system operators share network constraints or network representations with the market or with other TSOs or DSOs. This dimension is important to analyse whether any market clearing in the proposed market(s), whether run by the TSO, DSO, or third party, could lead to violation of network limits in any of the grids involved.
- **Forwarding of bids,** this describes whether bids can be submitted to different market sessions and whether or not they are forwarded automatically, with or without the possibility to make bid modifications.

On top of these classifications of the CSs, this deliverable adds two market classifications which are relevant to further describe the market design linked to the coordination scheme. These are:

- **Bid selection and clearing**, describes how submitted bids are selected and cleared, based on which selection criteria.
- **Timing aspects**, describes how the proposed CoordiNet markets are integrated in the timing of the existing market chain of wholesale markets and balancing markets, focusing on the respective Gate Closure Times (GCTs) of the different markets.

3.3.1 Spanish demonstrator

In the Spanish demonstrator, four system services, CM, balancing, voltage control and controlled islanding were tested. The services were tested under different CSs. Since CM needs to be solved at all voltage levels, a common congestion market is set up for the TSO and the DSO to ensure that the requirements of both the TSO and DSOs are accounted for. For flexible units below 1 MW, a separate local CM market was however established, which better reflects their capabilities and has less stringent requirements. The balancing services are procured under the central market model, in which the DSO can send limitations to the activation signals sent by the TSO to the FSPs connected to their distribution grid. Voltage control for the DSO and TSO is procured under a common voltage market model. Finally, controlled islanding provided by units located in the distribution grid is tested under a local market model. As indicated in D3.4 (Ivanova et al., 2021), the "CoordiNet Platform" developed in the Spanish demo consists of 3 systems: one at the TSO side (the central platform for balancing), a common TSO-DSO platform for CM and one at the distribution side (the local platform). The local platform is used in the local CM BUC and in the controlled islanding case. Furthermore, the local platform differs between the DSOs in the demonstrator (i-DE and e-distribución).

3.3.1.1 Co-existence common and local market model (combination ES-1a and ES 1-b)

BUC ES-1 focusses on solving CM issues. The key focus is on temporal congestions that might occur in both TSO and DSO networks. Currently in Spain, it is the TSO who manages these type of network congestions through a technical constraint management market by re-dispatching generation units. The purpose of BUC ES-1 is to ensure that flexibility for these temporal congestions is procured in a more coordinated and market-based manner. The DSO can also use the common platform to request flexibility to solve congestions at the distribution grid level. The BUC is split into BUC ES-1a (common market) and BUCS ES-1b (local market). This distinction is made because the Spanish demonstrator sorts FSPs in two big and small FSPs. Small FSPs are units below 1 MW. The distinction is needed as small FSPs might have economic difficulties to comply with the technical requirements of the common market (with respect to monitoring and controllability). It is less straightforward for these FSPs to support the grid with their flexibility. In addition, there is also more limited data available from the LV grid, which makes identification of flexibility needs more complicated (Lind et al., 2022). Therefore, BUC ES-1a is aiming to procure flexibility from big FSPs (>1 MW) connected at both TSO and DSO networks in a coordinated manner to solve temporal congestions that can occur at both networks, while BUC ES-1b aims to procure flexibility from small FSPs connected at the DSO LV networks to solve transitory congestions that can occur at the DSO LV networks, (Gürses-Tran et al., 2019), (Ivanova et al., 2021), (Lind et al., 2022).

Table 7 gives on overview of the common and local market model applied in the Spanish demonstrator to solve congestions, by describing the dimensions introduced in the introduction of this section 3.3.

Table 7: Overview of co-existence local and common market model applied in the Spanish demonstrator (BUC ES-1a and ES-1b)

Coordination scheme	Common market model (ES-1a)	Local market model (ES-1b)
Need	Local and central needs	Local need
Buyer	DSO and TSO	DSO
# Markets	1	1
TSO access to DER	Yes (units > 1MW)	N/A
Agreements on interface flow	No	N/A
Sharing of resources	Common order book	N/A
Network representation in the market	Yes (sensitivity factors)	Yes (simplified network model)
Network information sharing between system operators	Yes[6]	N/A
Bid forwarding	N/A	N/A
Bid selection and clearing	Closed gate auction	Closed gate auction
Timing aspects	Day-ahead (after local market) + RT	Day-ahead (before common market)

The common market (BUC ES-1a) considers **local and central needs** for CM, while the local market (BUC ES-1b) only considers **local congestion needs**. The common market is based on the already existing CM solution in Spain and the TSO is responsible for organising and clearing the market (Lind et al., 2022). The local market is a new market established and operated by the DSO. There are **two main types of buyers of flexibility**: DSOs and the TSO. The DSO can procure flexibility to solve its congestion needs at both the local and the common market (depending on their location in the system), while the TSO is only active as a buyer to solve its congestions at the common market. The **TSO has access to flexibility resources available on the distribution grid** which participate to the common market, as there is a **common order book**. It should

[6] The TSO is the MO of the common market, so, in this case, the TSO has access to the network information shared by the DSO according to the "observability grid" criteria defined in the System Operation Guideline national implementation.

be noted that FSPs with a capacity above 1 MW can only participate to the common market, while FSPs with a capacity up to 1 MW can also participate to the local CM market (Ivanova et al., 2021).

The representation of the network in the common market is done via **sensitivity factors**. No other network information needs to be shared between the TSO and DSOs, but, as the TSO is the market operator of the common market, the TSO has access to the sensitivity factors of the resources connected to the distribution grid. In the local market, on the other hand, a simplified network representation is used. There are **no specific agreements on the interface flow** between the TSO and DSOs as part of the common market design.

The local and common market are both organized as **closed gate auctions**. FSPs can bid into the common and local markets after prequalification. For each FSP, a baseline/forecast is computed and send to the platform. Afterwards, they receive information on the needs of the TSO and DSOs. Based on that information, they can check their available flexibility, aggregate resources where necessary and submit bids. **Bid forwarding** between the local and common market **is not considered**.

For the local CM, **the DSO** is the single buyer as already explained. Bids are selected using a techno-economic merit order. **Once the market is cleared**, the results of the market clearing are communicated to the common CoordiNet platform. In case the local platform does not solve all the constraints, the local platform could be run again, depending on the situation. For the **common congestion managemen**t BUC, all bids are put together in one pool and **resources are thus shared directly** among the DSO and TSO. The market is then cleared to alleviate the congestions at both network levels.

With regard to the **timing of the different markets**, the flexibility markets are integrated in the market sequence of the existing markets. All products are tested in the day-ahead and intraday market timeframe. Except for the reserved CM product, all products are also tested in near real-time. In Spain, after the day-ahead energy market, the new local CM takes place for congestions at LV level. Afterwards, the common CM market is cleared. Then, from about one hour before real-time, the TSO manages the balancing of the system and, finally, the congestions in real-time. Currently, in Spain, the TSO only contracts long-term flexibility through interruptible contracts with large industrial consumers for security reasons. It might also be relevant to procure long-term congestion flexibility, but this is not addressed in the Spanish demo.

3.3.1.2 Central market model (BUC ES-2)

BUC ES2 focuses on reducing balancing costs for the TSO, while taking into account unforeseen congestion problems at distribution level. Currently in Spain, generation resources connected at distribution networks can provide balancing services, but demand-side resources cannot (Gürses-Tran et al., 2019). The goal is to examine how to improve coordination between the TSO and DSOs when the usage of DER for balancing services for the TSO increases.

Table 8 gives on overview of the central market model applied in the Spanish demonstrator, by describing the dimensions introduced in the introduction of this section 3.3. The Balancing BUC is only applied under the scope of the existing Spanish mFRR market and not in the RR. This is because the latter takes place under the TERRE platform ("TERRE," n.d.), which makes the implementation more complex. The mFRR balancing process is nationally controlled by the TSO and is therefore easier to test (Lind et al., 2022).

This BUC focuses on the provision of a **central need** and the **TSO** is the sole buyer. There is **one central market** where flexibility is purchased. **FSPs connected at the distribution grid are allowed to participate** in the balancing market (Lind et al., 2022) and, thus, **direct sharing of resources** is thus considered. There are **no specific agreements on the TSO-DSO interface flows** and the DSO is not an active buyer of flexibility in this BUC, **bid forwading** is thus **not considered.**

Network information is not shared between the DSOs and the TSO. The DSO is, however, allowed to verify the impact of balancing activations in the distribution grid and eventually limit them. The needs for mFRR will be published by the TSO the day before delivery. Afterwards, the FSPs estimate their available flexibility and submit balancing capacity bids. The TSO communicates these bids to the CoordiNet platform, which sends them to the DSOs. The DSOs forecast and identify transitory limits in their networks. These limits can completely or partially restrict the bids from FSPs in the balancing market. The limits from DSOs are communicated to the platform. The TSO runs the balancing capacity market and obtains results. These results are then communicated to the platform which sends them to the DSOs and the FSPs. The DSOs consider this information in their systems and the FSPs inform the affected resources. Close to real time, a similar procedure is followed, where the DSO again checks if new limits on their networks are foreseen which may restrict the delivery of balancing energy (Merckx et al., 2021).

No network information is considered when clearing the mFRR market. In case of constraints created by the balancing actions, the CM market is used.

Table 8: Overview of central market model applied in the Spanish demonstrator (BUC ES-2)

Coordination scheme	Central market model (ES-2)
Need	Central
Buyer	TSO
# Markets	1
TSO access to DER	Yes
Agreements on interface flow	No
Sharing of resources	Direct sharing
Network representation in the market	No
Network information sharing between system operators	No
Bid forwarding	N/A
Bid selection and clearing	Merit order list; Closed gate auction
Timing aspects	Day-ahead balancing capacity market; RT balancing energy market

3.3.1.3 Common market model (BUC ES-3)

BUC ES3 implements a market mechanism to procure voltage control services. With increasing levels of RES connected at distribution networks, there is a risk of unwanted voltage variations. In addition, traditional synchronous generators are replaced by wind and solar plants whose voltage control capacity is usually more limited. However, with new technological improvements in inverters, these RES plants can also provide voltage control. Therefore, this BUC will implement a market mechanism to procure voltage control services next to the traditional solutions from DSOs and the TSO (Gürses-Tran et al., 2019). Currently, in Spain, there is no such market for voltage control services.

Table 9 gives on overview of the common market model applied in the Spanish demonstrator, by describing the dimensions introduced in the introduction of this section 3.3.

For this BUC, a common market will be applied with similar characteristics as the common market explained under subsubsection 3.3.1.1. The main differences are explained here, i.e., the traded product and how the sensitivity factors are computed. For voltage control, both active and reactive power can be used, as explained in subsection 3.2.1. This BUC, however, focuses on the delivery of reactive power provided by FSPs at the highest voltage of the distribution network and FSPs connected to the transmission grid. The process will start in day-ahead, as the TSO and DSOs will determine the location and need for voltage control and identify the flexible resources that would be able to contribute (from the ones which are prequalified). It should be noted that voltage problems are not frequent and, thus, the TSO and DSOs can inform the platform when and where voltage problems emerge. FSPs can then provide reactive power bids for the relevant locations. The market is cleared, and the market outcome is communicated to the market participants (FSPs, TSO and DSOs).

Table 9: Overview of common market model applied in the Spanish demonstrator (BUC ES-3)

Coordination scheme	Common market
Need	Local and central needs
Buyer	DSO and TSO
# Markets	1
TSO access to DER	Yes
Agreements on interface flow	No
Sharing of resources	Common order book
Network representation in the market	Yes (sensitivity factors)
Network information sharing between system operators	No[7]
Bid forwarding	N/A
Bid selection and clearing	Closed gate auction
Timing aspects	Day-ahead

3.3.1.4 Local market model (BUC ES-4)

BUC ES-4 aims to operate part of the distribution network in an islanding mode during outages or programmed maintenance periods. This BUC tested a completely new service and market (Lind et al., 2022). The demo focused mainly on whether controlled islanding was technically possible rather than on its market setting.

Table 10 gives on overview of the local market model applied in the Spanish demonstrator, by describing the dimensions introduced in the introduction of this section 3.3.

This BUC focuses on the provision of a **local need** and the **DSO is the single buyer**. There is only **one local market** to procure flexibility. In case part of the grid becomes disconnected from the system, the DSO's

[7] The TSO is the MO of the common market, so in this case the TSO has access to the network information shared by the DSO within the market in its role of MO.

actions may however affect the TSO. Therefore, the DSO communicates with the TSO, among others, about the size of the island and other characteristics. As such, the TSO can consider the effect on balancing, but is not actively involved in the process, so most of the characteristics of the coordination are not applicable to this case as shown in Table 10. There is no network representation in the market.

It is assumed that **capacity would be procured long term ahead**. In case of planned outages, the DSO communicates to the local platform the needs for islanding operation in day-ahead. The needed flexibility and timeframe will be specified. The FSP will determine the available flexibility and submit bids. The market will be cleared day-ahead, when needed.

Table 10: Overview of local market model applied in the Spanish demonstrator (BUC ES-4)

Coordination scheme	Local market model for controlled islanding (ES-4)
Need	Local
Buyer	DSO
# Markets	1
TSO access to DER	N/A
Agreements on interface flow	N/A
Sharing of resources	N/A
Network representation in the market	No
Network information sharing between system operators	N/A
Bid forwarding	N/A
Bid selection and clearing	Economic merit order Closed gate auctions
Timing aspects	Long-term procurement of capacity, day-ahead procurement of energy

3.3.2 Swedish demonstrator

In the Swedish demonstrator, two services, CM and balancing were tested. The first Swedish BUC (BUC SE-1a) and the fourth Swedish BUC (BUC SE-3) should be considered together when looking at market coordination. In this case, three different levels of system operation should be distinguished: the local DSO, the regional DSO and the TSO. The two BUCs focus, respectively, on a local need (CM for the local DSO and regional DSO in their respective grids) and a central need (balancing for the TSO) and how to acquire them in a coordinated manner. In addition, the CM service was also tested via a distributed market model, i.e. through a P2P market (BUC SE-1b) (Gürses-Tran et al., 2019). In the remainder of this subsection, the tested CSs are characterized, based on the dimensions explained above.

3.3.2.1 Multi-level market model (combination of BUC SE-1a and BUC SE-3)

The focus of BUC SE-1a is CM, with the goal of preventing the interface flow between the local DSO(s) and the regional DSO, and between the regional DSO and the TSO from surpassing a pre-set limit, which is known as the subscription level. The subscription level is the annually contracted level of power that can be drawn by the regional grid from the TSO, without further agreement. Also, the local DSO has a subscription level governing the amount of power with the regional DSO (Ruwaida and Etherden, 2022). DSOs can receive a temporary weekly subscription raise upon request. Subscription overruns that do not occur in the context of temporary subscription are not allowed and result in penalties. A multi-level market model is developed with the aim of bringing flexibility for the local DSO and regional DSO. The idea is to locally decrease energy demand or increase energy production to avoid constraint violation defined by the subscription level of the overlying grid (Merckx et al., 2021). BUC SE-3 focuses on balancing services towards the TSO and is linked to BUC SE-1a, as it describes the actions that are carried out when unused bids from the DSO markets set up to realize BUC SE-1a which meet the conditions for the balancing service mFRR (e.g. minimum bid size of 1 MW and granularity of 1 MW is foreseen for the CoordiNet pilot) are transferred to the existing mFRR balancing market operated by the TSO (Gürses-Tran et al., 2019).

Table 11 gives on overview of the multi-level market model applied in the Swedish demonstrator, by describing the dimensions introduced in the introduction of this section 3.3.

Table 11: Overview of multi-level market model applied in the Swedish demonstrator

Coordination scheme	Multi-level market model (BUC SE-1a and BUC SE-3)
Need	Local, regional and central needs
Buyer	Local DSO, regional DSO, TSO
# Markets	Three layers
TSO access to DER	Yes
Agreements on interface flow	Linked to the objective of the market (max. interface flow)
Sharing of resources	Direct sharing
Network representation in the market	Yes, with static impact factors
Network information sharing between system operators	Yes, with static impact factors
Bid forwarding	Automatic bid forwarding, with the option to place new bids
Bid selection and clearing	Impact factor weighted merit order list (for CM); Joint Nordic merit order list (for balancing) Closed gate auction in day-ahead; Continuous trading in intraday
Timing aspects	Sequential setting; Day-ahead and intraday market sessions

The combination of BUC SE-1a and BUC SE-3 considers **local and regional needs** for CM (i.e., avoid exceeding subscriptions levels) and a **central**, national **need** for balancing. There are **three main types of buyers of flexibility**: local DSOs, regional DSOs and the TSO.A separate market is set up for each type of flexibility buyer. This means that **three layers of markets** are proposed in the multi-level market model, while this could typically be two layers in other European contexts. The **TSO has access to flexibility resources available on the distribution grid**, as unused bids from the local and regional DSO markets with a capacity larger than 1 MW and which are prequalified for the mFRR market can be forwarded to the mFRR market if the FSP chooses this option (Ruwaida and Etherden, 2022).

The main objective of the market is to prevent the interface power flows both between the local DSO and regional DSO, and between the regional DSO and the TSO from surpassing a pre-set limit, which is known as the subscription level. **Agreements on the interface flow** are thus inherently part of the market design, as they are directly linked to the objective of the market. Hence, the subscription level corresponds to the maximum interface power flow, which is set on an annual (annual subscription) or weekly basis (temporary subscription). Subscription overruns result in penalties (Gürses-Tran et al., 2019). There is no risk for subscription overruns caused by activation of a subsequent market session, because the purpose of flexibility procurement is to decrease energy demand or increase energy production to avoid constraint violation or to provide mFRR upward balancing services. Therefore, **direct sharing of resources** is considered, as the system operator from an overlying grid level has access to flexible resources at a lower level.

There is **no need for a detailed network representation in the market**, due to the nature of the emerging grid constraints (limiting the interflace flow with the overlying grid) within the Swedish demonstration campaigns. Instead, impact factors (taking values between 0 and 1) are used (determined during the prequalification phase), representing the actual impact on the flow through the connection point that a flexibility bid would be able to deliver. In this case, the relevant connection points are the connection point towards the overlying grid (between the local DSO and regional DSO, and between the regional DSO and the TSO)(Merckx et al., 2021). Detailed information on the methodology to determine impact factors is given in (Etherden et al., 2020). The impact factors are incorporated in the calculation of the merit order list (see below) and thus considered in the market clearing. Similarly, **detailed network information is not shared between the local DSO and the regional DSO, nor between the regional DSO and TSO**. Instead, impact factors are shared between system operators of connected grids.

In this multi-level market model, **automatic forwarding of bids is considered**. As a result, FSPs submit their bids and, when bids that are not cleared in one market layer, they can be forwarded automatically to the next layer within the following sequence: 1) local market, 2) regional market and 3) mFRR market[8]. A distinction is made between **day-ahead and intraday market sessions**. Uncleared bids from the day-ahead flexibility sessions can be automatically passed to the intraday flexibility market trading, if the FSPs choose this option. In addition, FSPs still have the option to update their bids when they are automatically forwarded to the intraday session, or they can choose to place new bids. Only when the FSP has explicitly chosen the option, bids will finally be forwarded to the mFRR market.

For the day-ahead flexibility trading, the DSO receives the bids from different FSPs and selects the bids to be activated following an automatically generated **impact factor weighted merit order list** and based on the DSO's identified need. In more detail, based on the submitted bids and the impact factor of each of the assets, a merit order list and a suggestion for the list of bids to be cleared to meet the DSO's need are automatically generated. The submitted price of a bid is divided by its impact factor, while the submitted quantity is multiplied by the impact factor to determine the actual impact on the flow through the connection point that a flexibility bid would be able to deliver, resulting in an impact factor weighted merit order list. Then, this merit order list has to be cleared manually by the DSO, to allow the DSO to adjust for various events. The DSO clears bids considering the amount of flexibility needed and the related costs. The DSO procures flexibility at a cost which is lower than temporary subscription rates when a temporary raise of subscription is granted, or lower than applicable penalties if a temporary subscription raise is not granted. In the latter case, more expensive flexibility would be procured. The intraday market follows a continuous trading scheme. In this case, the DSO can also consult, at any time, a list of recommended bids in intraday in the form of an impact factor weighted merit order list (Ruwaida and Etherden, 2022), (Merckx et al., 2021). For the mFRR market, the TSO procures flexibility in close cooperation with the other Nordic TSOs, because the mFRR market is operated with a **joint Nordic merit order list**.

[8] During the Swedish demo both separate and common markets for the local and regional DSOs have been tested.

A **sequential market setting** is chosen in the multi-level market in the Swedish demonstrator, which allows to integrate the local and regional flexibility market in the market sequence of the existing wholesale and balancing markets. As bids can be automatically forwarded (at least from the local DSO market to the regional DSO market and, finally, to the mFRR market), the GCTs are the most important aspects. First, the day-ahead local DSO market closes, followed by the day-ahead regional DSO market, ahead of the national day-ahead wholesale market. The goal is to procure as much flexibility as possible in the day-ahead timeframe. However, considering new forecasts and/or unforeseen changes which result in a risk of exceeding subscription limits, additional flexibility may be procured. The intraday DSO flexibility market runs in parallel to the wholesale intraday spot market and is available until two hours before delivery time. The wholesale intraday market, on the other hand, remains open until one hour before delivery. Finally, bids not cleared in the local or regional DSO flexibility markets can be forwarded to the mFRR market (as from 1 hour before delivery) (Ruwaida and Etherden, 2022).

3.3.2.2 Distributed market model (BUC SE-1b)

The main focus of BUC SE-1b is CM among peers during planned maintenance periods, when grid capacity is constrained in the LV and MV distribution grids. The P2P market, enables, in a distributed manner, capacity trades between FSPs or peers, i.e. between producers or between producers and consumers, for managing the limited grid capacity which would arise during these periods to avoid curtailment (Ziu and Croce, 2021). By trading (buying or selling) capacity hourly, the peers can optimize production and/or consumption when operating under temporarily decreased subscription levels (Hugner et al., 2020).

Two different use cases are considered (Ziu and Croce, 2021), (Hugner et al., 2020):

- Case 1: In Gotland, the purpose of P2P trading is for wind power to produce more during curtailment periods by initiating additional electricity consumption to mitigate the surplus of production. In this case, the FSPs or peers are the consumers and producers.
- Case 2: In Västernorrland and Jämtland, a P2P market is also created to handle congestions in the grid during planned maintenance. The FSPs or peers here are only producers, i.e., hydro and wind power producers. The commodity that the peers trade in the market was set as “grid space”, i.e., excess capacity. Either the wind producer will sell unused capacity when the wind is not strong, or the hydro plant may opt not to produce up to its curtailed capacity limit if the capacity can be sold to the wind producer, that otherwise would have to reduce production.

In both cases, the peers or FSPs are the ones who trade with each other. The DSO gives information on curtailment periods needed to initiate the P2P trades and monitors the transactions to ensure that the obligation for reduced power flow is met, but it is not a part of the P2P market as a buyer nor seller (Ziu and Croce, 2021), (Hugner et al., 2020).

Table 12 gives an overview of the P2P distributed market model applied in the Swedish demonstrator, by describing the dimensions introduced in the introduction of this section 3.3.

BUC SE-1b considers **local and regional needs** for CM for the prevention of wind power curtailment (i.e., between wind power producers and consumers for case 1) and management of limited grid capacity (i.e., between producers for case 2), during scheduled maintenance periods (Merckx et al., 2021). The local DSOs and regional DSOs have a need for flexibility, but **the peers are the ones who trade flexibility** with each other on the **local P2P market**, which is set up when needed by the DSO. The TSO is not involved in the procurement process.

Table 12: Overview of Distributed market model applied in the Swedish demonstrator

Coordination scheme	Distributed market model (BUC SE-1b)
Need	Local and regional needs
Buyer	Peers
# Markets	
TSO access to DER	N/A
Agreements on interface flow	Linked to the objective of the market (max. interface flow)
Sharing of resources	Common order book
Network representation in the market	Yes, with static impact factors
Network information sharing between system operators	No
Bid forwarding	N/A
Bid selection and clearing	Continuous trading scheme
Timing aspects	Market set up during maintenance periods only, immediate matching

Similar as in the multi-level market model explained above (see 3.3.2.1), the **interface flow** (in the form of the subscription level) is an important part of the market design. In this case, it serves as an input to initiate the P2P market by the local or regional DSO, if there is a risk to overrun subscription level, to determine the capacity decrease needed.

This market does **not require a specific representation of the network**. The main grid requirement is the assessment of the increase or decrease in production/consumption needed on the constrained grid capacity. This impact is quantified in the impact factor that is determined through network simulations of the grid under high loading and used as a static parameter (Merckx et al., 2021). There is **no need for network information sharing between the different system operators, as the allowed power flow between them is covered by subscription limits**.

Trades are initiated when a capacity need is introduced by the DSO. **Each peer or FSP determines the buy or sell orders and submits them to the market** (Hugner et al., 2020). Bids can be aggregated, or single resources can be used to bid in the market and, typically, hourly bids are considered (Ruwaida and Etherden, 2022). In case 1, RES producers sell locally the amount of RES production (or a portion of it) that would have been curtailed, offering it at a lower price compared to the market value. This would then incentivize consumers to place buy orders to be able to purchase RES at an interesting price and adapt their consumption schedule accordingly. In case 2, some RES producers would sell their unused capacity, while some others would buy it. A **continuous, bilateral trading scheme** is applied: when a buy and sell order can be matched, the market is cleared, and a confirmation is sent to both counterparties (buyer and seller) (Hugner et al., 2020).

The market is used when needed, e.g., during maintenance periods with risks for capacity constraints, so a market session is initiated by the DSO. This typically happens near real-time (2 hours, 1 hour or 45 minutes before the delivery). Bids can be submitted up to 15 minutes before delivery. **Matching of bids is immediate** when a counterbid is present (Merckx et al., 2021), (Ruwaida and Etherden, 2022).

3.3.3 Greek demonstrator

The Greek demo examines two services: CM and voltage control. The services are tested on both pilot sites (Kefalonia and Mesogia). It should be noted that, currently, the demo sites do not face real congestion issues. This is, among others, due to the fact that the DSO does not allow the connection of new users (both producers and consumers) when that connection would lead to congestion and voltage violations in the distribution system. Furthermore, the islands have a lot of large-scale wind potential, which could lead to congestion and overloading issues in the future. The TSO is currently already facing network issues due to high increases in RES production, especially under N-1 conditions. Therefore, in the demonstrator, congestion issues in the transmission system are examined under N-1 conditions.

For each of the services, i.e., voltage control (BUC GR-1) and CM (BUC GR-2), two CSs, the multi-level market model (a) and the fragmented market model (b), are tested. In the remainder of this subsection, the tested coordination schemes are characterized, based on the dimensions explained above.

3.3.3.1 Multi-level market model (BUC GR-1a and BUC GR-2a)

The focus of BUC GR-1a and GR-2a is on the multi-level market model, to resolve voltage and congestion issues respectively, for the DSO and TSO. Table 13 gives an overview of the multi-level market model applied in the Greek demonstrator, by describing the dimensions introduced in the introduction of this section 3.3.

Table 13: Overview of Multi-level model applied in the Greek demonstrator

Coordination scheme	Multi-level market model (BUC GR-1a and BUC GR-2a)
Need	Local and central needs
Buyer	DSO and TSO
# Markets	Two layers
TSO access to DER	Yes
Agreements on interface flow	No
Sharing of resources	Direct sharing
Network representation in the market	Yes (sensitivity matrices are used in the local market)
Network information sharing between system operators	No
Bid forwarding	Yes
Bid selection and clearing	Closed gate auction in day-ahead and intraday Continuous trading scheme in near real-time
Timing aspects	Sequential setting: Day-ahead (DSO), intraday (DSO), real-time (DSO and TSO)

A combination of **local and central needs** is considered. Specifically, voltage and congestion needs are considered at local level (for the DSO) and at the central level (for the TSO). The **DSO and the TSO are the primary buyers** and for each of them a separate market is set up. There are therefore **two market layers**.

The DSO calculates the needed flexibility to solve CM and voltage control issues. Through the local market, the DSO can reserve or directly procure the necessary energy to resolve network issues for each feeder (CM and voltage control)[9]. There are three different market sessions (**day-ahead, intraday and real time**). There are no agreements on the interface flow between the DSO and the TSO. However, the DSO reports the scheduled energy exchange or, thus, **interface flow** with the TSO [D5.2]. Therefore, the **interface flow can change** in the multi-level setting, and the TSO is informed about this after each market session. The **TSO** market for voltage control and CM is active during the last market session (in real-time), where the TSO has **access to the remaining bids of the distribution system** for solving voltage and congestion issues. This **direct sharing of resources** implies that FSPs that are connected to the distribution system can provide flexibility to the transmission system. However, the latter is only possible after the DSO has ensured that their activation will **respect DSO grid constraints**. The flexibility not needed/procured at the local market is sent to the central TSO market, considering that the distribution network constraints are respected. The unused bids of the local market can thus be forwarded to the TSO market, implying that there is **automatic forwarding of bids**.

Network information is included in the form of sensitivity matrices for both CM and voltage control in the local market, i.e., voltage sensitivity factors for voltage control market and Power Transfer Distribution Factors (PTDF) for CM market. More information on the creation of sensitivity matrices for CM and voltage control can be found within D5.7 (Dimeas et al., 2021). **No network information is shared between the DSO and TSO**, but as said, the DSO informs the TSO about the changes in the interface flows and the DSO checks that the bids forwarded to the TSO market do not lead to network violations in case of activation.

Both in **day-ahead and intraday**, the local market is operated as a **closed gate auction,** with the objective to minimize the cost of activated flexibility. A techno-economic **merit order list** is used, considering the sensitivity matrices. In real-time, the local market is operated as a **continuous market**. The TSO market also operates in real-time. The TSO voltage control market, chronologically, precedes the TSO CM market. Remaining imbalances at system level are finally resolved as part of the near real time balancing market, where no participation of DERs is considered.

The latter is however considered in the "**multi-level market+" market model** of the Greek demo, which has been added in the course of the project. In this case, unused bids by the DSO from the local market can be forwarded to the near real time balancing market as well. An unused bid from the DSO local market can be used in the TSO voltage control, CM or balancing market in the following order: voltage control market, followed by CM market and, concluding, with the near real time balancing market (Dimeas et al., 2021).

3.3.3.2 Fragmented market model (BUC GR-1b and BUC GR-2b)

The focus of BUC GR-1b and GR-2b is on the fragmented market model, to resolve voltage and congestion issues respectively, for the DSO and the TSO. The fragmented market model is similar to the previously described multi-level market model. However, it differs on some clear distinct points:

- The TSO does not have access to resources connected to the distribution grid, so no sources are shared.
- As a consequence, bid forwarding cannot be considered.
- There are agreements on the interface flow between the DSO and TSO grids.

[9] The Voltage Control Market is executed first, and the CM Market is executed shortly after. A loopback function guarantees co-optimisation of both markets, to avoid system violations after the execution of both markets.

In the fragmented market model, **the TSO has no direct access to the bids of the distribution system**. The DSO has balancing responsibility of the distribution system, on top of the voltage control and CM. This implies that there is a **fixed net load or interface flow** between the DSO and the TSO that needs to be fulfilled at each moment in time. A predefined quarter-hourly schedule between the TSO and the DSO therefore has to be respected (Dimeas et al., 2020). The predefined schedule is based on the forecast of energy production and could be a net injection or consumption. The TSO and DSO cannot make any modification to the schedule and are obliged to respect the schedule using only flexibility sources located in their own network (Dimeas et al., 2020). This implies that each system operator can buy flexibility only from the resources connected to its system. The DSO, therefore, has the responsibility to reserve resources for balancing in its own system. As a result, network information sharing is not needed either.

Table 14 gives an overview of the fragmented market model applied in the Greek demonstrator, by describing the dimensions introduced in the introduction of this section 3.3.

Table 14: Overview of fragmented model applied in the Greek demonstrator

Coordination scheme	Fragmented market model (BUC GR-1b and BUC GR-2b)
Need	Local and central needs
Buyer	DSO and TSO
# Markets	Two layers
TSO access to DER	No
Agreements on interface flow	Yes
Sharing of resources	No sharing
Network representation in the market	Yes (sensitivity matrices are used in the local market)
Network information sharing between system operators	No
Bid forwarding	N/A
Bid selection and clearing	Closed gate auction in day-ahead and intraday Continuous trading scheme in real-time
Timing aspects	Sequential setting: Day-ahead (DSO), intraday (DSO), real-time (DSO and TSO)

3.3.4 Conclusions and lessons learnt

All the three demonstrators have different choices with regard to coordination schemes. An overview of the characteristics of the CSs tested in the three demonstrators is given in Table 15 according to the proposed classification in D6.2 (Sanjab et al., 2022). Only the Swedish and the Greek demo have chosen one similar CS for, at least, one of their BUCs: the multi-level market model, which is used for the combination of BUC SE-1a and SE-3 in Sweden, and for BUCs GR-1a and GR-2a in Greece. Although there is no sharing of resources within the Spanish case with the co-existence of the local and common market model (combination ES-1a and ES-1b), some similarities can also be found here with the multi-level market model. One general observation which can be made is that all the three different demo countries established markets at local level to address some of the local needs: in the case of the Swedish and Greek demonstration, separate markets have been set up to solve local DSO needs, while in the Spanish demonstrator, next to a common market for TSO and DSO needs, a local DSO market was proposed for smaller FSPs at the lower grid levels.

The reasons for the different choices can be found in regional and regulatory differences, indicating that **there is no one-size-fits all coordination scheme**. As discussed in D6.2 (Sanjab et al., 2022), CSs can be adapted in multiple ways to answer specific demo needs. Some of the observations explaining some demo choices are summarized below:

- **Type of FSPs**: In *Spain*, different CSs are used, depending on the type of FSPs and the nature of the congestion targeted. The demo explicitly targets small FSPs (up to 1 MW) at LV through a local market, as entry barriers for small FSPs in the common CM platform are too large. This is necessary due to the local nature of congestions in the LV network, where the DSO may not have full observability and monitoring capabilities due to limited data availability in LV grids. For larger FSPs, the Spanish demonstrator relies on common markets. The other demonstrations do not propose different markets for different FSP groups.
- **Number of markets**: In general, from the DSO perspective, the market-based solutions should be compared with other flexibility solutions (e.g., network reconfiguration or reinforcement) and the optimum of such solution and flexibilities activation can be an interdependent mixture of several solutions, which can make it quite complex to go for common market solutions with the TSO. In *Sweden*, it is important to understand that there are system operators at three levels (the local DSOs, the regional DSOs and the TSO). CSs with multiple market levels are therefore developed to bring flexibility to local and regional DSOs. The idea is to locally decrease energy demand or increase energy production to avoid constraint violation defined by the subscription level of the overlying grid. For this Swedish case, it is important to reflect the bottlenecks, grid topology and losses in the grid in a correct way in the market, and the final selection of preferred bids still needs a manual action by the DSO, which makes it harder to go for common procurement processes for the TSO and DSOs. In the *Greek demonstrator*, a multi-level / fragmented market is implemented, as they want to benefit from the existing wholesale markets by extending it with local flexibility markets. It would allow the Greek demonstrator to integrate the local DSO markets in the simplest way with existing markets. Indeed, for all demonstration campaigns, integrating these new markets without interferences in existing markets, is important. This is also the case for *Spain,* where at national level, there already exists a common balancing market where the demo wants to benefit from, but as said, the requirements for this market were too stringent for smaller FSPs.
- **Balancing and congestion management**: None of the demonstrators, combine balancing and CM for system operators in one market as, for instance, proposed as one of the models within (CEDEC et al., 2019). Several reasons have been identified: The TSO and DSO needs might be very different, resulting in different products and market requirements. The requirements for existing balancing products (which are already defined) and the new congestion products are not always aligned. Moreover, DSOs, in general, have less experience with market solutions, while the TSOs already have well established balancing markets. Additionally, the European harmonization of balancing markets and, at the same time, integration of CM services within these markets is rather complex. For example, balancing markets are moving closer to real time, while for CSs, long-term procurement is often targeted. Automatic forwarding of bids to the balancing market is however considered in the Swedish demonstrator and the multi-level market+ market model of the Greek demonstrator. The Spanish demonstrator, on the other hand, considers technical validation of balancing bids by the DSO for FSPs connected to their grids.
- **Timing**: Even though some demonstrators describe long-term process, the focus of all demonstrators lies on the shorter time frame from day-ahead to near real-time. As stated above, for all demos it is important that the DSO/TSO markets are integrated well in the timeframes of the existing energy and balancing markets. The exact approach to that is however demo and country specific.
- **Maturity**: When looking at the different market solutions being procured within the different demonstrators, it is clear that the balancing markets are well established, as they are already existing markets. Within CoordiNet, a lot of attention has been paid to the definition of markets for

CM, while the markets for the other services (voltage control, controlled islanding) are less developed. This is in line with the findings of D6.2 (Sanjab et al., 2022).

- **Sharing of network information:** In general, in the CoordiNet demonstrators, no detailed network information is shared with the markets and between system operators, so there is no guarantee that network violations are avoided at all times. The effect of limiting the level of network information sharing between the system operators on the market efficiency and the persistence of grid issues has been studied in D6.2 (Sanjab et al., 2022).

It is the CoordiNet vision that several different market platforms will co-exist at European level due to local differences, different regulation and different maturity levels. When these markets will mature, further harmonization might be possible and best practices will be replicated at different locations, although country-specific conditions may still play an important role, even in the future. One important prerequisite is that the different market platforms are, at least, interoperable (e.g., via standard interfaces), as discussed in D6.5 (Uslar and Köhlke, 2022).

Table 15: Overview of coordination scheme characteristics in the different demonstrators

BUC	CS	Need	Buyer	# Markets (market layers)	TSO access to DER	Sharing of resources	Sharing of DSO network info?	Guarantee of no network limit violations	Variation interface flow allowed	Interface pricing	Bid modification between market layers
ES-1a	Common	Local & Central	DSO & TSO	1	Yes (up to 1 MW)	Common order book	Yes	No	Yes	No	N/A
ES-1b	Local	Local	DSO	1	N/A	N/A	N/A	No	Yes	No	N/A
ES-2	Central	Central	TSO	1	Yes	Direct sharing	No	No	Yes	No	N/A
ES-3	Common	Local & Central	DSO & TSO	1	Yes	Common order book	Yes	No	Yes	No	N/A
ES-4	Local	Local	DSO	1	N/A	N/A	N/A	No	Yes	No	N/A
SE-1a & SE-3	Multi-level	Local, regional & central	Local DSO, regional DSO & TSO	3	Yes	Direct sharing	Yes	No	Yes	No	Yes (allowed)
SE-1b	Distributed	Local & regional	Local DSO & regional DSO	1	N/A	Common order book	Yes	No	Yes	No	N/A
GR-1a	Multi-level	Local & Central	DSO & TSO	2	Yes	Direct sharing	No	No	Yes	No	No
GR-1b	Multi-level	Local & Central	DSO & TSO	2	Yes	Direct sharing	No	No	Yes	No	No
GR-2a	Fragmented	Local & Central	DSO & TSO	2	No	No sharing	No	No	No	No	N/A
GR-2b	Fragmented	Local & Central	DSO & TSO	2	No	No sharing	No	No	No	No	N/A

3.4 TSO-DSO coordination schemes considered in the economic assessment

One of the main lessons learnt of the analysis of the CSs tested in the demonstrators, which is also in line with the findings of D6.2 (Sanjab et al., 2022), is that the balancing markets are well established (as they are already existing markets), while the markets for the other services (voltage control, controlled islanding) are less developed. Therefore, a lot of attention has been paid to the definition of markets for CM within CoordiNet and, hence, this deliverable focuses on the evaluation of the different coordination schemes for providing congestion management (CM) services. In particular, it is focused on the CSs which aim at solving needs of both the TSO and the DSO, (Delnooz et al., 2019), (Madina et al., 2020), i.e., the common market model, the multi-level market model, and the fragmented market model:

- *Common Market Model (CMM)*: both local and central needs coming from DSO and TSO are considered in a single market and, thus, the TSO can use assets connected to the distribution grid to solve all system needs. As an example, the sequence diagram of the application of the CMM in the Spanish demonstrator to solve CM (which was called BUC ES-1a) is shown in Figure 6. The procurement of system services to solve joint TSO and DSO needs (including balancing and congestion management) through the CMM was applied in the market simulation of the scalability and replicability scenarios for the Spanish demo, covered in (Cossent et al., 2022).
- *Multi-level Market Model (MMM)*: it is a variation of the CMM, in which each system operator uses its own market, rather than through a single market. Two alternatives can be considered in this case:
    - The unused bids in the market operated at distribution level are forwarded automatically to the market operated at transmission level. This market model is considered in the analysis. Figure 7 shows an example of the application of this market model to the Swedish demonstrator for CM (named as BUC SE-1a). The procurement of system services to solve joint TSO and DSO needs (including balancing and congestion management) through the MMM was applied in the Swedish scalability and replicability scenarios, covered in (Cossent et al., 2022).
    - Aggregators and other FSPs are allowed to submit new bids for their unused flexibility after the market operated at distribution level to the market operated at transmission level (as shown in Figure 80 in Annex II: Sequence diagrams for additional coordination schemes).
- *Fragmented Market Model (FMM)*: it is split as in the MMM, but the TSO has no access to DERs. Hence, resources connected to the distribution grid can only offer their flexibility to solve the DSO needs (see Figure 81 in Annex II: Sequence diagrams for additional coordination schemes). The fragmented market model has low coordination between TSO and DSOs and, thus, it was not covered in the market simulation in the presented scalability and replicability scenarios in (Cossent et al., 2022) and it is not included in the analysis in this deliverable.

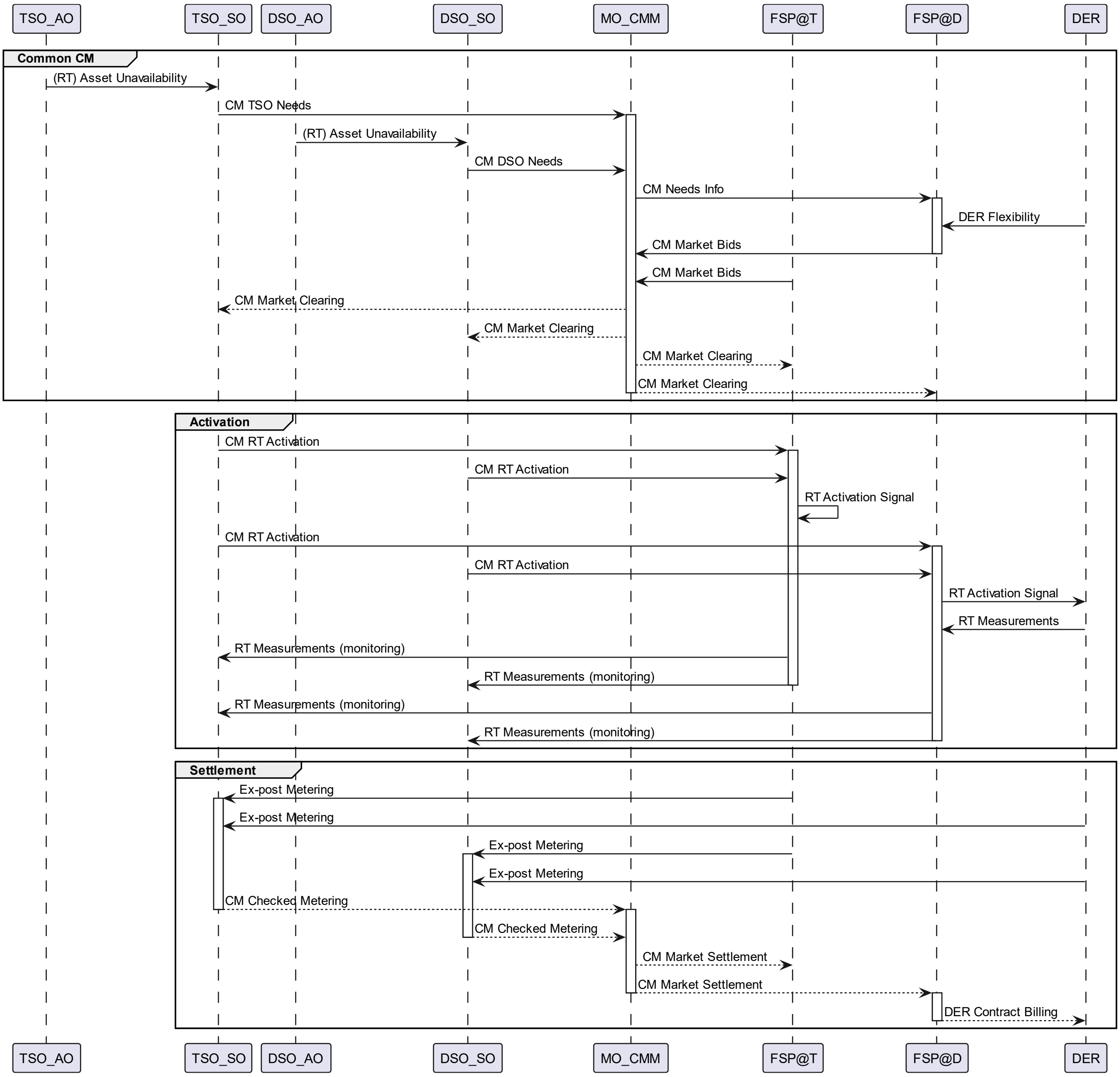

Figure 6: Sequence diagram for common market model, based on BUC ES-1a

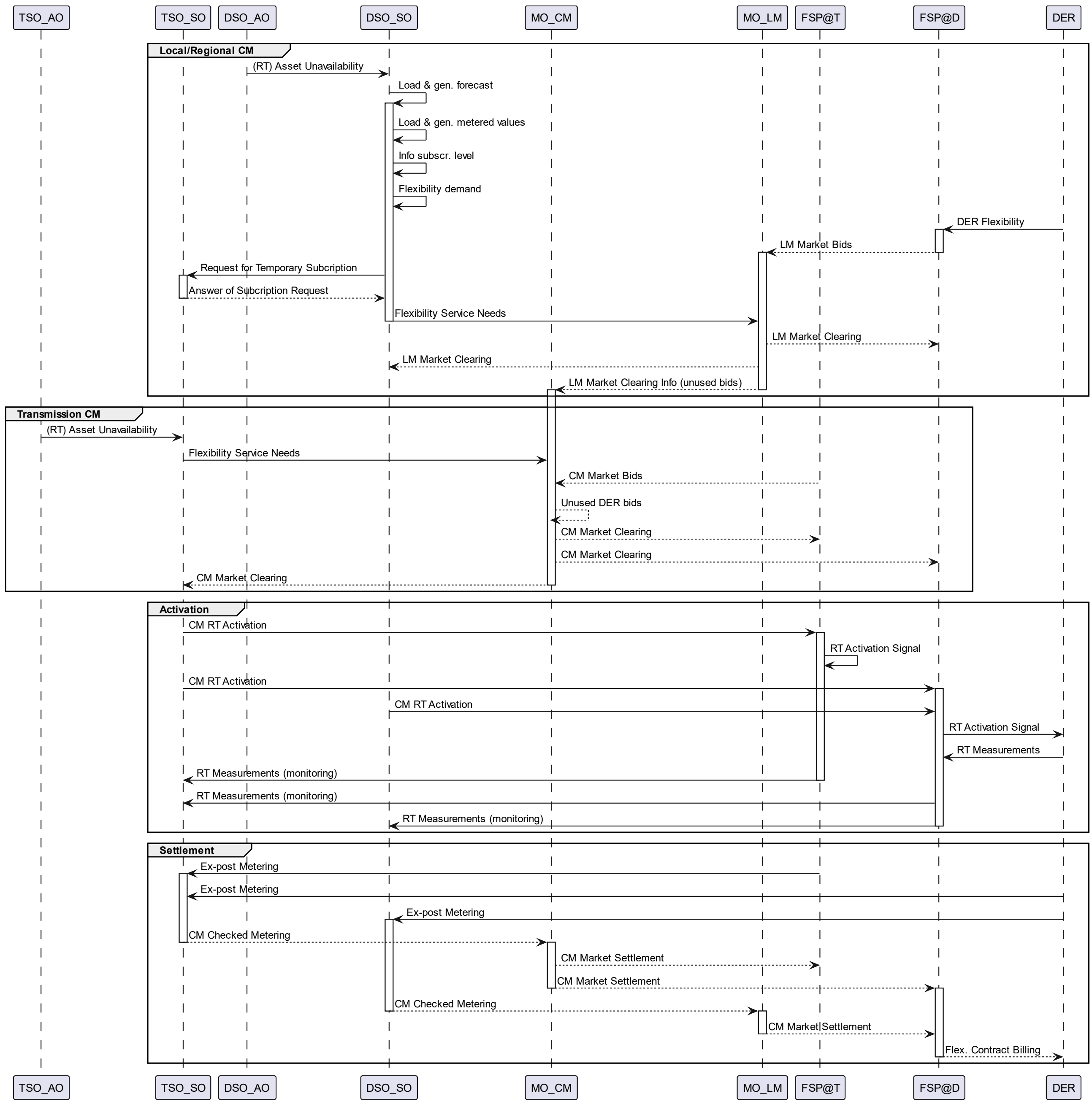

Figure 7: Sequence diagram for multi-level market model (automatic forwarding of bids), based on BUC SE-1a

Participation in flexibility markets, where needs of both TSOs and DSOs are satisfied, is not an easy task for small-scale DERs or energy aggregators with limited resources, because technical and economic requirements are tailored to ensure the overall power system security and are suitable for big-scale players, but not for small DERs at distribution level, such as energy storage, demand response, and local generators. However, these small units have an inherent flexibility which can still be very useful to solve other kind of issues in the system, such as local needs at distribution level. The Internal Electricity Market Directive (European Commission, 2019a) sets up a framework that mandates DSOs to use local flexibility to procure congestion management services, as long as they use transparent, non-discriminatory and market-based procedures and when "*such services cost effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system*" [Art. 32, (European Commission, 2019a)]. As a result, DSOs could establish local market models to exploit the flexibility of small DERs to solve congestion issues at distribution level. Those local markets will also be considered within this deliverable.

4 Methodology and pillars of analysis

The economic assessment of the different CSs is performed at two levels. On the one hand, this Deliverable D6.3 evaluates the overall efficiency of the different alternatives (flexibility market models) at system level, while, on the other hand, it covers the economic implications of all involved market agents in the value chain for regulated and non-regulated actors (a business-level analysis).

As discussed in section 3.4, this deliverable focuses on the evaluation of the different CSs for providing congestion management (CM) services and, in particular, in the CSs where a coordination between the TSO and the DSO is needed to solve joint TSO and DSO needs, i.e., the common market model and the multi-level market model.

Different aspects must be taken into account in order to evaluate the most efficient way to procure and use flexibility. These aspects are discussed in this chapter and result in the three pillars described in subsequent sections. In particular, the methodology described here aims at answering four core questions:

1. Under which conditions is the use of flexibility more suitable than the Business-as-Usual option (i.e., reinforcing the grid or ask for temporary subscription tariffs)?
2. Which is the most cost-effective way of coordinating the procurement (including the cost of developing the platforms necessary to do so) of system services between TSOs and DSOs?
3. Is the provision of flexibility a profitable business model for both FSPs and DERs?
4. Do local flexibility markets provide a cost-effective solution for solving specific needs of the DSO? If so, can they facilitate and incentivize the participation of both small FSPs and DERs?

Flexibility may or may not be more efficient than reinforcing the grid or using other traditional solutions (grid reconfiguration, etc.). Therefore, first, the conditions under which the use of flexibility is more effective (or provides a solution with a similar cost, but with a much faster commissioning time) must be determined. This analysis, which aims at answering core question #1 is the first of three pillars identified in this deliverable for the success of the flexibility use.

The second pillar refers to the selection of the most cost-effective coordination scheme between the TSO and DSO. The economic efficiency of the different coordination schemes at system level can be measured by comparing the costs for regulated agents (i.e., TSOs, DSOs and MOs, which are assumed to be regulated agents in this deliverable). These costs include both the cost of procuring system services and the cost of developing and deploying the ICT systems required for such procurement. Regulation must be set in such a way that regulated agents can see a reasonable return on capital investment, while ensuring the implementation of the most cost-efficient solutions from the system perspective. Furthermore, regulated agents must ensure that they will be able to respond to any contingency in the system, so they must ensure that there is enough availability of flexibility under extreme events causing congestion. In this sense, the casuistry of the congestion and grid alternatives is diverse and highly country specific, where traditional grid reinforcement and temporary commissioning solutions should be considered to solve joint TSO and DSO congestion management requirements and/or temporary capacity grid limitations. Under joint TSO and DSO congestion management needs, the system operators should compare the cost of the flexibility solution versus the business-as-usual grid alternatives in each specific country. This second pillar, thus, focuses in providing an answer to core question #2.

Additionally, it is also important to evaluate whether the provision of flexibility is a profitable business for FSPs, which is the core of the third pillar of the analysis. This way, and after the first two pillars assessed the coordination schemes at system level (as a macro analysis), the third pillar evaluates the business case performance (at micro level) and, hence, it looks at core question #3.

As discussed in section 3.4, participation in flexibility markets, where needs of both TSOs and DSOs are satisfied, is not an easy task for small-scale DERs or energy aggregator with limited resources. There may be cases where the appearance of congestions may hinder economic development or the connection of new users to the system, since the commissioning times of grid-based solutions may be too long. Therefore, the use of these local markets may allow to postpone the need to reinforce the grid, but also provide a temporary solution caused by vegetative increase of demand during the commissioning time of the new grid elements. Since these local markets are designed to solve specific needs of the DSO and, if designed properly, do not have an impact on the transmission network, the DSO may establish less strict technical and economic requirements for the market access and participation, which facilitates the participation of small-scale DERs.

Therefore, and in order to answer core question #4, the analysis for pillars 1 and 3 is split between two different application scopes, so that pillars 1.a and 3.a analyze the provision of flexibility for solving joint TSO and DSO needs, while pillars 1.b and 3.b look at the use of flexibility for solving DSO-specific needs (with no or little impact on the TSO) at the lowest voltage levels of the power system. This division of scope is also in line with the analysis of products, services and coordination schemes, where the definition of different products per bid size or the use of different coordination schemes per size of FSP is already studied.

The first pillar of the economic assessment included in this deliverable compares the flexibility solutions tested in the CoordiNet demonstrators with the Business as Usual (BaU) grid-based solution for each of them. The methodology to compare grid alternatives in each case is described in section 4.2:

- In Spain, a combined common market (to solve congestion issues of the TSO and the DSO at the highest voltage levels of the system) and a local market (to solve DSO-specific congestion issues at the lowest voltage levels) will be compared against reinforcing the grid.
- In Sweden, the implemented multi-level market model will be compared against the cost of overcoming the agreed subscription level with the overlaying network.
- According to the modelling for the Greek analysis in (Cossent et al., 2022), 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 multi-level and fragmented approaches. So, such local market will be compared versus the cost of reinforcing the grid.

The second pillar of the analysis will compare the performance of the selected coordination schemes, when there is a market model alternative which can provide an equivalent solution. Hence, the combined common market and local market in Spain will be compared versus a combined multi-level and local market, as this market may also solve the congestion issues of the TSO and DSO at the different voltage levels. Likewise, the multi-level market in Sweden will be compared against a common market, which can also help avoid congestions at both transmission and regional distribution grids. In case of Greece, only the local market is presented, and no TSO-DSO coordination is addressed in the simulation scenarios as described above. The methodology for both analyses within the second pillar is presented in section 4.3.

The third pillar evaluates the profitability of the provision of flexibility services by FSPs and DERs under the different alternatives analyzed in the two previous pillars, as described in section 4.4.

4.1 Cost components of the flexibility platforms of regulated actors

The three pillars that compose the economic assessment described in this deliverable focus on different parts of the value chain and evaluate the solutions for different needs in the system. However, many of the cost components included in each pillar are common to the three of them. In order to be able to use flexibility-based solutions to satisfy the different needs of the system, both regulated and non-regulated agents must develop different ICT platforms and systems, which include both CAPEX and OPEX terms.

Due to the natural lack of competition in the transmission and distribution of electricity, TSOs and DSOs, are subject to regulation to promote efficiency and quality of supply and to ensure fair prices for customers. Furthermore, regulated agents must ensure that they will be able to respond to any contingency in the system, so they must ensure that there is enough availability of flexibility under extreme events causing congestion.

Likewise, for the economic assessment in this deliverable, the specific role of the MO is considered to be, on the one hand, independent from system operators and, on the other, a regulated party. This assumption, though, does not mean that we recommend that this platform shall be owned and managed by third independent parties, such as Nominated Electricity Market Operator (NEMOs). Therefore, other existing business models are not addressed here for the flexibility market operator (i.e., non-regulated flexibility market platforms, which may be operated by private market operators, as it was the case in the Swedish demonstrator).

The MO platforms to provide these services may be operated and/or hosted by the TSO and/or DSOs, or the MO role may be performed by an independent agent (Valarezo et al., 2021). In order to present the most generic case, TMO, DMO and CMO platforms are considered and evaluated depending on the considered CS and products per each country under analysis. The TMO will be responsible for managing the flexibility market which solves the needs by the TSO, the DMO will be responsible for managing the flexibility market to solve needs by the DSO (when considering joint TSO and DSO needs), or otherwise, the CMO will be responsible for managing the flexibility market to solve needs by both the TSO and the DSO (see subsection 4.2.1). Moreover, DSOs can establish a local market model (LMM), operated by a LMO, to exploit the flexibility of small DERs to solve congestion issues at distribution level and which do not affect the TSO (see subsection 4.2.2).

Each of these regulated actors will have some expenditures that are related to the development and deployment of the required ICT infrastructures and software platforms, among other items, to allow for the flexibility procurement. These expenditures, as long as they become recognized costs by the National Regulatory Authority (NRA), will result in certain annual remuneration for the different agents:

- **TSO expenditure** ($C_{n,CS}^{TSO,flex}$) at system level corresponds to the annual remuneration for the TSO as system operator, in the year *n* and per coordination scheme *CS*, as a result of the incurred cost related to the integration, communication and procurement of new flexibility products.
- **DSO expenditure** ($C_{n,CS}^{DSO,flex}$) at system level corresponds to the annual remuneration for the DSO as system operator, in the year *n* and per coordination scheme *CS*, as a result of the incurred cost related to the integration, communication and procurement of new flexibility products.
- **MO expenditure** ($C_{n,CS}^{MO,flex}$) is the annual incurred cost for developing and managing the MO platform which solve flexibility needs in the year *n* and per coordination scheme *CS*. It may be referred to:
    - **TMO expenditure** ($C_{n,CS}^{TMO,flex}$), which refers to the annual costs of the MO platform to solve TSO needs when addressing joint TSO and DSO needs (in multi-level markets).
    - **DMO expenditure** ($C_{n,CS}^{DMO,flex}$), which refers to the annual costs of the MO platform to solve DSO needs when addressing joint TSO and DSO needs (in multi-level markets).
    - Or otherwise, when the joint TSO and DSO needs are tacked by the same market operator, **CMO expenditure** ($C_{n,CS}^{CMO,flex}$).
    - **LMO expenditure** ($C_{n,CS}^{MOs,flex}$), which refers to the annual costs of the LMO platform (in local markets).

All these annual expenditures include both CAPEX and OPEX terms, as shown in eq. (4-1).

$$C_{n,CS}^{Reg,flex} = Capex_{n,CS}^{Reg,flex} + Opex_{n,CS}^{Reg,flex} \tag{4-1}$$

where *Reg* refers to any regulated actor, i.e., TSO, DSO or MO (which may be TMO, DMO, CMO or LMO).

- **Annual capital expenditure** ($Capex_{n,CS}^{Reg,flex}$) is the annuity of CAPEX of the regulated actor of the investment i which is a recognized cost included in their annual remuneration. The annuities of CAPEX vary over the asset lifetime $\mathcal{N}^i$ (which include amortization and financial terms, following eq. (4-2). The annual CAPEX ($Capex_{n,CS}^{Reg,flex}$) includes amortization and financial terms per each year *n* along the asset lifetime $\mathcal{N}^i$. The amortization term ($Amort_n^i$) is the annual tangible asset costs ($TCost_n^i$) divided by the asset lifetime ($Lifetime^i$) of the investment i, while the financial remuneration term (Fin_n^i) represents the interest accruing each year, based on the financial remuneration rate (r^i) and the annual tangible asset costs.

$$Capex_{n,CS}^{Reg,flex} = Amort_n^i + Fin_n^i = \frac{TCost_n^i}{\mathcal{N}^i} + TCost_n^i \cdot \mathcal{R}^i \qquad \forall n \in \mathcal{N}^i \tag{4-2}$$

where:

  - $Amort_n^i$ is the annual amortization term of the investment *i* in the year *n*.
  - Fin_n^i is the annual financial remuneration term of the investment *i* in the year *n*.
  - $TCost_n^i$ is the value of standard net fixed costs of the investment *i* in the year *n*.
  - $\mathcal{R}^i$ is the financial remuneration rate of the investment *i*.
  - $\mathcal{N}^i$ is the expected lifetime of the investment *i*.

- **Annual operating expenses** ($Opex_n^{Reg,flex}$) in the year *n*. This term gathers the OPEX component for the operation and maintenance (O&M) activities related to each regulated actor, plus a margin.

$$Opex_n^{Reg,flex} = IOpex^{i,flex} \cdot (1 + \Delta Opex^{flex}) \qquad \forall n \in \mathcal{N}^i \tag{4-3}$$

  - $IOpex^{MO,flex}$ is the annual OPEX component (supposed to be invariable).
  - $\Delta Opex^{flex}$ is the financial margin which is applicable to the OPEX component.

These CAPEX and OPEX equations are also applied for the recognized costs of any other grid-based solution.

Throughout the economic analysis, CAPEX can be expressed on an annual basis by means of an equivalent cash flow. The **annual average capital expenditure** ($\overline{Capex}_{n,CS}^{Reg,flex}$) can be calculated as the sum of the annual CAPEX of the regulated actor ($Capex_{n,CS}^{Reg,flex}$) over the lifetime ($\mathcal{N}^i$) of the asset investment i, as:

$$\overline{Capex}_{n,CS}^{Reg,flex} = \frac{\sum_{n=1}^{\mathcal{N}^i} Capex_{n,CS}^{Reg,flex}}{\mathcal{N}^i} \qquad \forall n \in \mathcal{N}^i \tag{4-4}$$

The annual average CAPEX is evaluated as an equivalent cash flow sequence, with a unique single cost which occurs in every year of the project. In this way, it allows for a fair cost comparison between project with low/high capital and operating costs, different project lifetimes, or with different coordination schemes.

4.2 Pillar 1: Comparison of flexibility activation cost versus Business-as-Usual solutions

4.2.1 Overview of the methodology for joint TSO and DSO needs

Pillar 1 for joint TSO and DSO needs aims to compare the procurement of flexibility services versus the BaU alternative, focusing on the implemented CS in each demo-country. The accumulated costs for both alternatives are evaluated along a variable flexibility procurement period, with the aim of supporting the decision-making process of the medium-term grid expansion plans.

As discussed above, TSOs and DSOs are subject to regulation to promote efficiency and quality of supply and to ensure fair prices for customers, while they must also ensure that they will be able to respond to any contingency in the system and, thus, they must ensure the required availability under extreme events causing congestion. The casuistry of the congestion and grid alternatives is diverse and highly country specific. Concretely, the flexibility solution will be compared versus different BaU alternatives in each country: a reinforcement of the grid in the case of Spain and a temporary DSO subscription increase, as long as it is allowed by the TSO, in Sweden.

In line with the diagram presented in figure 8**¡Error! No se encuentra el origen de la referencia.**, the general framework to establish the comparison between two alternatives to provide a solution to grid congestion is presented. From the flexibility solution side, OPEX terms related to the SW platform and ICT costs for all actors are included (as CAPEX may be considered sunk costs), as well as the cost for the CM service procurement, both at distribution and transmission level. In the case of Sweden, the cost of the temporary subscription should also be identified when flexibility in distribution grids is not enough to solve all the congestion issues.

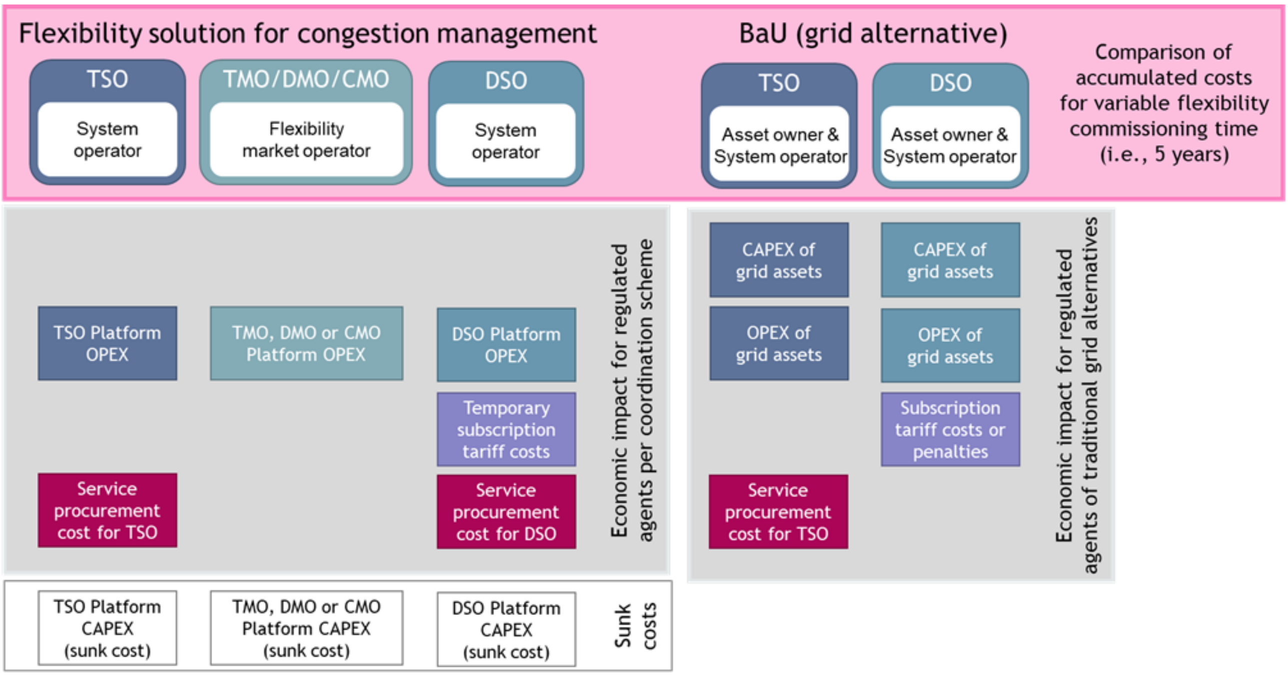

Figure 8: Cost components for regulated agents in the flexibility and BaU alternatives for joint TSO and DSO needs (Pillar 1.a)

From the BaU grid alternative, both CAPEX and OPEX terms for new grid assets (if needed in distribution and/or transmission network) are included in Spain, as well as the cost for the CM service procurement at transmission level (although the DSO may use a BaU alternative to solve its needs, the TSO may still need to procure flexibility to solve the needs at transmission level). Likewise, temporary subscription tariff cost or penalties should be also quantified (country-specific cost for Sweden), which will be higher than in the flexibility-based solution. The economic impact varies among the demos, depending on the concrete selection of the BaU grid alternative.

4.2.1.1 Cost of flexibility activation for joint TSO and DSO needs

This subsubsection aims to evaluate the cost of the procurement (activation) of flexibility services. As discussed in section 3.4, the Internal Electricity Market Directive (European Commission, 2019a) sets up a framework that mandates DSOs to use local flexibility to procure congestion management services, as long as they use transparent, non-discriminatory and market-based procedures and when "*such services cost effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system*" [Art. 32, (European Commission, 2019a). As shown in Table 3, the desired functionalities for the DSO's flexibility platform are not location-specific, maybe except the ones related to grid monitoring. However, the increased complexity in the operation of the distribution system requires the installation of the appropriate equipment in order for DSOs to improve the observability of the grid. Therefore, it is expected that these grid monitoring functionalities would become widespread in the future. As a result, once that the consideration of the flexibility markets as a potential means to solve system needs is granted, those platforms will be implemented and, thus, the cost of their implementation (i.e., CAPEX for the ICT infrastructure and SW platforms to enable new flexibility markets) has already been borne at system level (according to the decided coordination scheme, following the analysis in Pillar 2) and, hence, it becomes a sunk cost and it must not be taken into account when evaluating whether flexibility or grid reinforcement is the best solution for a given system need.

Therefore, the annual cost for the flexibility solution of the CS implemented in each country ($Cost_{n,CS}^{T\&D,flex}$) for joint TSO and DSO needs (in transmission and distribution networks) is evaluated along the lifetime of the assets ($\mathcal{N}^i$). In this case, a lifespan of 10 years can be assumed.

$$Cost_{n,CS}^{T\&D,flex} = C_{n,CS}^{MOs,flex} + C_{n,CS}^{TSO,flex} + C_{n,CS}^{DSO,flex} + SubC_{n}^{DSO,flex} + Mkt_{n,CS}^{TSO,flex} + Mkt_{n,CS}^{DSO,flex} \quad \forall n \in \mathcal{N}^i \tag{4-5}$$

In order to compare both grid alternatives, the accumulated cost of flexibility procurement ($Cost_{\mathcal{T},CS}^{T\&D,flex}$) is calculated for a specific time span. In this case, the flexibility procurement period ($\mathcal{T}$) is used as a dynamic time span in which the accumulated costs are calculated and compared among both grid solutions.

$$Cost_{\mathcal{T},CS}^{T\&D,flex} = \sum_{n=1}^{\mathcal{T}} Cost_{n,CS}^{T\&D,flex} \tag{4-6}$$

where:

- **Accumulated cost for joint TSO and DSO needs** ($Cost_{\mathcal{T},CS}^{T\&D,flex}$) is the accumulated cost for the procurement of flexibility services for a given time span ($\mathcal{T}$) (flex. procurement) and per coordination scheme CS.
- **Annual cost for joint TSO and DSO needs** ($Cost_{n,CS}^{T\&D,flex}$) is the annual cost for joint TSO and DSO needs to procurement (activation) of flexibility services in the year *n* and per CS, from the scope of Pillar 1.a.
- **MO expenditure** ($C_{n,CS}^{MO,flex}$) is the annual cost for development and operation of the MO platform itself which solves flexibility needs at transmission and distribution level in the year *n* and per coordination scheme CS. This annual expenditure includes only the OPEX term, as presented in eq. (4-3), as CAPEX is neglected. These incurred costs for the operation and management of the MO

platform will be recovered costs for the MO agent (via i.e., network tariffs). This expenditure should be calculated for each involved MO (DMO, TMO or CMO), as discussed in section 4.1.

- **TSO expenditure** ($C_{n,CS}^{TSO,flex}$) is the annual cost associated to the TSO as system operator in the year *n* per coordination scheme *CS*. The total expenditure includes only OPEX term (operating and maintaining the ICT and SW assets, workforce, etc.), presented in eq. (4-3). It is assumed that these incurred costs will be recovered by the TSO via i.e., network tariffs.
- **DSO expenditure** ($C_{n,CS}^{DSO,flex}$) is the annual cost associated to the DSO as system operator in the year *n* per coordination scheme *CS*. The DSO expenditure includes OPEX term (operating and maintaining the ICT and SW assets, workforce, etc.), presented in eq. (4-3). It is assumed that these incurred costs will be recovered by the DSO via i.e., network tariffs.
- **DSO subscription tariff costs** ($SubC_{n}^{DSO,flex}$) are included in the comparison framework of Pillar 1.a as an additional cost from the power system perspective (in the case of Sweden). In practice, all agents (including DSOs) connected to the Swedish TSO's transmission grid must pay network charges to cover the TSO's costs of building, operating, and maintaining the transmission network and the energy losses (see paragraph 4.2.1.2.2 – Temporary subscription level). The effective DSO cash flow may include these subscription costs, which are not recovered through power system tariffs and, hence, the net income for the DSO is lower due to the payment of temporary subscription costs.
- **Flexibility market costs** are the costs for the procurement of system services in the year *n* per coordination scheme *CS*, which corresponds to the remuneration received by the FSPs. For simplicity, the comparison of CSs only addresses CM cost, leaving aside the potential impact on balancing when a combined CM and balancing procurement is done. These costs may can be classified according to whom system operator the cost is allocated:
    - Flexibility service procurement cost for the TSO ($Mkt_{n,CS}^{TSO,flex}$).
    - Flexibility service procurement cost for the DSO ($Mkt_{n,CS}^{DSO,flex}$).
- The first superscript indicates the associated market agent ($MO,\ DMO,\ TSO,\ DSO,$ and FSP).
- The superscript $flex$ indicates that the item corresponds to the flexibility solution.
- The subscript CS corresponds to the coordination scheme.
- The subscript i indicates each investment.
- The subset $\mathcal{N}^{i}$ comprises the lifetime of the asset *i*.
- The subscript n corresponds to each year.
- The subset $\mathcal{T}$ corresponds to the time span (i.e., the given flexibility procurement period).

4.2.1.2 Cost of traditional grid solution for joint TSO and DSO needs

The cost of traditional grid solutions for joint TSO and DSO needs can include grid reinforcement actions, or other temporary commissioning solutions (such as the cost of a temporary increase of subscription level).

4.2.1.2.1 Grid reinforcement as Business-as-Usual solution

TSO and DSO regulation for investment is generally a cost-based scheme. The rate of return model guarantees that the regulated company receives a certain pre-defined rate of return on its regulatory asset base. In the absence of specific economic incentives or investments caps, the TSO and/or DSO have little incentives to minimize their costs under a cost-based regulation framework, because they can increase their profits by simply expanding the asset and, consequently, their cost base (CEER, 2017a). However, TSO and/or DSO investments on innovative projects could be rewarded by a higher rate of return or be remunerated by specific rates for innovation projects or avoided investments.

In the Spanish demonstrator, grid reinforcement actions are compared with the flexibility solution for joint TSO and DSO needs. The Business-as-Usual grid alternative is to reinforce the grid to tackle grid congestion events. When the line is reinforced, new lines are built, or other assets are repowered, the power system must deal with high CAPEX with the premise of reducing grid congestion or other inefficiencies. At a first glance, the grid reinforcement actions are mainly costly solutions, whose CAPEX from the TSO and DSO may be higher than the cost required to activate of flexibility (presented in subsubsection 4.2.1.1).

In case of the selection of grid reinforcement, the annual costs ($Cost_n^{T\&D,grid1}$) is evaluated along the lifetime of the grid asset ($\mathcal{N}^{grid}$) of e.g., 40 years:

$$Cost_n^{T\&D,grid1} = C_n^{DSO,grid} + Mkt_n^{TSO,flex} \qquad \forall n \in \mathcal{N}^{grid} \tag{4-7}$$

However, both alternatives have different lifetimes and, hence, to evaluate the best solution for the same life span, the flexibility procurement period ($\mathcal{F}$) is used as a dynamic time span (i.e., 5 years) in which the accumulated costs are calculated to evaluate the most cost-effective solution along the upcoming years. Then, the accumulated cost of grid reinforcement ($Cost_{\mathcal{T}}^{T\&D,grid1}$) is calculated for a given time span ($\mathcal{T}$) [10]:

$$Cost_{\mathcal{T}}^{T\&D,grid1} = \sum_{n=1}^{\mathcal{T}} Cost_n^{T\&D,grid1} = \sum_{n=1}^{\mathcal{T}} C_n^{DSO,grid} + Mkt_n^{TSO,flex} \tag{4-8}$$

where:

- **Accumulated cost for joint TSO and DSO needs** ($Cost_{\mathcal{T}}^{T\&D,grid1}$) is the accumulated cost for joint TSO and DSO needs of the grid reinforcement solution for a given flexibility procurement period ($\mathcal{T}$).
- **Annual cost for joint TSO and DSO needs** ($Cost_n^{T\&D,grid1}$) is the annual cost for joint TSO and DSO needs of the grid reinforcement solution in the year *n*, from the scope of Pillar 1.a.
- **DSO expenditure** ($C_n^{DSO,grid}$) for the DSO, which may include asset reinforcement(s) (and other SW and ICT investment costs if required). The cash flow for each incurred cost is calculated according to the specific lifetime of each asset (i.e., 40 years for grid assets and 10 years for SW or ICT costs).

$$C_n^{DSO,grid} = \sum_i Capex_{n,i}^{DSO,grid} + Opex_{n,i}^{DSO,grid} \qquad \forall i \in \mathfrak{I}, \forall n \in \mathcal{N}^i \tag{4-9}$$

  - **Annual CAPEX** ($Capex_{n,i}^{DSO,grid}$) is associated to the grid infrastructure investment for asset reinforcement, renewal or upgrade, and other required investments, incurred by the DSO in

[10] For clarification purposes, all costs with the subscript *n* consider their associated cash flow along the asset lifetime, divided into the investment costs which include annual amortization and financial terms and operational costs, as presented in section 4.1. The annual costs for regulated agents represent their annual remuneration to recover the incurred costs with a reasonable rate of return. Both grid alternatives are evaluated along a given time span, which enables to compare the accumulated costs along the upcoming years and select the most cost-effective solution under the current grid conditions (grid asset costs, level of congestion, flexibility activation costs). In case of flexibility solution convenience, grid-based alternative can be postponed or delayed in time.

the year n for the investment in each asset i in the distribution network. The annual remuneration for regulated agents for CAPEX is presented in eq. (4-2).

  - **Annual OPEX** ($Opex_{n,i}^{DSO,grid}$) is associated to the O&M costs in the year n of each asset i in the distribution network, presented previously in eq. (4-3).

- **Flexibility market costs** are the costs for the procurement of system services in the year n. It is assumed that there will be no CM need at distribution level due to the traditional grid solution, but the TSO needs may still exist ($Mkt_n^{TSO,flex}$).
- The subset $\mathcal{N}^{grid}$ is the lifetime of the grid asset.
- The subset $\mathcal{N}^{i}$ comprises the lifetime of the asset i.
- The subset $\mathfrak{I}$ comprises the asset investments.

4.2.1.2.2 Temporary increase of subscription level as Business-as-Usual solution

In case of the Swedish grid alternative, the grid-based alternative to the use of flexibility is not reinforcing the grid, but to make use of temporary increases of subscription level. As described in (Etherden et al., 2020) and shown in Figure 9, system operation in Sweden has three responsibility layers, with regional DSOs operating the 70 kV-130 kV grid in between the TSO and local DSOs.

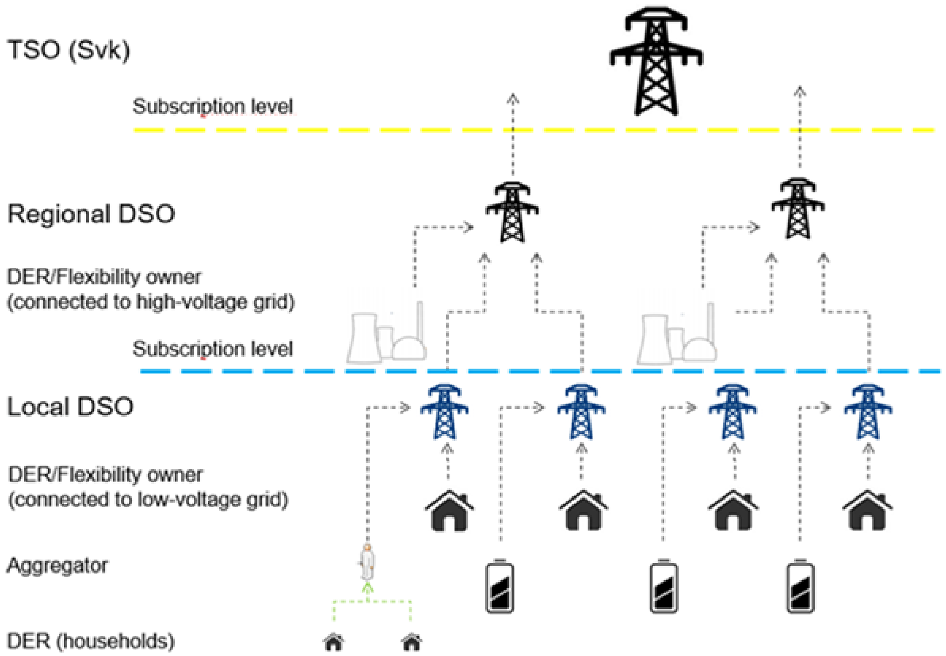

Figure 9: System operation responsibility layers in the Swedish power system (Etherden et al., 2020)

Therefore, regional DSOs have a direct connection to the transmission grid. All agents connected to the Swedish TSO's transmission grid, including regional DSOs, must pay network charges to cover the costs associated to the transmission grid extension, operation and maintenance, as well as to energy losses. These network charges include four main elements:

- **The usage fee**, which covers the energy losses, and is charged in Swedish Krona (SEK) per energy.
- **The regular capacity fee**, which covers the interconnection capacity that is subscribed on an annual basis and is charged in SEK per capacity.

- **The temporary capacity charge**, which covers temporary additional subscribed capacity for weekly durations, and is also charged in SEK per capacity. This temporary additional capacity must be requested at least one hour before the start of the subscription period and is subject to approval by the TSO, who only grants it if there is available capacity in the transmission network. This approval may even be revoked after its approval if the TSO forecasts that it may lead to congestions in the transmission network.
- **The temporary subscription usage fee**, which covers the energy consumed above the regular subscription level, but within the temporary additional subscription, and is charged in SEK per energy.

Therefore, both local DSOs and regional DSOs buy annual capacity subscriptions that allow the power consumption up to the agreed capacity with the TSO, and both the regular and the temporary subscription levels are important for the operational safety of the transmission grid and the Swedish power system in general. Overcoming the agreed subscription level results in a penalty for the agent (including the regional DSO) which is much higher than the usage fee (i.e., temporary subscription usage fees are in the range of 250 SEK/MWh, while penalties rise to 560 SEK/MWh, 1 400 SEK/MWh and 2 800 SEK/MWh for the first, second and subsequent hours with violations of the subscription level (Svenska kraftnät, 2022) . Since 2016, several regional DSOs were not permitted to raise their annual and temporal subscription levels, which resulted in both regional and local DSOs not being able to connect new customers (Etherden et al., 2020).

As a result, the annual costs ($Cost_n^{T\&D,grid2}$) for joint TSO and DSO needs for a given year *n* can be calculated according to eq. (4-10):

$$Cost_n^{T\&D,grid2} = SubC_n^{DSO,grid} + Mkt_n^{TSO,flex} \quad \forall n \tag{4-10}$$

The accumulated cost of the grid-based solution ($Cost_{\mathcal{T}}^{T\&D,grid2}$) is calculated for a specific time span ($\mathcal{T}$). The cost of the temporary subscription solution can be addressed in an annual basis, i.e., $\mathcal{T} = 1$.

$$Cost_{\mathcal{T}}^{T\&D,grid2} = \sum_{n=1}^{\mathcal{T}} Cost_n^{T\&D,grid2} = \sum_{n=1}^{\mathcal{T}} SubC_n^{DSO,grid} + Mkt_n^{TSO,flex} \tag{4-11}$$

- **Accumulated cost for joint TSO and DSO needs** ($Cost_{\mathcal{T}}^{T\&D,grid2}$) is the accumulated cost of the temporary solution for a given time span ($\mathcal{T}$).
- **Annual cost for joint TSO and DSO needs** ($Cost_n^{T\&D,grid2}$) is the annual cost of the temporary solution in the year *n,* from the scope of Pillar 1.a.
- **DSO subscription tariff costs** ($SubC_n^{DSO,grid}$) in the year *n* are included in the case of Sweden, in the comparison framework of Pillar 1.a, as an additional cost from the power system perspective.
- **Flexibility market costs** are the costs for the procurement of system services in the year *n*. It is assumed that CM needs at distribution level can be avoided by to the traditional grid solution. However, the TSO needs may still exist ($Mkt_n^{TSO,flex}$).

4.2.1.3 Impact of flexibility and grid-based solutions on the DSO

This subsubsection focuses on the economic impact that the different alternatives, i.e., flexibility or grid-based solution, have on the DSO. On the one hand, the flexibility solution is similar for the Spanish and Swedish demonstrators, while traditional alternatives differ from countries: a grid reinforcement cost is considered in Spain, whereas increased DSO subscription tariff costs are considered for Sweden.

Additionally, the remuneration of the regulated agents and the regulation of the network tariffs is different among European Union (EU) Member States. Therefore, Figure 10 presents the items to be considered in the comparison between the flexibility solution implemented in each demo and the two traditional alternatives (the temporary subscription cost only applies in the case of Sweden).

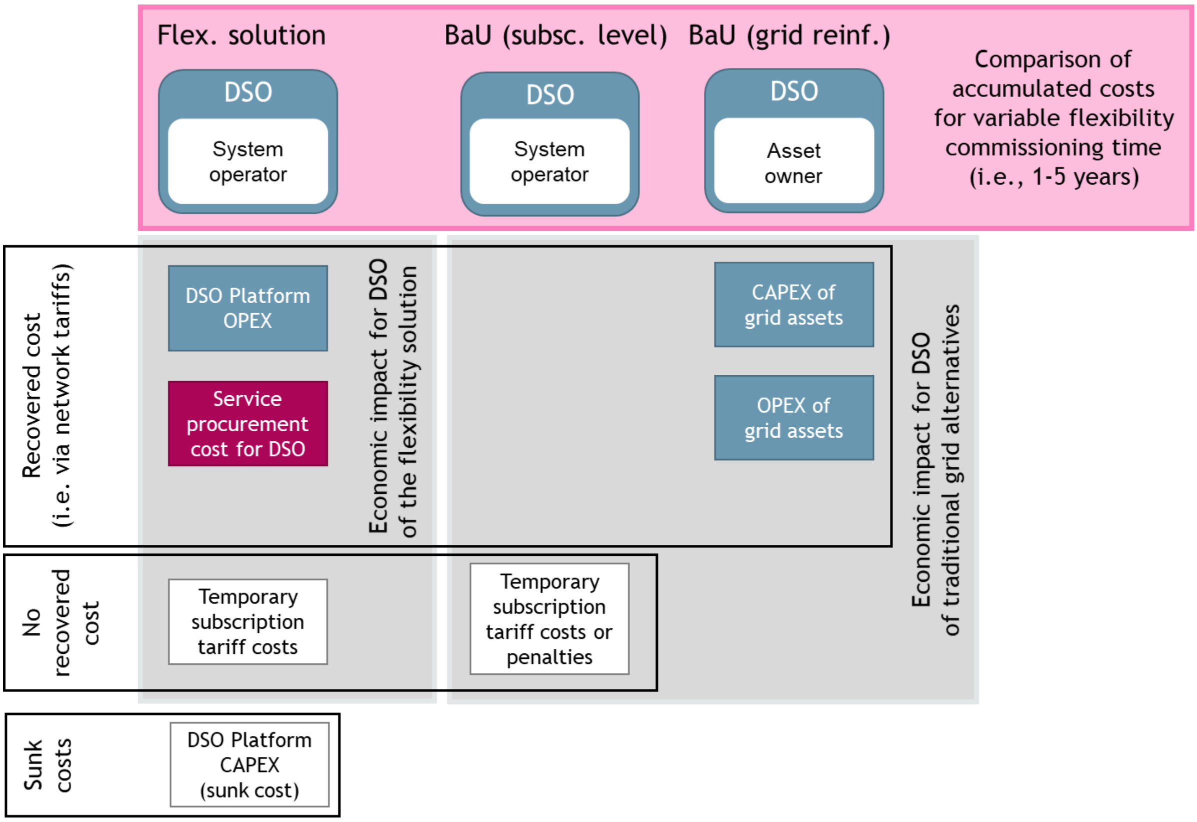

Figure 10: Cost components for the DSO in the flexibility and BaU alternatives for joint TSO and DSO needs (Pillar 1.a)

4.2.1.3.1 Flexibility solution versus traditional grid reinforcement

In the Spanish demo, the impact on the DSO is evaluated for a variable specific time span ($\mathcal{T}$). In this case, the time span corresponds to the given flexibility procurement period (i.e., up to 10 years). The flexibility solution will be the preferred option, as long as the impact of using flexibility ($BM_{\mathcal{T},CS}^{DSO,flex1}$) is lower than the impact of reinforcing the grid ($BM_{\mathcal{T}}^{DSO,grid1}$) in terms of cost for the DSO, as shown in eq. (4-12).

$$BM_{\mathcal{T},CS}^{DSO,flex1} < BM_{\mathcal{T}}^{DSO,grid1} \tag{4-12}$$

- The impact of the flexibility use on the DSO ($BM_{\mathcal{T},CS}^{DSO,flex1}$) for a specific time span ($\mathcal{T}$) corresponds to the accumulated costs (which are recovered through network charges), including operational expenditures ($Opex_{n,CS}^{DSO,flex}$), and service procurement costs for the DSO ($Mkt_{n,CS}^{DSO,flex}$), as described in subsubsection 4.2.1.1.
- The impact of the grid reinforcement ($BM_{\mathcal{T}}^{DSO,grid1}$) for a specific time span ($\mathcal{T}$) corresponds to the accumulated costs (which are also recovered through network charges), including capital ($Capex_{n,i}^{DSO,grid}$) and operational expenditures ($Opex_{n,i}^{DSO,grid}$) for grid assets, as described in paragraph 4.2.1.2.1.

Eq. (4-12) can thus be expressed as eq. (4-13) for a given flexibility procurement period ($\mathcal{T}$)[11]:

$$\sum_{n=1}^{\mathcal{T}} Opex_{n,CS}^{DSO,flex} + Mkt_{n,CS}^{DSO,flex} < \sum_{n=1}^{\mathcal{T}} \sum_{i \in \mathfrak{I}} Capex_{n,i}^{DSO,grid} + Opex_{n,i}^{DSO,grid} \tag{4-13}$$

4.2.1.3.2 Flexibility solution versus temporary increase of subscription level

In the Swedish demonstrator, the impact on the DSO is evaluated for a specific time span ($\mathcal{T}$), but, as there is no investment considered for any alternative, the comparison will be addressed for an annual basis, i.e., $\mathcal{T} = 1$. As in the case of Spain, the flexibility solution will be the preferred option, as long as the impact of using flexibility ($BM_{\mathcal{T},CS}^{DSO,flex2}$) is lower than the impact of requesting more often an increase of temporary DSO subscription level ($BM_{\mathcal{T}}^{DSO,grid2}$) in terms of cost for the DSO, as shown in eq. (4-14).

$$BM_{\mathcal{T},CS}^{DSO,flex2} < BM_{\mathcal{T}}^{DSO,grid2} \tag{4-14}$$

- The impact of the flexibility use on the DSO ($BM_{\mathcal{F},CS}^{DSO,flex2}$) for a specific time span ($\mathcal{T}$) corresponds to the accumulated costs including operational expenditures ($Opex_{n,CS}^{DSO,flex}$), DSO service procurement costs ($Mkt_{n,CS}^{DSO,flex}$) and DSO subscription tariffs cost ($SubC_{n}^{DSO,flex}$), as described in subsubsection 4.2.1.1.
- The impact of the traditional grid solution on the DSO ($BM_{\mathcal{T}}^{DSO,grid2}$) for a specific time span ($\mathcal{T}$) corresponds solely to the accumulated cost for the DSO subscription tariffs ($SubC_{n}^{DSO,grid}$), as described in paragraph 4.2.1.2.2.

Eq. (4-14) can thus be expressed as eq. (4-15) and evaluated in an annual basis:

$$\sum_{n}^{\mathcal{T}=1} Opex_{n,CS}^{DSO,flex} + Mkt_{n,CS}^{DSO,flex} + SubC_{n}^{DSO,flex} < \sum_{n}^{\mathcal{T}=1} SubC_{n}^{DSO,grid} \tag{4-15}$$

The CAPEX, OPEX and service procurement costs are recovered by the DSO via network tariffs (including a reasonable rate of return of investment), while the DSO subscription costs are not recovered, so that the DSO has an incentive to reduce them as much as possible.

[11] For clarification purposes, all costs with the subscript *n* consider their associated cash flow along the asset lifetime, divided into the investment costs which include annual amortization and financial terms and operational costs, as presented in section 4.1. The annual costs for regulated agents represent their annual remuneration to recover the incurred costs with a reasonable rate of return. Both grid alternatives are evaluated along a given time span, which enables to compare the accumulated costs along the upcoming years and select the most cost-effective solution under the current grid conditions (grid asset costs, level of congestion, flexibility activation costs). In case of flexibility solution convenience, grid-based alternative can be postponed or delayed in time.

4.2.2 Overview of the methodology for local needs

Participation in flexibility markets under common or multi-level coordination schemes, where needs of both TSOs and DSOs are satisfied, is not an easy task for small-scale DERs or energy aggregators with limited resources. Technical and economic requirements are tailored to ensure the overall power system security and are suitable for big-scale players, but they may be difficult to meet for small DERs at distribution level, such as energy storage, demand response, and local generators. However, these small units have an inherent flexibility which can still be very useful to solve other kind of issues in the system, with special attention to solve local needs.

Moreover, there may be cases where the appearance of congestions may hinder economic development or the connection of new users to the system, may result in renewable curtailment or non-supplied energy, when commissioning times of grid-based solutions are too long (such as new grid elements). DSOs can establish a local market to exploit the flexibility of small DERs to solve congestion issues at distribution level, with lower commissioning time (i.e., three years) or, even less when the infrastructure and SW is already available, or take remedial actions (i.e., an installation of a small generation asset).

Therefore, the use of these local markets (for a given flexibility commission time) may allow for not only postponing the need to reinforce the grid, but also provide a temporary solution caused by vegetative increase of demand during the commissioning time of the new grid elements.

Since these local markets are designed to solve specific needs of the DSO and, if designed properly, do not have an impact in the transmission network, the DSO may establish less strict technical and economic requirements for participation, which facilitates the participation of small-scale DERs.

In order to be able to use flexibility-based solutions locally, DSOs must develop, deploy and integrate several ICT-based platforms. Such platforms require massive investments but are easily scalable and replicable. In fact, their implementation does not only solve one specific issue in the system but can be used to solve many issues in many different locations. Therefore, once that the consideration of flexibility as a potential means to solve system needs is granted, the cost of their implementation becomes a sunk cost and, hence, it must not be taken into account when evaluating whether flexibility or grid reinforcement is the best solution for a given system need, as discussed in subsubsection 4.2.1.1.

The Pillar 1 for local needs (Pillar 1.b) assesses the conditions under which the use of flexibility can postpone or temporarily replace traditional, grid-based solutions to solve DSO-specific needs, especially in Spain (Málaga and Murcia) and Greece (Kefalonia network) local distribution grids.

In the short term, the flexibility solution may be compared to the cost of a remedial action when congestions are already appearing, in which non-supplied energy must be a DSO concern, while, in the medium term, the use of flexibility for a given commissioning time may be compared to the cost of traditional grid reinforcement when the DSO should take decisions for the upcoming distribution grid planning period.

In line with the diagram presented in Figure 11, the general framework to establish the comparison between two alternatives to solve local congestion issues is presented. From the flexibility solution side, CAPEX are considered to be sunk costs for both the LMO and DSO actors, as discussed above, while OPEX terms related to the SW platform and ICT costs and the cost for the CM service procurement at distribution level are included. Additionally, there may be some "flexibility" not supplied (FNS) when there is not enough flexibility to completely solve the congestion. The FNS is only considered in local needs, while in joint TSO and DSO needs it is assumed that there is enough liquidity and available flexibility so as to solve the simulated needs. On the other hand, the DSO, as distribution asset owner, should consider CAPEX and OPEX of the traditional grid reinforcement (i.e., repowered line, new transformer, new generation asset, etc.).

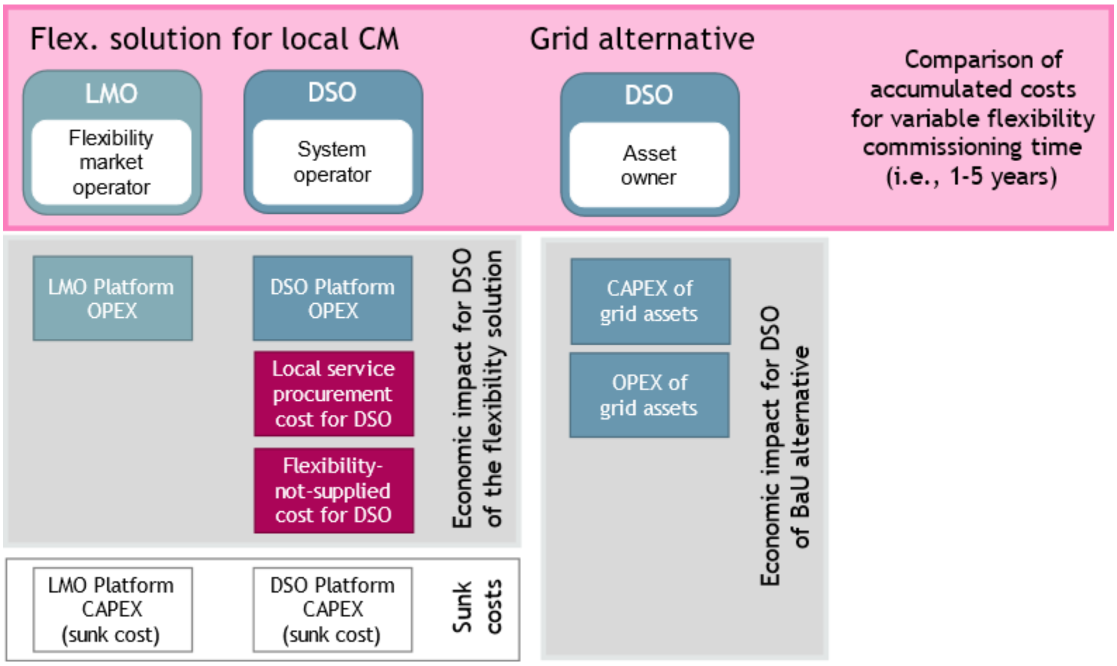

Figure 11: Cost components for regulated agents in the flexibility and BaU alternatives for local needs (Pillar 1.b)

4.2.2.1 Cost of flexibility activation for local needs

This subsubsection aims to evaluate the cost of the procurement (activation) of flexibility services. Once the consideration of the flexibility markets as a potential means to solve local system needs is granted, the cost of their implementation (i.e., CAPEX for the ICT infrastructure and SW platforms to enable new flexibility markets) becomes a sunk cost and, hence, it must not be taken into account when evaluating whether flexibility or grid reinforcement is the best solution for a given system need.

Therefore, the annual cost for flexibility solution ($Cost_n^{local,flex}$) is evaluated along the lifetime of the assets ($\mathcal{N}^i$). In this case, a lifespan of 10 years can be assumed.

$$Cost_n^{local,flex} = C_n^{LMO,flex} + C_n^{DSO,flex} + Mkt_n^{DSO,flex} + FNS_n^{DSO,flex} \quad \forall n \in \mathcal{N}^i \tag{4-16}$$

In order to compare both grid alternatives, the accumulated cost of flexibility procurement ($Cost_{\mathcal{T}}^{local,flex}$) is calculated for a specific time span. In this case, the flexibility procurement period ($\mathcal{T}$) is used as a dynamic time span in which the accumulated costs are calculated and compared among both grid solutions.

$$Cost_{\mathcal{T}}^{local,flex} = \sum_{n=1}^{\mathcal{T}} Cost_n^{local,flex} \tag{4-17}$$

where:

- **Accumulated cost** ($Cost_{\mathcal{T}}^{local,flex}$) is the accumulated cost for the procurement of local flexibility services for a given time span ($\mathcal{T}$), such as the flexibility procurement period.

- **Annual cost** ($Cost_n^{local,flex}$) is the annual cost for the local procurement (activation) of flexibility services in the year *n*, from the scope of Pillar 1.b.
- **LMO expenditure** ($C_{n,CS}^{LMO,flex}$) is the annual cost for the LMO platform to solve flexibility needs at local distribution level in the year *n* and per coordination scheme *CS*. This annual expenditure includes only an OPEX term, presented in eq. (4-3). These incurred costs for the operation and management of the MO platform will be recovered costs for the LMO agent via network tariffs.
- **DSO expenditure** ($C_n^{DSO,flex}$) is the annual cost associated to the DSO as system operator in the year *n*. The DSO expenditure includes an OPEX term (operating and maintaining the ICT and SW assets, workforce, etc.), which the DSO will recover through network charges. It is presented in eq. (4-3).
- **Flexibility market costs** are the costs for the procurement of local CM to solve the DSO needs ($Mkt_n^{DSO,flex}$) in the year *n*, which corresponds to the remuneration received by FSPs.
- **Flexibility-not-supplied cost** ($FNS_n^{DSO,flex}$) is the flexibility not supplied, which may result in energy not supplied by the DSO to the consumers, when there is not enough flexibility available nor a traditional grid solution (or other remedial actions, such as the installation of onsite backup generators) is implemented when congestions occur.
- The superscript $flex$ indicates that the item corresponds to the flexibility solution.
- The subscript i indicates each investment.
- The subset $\mathcal{N}^i$ comprises the lifetime of the asset *i*.
- The subscript n corresponds to each year.
- The subset $\mathcal{T}$ corresponds to the time span (i.e., the given flexibility procurement period).

4.2.2.2 Cost of traditional grid solution for local needs

The cost of traditional grid solutions for local needs can include grid reinforcement actions evaluated in the medium term, or other temporary remedial actions for more urgent issues. In the economic assessment for local needs, it is supposed that local congestions can be eliminated by means of the grid solution.

4.2.2.2.1 Medium-term grid solution

Current revenue regulation incentivizes grid reinforcements more than the usage of “local services” (Lind and Chaves, 2019). The grid alternative is to reinforce the grid to tackle congestion events. When the line is reinforced, new lines are built, or other assets are repowered, the power system must deal with high CAPEX in order to reduce grid congestion or other inefficiencies.

In case of selecting the grid reinforcement option, the annual costs ($Cost_n^{local,grid1}$) are evaluated along the lifetime of the grid asset ($\mathcal{N}^{grid}$) of i.e., 40 years:

$$Cost_n^{local,grid1} = C_n^{DSO,grid} \qquad \forall n \in \mathcal{N}^{grid} \tag{4-18}$$

However, both alternatives (flexibility and grid reinforcement) have different lifetimes. In order to evaluate which is the best solution along the same life span in Pillar 1.b, the flexibility procurement period ($\mathcal{F}$) is used as a dynamic time span (i.e., 5 years) in which the accumulated costs are calculated and compared among both grid alternatives.

Then, the accumulated cost of grid reinforcement ($Cost_{\mathcal{T}}^{local,grid1}$) is calculated for a given time span ($\mathcal{T}$):

$$Cost_{\mathcal{T}}^{local,grid1} = \sum\nolimits_{n=1}^{\mathcal{T}} Cost_n^{local,grid1} \quad (4\text{-}19)$$

where:

- **Accumulated cost for local needs** ($Cost_{\mathcal{T}}^{local,grid1}$) is the accumulated cost of the local grid reinforcement solution for a given flexibility procurement period ($\mathcal{T}$).
- **Annual cost for local needs** ($Cost_n^{local,grid4.1}$) is the annual cost of the local grid reinforcement solution in the year *n*, from the scope of Pillar 1.b.
- The subset $\mathcal{N}^{grid}$ is the lifetime of the grid asset.
- **DSO expenditure** ($C_n^{DSO,grid}$) for the DSO, which may include asset reinforcement(s), but also SW and ICT costs might be covered. Each incurred cost should be calculated according to their specific lifetime (i.e., 40 years for grid assets and 10 for SW or ICT costs).

$$C_n^{DSO,grid} = \sum\nolimits_i Capex_{n,i}^{DSO,grid} + Opex_{n,i}^{DSO,grid} \qquad \forall i \in \mathfrak{I}, \forall n \in \mathcal{N}^i \quad (4\text{-}20)$$

  - **Annual CAPEX** ($Capex_{n,i}^{DSO,grid}$) is associated to the grid infrastructure investment for asset reinforcement, renewal or upgrade, and other required investments, incurred by the DSO in the year *n* for the investment on each asset *i* in the distribution network. The annual remuneration for regulated agents for CAPEX is presented previously in eq. (4-2).
  - **Annual OPEX** ($Opex_{n,i}^{DSO,grid}$) is associated to the O&M costs in the year *n* of each asset *i* in the distribution network, presented previously in eq. (4-3).
- The subset $\mathcal{N}^{grid}$ is the lifetime of the grid asset.
- The subset $\mathcal{N}^i$ comprises the lifetime of the asset *i*.
- The subset $\mathfrak{I}$ comprises the asset investments.

4.2.2.2.2 Short-term remedial action

When there is a need for an urgent solution to avoid local CM (i.e., the congestion is already happening), remedial actions may be selected. In case of selecting a temporary solution, such as the installation of a new grid asset (e.g., a diesel generator), the annual costs ($Cost_n^{local,grid2}$) are evaluated for a given year *n*:

$$Cost_n^{local,grid2} = C_n^{DSO,grid} \qquad \forall n \quad (4\text{-}21)$$

Then, the accumulated cost of a temporary solution ($Cost_{\mathcal{T}}^{local,grid2}$) is calculated for a given time span ($\mathcal{T}$):

$$Cost_{\mathcal{T}}^{local,grid2} = \sum\nolimits_{n=1}^{\mathcal{T}} Cost_n^{local,grid2} \quad (4\text{-}22)$$

where:

- **Accumulated cost** ($Cost_{\mathcal{T}}^{local,grid2}$) is the accumulated cost of the local temporary solution for a given time span ($\mathcal{T}$), which could be equal to the flexibility procurement period.
- **Annual cost for local needs** ($Cost_n^{local,grid2}$) is the annual cost of the local temporary solution in the year *n*, from the scope of Pillar 1.b.

- **DSO expenditure** ($C_n^{DSO,grid}$) for the DSO, which may include asset reinforcement(s), but also SW and ICT costs might be covered. Each incurred cost should be calculated according to their specific lifetime (i.e., 40 years for grid assets and 10 for SW or ICT costs).

$$C_n^{DSO,grid} = \sum_i Capex_{n,i}^{DSO,grid} + Opex_{n,i}^{DSO,grid} \qquad \forall i \in \mathfrak{I}, \forall n \in \mathcal{N}^i \tag{4-23}$$

  - **Annual CAPEX** ($Capex_{n,i}^{DSO,grid}$) is associated to the temporary solution cost, incurred by the DSO in the year *n* for the investment on each asset *i* in the distribution network. The annual remuneration for regulated agents for CAPEX is presented in eq. (4-2). That is, if the asset is used for two years, the two first annuities are recovered.
  - **Annual OPEX** ($Opex_{n,i}^{DSO,grid}$) is associated to the O&M costs in the year *n* of each asset *i* in the distribution network, as presented in eq. (4-3).

4.2.2.3 Impact of flexibility and grid-based solutions on the DSO

This subsubsection focuses on the economic impact that the different alternatives, i.e., flexibility or grid-based solution, have on the DSO. On the one hand, the comparison between alternatives is similar for the two demos (Spanish and Greek) in which local congestion needs are partially or totally solved by the DERs installed at distribution level (i.e., the ones considered in the demonstrators). On the other hand, CAPEX and OPEX for grid reinforcement (lines, transformers, generators, etc.) are supposed for local needs.

The comparison of the economic impact that the flexibility and grid-based solutions have on the DSO is done at two timeframes: a remedial action for short term and grid reinforcement for the medium-term. Figure 12 presents the items to be considered for the comparison of the impact on the DSO, where some costs and service procurement are recovered via tariffs, while the flexibility-not-supplied is an extra cost.

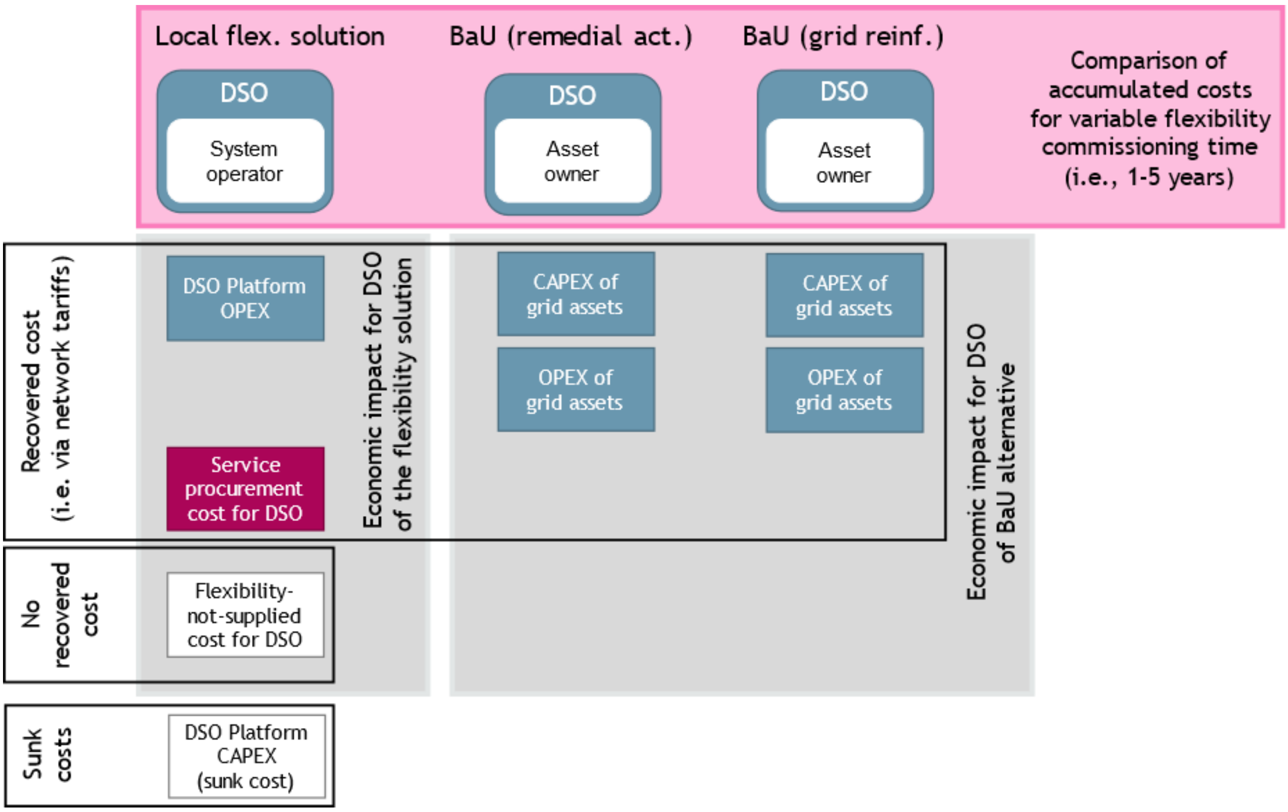

Figure 12: Cost components for the DSO in the flexibility and BaU alternatives for local needs (Pillar 1.b)

4.2.2.3.1 Flexibility use versus medium-term grid solution

In the medium-term, the economic impact on the DSO is evaluated for a variable specific time span ($\mathcal{T}$). In this case, the time span corresponds to the given flexibility procurement period (i.e., up to 5 years) [12].

$$BM_{\mathcal{T}}^{DSO,flex} < BM_{\mathcal{T}}^{DSO,grid1} \tag{4-24}$$

$$\sum_{n=1}^{\mathcal{T}} Opex_n^{DSO,flex} + Mkt_n^{DSO,flex} + FNS_n^{DSO,flex} < \sum_{n=1}^{\mathcal{T}} \sum_{i \in \mathfrak{T}} Capex_{n,i}^{DSO,grid} + Opex_{n,i}^{DSO,grid} \tag{4-25}$$

- The impact of the flexibility use on the DSO ($BM_{\mathcal{T}}^{DSO,flex}$) for a specific time span ($\mathcal{T}$) corresponds to the accumulated costs (which are recovered via network charges), including operational expenditures ($Opex_{n,CS}^{DSO,flex}$), DSO service procurement costs ($Mkt_{n,CS}^{DSO,flex}$) and the cost of the flexibility-not-supplied ($FNS_n^{DSO,flex}$), if any, as described in subsubsection 4.2.2.1.
- The impact of the grid reinforcement solution on the DSO ($BM_{\mathcal{F}}^{DSO,grid1}$) corresponds to the accumulated costs (which are recovered via network charges), including capital ($Capex_{n,i}^{DSO,grid}$) and operational expenditures ($Opex_{n,i}^{DSO,grid}$) for grid assets, as described in paragraph 4.2.2.2.1.

4.2.2.3.2 Flexibility use versus short-term remedial action

In the short-term, the economic impact on the DSO is evaluated for a specific time span. As there is a need for an urgent and temporal remedial action, the comparison will be made for 1 year.

$$BM_{\mathcal{T}}^{DSO,flex} < BM_{\mathcal{T}}^{DSO,grid2} \tag{4-26}$$

$$\sum_{n}^{\mathcal{T}=1} Opex_{n,CS}^{DSO,flex} + Mkt_{n,CS}^{DSO,flex} + FNS_n^{DSO,flex} < \sum_{n}^{\mathcal{T}=1} \sum_{i \in \mathfrak{T}} Capex_{n,i}^{DSO,grid} + Opex_{n,i}^{DSO,grid} \tag{4-27}$$

- The impact of the flexibility use on the DSO ($BM_{\mathcal{T}}^{DSO,flex}$) for a specific time span ($\mathcal{T}$) corresponds to the accumulated costs (which are recovered via network charges), including operational expenditures ($Opex_{n,CS}^{DSO,flex}$), DSO service procurement costs ($Mkt_{n,CS}^{DSO,flex}$) and the cost of the flexibility-not-supplied ($FNS_n^{DSO,flex}$), if any, as described in subsubsection 4.2.2.1.
- The impact of the urgent remedial action on the DSO ($BM_{\mathcal{F}}^{DSO,grid2}$) corresponds to the accumulated costs (which are recovered via network charges), including capital ($Capex_{n,i}^{DSO,grid}$) and operational expenditures ($Opex_{n,i}^{DSO,grid}$) for grid assets, as described in paragraph 4.2.2.2.2.

[12] For clarification purposes, all costs with the subscript *n* consider their associated cash flow along the asset lifetime, divided into the investment costs which include annual amortization and financial terms and operational costs, as presented in section 4.1. Both grid alternatives are evaluated along a given time span, which enables to compare the accumulated costs along the upcoming years and select the most cost-effective solution under the current grid conditions. In case of flexibility solution convenience, grid-based alternative can be postponed.

4.3 Pillar 2: Performance of the coordination schemes at system level

The economic efficiency of the different coordination schemes at system level can be measured by comparing the costs for regulated agents (i.e., TSOs, DSOs and MOs) in each case. This Pillar 2 is focused on the evaluation and comparison of the different CSs for providing congestion management (CM) services and in the CSs which aim at solving needs of both the TSO and the DSO:

- In Spain, a common market model is implemented, together with a local market which is aimed at solving DSO-specific needs in the LV distribution grid, with no or little impact on the TSO. This alternative will be compared to a combined multi-level market (to solve TSO and DSO needs at the highest voltage levels) and local market (to solve DSO-specific needs at LV) arrangement.
- In Sweden, the implemented multi-level market will be compared against a common market.

The procurement of flexibility services should be done through a market-based mechanism according to a chosen coordination scheme, but, in the end, regulated parties cover their costs by a reasonable return rate of investment according to a specific mechanism defined by national (or regional) regulation. The overall costs at system level include both the cost of procuring system services and the cost of developing, deploying, and operating the ICT platforms and systems (among other items) required for such procurement, as discussed in section 4.1.

4.3.1 Overview of flexibility cost at system level

As shown in Figure 13, the economic impact at system level of the flexibility solution per each coordination scheme is evaluated, including the procurement of the services as well as other regulated costs. The CAPEX and OPEX terms related to the SW platform and ICT costs for all actors are included, as well as the cost for the CM service procurement at distribution and transmission level.

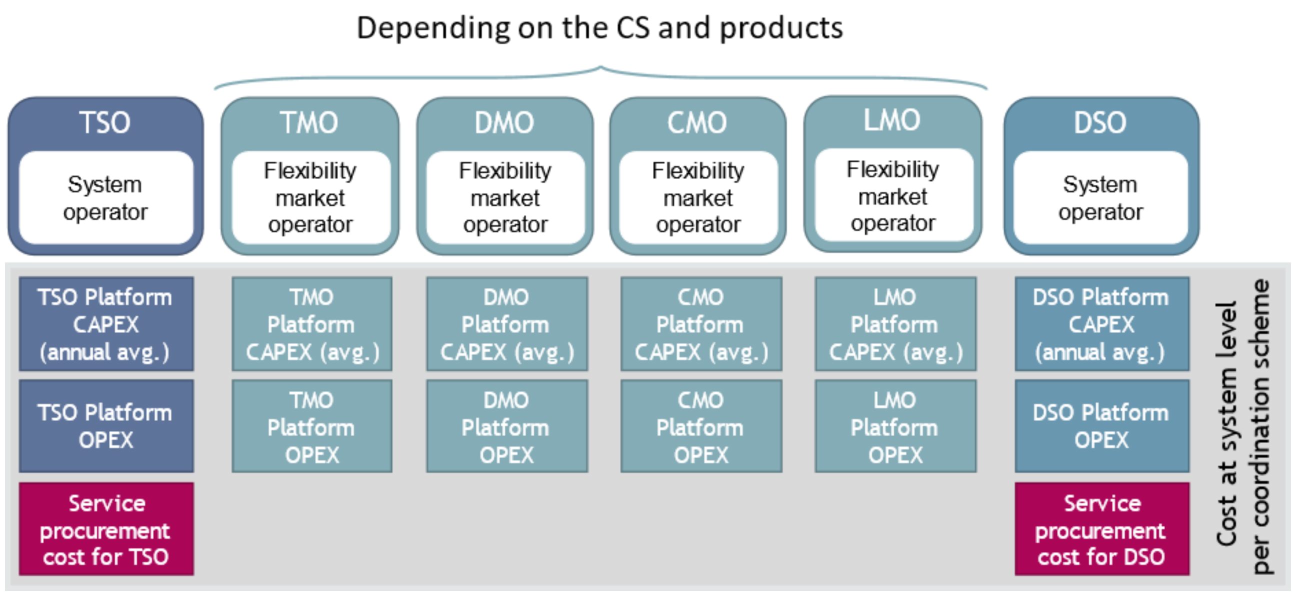

Figure 13: Economic impact of flexibility solution per CS at system level (Pillar 2)

The annual average cost per coordination scheme ($\overline{Cost}_{n,CS}^{SC,flex}$) is calculated according to equation (4-28):

$$\overline{Cost}_{n,CS}^{SC,flex} = C_{n,CS}^{MOs,flex} + C_{n,CS}^{TSO,flex} + C_{n,CS}^{DSO,flex} + Mkt_{n,CS}^{TSO,flex} + Mkt_{n,CS}^{DSO,flex} \quad (4\text{-}28)$$

where:

- **Annual average cost at system level** ($\overline{Cost}_{n,CS}^{SC,flex}$) represents the cost at system level of the flexibility solution in the year *n* and per CS, from the scope of Pillar 2. This cost per year at system level for the flexibility solution will comprise all the costs the system incurs over its lifetime (i.e., 10 years), including annuities of CAPEX, annual OPEX and annual service procurement cost.

  Except the platform-related CAPEX, the other terms are assumed to be annually stable (OPEX) as it would be difficult to provide an accurate future trend (i.e., for service procurement cost) (Cossent et al., 2022). The annuities of CAPEX vary over the lifetime (which include amortization and financial terms, following eq. (4-2)). Thus, these CAPEX in Pillar 2 are evaluated as an equivalent cash flow sequence with a unique single cost occurring in every year of the project, following eq. (4-4).

- **MO expenditure** ($C_{n,CS}^{MOs,flex}$) is the annual average cost for the MO platform to solve flexibility needs at transmission and/or distribution level in the year *n* and per coordination scheme CS, and it includes both CAPEX and OPEX terms, as described in section 4.1. These incurred costs for the development and management of the MO platform will be recovered costs for the MO agent, as presented in section 4.1. This expenditure may refer to a CMO ($C_{n,CS}^{CMO,flex}$), to a TMO ($C_{n,CS}^{TMO,flex}$), to a DMO ($C_{n,CS}^{DMO,flex}$) or to a LMO ($C_{n}^{LMO,flex}$).

- **TSO expenditure** ($C_{n,CS}^{TSO,flex}$) is the annual average cost associated to the TSO as system operator in the year *n* per coordination scheme CS. This total expenditure gathers CAPEX and OPEX terms, as described in section 4.1, which account for:
  - Annual average CAPEX cost of developing and deploying the ICT infrastructure, SW updates and other investments.
  - OPEX for the O&M of the ICT and SW assets, workforce, etc.

- **DSO expenditure** ($C_{n,CS}^{DSO,flex}$) is the annual average cost associated to the DSO as system operator in the year *n* per coordination scheme CS. This total expenditure gathers CAPEX and OPEX terms, as described in section 4.1, which account for:
  - Annual average CAPEX for developing and deploying the ICT, SW, and other assets.
  - OPEX of operating and maintaining the ICT and SW assets, workforce, etc.

- **Flexibility market costs** are the costs for the procurement of system services in the year *n* per coordination scheme CS, which corresponds to the remuneration received by the FSPs for the flexibility they provide. For simplicity, the comparison of CSs will only address CM cost, leaving aside the potential impact in balancing when a combined CM and balancing procurement is done. This cost may be divided, depending on the voltage level of the activation (service procurement for TSO and for DSO):
  - Flexibility service procurement cost for the TSO needs ($Mkt_{n,CS}^{TSO,flex}$).
  - Flexibility service procurement cost for the DSO needs ($Mkt_{n,CS}^{DSO,flex}$).

- The first superscript indicates the associated market agent ($MO,\ DMO,\ TSO,\ DSO,$ and FSP)
- The superscript $flex$ indicates that the item corresponds to the flexibility solution.
- The superscript SC indicated an economic analysis at system level.
- The subscript n corresponds to each year.
- The subscript CS corresponds to the coordination scheme.

4.3.2 Flexibility market operator

As discussed in section 4.1, the operation of the flexibility market is considered to be a regulated activity and it may refer to a market operator who solves flexibility needs at transmission level (TMO), at distribution level (DMO), at both levels (CMO) or DSO-specific needs in a local market (LMO). Hereafter, and to avoid repetition, the terms will be detailed for a generic MO agent.

MO expenditure ($C_{n,CS}^{MO,flex}$) is the annual average incurred cost for the MO platform to solve flexibility needs in the year *n* and per coordination scheme *CS*, which includes both a CAPEX and an OPEX component, as shown in eq. (4-1). The annual average capital expenditure ($\overline{Capex}_{n,CS}^{MO,flex}$) of the MO in year *n*, which can be calculated as described in equations (4-4) and (4-2) in section 4.1, includes all the costs related with the MO platform development (i.e. market clearing algorithms, licenses, data storage, front-end hardware, enterprise service bus, APIs, reporting tool, SQL server, settlement process, security and data classification, etc.). Likewise, annual operating expenses ($Opex_{n}^{MO,flex}$) of the MO in year *n* gather the OPEX component for the operation and maintenance (O&M) activities related to the market platform: platform operation and personnel costs, data handling, licenses update, weather prediction license, and communication costs (i.e. to receive balancing and congestion managements needs from TSOs and/or DSOs, flexibility bids, and send market clearing and settlement/billing to market players) and can be calculated according to eq. (4-3).

The development of infrastructure or innovative projects will often be associated with higher costs and risks. Insufficient financial incentives can lead regulated agents not to invest, unless there are specific budget allocations defined by the NRA. In most regulatory frameworks, MOs, TSOs and/or DSOs have a fixed rate of return for investment. Likewise, a specific budget for OPEX-based solutions could also be considered (see section 12.1 in Annex III: Regulatory mechanisms for market actors). Thus, for certain investments, the regulator may alter the weighted average cost of capital (WACC) or other financial indicators in a more favorable direction to incentivize these innovative investments (European Commission et al., 2019). In order to incentivize flexibility solution over the traditional grid alternative, a financial remuneration rate (r^{i}) and a risk based financial OPEX margin may be established at e.g., 8%.

The MO platform cost (including TMO, DMO, CMO or LMO) due to the flexibility solution ($C_{n,CS}^{TMO,flex}$, $C_{n,CS}^{DMO,flex}$) can be socialized at system level or can paid by market players (i.e., FSPs at distribution level). At early stages of the flexibility market deployment, the MO cost cannot be covered by a very few market participants. Thus, in order to incentivize market players (FSPs and DERs) to participate in the flexibility market, it is assumed that all the involved MO costs are socialized at system level (i.e., paid through network tariffs), to evaluate and compare the overall MO costs per coordination scheme in Pillar 2.

As soon as the market is mature enough and has enough liquidity, the MO platform costs could be shared between market players (i.e., an access fee to cover several costs mainly related to OPEX terms).

4.3.3 Transmission System Operator

The TSO, as system operator itself, will be in charge of the transmission network management and operation, assuming the technical management of the electricity system and supporting grid development plans to meet the electricity demand in the medium and long term at the lowest cost for the system. The TSO should manage the technical and economic redispatch and financial settlements. The TSO may make investment in software applications to be adapted to the European regulation or singular European projects. TSO’s recognized costs are recovered through i.e., network tariffs.

TSO expenditure ($C_{n,CS}^{TSO,flex}$) can also be calculated according to eq. (4-1), as the addition of CAPEX and OPEX. The annual average TSO CAPEX in year *n* ($\overline{Capex}_{n,CS}^{TSO,flex}$) include costs due to TSO software development or upgrade, service bus for data exchange, communication infrastructure, and additional ICT costs required to be integrated or communicate to the MO flexibility platform and share new information, and can be calculated as described in equations (4-4) and (4-2). The annual TSO OPEX in year *n* ($Opex_{n,CS}^{TSO,flex}$), which are calculated according to eq. (4-3), may include grid operation costs related with flexibility and additional ICT costs to send flexibility needs to the MO, to activate bids in transmission/ distribution network, and to communicate with the MO, DSO, FSPs, and other market actors.

4.3.4 Distribution System Operator

The DSO is in charge of developing, operating and ensuring the maintenance of the distribution grid facilities, ensuring system stability and security of supply efficiently. The Clean Energy Package (European Commission, 2019b) defines a framework to incentivize the use of flexibility by DSOs to optimize network investment decisions. In this context, remuneration schemes are required to foster alternative solutions and their efficient procurement. DSO's recognized costs are recovered through i.e., network tariffs.

DSO expenditure ($C_{n,CS}^{DSO,flex}$) at system level corresponds to the annual remuneration for the DSO as system operator, as a result of the incurred cost related to the integration with the flexibility platform and procurement of these services. In line with the MO and the TSO, the proposal for the recognized costs of the DSO follows eq. (4-1), including an annual average CAPEX term ($\overline{Capex}_{n,CS}^{DSO,flex}$) to consider the costs incurred by the DSO in year *n* for communication, protection, SW update and development, and control activities for the proper flexibility procurement that can be calculated with equations (4-4) and (4-2). Likewise, an annual OPEX component ($Opex_{n,CS}^{DSO,flex}$) is included following eq. (4-3), for the O&M activities related to flexibility procurement, mainly additional ICT costs to communicate with the TSO, MO and metering to provide flexibility and handle metering data (to send local congestion management needs, receive market clearing results, send real-time setpoints to FSPs, receive real-time and ex-post measurements, etc.); annual costs for cloud services, hosting, licenses, security and data hub; smart-meters installation and communication, forecasting module updates and other software update and maintenance.

4.4 Pillar 3: Profitability assessment for non-regulated agents

4.4.1 Overview of the methodology for joint TSO and DSO needs

The third pillar (Pillar 3.a) evaluates the profitability of the provision of flexibility services by FSPs and DERs under the different TSO-DSO coordination schemes analyzed.

Non-regulated agents, such as aggregators and other FSPs, will only participate in flexibility markets if they can see an attractive business model for providing services. That is, the remuneration that they receive for participating in those markets must be higher than the cost of providing them.

As described in section 2.2, the set of FSPs at transmission network (FSP@T) are direct owners of flexible resources participating in the provision of CM as a system service. In contrast, two kinds of sellers are considered at distribution level. FSPs at distribution network may also be direct owners of flexible resources participating in the provision of CM as a system service (FSP@D) or may be aggregators which encompass the multiple types of flexible DERs and end-users connected to the distribution grid (FSP-ag@D). In fact, DERs installed at distribution level usually need to participate in flexibility and other wholesale markets through aggregation. That said, DERs (the ones participating at the demonstrators in CoordiNet) are supposed to participate via an energy aggregator in flexibility markets and obtain a remuneration via a bilateral contract with the FSP-ag@D.

FSPs and aggregators receive market incomes for the provision of flexibility services (from the TSO, from the DSO or from both in the case of the common market model), but they must deal with additional costs associated to this business activity, including the costs of developing, deploying and operating the necessary ICT systems (CAPEX and OPEX terms), flexibility market fee to access the market, and other costs linked to the activation of flexibility, as shown in Figure 14. FSP-ag@Ds should consider both the cost of the aggregation platform and other costs associated to the DERs they represent, while it is assumed that both FSP@Ts and FSP@Ds already have the required infrastructure to provide flexibility services and they do not require any aggregation platform. The market incomes of the FSPs will vary depending on the pricing scheme (pay-as-bid, pay-as-clear, etc.), the adopted coordination scheme, and the features of competitors (demand response, generation units, etc.).

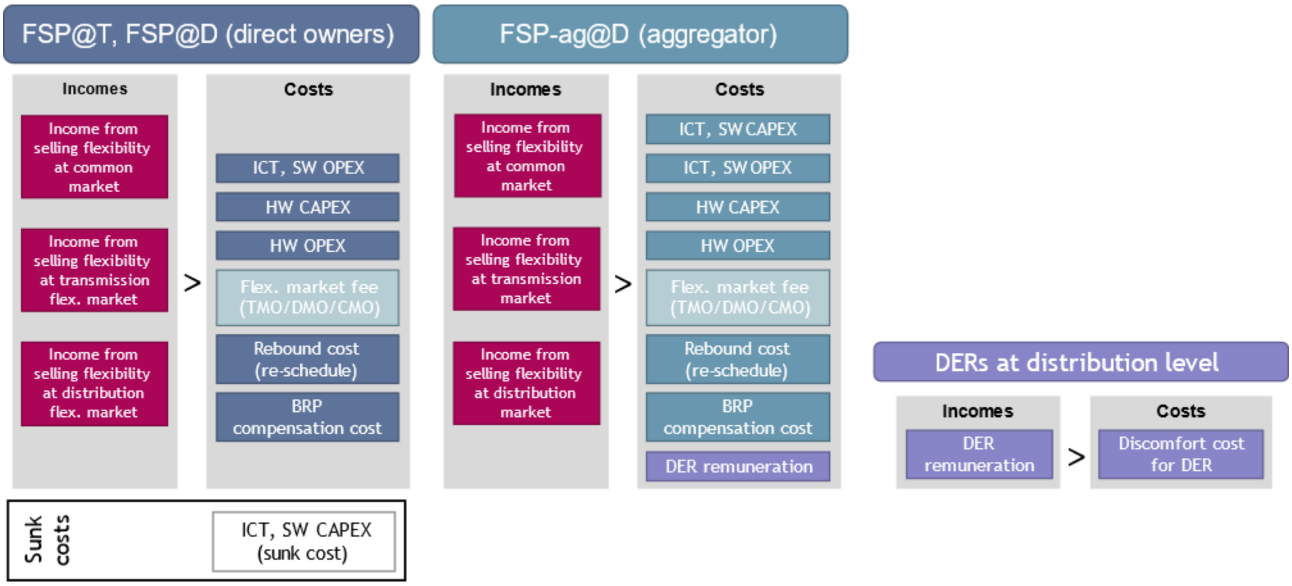

Figure 14: Incomes and costs for non-regulated actors (Pillar 3)

4.4.1.1 Flexibility Service Providers for joint TSO and DSO needs

FSPs (both FSP@T, FSP@D, and FSP-ag@D) participate in the flexibility markets on behalf of their own facilities or third parties, receiving the flexibility market incomes, but they face different costs associated to this business activity. In order to obtain a positive business case, each FSP responsible of flexible resources at transmission or distribution level must satisfy the eq. (4-29), while FSP-ag@D must satisfy eq. (4-30).

$$Mkt_{f,CS,n}^{FSP,flex} > C_{f,n}^{MO,FSP} + Opex_{f,n}^{FSP} + BRP_{f,CS,n}^{FSP} + Retail_{f,CS,n}^{FSP} \quad \forall f \in \mathcal{F}^{FSP}, \forall d \in \mathcal{D}_f, \forall n \in \mathcal{N}^i \tag{4-29}$$

$$Mkt_{f,CS,n}^{FSP,flex} > \left(\begin{array}{c} C_{f,n}^{MO,FSP} + Capex_{f,n}^{FSP} + \sum_d Capex_{f,d,n}^{HW} + Opex_{f,n}^{FSP} \\ +Rem_{f,CS,n}^{FSP} + BRP_{n,CS,f}^{FSP} + Retail_{f,CS,n}^{FSP} \end{array} \right) \quad \forall f \in \mathcal{F}^{ag}, \forall d \in \mathcal{D}_f, \forall n \in \mathcal{N}^i \tag{4-30}$$

where:

- $Mkt_{f,CS,n}^{FSP,flex}$ corresponds to the flexibility market incomes per FSP f and CS in the year n.
- $C_{f,CS,n}^{MO,FSP}$ corresponds to the MO platform costs paid per FSP f and CS in the year n.

- $Capex_{f,n}^{FSP}$ corresponds to the FSP capital expenditure per FSP f in the year n.
- $Capex_{f,d,n}^{HW}$ corresponds to the hardware (HW) capital expenditures per FSP f in the year n, related to the required investment needed in each DER d.
- $Opex_{f,n}^{FSP}$ corresponds to the FSP operational expenses per FSP f in the year n.
- $Rem_{f,CS,n}^{FSP}$ corresponds to the financial DER remuneration per FSP f and CS in the year n.
- $BRP_{f,CS,n}^{FSP}$ corresponds to the BRP compensations per FSP f and CS in the year n.
- $Retail_{f,CS,n}^{FSP}$ corresponds to the rebound effect cost per FSP f and CS in the year n.
- The subscript CS corresponds to the coordination scheme.
- The subscript d indicates each flexible resource or DER behind a FSP f.
- The subset $\mathcal{D}_f$ comprises all flexible resources or DER of a FSP f.
- The subscript f indicates each FSP (including FSP@T, FSP@D, and FSP-ag@D).
- The subset $\mathcal{F}^{FSP}$ comprises FSPs which are direct owners of the flexible resources.
- The subset $\mathcal{F}^{ag}$ comprises FSPs which are energy aggregators.
- The subscript n corresponds to each year.
- The subset $\mathcal{N}^i$ comprises the lifetime of the asset i.

Hereafter, a detailed description for each item is provided:

- **Flexibility market incomes** ($Mkt_{f,CS,n}^{FSP,flex}$) are the remuneration received by each FSP (f) for the procurement (activation) of system services they provide in the year n per coordination scheme CS. For simplicity, the comparison of CSs will only address CM cost, leaving aside the potential impact on balancing when a combined CM and balancing procurement is done. These incomes may come from different markets operated by the TMO, DMO or CMO. This market may be pay-as-bid or pay-as-cleared, according to the market design.

$$Mkt_{f,CS,n}^{FSP,flex} = \sum_{d:\forall d \in \mathcal{D}_f} \sum_{h} \lambda_{d,h,n}^{flex} \cdot E_{d,h,n}^{flex} \qquad \forall f \in \mathcal{F} \tag{4-31}$$

  The weighted price of the FSP is a key indicator to evaluate the cost-efficiency of flexibility solution according to the CS implemented and the bid price of the flexibility resources behind this FSP.

$$\bar{\lambda}_{f,CS,n}^{flex} = \frac{Mkt_{f,CS,n}^{FSP,flex}}{\sum_{d:\forall d \in \mathcal{D}_f} \sum_{h} E_{d,h,n}^{flex}} \qquad \forall f \in \mathcal{F} \tag{4-32}$$

  where:
  - $E_{d,h,n}^{flex}$ is the energy transacted per each flexible resource (d) per hour (h) in the year n.
  - $\lambda_{d,h,n}^{flex}$ is the hourly bid price of each flexible resource (d) per hour (h) in the year n.
  - $\bar{\lambda}_{f,CS,n}^{flex}$ is the weighted annual bid price of a FSP f per CS in the year n.

- **MO platform costs** ($C_{f,CS,n}^{MO,FSP}$) are associated to the MO platform costs (comprising TMO, DMO and CMO platforms accordingly). It is assumed that MO charges a fee for participating in flexibility markets to aggregators and other FSPs, which is used to pay for i.e. the OPEX of MO platform(s), in a similar way as the Spanish NEMO does (CNMC, 2021), while the rest of the costs are socialized through system costs.
- **Annual FSP capital expenditures** ($Capex_{f,n}^{FSP}$) are associated to the SW development and ICT costs to reach an effective interaction and communication with the MO platform, TSO and/or DSO, and DERs. This CAPEX is only considered for FSP-ag@D, who operates DERs at distribution level, because it is assumed that other FSPs with their own flexibility resources (FSP@T, FSP@D,) already provide e.g., balancing services and, hence, do not face capital expenditures in this solution.

- **Annual DER capital expenditures** ($Capex_{f,d,n}^{HW}$) is associated to the HW equipment needed by DERs to reach an effective interaction and communication with FSP-ag@D. Specially, this capital cost is only incurred by new DERs at distribution level which start their participation in flexibility services. In the case of aggregators, it is assumed that the costs of local controllers installed at the premises of DERs (i.e., energy box, (Ivanova et al., 2021)) and of the ICT to control them are born by aggregators in order to facilitate DER engagement.
- **Annual FSP operational expenses** ($Opex_{f,n}^{FSP}$) are associated to the additional O&M, HW, and ICT costs (i.e., to interact with the flexible resources to receive their flexibility availability, system status and real-time measurement, to send these real-time measurement to the TSO and DSO, to interact with the MO platform to send flexibility bids and receive market clearing results, to receive and send real-time setpoints and financial settlements to the resources, etc.) and SW maintenance costs.
- **Financial DER remuneration** ($Rem_{f,CS,n}^{FSP}$) based on (bilateral) contractual agreement, paid by the aggregator FSP-ag@D to the DERs. This remuneration could be based on a fixed monthly amount, price-index contract and/or include performance penalties (although it is preferable not to use them in initial stages, in order to facilitate DER engagement). For simplicity, a fixed percentage (%) may be applied to the FSP market incomes ($Mkt_{f,CS,n}^{FSP,flex}$).
- **"Transfer of energy" compensations** ($BRP_{f,CS,n}^{FSP}$) are defined to compensate economically the effects of the activation of flexibility that FSPs make, when these actions (via an independent aggregator FSP-ag@D) imply an imbalance charge for the suppliers of participating customers or BRPs [Article 17, (European Commission, 2019a)]. An FSP-ag@D (on behalf of final customers and other flexible resources in flexibility markets) may be obliged to pay financial compensation to the market participants' BRPs, if those market participants are directly affected by their flexibility activation (as discussed in section 2.2). At early stage of flexibility deployment, such financial compensation shall not create a barrier to market entry for market participants engaged in aggregation. Thus, the following assumptions are included:
    - For FSP-ag@D, they could be exempted from this compensation, that is, being initially socialized through system costs in early stages of the deployment of flexibility markets when there are low volumes of flexibility and the business model for them is uncertain or risky.
    - FSP@T and FSP@D should be responsible for the energy imbalances they cause to energy suppliers and BRPs, and thus, should pay the associated economic compensations.
- When flexibility is provided by demand side or storage units, flexibility actions are expected to create some **rebound effect** ($Retail_{f,CS,n}^{FSP}$), in which the aggregator and the FSPs, or their retailer, should reschedule the load profile or take other energy time-shift actions. This may imply some extra costs, as the hours to which the energy is shifted may have less attractive market prices (e.g., if generation and consumption profiles had been optimized for the participation in the day-ahead market) than the previous ones. These rebound effects are difficult to estimate without an exhaustive simulation, so the energy shift will be charged at intraday market prices.

4.4.1.2 Distributed Energy Resources for joint TSO and DSO needs

A DER is a kind of flexible resource connected at distribution level, which encompasses the multiple types of end-users connected to the distribution grid, able to provide energy and/or services to the grid by mobilizing their flexibility (Lind and Chaves, 2019).

DERs are remunerated by the FSP-ag@D for their flexibility provision and performance, but they could face several costs. In general, the following eq. (4-33) must be satisfied for each DER *d* so that they are properly incentivized to provide flexibility:

$$Rem_{d,CS,n}^{DER} > Disc_{d,n}^{DER} \quad \forall d \in \mathcal{D}_f, \forall f \in \mathcal{F}^{ag} \tag{4-33}$$

- **Financial DER remuneration** ($Rem_{d,CS,n}^{DER}$) based on (bilateral) contractual agreement, paid by the aggregator to each DER. This remuneration could be based on a fixed monthly amount, price-index contract and/or include performance penalties. For simplicity, a fixed percentage ($\mu_{f,n}^{rem}$) is applied to the market incomes ($Mkt_{f,CS,n}^{FSP,flex}$) of the FSP-ag@D, as presented in eq. (4-34).

$$Rem_{f,CS,n}^{DER} = \mu_{f,n}^{rem} \cdot Mkt_{f,CS,n}^{FSP,flex} = pct^{rem} \cdot \sum\nolimits_{d:\forall d \in \mathcal{D}_f} \sum\nolimits_{h} \lambda_{d,h,n}^{flex} \cdot E_{d,h,n}^{flex} \quad \forall d \in \mathcal{D}_f, \forall f \in \mathcal{F}^{ag} \tag{4-34}$$

The weighted price of the FSP is a key indicator to evaluate the cost-efficiency of flexibility solution according to the CS implemented and the bid price of the flexibility resources behind this FSP. As can be observed, the weighted annual bid price for the FSP-ag@D is calculated in eq. (4-35).

$$\bar{\lambda}_{f,CS,n}^{flex} = \frac{Mkt_{f,CS,n}^{FSP,flex}}{\sum_{d:\forall d \in \mathcal{D}_f} \sum_h E_{d,h,n}^{flex}} \quad \forall d \in \mathcal{D}_f, \forall f \in \mathcal{F}^{ag} \tag{4-35}$$

where:

- $E_{d,h,n}^{flex}$ is the energy transacted per each flexible resource (d) per hour (h) in the year *n*.
- $\lambda_{d,h,n}^{flex}$ is the hourly bid price of each flexible resource (d) per hour (h) in the year *n*.
- $\bar{\lambda}_{f,\text{CS},n}^{flex}$ is the weighted annual bid price of a FSP f per CS in the year *n*.
- $Mkt_{f,CS,n}^{FSP,flex}$ corresponds to the flexibility market incomes per FSP f and CS in the year *n*.
- The subset $\mathcal{D}_f$ comprises all flexible resources or DER of a FSP f.
- The subset $\mathcal{F}^{ag}$ comprises the FSPs which are energy aggregators.

- **Discomfort cost** ($Disc_{d,n}^{DER}$) defines the minimum revenue at which the DERs are willing to provide flexibility. The discomfort costs lead the users to accept bilateral contracts that allow the FSP to manage and trade flexibility (Khan, 2018), by managing users' renewable resources or shifting flexible loads. Generally, this discomfort cost is designed as a variable cost curve with time preference ranges to provide, shift or reduce the flexibility (Charoen et al., 2019). This modelling approach is out of the scope of D6.3, so the discomfort cost is evaluated by a minimum average price ($\bar{\lambda}_{d,n}^{disc}$) multiplied by the energy transacted per DER.

$$Disc_{d,n}^{DER} = \bar{\lambda}_{d,n}^{disc} \cdot \sum\nolimits_i \sum\nolimits_h E_{d,h,n}^{flex} = \cdot \sum\nolimits_i \sum\nolimits_h \lambda_{d,h,n}^{disc} \cdot E_{d,h,n}^{flex} \tag{4-36}$$

4.4.2 Overview of the methodology for local needs

Pillar 3.b evaluates the profitability of the provision of flexibility services by FSPs and small DERs in the local markets that have been described in subsection 4.2.2.

Non-regulated agents, such as aggregators and other FSPs, will only participate in flexibility markets if they can see an attractive business model for providing services. That is, the remuneration that they receive for participating in those markets must be higher than the cost of providing them. For the participation in local markets, DERs installed at distribution level usually need to participate in flexibility markets via aggregation. That said, DERs (the ones participating at demo sites) are supposed to participate via an energy aggregator in flexibility markets and obtain a remuneration via a bilateral contract with the FSP-ag@D.

The aggregator FSP-ag@D receives market incomes by the provision of local flexibility services in the local market, but they must deal with additional costs associated to this business activity.

In order to be able to use flexibility-based solutions locally, DSOs must develop, deploy and integrate several ICT-based platforms. Such platforms require massive investments, but they are easily scalable and replicable. In fact, their implementation does not only solve one specific issue in the system but can be used to solve many issues in many different locations. However, the FSP-ag@D could face a flexibility market fee to access the market, and other market cost related to the activation of flexibility, as shown in Figure 15. The market income obtained by the FSPs will vary depending on the pricing scheme and other criteria.

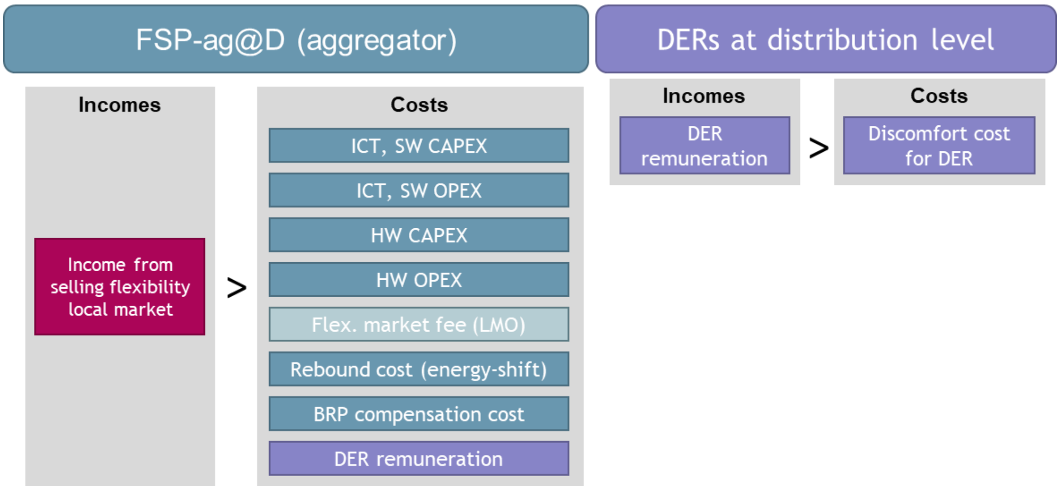

Figure 15: Incomes and costs for non-regulated actors in local markets (Pillar 3.b)

4.4.2.1 Flexibility Service Providers for local needs

FSP-ag@Ds participate in the local flexibility markets on behalf of the small flexible resources they represent (DERs), receiving flexibility market incomes, but they face multiple costs associated to this business activity. Eq. (4-37) must be satisfied in order for FSP-ag@D to have a positive business case:

$$Mkt_{f,n}^{FSP,flex} > \begin{pmatrix} C_{f,n}^{MO,FSP} + Capex_{f,n}^{FSP} + \sum_d Capex_{f,d,n}^{HW} + Opex_{f,n}^{FSP} \\ + Rem_{f,n}^{FSP} + BRP_{n,f}^{FSP} + Retail_{f,n}^{FSP} \end{pmatrix} \quad \forall f \in \mathcal{F}^{ag}, \forall d \in \mathcal{D}_f, \forall n \in \mathcal{N}^i \qquad (4\text{-}37)$$

where:

- $Mkt_{f,n}^{FSP,flex}$ corresponds to the flexibility market incomes per FSP *f* in the year *n*. In this case, these market incomes are the remuneration received by each FSP for the procurement (activation) of system services they provide in the year n in the local market.
- $C_{f,CS,n}^{MO,FSP}$ corresponds to the MO platform costs paid per FSP *f* in the year *n*.
- $Capex_{f,d,n}^{SW}$ corresponds to the SW and ICT capital expenditures per FSP *f* in the year *n*, related to the required aggregation platform for the participation in local markets.
- $Capex_{f,d,n}^{HW}$ corresponds to the HW capital expenditures per FSP *f* in the year *n*, related to the required investment needed in each distributed energy resource *d*.
- $Opex_{f,n}^{FSP}$ corresponds to the FSP operational expenses per FSP *f* in the year *n*.
- $Rem_{f,n}^{FSP}$ corresponds to the financial DER remuneration per FSP *f* in the year *n*.
- $BRP_{f,n}^{FSP}$ corresponds to the BRP compensations per FSP *f* in the year n (which may be socialized).
- $Retail_{f,n}^{FSP}$ corresponds to the rebound effect cost per FSP *f* in the year *n*.

- The subscript i corresponds to each considered asset.
- The subscript d indicates each flexible resource or DER behind a FSP f.
- The subset $\mathcal{D}_f$ comprises all flexible resources or DER of a FSP f.
- The subscript f indicates the considered FSP (in this case the FSP-ag@D).
- The subset $\mathcal{F}^{ag}$ comprises FSPs which are energy aggregators (FSP-ag@D).
- The subscript n corresponds to each year.
- The subset $\mathcal{N}^i$ comprises the lifetime of the ICT, SW asset i.

A detailed description of the components included here can be seen in subsubsection 4.4.1.1.

4.4.2.2 Distributed Energy Resources for local needs

The DERs are remunerated by the FSP-ag@D for the flexibility they provide and their performance in local markets, but they face several costs.

$$Rem_{d,n}^{DER} > Disc_{d,n}^{DER} \quad \forall d \in \mathcal{D}_f, \forall f \in \mathcal{F}^{ag} \tag{4-38}$$

- **Financial DER remuneration** ($Rem_{d,n}^{DER}$) is based on a (bilateral) contractual agreement, paid by the aggregator to the DERs. This remuneration is based on the energy transacted ($E_{d,h,n}^{flex}$) per each flexible resource *d*, which depends on the flexibility available per resource (size, technology, etc.). DERs are assumed to have different flexibility capacities, which can solve local CM needs partially or totally.
- **Discomfort cost** ($Disc_{d,n}^{DER}$) defines the minimum revenue at which the DERs are willing to provide flexibility. It is modelled by a minimum average price ($\bar{\lambda}_{d,n}^{disc}$).

A detailed description of the remuneration and costs of DERs can be seen in subsubsection 4.4.1.2.

5 Economic assessment for Spain

5.1 Brief demo description

The renewable generation units considered in the demonstrator are connected at e-distribución's, i-DE's (the two Spanish DSOs involved in CoordiNet) and REE's (the Spanish TSO) networks, at all voltage levels. There are some small photovoltaic (PV) plants and medium-sized CHP and biogas-fired plants in Málaga, while big power plants (mostly wind, although there are also PV and hydro plants) are present in Cádiz and Albacete. In addition, demand-side resources considered are connected at LV and MV networks from e-distribución (in Málaga) and i-DE (in Alicante and Murcia).

Regarding the platforms developed in the Spanish demonstrator, the TSO has performed several adaptations to the existing market platforms in order to incorporate the new resources, products, etc. In addition, the CoordiNet Platform was developed, including one system on the TSO side (the common platform), and other systems on the distribution side (the local platforms). The local platforms were established to handle, on the one hand, local CM needs by e-distribución and i-DE and, on the other, to procure controlled islanding by i-DE. Due to the different needs of e-distribución and i-DE, the outcome has been two separate local platforms, one developed by each DSO. Both platforms communicate with the common platform, owned by the TSO (Ivanova et al., 2021). As it was already detailed in section 2.3, it must be noted that these developments are the ones needed to launch a pilot demonstrator and, thus, they are not based on the real implementation and do not include the necessary arrangements to provide an industrialized solution, nor the functionalities for integrating them into existing ICT systems of the different agents.

Figure 16 shows the main information regarding the Spanish demonstrator: services, products and CSs tested, as well as the available FSPs, locations and the DSO involved in each demo site.

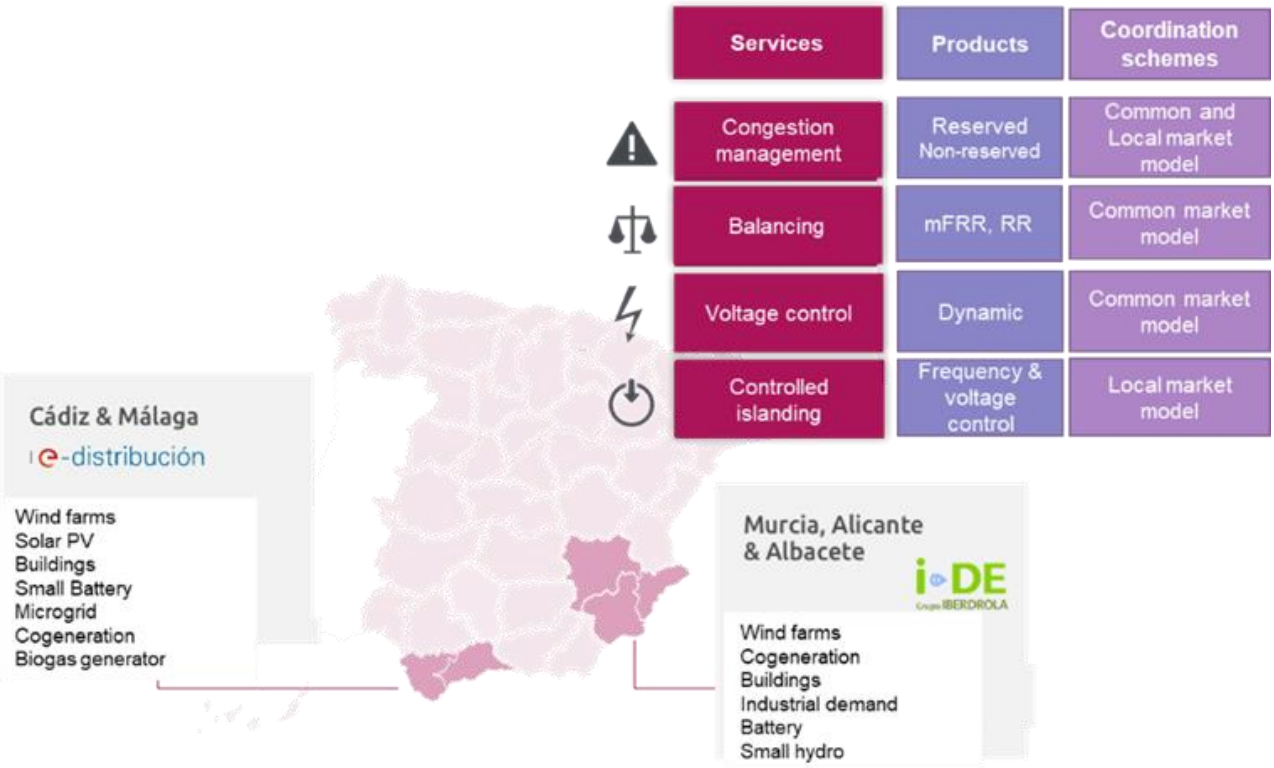

Figure 16: Spanish demonstrator (Ivanova et al., 2021)

In the Spanish demonstrator, two demonstration campaigns were planned:

- **Demo-run 1,** which focused on BUC-ES1a (common CM) in Cádiz, Albacete, Alicante and Murcia, BUC-ES2 (balancing) in Cádiz, Albacete and Alicante, and BUC-ES4 (controlled islanding) in Murcia.
- **Demo-run 2**, which tested BUC-ES1a (common CM) in Málaga, BUC-ES1b (local CM) in Málaga and Murcia, and BUC-ES3 (voltage control) in Cádiz, Albacete, Alicante, and Murcia.

5.2 Analysis of costs for the demonstrator and their scalability

5.2.1 CAPEX

The information regarding the incurred costs by the Spanish demonstrator is provided in D3.4 (Ivanova et al., 2021) for demo run 1 and in D3.6 (Ivanova et al., 2022) for demo run 2. However, although some of the data were provided after demo run 1, while some other ones after demo run 2, once a cost was calculated, the value was not modified afterwards. Therefore, once the ICT solutions were integrated into the demonstrations, no further capital expenditures were required. Moreover, the information was provided with different level of detail by each partner taking part in the demonstrator (e.g., some partners indicate values for each BUC individually while others only indicate a unique value gathering all the incurred costs). These costs are analysed in (Trakas et al., 2022), specifically as KPI 20-ICT costs. The main outcomes of such analysis for the Spanish demonstrator are summarized below.

The incurred costs indicated by the TSO and DSOs participating in the Spanish demonstrator in order to test the BUCs described in section 5.1. are:

- The Spanish TSO, Red Eléctrica de España, performed several adaptations on the already existing platform in order to incorporate the DSO limitations in the balancing process and to modify the CM process from the current centralized approach to the common one. These modifications and updates are valued at 12 694 € (Ivanova et al., 2021). In addition, the TSO specified a cost, of about 100 000 €, for the development of the voltage control platform (Ivanova et al., 2022).
- e-distribución has valued the modifications and developments necessary by the DSO to test all the evaluated BUCs at 181660 €.
- In the case of i-DE, the estimation for the DSO reaches 265 000 €. It must be noted that i-DE was the only DSO testing BUC ES-4, but the specific cost incurred to test the controlled islanding service was not provided.

In addition, other costs were also justified by other partners participating in the demonstrator (e.g., developments of the aggregation and local market platforms). Thus, these additional costs indicated in (Ivanova et al., 2022) are 320 000 € for the development of the aggregation platform and 160 000 € for the development of the local market platform.

Based on these data and taking into account the specific analysis developed in this deliverable, mainly focused on CM in common, multi-level and local markets, several assumptions were necessary when calculating the individually incurred cost by each agent for its participation in a specific market. Table 16 shows the costs which are considered in the calculations and the assumptions are explained below.

Table 16: CAPEX considered in the Spanish demonstrator

Agent	Common (€)	Multi-level (€)	Local (€)
TSO (1)	9 000	9 000	4 000
DSO (2)	250 000	250 000	180 000
MO (3)	100 000	200 000	100 000
FSP (Aggregator) (4)	250 000	242 000	80 000
DER (5)	300	300	300

(1) The Spanish TSO, Red Eléctrica de España, indicated a cost of 8 847 € in (Ivanova et al., 2021) for the required adaptations on the already existing platform in order to modify the CM process from the current centralised approach to the common one. Therefore, it has been considered that 9 000 € would be the cost for the TSO in the common market model, and also in the multi-level approach, since the modifications to be integrated would be very similar. The TSO also specified in (Ivanova et al., 2021) a cost of 3 847 € for the adaptations on its already existing platform in order to incorporate the DSO limitations in the balancing process. In this case, it has been assumed that the modification for the development of the local market platform should be very similar, so 4 000 € has been the cost assigned to the TSO for the local approach.

(2) Both DSOs, i-DE and e-distribución, have indicated a cost for the development of their own platforms in CoordiNet demonstrator ((Ivanova et al., 2021) and (Ivanova et al., 2022)). However, as it was explained in section 2.3, the CoordiNet project has not tested all the necessary functionalities to fully implement flexibility at the DSO (see Table 3 which presents the functionalities that a DSO platform would require and whether those functionalities have been developed or not within CoordiNet). Therefore, and on the basis of the values specified by both DSOs (i.e., 181 660 € by e-distribución and 265 000 € by i-DE), a cost of 250 000 € has been assigned to the DSO for the participation in the common and multi-level markets, while a lower value of 180 000 € is assigned for the local market case, to account for the highest and lowest figures provided by DSOs.

(3) When calculating the costs to be assigned to the MO, the cost justified by Red Eléctrica de España for the development of the platform for the voltage control service (i.e., 100 000 €) was considered as starting point, since the developments by the MO in the common and local markets may be expected to be rather similar. In the case of the multi-level approach, the MO should run two different markets, so the assigned cost in this case is 200 000 €. It is assumed that the market platform to solve DSO needs in the multi-level market model could be the same as for the local market.

(4) The costs incurred by the aggregator for the development of the aggregation platform is valued at 320 000 € in (Ivanova et al., 2022). Based on that value, it has been estimated that the required developments for the deployment of just one BUC, the common or multi-level CM, would cost 240 000 €. The cost when including the local market is valued at 80 000 €. In addition, in the common market in Spain, a duplicated (for security reasons), dedicated communication line is mandatory between the TSO and every FSP for the communication, being that communication line valued at 10 000 €. In the case of the multi-level market, it is assumed that the DSO can manage the communication with the TSO, for which a Remote Terminal Unit (RTU) with the DSO is required, whose cost is estimated at 2 000 €.

(5) The cost to be allocated to the DERs participating in the different markets is based on the cost of the energy box. A standard cost of 300 € per energy box has been considered.

5.2.2 OPEX

The OPEX include the recurrent costs that are required in order to operate and maintain the installed equipment. As in the CAPEX case, based on the values provided in (Ivanova et al., 2021) and (Ivanova et al., 2022), several assumptions were necessary in order to identify the OPEX to be applied to the agents participating in the approaches considered.

Table 17 shows such values and a brief explanation of the key assumptions is provided next.

Table 17: OPEX considered in the Spanish demonstrator

Agent	Common (€/year)	Multi-level (€/year)	Local (€/year)
TSO (1)	0	0	0
DSO (2)	36 000	36 000	15 000
MO (3)	20 000	40 000	20 000
FSP (Aggregator) (4)	72 000	50 400	16 000
DER (5)	12 000	600	600

1) The Spanish TSO considers that there are no additional recurrent costs to operate the new services, apart from the costs which are already assumed for the normal operation of its equipment and systems.

(2) The DSOs provided the information regarding the OPEX with different level of detail: e-distribución assumed that the recurrent costs related to the BUC ES-1a (common CM) and the ES-2 (balancing) are 28 650 €/year, while i-DE performs the estimation based on the number of activations and its duration and provided a cost of 42 880 €/year for the common CM market. In view of both values, an intermediate value, 36 000 €/year, is considered as the OPEX to be applied to the DSOs both in the common and multi-level approaches. For the local market, 15 000 €/year are considered, since this value is indicated by i-DE in (Ivanova et al., 2022) as individual OPEX for the CM local market.

(3) The OPEX of the MO is assumed to be 20% of the indicated CAPEX. This percentage is based on previous literature, in which a range from 10% to 20% is defined as the most appropriate value (e.g., (Gómez et al., 2019)).

(4) The OPEX for the maintenance of the SW is also 20% of its CAPEX in the common and multi-level approaches (i.e., 48 000 €/year). In addition, the maintenance cost for communication must be added. Therefore, 2 000 €/month is considered for the communication in the common CM market, while 200 €/month expected cost in a multi-level approach (as detailed in subsection 5.2.1, it is assumed that the DSO can manage the communication with the TSO, so the OPEX are expected to be lower) and no additional communication cost would be necessary for the local market. As result, 72 000 €/year is the total OPEX for the common CM market, and 50 400 €/year and 16 000 €/year for the multi-level and local market approaches respectively.

(5) The only OPEX to be considered for the DER is the cost of the required communication. The common CM market involves a specific point to point line, valued at 1 000 €/month (i.e., 12 000 €/year). For the participation in the multi-level and local markets, only an ethernet line sending the information every 4 seconds would be necessary. The cost of this ethernet line is 50 €/month (i.e., 600 €/year).

5.3 Case study: Joint TSO and DSO needs

5.3.1 Simulation scenario for joint TSO and DSO needs

This case study evaluates the cost-efficiency of the flexibility solutions to solve CM needs in transmission and distribution networks, i.e., joint TSO and DSO needs. For that purpose, the experience of the demonstrators in Albacete and Cádiz is taken as a basis.

5.3.1.1 Challenges in Albacete and Cádiz

The Spanish replication scenario (Cossent et al., 2022) is selected to assess the economic viability of the flexibility solution for different coordination schemes, in which the FSPs at distribution level are able to provide balancing and CM services (BUCs ES-1a and ES-2). That is, flexibility for balancing and CM services is considered to be connected at transmission and distribution (T&D) HV grids in D6.4 (Cossent et al., 2022).

However, the economic assessment for joint TSO and DSO needs in this deliverable D6.3 is focused on the evaluation of the economic implication of the implemented CS for the procurement of CM service (as balancing service is already procured through a pan-European market) for the involved market agents (Pillar 1.a & Pillar 3.a) in the Spanish demonstration campaigns. Additionally, the cost-efficiency of the TSO-DSO coordination schemes to solve joint TSO and DSO CM needs is compared and evaluated (Pillar 2).

In Spain, the DSOs do not have the need to procure flexibility nowadays and, hence, they do face real needs (no overloads in distribution grids which cannot be tackled through normal system operations). However, potential congestions are simulated in D6.4 (Cossent et al., 2022), in order to assess the cost-efficiency of the flexibility solution in future, constrained grids. Figure 17 and Figure 18 illustrate the congestions at distribution level, which are described below:

- **Albacete**: A congestion is simulated in the grid line from Morrablancar wind park to Higueruela substation. This is a 132 kV double-circuit line, with 10 km of longitude. The congestion simulated is an overloading of approximately 20%, during a few hours of the peak representative day.
- **Cádiz**: The congestion simulated is an overloading of approximately 20% of a 220/66 kV transformer in the substation of Pinar del Rey, during a few hours of the peak representative day.

Figure 17: Albacete overloaded grid line

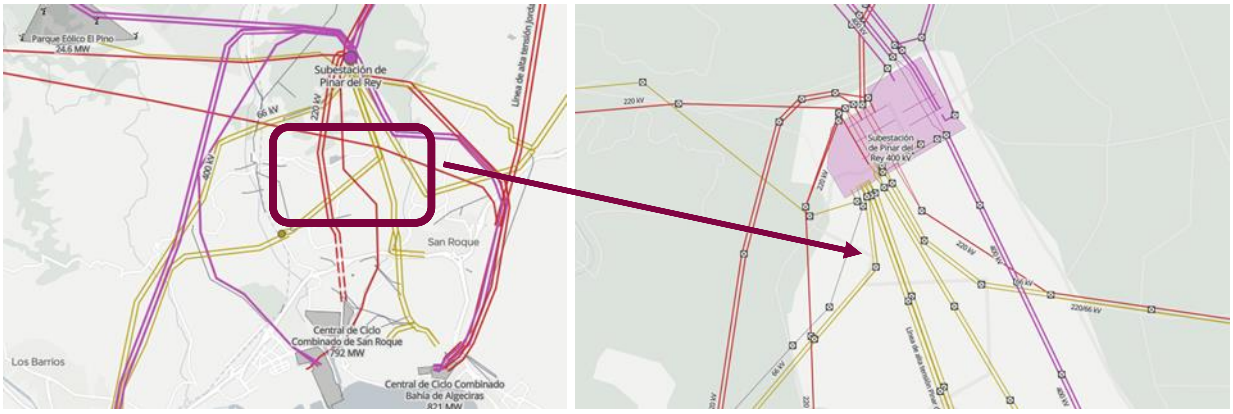

Figure 18: Cádiz undersized substation (220/66 kV transformer)

The flexible resources considered in the economic analysis are listed in Table 18 (adapted from (Cossent et al., 2022)). Balancing and CM needs at T&D HV grids are simulated at system level. Under these assumptions, the existing DERs in the demo, which are mainly RES-based, do not have enough flexibility to solve the problem at all times (as RES can provide limited upward activation, i.e., 5% of the energy the traded in day-ahead, as shown in Table 18, in comparison to the 100% that they can provide for downward activation). This situation can be considered to be a non-supplied flexibility state. In that context, the replication scenario described in D6.4 (Cossent et al., 2022) considers not only the real FSPs at transmission and distribution level, but also some additional FSPs at distribution level (mainly demand and storage) in both Cádiz and Albacete networks.The characterisation of these additional FSPs has been taken from the Swedish demonstrator (marked with “(SE)” in Table 18). Based on observations from the Swedish demonstrator, their capacities to offer upward and downward flexibility have been determined, and the offered bid prices, which are the same in both directions, have been calculated, as shown in Table 18.

Table 18: FSPs considered in the Spanish scenario for joint TSO and DSO needs

FSP ID	Network acronym	Network	Installed capacity (MW)	Downward capacity	Upward Capacity	Bid (€/MWh)	Technology
WindALB1	D11	Albacete 1	38	100% DA	5% DA	1.00	Wind
WindALB2	D11	Albacete 1	49.5	100% DA	5% DA	1.00	Wind
WindALB3	D11	Albacete 1	13.2	100% DA	5% DA	0.99	Wind
WindALB4	D11	Albacete 1	37	100% DA	5% DA	1.02	Wind
WindALB5	D11	Albacete 1	23	100% DA	5% DA	1.02	Wind
WindALB6	D11	Albacete 1	24	100% DA	5% DA	0.98	Wind
Cogen1	D11	Albacete 1	10	2 MW	2 MW	39.90	CHP
fsp4	D11	Albacete 1	-	0	0.5 MW	12	(SE) Hospital
fsp6	D11	Albacete 1	-	0	0.5 MW	16	(SE) Multi-family house
WindALB16	D12	Albacete 2	49.5	100% DA	5% DA	0.99	Wind
WindALB17	D12	Albacete 2	45.5	100% DA	5% DA	1.01	Wind
SolarCAD1	D21	Cádiz 1	12.3	100% DA	0% DA	1.00	Solar

FSP ID	Network acronym	Network	Installed capacity (MW)	Downward capacity	Upward Capacity	Bid (€/MWh)	Technology
WindCAD3	D21	Cádiz 1	42	100% DA	5% DA	1.01	Wind
WindCAD4	D21	Cádiz 1	6	100% DA	5% DA	1.02	Wind
fsp1	D21	Cádiz 1	-	5 MW	5 MW	8	(SE) Battery
fsp2	D21	Cádiz 1	-	0	0.5 MW	10	(SE) Office buildings
fsp3	D21	Cádiz 1	-	0	0.5 MW	16	(SE) Multi-family house
fsp5	D21	Cádiz 1	-	5 MW	30 MW	20	(SE) District heating
fsp7	D21	Cádiz 1	-	0.5 MW	1 MW	16	(SE) Industry
fsp11	D21	Cádiz 1	-	n/a	n/a	8	(SE) Battery
WindCAD2	D22	Cádiz 2	32	100% DA	5% DA	0.98	Wind
WindCAD1	D22	Cádiz 2	10.68	100% DA	5% DA	1.01	Wind
fsp8	D22	Cádiz 2	-	0.5 MW	1 MW	16	(SE) Industry

(*) "%DA" means the share of day-ahead energy that can be provided as flexibility

5.3.1.2 Services needs and network modelling

Regarding network models, a simplified 11-node transmission grid is modelled, together with the sub-transmission grids of the demos. For the Cádiz region (66 kV), the general parameters for the DSO grids were provided by the DSOs. For the Albacete region (132 kV), a representative grid was constructed based on available data for the 132 kV network, published by the Spanish TSO.

For the overall wholesale market parameters, including the modelling of the different representative days that lead to the whole-year results provided, data from multiple sources are used. The goal is to have a well calibrated wholesale energy model that will serve as the basis for the different CSs. In Spain, a demand of 240 TWh is considered for the wholesale market and around 3.5 TWh for balancing needs (Cossent et al., 2022).

In contrast, as presented in D6.4 (Cossent et al., 2022), congestions are not an input data. In fact, the congestions appear when the power flow is performed after the wholesale market. Therefore, the size of the transmission grid was calibrated so that the congestions produced would match the transmission congestions needs (2.5 TWh) observed in Spain in 2020, specifically at transmission level (Table 19). Additionally, the congestions in Albacete and Cádiz networks are created as described in subsubsection 5.3.1.1 (an overloaded line and substation).

Table 19: Balancing and CM in the Spanish economic assessment (in MWh/year) (Cossent et al., 2022)

Network	Network acronym	Upward Balancing needs	Downward Balancing needs	Congestion Management
Albacete	D11	6 622 97	4 938.99	153 666.09
Albacete	D12	1 392.10	1 039.29	-
Cádiz	D21	11 605.66	8 661.24	10 060.27
Cádiz	D22	629.24	466.35	-
Transmission	T	1 983 632.49	1 478 315.29	2 495 102.86

5.3.1.3 TSO-DSO coordination schemes

Three basic CSs (Common, Central and Multi-level) are modelled in D6.4 (Cossent et al., 2022) for joint TSO and DSO needs, following the general CoordiNet concepts presented in (Delnooz et al., 2019). In Spain, DSOs can use DER to solve congestions in the same way that the TSO does. This process, however, is done through the TSO (Lind and Chaves, 2019). Once congestions in the distribution grid are identified, together with the generation units that have an impact on the congestion, the needs for change in the dispatch are sent from the DSO to the TSO, who accesses the bids and calculates the necessary redispatch to ensure solving the detected constraints (REE, 2022). In contrast, the central CS is considered for Balancing Services.

The general approach for the Common CS is that a single entity (e.g., TSO) runs the service(s) market considering the full grid (T&D), having full observability over the DSO network as well[13]. In this market model, resources at distribution and transmission are automatically shared. This CS demands a simultaneous optimization for the whole system, where the flexibility needs are jointly optimized for the TSO and DSOs.

Additionally, a **"Common Limited" CS** is also designed in (Cossent et al., 2022) to meet the specifications of the Spanish demonstration. Yet, in the Spanish demonstration, the Common CS understanding is slightly different. For both CM (BUC ES-1a) and balancing (BUC ES-2), the "Common Limited" CS means that (1) the TSO runs its service market without the visibility over the distribution grid, (2) sends the market results to the DSO, (3) the DSO checks for possible congestions being created, (4) the DSO sends back eventual limitations on the original FSP bids cleared, and (5) the TSO re-runs the service(s) market. However, this "Common Limited" CS does not give a suitable framework for the joint TSO and DSO needs, as it is assumed no visibility over the distribution grid (and thus, there is no flexibility activation to solve them).

The market design for balancing and CM is modelled as a pay-as-bid auction, in which FSP bid their variable cost (without strategic bidding). This approach could underestimate the flexibility incomes compared to a pay-as-clear market clearing approach in which the FSPs participate in a competitive and strategic manner. This factor will be addressed in the sensitivity analysis.

In the economic assessment for joint TSO and DSO needs, the overall cost at system level covered in the Pillar 2 will be presented for the main representative CSs: the common and multi-level market model.

[13] It is important to have in mind that the simulations in D6.4 (Cossent et al., 2022) do not consider the cost/benefit sharing aspects which are explored in D6.2 (Sanjab et al., 2022), which may be important for the CMM.

5.3.2 Economic impact for regulated agents (joint TSO and DSO needs)

The Spanish flexibility scenario for joint TSO and DSO CM needs is focused on Albacete and Cádiz HV distribution grids, where several grid assets are congested at distribution level (as exposed in subsubsection 5.3.1.1). The FPS@D in distribution networks are allowed to participate in flexibility markets to solve CM needs. In the BaU alternative, the most congested lines/assets (at HV distribution level) are identified and upgraded (increase of capacity).

The comparison of the flexibility use versus a specific grid reinforcement action for the DSOs in both networks will be evaluated specially for the CS implemented at demos, that is, to the CMM (operated by a CMO) which is implemented at the demos (Cádiz and Albacete). The comparison will be carried out considering the flexibility solution as a temporary solution for a given time span (i.e., 5 years).

As discussed in subsubsection 4.2.1.1, once that the consideration of the flexibility markets as a potential means to solve system needs is granted, the cost of their implementation (i.e., CAPEX for the ICT infrastructure and SW platforms to enable new flexibility markets) becomes a sunk cost and, hence, it must not be taken into account when evaluating whether flexibility or grid reinforcement is the best solution for a given system need. The costs involved (OPEX and service procurement) for the comparison of both grid solutions for joint TSO and DSO needs (flexibility versus BaU solution) is evaluated at different time spans, based on the duration of the flexibility commissioning, as depicted in Figure 19. The economic comparison is focused on the costs for the DSO, which is the agent that should take a grid planning decision, either using flexibility or reinforcing the grid.

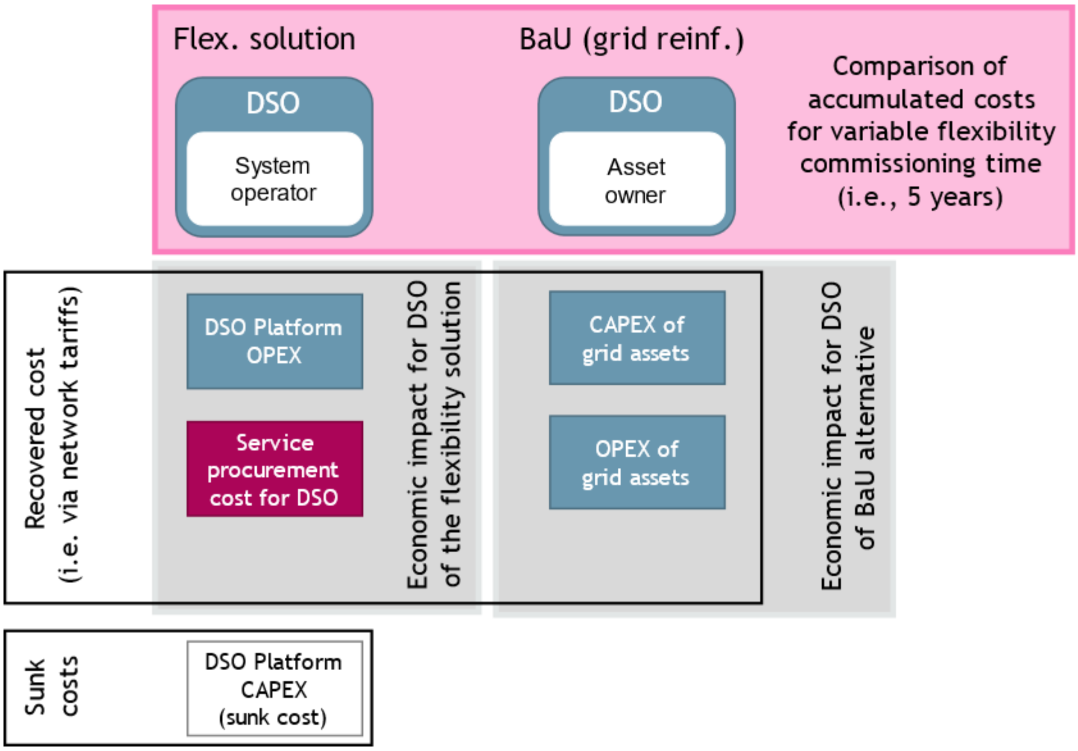

Figure 19: Cost components for the DSO in the flexibility and BaU alternatives for joint TSO and DSO needs in Albacete and Cádiz (Pillar 1.a)

The features and reference costs of the main grid assets to solve joint TSO and DSO CM needs are indicated below. The lifetime of the grid assets is assumed to be 40 years. The reference costs are obtained from (Spanish Government, 2015) and the grid assets are sized based on the CM needs and the features of the distribution networks, D11 and D21 (see subsection 5.3.1). Figure 20 depicts the annuity payment to the

DSOs, which is the regulated remuneration established by the (Spanish Government, 2019a) for the considered grid reinforcement:

- A **132 kV double-circuit line** (TI-4UZ) of 10 km of longitude is considered in Albacete (AL). The reference investment is 336 972 €/km (3 369 720 € in total), and the annual maintenance cost is 3 497 €/km per year, in which a financial rate of return of 5.56% for the CAPEX and a margin of 5% for the OPEX are included.
- A **220/66 kV transformer** (TI-162U) of 30 MVA is considered in the substation of Pinar del Rey in Cádiz (CA), whose reference investment is 12 909 €/MVA (387 270 € in total) and whose annual maintenance cost is 9 682 €/year, in which a financial rate of return of 5.56% for the CAPEX and a margin of 5% for the OPEX are included.

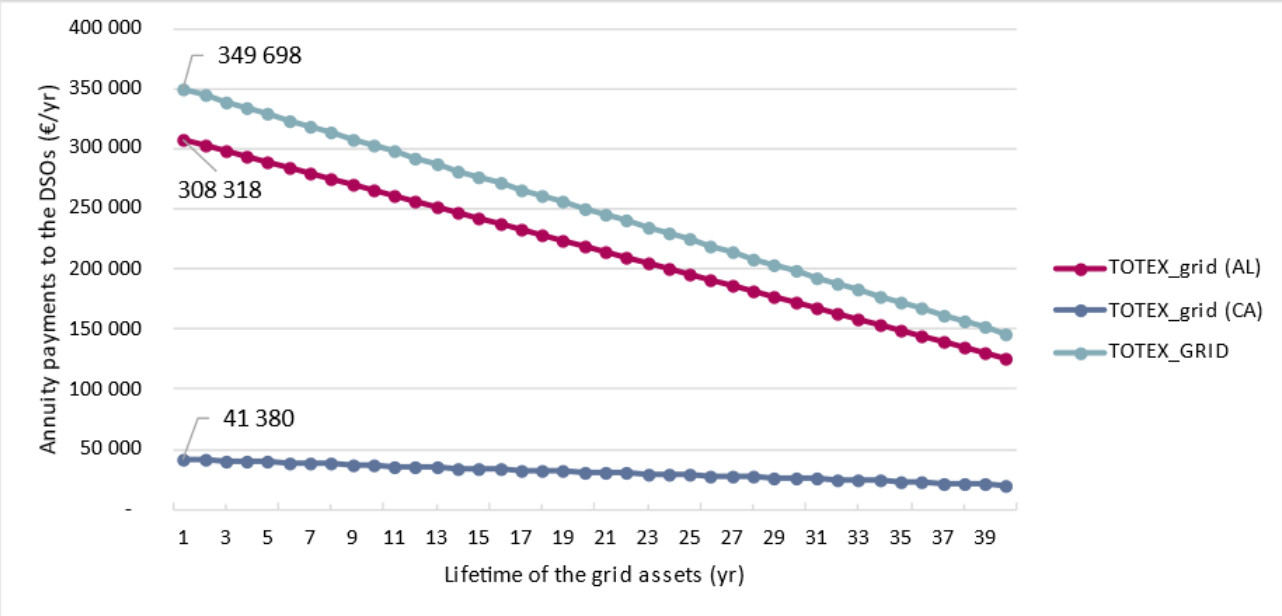

Figure 20: Annuity payment to the DSOs, based on the grid reinforcements in Cádiz and Albacete

On the other hand, the flexibility markets are simulated in D6.4 (Cossent et al., 2022) for covering balancing and CM needs. In order to evaluate specifically the cost-efficiency of the flexibility solutions to solve CM needs in transmission and distribution networks, the provision of flexibility for balancing services is disregarded. The CM needs for the TSO and DSOs are depicted in Table 20, being provided by the FSPs at distribution network in the demonstrator (FSP@D) listed in Table 18, jointly with FSP@T. The CM activations at distribution and transmission level obtained from the market clearing executed in (Cossent et al., 2022) are presented in Table 20.

Table 20: CM for joint TSO and DSO needs in Albacete, Cádiz, and the transmission grid (Cossent et al., 2022)

Network	Network acronym	CM needs (MWh/year)	CM activation in RT (MWh/year)
Albacete	D11	153 666	163 726
Albacete	D12	-	
Cádiz	D21	10 060	
Cádiz	D22	-	
Transmission	T	2 495 103	5 503 094
Total	T&D	2 658 829	5 666 820

Table 21 provides information about the energy activation and cost for CM and balancing needs in Albacete, Cádiz, and the transmission grid, depending on the location of the FSPs which provide each service. The Pillar 1 aims to compare of the flexibility activation of regulated actors versus the Business-as-Usual scenario (grid reinforcements). Particularly, the grid reinforcements need to be done by the DSOs for the Spanish scenario. For this reason, this subsection focuses on the cost comparison for the DSO, who need to procure flexibility (provided by FSP@D with lower bid prices), rather than reinforcing the distribution grid.

The common market model is selected for the Spanish scenario to solve TSO and DSO CM needs, in which the TSO and DSO needs are solved by a single CMO, which may be located on the TSO premises, or be an independent agent. The CM weighted price is 27.93 €/MWh for joint TSO and DSO needs (Cossent et al., 2022), considering the cleared bids from FSP@D and FSP@T, in a pay-as-bid pricing model. As can be observed in Table 21, the CM bid prices from FSP@D (1.48 €/MWh) are lower than the ones from FSP@T (29.13 €/MWh). The CM cost for both system operators is 158.2 M€/year, but, as discussed above, this subsection focuses on the cost for the DSO, whose needs are satisfied by the flexibility provided by FSP@D.

Table 21: Energy activation and cost for joint TSO and DSO needs in Albacete, Cádiz, and the transmission grid divided by FSPs (Cossent et al., 2022)

	FSPs	FSP@D	FSP@T
CM cost (€)	158 262 620	365 186	157 897 435
CM energy activation (MWh)	5 666 820	247 234	5 419 585
CM weighted price (€/MWh)	27.93	1.48	29.13
Balancing cost (€)	11 978 967	456 847	11 522 121
Balancing energy activation (MWh)	3 497 304	242 302	3 255 002
Balancing weighted price (€/MWh)	3.43	1.89	3.54
Weighted price (€/MWh)		1.68	19.53

Therefore, the flexibility solutions oriented to the DSO needs are evaluated as follows:

- **Base case scenario**: The annual CM needs for the DSO are 163 726 MWh/year, which are solved by FSP@D at Albacete and Cádiz demos, whose weighted price is 1.48 €/MWh. This results in a cost of 242.314 €/year for the DSO to solve the congestions at distribution level. As mentioned in D6.4., the price clearing mechanism is modelled as a pay-as-bid approach in which each unit calculates its flexibility bid based on the variable operating cost per technology. However, this flexibility bid price may well result higher in competitive and strategic price clearing mechanisms.
- **Threshold scenario**: From the baseline simulation, whose flexibility cost provided by FSP@D is 1.48 €/MWh, the flexibility cost will be increased to the point in which it is equal to the reinforcement cost along the flexibility procurement period (5 years). With a higher weighted price of 1.85 €/MWh, the distribution congestions of 163 726 MWh can be considered to be structural or too expensive, so as for the DSO to opt for reinforcing the distribution grids in Albacete and Cádiz. As can be observed, the flexibility bid price in the threshold scenario is still relatively low if it is compared to the wholesale or other grid services' prices.

Additionally, the OPEX for the DSOs is estimated in 36 000 €/year, with an OPEX margin of 5%.

Figure 21 depicts the estimated annual costs (in €/year) in stacked bars along the first annuities for the evaluated grid alternatives, i.e., grid reinforcement ('_grid') versus baseline scenario ('_Flex (BC)') and threshold scenario ('_Flex (THR)') for the flexibility solution.

The total expenditures (TOTEX) for both grid reinforcement in Cádiz (CA) and Albacete (AL) reach 349 698 € for the first annuity, while the cost for the base case scenario for the flexibility solution is 280 114 €/year. The values for the base case (at a weighted bid price of 1.48 €/MWh) and for the threshold scenario (at a weighted bid price of 1.84 €/MWh) are provided for the flexibility solution.

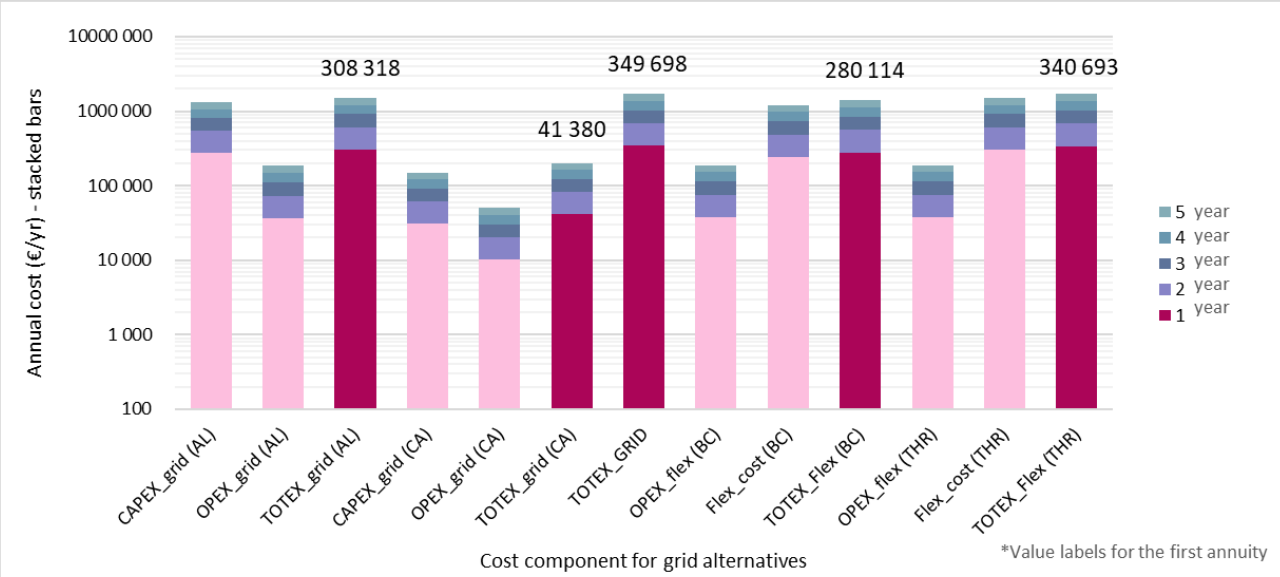

Figure 21: Accumulated annual CAPEX, OPEX and TOTEX (€/year) in Albacete and Cádiz for grid-based and flexibility solutions (base case and threshold scenario)

Figure 22 presents a comparison between the accumulated costs (€/year) within the commissioning time (up to 5 years of flexibility procurement period) for the compared grid alternatives: CAPEX, OPEX and TOTEX in Albacete (AL); CAPEX, OPEX and TOTEX in Cádiz (CA), TOTEX for both grid reinforcements; OPEX, flexibility cost and TOTEX in the base case (BC) flexibility scenario (163 726 MWh/year and 1.48 €/MWh).

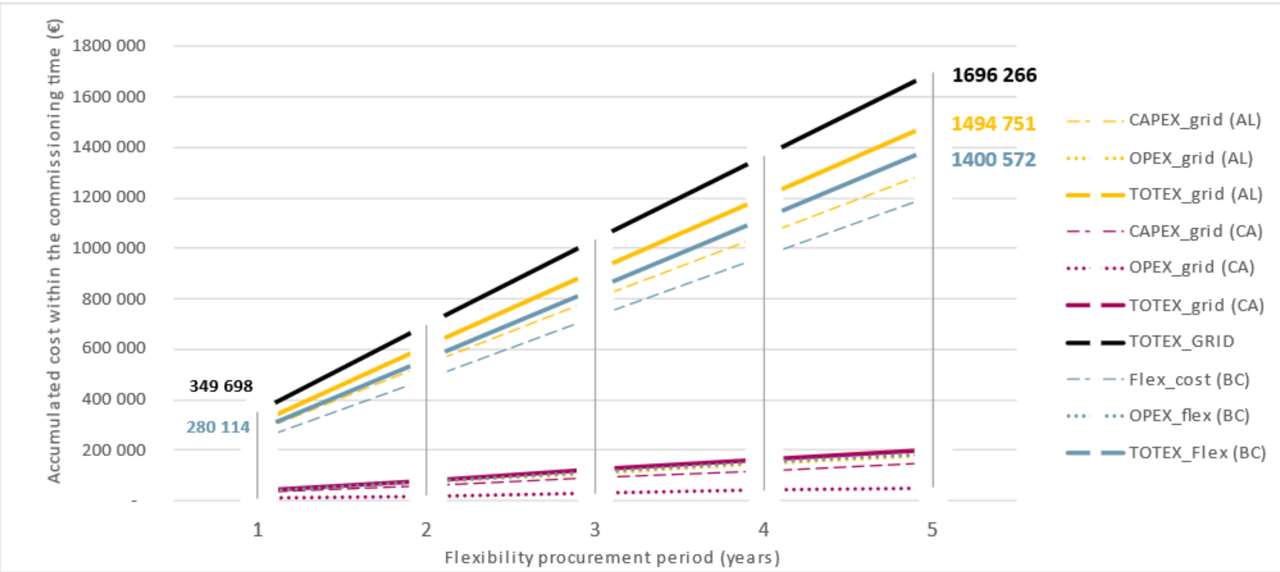

Figure 22: Accumulated CAPEX, OPEX and TOTEX (€/year) in Albacete and Cádiz for the first 5 years for grid-based and flexibility solution

It can be concluded from the simulated scenario for joint TSO and DSO CM needs that the flexibility solution can be a more cost-effective solution than traditional grid reinforcements which a weighted price of

1.48 €/MWh. However, the simulated scenario already has significant flexibility needs (almost 165 GWh/year), which means that it is a structural congestion, so the flexibility price must be quite low. In fact, the flexibility solution, in this case, is more cost-effective than reinforcing the grid while the flexibility price remains below 1.85 €/MWh, as shown in Table 22. For other scenarios with lower flexibility requirements, the weighted average price of flexibility may be higher, as shown in Table 22.

Table 22: Threshold scenarios depending on the level of congestion and the weighted flexibility price

Weighted bid price (€/MWh)	Congestion level (%)	Flex needs (MWh/year)	Flexibility cost (€/year)	Total cost of the flexibility solution (€/year)	Case study
1.48	1.00	163 657.75	241 736.05	279 536.05	Base case
1.85	1.00	163 657.75	302 766.84	340 566.84 (equal to grid reinforcements cost along 5 years: 1 400 572€)	Threshold scenario
3.70	0.50	81 828.88			
7.40	0.25	40 914.44			
18.50	0.10	16 365.78			

5.3.3 Profitability assessment for non-regulated agents (joint TSO and DSO needs)

FSPs (FSP@T, FSP@D, and FSP-ag@D) participate in the flexibility markets to solve joint TSO and DSO needs by offering flexibility of their own facilities or of assets of third parties, receiving the flexibility market incomes. They face multiple costs associated to this business activity, according to Figure 23. The market incomes obtained by the FSPs vary depending on the market clearing process (pay-as-bid, pay-as-clear, etc.).

It is assumed that both FSP@Ts and FSP@Ds, which are owners of their own facilities (big and medium sizes), already have the required infrastructure to provide flexibility services. In contrast, FSP-ag@D should consider both the cost of the aggregation platform and other costs associated to the small or medium DERs they represent, as well as the DER remuneration agreed through a bilateral contract among both parties.

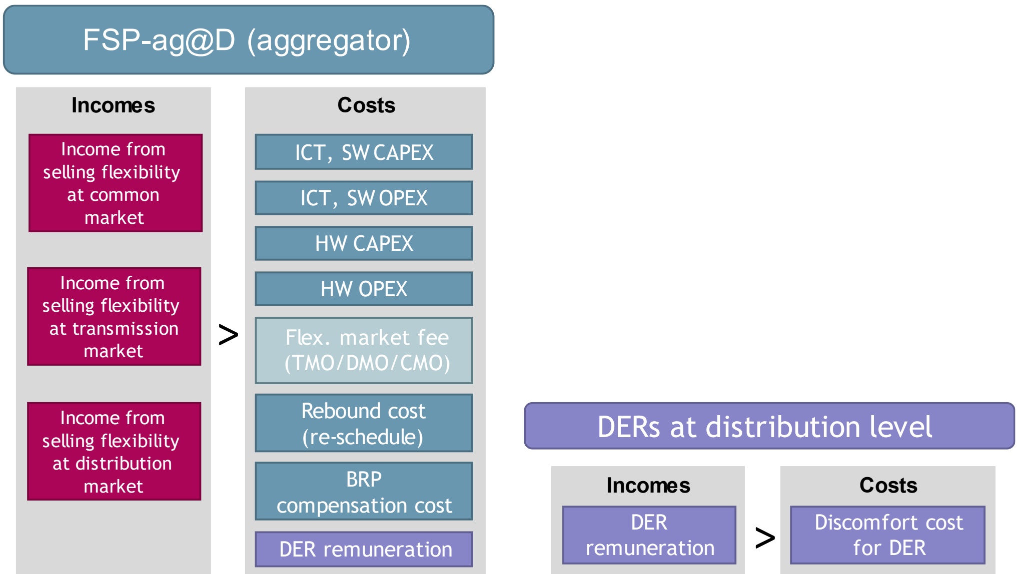

Figure 23: Incomes and costs for non-regulated agents in the flexibility and BaU alternatives when solving joint TSO and DSO needs in Spanish scenarios (Pillar 3)

This subsection focuses on the profitability for the FSP-ag@D, that is, a flexibility service provider which provides flexibility for joint TSO and DSO needs and requires to develop both a SW platform for aggregation of resources and the required ICT to communicate with system and market operator(s).

Table 23 summarizes the economic and technical assumptions, considered for the profitability assessment. For the analysis of FSP-ag@D, the CAPEX and OPEX values are extracted from section 5.2. In Albacete and Cádiz, 23 flexible resources are considered to be controlled by the energy aggregator (see Table 18). The OPEX of the MO platform are partially covered by the FSPs at distribution level, with an energy-indexed fee of 0.03 €/MWh[14] (based on the fee paid to the NEMO in the regulated tariff "voluntary price for the small consumer"). Additionally, the rebound effect is also included, according to which the aggregator and the FSPs (or their retailer) should reschedule the load profile or take other energy time-shift actions. The cost of rebound effect is estimated at 1.75 €/MWh, by considering that only 5% of the energy delivered in the flexibility market should be rescheduled and that the weighted price of the intraday markets[15] by auction in 2020 was 35.02 €/MWh, as mainly renewable assets are participating in flexibility markets (with both upward and downward flexibility). Finally, the BRP compensation is estimated at 0.17 €/MWh[16], referred to the annual average price component for the measured imbalances of reference suppliers in 2020.

Table 23: Economic and technical data of the FSP@D for joint TSO and DSO needs (initial scenario based on Albacete and Cádiz demo)

	Unit	Value	Comment
Flexibility energy provision	MWh/year	247 234	-
Flexibility incomes	€/year	365 185	at 1.48 €/MWh
Annual average CAPEX related to SW platform, ICT…	€/year	25 000	Lifetime = 10 years
Annual average CAPEX HW, DERs (i.e., energy-box)	€/year	690	300 € per FSP
Annual OPEX related to the energy aggregator role	€/year	72 000	
Annual OPEX related to flexible units	€/year	276 000	12 000 € per FSP
Annual MO fee	€/year	7 417	0.03 €/MWh
Rebound effect cost	€/year	432 889	1.75 €/MWh
BRP compensation	€/year	42 029	0.17 €/MWh
Number of FSPs at demonstrator (Albacete & Cádiz)	#	23	-

[14] The market operator fee is extracted from the breakdown of the Spanish regulated tariff "voluntary price for the small consumer", available in https://www.esios.ree.es/en/pvpc?date=01-01-2020
[15] Weighted prices for auction intraday markets in 2020 in the Iberian Market (Spain and Portugal), available in https://www.esios.ree.es/es/analisis/612?vis=1&start_date=01-01-2020T00%3A00&end_date=31-12-2020T23%3A55&compare_start_date=01-01-2019T00%3A00&groupby=year&compare_indicators=613,614,615,616,617,618&geoids=3
[16] The "annual average price of the measured imbalances of referenced suppliers" refers to the average cost resultant from the energy imbalances that the last resort suppliers incur from their schedule and their final profiles. These changes may come from forecast errors, changes in the final demand, but also for the flexibility activation, which result in an extra cost from the BRP's side. Available in https://www.esios.ree.es/en/analysis/955?vis=1&start_date=01-01-2020T00%3A00&end_date=31-12-2020T23%3A55&compare_start_date=01-01-2019T00%3A00&groupby=year

As can be observed, the weighted flexibility price is 1.48 €/MWh (which mostly represent the operating cost of the renewable resources). A strategic bid price will be evaluated versus this initial naïve bid price. Figure 24 depicts a sensitivity analysis of the profitability of FSPs to solve joint TSO and DSO needs in Albacete and Cádiz demonstrators, according to an increase of the number of locations with congestion at distribution level (up to 10 times) and the bid prices (from 1.48 €/MWh up to 50 €/MWh).

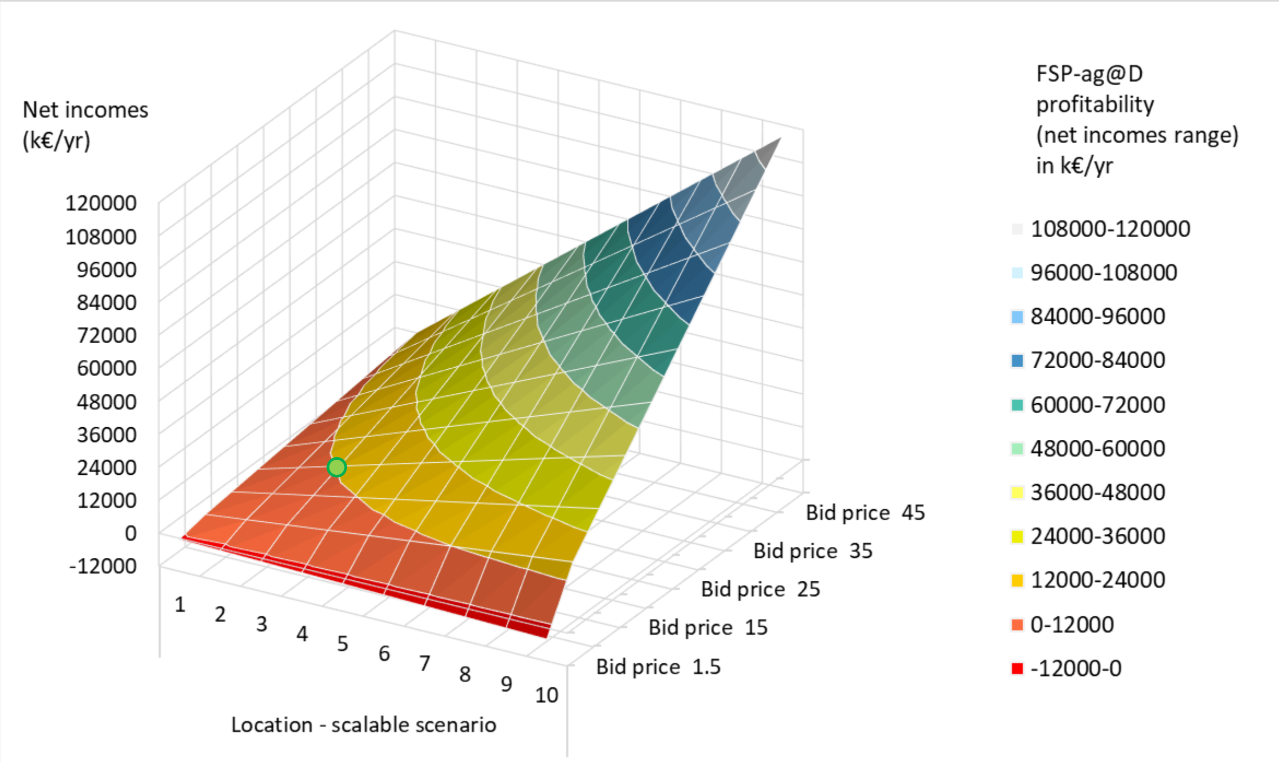

Figure 24: Sensitivity of the profitability of FSPs to solve joint TSO and DSO needs in Albacete and Cádiz demo to the number of locations and bid prices

The profitability for the initial scenario (247 234 MWh/year for joint TSO and DSO needs, based on Albacete and Cádiz demos) is not attractive, especially due to the high rebound cost and high OPEX terms, and the low weighted flexibility bid price based on technology-indexed operating cost (1.48 €/MWh). The assessment becomes positive when the price is 30 €/MWh, and the scenario is scaled by three (3 times the flexibility resources at Albacete and Cádiz, providing 3 x 247 234 = **741 702 MWh/year** of flexibility).

It must be noted that the FSPs may also participate in other electricity markets (such as balancing markets, day-ahead markets, etc.), which are not included in this analysis. This would lead to extra market incomes, while the investment and operational costs for the SW platform or other ICT needed would be common. In fact, the FSPs participating in the Spanish demonstrator may already have developed their SW and communication needs beforehand. They could be considered sunk costs, following the methodology presented in the Pillar 3 for FSP@D profitability (see Figure 23). Additionally, the sensitivity analysis presented in Figure 24 cannot be extrapolated as a generic result for energy aggregators which participate in flexibility needs, as the CAPEX and OPEX terms may vary, the number of DER and their flexibility capacity can differ, as well as the flexibility incomes obtained based on market clearing. Other market costs, such as the rebound cost or BRP compensation might be avoided, according to the specific regulation.

Once the net incomes for the FSP as market player are evaluated (through a sensitivity analysis like the one in Figure 24), the remuneration of DERs must be addressed. In this deliverable, the FSP-ag@D is considered to be an aggregator (either independent or not) which encompasses the multiple types of flexible resources and end-users connected to the distribution grid (e.g., the ones participating at demonstration campaigns). The DERs may be remunerated according to a revenue sharing ration on the flexibility income of the FSP.

Figure 25 presents the economic assessment for the FSP and the remuneration for the DERs, according to different revenue sharing ratio, assuming that the weighted average price of flexibility is 30 €/MWh and that the flexibility need is three times as much the required flexibility in Albacete and Cádiz. For each ratio, the minimum discomfort price perceived by the DER can be calculated (the minimum revenue or price at which the DERs are willing to provide flexibility in return for economic payment). For example, the annual incomes for the FSP are 4 301 k€/year with a revenue sharing of 70%, while the yearly remuneration for all DERs is 15 576 k€/year (at a discomfort price of 21 €/MWh), which is shared among them according to their specific contribution to flexibility activation and their flexibility bid price.

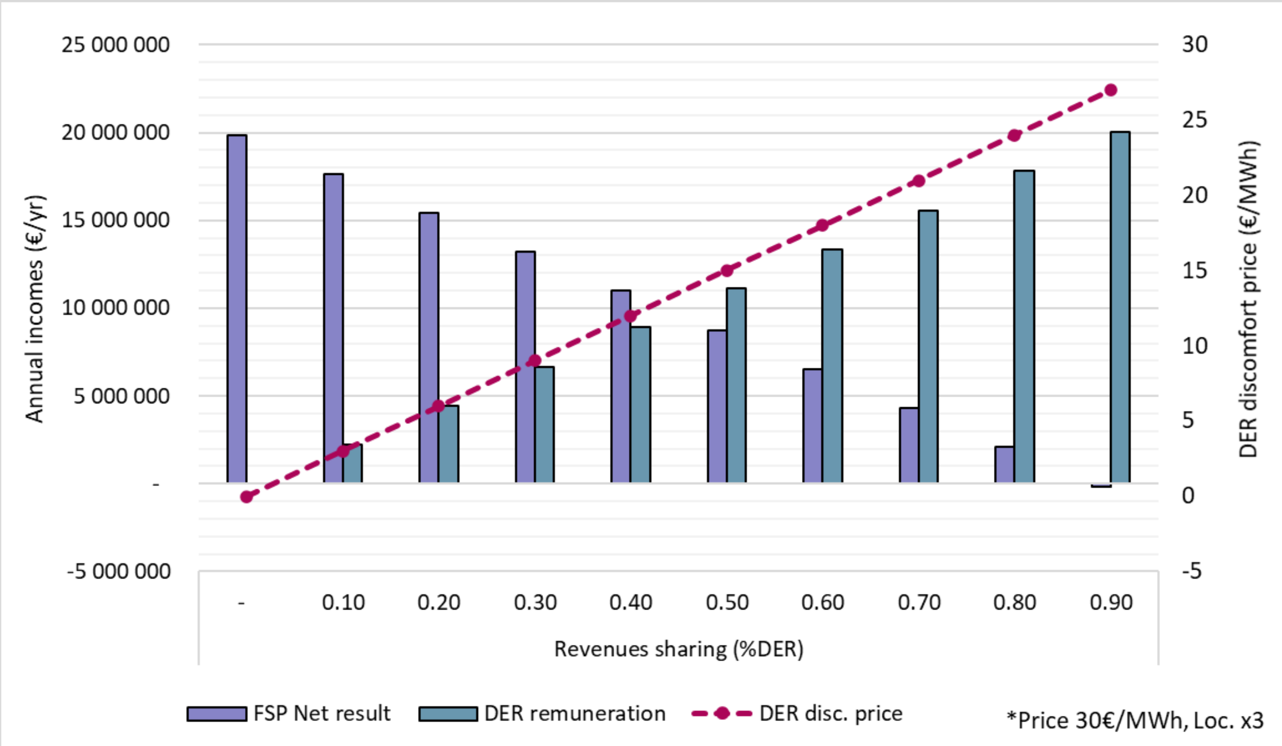

Figure 25: Sensitivity to revenue sharing between the aggregator and DERs in Albacete and Cádiz

5.4 Case Study: Local needs

The Spanish scalability scenario presented in D6.4 (Cossent et al., 2022) for local needs is based on the Málaga and Murcia demo sites, because a local market for CM is tested in these locations. In the case of Málaga, the flexibility scenario considers local congestions due to an overloaded line. In the case of Murcia, the flexibility scenario considers local congestion in an undersized substation.

The economic assessment for local needs in this deliverable D6.3 is focused on the evaluation of the economic implication for the involved market agents, in particular the DSO and FSPs and local energy resources (Pillar 1.b & Pillar 3.b).

5.4.1 Málaga case study

5.4.1.1 Simulation scenarios for the demonstrator in Málaga

The Málaga demo site comprises four separated MV networks. The network related to the industrial park of Guadalhorce and the Cádiz Road district area is modelled, because most of the FSPs considered in the demonstrator are connected there. In Málaga, the DSO does not have real local needs to procure flexibility nowadays (no overloads in distribution grids). However, potential congestions are simulated in the flexibility scenario (corresponding to Scenario 2 described in (Cossent et al., 2022)), in which a reduction of the maximal thermal current of several lines is considered: feeder 398 (Palacio de las Ferias), and 481 (Tabacalera/Pacífico), respectively. These lines were selected because most of the FSPs are connected there.

Figure 26 presents a diagram of the Industrial Park of Guadalhorce & Cádiz Road district area in Málaga.

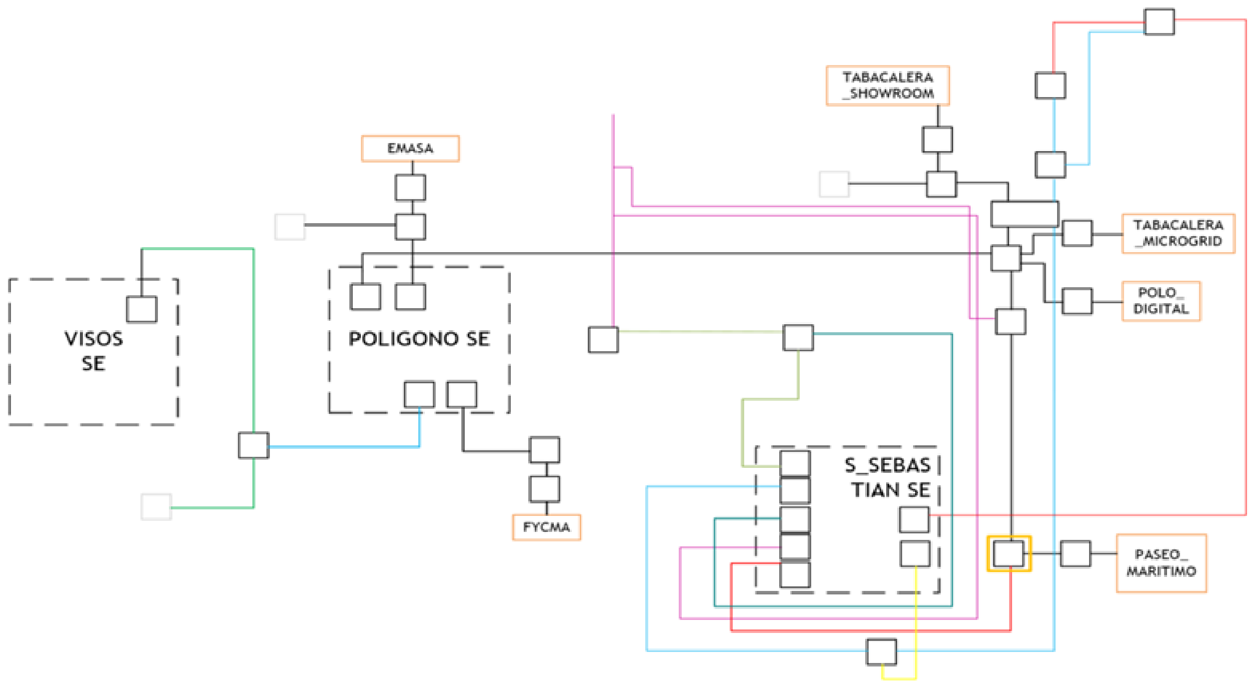

Figure 26: Industrial Park of Guadalhorce & Cádiz Road District area in Málaga (Ivanova et al., 2022)

Table 24 describes the FSPs characteristics for the Málaga case study for local needs, which will provide flexibility to solve the local CM needs.

Considering the conditions of scenario 2 in (Cossent et al., 2022), a power flow analysis was run for 24 hours to detect congestions. The outcomes are shown in Figure 27, where each color represents the loading of one of the lines under study. As can be seen, line 398 is congested at hours 9-12, and line 481 is overloaded at hours 20 and 21.

Table 24: FSPs characteristics for the Málaga case study for local needs (Cossent et al., 2022)

FSP ID	Name	Feeder	Technology	Installed capacity (MW)	Downward Bid (€/MWh)	Upward Bid (€/MWh)
FSP1	Polo Digital	Tabacalera	Consumption / Buildings	0.316	-	54.41
FSP2	Microgrid Tabacalera	Tabacalera	Microgrid	0.035	84.91	121.31
FSP3	Microgrid Smart City (Paseo Marítimo)	Pacífico (trafo 481)	Microgrid	0.055	66.09	94.42
FSP4	Tabacalera Showroom	Tabacalera	Consumption, Storage, & PV	0.11	64.79	90
FSP5	Palacio de Ferias / FYCMA	Palacio ferias (trafo 398)	PV	0.10	64.79	90

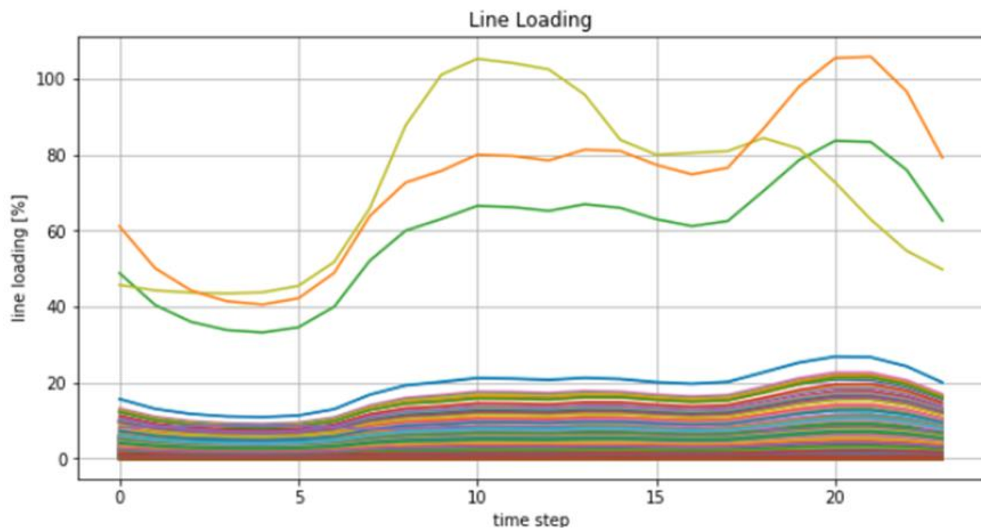

Figure 27: Line loading (%) for the flexibility scenario in Málaga (Cossent et al., 2022)

The maximum current of these two lines is 0.379 kA, requiring a daily upward flexibility need for 6 hours. Table 25 (based on (Cossent et al., 2022) and (Chaves et al., 2020)) presents the daily DSO flexibility needs in terms of MW for the two congested lines. In total, six criticalities per day need to be solved, reaching a flexibility need of 0.338089 MW per day, which will be extended to the annual horizon in this deliverable.

As an alternative to using flexibility, the grid reinforcement scenario in Málaga corresponds to Scenario 0 in (Cossent et al., 2022), in which the maximum thermal current of line 398 (Palacio de las Ferias), and 481 (Tabacalera) is 0.421 kA. In this way, by reinforcing the previous overloaded lines, the congestion is avoided.

Table 25: DSO flexibility needs for flexibility solution

Line ID	Primary substation	Voltage level	Hour	Upward flexibility needs (MWh)
398	SUB_MAL3 (FSP5)	20 kV (MV)	9	0.012489
398	SUB_MAL3 (FSP5)	20 kV (MV)	10	0.061598

Line ID	Primary substation	Voltage level	Hour	Upward flexibility needs (MWh)
398	SUB_MAL3 (FSP5)	20 kV (MV)	11	0.048323
398	SUB_MAL3 (FSP5)	20 kV (MV)	12	0.028777
481	SUB_MAL5 (FSP3)	20 kV (MV)	20	0.090260
481	SUB_MAL5 (FSP3)	20 kV (MV)	21	0.096642

5.4.1.2 Economic impact for regulated agents (local needs in Málaga)

The use of local markets (for a given flexibility commission time) may allow to postpone the need to reinforce the grid. It can also provide a cost-efficient solution in case of an occasional congestion, as well as be a temporary solution during the commissioning time of the new grid elements in case of structural congestions caused by vegetative increase of demand.

In the short term, the flexibility solution may be compared to the cost of a remedial action to cope with actual congestions, in which non-supplied energy is a DSO concern. In the medium term, the use of flexibility may be compared to the cost of a traditional grid reinforcement for a given commissioning time when the DSO should make decisions for the upcoming distribution grid expansion plan.

The comparison of the economic impact that the flexibility and grid-based solutions have on the DSO is done at two timeframes: a remedial action for the short term and grid reinforcement for the medium-term. Figure 28 presents the items to be considered for the comparison of the impact on the DSO, where some costs including service procurement are recovered via tariffs, while the flexibility-not-supplied is an extra cost.

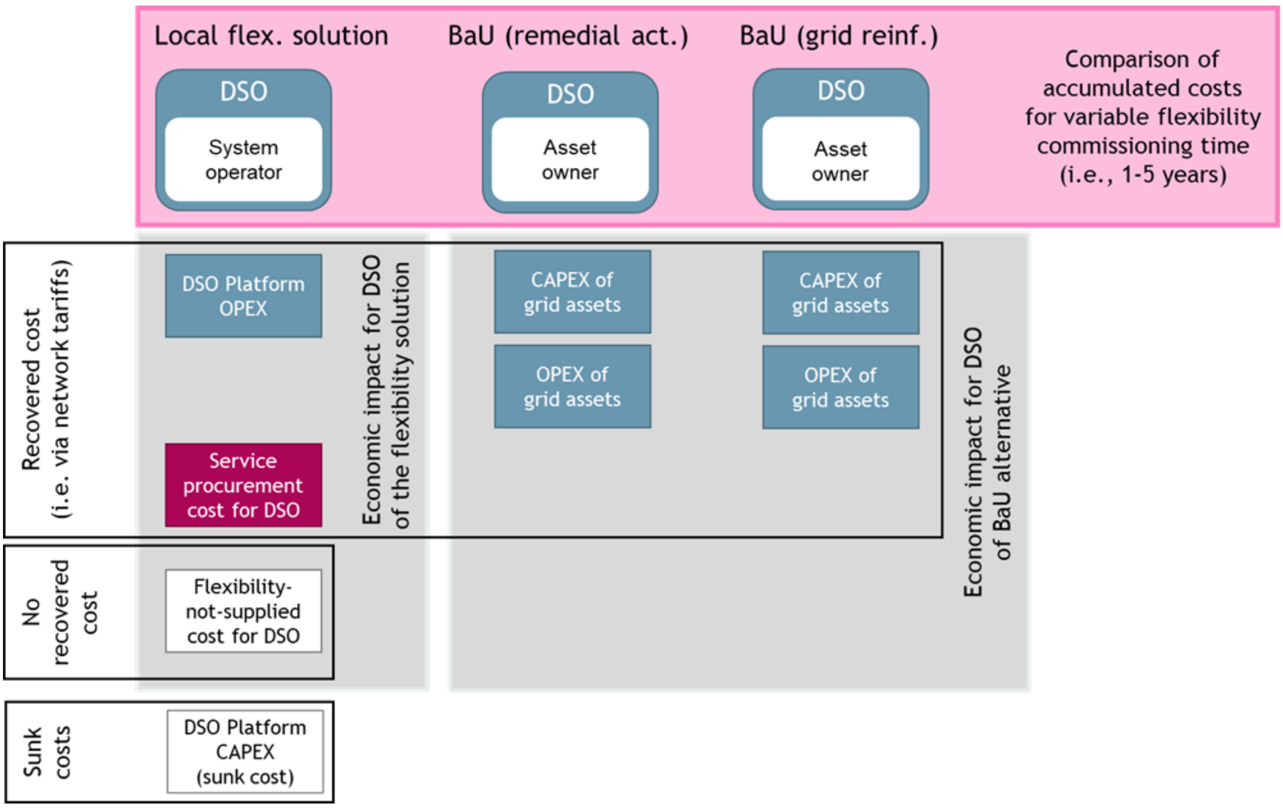

Figure 28: Cost components for the DSO in the flexibility and BaU alternatives for local needs in Spanish scenarios (Pillar 1.b)

In the case of Málaga, potential congestions are simulated for the flexibility scenario with local congestion (two overloaded lines), while the reinforced scenario considers two new lines in the affected part of the network.

The features and reference cost of the main grid asset to solve local CM needs are indicated below. The reference cost is obtained from (Spanish Government, 2015). Figure 29 depicts the annuity payment to the DSO, which is the regulated remuneration established by the (Spanish Government, 2019a) for the considered grid reinforcement or the installation of a temporary asset for remedial actions:

- **Grid reinforcement**: Two 20 kV lines (TI-9VZ) of 5 km of length each are considered to be reinforced. The reference investment is 71 522 €/km (715 220 € in total), and annual maintenance cost is 742 €/km per year, in which a financial rate of return of 5.56% for the CAPEX and a margin of 5% for the OPEX are included. The lifetime of the asset is assumed to be 40 years.
- **Remedial action**: A diesel generator is selected as the remedial action in case there are already congestions at LV (and no flexibility solution or grid reinforcement is ready yet). The following features have been considered: a nominal power of 400 kW (assuming CM needs of 372 kW), 1 150 €/kW for investment cost and an OPEX related to the fossil fuel consumption of 0.3 €/kWh. The lifetime of the asset is assumed to be 30 years, although the annuity payments will only encompass the years in which it is in operation to solve the congestion.

As can be observed in Figure 29, the level of congestion is relatively high in Málaga and, thus, a traditional grid reinforcement cost could be a more suitable solution than the remedial action, due to the high OPEX due to the fossil fuel price.

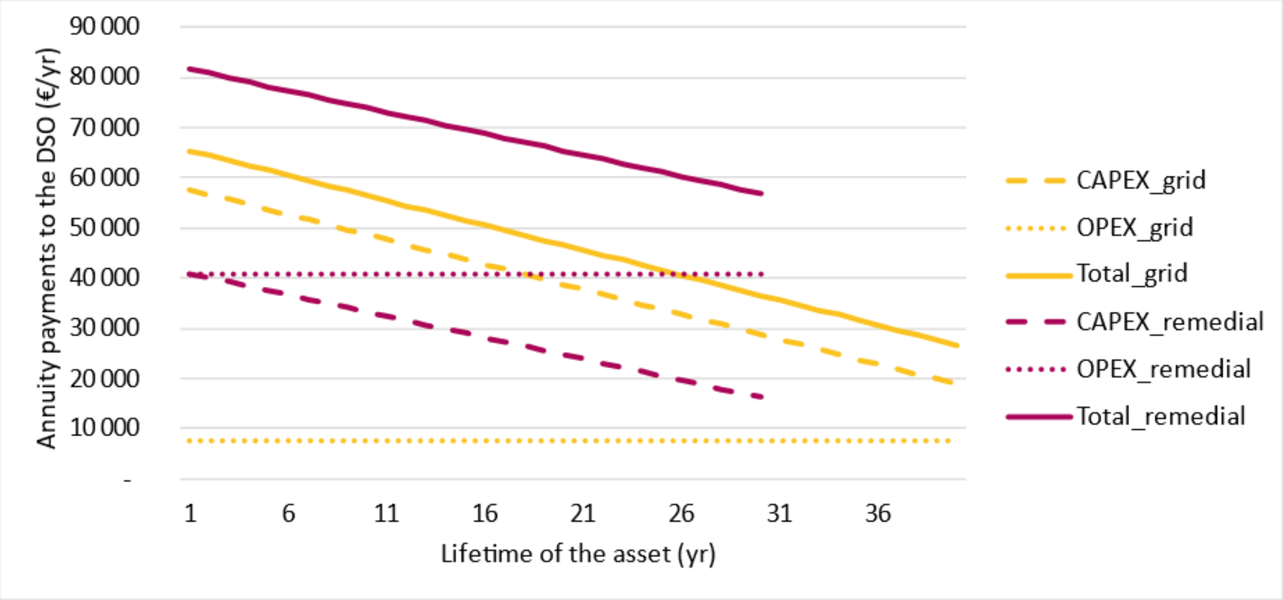

Figure 29: Annuity payment to the DSO for the traditional grid reinforcement or remedial action for local congestion management in Málaga demo

In total six criticalities per day need to be solved, in which the DSO requests an annual flexibility of 135.74 MWh/year (0.37 MWh per day). The FSPs provide flexibility with weighted prices from 92.56 €/MWh to 97.39 €/MWh (according to bid prices in Table 24). It is supposed that the flexibility needs are maintained equal throughout the considered time span (i.e., the flexibility contracting time).

- **Limited flexibility scenario**: If only the FSPs available at Málaga demo (see Table 24 for their characteristics for the market simulation) are considered, there is not enough flexibility to solve the local congestions totally. FSPs receive **5 090 €/year** for their flexibility when they solve partially the congestion event (52.2 MWh/year). The flexibility not supplied is estimated at a cost of 7 880 €/MWh, i.e., the value of lost load (VOLL), resulting in 712 243 €/year of FNS cost. The annual cost for the flexibility solution (with FNS) is expected to be 733 834 €/year (first annuity).

- **Flexibility scenario**: If the capacity of the FSP flexibility is increased by 7 times (either by increasing the number of FSPs or the capacity of the existing FSPs), the annual cost of flexibility procurement **is 13 278 €/year,** to solve all congestion events (143.4 MWh/year). The annual cost for flexibility solution (without FNS) is expected to be 29 778 €/year (first annuity).

In both scenarios, the OPEX for the DSO is considered to be 15 000 €/year with an OPEX margin of 10%.

It can be concluded that, considering the presented scenario and local flexibility needs described in subsubsection 5.4.1.1, the flexibility solution (without flexibility not supplied) can be a more cost-effective solution than either a traditional grid reinforcement or other remedial actions, as shown in Figure 30, where the accumulated costs (CAPEX, OPEX and TOTEX) of the grid reinforcement ('_grid'), remedial action ('_remedial') and the two flexibility scenarios, both with limited flexibility ('FNS') and with enough flexibility, for the first 5 years are presented in stacked bars.

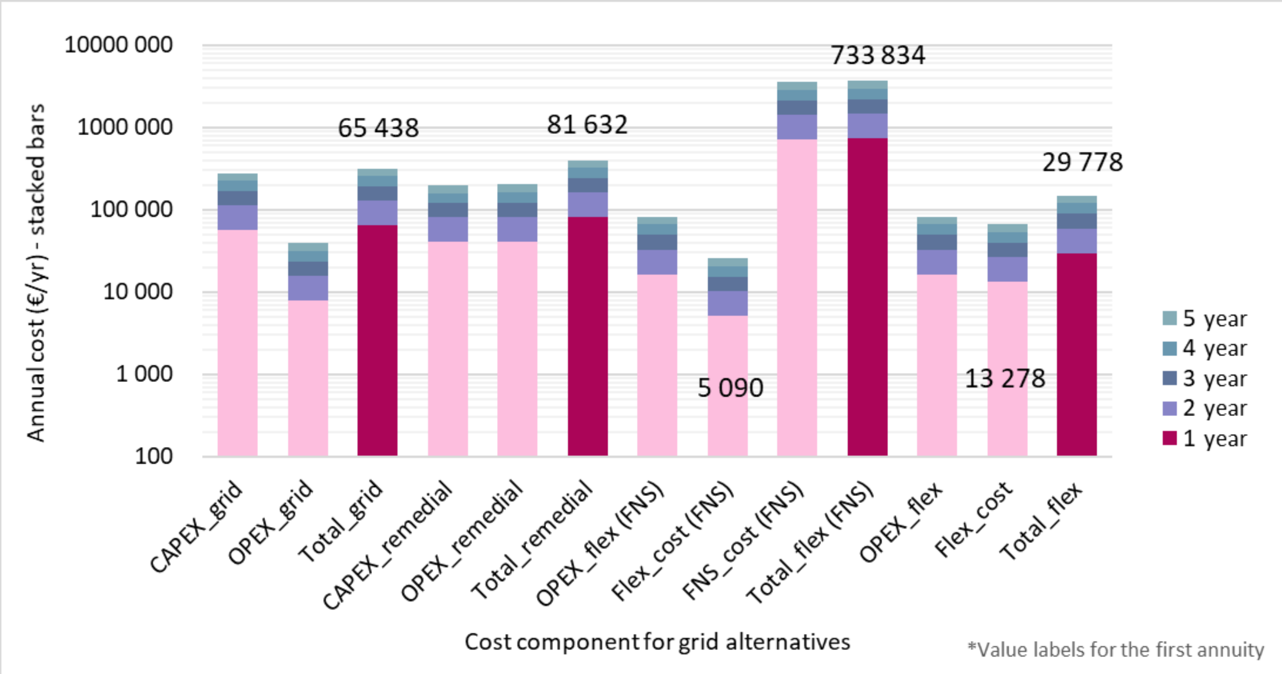

Figure 30: Comparison of CAPEX, OPEX and TOTEX (€/year) for the grid reinforcement, remedial and flexibility scenarios in Málaga

This economic analysis can be analyzed from two perspectives:

- **In the short term,** when the congestion is already or almost happening: The cost comparison should be done between a flexibility solution or a remedial action, assuming that both of them have reduced commissioning times, so that they can be disregarded. That is, both solutions will be ready when the congestion incurs. The flexibility solution (purple lines in Figure 31) along 5 years of timespan (i.e., the flexibility commissioning time) is more cost-efficient than the remedial action (maroon lines in Figure 31).

  The remedial action is only a suitable decision when the distribution grid needs a solution urgently to avoid energy not supplied to LV consumers, in case of insufficient flexibility from available FSPs or in case ICT and SW platforms are not yet available for local CM procurement.

- **In the medium term**, a decision can be made in advance, when there is no congestion yet, but it is expected that, due to the vegetative increase of demand or any other reason, congestions will appear in the system during the commissioning period of a traditional grid reinforcement. The use of flexibility may be compared to a traditional grid reinforcement for a given flexibility procurement period. As can be observed in Figure 31, the flexibility solution (purple lines in Figure 31) along a 5 year timespan (i.e., the flexibility commissioning time) is also more cost-efficient than the traditional grid reinforcement (yellow lines in Figure 31). Thus, the decision to start the commissioning of a new grid element can be postponed.

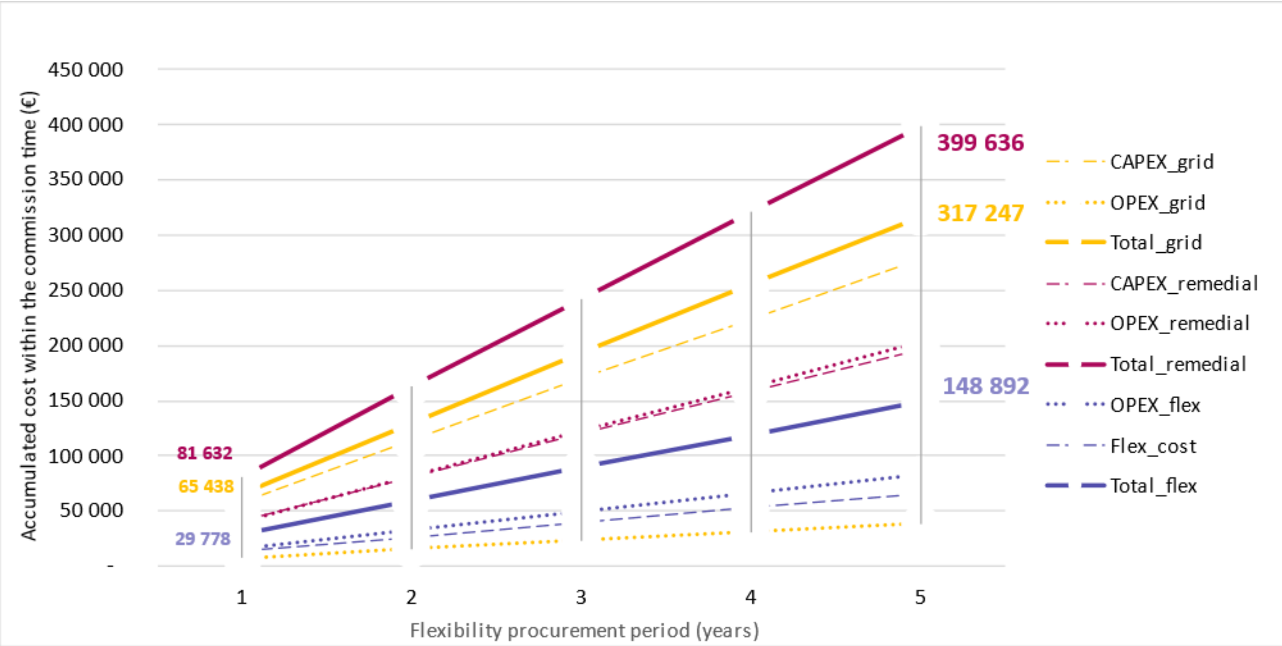

Figure 31: Accumulated CAPEX, OPEX and TOTEX (€/year) for grid reinforcement, remedial action and flexibility use in Málaga

The flexibility solution can be an efficient temporary solution. The vegetative increase of demand tends to increase the level of congestion in the future distribution grid and, consequently, its cost.

The cost of the flexibility solution can increase, due to both the congestion needs and the bid prices. Under these circumstances, there is a threshold in which the cost of flexibility is equal to traditional grid reinforcements. This threshold is reached with local CM needs of 475 MWh/year (1.3 MWh along the day) for this particular flexibility scenario (i.e., increasing the simulated congestion by 3.5 times in energy-terms), if the lowest weighted flexibility bid price in Table 24 (92.56 €/MWh) is considered, as depicted in Figure 32 and Figure 33.

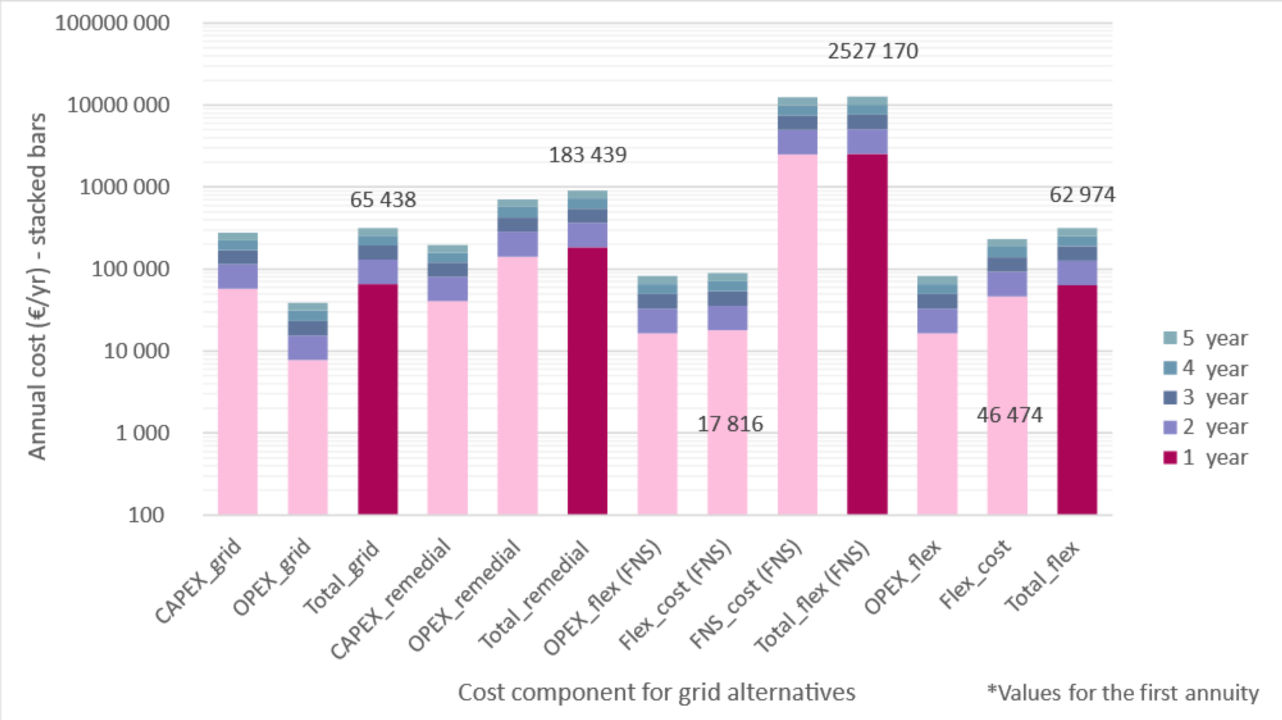

Figure 32: Comparison of CAPEX, OPEX and TOTEX (€/year) for the grid reinforcement and flexibility scenarios in Málaga when the level of congestion increases by 3.5 times

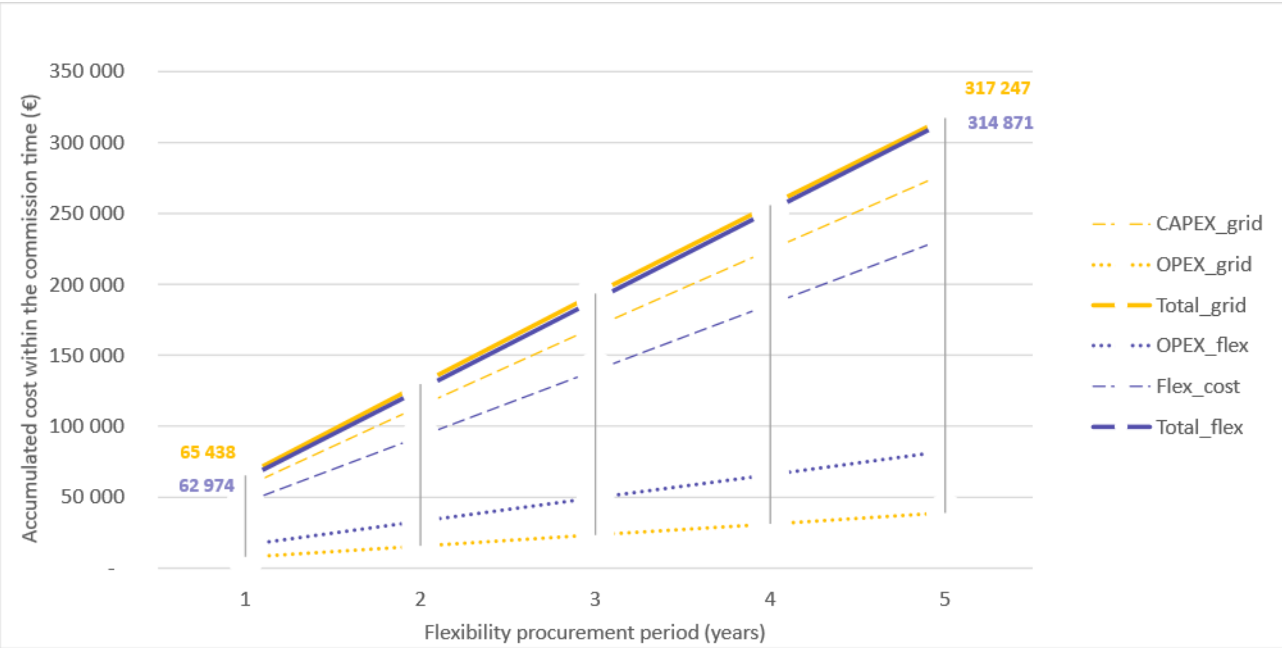

Figure 33: Accumulated CAPEX, OPEX and TOTEX (€/year) for grid reinforcement, remedial action and flexibility use in Málaga when the level of congestion increases by 3.5 times

Table 26 summarizes other threshold scenarios (depending on the level of congestion and the weighted flexibility price) in which the cost of the flexibility solution could be comparable to the cost of the grid reinforcements. As the level of congestion is reduced, the weighted flexibility prices that the DSO could afford to pay increase proportionally.

Table 26: Threshold scenarios depending on the level of congestion and the weighted flexibility price

Average bid price (€/MWh)	Congestion level (%)	Flex needs (MWh/year)	Flexibility cost (€/year)	Total cost of the flexibility solution (€/year)	Case study
92.56	1.00	143.46	13 278.33	29 778.33	Base case
92.56	3.50	502.10	46 474.16	62 974.16 (almost equal to grid reinforcements cost along 5 years: 314 871 €)	Threshold
69.4	4.67	669.47			
46.3	7.00	1 004.21			
23.1	14.00	2 008.41			

The use of flexibility, thus, can be a temporary cost-efficient solution during the commissioning time of the new grid elements in case of structural congestions caused by vegetative increase of demand.

5.4.1.3 Profitability assessment for non-regulated agents (local needs in Málaga)

The aggregator FSP-ag@D receives market incomes for the provision of local flexibility services in the local market, but they must deal with additional costs associated to this business activity.

This subsubsection focuses on the profitability assessment for the FSP-ag@D, that is, a flexibility service provider which participates to provide flexibility for local CM needs in the local market and requires to develop both a SW platform to aggregate resources and ICT systems to communicate with the DSO, DERs and the LMO.

In order to be able to use flexibility-based solutions locally, DSOs must develop, deploy and integrate several ICT-based platforms. Additionally, the FSP-ag@D should pay a flexibility market fee to access the market, and would face other market cost related to flexibility, as shown in Figure 34. FSP-ag@D should also consider other costs associated to the small DERs they represent (i.e., energy-box), as well as the DER remuneration by means of a bilateral contract agreement among parties.

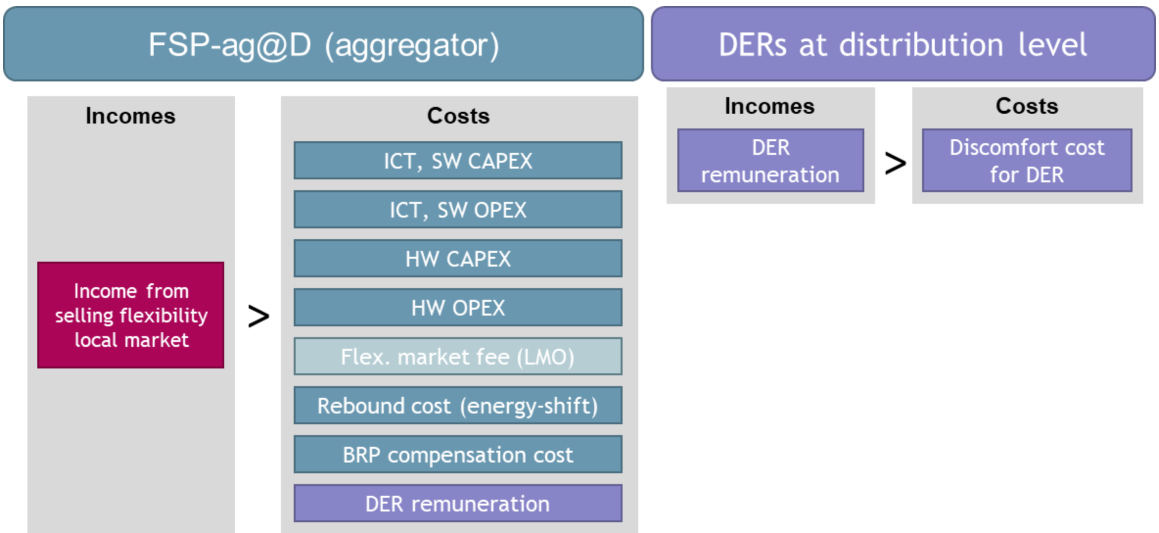

Figure 34: Incomes and costs for non-regulated agents in the flexibility and BaU alternatives when solving local needs in Spanish scenarios (Pillar 3)

A sensitivity analysis will be done, in which the scenario is scaled geographically (more locations) and based on the level of local congestions. As the number of locations and the level of CM provision increase, the flexibility incomes increase to a greater extent than some incurred costs. For example, CAPEX and OPEX costs are assumed independent from the level of CM needs, while CAPEX and OPEX costs related to the DERs increase proportionally based on the number of DERs and locations.

Table 27 summarizes the economic and technical assumptions, considered for the local CM in Málaga. For the profitability assessment of FSP-ag@D, the CAPEX and OPEX values are extracted from section 5.2 (local markets). In Málaga, 5 flexible resources are considered and controlled by the energy aggregator (see Table 24). The OPEX of the LMO platform are partially covered by the FSPs at distribution level, considering an energy-indexed fee of 0.03 €/MWh[17] (based on the fee paid to the NEMO in the regulated tariff "voluntary price for the small consumer"). Additionally, rebound effects are included, in which the aggregator and the FSPs, or their retailer, should reschedule the load profile or take other energy time-shift actions. The cost of the rebound effect is estimated at 35.02 €/MWh (the weighted price of the intraday markets by auction in 2020, (REE, 2020)), as nearly all the energy delivered in the flexibility market should be rescheduled later (assuming mainly demand response participation). Finally, the BRP compensation is estimated at 0.17 €/MWh[18], which is the annual average price component for the measured imbalances of reference suppliers in 2020.

Table 27: Economic and technical data of the FSP@D for local needs (initial scenario based on Málaga demo)

	Unit	Value	Comment
Flexibility energy provision	MWh/year	143.46	-
Flexibility incomes	€/year	13 278	at 92.56 €/MWh
Annual average CAPEX related to SW platform, ICT…	€/year	8 000	Lifetime = 10 years
Annual average CAPEX HW, DERs (i.e., energy-box)	€/year	150	300 € per DER
Annual OPEX related to the energy aggregator role	€/year	16 000	
Annual OPEX related to flexible units	€/year	3 000	600 €/year per DER
Annual MO fee	€/year	4.30	0.03 €/MWh
Rebound effect cost	€/year	5 024	35.02 €/MWh
BRP compensation	€/year	24	0.17 €/MWh
Number of flexible DERs at demo (Málaga)	#	5	-

[17] The market operator fee is extracted from the breakdown of the Spanish regulated tariff "voluntary price for the small consumer", available in https://www.esios.ree.es/en/pvpc?date=01-01-2020

[18] The "annual average price of the measured imbalances of referenced suppliers" refers to the average cost resultant from the energy imbalances that the last resort suppliers incur from their schedule and their final profiles. These changes may come from forecast errors, changes in the final demand, but also for the flexibility activation, which result in an extra cost from the BRP's side. Available in https://www.esios.ree.es/en/analysis/955?vis=1&start_date=01-01-2020T00%3A00&end_date=31-12-2020T23%3A55&compare_start_date=01-01-2019T00%3A00&groupby=year

In this local CM market, the weighted flexibility price (pay-as-bid pricing mechanism) is established at 92.56 €/MWh (mainly due to demand response participation). Figure 35 depicts a sensitivity analysis of the profitability assessment of FSPs to solve local needs in Málaga demo, according to:

- an increase in the number of locations with congestion at distribution level (up to 10 times), which increases the number of DERs considered in the economic analysis, and
- an increase of the level of CM needs (from 143.46 MWh/year up to 10 times more).

As can be observed in Figure 35, the initial scenario (143.46 MWh/year in Málaga) is not attractive, especially due to the high rebound cost and high OPEX terms per year. The business case becomes positive above twice the level of congestion in two similar locations than the modelled one (red dot in Figure 35). For example, with 5 times the level of congestions and with 5 similar locations (at a weighted flexibility price is at 92.56 €/MWh), the FSP can obtain 165 899 €/year (green dot in Figure 35).

However, the sensitivity analysis cannot be extrapolated as a generic result for energy aggregators which participate in local flexibility needs, as the CAPEX and OPEX terms may vary, the number of DER and their flexibility capacity can differ, as well as the flexibility incomes obtained based on the flexibility bid price. It should be pointed out that other market costs, such as the rebound cost or BRP compensation, might be avoided according to the specific regulation in force at that moment, to incentivize the participation of small DERs and aggregators in local flexibility markets, until enough market liquidity and an attractive remuneration can be realized. Finally, the DERs may be remunerated according to a revenue sharing ratio on the flexibility income of the FSP. Figure 36 presents the economic evaluation for the FSP and the remuneration for the DERs according to different revenue sharing ratio. For each ratio, the minimum discomfort price perceived by the DER can be calculated (the minimum revenue or price at which the DERs are willing to provide flexibility in return for economic payment).

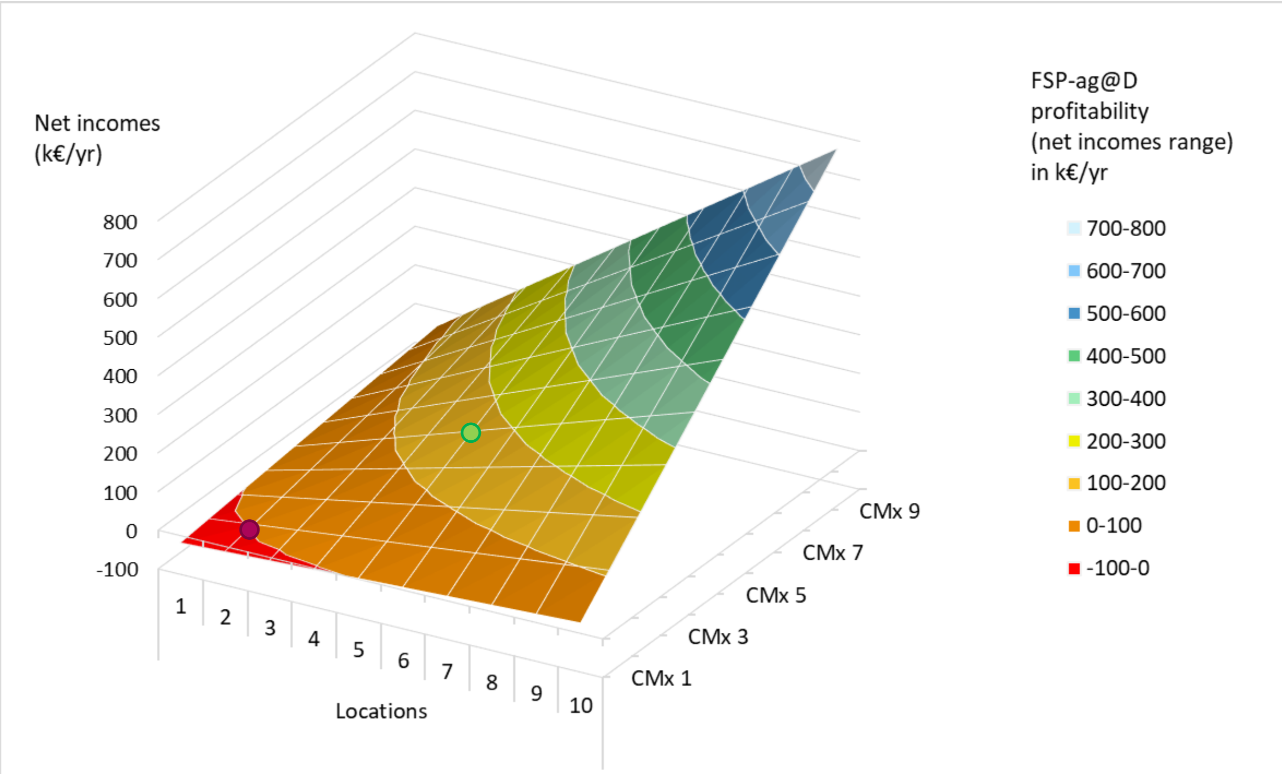

Figure 35: Sensitivity of the profitability of FSPs to the number of locations and level of congestions to solve local needs in Málaga

In the example above, when there are 5 locations and the CM needs are 5 times higher and the weighted flexibility price is at 92.56 €/MWh (annual incomes for the FSP of 165 899 €/year), with a revenue sharing of 40% (40% of the market income by the FSP), while the yearly remuneration for all DERs is 134 783 €/year (at a discomfort price of 37 €/MWh), which is shared among them according to their specific contribution to flexibility activation and their flexibility bid price.

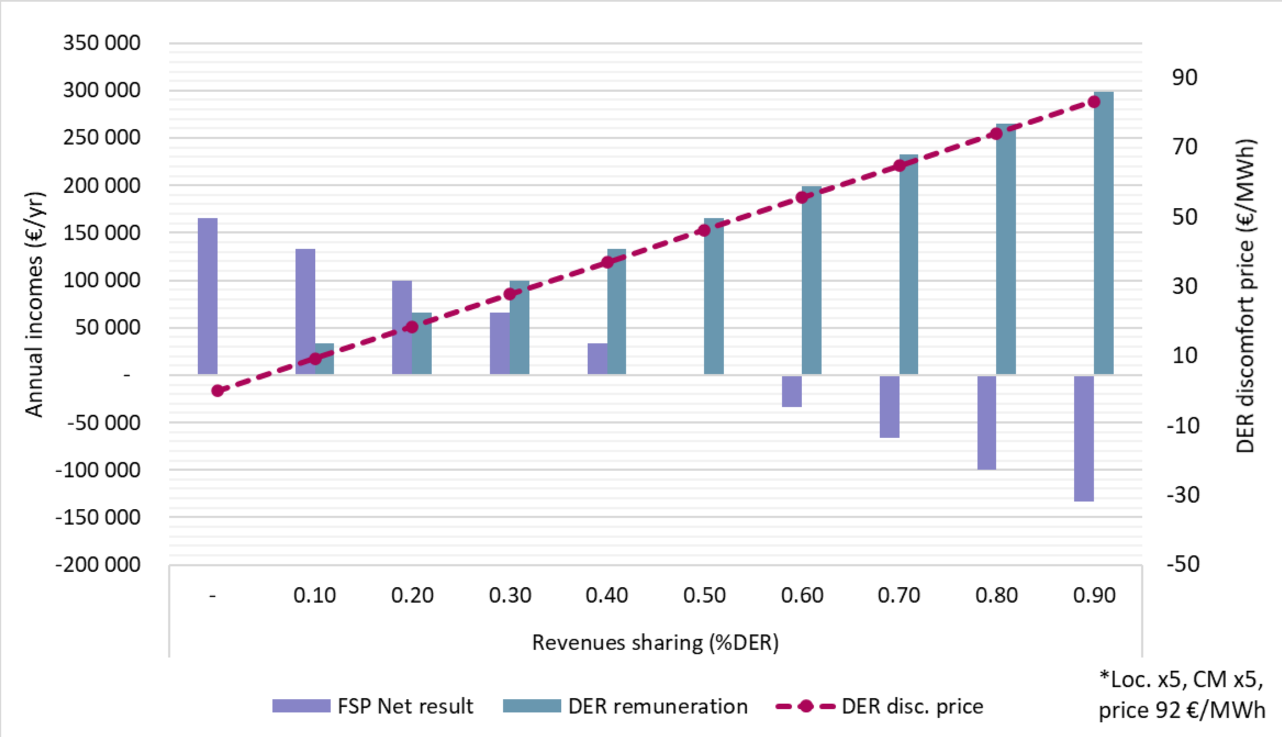

Figure 36: Sensitivity to revenue sharing between the aggregator and DERs in Málaga

5.4.2 Murcia case study

5.4.2.1 Simulation scenarios for the demonstrator in Murcia

For the Murcia demo site, a synthetic grid is built with similar characteristics to the real network. For that, the reference network model was used to build a MV network for the urban area of Murcia city.

The resulting MV synthetic network is depicted in Figure 37, where HV lines are represented in red and MV lines in yellow. 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 CM BUC of Murcia. Table 28 (based on (Ivanova et al., 2022) and (Cossent et al., 2022)) details the information related to the only FSP considered in the Murcia demo for local CM.

Figure 37: Murcia MV synthetic network

Table 28: FSPs characteristics for the Murcia case study for local needs

FSP ID	Name	Upward Bid (€/MWh)	Installed capacity (MW)	Upward flexibility (MWh)	Technology
FSP1	Murcia City Hall	25	0.76	0.63	Consumption

In Murcia, the DSO does not have a real need to procure flexibility at present (no overloads in distribution grids). However, potential congestions are simulated in the flexibility scenario (corresponding to Scenario 1 - Murcia described in D6.4 (Cossent et al., 2022)), in which the load of all feeders is increased by a factor of 2.13 according to the scenario definition, resulting in a transformer overloading. If this factor is greater than this value, the number of identified criticalities will be higher.

From this congested scenario, the 132/20 kV secondary substation (T301) and other lines may be congested at hour 20, requiring 0.219883 MW of flexibility. Again, these daily values will be considered for the annual horizon in this deliverable.

Table 29: DSO flexibility needs for flexibility scenario – Murcia case study (Cossent et al., 2022)

Location	Congested assets	Hour	Upward flexibility needs [MW]
T301	132/20 kV substation and MV/LV lines	20	0.219883

The transformer loading for the congested scenario with FSP flexibility is depicted in Figure 38, where each color represents the loading of each grid element under study in Murcia.

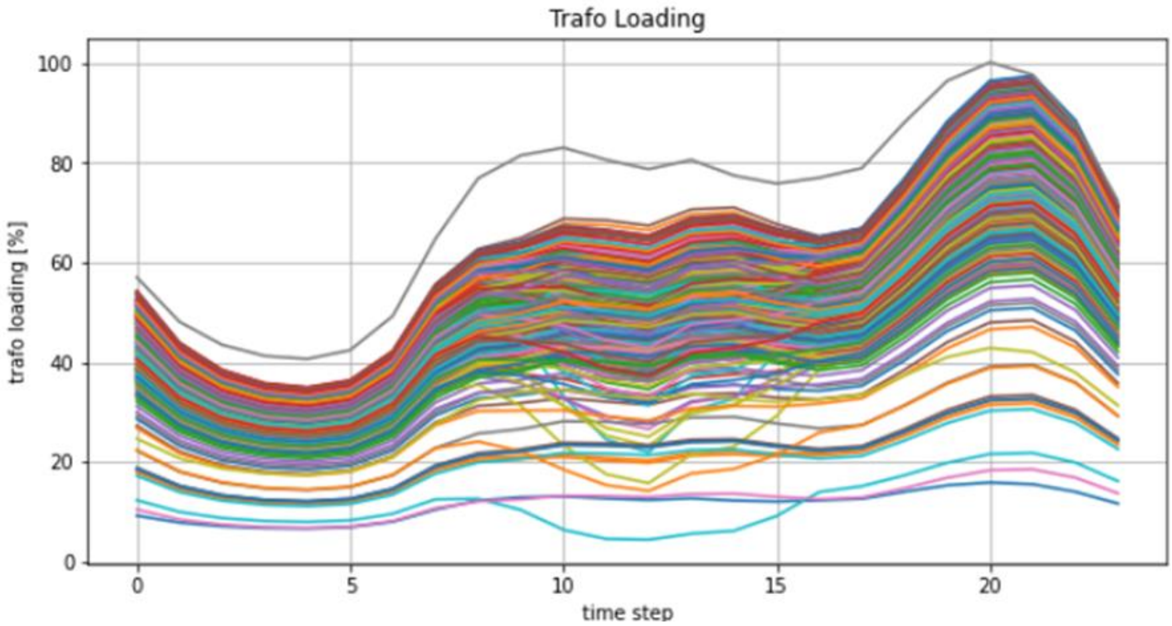

Figure 38: Transformers loading (%) for the flexibility scenario, Murcia case study (Cossent et al., 2022)

As an alternative to using flexibility, the grid reinforcement scenario in Murcia includes several grid actions in the 132/20 kV secondary substation (T301) and other auxiliary MV/LV lines, that should be reinforced to solve the local congestion in the area.

5.4.2.2 Economic impact for regulated agents (local needs in Murcia)

As in the case of Málaga, the comparison of the economic impact that the flexibility and grid-based solutions have on the DSO is done at two timeframes: a remedial action for the short term and grid reinforcement for the medium-term. In this case too, the items to be considered for the comparison of the impact on the DSO are presented in Figure 28.

In case of Murcia, potential congestions are simulated for the flexibility scenario with local congestion (undersized substation), while the reinforced scenario considers several grid actions in the network.

The features and reference cost of the main grid asset to solve local CM needs are indicated below. The reference cost is obtained from (Spanish Government, 2015). Figure 39 depicts the annuity payment to the DSO, which is the regulated remuneration (Spanish Government, 2019a) for the considered grid reinforcement or the installation of a temporary asset for remedial actions:

- **Grid reinforcement**: Several grid reinforcement actions will be considered in the 132/20 kV secondary substation (T301) and other auxiliary MV/LV lines. The estimated investment reaches 484 179 € and annual maintenance is 12 104 € per year, in which a financial rate of return of 5.56% for the CAPEX and a margin of 5% for the OPEX are included. The lifetime of the asset is 40 years.
- **Remedial action**: A diesel generator is selected as the remedial action in case there are already congestions at LV (and no flexibility solution or grid reinforcement is ready yet). The following features have been considered: a nominal power of 250 kW (assuming CM needs of 220 kW), 1 150 €/kW for investment cost and an OPEX related to the fossil fuel consumption of 0.3 €/kWh. The lifetime of the asset is 30 years, although the annuity payments will only encompass the years in which it is in operation to solve the congestion.

As can be observed in Figure 39, the level of congestion is relatively low in Murcia and, thus, a traditional grid reinforcement cost (to respond to a structural issue assuming a vegetative increase of demand) could have a similar cost than the remedial action, despite the high OPEX due to the fossil fuel price.

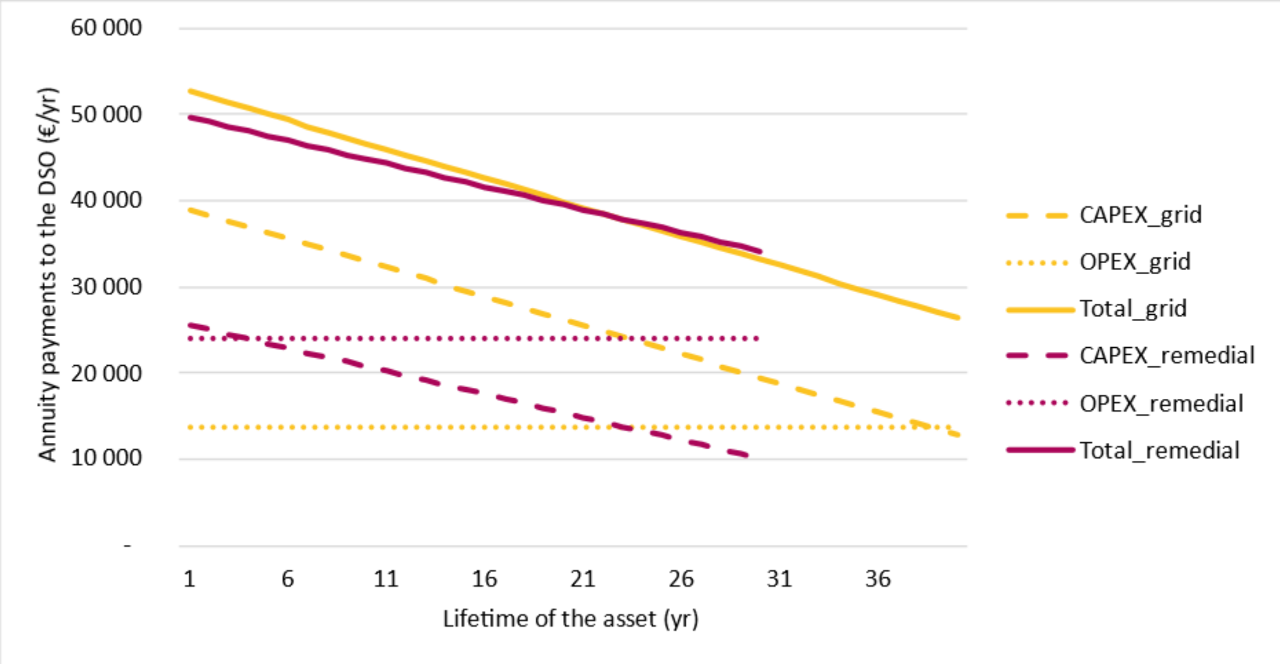

Figure 39: Annuity payment to the DSO for the traditional grid reinforcement or remedial action for local congestion management in Murcia demo

In total, one criticality per day needs to be solved, in which the DSO requests an annual flexibility of 80.25 MWh/year (0.22 MWh per day). The FSPs provide flexibility with a weighted average price of 25 €/MWh (according to bid prices in Table 28). It is supposed that the flexibility needs are maintained at 80.25 MWh/year throughout the considered time span (i.e., the flexibility contracting time).

- **Limited flexibility scenario**: If it is assumed that the available flexibility is 20% of the real flexibility in Murcia (that is, 0.13 MWh see Table 28 for the features of existing FSPS), so there is not enough flexibility to completely solve the local congestions (0.22 MWh). FSPs receive 1 094 €/year for their flexibility when they partially solve the congestion event (**43.78 MWh/year**). The flexibility not supplied is estimated at a cost of 7 880 €/MWh for the VOLL, resulting in 287 412 €/year of FNS cost. The annual cost for the flexibility solution (with FNS) is expected to be 305 007 €/year (first annuity).
- **Flexibility scenario**: When the flexibility capacity that is really available in Murcia is considered, it can provide the required flexibility to totally solve the congestion event (that is, 0.219883 MWh, see Table 29 for the DSO needs) and the annual cost of flexibility procurement is 2 006 €/year to provide all the flexibility required throughout the year (**80.25 MWh/year**). The annual cost for the flexibility solution without FNS is 18 506 €/year (first annuity).

In both scenarios, the OPEX for the DSO is considered to be 15 000 €/year with an OPEX margin of 10%.

It can be concluded that, considering the presented scenario and local flexibility needs described in subsubsection 5.4.2.1, the flexibility solution (without FNS) can be a more cost-effective solution for occasional congestions than either a traditional grid reinforcement or other remedial action, as shown in Figure 40, where the accumulated costs (CAPEX, OPEX and TOTEX) of the grid reinforcement ('_grid'), remedial action ('_remedial') and the two flexibility scenarios, both with limited flexibility ('FNS') and with enough flexibility, for the first 5 years are presented in stacked bars.

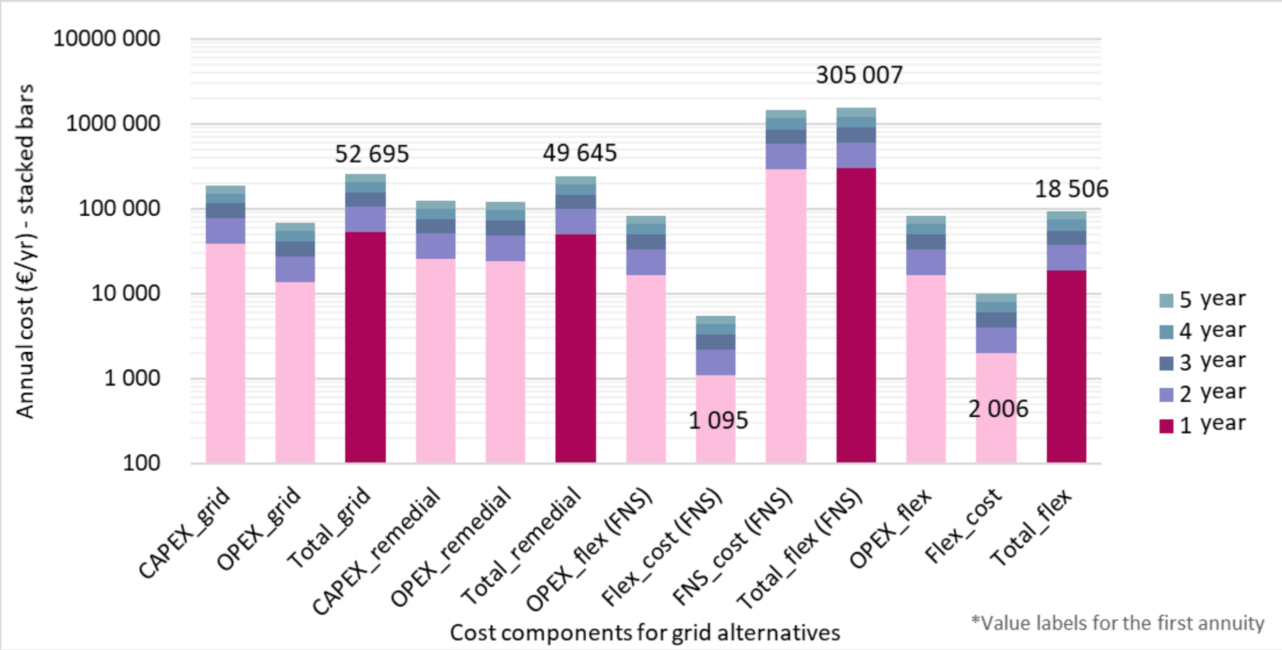

Figure 40: Comparison of CAPEX, OPEX and TOTEX (€/year) for the grid reinforcement, remedial and flexibility scenarios in Murcia

This economic analysis can be analyzed from two perspectives:

- **In the short term**, when the congestion is already there or almost happening: The cost comparison should be done between a flexibility solution or a remedial action, assuming that both have reduced commissioning times, which can be disregarded. That is, both solutions will be ready when the congestion incurs. The flexibility solution (purple lines in Figure 41) is always more cost-efficient than the remedial action (maroon lines in Figure 41) along a 5-year timespan.

  The remedial action is a suitable decision only when the distribution grid needs a solution urgently to avoid energy not supplied to LV consumers, in case of insufficient flexibility from available FSPs or when ICT and SW platforms are not available yet for local CM procurement.

- **In the medium term**, a decision can be made in advance when there is no congestion yet, but congestions are expected during the commissioning time of a traditional grid reinforcement. The use of flexibility may be compared to a traditional grid reinforcement for a given flexibility procurement period. As can be observed in Figure 41, the flexibility solution (purple lines in Figure 41) along a time span of 5 years (i.e., the flexibility commissioning time) is always more cost-efficient than the traditional grid reinforcement (yellow lines in Figure 41). Thus, the decision to start the commissioning of a new grid element can be postponed.

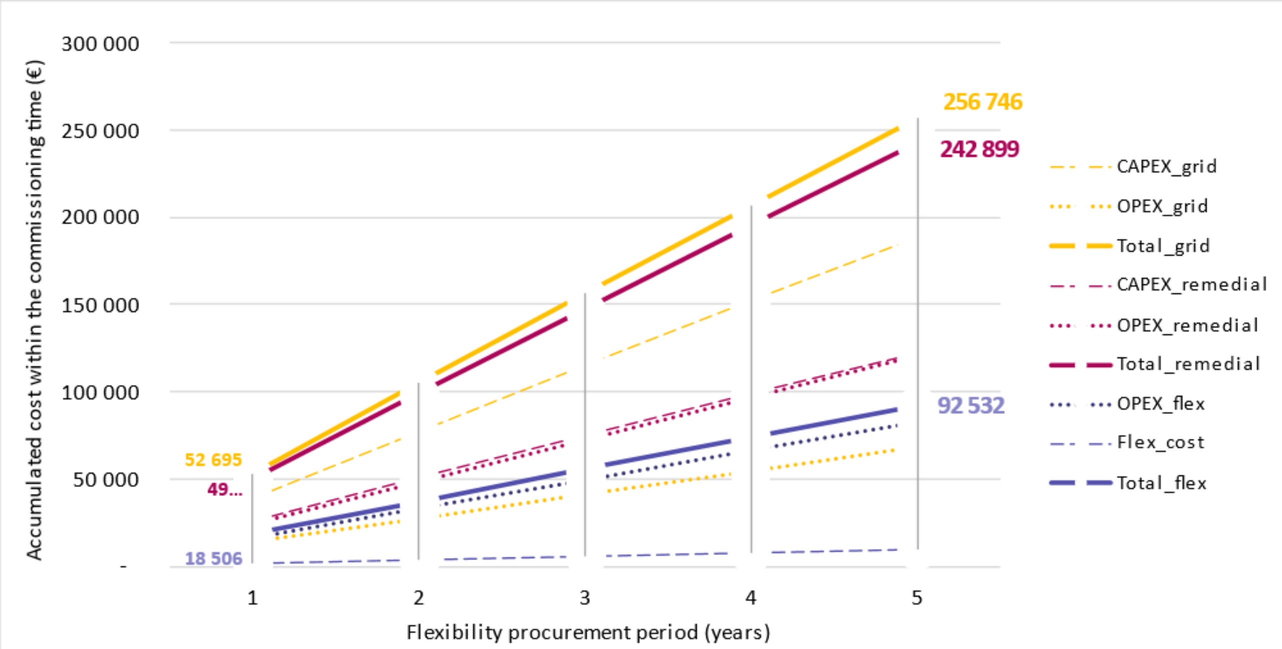

Figure 41: Accumulated CAPEX, OPEX and TOTEX (€/year) for grid reinforcement, remedial action and flexibility use in Murcia

The flexibility solution can be an efficient temporary solution. The vegetative increase of demand tends to increase the level of congestion in the future distribution grid and, consequently, its cost. The cost of the flexibility solution can increase, due to the increasing congestion needs and bid prices. Under this circumstance, there is a threshold in which the cost of flexibility is equal to traditional grid reinforcement. In this particular case of Murcia, this threshold is reached when the CM local needs are 1 764 MWh/year (3.73 MWh along the day), that is, a 17-fold increase in the simulated congestion in energy terms, by keeping the weighted flexibility bid price at 25 €/MWh, as depicted in Figure 42 and Figure 43.

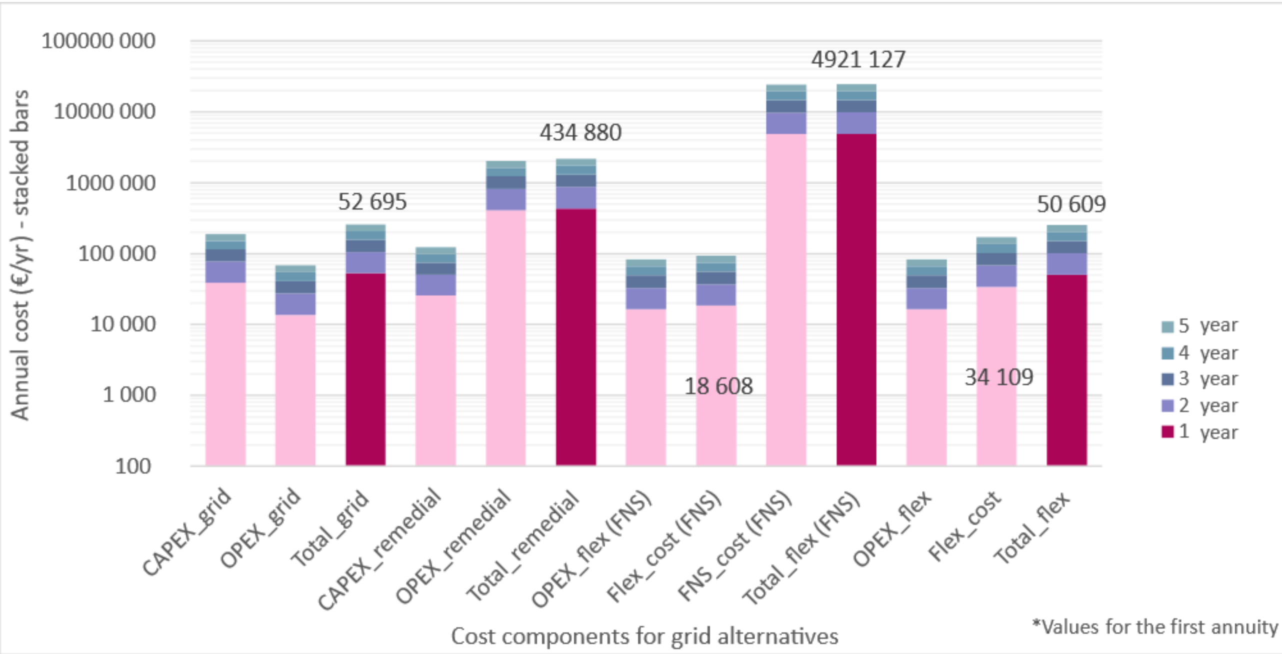

Figure 42: Comparison of CAPEX, OPEX and TOTEX (€/year) for the grid reinforcement and flexibility scenarios in Murcia when the level of congestion increases by 17 times

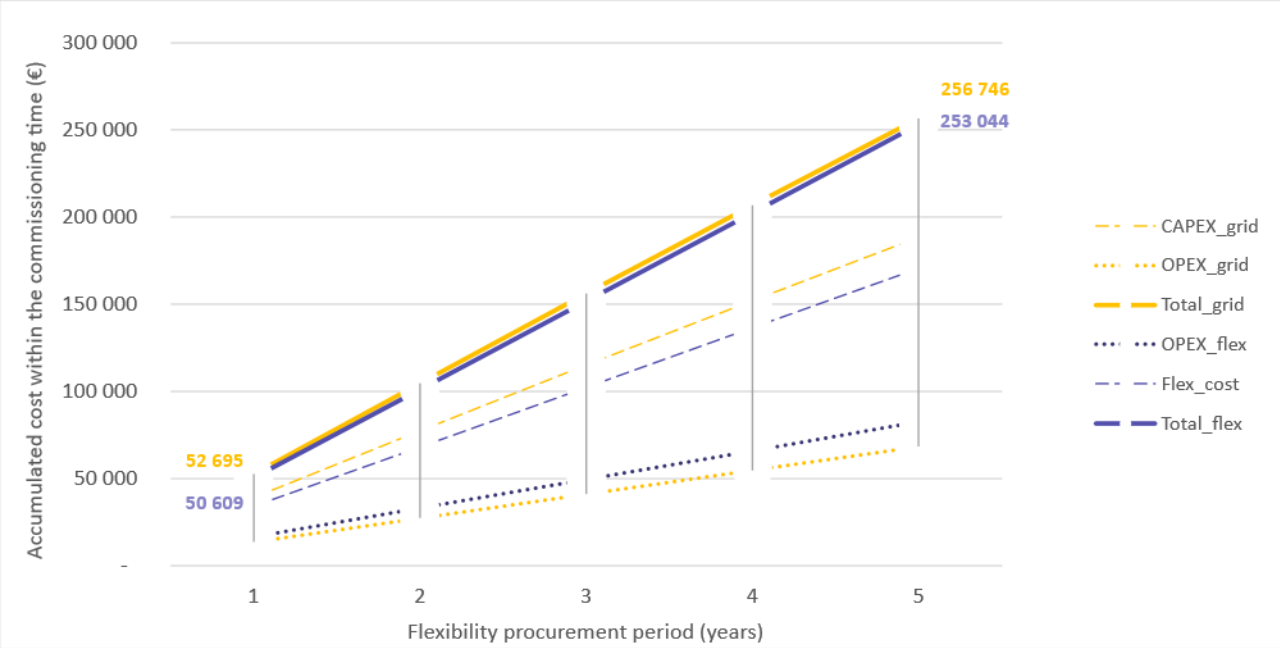

Figure 43: Accumulated CAPEX, OPEX and TOTEX (€/year) for grid reinforcement, remedial action and flexibility use in Murcia when the level of congestion increases by 17 times

Table 30 summarizes other threshold scenarios (depending on the level of congestion and the weighted flexibility price) in which the cost of the flexibility solution provides a comparable cost to grid reinforcements. As the level of congestion is reduced, the weighted flexibility prices that the DSO can afford to pay the DSO increase.

Table 30: Threshold scenarios depending on the level of congestion and the weighted flexibility price

Weighted bid price (€/MWh)	Level of congestions (%)	Flex needs (MWh/year)	Flexibility cost (€/year)	Total cost of the flexibility solution (€/year)
25	1.00	80.26	2 006.41	18 506.41
25	17.00	1 765.64	34 109	50 609 (almost equal to grid reinforcements cost along 5 years: 253 044 €)
50	8.5	682.17		
75	5.67	454.78		
100	4.25	341.09		

5.4.2.3 Profitability assessment for non-regulated agents (local needs in Murcia)

For the profitability assessment of FSP-ag@D, the market incomes and the additional costs associated to this business activity in Figure 34 must be compared. The CAPEX and OPEX values are extracted from section 5.2 (local markets). In Murcia, 1 flexible resource is considered and controlled by the aggregator (see Table 28). The OPEX costs of the LMO platform are partially covered by the FSPs at distribution level, considering an energy-indexed fee of 0.03 €/MWh (based on the fee paid to the NEMO in the regulated tariff “voluntary price for the small consumer”, see section footnote 17 in subsubsection 5.4.1.3 for clarification). Additionally, rebound effects are included, in which the aggregator and the FSPs, or their retailer, should reschedule the load profile or take other energy time-shift actions. The cost of the rebound effect is estimated at 8.75 €/MWh (based on the weighted price of the intraday markets by auction in 2020), as not all the energy delivered in the flexibility market should be rescheduled later (only 25%), assuming mainly demand response and local generation participation. Finally, the BRP compensation is estimated in

0.17 €/MWh, which is the annual average price component for the measured imbalances of reference suppliers in 2020 (see footnote 18 in subsubsection 5.4.1.3 for clarification). Table 31 summarizes the economic and technical assumptions, considered for the local CM in Murcia.

Table 31: Economic and technical data of the FSP@D for local needs (initial scenario based on Murcia demo)

	Unit	Value	Comment
Flexibility energy provision	MWh/year	80.26	-
Flexibility incomes	€/year	2 006	at 25 €/MWh
Annual average CAPEX related to SW platform, ICT…	€/year	8 000	Lifetime = 10 years
Annual average CAPEX HW, DERs (i.e., energy-box)	€/year	30	300 € per DER
Annual OPEX related to the energy aggregator role	€/year	16 000	
Annual OPEX related to flexible units	€/year	600	600 €/year per DER
Annual MO fee	€/year	2.41	0.03 €/MWh
Rebound effect cost	€/year	702.61	8.75 €/MWh
BRP compensation	€/year	13.64	0.17 €/MWh
Number of flexible DERs at demo (Murcia)	#	1	-

In this local CM market, the weighted flexibility price (pay-as-bid pricing mechanism) is established at 25 €/MWh (mainly due to demand response participation). Figure 44 depicts a sensitivity analysis of the profitability assessment of FSP agents to solve local needs in Murcia demo, according to:

- an increase of the number of locations with congestion at distribution level (up to 10 times), which increases the number of DERs considered in the economic analysis, and
- an increase of the level of CM needs (from 143.46 MWh/year up to 10 times more).

As observed in Figure 44, the initial scenario (143.46 MWh/year in Murcia demo) is not attractive, especially due to the high rebound cost and high OPEX terms per year. The business case becomes positive i.e., above 5 times the level of CM needs and scaled above 4 locations (red dot in Figure 44). For example, with 20 times the level of congestions and with 10 similar locations (at a weighted flexibility price is at 92.56 €/MWh), the FSP can obtain 227 248 €/year (green dot in Figure 44).

However, the sensitivity analysis cannot be extrapolated as a generic result for energy aggregators which participate in local flexibility needs, as the CAPEX and OPEX terms may vary, the number of DER and their flexibility capacity can differ, as well as the flexibility incomes obtained based on the flexibility bid price.

It should be pointed out that other market costs, such as the rebound cost or BRP compensation, might be avoided according to the specific regulation in force at that moment, to incentive the participation of small DERs and aggregators in local flexibility markets, until enough market liquidity and an attractive remuneration can be realized. Finally, the DERs may be renumerated according to a revenue sharing ratio on the flexibility income of the FSP. It can be established by the billing agreement between the FSP and individual DERs. Figure 45 presents the final sensitivity analysis for the FSP and the remuneration for the DERs according to different revenue sharing ratio. For each ratio, the minimum discomfort price perceived by the DER can be calculated (the minimum revenue or price at which the DERs are willing to provide flexibility in return for economic payment).

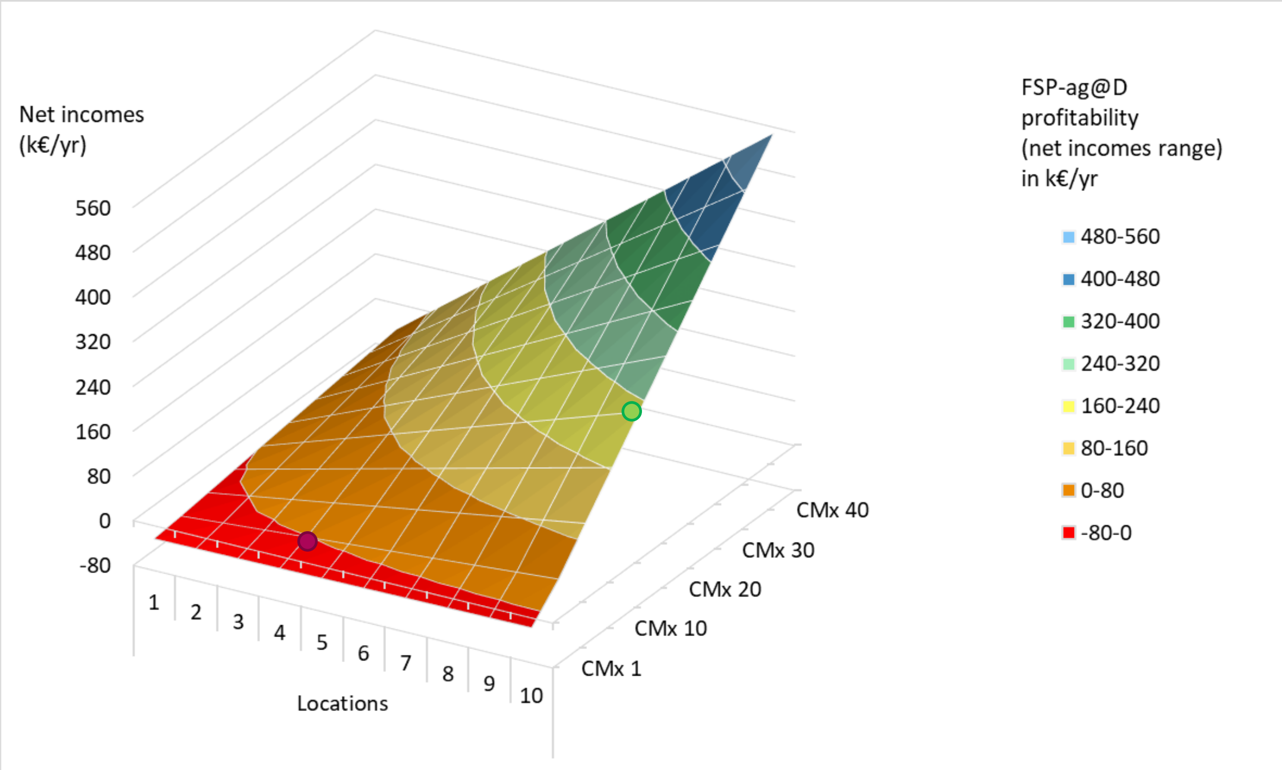

Figure 44: Sensitivity of the profitability assessment of FSPs to the number of locations and level of congestions to solve local needs in Murcia

In the example above, when the annual incomes for the FSP are 227 248 €/year, if a revenue sharing of 40% is considered, the yearly remuneration for all DERs is 160 512 €/year (at a discomfort price of 10 €/MWh), which is distributed according to their own to flexibility activation and their flexibility bid price.

Figure 45: Sensitivity to revenue sharing between the aggregator and DERs in Murcia

5.5 Cost-efficiency of coordination schemes at system level

The Spanish economic assessment at system level considers the regulated agents' costs, as depicted in Figure 46. The recognized CAPEX and OPEX (SW, ICT) for TSO, DSO and MOs (TMO, DMO or CMO, depending on the CS under study) are considered. The service procurement costs for solving the needs of the TSO and DSOs are also considered for the different CSs, i.e., TSO needs, DSO needs which may affect the TSO and DSO-specific local needs that result from market simulations at (Cossent et al., 2022).

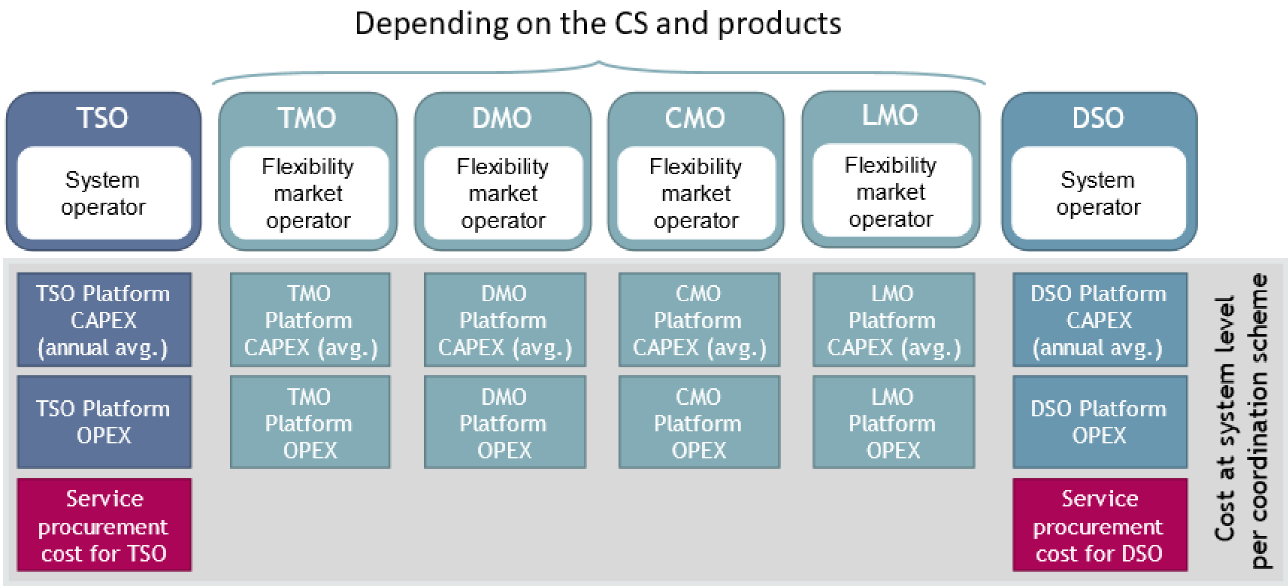

Figure 46: Economic impact of flexibility solution at system level in Spanish scenarios (Pillar 2)

Figure 47 presents the annual cost (€/year) at system level (including flexibility procurement, CAPEX and OPEX for regulated actors) for combined markets (CMM for joint TSO and DSO needs + LMM for local needs versus MMM for joint TSO and DSO needs + LMM for local needs). The flexibility to solve joint TSO and DSO needs is provided by FSPs located both at transmission and at distribution level and, additionally, small DERs also provide flexibility in local markets. In Figure 47, the cost of the flexibility activation is depicted and classified as follows:

- Flexibility cost of the FSPs at distribution level (the FSPs considered in the market simulations based on the demonstrators in Albacete and Cádiz, as described in subsection 5.3.1) to solve joint needs of TSO and DSO (Flex FSP@D).
- Flexibility cost of the FSPs at transmission level to solve joint needs of TSO and DSO (Flex FSP@T).
- Flexibility cost of the FSPs at distribution level (the FSPs considered in the market simulations based on Málaga and Murcia demonstrators, as described in subsections 5.4.1 and 5.4.2, respectively) to solve local needs by the DSO (Flex local FSP@D).

A pay-as-bid pricing scheme is assumed (Cossent et al., 2022) and bid prices are based on the operational expenditures and other criteria of each FSP. The cleared bids are selected according to the optimization formulation of each coordination scheme.

Under these market assumptions, the annual cost of the common market is higher than the multi-level market. The FSPs at distribution level participate to a greater extent in the multi-level scheme (specially, in the first stage of local DSO needs), which result in higher remuneration of the FSP@D (414 k€/year in MMM versus 365 k€/year in CMM). In contrast, the flexibility cost indexed to the FSPs at transmission level

(Flex FSP@T) in the CMM is higher than in the MMM (157.63 M€/year in MMM versus 157.90 M€/year in CMM), due to this lower participation of FSPs at distribution level and the higher weighted bid price for FSP@T. Consequently, the cost at system level of the MMM is lower than the expected cost of the CMM, as shown in Figure 47 (note that the y-axis starts in 156.5 M€, so that the difference can be noticed).

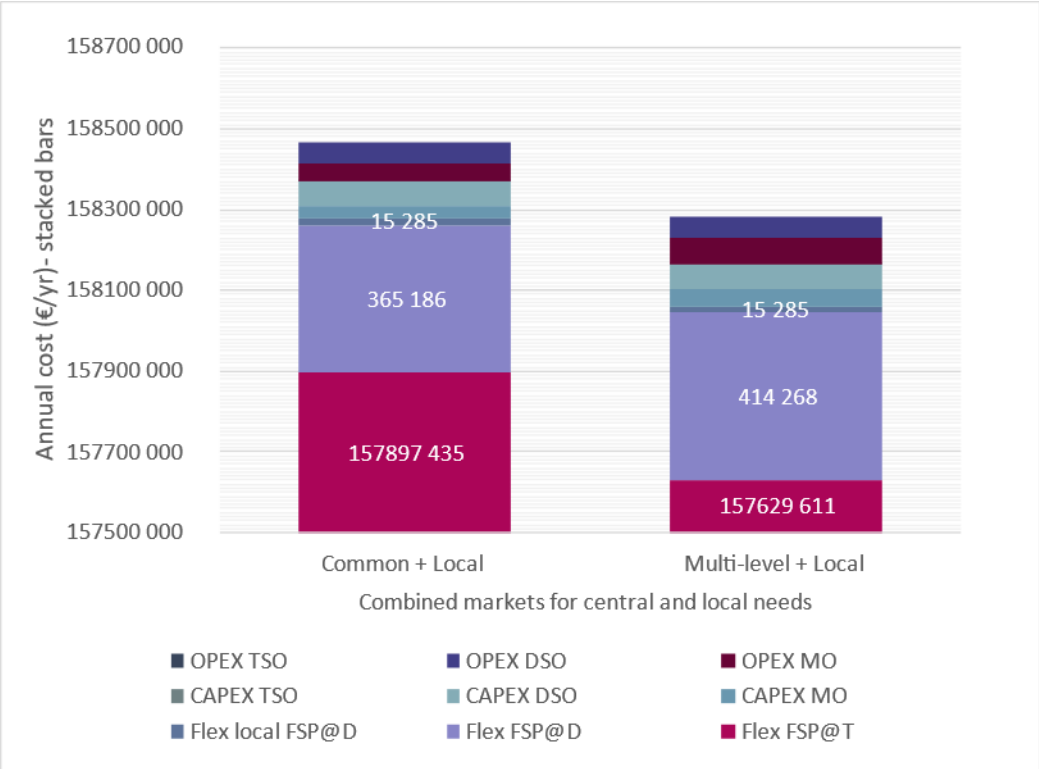

Figure 47: Annual cost (€/year) at system level (including flexibility procurement, CAPEX and OPEX cost for regulated actors) for combined markets (common coordination scheme + local markets and multi-level coordination scheme + local markets)

Table 32 provides detailed information about the energy activation, CM flexibility cost for FSP@D and FSP@T and weighted prices at different coordination schemes (CMM and MMM). As can be observed, the weighted price and costs are strongly dependent on the characteristics of the market simulation. As modelled in (Cossent et al., 2022), the CM weighted prices of FSP@D for joint TSO and DSO needs are relatively low, as the technologies which participate in CMM and MMM are RES-based assets with low operating costs. In contrast, the CM weighted prices in the LMM are greatly influenced by the technologies existing in each local market (demand response) and their higher bid prices are mostly related with their discomfort or predisposition to provide flexibility.

The cost of flexibility is difficult to estimate, due to the volatility of prices and uncertainty of system needs, and it also depends on the mechanism for flexibility procurement (i.e., market mechanisms based on pay-as-bid or pay-as-clear, bilateral contract agreements, capacity and/or energy payments, etc.), the liquidity, technologies which provide flexibility, etc. Therefore, the results presented in Figure 47 and Table 32 can provide some trends, based on the simulated scenarios under pay-as-bid mechanisms for the selected demos, but they should not be extrapolated to a large-scale procurement of flexibility.

Despite the difference on the participation rate between FSP@T and FSP@D, it can be concluded that both coordination schemes reach the same cost-efficiency in their market clearing process (as the CMM increase in 0.17 % from the MMM -157.63 M€/year in MMM versus 157.90 M€/year in CMM-, which is a negligible difference among CSs).

Table 32: Energy activation, cost, and weighted prices for joint TSO and DSO needs in Albacete and Cádiz in the two TSO-DSO coordination schemes (CMM and MMM) and for local needs in Murcia and Málaga (included in LMM)

		FSPs	FSP@D	FSP@T
Common Market Model (CMM)	CM cost (€)	158 262 620	365 186	157 897 435
	CM energy activation (MWh/year)	5 666 820	247 234	5 419 585
	CM weighted price (€/MWh)	27.93	1.48	29.13
Multi-level Market Model (MMM)	CM cost (€)	158 043 879	414 268	157 629 611
	CM energy activation (MWh/year)	5 668 877	257 578	5 411 299
	CM weighted price (€/MWh)	27.88	1.61	29.13
Local Market Model (LMM)	CM cost (€)		15 285	
	CM energy activation (MWh/year)		224	
	CM weighted price (€/MWh)		68.32	

After evaluating the flexibility costs for each CS, there are other costs at system level related to the recognized remuneration for regulated actors (CAPEX and OPEX), based on the investment and operational cost of the flexibility markets. These costs are presented previously in Figure 47, as stacked bars for each combination of markets (common for joint TSO and DSO needs + local for local needs, multi-level for joint TSO and DSO needs + local for local needs). In percentage relationship, Figure 48 presents the cost component per market (CMM, MMM and LMM) considering the expected costs, based on the features of these demonstrators (see section 5.2) and market simulations. Additionally, Figure 49 presents the cost component per market after applying financial costs for the CAPEX and the OPEX margin, according to the Spanish regulation and following the methodology described in section 4.1. A financial rate of return of 8% for the CAPEX (riskier investment) and margins of 5% for the OPEX in joint TSO and DSO markets and 10% in local markets are included. The lifetime of the SW assets is established in 10 years.

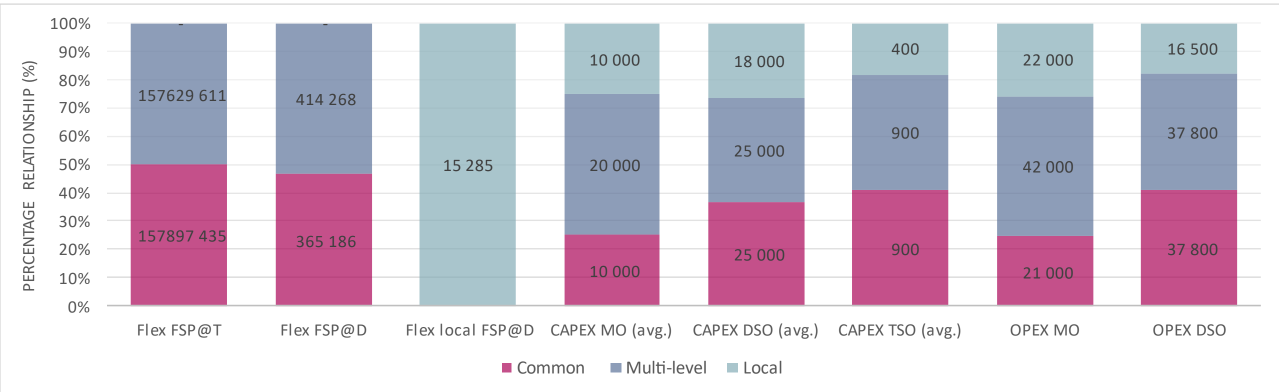

Figure 48: Percentage relationship between CAPEX and OPEX component for Common, Multi-level and Local markets

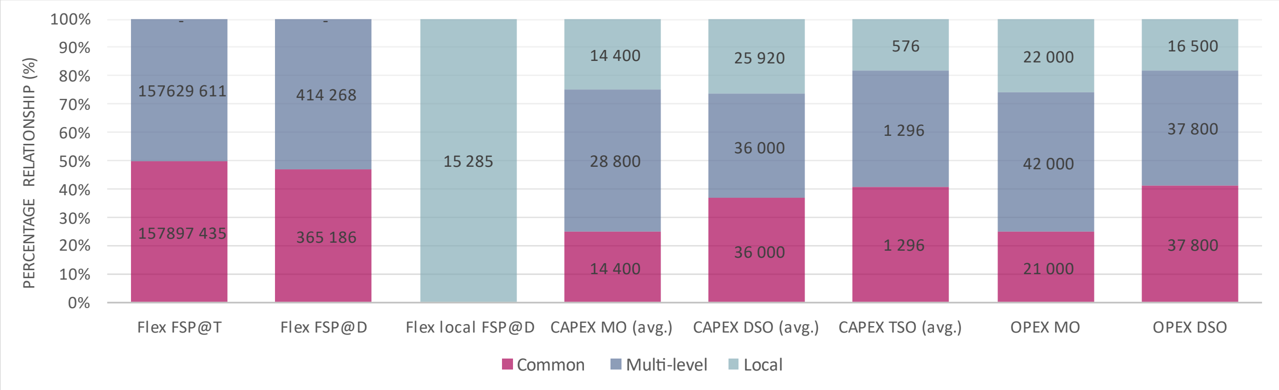

Figure 49: Percentage relationship between CAPEX and OPEX component after financial costs, OPEX margins and flexibility for Common, Multi-level and Local markets

Figure 50 presents the annual cost at system level to solve joint TSO and DSO needs, where the CAPEX is expressed in an annual basis, considering a lifetime of 10 years, and the annual OPEX for each regulated agent is also shown. Addressing the comparison of multi-level and common markets, it can be pointed out that the MMM has more complex communications and requires more SW development from the MO perspective, as the market is cleared at multiple stages, levels, and premises. In contrast, the economic implications for the TSO and the DSO are expected to hardly change in case of opting for the MMM or the CMM. In this sense, the CMM seems to be more efficient from the market and economic perspective to solve joint TSO and DSO congestion managements, as depicted in Figure 50.

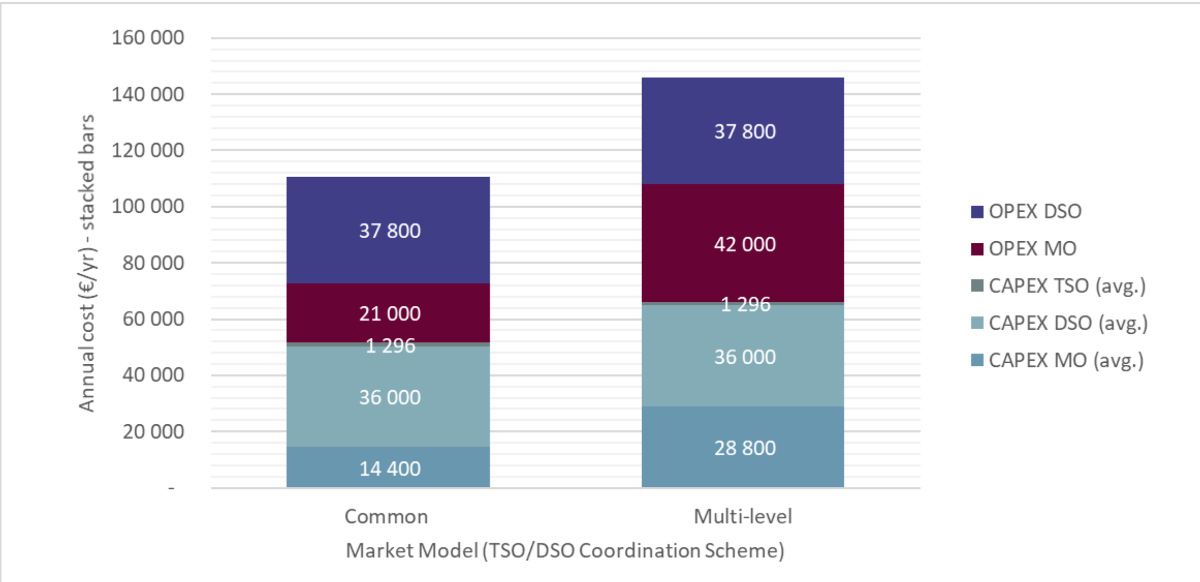

Figure 50: Annual costs for Common and Multi-Level markets at system level for joint TSO and DSO needs

Figure 51 presents the annual cost at system level for combined markets (both joint TSO and DSO and local needs). The local market is expected to have lower CAPEX and OPEX than other TSO-DSO coordination schemes, with less demanding market access and communication procedures (see also Figure 48). These local markets are focused on solving local needs from the DSO at MV and LV and, therefore, the cost of these local markets at system level should be added to the cost of flexibility for joint TSO and DSO needs. Since these local markets are expected to be used as the DSO-related level of the multi-level market, MO costs are the same under both options.

These costs are presented in section 5.2, as estimated costs for a demonstration solution, according to the functionalities developed and validated. The commercial flexibility solution will require a higher level of integration with the existing TSO, DSO and MO platforms, some new functionalities not covered in the demonstrators (see Table 3), higher communication deployment and a full-scale validation, for a successful deployment of flexibility markets. Thus, these costs will be higher than the ones presented in this deliverable.

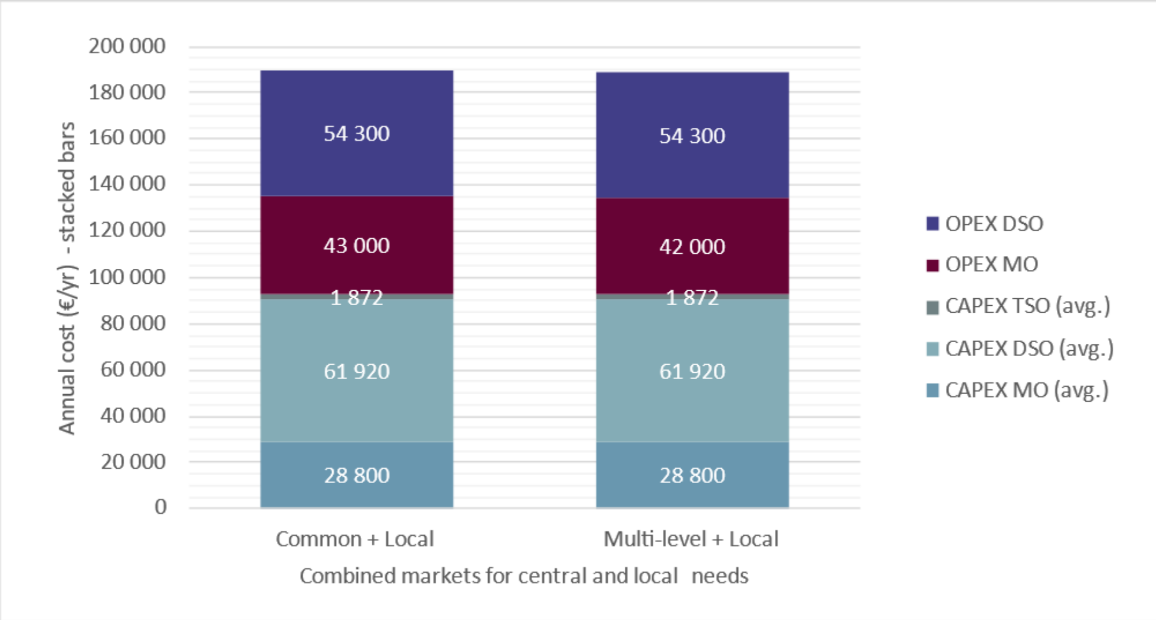

Figure 51: Annual costs for combined markets (Common or Multi-Level for joint TSO and DSO needs + Local for DSO-specific needs) at system level

5.6 Main conclusions of the flexibility solution in Spain

The economic analysis performed for the demonstration areas in Spain focused on congestion management services, with a twofold scope. On the one hand, the assessment for using flexibility to tackle joint TSO and DSO needs has been presented, while, on the other, the potential for using flexibility to solve DSO-specific needs at the lowest voltage levels was evaluated. For each type of system need, the economic implication for the DSO and the FSPs have been addressed, while the possible coordination schemes have been compared at system level.

In case of joint TSO and DSO needs, it can be highlighted the need for interoperability of distinct flexibility markets. Congestion management products in transmission and distribution level can be procured efficiently in common and multi-level markets as presented. The centralized market model should be avoided, even if it enables the participation of FSPs located at distribution level, whenever it disregards the specific DSO needs. Therefore, it should only be considered if the DSO has mechanisms to check or prevent congestions by e.g., blocking or limiting the flexibility to be dispatched at distribution level, as, for example, in BUC ES-2 for balancing in the Spanish demonstrator.

From the market clearing process, there are not significant differences in weighted price and resources allocations, as long as the FSPs at distribution level maintains competitive bid prices compared to the existing FSPs at transmission level. The common market seems to be more cost-efficient from the market design and deployment perspective than the multi-level market model, to solve jointly transmission and distribution needs. On the one hand, the already existing market structure and legacy systems support the adoption of common markets, at the expense of the multi-level. On the other hand, the multi-level coordination scheme would implicate more SW development from the MO perspective and more communications among market actors, i.e., each DSO should deploy their own SW and ICT infrastructure to procure congestion management in their local regions, or the available FSPs bids should be forwarded to the DSO and, later, to the TSO. However, for a combination of CM markets to solve both joint TSO and DSO needs, and DSO-specific needs (like the one tested in the Spanish demonstrator,) the DSO-related stage of the multi-level market model can use the same market platform as the one used in the local market, thus reducing the overall costs for the system.

From the DSO perspective, both joint TSO and DSO needs, and DSO-specific local congestion needs have been analysed. Congestions at distribution level are not frequent nowadays, because DSOs invest in grid assets to continue providing system security and quality of service to their customers according on their expansion plans. However, the economic analyses presented in this deliverable give the opportunity to evaluate how to solve them in the near future.

In case of occasional congestions (like the ones simulated in Murcia demo), i.e., blackouts or unexpected events, flexibility may be more economically efficient than reinforcing the grid or take costly remedial actions (often used by the DSO to solve local congestion in distribution grids), due to the amount of flexibility needs is low and it happens just a few times a year. In this context, the activation of flexibility from FSPs connected to the distribution grid could lead to solve unforeseen congestions. Short-term market mechanisms may be an efficient solution to solve these occasional congestions, in which a few FSPs are required to be ready for flexibility. To the extent the congestion becomes a structural one, the flexibility may provide a faster and temporary solution, until the grid-based solution is commissioned and ready.

Whereas, in case of structural congestions (like the ones simulated in Málaga, Albacete and Cádiz grids), the amount of flexibility needs is higher than in the case of occasional congestions and, thus, flexibility needs to be procured more frequently. Although not covered in this deliverable, long-term markets may be recommended to ensure the level of required flexibility (i.e., via bilateral contracts), until there is enough liquidity in short-term markets to procure it. Specially, this problem arose in Málaga simulation in which it is required more than 7 times the flexibility provided by the FSPs initially considered in the demo. In this case, the flexibility solution can be used to postpone grid reinforcements, in case of the cost of flexibility solution is cheaper than the traditional grid-based solution. As the flexibility costs tend to increase (due to the vegetative increase of demand), the grid-based solution can be selected and planned in advance.

Finally, the profitability for the flexibility sellers' actors (FSPs, aggregators, distributed energy resources, etc.) has been evaluated both for markets to solve join TSO and DSO needs, and for local markets. The business case is not profitable and attractive for individual locations (and with low pay-as-bid flexibility prices), due to the high initial investment costs (SW and ICTs), OPEX costs for the demanding communication requirements (especially with the TSO) and other costs (related to the BRP or retailers). These entry costs can disincentivise their participation. Therefore, the business model needs to be scaled up, so that the aggregator can use its own infrastructure to solve congestions in various locations, both at the transmission and or distribution level.

6 Economic assessment for Sweden

6.1 Brief demo description

Figure 52 shows the main information regarding the Swedish demonstrator and its demos runs (Ruwaida and Etherden, 2022).

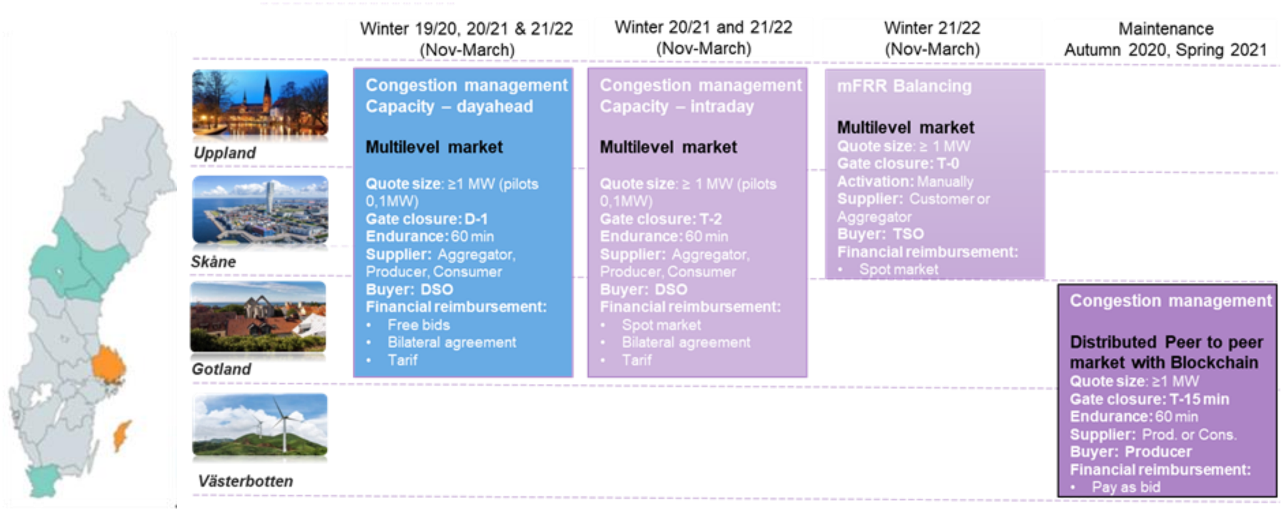

Figure 52: Markets and their respective products in the Swedish demonstration

6.2 Demo cost analysis review and scalability

6.2.1 CAPEX

The CAPEX of the Swedish demonstrator was calculated in (Ruwaida and Etherden, 2022) and later analyzed in (Trakas et al., 2022). The incurred costs were: 1 947 913 €, in the multi-level market (BUC SE-1a) and 166 500 € for the P2P market (BUC SE-1b).

For the analysis carried out in this report, only the value assigned to the BUC SE-1a (multi-level congestion management) will be considered, since the P2P approach is not included in this analysis. Due to the nature of the demonstration activity, the most important development has been the DSO platform, which allows the DSO to perform both the roles of system operator and market operator. In addition to the costs borne by the DSO, the TSO also needs to incur some costs to adapt their systems to the new DSO platform.

As a first approach, the Swedish demonstrator identified the main functionalities to be developed and their related ICT costs were valued. Then, within (Trakas et al., 2022) and as part of the ICT cost analysis performed, on the basis of such functionalities, the values were assigned to the pertinent actor in charge of each functionality (i.e. DSO, market operator (MO) and the Swedish TSO). Table 33 (own elaboration with information from (Trakas et al., 2022)) shows such costs and their allocations:

Table 33: ICT CAPEX allocation - Sweden

Cost	DSO	MO	TSO
Grid monitoring (visualization, optimization, subscription integration)	333 000 €		
Market engine (bid generation, gating, clearing, subscription integration) – common costs for all demo-sites		832 500 €	
Load forecasting (models built outside platform)	83 250 €		
Integration (e.g., external API, data storage)	416 250 €		
Integration with the mFRR market			37 689 €
Changes in SUSIE (Swedish TSO's tool to request temporary subscriptions)			37 689 €
Meters at consumer/producer facilities	80 370 €		
Forecasting (models, Expektra)	41 234 €		
Security & data classification	26 476 €	26 476 €	
Data Hub	32 978 €		
TOTAL	***1 013 558 €***	***858 976 €***	***75 378 €***

The calculated total ICT costs, including those related to the system operation, market operation and the costs assumed by the TSO for the updating of its own systems, are 1 947 913 €. The costs assumed by each actor are split as follows: i) DSOs assume 1 013 558 €, ii) the MO faces 858 976 €, and iii) TSO's update costs are valued at 75 378 €. Additional and very detailed information regarding the ICT costs in the Swedish demonstrator can be found in (Trakas et al., 2022). On one hand, the total estimated costs for the development of each one of the tools developed and used in the Swedish demonstrator are calculated. On the other hand, the ICT costs calculated by each pilot site are also specified. Since this information is not relevant for the analysis described in this document, this level of detail is not included in this subsection.

Based on the values indicated in Table 33 and taking into account several assumptions when necessary (e.g., values for the common approach or costs for FSP and DERs), the values finally considered in the performed analysis are shown in Table 34. A brief explanation of such values is also included below.

Table 34: CAPEX considered in the Swedish demonstrator

Agent	Common (€)	Multi-level (€)
TSO (1)	75 378	75 378
DSO (2)	900 000 (estimated)	1 013 558
MO (3)	500 000 (estimated)	858 976
FSP (Agg) (4)	250 000	242 000
DER (5)	300	300

(1) The same TSO cost has been considered for the common and the multi-level markets.

(2) Based on the value indicated for the multi-level case, 900 000 € have been considered for the common market approach.

(3) Based on the value provided for the MO in the multi-level approach, it is considered that the cost for running just one market in the common management approach, should be lower.

In Sweden, the FSPs and DERs participating in the demonstrator are not part of the CoordiNet consortium, so no information regarding the incurred costs for their developments is available. Hence, and considering that the flexibility provision cost in Sweden and Spain is very similar, the values indicated in Table 34 for the FSP (Agg) and DERs are the same as the ones in Table 16 for the Spanish case (see subsection 5.2.1):

(4) The costs incurred by the aggregator for the development of the aggregation platform is valued at 320 000 € in (Ivanova et al., 2022). Based on that value, it has been estimated that the required developments for the deployment of just one BUC, the common or multi-level congestion management, would cost 240 000 €. In addition, taking as basis the Spanish case, a duplicated dedicated line is mandatory between the TSO and every FSP for the communication, valued at 10 000 €. In the case of the multi-level market, a Remote Terminal Unit (RTU) with the DSO is required with an estimated cost of 2 000 €.

(5) The cost assignable to the DERs participating in the different markets is based on the cost of the energy box. A standard cost of 300 € for each energy-box has been considered.

6.2.2 OPEX

The OPEX include the recurrent costs that are required in order to operate and maintain the installed equipment. This value has been calculated for the BUC SE-1a and is equal to 135 214 €.

The analysis of KPI 4 included in (Trakas et al., 2022) is mainly based on the sharing of costs between the flexibility tool and the market platform tool developed by the Swedish demonstrator and the allocation of costs among demo sites. In order to establish the sharing of costs among the main actors (i.e. MO, DSO, TSO) the identified components to be valued when calculating the OPEX have been allocated among such actors according to a criterium of coherence (since in the Swedish demonstrator the role of operating the market is performed by the DSO, in many cases it is complex to determine whether the cost should be assigned to the MO or DSO). This information is provided in Table 35.

Table 35: OPEX allocation - Sweden

Cost	DSO (€/year)	MO (€/year)	TSO
Hosting (Azure cloud)	25 000		
Licenses	7 000		
Security & data classification	500	500	
Cloud service, export, and service of meters	40 044		
Communication (e.g., mobile subscriptions)	11 589		
Forecasting (models, Expektra)	1 696		
Data Hub	31 885		
Installation and service of meters	2 000		
Communication meters (e.g., mobile subscriptions)	5 000		
Forecasting	10 000		
TOTAL	***134 714***	***500***	***0***

Considering these values, and making several assumptions, Table 36 gathers the costs considered when performing the calculations.

Table 36: OPEX considered in the Swedish demonstrator

Agent	Common (€/year)	Multi-level (€/year)
TSO (1)	0	o
DSO (2)	100 000 (estimated)	134 714
MO (3)	500	500
FSP (Agg) (4)	72 000	50 400
DER (5)	12 000	600

(1) The TSO has no additional recurrent costs for the operation of the common or multi-level approaches.

(2) Based on the 134 714 € stated for the DSO in the multi-level approach, it is considered that the cost for the common market would be lower.

In Sweden, the FSPs and DERs participating in the demonstrator are not part of the CoordiNet consortium, so, no information regarding the recurrent costs is available. Therefore, and considering that the flexibility provision cost in Sweden and Spain is very similar, the values indicated in Table 36 for the FSP (Agg) and DERs are the same as the ones indicated in Table 17 for the Spanish case (see subsection 5.2.2).

(4) The OPEX for the maintenance of the SW is valued at 48 000 €. In addition, the communication maintenance must be added. Therefore, 2 000 €/month is the cost considered for the communication in the common CM market, while 200 €/month is the expected cost in a multi-level approach. As result, 72 000 €/year is the total OPEX for the common CM market and 50 400 €/year for the multi-level approach.

(5) The only OPEX to be considered for the DER is the cost of the required communication. The common CM market involves a specific point to point line valued at 1 000 €/month (i.e., 12 000 €/year). For the participation in the multi-level market only an ethernet line would be necessary. The cost of this ethernet line is 50 €/month (i.e., 600 €/year).

6.3 Case study: Joint TSO and DSO needs

6.3.1 Simulation scenario for joint TSO and DSO needs

6.3.1.1 Challenges in Uppsala

As discussed in subsection 3.1.2, the Swedish distribution networks are organized into two levels: the local network (up to 50 kV) managed by the local DSO, and the regional network (normally between 70 kV-130 kV) managed by the regional DSO. The regional DSOs have a contract with a specific subscription level towards the TSO. The subscription level is the annually contracted level of power that is allowed to be drawn by the regional grid from the TSO, without further agreement (Ruwaida and Etherden, 2022). Until recently, it was also possible to apply for a temporary subscription in addition to the annual subscription. Historically, there has not been any problem for the regional DSOs to get subscription raise or temporary subscriptions. However, in recent years, the regional DSO in Uppland has been denied subscription raises, while awaiting completion of TSO's grid enforcements. The denial of subscription requests is especially problematic given the long planning time for HV levels of the grid. Also, the local DSOs have a subscription level with the regional DSO (Etherden et al., 2020). Thus, there is an increasing need for flexibility for the TSO and, also the DSOs have an urgent need for flexibility for local needs. In the remainder of this subsection, any reference to the DSO must be understood as a reference to the regional DSO, as the aim is to assess the performance of flexibility to solve joint TSO and DSO needs.

The Swedish scenario considered the Uppland region (Cossent et al., 2022), the Uppsala substation in particular, in which the distribution network under study is connected, with several FSPs@D listed in Table 37. Balancing and CM services are considered at T&D HV grids. The CAPEX and OPEX for the TSO, DSOs and MOs (SW, ICTs) should be considered, as well as the temporary subscription tariffs costs for the DSO.

The economic assessment for joint TSO and DSO needs of D6.3 is focused on the evaluation of the economic implication for the involved market agents (Pillar 1.a & Pillar 3.a), according to the implemented CS oriented to provide CM services for joint TSO and DSO needs (as balancing service is already procured through a pan-European market) in the Swedish demonstrator. Additionally, the cost-efficiency of the TSO-DSO coordination schemes to solve these joint TSO and DSO needs is compared and evaluated (Pillar 2).

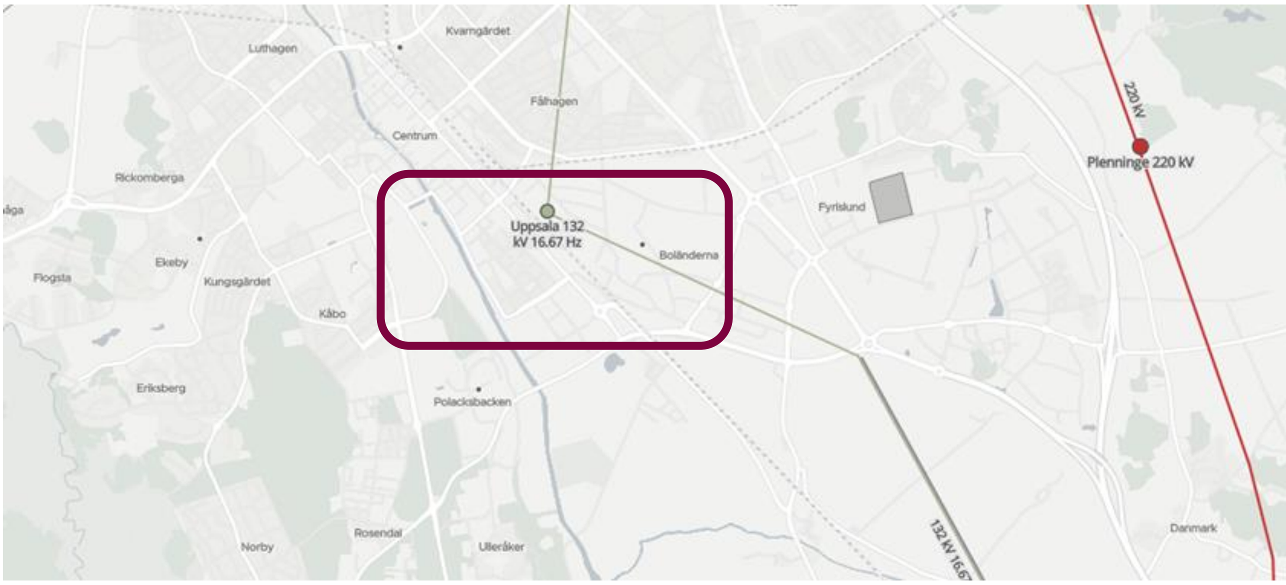

Figure 53: Uppsala substation in Sweden

Table 37: FSPs considered in the Swedish economic assessment

DER	Network	Node	Downward capacity (MW)	Upward Capacity (MW)	Bid (€/MWh)	Technology
fsp1	Uppsala	D713	5	5	8	Battery
fsp2	Uppsala	D716	0	0.5	10	Office buildings
fsp3	Uppsala	D12	0	0.5	16	Multi-family housings
fsp4	Uppsala	D710	0	0.5	12	Commercial building
fsp5	Uppsala	D712	5	30	20	District heating
fsp6	Uppsala	D712	0	0.5	16	Multi-family housings
fsp7	Uppsala	D712	0.5	1	16	Industry
fsp8	Uppsala	D714	0.5	1	16	Industry

6.3.1.2 Services needs and network modelling

The 32-node Swedish transmission network is considered, as well as a simplified sub-transmission (distribution) grid of the demo downstream the Uppsala substation, one of the Swedish demonstration sites. This sub-transmission network is a representation of the 70 kV network of the Uppsala site.

Figure 54 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 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.

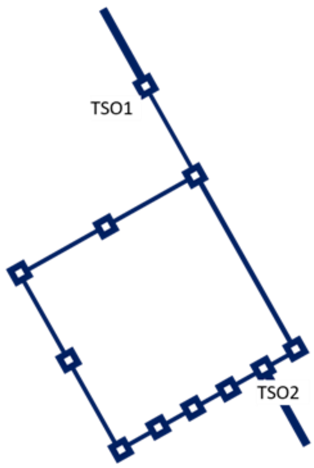

Figure 54: Representation of 70 kV distribution grid in Uppsala

For the overall wholesale market parameters, including the modelling of the different representative days that lead to the whole-year results provided, data from multiple sources are used in market simulations, covered in (Cossent et al., 2022). The goal is to have a well calibrated wholesale energy model that will serve as the basis for the different CSs. For Sweden, a demand of 140 TWh (approx.) is considered, to match the demand of 2020. For balancing, a need of 3 TWh is considered at transmission and distribution level, as summarized in Table 38. However, the balancing services will be disregarded from the economic analysis.

The scenario modelled for joint TSO and DSO congestion management, which considers a multi-level market model, CM needs and the FSPs connected at the distribution grid, aims at reaching the best approximation possible for the demonstration in Sweden in the year 2020. There is no congestion at distribution grids (overloaded lines or due to thermal issues), but only the limited capacity in the connections between the TSO and DSO which require to evaluate the subscription level. Although the demonstration campaign in Sweden focused on solving congestions at the TSO-DSO boundary, the simulated scenario described in (Cossent et al., 2022) also considers CM needs at transmission level (206 686 MWh/year).

Table 38: Balancing and Congestion Management in the Swedish economic assessment (in MWh/year)

Network	Network acronym	Upward balancing needs	Downward balancing needs	Congestion management needs
Uppsala	D1	8 731.11	5 811.89	-
Transmission	T	1 797 928.73	1 196 797.40	206 686.16

6.3.1.3 TSO-DSO coordination schemes

Three basic CSs (Common, Central and Multi-level) are modelled in (Cossent et al., 2022), following the general CoordiNet concepts presented in (Delnooz et al., 2019). In Sweden, an adaptation of the Multi-level CS is performed. On the “general” Multi-level CS, the DSO runs first a direct-current (DC) Optimal Power Flow (OPF) to solve local congestions (congestion understood as overload of grid elements) and passes on the unused bids to the TSO market(s), together with the information of activated FSPs in the distribution grid.

The variation proposed is based on the Swedish demonstration, described in the deliverables of WP4 (Vattenfall, n.d.). In this implementation, the DSO evaluates the use of flexibility from DER against surpassing the subscription levels of each substation connected to the overlaying grid (which would lead to an expensive penalty). Therefore, only the power at those substations is considered, as the DSO tries to solve these “virtual congestions”. The optimization algorithm is also different from the OPF implementation, as it does not run an OPF. Instead, it considers the Power Transfer Distribution Factor (PTDF) of each FSP on the “congested” element (the two substations in Uppsala). From the results in (Cossent et al., 2022), it is possible to observe that both implementations lead to similar results, as the network does not present significant network constraints downstream at distribution (sub-transmission) level.

In the economic assessment for joint TSO and DSO needs, the overall cost at system level covered in the Pillar 2 will be presented for the main representative CSs: the common and multi-level (PTDF) market model.

6.3.2 Economic impact for regulated agents (joint TSO and DSO needs)

The flexibility scenario is to procure the flexibility from FSPs connected to the regional DSO, in order to reduce the subscription cost paid by the DSO, in case of lack of enough interconnection capacity with the TSO.

The Swedish flexibility scenario for joint TSO and DSO needs focuses on Uppsala sub-transmission grid, where temporary increases of subscription level in connection to the transmission grid are required, in addition to TSO congestion needs at transmission level (as described in subsubsection 6.3.1.2). The FPS@D in distribution networks are allowed to participate in these flexibility markets to solve joint TSO and DSO needs. Additionally, there are FPS@T which also provide joint TSO and DSO CM needs to a greater extent.

The comparison of the flexibility use versus a non-flexibility scenario from the DSO perspective is evaluated specially for the CS implemented at demo and covered in (Cossent et al., 2022), that is, the multi-level market model (operated by a DMO). The comparison will be carried out considering the flexibility solution as a temporary solution for a given time span (i.e., 1 year is sufficient, as neither future tendency of joint TSO and DSO CM need nor temporary subscription necessities have been estimated along several years).

In the Swedish BaU scenario for joint TSO and DSO needs, congestion issues at the Uppsala substation are assumed (which require to increase the level of DSO subscription, or even worse, pay the penalties for surpassing the agreed subscription level), as well as congestion management needs at transmission level. Balancing services are also simulated, but it will be disregarded for this CM-oriented economic analysis.

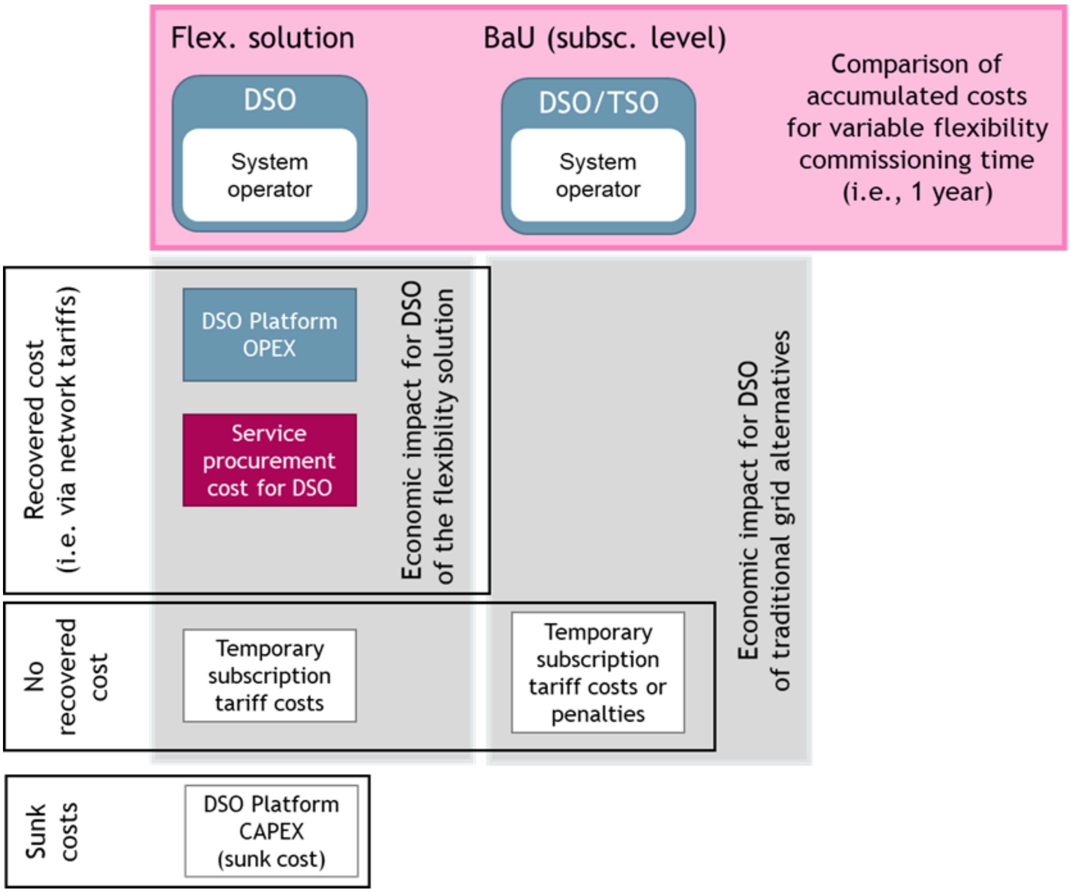

Figure 55: Cost components for the DSO in the flexibility and BaU alternatives for joint TSO and DSO needs in Uppsala (Pillar 1.a)

The costs involved (OPEX and service procurement) for the comparison of both alternatives for joint TSO and DSO needs (flexibility versus BaU solution) are evaluated at different time spans, based on the duration of the flexibility commissioning, as depicted in Figure 55. The economic comparison focuses on the DSO costs, as DSOs have to buy flexibility or, otherwise, they would be forced to ask and pay for an increase in subscription level.

As stated above, several flexibility markets are addressed in (Cossent et al., 2022) for balancing and congestion management needs. In order to evaluate specifically the cost-efficiency of the flexibility solutions to solve CM needs in the transmission and distribution networks (including also the temporary subscription for the limited capacity), the provision of flexibility for balancing services are disregarded.

The CM needs for TSO are depicted in Table 38, being provided by the flexible resources at distribution network in the demonstrators (FSP@D) listed in Table 37, jointly with FSP@T.

Table 39: Congestion Management for joint TSO and DSO needs in Uppsala and transmission level. Source: (Cossent et al., 2022)

Provider	CM activation in RT
FSP@D in the Uppsala network	10 066 MWh/year
FSP@T in the transmission network	635 566 MWh/year
FSPs	645 633 MWh/year

A multi-level market model is selected for the Swedish scenario to solve CM and BM needs, but with the effective coordination of the DSO to access the participation of FSPs located at distribution level. Table 40 provides more information about the energy activation and cost for CM and balancing needs.

The CM weighted price is 6.91 €/MWh for joint TSO and DSO CM needs, considering the cleared bids from FSP@D and FSP@T, according to a pay-as-bid price model. As can be observed, the CM bid prices from FSP@D (15.74 €/MWh) are higher than the ones from FSP@T (6.77 €/MWh), on the contrary to the Spanish scenario. The Swedish large-scale generation assets are mostly hydropower plants, while combined cycle power plants with higher operation cost influenced the CM weighted price in Spain.

For clarification purposes, the FSP@D are able to participate and solve balancing markets in the simulation scenario. However, as FSP@D's prices are higher than Swedish large-scale generation assets at transmission level, their participation is restricted only to CM in the multi-level CS.

Table 40: Energy activation and cost for joint TSO and DSO needs in the Swedish transmission grid, divided by FSPs

	FSPs	FSP@D	FSP@T
CM cost (€)	4 462 471	158 454	4 304 018
CM energy activation (MWh)	645 633	10 066	635 566
CM weighted price (€/MWh)	6.91	15.74	6.77
Balancing cost (€)	8 465 227	-	8 465 227
Balancing energy activation (MWh)	3 009 269	-	3 009 269
Balancing weighted price (€/MWh)	2.81	-	2.81
Weighted price (€/MWh)	3.54	15.74	3.50

Figure 56 depicts the estimated annual costs (in €/year) for the considered alternatives (flexibility scenario or BaU with higher subscription costs or, even worse, penalties for surpassing the agreed subscription level). For the DSO with the flexibility solution, the total cost is 920 k€ per year. This cost includes not only the procurement of flexibility (10 GWh), but also the payment of temporary subscription fees and estimated OPEX cost of the software platform and ICT-related and other maintenance costs. In fact, the temporary subscription fee account for 620 k€, while the procurement of flexibility reaches 158 k€ per year, required at distribution level and provided by the FSP@D in the multi-level market model, and a recurrent OPEX term of about 141 k€ per year.

In contrast, the BaU alternatives are to pay for higher temporary subscription fees because of there is no flexibility at distribution level or not asking for a temporary subscription on time and pay higher penalties. Overcoming the agreed subscription level results in a penalty for the agent (including the regional DSO) which is much higher than the usage fee, i.e., temporary subscription usage fees are in the range of 250 SEK/MWh (around 23.34€/MWh), while penalties rise to 560 SEK/MWh (around 52.29€/MWh) for the first hours with violations of the subscription level (Svenska kraftnät, 2022).

The energy associated to the subscription level in BaU alternatives is around 77 833 MWh (almost 8 times higher than with the flexibility solution). Assuming the fees presented above, the subscription-related cost are 1 816 k€ per year (asking for temporary subscription) and 4 070 k€ per year (not asking for temporary subscription on time and paying penalties).

It can be concluded that the flexibility solution is more favorable for the DSO than the BaU, which implies to increase the subscription level where necessary and without flexibility resources at distribution level. The estimated annual costs (TOTEX DSO) for the flexibility solution account for 920 k€ per year, in comparison to the cost of the BaU alternative. In case of no flexibility at distribution level, it is desirable to ask for an increase of temporary subscription level than paying for the associated penalties. Hereafter, the analysis will be focused only in the BaU which considers the temporary subscription tariffs.

Additionally, the modelled scenario for joint TSO and DSO needs also considers the resolution of CM needs at transmission level, where FSPs@T have higher participation due to their lower bid price. The total costs to solve all joint TSO and DSO needs (in transmission and distribution level) are 4 462 k€/year, as compared with the BaU cost of 4 285 k€/year (Total CM cost bars in Figure 56). This cost difference among alternatives arises from the need to activate more flexibility in the distribution network to reduce avoidable subscription needs, which lead to opposite activation at transmission level. As will be presented in the results of Pillar 2 for Sweden, the flexibility scenario may result better at system level, as the increase of CM activation (and its costs) in the flexibility scenario is counteracted by the reduction of the cost temporary subscription.

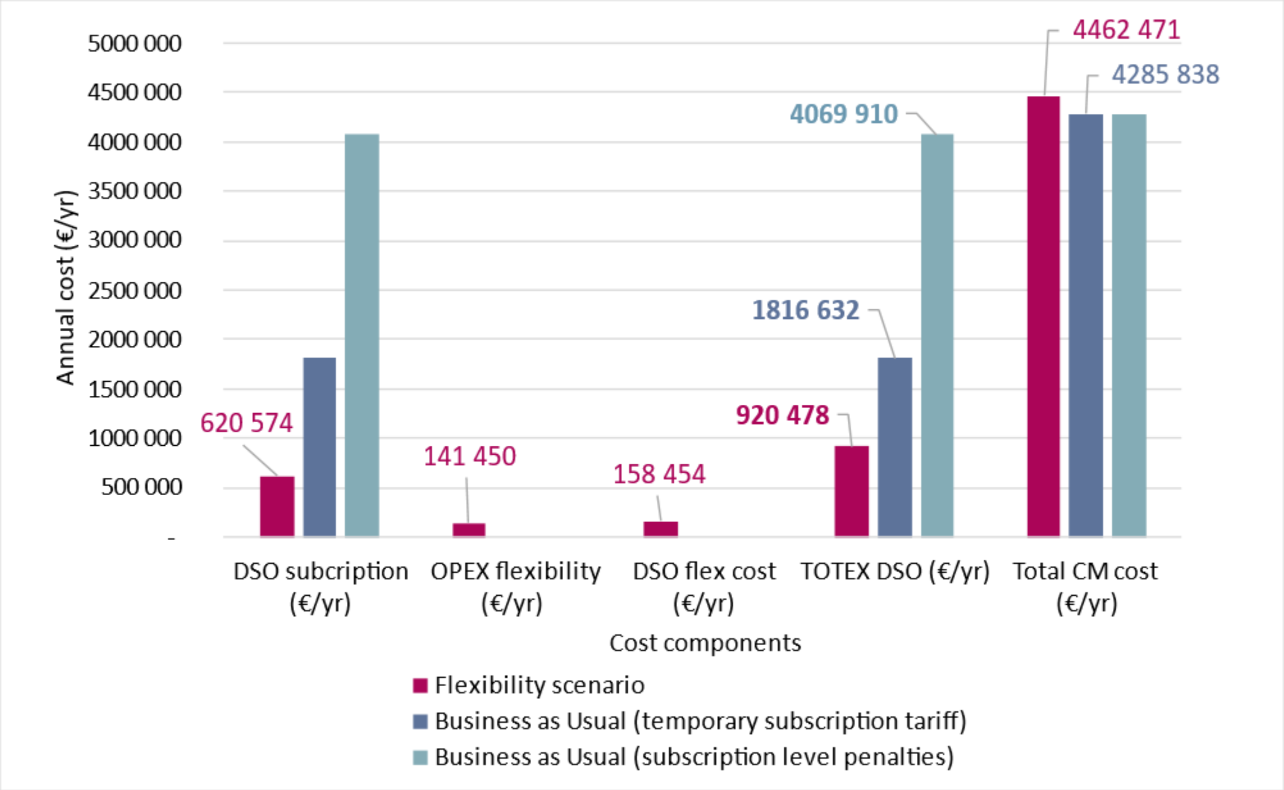

Figure 56: Annual costs (€/year) of the cost components for the DSO and CM costs according to the grid alternative

Figure 57 summarizes the previous information raised in this subsection and provides in a visual way the percentage relationship in order to compare each term of both grid alternatives (flexibility scenario and BaU scenario). The following items are presented for the Swedish scenario:

- DSO temporary subscription cost, OPEX flexibility cost for the DSO (if applicable) and the flexibility cost for the CM procurement (if applicable). These items sum to the annual TOTEX cost for the DSO.
- The CM incomes for the FSP@D in €, as well as the annual CM energy activation.
- The CM incomes for the FSP@T in €, as well as the annual CM energy activation.
- The total CM cost, composed by the CM incomes for the FSP@D and FSP@T.

As can be observed, the flexibility scenario gives the opportunity to FSP@D to participate in flexibility services and obtain a remuneration, creating new business models at distribution level.

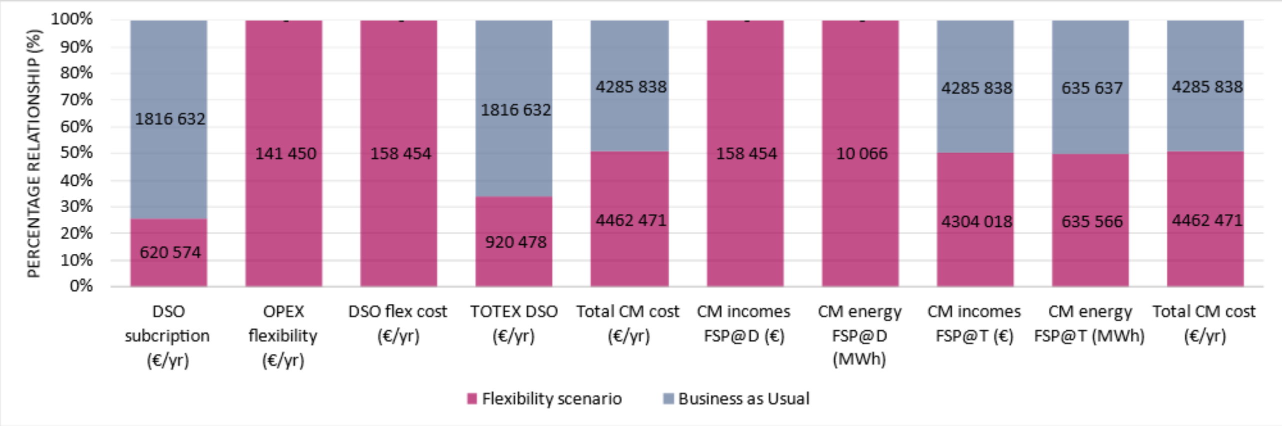

Figure 57: Percentage relationship between each cost component for the DSO, CM costs and CM activation per FSP

6.3.3 Cost-efficiency of coordination schemes at system level (joint TSO and DSO needs)

The Swedish economic assessment at system level considers the recognized CAPEX and OPEX (SW, ICTs, etc.) for regulated agents, i.e., TSO, DSO and MOs are considered, as depicted in Figure 58. In the multi-level coordination scheme, TMO and DMO may exist, in which the DMO manages the local needs at distribution level at a first stage and then, the TMO manages the central needs at transmission level. Otherwise, in the common market, a single MO at transmission level is required. The service procurement costs for TSO and DSO needs are also considered at different CSs. The temporary subscription tariffs costs for the DSO are also considered in the analysis at system level, as an extra direct cost for the DSO.

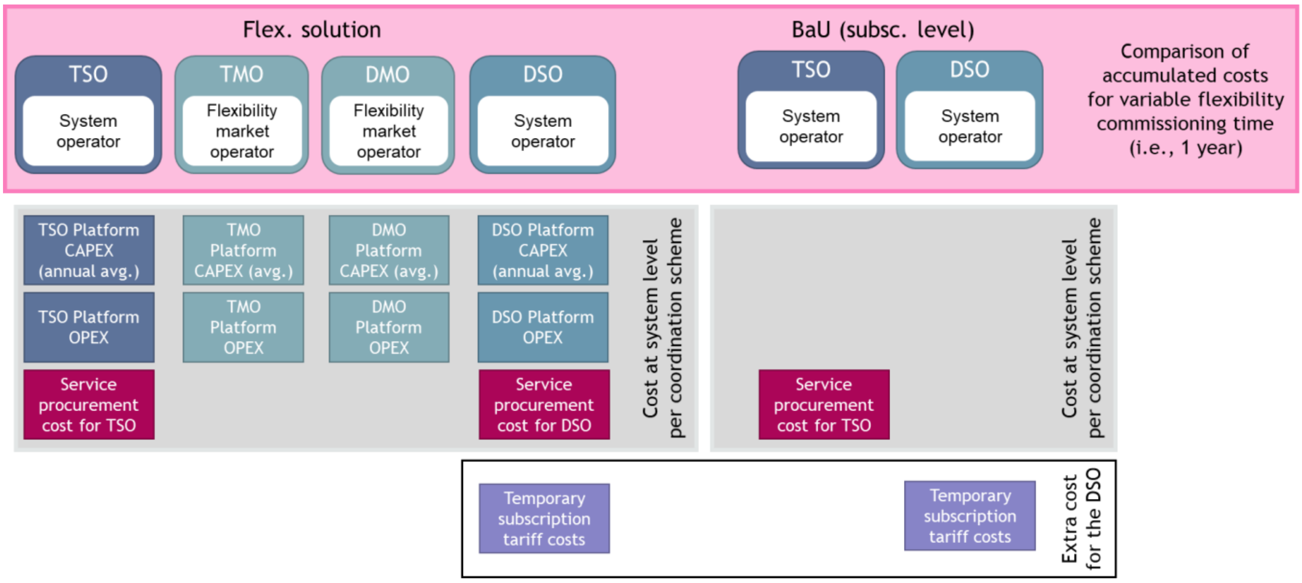

Figure 58: Economic impact of flexibility solution at system level in Swedish scenarios (Pillar 2)

However, the available data for CAPEX, OPEX, and service procurement cost have been calculated and categorized slightly different to what is presented in Figure 58. The costs for the MO are evaluated as a whole, without distinguishing between the TMO and the DMO. Additionally, the initial TSO and/or DSO needs for central markets (see Table 38) are provided by FSPs located at transmission and at distribution level.

However, the flexibility activation is not classified according to which system operators belong to. The cost of the flexibility activation is only broken down according to the types of FSP that provide the flexibility:

- Flexibility cost of the FSPs at distribution level (FSPs considered within the market simulations based on the Swedish demo, as described in subsection 6.3.1) to solve joint TSO and DSO needs (Flex FSP@D).
- Flexibility cost of the FSPs at transmission level to solve joint TSO and DSO needs (Flex FSP@T).

A pay-as-bid pricing clearing mechanism is assumed (Cossent et al., 2022) and bid prices are based on the operational expenditures and other criteria of each FSP. The cleared bids are selected according to the optimization formulation of each coordination scheme.

Table 41 provides detailed information about the energy activation, CM flexibility cost for FSP@D and FSP@T and weighted prices for different coordination schemes (CMM and MMM). As can be observed, the weighted costs are dependent on the characteristics of the market simulation, the flexibility bid prices of each FSP, their location in the network, the market access, and their priority in each CS (i.e., in multi-level model the FSP@D as prior access than FSP@T to solve CM or other issues that happen in distribution level).

As modelled in (Cossent et al., 2022), the weighted prices of FSP@D for joint TSO and DSO CM needs are relatively high compared to FSP@T (especially due to RES assets, such as hydropower, with low market bids). In fact, the weighted prices in the first stage of the CM MMM, with local FSP@D participation, are greatly influenced by the technologies providing flexibility, such as demand response, industry or other building loads, whose bid prices are higher.

The cost of flexibility is difficult to estimate due to price volatility and needs uncertainty, as it depends on the mechanism for flexibility procurement (i.e., market mechanisms based on pay-as-bid or pay-as-clear, bilateral contract agreements, capacity and/or energy payments, etc.), the liquidity, technologies which provide flexibility, etc. Therefore, the results presented in Table 41 can provide the economic results and some trends, based on the simulated scenarios with a pay-as-bid pricing mechanisms for the selected demos, but they should not be extrapolated to a large-scale procurement of flexibility.

Regardless of the quantitative results presented in Table 41, multi-level CS increases the participation of small or medium-sized FSPs located at distribution level, giving a market access priority of these market players to solve grid issues, such as the flexibility activation to reduce the necessity of asking for an increase in the subscription level of the DSO. As can be observed, unless the FSPs can participate to solve central TSO needs, they have no relevant participation. The low flexibility bid prices of FSP@T boost the participation of FSP@T, at the expense of the FSP@D.

Table 41: Energy activation, cost, and weighted prices for joint TSO and DSO needs in Swedish flexibility scenario

		FSPs	FSP@D	FSP@T
Multi-level Market Model (MMM)	CM cost (€)	4 462 471	158 454	4 304 018
	CM energy activation (MWh/year)	645 633	10 066	635 566
	CM weighted price (€/MWh)	6.91	15.74	6.77
Common Market Model (CMM)	CM cost (€)	4 012 735	28 749	3 983 987
	CM energy activation (MWh/year)	603 443	1 535	601 908
	CM weighted price (€/MWh)	6.65	18.72	6.62

On the other hand, in the common coordination schemes, FSP@D and FSP@T participate under the same conditions. In this case, the market clearing results to solve central TSO needs are mostly related to the flexibility bid prices of each FSP. As the weighted price of FSP@D is higher than FSP@T, it is observed that the participation of FSP@D is lower: 1 535 MWh/year in CMM, in comparison with 10 066 MWh/year in MMM.

Figure 59 presents the estimated annual costs (in €/year) at system level to solve joint TSO and DSO needs, where the CAPEX is expressed on an annual basis considering 10 years of lifetime and the annual OPEX for each regulated agent. Addressing the comparison of multi-level and common markets, it can be pointed out that the MMM has more complex communications and requires more SW development from the MO perspective, as the market is cleared at multiple stages, levels, and premises. As a result, some costs of the CMM may be estimated to be lower than the MMM, with less market clearing procedures and lower communication requirements between the MO and the market sellers and buyers. In contrast, the economic implications for the TSO are expected to change hardly in case of opting for one or another CS.

Figure 59 summarizes the annual costs for regulated agents, after applying financial costs for the CAPEX and the OPEX margin from section 6.2, which are the recognized remuneration for regulated agents to obtain a reasonable rate of return of investment, while ensuring an efficient, safe, reliable, economic and environmentally sustainable activity.

A financial rate of return of 8% for the CAPEX (riskier investment) and a margin of 5% is included for the OPEX of central markets. The lifetime of the SW assets is assumed to be 10 years.

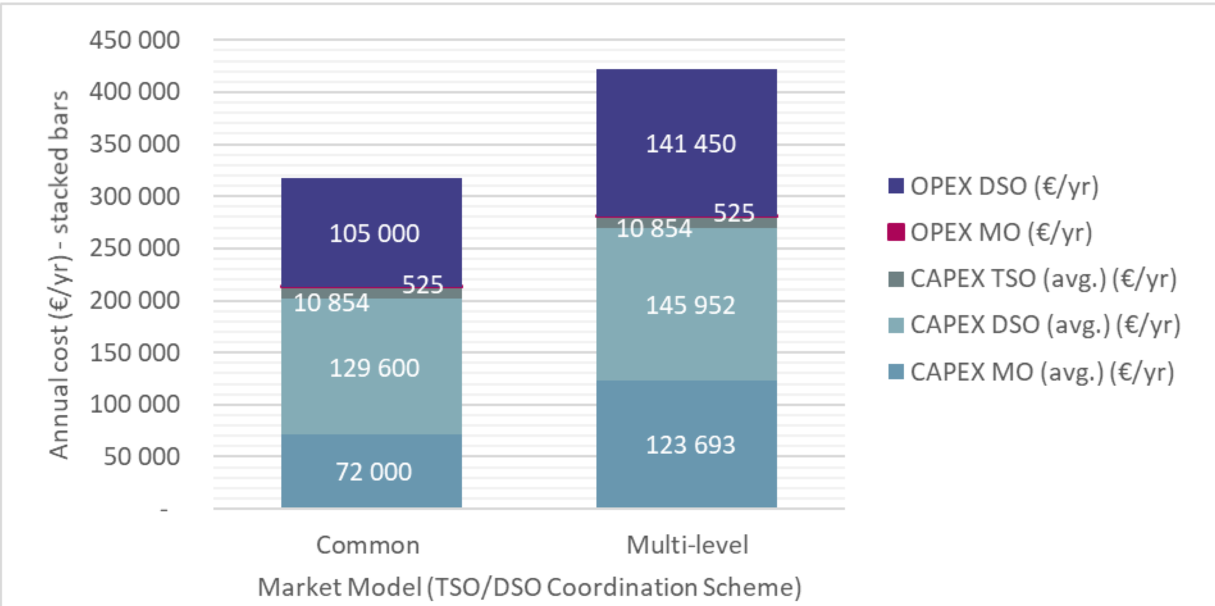

Figure 59: Annual costs (€/year) in stacked bars for the cost components for the compared grid alternatives

Figure 60 presents a summary of the involved cost at system level for different alternatives:

- The flexibility procurement costs (Flexibility cost divided in FSP@D and FSP@T).
- The cost for regulated agents (CAPEX and OPEX for MO, TSO and DSO).
- The total cost at system level, including all the costs discussed above.

These costs are presented as percentages, which enables the comparison of every cost component for both CSs and alternatives (the flexibility solution with CMM and MMM coordination schemes, compared to the BaU scenario).

Figure 60 also presents a comparison of the total cost at system level for three alternatives. As can be observed, the BaU alternative under this analysis is more economically attractive (4 285 k€/year) than flexibility solutions (4 884 k€/year at MMM coordination scheme), as there is no need for additional investments in market platforms or communications. However, it must be taken into account that the subscription tariffs costs for the DSO are increasingly higher (not included so far in the total cost at system level) and that a temporary increase in the subscription level may even be denied by the TSO. In these cases, the use of flexibility markets is a faster solution than reinforcing the grid.

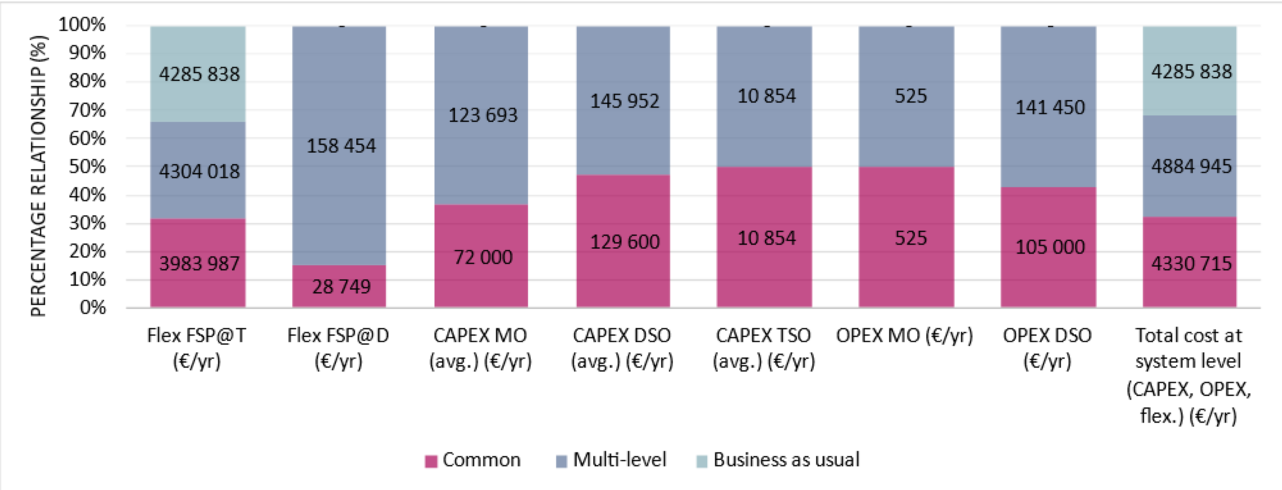

Figure 60: Percentage relationship between each CAPEX and OPEX component after financial costs and OPEX margins and flexibility costs in the flexibility and BaU scenarios

On the other hand, the cost at system level of different coordination schemes can be compared. Although the common market in a theoretical analysis seems to be more cost-effective than the multi-level market (expected less CAPEX costs and higher participation of cheaper technologies, mostly from FSP@T), the most suitable coordination scheme should be evaluated according to the platforms already existing in each country, the roles of the TSO and DSOs and the national regulations.

Figure 61 presents the annual costs at system level for the Sweden analysis, including DSO temporary subscription costs above the flexibility cost and CAPEX and OPEX terms from regulated actors.

As can be observed, a fair comparison cannot be done between CMM and MMM coordination schemes, because the DSO subscription tariff is not evaluated in the market optimization of the common coordination scheme. The CMM solves the joint TSO and DSO CM needs with FSP@T and FSP@D, but the subscription level in the TSO-DSO boundary is not addressed. Although the CMM seems to be theoretically more cost-efficient to solve joint TSO and DSO needs at lower price, it ignores the specific features of the Swedish market, such as the subscription level.

On the other hand, the business-as-usual scenario does not require new platform and communications, but the DSO subscription costs are higher than in the flexibility scenario (3 times for the presented results). Therefore, it can be concluded that the cost of the BaU scenario at system level including the DSO temporary subscription costs is higher (6 102 k€/year) than the flexibility solution with MMM (5 505 k€/year).

In the near future, the BaU alternative would be an inadequate decision, to the extent that the TSO is not able to increase subscription level for the local and regional DSOs and has to deny this increase (as it is presently doing in Uppland and Skåne grids). Thus, even if the flexibility solution is more costly than the business-as-usual scenario (considering the cost of an industrialized and integrated flexibility solution), it reduces the need to increase the subscription level, enables to a higher extent the connection of new customers (and fewer disconnections of the existing ones). In addition, it has proven to be a faster and efficient solution, while the TSO reinforces the transmission grid.

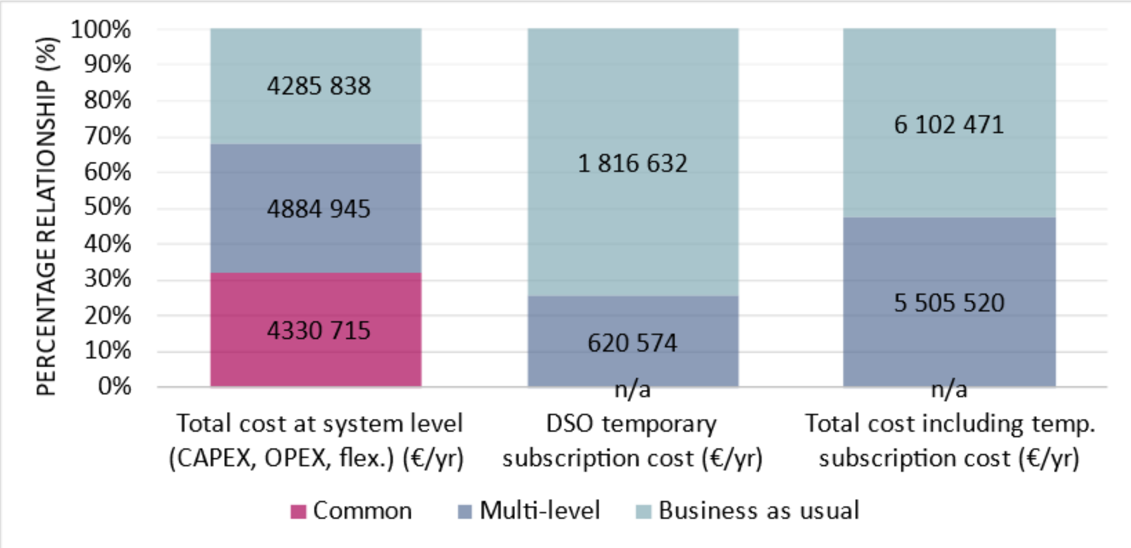

Figure 61: Percentage relationship between annual costs at system level, with and without DSO temporary subscription costs, for the flexibility and BaU alternatives

6.3.4 Profitability assessment for non-regulated agents for joint TSO and DSO needs

FSPs participate in the flexibility markets to solve joint TSO and DSO needs by offering flexibility of their own facilities or assets of third parties, receiving the flexibility market incomes. They face multiple costs associated to this business activity, according to Figure 62. The market incomes obtained by the FSPs will vary depending on the market clearing process (pay-as-bid, pay-as-clear, etc.). It is assumed that both FSP@Ts and FSP@Ds, which are owners of their own facilities (large and medium size), already have the required infrastructure to provide flexibility services. In contrast, FSP-ag@D should consider both the cost of the aggregation platform and other costs associated to the small or medium DERs that they represent, or new FSPs which require the development of software platforms to access the market.

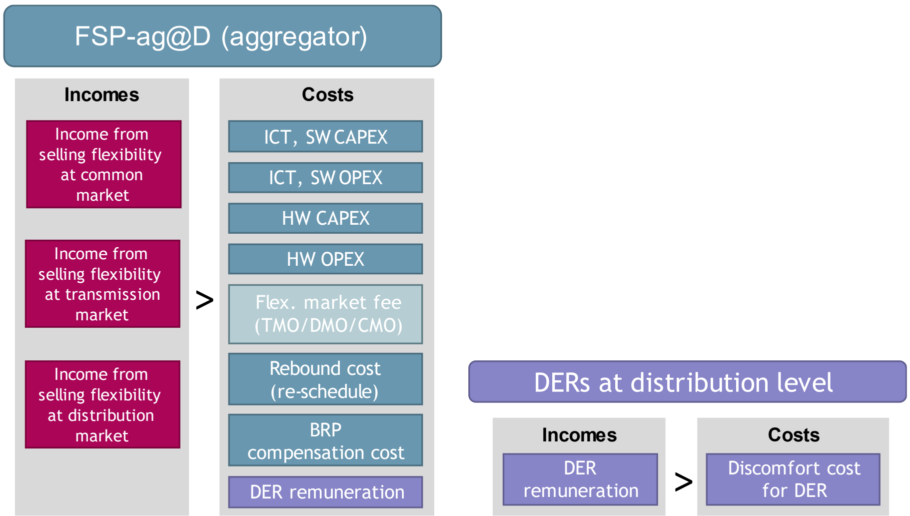

Figure 62: Incomes and costs for non-regulated agents in the flexibility and BaU alternatives when solving joint TSO and DSO needs in Swedish scenarios (Pillar 3)

This subsection focuses on the profitability assessment for the FSP-ag@D, that is, a flexibility service provider which participates to provide flexibility for joint TSO and DSO needs and which requires to develop an aggregation platform and ICT systems to communicate with the system and market operator(s).

Table 42 summarizes the economic and technical assumptions, considered for the FSP-ag@D profitability assessment. The CAPEX and OPEX values are extracted from section 6.2. In Uppsala sub-transmission grid, 8 flexible resources are considered and controlled by the energy aggregator (see Table 37). The OPEX costs of the MO platform are partially covered by the FSPs at distribution level, considering an energy-indexed fee of 0.03 €/MWh[19] (based on the fee paid to the NEMO in the regulated tariff "voluntary price for the small consumer" in Spain, see footnote 17 in subsubsection 5.4.1.3 for clarification).

Additionally, rebound effects are included, in which the aggregator and the FSPs, or their retailer, should reschedule the load profile or take other energy time-shift actions. The cost of the rebound effect is estimated at 5.3 €/MWh (based on the day-ahead price of 21.19 €/MWh in SE3 during 2020[20]). Partially interruptible supply is considered (mainly industries, tertiary sector, and district heating demand) with both upward and downward flexibility, so that not all the energy delivered in the flexibility market should be rescheduled later (only 25% is considered). Finally, the BRP compensation is estimated at 0.17 €/MWh[21], as an average price component for the measured imbalances of the suppliers.

[19] Assumed same cost structure as for the Spanish case, the market operator fee is extracted from the breakdown of the Spanish regulated tariff for small consumers, available in https://www.esios.ree.es/en/pvpc?date=01-01-2020

[20] Day-ahead price in SE3 from NordPool website, available in https://www.nordpoolgroup.com/en/Market-data1/Dayahead/Area-Prices/ALL1/Yearly/?view=table

[21] Assumed same cost structure as for the Spanish case, the "annual average price of the measured imbalances of referenced suppliers" refers to the average cost resultant from the energy imbalances that the last resort suppliers incur from their schedule and their final profiles. These changes may come from forecast errors, changes in the final demand, but also for the flexibility activation, which result in an extra cost from the BRP's side. Available in https://www.esios.ree.es/en/analysis/955?vis=1&start_date=01-01-2020T00%3A00&end_date=31-12-2020T23%3A55&compare_start_date=01-01-2019T00%3A00&groupby=year

Table 42: Economic data of the FSP@D for joint TSO and DSO needs (initial scenario based on Uppsala demo)

	Unit	Value	Comments
Flexibility energy provision	MWh/year	10 066	-
Flexibility incomes	€/year	158 453	at 15.74 €/MWh
Annual average CAPEX related to SW platform, ICT…	€/year	24 200	10 years
Annual average CAPEX HW, DERs (i.e., energy-box)	€/year	240	300 € per FSP
Annual OPEX related to the energy aggregator role	€/year	50 400	
Annual OPEX related to flexible units	€/year	4 800	600 €/year per FSP
Annual MO fee	€/year	302	0.03 €/MWh
Rebound effect cost	€/year	53 326	5.3 €/MWh
BRP compensation	€/year	1 711	0.17 €/MWh
Number of FSPs at demo (Uppsala)	#	8	-

When the number of locations, the level of CM provision, and/or the weighted flexibility bid price increase, the flexibility incomes increase to a greater extent than some incurred costs. As can be observed, the weighted flexibility price is 15.74 €/MWh (which mostly represents the discomfort price of the loads). Figure 63 depicts a sensitivity analysis of the profitability of FSP agents to solve joint TSO and DSO needs in the Uppsala demo, according to an increase of the number of locations with congestion at distribution level (up to 10 times more) and the bid prices (from 2 €/MWh up to 15.74 €/MWh), keeping the needs at 10 066 MWh/year.

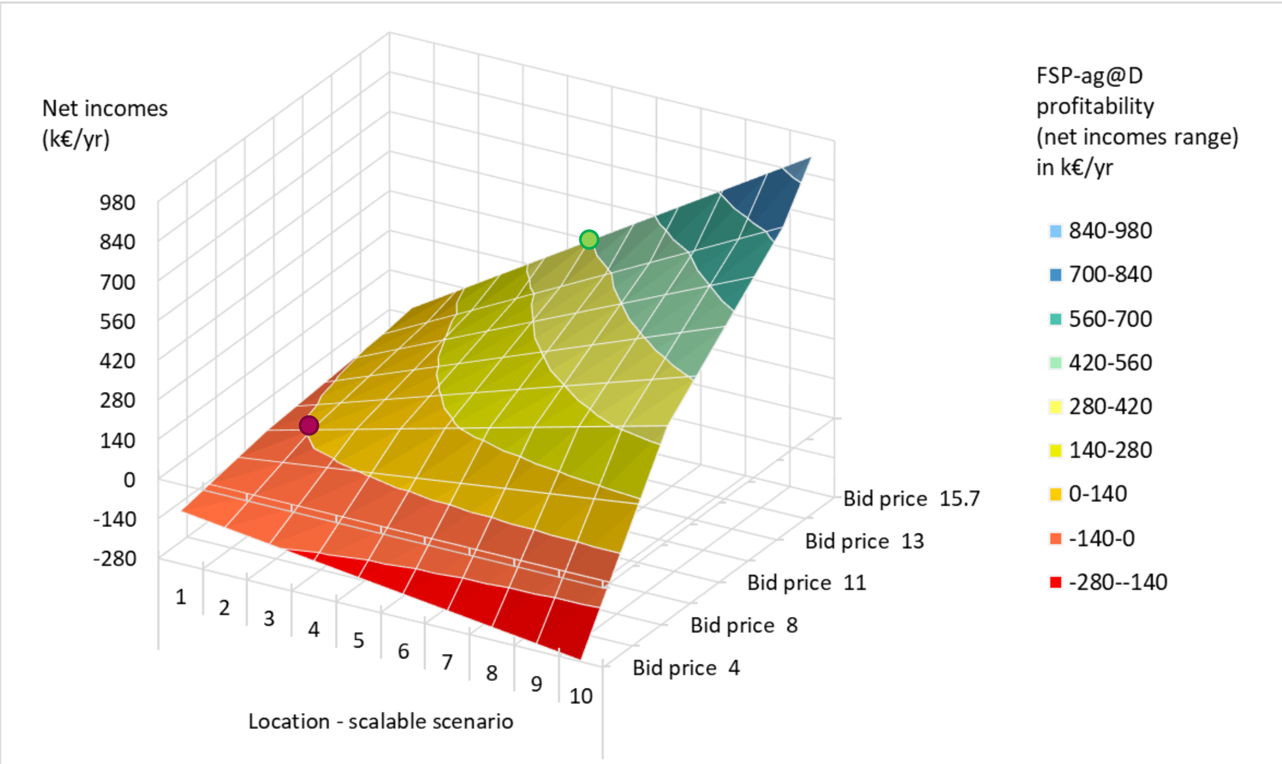

Figure 63: Sensitivity of the profitability assessment of FSPs to the number of locations and prices to solve joint needs in Uppsala

As can be observed, the provision of flexibility for joint TSO and DSO needs is not attractive to solve congestion needs of 10 066 MWh per year, below a weighted flexibility price of 10 €/MWh in 2 locations similar than Upsala scenario (red dot in Figure 63), especially due to the high rebound cost and high CAPEX and OPEX terms related to the market and aggregation platform. The business case becomes positive when the flexibility price increases and the scenario is scaled up, assuming that the aggregator can provide flexibility in other locations to solve the same kind of problems as in Uppland and Skåne grids.

It should be noted that the FSPs and DERs considered in this demo may also participate in other electricity markets (such as balancing markets, day-ahead markets, etc.), which are not included in this analysis. This could lead to extra market incomes, while the investment and operational costs for the SW platform or other ICT needed would be common. Additionally, the sensitivity analysis presented in Figure 63 cannot be extrapolated as a generic result for energy aggregators which participate in flexibility needs, as the CAPEX and OPEX terms may vary, the number of DER and their flexibility capacity can differ, as well as the flexibility incomes obtained based on the market clearing.

Once the net incomes for the FSP as market player are evaluated (through a sensitivity analysis like the one in Figure 63), the remuneration to be paid to DERs can be assessed. In this subsection, the FSP-ag@D is considered to be an aggregator (either independent or not) which encompasses the multiple types of flexible resources and end-users connected to the distribution grid (e.g., the ones participating at demo sites). The DERs may be renumerated according to a revenue sharing ratio on the flexibility income of the FSP. Figure 64 presents the profitability assessment for the FSP and the remuneration for the DERs, according to different revenues sharing ratio, considering flexibility needs in 5 locations similar to Uppsala and with a weighted flexibility price of 15.74 €/MWh (green dot in Figure 63). For each ratio, the minimum discomfort price perceived by the DER can be calculated (the minimum revenue or price at which the DERs are willing to provide flexibility in return for economic payment).

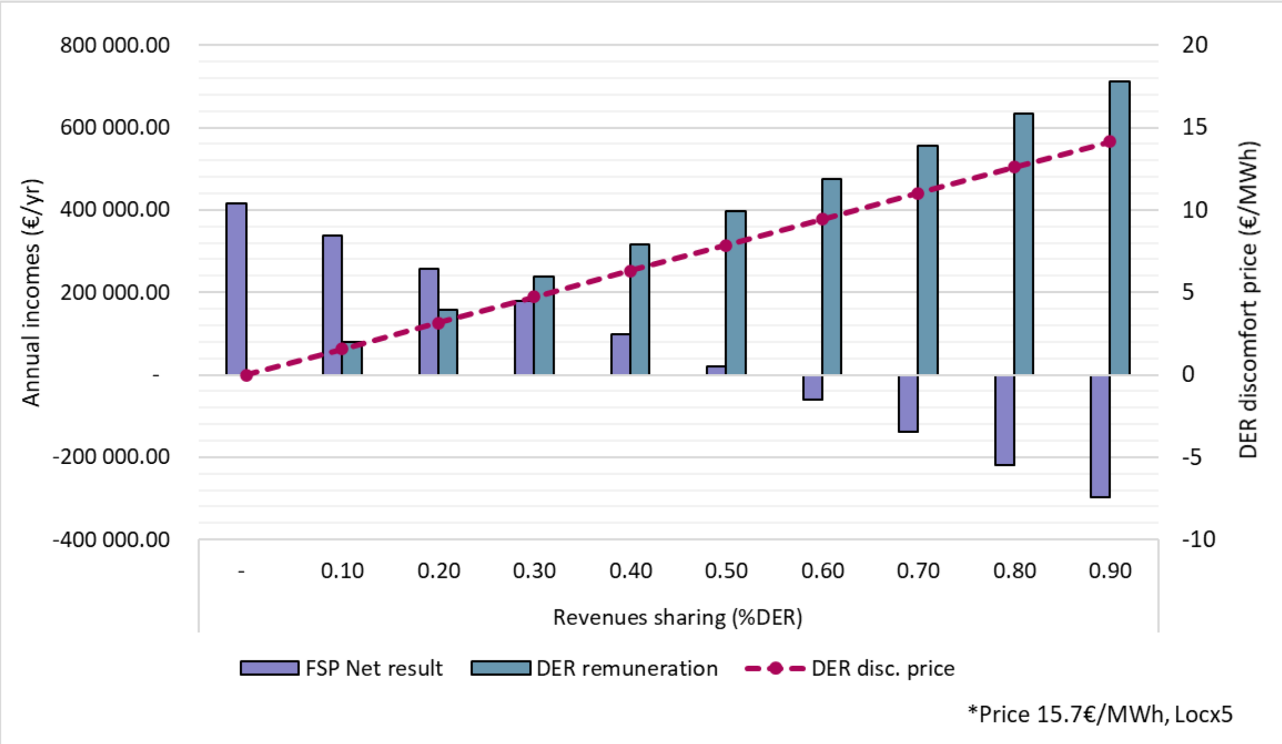

Figure 64: Sensitivity to revenue sharing between the aggregator and DERs in Uppsala

6.4 Main conclusions of the flexibility solution in Sweden

In the Swedish economic analysis, joint TSO and DSO needs have been analyzed in the region of Uppland, focusing on the congestion management service. For this purpose, the economic implication for the DSO and the FSPs have been addressed, in which the temporary subscription level is of great importance.

In recent years, the regional DSO in Uppland has been denied subscription raises (this problem has been also arisen in other regions), due to limited TSO capacity. Thus, the focus of the Swedish analysis has been the evaluation of the DSO economic implications with and without flexibility at distribution level. Here, the controllable FSPs at distribution level can provide flexibility and reduce the peak demand and the requests of a temporary DSO subscription level, in return for a remuneration for the flexibility activation.

Focusing on the TSO-DSO coordination schemes, the multi-level market model seems to be more suitable to address the casuistry of Sweden regarding the subscription tariffs, as until now. Firstly, the already existing market structure and legacy systems support the continuity and adoption of multi-level markets for the procurement of new flexibility services by FSPs at distribution level. Secondly, the multi-level model increases the participation of small or medium FSPs located at distribution level, giving a market access priority of these players to solve downstream grid issues and reduce necessity of asking for an increase in the subscription level of the DSO and, thus, reduce its cost. Thirdly, the DSO subscription tariffs are not modelled and evaluated in the common market, so a fair comparison cannot be addressed among them. In both TSO-DSO coordination schemes (common and multi-level), the cheapest bids to solve transmission needs are guaranteed.

Addressing the overall cost at system level (including annual CAPEX and OPEX of regulated actors, flexibility procurement and the temporary subscription costs) of the simulated scenario in Uppland, the business-as-usual scenario (here understood as the payment of subscription penalties by the DSO) has a higher cost than the use of flexibility by FSPs at distribution level. It can be pointed out that the flexibility cost of an industrialized integrated flexibility solution could be higher than the one presented here. Even if the industrialized flexibility solution were more costly than the business-as-usual scenario, it would reduce the need to ask for higher subscription level (and the risk to be denied for it), enables to a higher extent the connection of new customers (a fewer disconnections of the existing ones), and has proven to be a faster and efficient solution, while the TSO reinforces the transmission grid.

From the pure DSO perspective, the flexibility solution simulated in Uppland region reduces the potential subscription penalties for the DSO by around 3 times. Although the DSO should bear the cost of the flexibility use and the OPEX related to the flexibility service, the flexibility solution seems to be more cost-efficient than the business-as-usual scenario by far.

Finally, the profitability for the flexibility sellers' actors (FSPs, aggregators, DERs, etc.) has been evaluated when they provide flexibility. The business case is not attractive enough in the analyzed scenario (only implemented in one specific place, the Uppland region), because the high entry costs (platform development, communication infrastructure and maintenance, prequalification, market participation fee or other cost related to the retailers or BRP) disincentive their participation.

As declared, there are other regions with similar problems to the ones in Uppland (such as Skåne) in which the electrified demand is increasingly growing, and there might exist a risk or a delay in the connection of new customers. Customers need to be connected as soon as possible with a reliable security of supply. Therefore, it is expected that the niche market for FSPs and aggregators will increase in other locations. The scalability of the business model will make it attractive and cost-efficient in case of more widespread congestions.

7 Economic assessment for Greece

7.1 Brief demo description

The Greek pilot includes two demonstration sites:

- Kefalonia, the largest of the Ionian Islands in Western Greece, connected with the neighboring islands through two submarine cables and, therefore, interconnected with the mainland of Greece.
- Mesogia, located in the area of Mesogia at the south-eastern part of Attica, near Athens, including several municipalities and the interconnected islands of Kea, Andros and Tinos.

All services and products were tested in both pilot sites, Kefalonia and Mesogia (Trakas et al., 2022). The assets of Kefalonia include large generators (large wind farms connected to the transmission system), renewable energy sources connected to the distribution system, aggregators, consumers, and other FSPs, such as back-up generators. In Mesogia area, the assets used as part of the CoordiNet project include aggregators, consumers and renewable generators (Dimeas et al., 2020).

The list of FSPs in the Greek demonstrator consists of a small CHP, a residential battery, irrigation pumps, diesel gensets, loads and RES (wind farms and PVs). Figure 65 shows products, CSs and location of the FSPs available in this demonstrator. More specific details of these FSPs can be found in (Bachoumis et al., 2019).

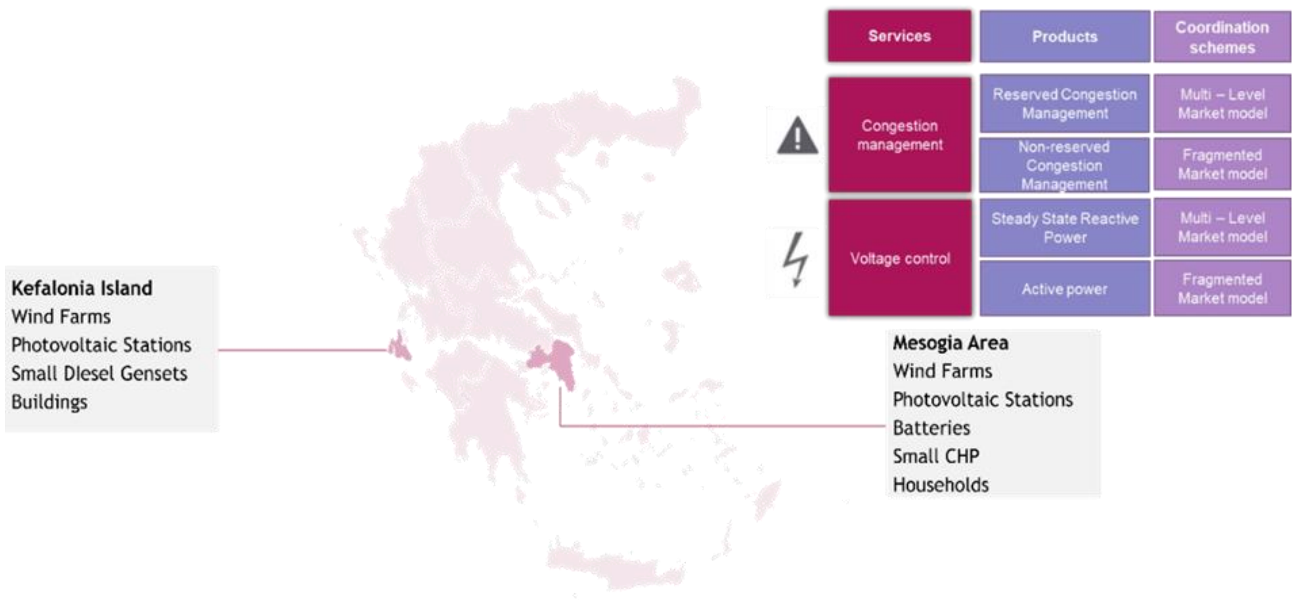

Figure 65: Map of the Greek demonstrator areas (Bachoumis et al., 2019)

7.2 Demo cost analysis review and scalability

7.2.1 CAPEX

The ICT costs calculated by the Greek demonstrator include the incurred costs considering the four BUCs deployed in the demonstrator; CM and voltage control services, being tested under the multi-level, and fragmented market models each. However, it may be assumed that there would be no difference in the total costs in case that just one coordination scheme (multi-level/ fragmented) was deployed, since the required communication, algorithms, etc., would be almost the same.

The ICT costs considered are those directly related to the deployment of the TSO-DSO communication platform, which is responsible for coordinating the necessary functions to implement the BUCs (e. g., data sharing between TSO and DSO, gathering of flexibility needs from TSO and DSO, exchanging the flexibility from FSPs, gathering of market bids, performing market clearing, etc.).

Algorithms, communication infrastructures, etc. finally used and developed in the Greek demonstrator are listed, valued, and assigned to the pertinent agent in Table 43. The total ICT cost is estimated at 1 352 000 €, out of which 347 000 € would be incurred by the DSO, 740 000 € by the MO and 265 000 € by the TSO. Furthermore, Table 43 specifies in detail the concepts are assignable to each role:

Table 43: ICT costs allocation - Greece

Cost	DSO (€)	MO (€)	TSO (€)
Load forecasting algorithms	6 000		
RES forecasting algorithms	6 000		
Data storage for forecasting tools	60 000		
Power flow and state estimation tool	50 000		
Topology Manager	70 000		
Enterprise Service Bus (ESB) for data exchange between system operators	75 000		75 000
Communication infrastructure to communicate with ESB	40 000		60 000
Communication infrastructure to collect metering data	40 000		
Local market algorithm for CM and voltage control		100 000	
TSO market for congestion management and voltage control		100 000	
Licenses (e.g., solver of the market algorithm)		60 000	
Data Storage		50 000	
Front-End		60 000	
Main Enterprise Service Bus (Communication with all parties)		150 000	
API		60 000	
Reporting tool		60 000	
SQL server		50 000	
Calculation of settlement		50 000	
TSO validation tool or upgrade of the existing market to take into account activated bids in distribution system			100 000
Data storage for bids forwarded from distribution system			30 000
TOTAL	***347 000***	***740 000***	***265 000***

Based on this information, but also considering that the analysis performed for the Greek case is focused on the local market approach, several considerations and assumptions were necessary in order to assign a specific cost to each participant in the Greek demonstrator. Table 44 shows the costs considered for the calculation of the Greek case and a brief explanation is included below:

Table 44: CAPEX considered in the Greek demonstrator

Agent	Local (€)
TSO (1)	265 000
DSO (2)	347 000
MO (3)	740 000
FSP (Agg) (4)	80 000
DER (5)	300

(1), (2), (3) According to the modelling for the Greek analysis in (Cossent et al., 2022), 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 multi-level and fragmented approaches. Consequently, the considered costs in the local market for TSO, DSO and MO in the Greek analysis are the ones indicated in (Trakas et al., 2022).

(4), (5) The costs incurred by FSPs and DERs are not identified within the Greek demonstrator, so, these values are based on the costs identified by the Spanish demonstrator (see more details in subsection 5.2.1 and Table 16.

7.2.2 OPEX

The OPEX include the recurrent costs that are required to operate and maintain the installed assets, which are 626 000 €/year in this case (Trakas et al., 2022). As explained for the CAPEX in subsection 7.2.1, the OPEX are the same for all BUCs considered within the Greek demonstrator, since the required communication, algorithms, etc. would not differ in the case that just a single specific BUC was tested.

Table 45 shows the costs to be assumed and by whom:

- MO: 333 000 €/year. The main costs are related to the operation of the market platform (252 000 €/year) and a weather forecast license (60 000 €/year). It should be pointed out that both costs are estimated for the whole country, and not only for the demo. Other costs include data handling, updates of licenses and communications.
- DSO: 147 000 €/year. The main cost, 144 000 €/year, is allocated to the operation of tools. Other costs include communication and metering activities.
- TSO: 146 000 €/year. The main cost, 144 000 €/year, is allocated to the operation of tools. Other costs include communication.

Table 45: OPEX allocation - Greece (Trakas et al., 2022)

Cost	DSO (€/year)	MO (€/year)	TSO (€/year)
Costs for operating the market platform (country)		252 000	
Costs for data handling		10 000	
Cost to update licenses		10 000	
Communication costs (TSO, DSO, FSPs)		1 000	
Weather prediction license (country)		60 000	
Costs for operating the tools	144 000		
Costs for communicating with the TSO	1 000		
Costs for communicating with the market platform	1 000		
Costs for metering provided flexibility and handling data	1 000		
Costs for operating the tools (country)			144 000
Costs for communicating with the DSO			1 000
Costs for communicating with the market platform			1 000
TOTAL	***147 000***	***333 000***	***146 000***

Based on these values and several assumptions explained below, Table 46 shows the OPEX to be considered in the calculations:

Table 46: OPEX considered in the Greek demonstrator

Agent	Local (€/year)
TSO (1)	29 000
DSO (2)	29 000
MO (3)	65 000
FSP (Agg) (4)	16 000
DER (5)	600

(1), (2), (3) Although in (Trakas et al., 2022) it is assumed that OPEX are the same for all BUCs considered for these three agents (i.e. TSO, DSO, MO), in this deliverable it will be assumed that the OPEX for performing only a local market located in Kefalonia will be around 20% of the values provided in Table 45 (as only one of the two services is considered, in only one of the two locations and for a local market) so that they are also in line with the values considered for Spain (see Table 17).

(4), (5) The OPEX are not identified for the FSPs and DERs within the Greek demonstrator, so, these values are based on the costs identified by the Spanish demonstrator (see more details in subsection 5.2.2 and Table 17).

7.3 Case Study: Local needs

7.3.1 Simulation scenario for local needs

7.3.1.1 Challenges in Kefalonia

The Greek scalability scenario presented in (Cossent et al., 2022) for local needs is based on the Kefalonia demo site. Figure 66 illustrates the distribution network in Kefalonia island, downstream the Argostoli substation, in which the CM flexibility services are simulated (as the grid is not congested nowadays) in (Cossent et al., 2022). The Greek scenario designed to assess the economic viability of the flexibility solution is based on a local market in which the DSO buys flexibility from the DERs connected at distribution level.

The economic assessment for local needs of this deliverable D6.3 is focused on the evaluation of the economic implication for the involved market agents, in particular the DSO, FSPs and DERs (Pillar 1.b & Pillar 3.b).

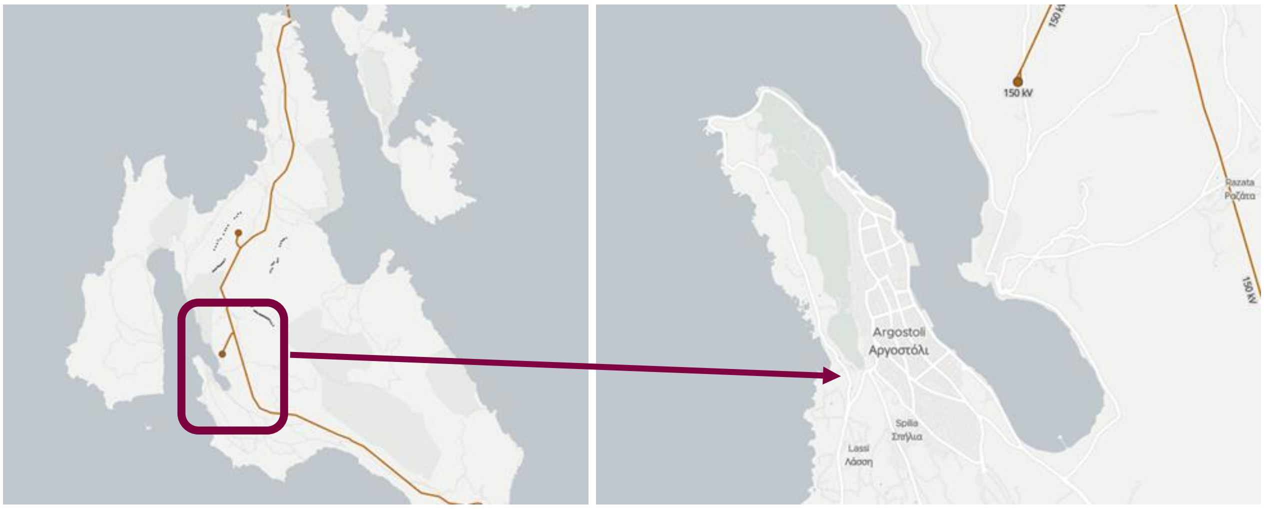

Figure 66: Location of the Argostoli substation and the modelled distribution grid

In Greece, the DSOs do not have the need to procure flexibility at present in the locations of CoordiNet demonstrators (no overloads in distribution grids). However, two sources of congestions are simulated in (Cossent et al., 2022):

- an increase of demand, which leads to the appearance of an overloaded line, and
- congestions due to the unavailability of the substation 50 MVA transformer (N-1 scenario).

The second scenario (unavailability of the 50 MVA transformer) is selected to evaluate the flexibility solution versus a traditional grid reinforcement, as well as for the analysis of the profitability for the FSPs.

As summarized in Table 47, existing DERs at distribution level are classified as buildings and irrigation pumps, whose bid prices are quite high (87.57 and 81.35 €/MWh, respectively). Additionally, more DERs at distribution level are considered to avoid or reduce the flexibility not supplied in the N-1 scenario with the unavailability of the transformer. The total capacity of demand response is 7.76 MW, with a downward flexibility of 10% of their capacity.

Under some circumstances, the flexibility capacity of DERs at distribution level may not solve the total DSO flexibility needs. As a result, energy not supplied is considered, when the flexibility needs are not totally satisfied. Thus, FSP engagement and availability is key to the success of local flexibility market solutions for CM.

Table 47: DERs considered in the Greek economic assessment

DER	Feeder	Node	Installed/Nominal capacity (MW)	Available capacity (%)	Bid (€/MWh)	Technology
Fsp1	25	129	0.1332	10	87.5704	Prefecture building
Fsp2	25	135	0.1215	10	87.5704	Municipal building
Fsp3	25	164	0.243	10	87.5704	Municipal building
Fsp4	25	164	0.1485	10	87.5704	Municipal building
Fsp5	25	164	0.09	10	87.5704	Municipal building
Fsp6	25	166	0.27	10	87.5704	Municipal building
Fsp7	24	96	0.2125	10	81.3576	Irrigation pumps
Fsp8	24	98	0.34	10	81.3576	Irrigation pumps
Fsp9	24	101	0.34	10	81.3576	Irrigation pumps
Fsp10	24	105	0.34	10	81.3576	Irrigation pumps
Fsp11	22	49	0.415	10	81.3576	new FSP (N-1)
Fsp12	22	46	0.345	10	81.3576	new FSP (N-1)
Fsp13	23	62	0.57	10	81.3576	new FSP (N-1)
Fsp14	23	84	0.25	10	81.3576	new FSP (N-1)
Fsp15	26	172	0.215	10	81.3576	new FSP (N-1)
Fsp16	26	173	0.245	10	81.3576	new FSP (N-1)
Fsp17	27	199	0.905	10	81.3576	new FSP (N-1)
Fsp18	27	204	0.32	10	81.3576	new FSP (N-1)
Fsp19	28	220	0.245	10	81.3576	new FSP (N-1)
Fsp20	28	245	0.205	10	81.3576	new FSP (N-1)
Fsp21	29	288	0.33	10	81.3576	new FSP (N-1)
Fsp22	29	296	0.2	10	81.3576	new FSP (N-1)
Fsp23	30	309	0.34	10	81.3576	new FSP (N-1)
Fsp24	30	325	0.42	10	81.3576	new FSP (N-1)
Fsp25	31	342	0.225	10	81.3576	new FSP (N-1)
Fsp26	31	356	0.295	10	81.3576	new FSP (N-1)

Considering both the load and generation profiles of high peak demand and the N-1 conditions of (Cossent et al., 2022), a power flow analysis is run for 24 hours to detect eventual constraints. The power flow results are illustrated in Figure 67, where the two parallel HV/MV transformers in Argostoli substation (represented by the line green) are congested from hour 18 to hour 23, when the 50 MVA transformer is not available.

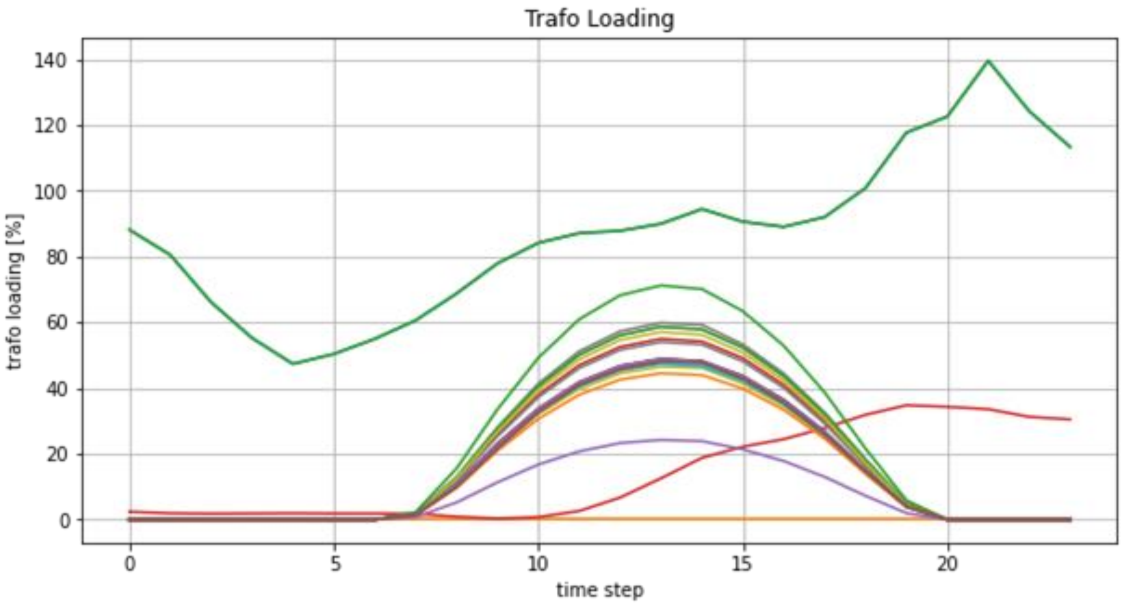

Figure 67: Loading of transformers [%] in the Greek scenario

7.3.1.2 Services needs and network modelling

The distribution network behind the Argostoli substation is considered, whose single diagram is depicted in Figure 68.

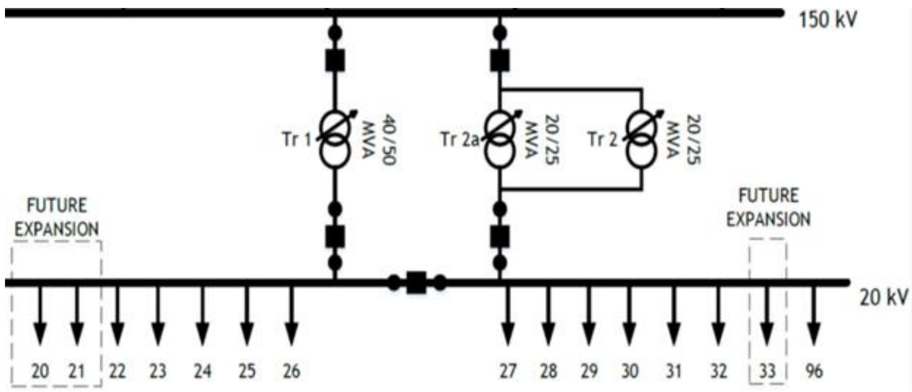

Figure 68: Argostoli distribution network single diagram

Table 48 shows the congested energy and local CM needs for both scenarios designed in (Cossent et al., 2022). As discussed above, this report will focus on the N-1 scenario, characterized by the transformer (Tr 1) unavailability at the substation.

The congestion events simulated in Greece are only foreseen in the transformers located in the boundary between transmission and distribution and in the distribution lines. In Greece, the boundary between the TSO and DSO is set at the 150 kV/20 kV substations. Therefore, a local market downstream of the congested substation is modelled. Contrary to the central market analysis in (Cossent et al., 2022), this study only requires modelling the distribution system downstream the substation, with focus on the MV and LV grids.

Table 48: Congestion Management in the Greek economic assessment (in MWh/year)

Network	Congested events (h) - criticalities	Annual DSO congested needs (MWh)	Congested event needs (Average MVA or MW)
Transformer (N-1 scenario)	12	605.22	51.15
Congested line	3	2.4656	0.8219

7.3.1.3 TSO-DSO coordination scheme

The CS simulated in (Cossent et al., 2022) is a linearized local flexibility market using PTDF. It does not lead to new congestion problems after the market clearing, according to the post-evaluation process and under the scenarios analyzed. Table 49 presents the services and CS simulated for the Greek scenario and used in this report.

Table 49: Services and CS analyzed in the Greek economic assessment at system level

Modelling services	Sites	Coordination schemes
Local CM at distribution grids	Distribution grid at Argostoli	Multi-level Local (PTDF)

As an alternative to using flexibility, the grid reinforcement scenario is considered, where a reinforcement of the equipment at the substation is envisaged considered, by installing a redundant transformer. Being a local simulation, there is no need for other flexibility services (i.e., balancing). In fact, only the CAPEX and OPEX of the new grid asset for the DSO should be considered in the economic assessment at system level.

7.3.2 Economic impact for regulated agents for local needs

The Greek scalability scenario for local needs is based on the Kefalonia demonstration site.

The use of local flexibility markets (for a given flexibility commission time) may allow to not only postpone the need to reinforce the grid, but also to provide a cost-efficient solution in case of an occasional congestion, as well as being a temporary solution during the commissioning time of the new grid elements in case of structural congestions caused by vegetative increase of demand.

In the short term, the flexibility solution may be compared to the cost of a remedial action when the congestion is already happening, in which the non-supplied energy must be a DSO concern, while, in the medium term, the use of flexibility may be compared to the cost of a traditional grid reinforcement for a given commissioning time, when the DSO should take decisions for the upcoming distribution grid expansion plan.

The comparison of the economic impact that the flexibility and the grid-based solutions have on the DSO is done at two timeframes: a remedial action for short term and a grid reinforcement for the medium-term. Figure 69 presents the items to be considered for the comparison of the impact on the DSO, where some costs and service procurement are recovered via tariffs, while the flexibility-not-supplied (FNS) is an extra cost.

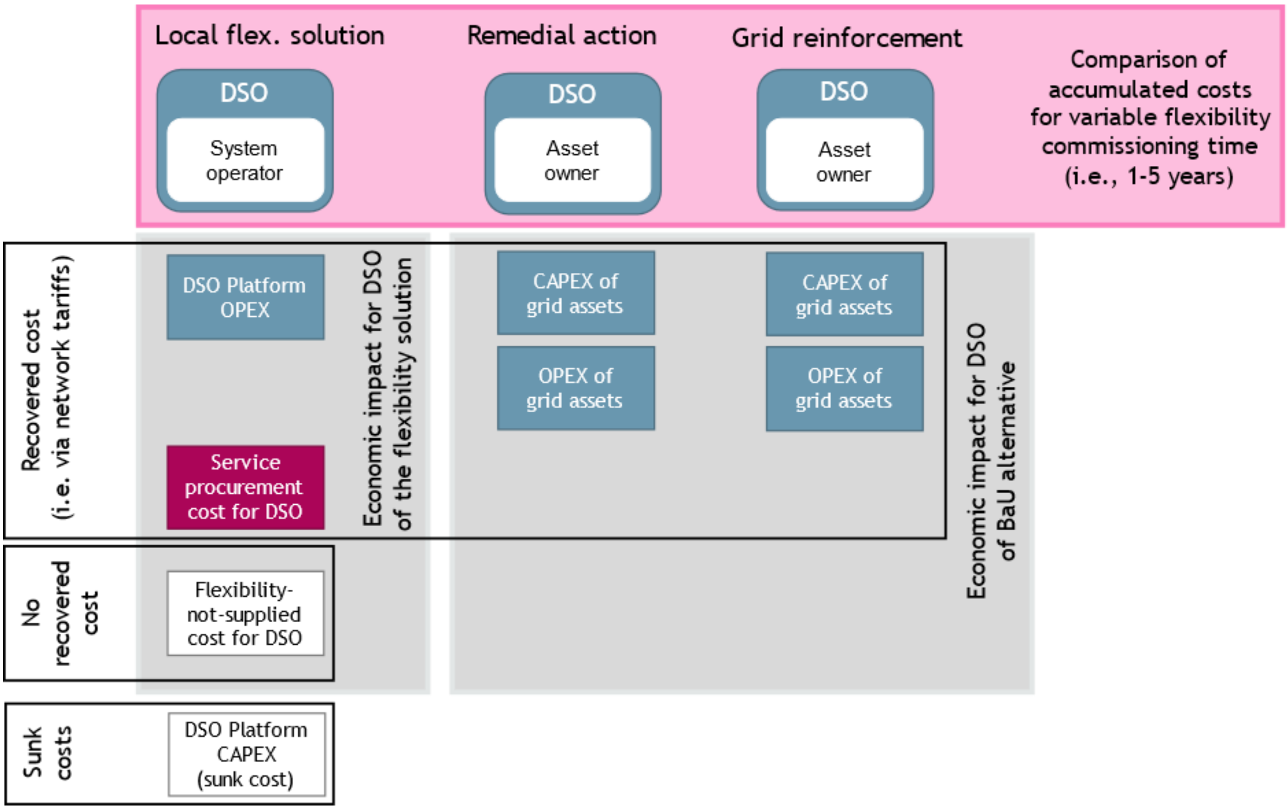

Figure 69: Cost components for the DSO in the flexibility and BaU alternatives for local needs in Kefalonia (Pillar 1.b)

In case of the demonstrator in Kefalonia, potential congestions are simulated for the flexibility scenario with local congestion (the unavailability (not existence) of the transformer at the substation), while the reinforced scenario considers the installation of the 50 MVA transformer at the substation.

The features and reference cost of the main grid asset to solve local CM needs is indicated below. Figure 70 depicts the annuity payment to the DSO related to the grid reinforcement investment and operation costs, and the cost related to a temporary asset for remedial actions:

- **Grid reinforcement**: A 50 MVA transformer is considered in the Argostoli substation from 150 kV to 20 kV, whose reference investment is 12 909 €/MVA (806 950 €) and annual maintenance costs 21 700 €/year, in which a financial rate of return of 5.16% for the CAPEX and a margin of 5% for the OPEX are included. The lifetime of the asset is 40 years.
- **Remedial action**: A diesel generator is selected as a remedial action in case of congestions at LV are already occurring (and no flexibility solution is available, nor grid reinforcement is ready). The following features have been considered: a nominal power for the diesel generator of 10 MW (assuming hourly peak CM needs of 8.42 MW), 1 150 €/kW for investment cost, and an OPEX related to the fossil fuel consumption of 0.3 €/kWh. The lifetime of the asset is 30 years, although the annuity payments will only encompass the years in which it is in operation.

As can be observed in Figure 70, the level of congestion is relatively high in Kefalonia and thus, a traditional grid reinforcement cost could be a more suitable solution than the remedial action, due to the high OPEX resulting from the fossil fuel price.

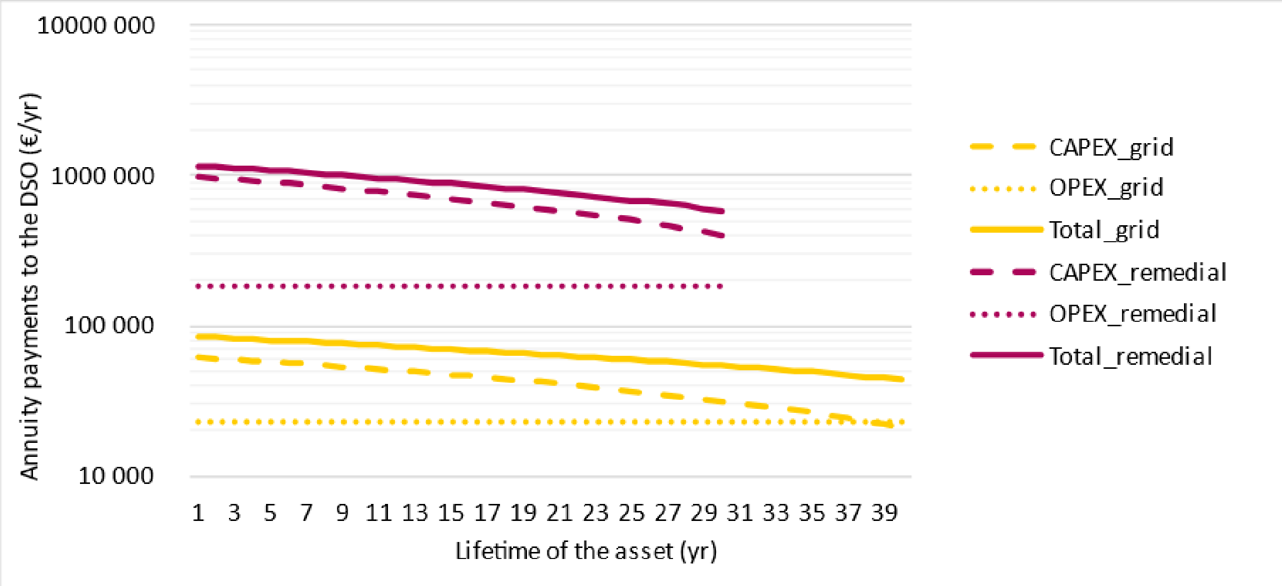

Figure 70: Annuity payment to the DSOs, based on the grid reinforcements in Kefalonia demo

From the daily analysis in (Cossent et al., 2022), 12 criticalities per year can be estimated to be solved in Kefalonia due to the unavailability of the transformer at Argostoli substation, in which the DSO requests an annual flexibility of 605.22 MWh/year (average of 50 MWh per criticality, with an hourly peak of 8.42 MW). The FSPs provide flexibility with a weighted price of 82.09 €/MWh (according to the bid prices in Table 47). It is supposed that the flexibility needs are maintained equal throughout the considered time span (i.e., the flexibility contracting time).

- **Limited flexibility scenario**: In case of considering the FSPs available at the demonstrator in (see Table 47 for their characteristics for the market simulation), there is not enough flexibility to totally solve the local congestions. The FSPs receive **4 199 €/year** for their flexibility when they partially solve the congestion events (51.15 MWh/year provided out of 605.22 MWh/year needed, according to (Cossent et al., 2022)).

  The flexibility not supplied is estimated at a cost of 4 240 €/MWh for the value of lost load (VOLL), resulting in 2 349 237 €/year of FNS cost. The annual cost for the flexibility solution (with flexibility not supplied) is expected to be 2 385 336 €/year.

- **Flexibility scenario**: In case of increasing the FSP's flexibility by 12 times (either the number of FSPs or higher flexibility capacity of each existing FSP), the annual cost of flexibility procurement is **49 683 €/year**, when they solve all occurring congestions (605.22 MWh/year), and 31 900 € of OPEX, including an extra OPEX margin of 10%. The annual cost for the flexibility solution (without flexibility not supplied) is expected to be 81 583 €/year (first annuity).

In both flexibility scenarios, the OPEX for the DSO related to the network behind the Argostoli substation is considered to be 29 000 €/year, with an OPEX margin of 10% for the annual remuneration of the DSO for incurred regulated cost.

It can be concluded that, considering the presented scenario and local flexibility needs described in subsubsection 7.3.1.2, the flexibility solution (without flexibility not supplied) can be a more cost-effective solution compared than either a traditional grid reinforcement or other remedial actions.

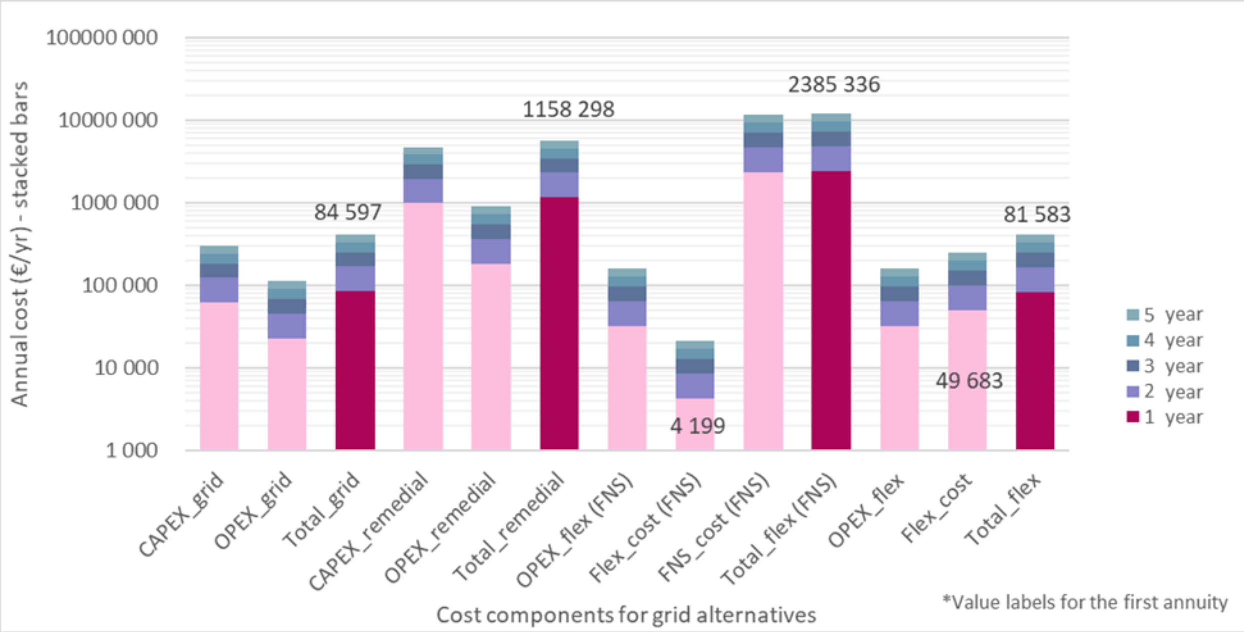

Figure 71: Comparison of CAPEX, OPEX and TOTEX (€/year) in Kefalonia demo for grid-based and flexibility solutions (not-supplied-flexibility and flexibility scenario)

This economic analysis can be analyzed from two perspectives:

- **In the short term** when congestions are already occurring or will occur soon: The cost comparison should be done between a flexibility solution or a remedial action, assuming that both of them have reduced commissioning times that can be disregarded, so that both solutions will be ready when the congestion occurs. The flexibility solution (purple lines in Figure 72) along 1 or 5 years of timespan (i.e., the flexibility commissioning time) is always more cost-efficient than the remedial action. The cost of the use of the flexibility is 81 583 €/year (6 times less than annual remedial cost).

  The remedial action is only a suitable decision when the distribution grid need for urgent decisions to avoid not being able to supply energy to LV consumers, in case of insufficient flexibility from available FSPs or in case ICT and SW platforms are not available yet for local CM procurement.

- **In the medium term**, a decision can be made in advance, when there is no congestion yet, but it is expected that, due to the vegetative increase of demand or any other reason, congestions will appear in the system during the commissioning period of a traditional grid reinforcement. The use of flexibility may be compared to a traditional grid reinforcement for a given flexibility procurement period. As can be observed, the flexibility solution (purple lines in Figure 72) along 5 years of timespan (i.e., the flexibility commissioning time) is always more cost-efficient than the traditional grid reinforcement (yellow lines in Figure 72). Thus, the decision to start the commissioning of a new grid element should not be postponed, due to an expected increase of CM needs, as well as the flexibility solution is a riskier alternative (with higher degree of uncertainty related to the flexibility cost and performance) than reinforcing the grid assets.

  The accumulated cost of the use of the flexibility is 407 914 € for 5 years of flexibility commissioning time, while the cost of the grid reinforcement amounts to 412 577 € (the first 5 annuities for the DSO).

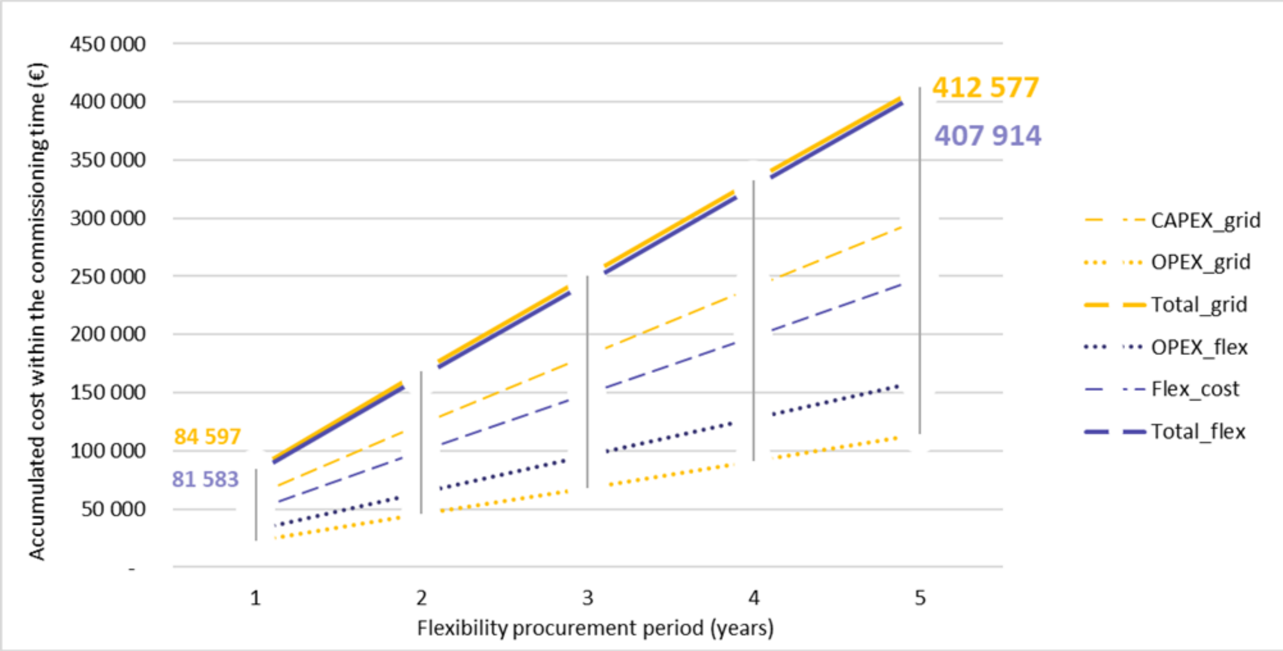

Figure 72: Accumulated CAPEX, OPEX and TOTEX (€/year) in Kefalonia for the first 5 years for grid-based and flexibility solution

The flexibility solution can be an efficient temporary solution along the commissioning time of the grid reinforcement solution. The vegetative increase of demand tends to increase the level of congestion in the future distribution grid and, consequently, its cost.

The cost of the flexibility solution can increase, due to both the congestion needs and the flexibility bid prices. Under these circumstances, there is a threshold in which the cost of flexibility is equal to that of traditional grid reinforcement. This threshold is reached with local CM needs of 696 MWh/year for the simulated flexibility scenario (scarcely an increase of 2% in energy-terms) considering the weighted flexibility bid price of 82.09 €/MWh, as depicted in Figure 73 and Figure 74. The accumulated cost of the use of the flexibility is 412 882 € for 5 years of flexibility commissioning time (the first annuity equals to 82 576 €), while the accumulated cost of the grid reinforcement is 412 577 € (the first annuity equals 84 597 €).

Table 50 summarizes other threshold scenarios (depending on the level of congestion and the weighted flexibility price) in which the cost of the flexibility solution is comparable to the cost of the grid reinforcements. As the level of congestion is reduced, the weighted flexibility prices that the DSO could pay are increase proportionally.

Table 50: Threshold scenarios depending on the level of congestion and the weighted flexibility price

<table>
<tr><th>Weighted bid price (€/MWh)</th><th>Level of congestions (%)</th><th>Flex needs (MWh/year)</th><th>Flexibility cost (€/year)</th><th>Total cost of the flexibility solution (€/year)</th></tr>
<tr><td>82.09</td><td>1.00</td><td>605.22</td><td>49 683</td><td>81 583</td></tr>
<tr><td>82.09</td><td>1.02</td><td>617.32</td><td rowspan="4">50 676</td><td rowspan="4">82 576 (almost equal to grid reinforcements cost along 5 years: 412 882 €)</td></tr>
<tr><td>61.57</td><td>1.36</td><td>823.10</td></tr>
<tr><td>41.05</td><td>2.04</td><td>1 234.64</td></tr>
<tr><td>20.52</td><td>4.08</td><td>2 469.29</td></tr>
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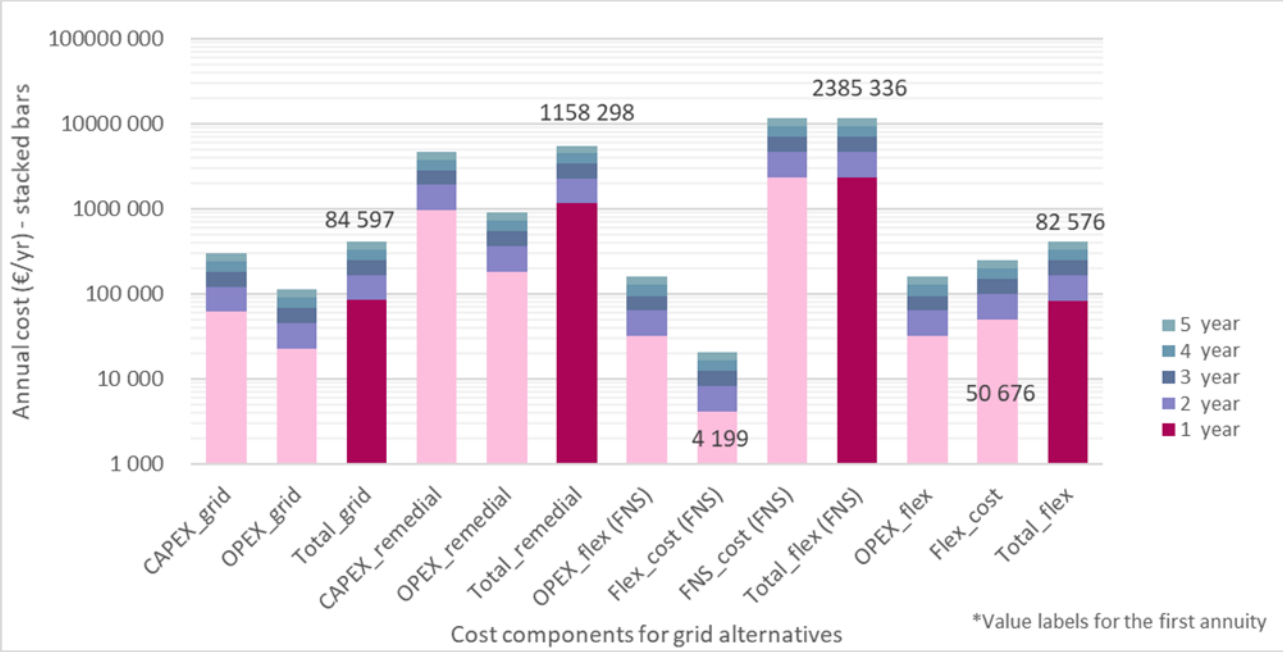


Figure 73: Comparison of CAPEX, OPEX and TOTEX (€/year) in Kefalonia for grid-based and flexibility solutions (not-supplied-flexibility and flexibility scenario) when the level of congestion increases up to threshold scenario

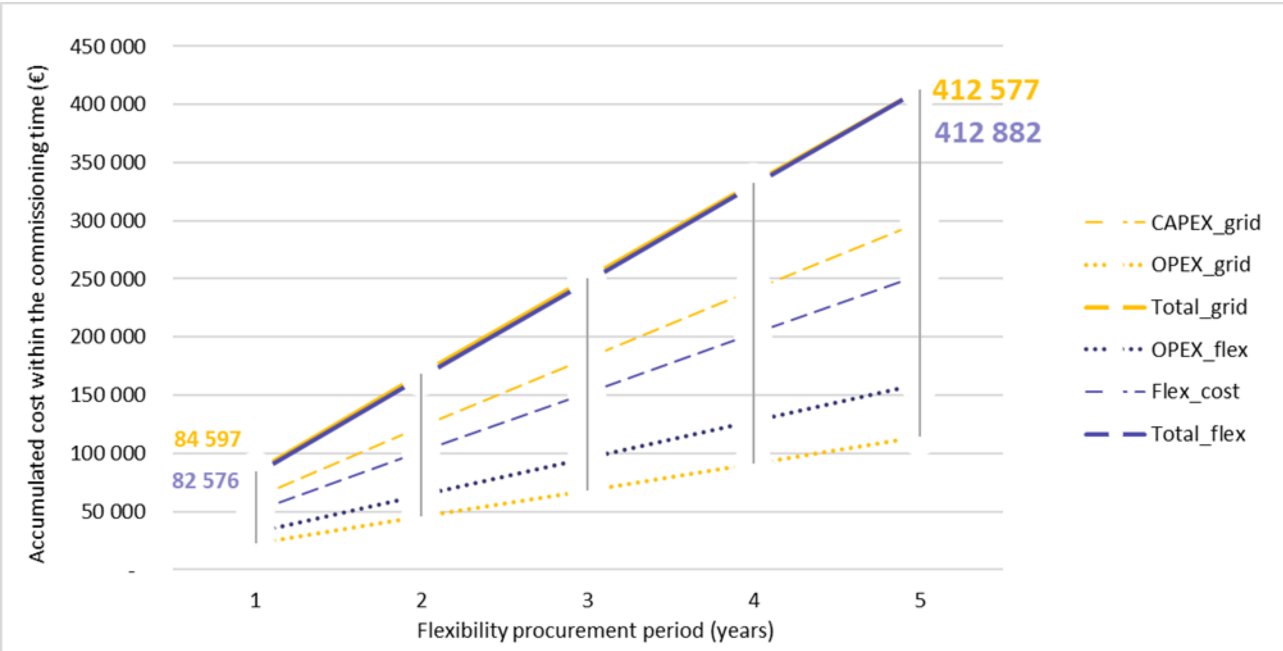


Figure 74: Accumulated CAPEX, OPEX and TOTEX (€/year) in Kefalonia for the first 5 years for grid-based and flexibility solution when the level of congestion increases up to threshold scenario

7.3.3 Cost-efficiency of the local market at system level

The Greek economic assessment at system level considers the following regulated agents' costs depicted in Figure 75. The recognized CAPEX and OPEX (SW, ICT) for TSO, DSO and MOs (LMO, according to the local market CS) are considered. The service procurement costs for the DSO local needs are also considered resulting from market simulation (Cossent et al., 2022), as presented in subsubsection 7.3.1.2. As the replicability and scalability analyses in Greece are focused on the local market model, and no congestion at transmission level is simulated, it cannot be compared with the CSs to solve joint TSO and DSO needs, as done for Spain and Sweden.

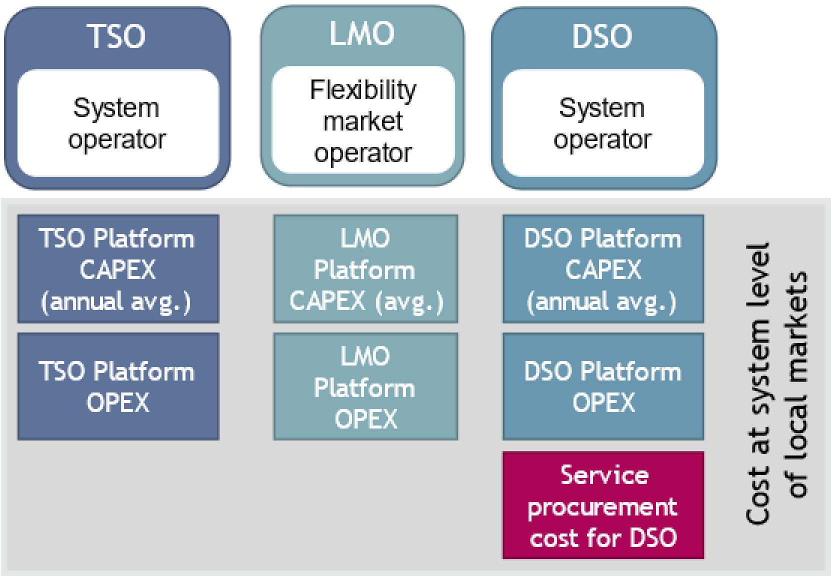


Figure 75: Economic impact of flexibility solution at system level (Pillar 2)

Figure 76 presents the annual cost at system level (including flexibility procurement, CAPEX and OPEX for regulated agents) for local CM needs in the demonstrator in Kefalonia. Only DSO needs are simulated at distribution level, which should be solved with the available flexibility of FSPs at distribution level (those FSPs considered in the market simulations based on demonstrator in Kefalonia, see Table 47).

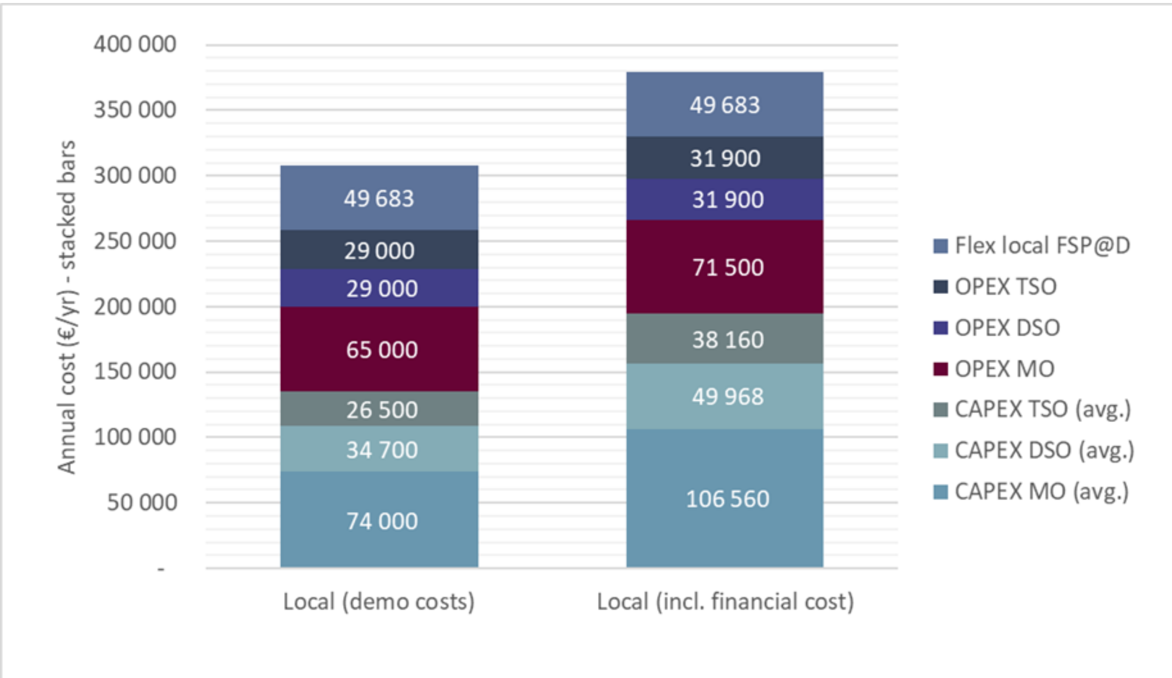


Figure 76: Annual cost (€/year) at system level (including CAPEX and OPEX cost for regulated actors and flexibility procurement cost) for local CM needs in Kefalonia

A pay-as-bid pricing scheme is assumed (Cossent et al., 2022) and bid prices (82.09 €/MWh) are based on the operational expenditures and other criteria of each FSP. The cleared bids are selected according to the optimization formulation of each coordination scheme. However, the cost of the flexibility is difficult to estimate due to the bid price volatility and uncertainty of needs, as it depends on the mechanism for flexibility procurement (i.e., market mechanisms based on pay-as-bid or pay-as-clear, bilateral contract agreements, capacity and/or energy payments, etc.), the liquidity, technologies which provide flexibility, etc.

On the other hand, the CAPEX and OPEX are taken from section 7.2, as estimated costs for a demonstration solution (including a financial remuneration rate of 8% for CAPEX terms, and an operational margin of 10% for OPEX terms), according to the functionalities developed and validated. The commercial flexibility solution shall require a higher level of integration with the existing TSO, DSO and MO platforms, new functionalities still not covered, higher communication deployment, and full validation, for a successful deployment of flexibility markets, as discussed in section 2.3. The cost of the regulated actors for a commercial flexibility solution should be higher and carefully estimated.

7.3.4 Profitability assessment for non-regulated agents for local needs

The aggregator FSP-ag@D receives market incomes by the provision of local flexibility services in the local market model LMM, but they face additional costs associated to this business activity.

This subsection focuses on the profitability assessment for the FSP-ag@D, that is, a flexibility service provider which provides flexibility for local CM needs in LMM and requires to develop an aggregation platform and ICT systems to communicate with the DSO, DERs and the LMO.

In order to be able to use flexibility-based solutions locally, DSOs must develop, deploy and integrate several ICT-based platforms. Additionally, the FSP-ag@D should pay the flexibility market access fee, and other market costs related to flexibility provision, as shown in Figure 77. The FSP-ag@D should also consider other costs associated to the small DERs they represent (i.e., energy-box device), as well as the DER remuneration by means of a bilateral contract agreement among parties.

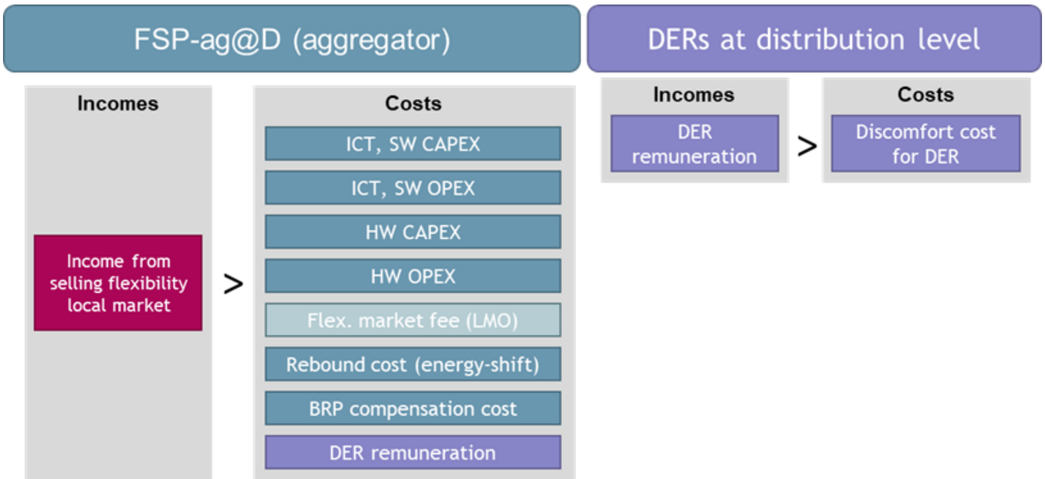


Figure 77: Incomes and costs for non-regulated agents in the flexibility and BaU alternatives when solving local needs in Greek scenarios (Pillar 3)

A sensitivity analysis is performed for the demonstrator in Kefalonia, in which the scenario is scaled geographically (more locations) and according to the level of local congestions. When the number of locations and the level of CM needs increase, the flexibility incomes increase to a greater extent than some incurred costs. For example, CAPEX and OPEX are assumed independent from the level of CM needs, while CAPEX and OPEX related to the DERs increase proportionally based on the number of DERs and locations.

Table 51 summarizes the economic and technical assumptions, considered for the local CM in Kefalonia.

For the profitability assessment of FSP-ag@D, the CAPEX and OPEX values are extracted from section 7.2 (for local markets). In Kefalonia, 10 flexible resources are initially considered by the energy aggregator (see Table 47). However, more DERs at distribution (up to 26) are considered in order to avoid or reduce the flexibility not supplied in the N-1 scenario with the unavailability of the transformer. Even so, there is not sufficient flexibility to solve all congestions (as presented previously in subsection 7.3.2). Consequently, 30 DERs are finally considered for the Greek analysis of the profitability of FSP-ag@D. The large number of DERs considered to solve local needs increases the OPEX and CAPEX costs needed to an effective communication and control, resulting in higher costs than in the simulated scenarios in previous countries (Spain or Sweden).

Table 51: Economic and technical data of the FSP@D for local needs in Kefalonia

	Unit	Value	Comment
Flexibility energy provision	MWh/year	605	-
Flexibility incomes	€/year	49 683	at 82.09 €/MWh
Annual average CAPEX related to SW platform, ICT...	€/year	8 000	10 years
Annual average CAPEX HW, DERs (i.e., energy-box)	€/year	900	300 € per DER
Annual OPEX related to the energy aggregator role	€/year	16 000	
Annual OPEX related to flexible units	€/year	18 000	600 €/year per DER
Annual MO fee	€/year	18	0.03 €/MWh
Rebound effect cost	€/year	13 864	22.91 €/MWh
BRP compensation	€/year	103	0.17 €/MWh
Number of flexible unit/resources at demo (Kefalonia)	#	30	-

The OPEX for the LMO platform are partially covered by the FSPs at distribution level, considering an energy-indexed fee of 0.03 €/MWh (based on the fee paid to the NEMO in the regulated tariff “voluntary price for the small consumer” in Spain, see footnote 17 in subsubsection 5.4.1.3 for clarification). Additionally, rebound effects are included, in which the aggregator and the FSPs, or their retailer, should reschedule the load profile or take other energy time-shift actions. The cost of rebound effect is estimated at 22.91 €/MWh (the weighted price of the wholesale market in 2020 is 45.82 €/MWh[22]). As a municipal building and irrigation pumps, among other technologies, are considered to provide flexibility, it is assumed that nearly 50% of the energy delivered in the flexibility market should be rescheduled later. Finally, the BRP compensation is estimated at 0.17 €/MWh[23], as an average price component for the measured imbalances of the suppliers.

[22] Annual Report 2020, Henex, Weighted Average Prices in Greece, available in https://www.enexgroup.gr/c/document_library/get_file?uuid=e8d7ae02-2046-e5fd-5c41-6a8ef3c9fc7b&groupId=20126

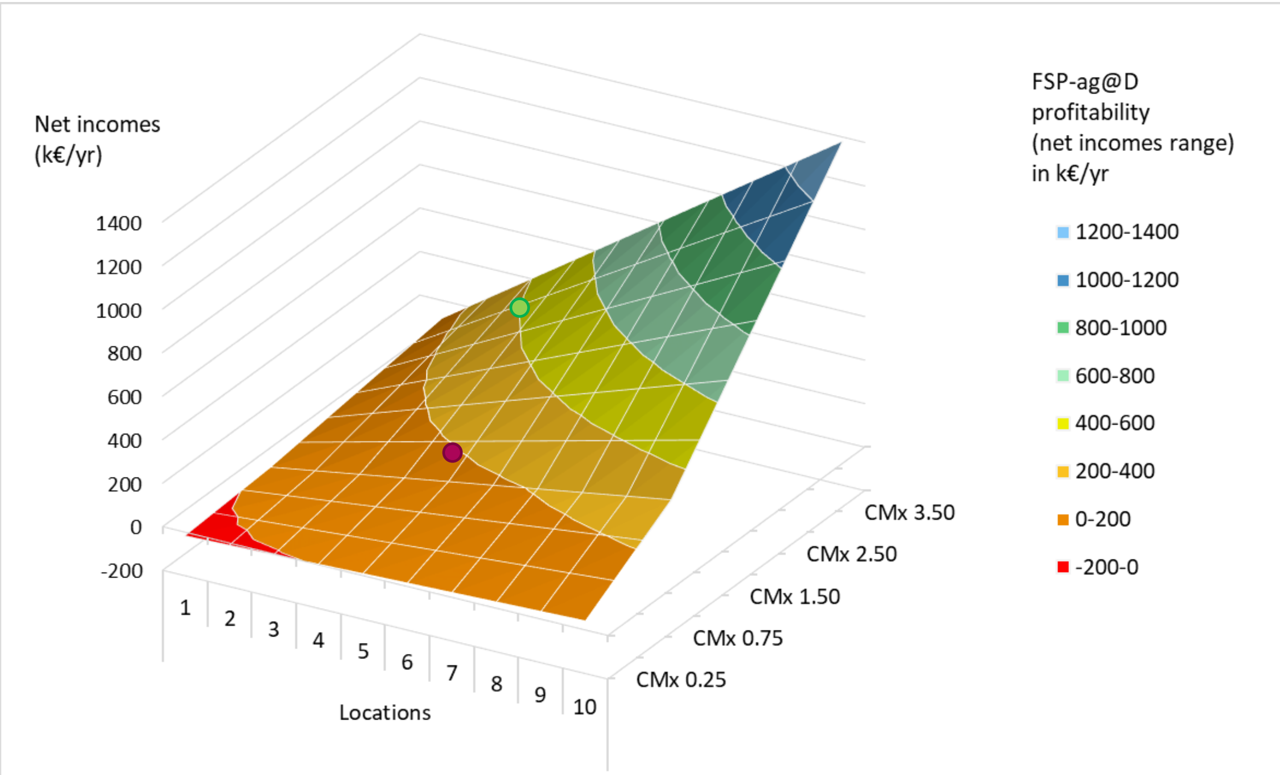
[23] Assumed same cost structure as for the Spanish case, the “annual average price of the measured imbalances of referenced suppliers” refers to the average cost resultant from the energy imbalances that the last resort suppliers incur from their schedule and their final profiles. These changes may come from forecast errors, changes in the final demand, but also for the flexibility activation, which result in an extra cost from the BRP’s side. Available in

In this local CM market, the weighted flexibility price (pay-as-bid pricing mechanism) is established at 82.09 €/MWh. Figure 78 depicts a sensitivity analysis of the profitability assessment of FSPs to solve local needs in the demonstrator in Kefalonia, according to:

- an increase in the number of locations with congestion at distribution level (up to 10 times more), which increase the number of DERs considered in the economic analysis, and
- an increase of the level of CM needs (605.22 MWh/year from 0.25 up to 3.5 times).

As can be observed in Figure 78, the initial scenario (605 MWh/year) is not attractive (-22 702 €/year), especially due to the high rebound cost and high OPEX terms per year. The business case becomes positive i.e., above 3 times the level of CM needs and scaled above 4 locations (green dot in Figure 78). For example, with the same level of congestions in Kefalonia in 5 similar locations (at a weighted flexibility price is at 82 €/MWh), the FSP can obtain 142 488 €/year (red dot in Figure 78).

However, the sensitivity analysis cannot be extrapolated as a generic result for energy aggregators which participate in local flexibility needs, as the CAPEX and OPEX terms may vary, the number of DER and their flexibility capacity can differ, as well as the flexibility incomes obtained based on the flexibility bid price. Some market costs, such as the rebound cost or BRP compensation, might be avoided, depending on the regulation in force at that moment, to incentivize the participation of small DERs and aggregators in flexibility local markets, until enough market liquidity is realized, and they can obtain an attractive remuneration.



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https://www.esios.ree.es/en/analysis/955?vis=1&start_date=01-01-2020T00%3A00&end_date=31-12-2020T23%3A55&compare_start_date=01-01-2019T00%3A00&groupby=year

Figure 78: Sensitivity of the profitability assessment of FSPs to the number of locations and level of congestions in Kefalonia

The DERs may be renumerated according to a revenue sharing ratio on the flexibility income of the FSP. In the example below, Figure 79 presents the sensitivity of the profitability assessment for the FSP and the remuneration for the DERs according to different revenue sharing ratios, especially with the same level of congestions in Kefalonia in 5 similar locations (annual incomes for the FSP of 142 489 €/year). Under this scenario, the annual incomes for the FSP are 43 123 €/year with a revenue sharing ratio of 40% (being 40% of the market income by the FSP), while the yearly remuneration for all DERs is 99 366 €/year, which is shared among them according to their specific contribution to flexibility activation and their flexibility bid price.

For each ratio, the minimum discomfort price perceived by the DER can be calculated (the minimum revenue or price at which the DERs are willing to provide flexibility in return for economic payment), which should be less than the flexibility bid price sent to the LMO by the FSP. Under the 40% revenue sharing presented in Figure 79, the weighted discomfort price for DERs is 35 €/MWh.

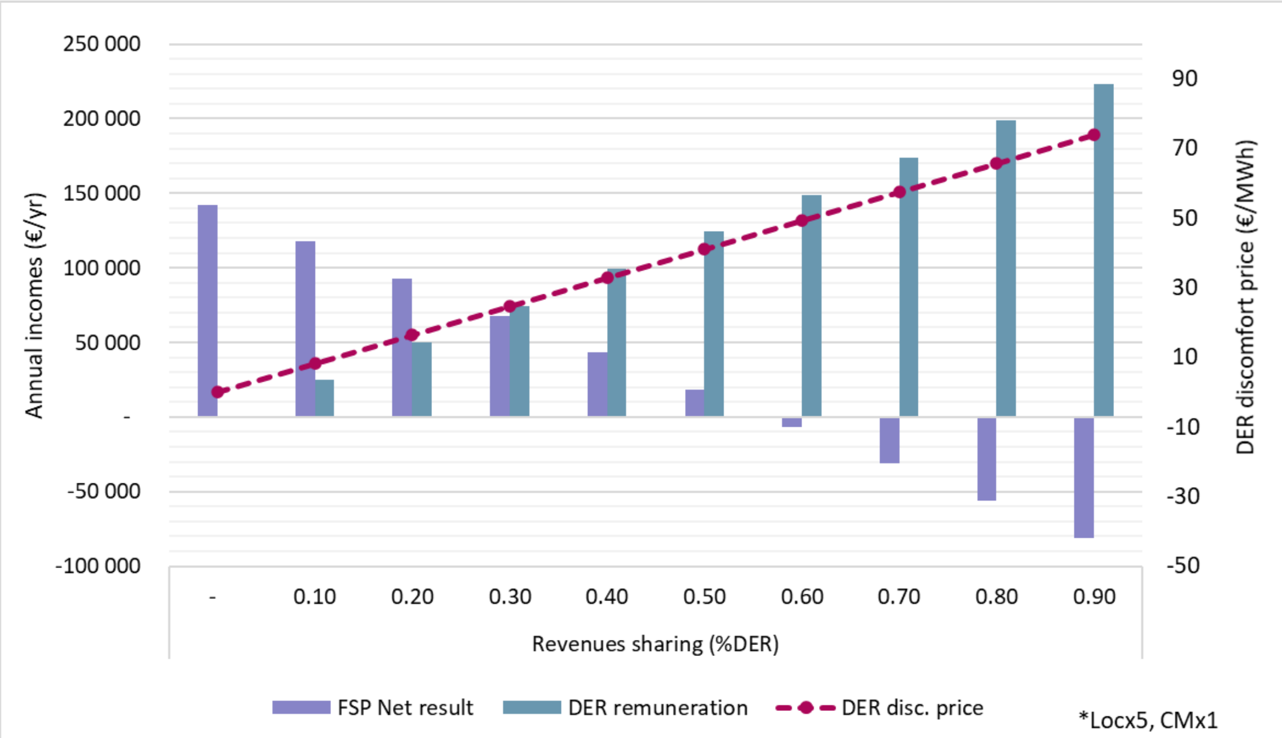

Figure 79: Sensitivity to revenue sharing between the aggregator and DERs in Kefalonia

7.4 Main conclusions of the flexibility solution in Greece

In the Greek economic analysis, local system needs have been analyzed in the region of Kefalonia, focusing on the congestion management service. The economic implications for the DSO and the FSPs have been assessed, when the unavailability of a transformer at the Argostoli substation has been considered.

Local congestions at distribution level are not frequent nowadays, so potential congestions have been simulated in this case through the unavailability (not existence) of the transformer at the substation. The economic analysis presented in this deliverable gives the opportunity to evaluate how to solve a local congestion with similar characteristics through local markets oriented to DSO needs.

From the DSO point of view, the local congestion can be categorized as structural congestion due to the large amount of annual flexibility needs and the limited flexible FSP available in the demonstrator in Kefalonia, even if only 12 criticalities per year have been estimated behind the Argostoli substation due to the unavailability of the transformer. Although not covered in this deliverable, long-term markets may be recommended to ensure the level of required flexibility (i.e., via bilateral contracts) between the DSO and large FSPs (i.e., industries, controllable loads, etc.), until there is enough liquidity in short-term markets to procure it. Specially, this problem arose in the simulation for Kefalonia, where it is required more than 12 times the flexibility initially provided and with more FSPs than the existing ones. Therefore, it is necessary to ensure sufficient market liquidity or flexible availability to solve local DSO congestion by means of the flexibility solution.

Due to the large amount of flexibility needs simulated, the remedial action should be discarded because of its expensive operating cost, being only a suitable option in urgent ad unplanned problems to avoid energy nor supplied to consumers. In the presented simulation, the flexibility solution can be used to postpone grid reinforcements for the DSO, in case of the cost of flexibility solution is cheaper than the traditional grid-based solution. As the flexibility needs tend to increase (due to the vegetative increase of demand), the grid-based solution can be selected and planned in advance, being the flexibility solution a temporary and faster mechanism than other urgent alternatives, until the grid-based solution is commissioned and ready.

Finally, the profitability for the flexibility sellers' actors (FSPs, aggregators, distributed energy resources, etc.) has been evaluated when they provide local flexibility. The business case is not enough attractive in the presented demo (only implemented in a specific location, the distribution grid behind the Argostoli substation in Kefalonia), although the remuneration for the provision of flexibility is relatively high, based on the operational expenditures and other criteria of each FSP. The high entry costs (platform development, communication infrastructure and maintenance, prequalification, market participation fee or other cost related to the retailers or BRP) disincentive their participation. The annual remuneration is not enough to recover the costs. Therefore, it is expected that niche market for FSPs and aggregators will increase in case of more widespread congestions, scaling the business model to become cost-efficient.

8 Conclusions and Recommendations

This deliverable D6.3 addresses the economic assessment of the proposed coordination schemes (CSs) and products for system services, by evaluating the cost-efficiency of different coordination schemes at system level, together with the economic implications for all market agents, especially for the distribution system operator (DSO) and flexible services providers (FSP), when either joint TSO and DSO needs, or DSO-specific local needs are considered. In particular, the **following four core questions** are addressed:

1. Under which conditions is the use of flexibility more suitable than the Business-as-Usual option (i.e., reinforcing the grid or ask for temporary subscription tariffs)?
2. Which is the most cost-effective way of coordinating the procurement (including the cost of developing the platforms necessary to do so) of system services between TSOs and DSOs?
3. Is the provision of flexibility a profitable business model for both FSPs and DERs?
4. Do local flexibility markets provide a cost-effective solution for solving specific needs of the DSO? If so, can they facilitate and incentivize the participation of both small FSPs and DERs?

Firstly, a qualitative analysis of the different approaches between the Coordinet demonstrators was done, in which the services, products, and coordination schemes deployed and tested in demonstration campaigns were compared. Both capacity and energy products were evaluated in different demos, in which a wide consensus was observed as the co-existence of capacity and energy products could be targeted, certainly for markets which are still rather immature. Regarding reactive power products, it is concluded that further investigation on the product and market design is needed mainly focused on the demand side and distributed generation, in which the interdependency between reactive and active power leads to more operational constraints.

According to the service size and quantity, there is a trend towards lowering the minimum bid size in all countries. A distinction between products (bid size, market access, requirements, etc.) could be proposed for small flexible service providers to facilitate their service provision. In this regard, the trend toward asymmetric products seems advisable, as it allows more effective participation of FSPs, by adapting their bids to the nature of their own technologies and to the features of the service. In this line, the aggregation of small resources will foster their participation and improve the reliability of their service provision.

From the level of adoption of standardized product in the demos, it can be concluded that the achieved standardization level is limited, as the products are mainly adapted to the specific needs considered. It therefore seems that a high level of standardization across the different demonstrators is not possible at this stage, but rather standardization is to be sought, to the extent possible, at member state level, serving the defined products in CoordiNet as a common guideline.

In relation to the coordination schemes, there is no one-size-fits all coordination scheme. The reasons for the different choices can be found in the casuistry of each country, the local and regional needs, regulatory differences, existing market structure and legacy systems, the role of each agent, the disparity of maturity levels of services and products, and type of FSPs among countries, among other specific criteria.

Additionally, the joint procurement of flexibility for congestion management and balancing services was not addressed within the CoordiNet project. When looking at the different market solutions being procured within the different demonstrators, it is clear that the balancing markets are well established, while the markets for the other services (voltage control, controlled islanding) are less developed. Therefore, a lot of attention has been paid to the definition of markets for congestion management in CoordiNet.

In the light of the conclusions above, the quantitative examples presented per country in the deliverable focused on the evaluation of the cost-effectiveness of different coordination schemes oriented to the congestion management, together with the economic implications for the main involved market agents.

The methodology for the economic assessment of the procurement of congestion management was based on three pillars, whose objectives were: 1) to compare the procurement of flexibility services versus the Business-as-Usual alternative (which is different for each country analyzed), specially the economic implication for the DSO, both to address joint TSO and DSO, and for DSO-specific local needs, 2) to evaluate the economic impact at system level of the flexibility solution, looking at the cost-efficiency of each coordination scheme, and 3) to evaluate the profitability of the provision of flexibility services by flexible services providers and other non-regulated actors under the scenario modelled in each demo country, performing again separate analyses for the case where there are joint TSO and DSO needs, and when flexibility is used to solve DSO-specific local needs.

Starting from **Pillar 2**, it can be highlighted the need for interoperability of distinct flexibility markets, system and market operators. Congestion management products at transmission and distribution levels can be procured efficiently in common and multi-level markets as presented in the Spanish case, in which the most competitive flexibility bids are cleared in short-term market mechanisms to achieve a cost-efficient service. In contrast, the multi-level market model seems to be more suitable to address the specific conditions in Sweden, both because it is better suited to address the challenges of subscription tariffs, and because it increases the participation of small or medium FSPs located at distribution level, by giving a market access priority of these players to solve downstream grid issues and reduce necessity of asking for an increase in the subscription level of the DSO. In both cases, existing market structure and legacy systems have a strong impact on the efficiency of the different coordination schemes.

Therefore, as stated above, the specific casuistry of each country strongly affects the performance and the final selection of the most appropriate coordination scheme per country, due to the voltage levels operated by each system operator, the number and size of TSOs and DSOs, already existing market structure and legacy systems, the role of each agent, and the features of the case studies modelled in the deliverable.

Regarding **Pillar 1**, the procurement of flexibility services is compared to the Business-as-Usual alternative, grid reinforcement or remedial actions are of main interest for Spain and Greece, while the payment of subscription penalties by the DSO is evaluated in Sweden with and without flexibility.

In case of occasional congestions (like the ones simulated in the Murcia demonstration area), flexibility may be more cost-efficient than reinforcing the grid or take costly remedial actions (i.e., the use of a diesel generator). Hence, the activation of flexibility from FSPs connected to the distribution grid could help solve unforeseen congestions via short-term market mechanisms in the most economically and efficiently manner.

In the case of structural congestions (like the ones simulated in Málaga, Albacete, Cádiz and Kefalonia), the flexibility needs to be procured more frequently or the amount of flexibility needed is higher than in the case of occasional congestions. Specially, there is a special concern in structural congestion at local level, in which the quality and security of supply might be at risk for the DSO, resulting in high costs due to non-supplied energy. Due to the large amount of flexibility needs simulated, the remedial action should be discarded because of its expensive operating cost, being only a suitable option in urgent and unplanned problems to avoid situations in which energy cannot be supplied to consumers. Therefore, long-term markets may be recommended to ensure enough available flexibility (i.e., via bilateral contracts), until there is enough liquidity in short-term markets to procure it. This conclusion is in line with the overall recommendation to consider the co-existence of capacity and energy products, as discussed above.

In any case, the flexibility solution has demonstrated to be a cheaper and more effective option than remedial actions in all the simulated cases, and a faster and temporary mechanism to avoid or postpone grid reinforcements, while the grid-based solution is commissioned and comes into service before unaffordable congestions are present due to vegetative increase of demand.

In Sweden, the flexibility solution may also be interesting to avoid the payment of high temporary subscription usage fees or even more expensive penalties for overcoming the subscription level. The flexibility solution will reduce the need to ask for higher subscription level (and the risk to have it denied), enable the connection of new customers to a higher extent (together with fewer disconnections of the existing ones), and it has proven to be a faster and efficient solution, until the TSO reinforces the transmission grid and is able to provide higher subscription levels.

Finally, the business model for the flexibility sellers (aggregators, flexibility providers, distributed resources, prosumers, etc.) seems to be still uncertain and risky under the simulated cases in all countries, because the high entry costs (platform development, communication infrastructure and maintenance, prequalification, market participation fee or other allocated costs) disincentive their participation until the congestions are more frequent. Additionally, the revenue of providing flexibility is difficult to estimate, due to the immaturity of flexibility markets (which is even more evident in the case of small DERs or other FSPs connected at distribution level), uncertainty and disparity of prices, uncertainty of system needs and their trends, the mechanism established for flexibility procurement (i.e., market mechanisms based on pay-as-bid or pay-as-clear, bilateral contract agreements, capacity and/or energy payments, etc.), the available liquidity, the mix of technologies which provide flexibility, etc.

The business model is not enough attractive in the simulated scenarios, when the solution is only implemented in a specific location, such as Cádiz, Albacete, Murcia, Málaga, Upland, or Kefalonia. The annual remuneration for the procurement of a given need is not enough to recover the costs of deployment the flexibility solution by the FSPs. The scalability of the business model will make it more attractive and cost-efficient in case of more widespread congestions. Moreover, DSOs could also establish local market models to exploit the flexibility of small DERs to solve congestion issues at distribution level. These local markets seem to be more accessible and attractive for small DERs, as the communications and reliability requirements and costs may be lower, as well as being a highly valuable service for the DSO at local level.

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10 Annex I: Product definitions

10.1 Product definitions in the Spanish demonstrator

Table 52: Definition of the products for system services tested in the Spanish demonstrator (Ivanova et al., 2021), (Ivanova et al., 2022)

Product	Non-reserved congestion management	Non-reserved congestion management	mFRR	RR	Steady state reactive power	Programmed islanding	Outage islanding
Service	Congestion management	Congestion management	Balancing	Balancing	Voltage control	Controlled islanding	Controlled islanding
BUC	ES-1a	ES-1B	ES-2	ES-2	ES-3	ES-4	ES-4
Preparation period	N/A	N/A	N/A	N/A	N/A	Until 1.6 hours before the island (worst case scenario, when recovery period not performed)	N/A
Ramping period	N/A	N/A	N/A	N/A	N/A	N/A	3 min
Full activation time	N/A	30 minutes	Current: 15 minutes Future: 12,5 minutes	30 minutes	N/A	Same as preparation period (instant when 100% recovered)	3 min
Minimum quantity	0.1 MW	1 kW	1 MW	1 MW	1 MW x Mvar[24]	0.1 MW and 0.025 MWh with minimum cos φ=0.9	0.1 MW and 0.025 MWh with minimum cos φ=0.9
Maximum quantity	N/A	1MW	N/A	N/A	N/A	1.2 MW and 2 MWh (generating or consuming)	1.2 MW and 2 MWh (generating or consuming)
Minimum duration of delivery period	N/A	15 minutes	N/A	15 minutes	N/A	15 minutes	15 minutes

[24] The product is defined as an area.

Maximum duration of delivery period	N/A	6 hours	N/A	Current: 4 hours Future: 60 minutes	N/A.	worst case scenario: 1.6*60=96 min	worst case scenario: 1.6*60=96 min
Deactivation period	N/A	15 minutes	N/A	N/A	N/A	Instant	Instant
Granularity	0.1 MW	1 kW	0.01 MW or 0.001 MW	0.01 MW or 0.001 MW	N/A	1kW and 1kWh	1kW and 1kWh
Validity period	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mode of activation	Manual	Manual	Manual	Manual	Automatic	Manual / automatic	Manual
Availability price	N.A.	No	Possible, dependent on the procurement process	Possible, dependent on the procurement process	Yes	No	Yes
Activation price	Yes	Yes	Yes	Yes	No. The price refers to an area	Yes	Yes
Divisibility	Divisible and indivisible bids allowed	Divisible and indivisible bids allowed	Divisible and indivisible bids allowed	Divisible and indivisible bids allowed	Only indivisible bids allowed	Divisible and indivisible bids allowed	Divisible and indivisible bids allowed
Location	Included in bid	Node location	At least the smallest of LFC area or bidding zone	At least the smallest of LFC area or bidding zone	By default, at generator terminals	Secondary substation in rural area	Secondary substation in rural area
Recovery period	N/A	2 hours	N/A	N/A	N/A	1,6 hours (worst case)	1,6 hours (worst case)
Aggregation allowed	Yes	Yes	Yes	Yes	No	No	No
Product Symmetry	Asymmetric	Asymmetric	Asymmetric	Asymmetric	Asymmetric	Asymmetric	Asymmetric

10.2 Product definitions in the Swedish demonstrator

Table 53: Definition of the products for system services tested in the Swedish demonstrator (Hugner et al., 2020)

Product	Reserved congestion management (long term capacity bids)	Non-reserved congestion management (free bids)	Peer to peer congestion management	mFRR
Service	Congestion management	Congestion management	Congestion management	Balancing
BUC	BUC SE-1a	BUC SE-1a	BUC SE-1b	BUC SE-3
Preparation period	N/A	N/A	N/A	N/A
Ramping period	N/A	N/A	N/A	N/A
Full activation time	N/A	N/A	N/A	15 minutes
Minimum quantity	1 MW	0,1 MW	0,1 MW	1 MW in CoordiNet demo (10 MW otherwise, 5 MW for the price area in Skåne)
Maximum quantity	N/A	N/A	N/A	N/A
Minimum duration of delivery period	60 min	60 min	60 min (on average)	At least 15 minutes (from request commerce to end of hour)[25]
Maximum duration of delivery period	N/A	N/A	As decided between peers (can be as long as maintenance period)	60 minutes
Deactivation period	N/A	N/A	N/A	N/A
Granularity	N/A	0.1 MW	N/A	1 MW
Availability	99%	As bid	As bid	As agreed individually for each FSP
Validity period	According to contract (all hours yearly, all hours Nov-March, defined hours Nov-March)	N/A	During maintenance periods in the DSO or TSO grid	The bid is valid for the specified hour of delivery

[25] This means that the TSO may send an activation request any time during the hour and the FSP must start to deliver the requested volume within 15 min and keep doing this for the remainder of the hour, so maximum 45 minutes.

Mode of activation	Manual by FSP, API or text message and e-mail notification	Manual by FSP, API or text message and e-mail notification	Manual by FSP	Manual by FSP, Electronic ordering through CoordiNet platform.
Availability price	Possibly (Differs depending on type of contract and resource type)	No	No	No
Activation price	Yes [Fixed price (according to contract)]	Yes	Yes	Yes
Divisibility	Divisible and indivisible bids allowed	Divisible and indivisible bids allowed	Divisible and indivisible bids allowed	Only indivisible bids allowed
Location	Yes (Impact factor for each substation with a congestion market linked to it)	Yes (Impact factor for each substation with a congestion market linked to it)	Yes (Impact factor for each substation with a congestion market linked to it)	Yes (bidding zone)
Recovery period	N/A	No requirements set (FSP may configure recovery period in market platform)	N/A	N/A
Aggregation allowed	Yes	Yes	Yes	Yes
Product Symmetry	Only upward regulation (load reduction)	Only upward regulation (load reduction)	Upward regulation (production increase) peered with Downward regulation (load increase, production decrease)	No symmetry requirement. Up and down regulation is procured. In CoordiNet demo: only upward regulation.

10.3 Product definitions in the Greek demonstrator

Table 54: Definition of the products for system services tested in the Greek demonstrator (Leonidaki et al., 2021)

Product	Reserved congestion management	Non-reserved congestion management	Steady state reactive power	Active power
Service	Congestion management	Congestion management	Voltage control	Voltage control
BUC	GR-2a&b	GR-2a&b	GR-1a&b	GR-1a&b
Preparation period	2,5 minutes	2,5 minutes	N/A	2,5 minutes
Ramping period	10 minutes	10 minutes	N/A	10 minutes
Full activation time	12,5 minutes	12,5 minutes	12,5 minutes	12,5 minutes
Minimum quantity	0,01 MW	0,01 MW	0,01 MVAr	0,01 MW
Maximum quantity	N/A	N/A	Within technical limits of the installation	N/A
Minimum duration of delivery period	15 minutes	15 minutes	N/A (constant activation)	15 minutes
Maximum duration of delivery period	15 minutes	15 minutes	N/A (constant activation)	15 minutes
Deactivation period	10 minutes	10 minutes	N/A	10 minutes
Granularity	0,01 MW	0,01 MW	0,01 MVAr	0,01 MW
Validity period	N/A	N/A	N/A	N/A
Mode of activation	Manual	Manual	Automatic (reactive setpoint)	Manual
Availability price	Yes	No	Yes	No
Activation price	N.A.	Yes	No	Yes
Divisibility	Divisible and indivisible bids allowed	Divisible and indivisible bids allowed	Only indivisible bids allowed	Divisible and indivisible bids allowed
Location	Based on a list of customers' ID (Aggregator) and a list of units' ID of system operator (unit individual bids	Based on a list of customers' ID (Aggregator) and a list of units' ID of system operator (unit individual bids	Based on a list of units' ID of system operator (unit individual bids)	Based on a list of customers' ID (Aggregator)
Recovery period	N/A	N/A	N/A.	N/A.
Aggregation allowed	Yes	Yes	Yes	Yes
Product Symmetry	Asymmetric	Asymmetric	Asymmetric	Asymmetric

11 Annex II: Sequence diagrams for additional coordination schemes

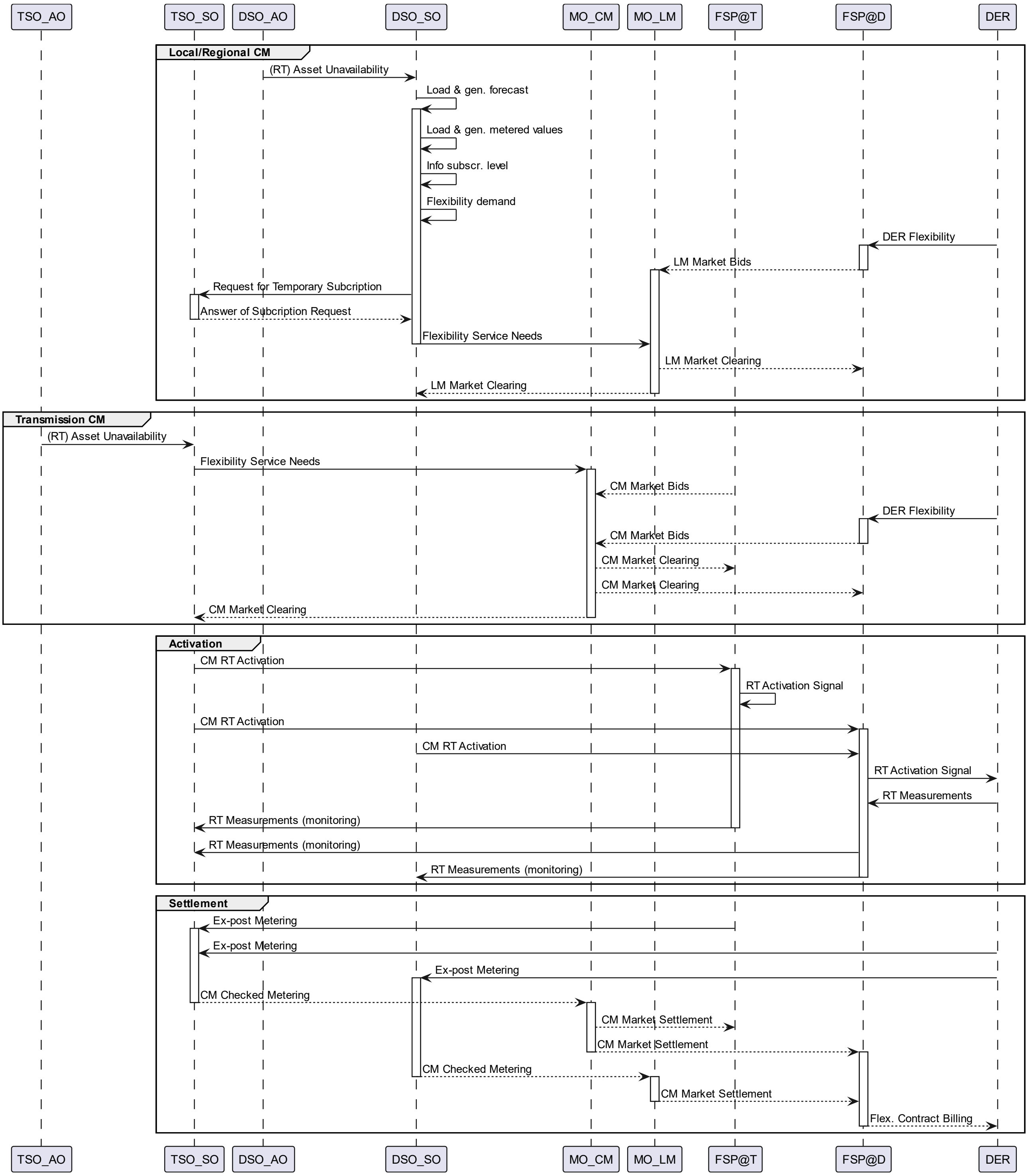

Figure 80: Sequence diagram for multi-level market model (ability to modify bids between market sessions), based on BUC SE-1a

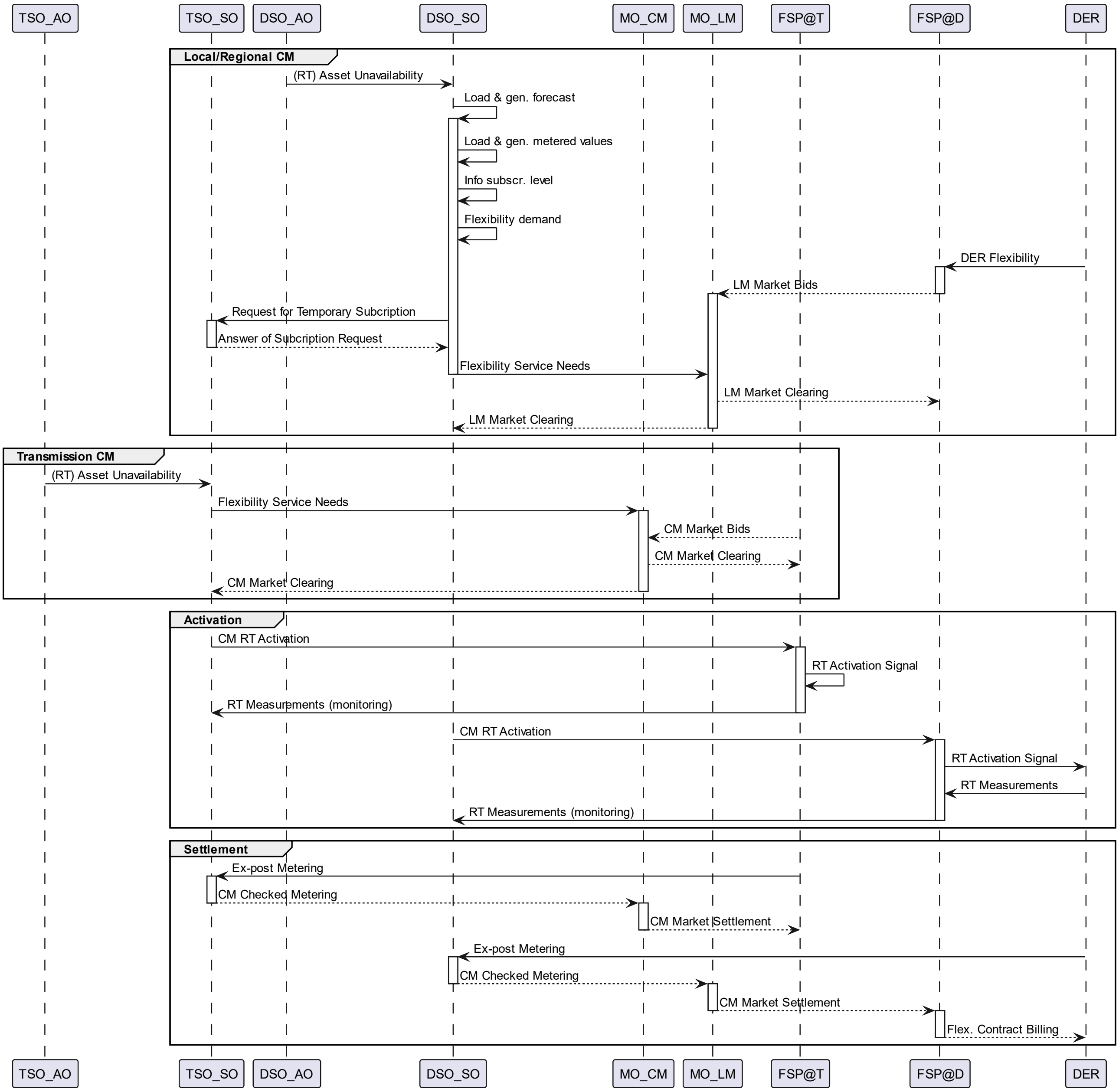

Figure 81: Sequence diagram for fragmented market model

12 Annex III: Regulatory mechanisms for market actors

12.1 Regulatory mechanism for System Operators: current state and trends

From the TSO and DSO perspectives, the procurement of flexibility services should be designed through a market-based mechanism. As regulated parties, they cover their investment and operational costs by a reasonable return rate of investment according to a specific mechanism, based on national (or regional) regulations (European Commission et al., 2019). In this way, three main categories of remuneration schemes for TSO and DSO can be (CEER, 2017a):

- **Cost-based regulation**, which is widely used by Member States. The rate of return model guarantees the regulated company a certain pre-defined rate of return on its regulatory asset base. Obviously, TSOs and DSOs have no incentive to minimize its costs under a cost-based regulation framework, because it can increase its profits by expanding the asset or cost base.
- **Incentive-based regulation**, which is characterized by the use of financial rewards and penalties to induce the regulated company to achieve the desired goals, by allowing it to share the 'extra profit' if it overfulfils some indicators. In general, these incentives are focused on aiming cost control at system level, so that grid users could benefit in a quantitative way through lower tariffs.
- **Hybrid approach**, which is a blend of previous methodologies with an extensive variety of approaches, in which incentive-based method may be applied to the CAPEX and/or OPEX or independently. This remuneration scheme for regulated agents is usually composed of a base remuneration (CAPEX and OPEX) and an incentive-based complement, which can be either positive or negative, depending on the performance of the indicators under supervision.

As conclusion of a report by the European Commission (European Commission et al., 2019), there is no clear and consistent approach in the regulatory frameworks in the Member States to foster innovative investments, as traditionally regulation puts a strong emphasis on the (short-term) efficiency of the network, instead of innovation alternatives with a long-term vision. Table 55 summarized the regulatory mechanism for investments:

Table 55: Summary of TSO regulatory mechanism for investments in demo countries

Member State	Regulatory mechanism for investments	Possible investment method for innovative projects
Spain	Cost-based. Rate-of-Return, Revenue Cap	Reference unit values of investment and O&M costs, while investment conditions are considered for special projects.
Sweden	Cost-based. Revenue Cap	May provide opportunity to include cost for innovative investments if they are reasonable and necessary.
Greece	Cost-based. Revenue Cap	Premium rate of return for projects of major importance.

At the decision-making stage, Social Cost-Benefit Analyses for larger projects should be performed to ensure wider societal benefits and justify the long-term economic impacts of the grid alternatives considered in the network development plans. This Deliverable D6.3 is focused on the economic perspective, comparing the economic performance for two grid planning alternatives: flexibility market versus the main traditional grid-based alternative per demo.

This economic assessment should include overall cost in the long-term, which enable TSOs and DSOs to use flexibility when it is a more cost-efficient option than traditional grid solution for congestion management.

In this economic analysis, the remuneration for TSOs and DSOs is designed by CAPEX, OPEX and incentives (if desired). The regulatory mechanisms for TSOs and DSOs will directly have an economic impact on the economic assessment at system level, which enables to evaluate the best grid solution per demo country.

Therefore, regulatory mechanisms for TSO and DSOs should be reviewed, aligned, and designed to reach a reasonable return of investment and, also, to foster the procurement of flexibility services. This may involve **introducing incentives of interest or a specific budget for CAPEX/OPEX-based solutions**.

Hereafter, several proposals to include incentives or remuneration terms, oriented to foster flexibility services as innovation projects (CEER, 2017b), (EDSO, 2014), (European Commission et al., 2019), are listed:

- Mitigation of CAPEX bias by encouraging a balanced consideration of OPEX-based solutions
  - introducing incentives or a specific budget for OPEX-based solutions
- Innovative options chosen funded through tariffs to reduce uncertainty of investments
- Risk-based regulation for CAPEX/OPEX remuneration:
  - using a separate and higher WACC for certain activities, i.e., innovative projects
- Higher welfare for all the actors involved, DSOs included
- Incentives based on output-based indicators:
  - Optimized distribution network capacity investments:
    - avoided infrastructure investments
    - asset or defer reinforcement
  - Optimized infrastructure use
    - efficiently maintenance, asset replacement, and connection works
    - asset lifetime extension
- Incentives based on performance indicators:
  - Incentives to reduce line losses
  - Incentives to reduce curtailment of distributed generation
  - Incentives to reduce outage times
  - Incentives to reduce increase the distributed generation hosting capacity
  - Incentives to invest in OPEX solutions to counteract any CAPEX bias
  - Incentives which maximize the security of supply in the most efficient way
  - Incentives which maximize the quality of supply in the most efficient way
  - Incentives which recognize uncertainty of accepting “riskier” expenses

As conclusion, the regulatory mechanism for TSOs and DSOs should be composed by a base remuneration for the recognized costs (capital and operational expenditures associated to new flexibility services and related to the selected coordination scheme) and additional incentives, if desired.

Specific incentives may be considered to foster grid operators to make available system services (in this case, local congestion management) to network users or improve the efficiency of their performance, while these overall cost from the power system point of view does not increase to a certain extent. In general, these incentives should be oriented **toward a reduction of the overall long-term costs at system level**, so that the grid users could benefit in a quantitative way through lower tariffs in the present or in the future.

12.1.1 Spanish regulatory mechanism for System Operators

The Spanish methodology developed for the remuneration of the transmission and distribution activity has the purpose of establishing the criteria for covering the recognized costs, encouraging the continuous improvement of the efficiency of the management, and the quality of supply, all of this, *“with homogeneous criteria for the entire Spanish territory and* ***at the lowest possible cost for the electrical system****”.*

The TSO is clearly divided into two entities, with regard to its main roles (European Commission, 2009):

- **TSO as asset owner** with the responsibility of operating, maintaining and developing the transmission network in an efficient, safe, reliable, economic and environmentally sustainable manner; and providing third party access on a non-discriminatory basis.
- **TSO as asset operator** with the responsibility of: contributing to the real-time operation and the security of supply through long-term network planning in order to meet reasonable demands and development of the network; cooperating with neighboring/regional TSOs on cross-border interconnections; exchanging information with other TSOs particularly in relation to security and congestion management; and providing dispatching (for electricity only) and balancing services.

Distribution System Operator (DSO) (European Commission, 2019a) is responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity, by supplying their connected customers.

In the case of Spain, TSO and DSOs’ base remuneration (CAPEX and OPEX), which a rate of return on equity is 5.56% after taxes (8.53% before taxes) (Banco de España, 2019a):

- TSO, as asset owner, recognized CAPEX for asset investment and asset upgrades (based on reference values), considering a regulated financial remuneration rate
- TSO, as asset owner, recognized OPEX for asset O&M (based on reference values), considering a financial margin applicable, and additional OPEX for asset lifetime extension
- TSO, as system operator, recognized CAPEX for regulated duties (software apps renewal, European reg. compliance projects, etc.)
- TSO, as system operator, recognized OPEX for regulated duties (settlement, etc.).
- DSO recognized CAPEX for asset investment (based on reference values), considering a regulated financial remuneration rate, and other activities, such as control centers, land purchase, other assets investment and additional duties
- DSO recognized OPEX for asset O&M (based on reference values), considering a financial margin applicable, and additional OPEX for asset lifetime extension

This base remuneration is complemented by specific performance incentives:

- to increase the asset availability (quality of supply) and to extend the lifetime of equipment and TSO assets in the case of TSO as asset operator, (Spanish Government, 2019b).
- to reduce the re-dispatched energy to solve congested events and to improve the load and generation forecasts in the case of TSO as asset owner (Banco de España, 2019b)
- to reduce system losses (benchmarking among DSOs) and improve the quality of supply in the case of DSOs (Spanish Government, 2019a).

12.1.2 Swedish regulatory mechanism for System Operators

In Sweden, Ei is the National Regulatory Authority (NRA) responsible for designing the regulation in a way that minimizes the welfare losses from electricity natural monopoly. The main objective of the regulation is to ensure that the network operators do not make unreasonably high profits while retaining efficient operations of the grid with a good quality of supply (CEER, 2022). Any network activity shall have a specific revenue framework which should not be greater than what is needed to: i) cover costs for the operation of the network, carried out in an efficient manner; ii) cover depreciation, and, iii) provide the rate of return that is necessary to compete with other alternative investments with equivalent risk (HyLAW, 2018).

From 2012, the revenue cap mechanism is established, which shall cover reasonable operational costs and a reasonable return on the assets used for distribution and transmission. This revenue cap comprises:

- Return of investments and depreciation during the supervisory period. The Total Expenditure (TOTEX) is divided into CAPEX, non-controllable OPEX and controllable OPEX. The rate of return in Sweden is 5.52% before taxes (CEER, 2022).
    - Controllable OPEX is based on data reported by the network operators on historical costs
    - Non-controllable OPEX is based on estimates provided by the network operators prior to the period, that are corrected for actual outcome ex post.
    - Efficiency target of reducing the controllable OPEX has been set to 1% annually for TSO, while efficiency benchmarking model is used case for the DSOs.
- Incentive for a good security of supply is considered, based on the average interruption time and frequency, which may result in an increase or decrease in the revenue cap.
- Incentive for an efficient network utilization is considered, based on the average load factor and network losses, which may lead to an increase or decrease in the revenue cap.

Additionally, DSOs have a so-called concession (permission) for the distribution of electricity (Hugner et al., 2020). That is, the regional DSOs in Sweden have an annual contract with a subscription level towards the TSO. Also, the local DSO will have a subscription level governing the amount of power that it can draw, but this is often with the regional DSO. It is possible to apply for a temporary subscription in addition to the annual subscription, prior notification and acceptance of the TSO or regional DSO (Hugner et al., 2020).

12.1.3 Greek regulatory mechanism for System Operators

Electricity transmission and distribution in Greece is conducted by one TSO (ADMIE-IPTO) and one DSO (HEDNO), respectively. The regulatory model is essentially a multi-year revenue cap on OPEX and cost-plus on CAPEX (Greek Government, 2011), where the allowed revenue is determined as follows:

- CAPEX (Regulated asset base) is derived by approved network development plans (fixed assets, approved investment plans, and estimated working capital), including depreciation of the fixed assets. The rate of return on equity is 8.2% (TSO) and 8.16% (DSO) before taxes.
- WACC is established at 6.95% (TSO) and 7% (DSO). For specific projects of the TSO, a premium rate of return (between 1% and 2.5%) can be provided, in addition to WACC. Similarly, for the electricity DSO, a 0.5% to 2% premium over the cost of capital is allowed for specific projects.
- OPEX (controllable costs) are determined in the context of the allowed revenue decision, including payroll costs of staff, costs for functions it performs, material and consumables.
- OPEX (non-controllable costs) are determined in the context of the allowed revenue decision, including regulatory fees, local authority fees, indirect taxes, and other compensation costs.
- Estimated revenues from other Regulated and non-Regulated Activities

In 2020, a new regulatory regime for the DSO is adopted in Greece (RAE, 2020), including an incentives to reduce network losses (penalty/reward scheme), and a quality regulation with minimum guaranteed standards assuming a penalty/reward scheme.

12.2 Regulatory mechanism for Market Operators: current state and trends

A **Nominated Electricity Market Operator** (NEMO) is an entity designated by the competent authority to perform tasks related to single day-ahead or single intraday market coupling. In other words, NEMOs are the organizations mandated to run the day-ahead and intraday integrated electricity markets in the EU, where every Member State has currently at least one designated NEMO (ACER, n.d.), (ACER, 2021).

Additionally, the EU Regulation 2015/1222 (European Commission, 2015) establishing a guideline on Capacity Allocation and Congestion Management (CACM), which gave a new regulatory framework for cross-border trading and Market Coupling. The CACM regulation clearly defines the tasks and obligations of TSOs and of Power Exchanges designated as NEMOs. A NEMO, whose status is as a "passport" (EPEX SPOT, n.d.), can operate power spot markets in other European countries.

Table 56 below shows the NEMOs designated in each demo country, as well as their specific operating roles and competitive status:

Table 56: Current Nominated Electricity Market Operators (NEMO) in demo countries (ACER, 2021)

Member State	NEMO for day-ahead and intraday markets	Operating role	Competitive status
Spain	OMIE S.A.	Designated	Monopoly
Sweden	Nord Pool EMCO AS EPEX Spot SE	Designated Passporting	Competitive
Greece	HEnEx SA	Designated	Monopoly

According to Regulation (EU) 2019/943 (European Commission, 2019c), NEMOs operate with regard to the performance of their predefined tasks within a formal framework under regulatory oversight and they take coordinated decisions according to transparent and well-known applicable rules.

For simplicity, in the Coordinet project, the flexibility Market Operator (MO) platforms will be located on the TSO and DSO premises (Valarezo et al., 2021). Hence, system operators will manage and operate the market platform for flexibility procurement. For the economic assessment of Deliverable D6.3, the specific role of the MO is separated from SOs and is considered a regulated party, such as NEMOs, to manage the products for flexibility services. Specially, the MO platform considered here depends on the BUC deployed at demo countries.

12.2.1 Spanish regulatory mechanism for NEMO

In the case of Spain, most of the energy and balancing services are contracted one day before delivery, 80% of the electricity supplied in Spain and Portugal is traded through OMIE (Lind and Chaves, 2019). The market operator for day-ahead and intraday markets receives a base remuneration for their investment and operational costs and have several incentives and additional regulatory remuneration terms (CNMC, 2021):

- The base remuneration, which includes the total annual costs incurred by the MO as a result of the regulated functions that MO performs, including a CAPEX (annual cost of net fixed assets with a fixed financial remuneration rate) and OPEX (with a financial margin applicable to OPEX).
- An additional regulatory remuneration of the MO applied, which have not been considered in the base remuneration, to cover:
    - Additional CAPEX from singular projects (e.g. integration in the European intraday market)
    - Additional CAPEX for new duties derived from European or national regulation
- Several adjustments due to:
    - Other recognized incomes which are not directly related to market operation activities
    - Historical or recognized past costs that should have been included in the regulated activity
- An incentive-based remuneration for the MO in year *n*, with two purposes:
    - An incentive to detect abnormal market behaviors
    - An incentive to perform R&D activities

Likewise, (CNMC, 2021) also defines how such MO remuneration should be paid by system users. Both sellers (generators) and buyers (retailers/direct consumers) pay MO's remuneration, each one 50% of the total remuneration:

- Generator owners pay a fixed monthly amount for each installation of more than 1 MW they have, based on their available capacity (based on the installed power) and a fixed price per MW.
- Retailers and direct consumers pay an hourly amount for each MWh in their final schedule resulting from their participation in the day-ahead market and intraday markets and the redispatch resulting from the day-ahead congestion management, based on an hourly price per MWh.

12.2.2 Swedish regulatory mechanism for NEMO

Nord Pool European Market Coupling Operator AS ("Nord Pool EMCO") is the designated NEMO in Sweden. Nord Pool EMCO is not regulated by any financial authority (Nord Pool, 2021), but by the National Energy Regulatory Authority ('Reguleringsmyndigheten for Energi' – RME).

The annual financial report of the Nord Pool group (Nord Pool, 2019) summarized the annual cash flow including operating and investment activities: **operating incomes** (fixed and dependent fees applied to customers for buying or selling electricity) and **expenses** (depreciation, payroll costs, etc.). The operating profits before taxes, net incomes after taxes and net cash flow are presented. Moreover, fixed assets are described, including receivables and bank deposits, in addition to equity, and liabilities results.

12.2.3 Greek regulatory mechanism for NEMO

HEnEx ("Hellenic Energy Exchange SA") is the Greek NEMO, which continues to actively participate in the reorganization of the Hellenic energy market for the implementation of the European Regulatory Framework (Target Model), for the integration of the Single Internal Electricity Market. HEnEx is in charge of operating the day-ahead and intraday markets, whereas the Balancing Market will be operated by ADMIE (Lind and Chaves, 2019) and EnEx Clearing House S.A. (EnExClear) provides clearing and settlement services.

Through the annual financial report (HEnEx, 2020), the Greek MO provides a detailed cash flow, including: i) **Incomes** from DSO revenues, auction fee, NEMO revenues, subscriptions, energy transaction commissions, market support revenues, and other revenues (i.e. grants), and ii) **Costs** of work and expenses including personnel expenses, third party expenses, utilities, maintenance support, taxes and other operating expenses. A detailed financial position, including circulating and non-circulating assets costs, equity, and liabilities.

12.3 Legal framework for Flexibility Service Providers

A balancing service provider means a market participant with reserve-providing units or reserve-providing groups able to provide balancing services to TSOs (European Commission, 2017). Similarly, a Flexibility Service Provider (FSP) is a legal entity that provides flexibility services, being the owner or the representative (on their behalf in the market) of large-scale or small-scale assets, which are connected to the electricity network and which can provide energy services for TSOs and/or DSOs. FSP can participate in the market on behalf on one flexible resource or acquired capabilities of several aggregated FSP (named as independent aggregator).

Whereas, a Distributed Energy Resource is a kind of flexible resource, which encompasses the multiple types of end-users connected to the distribution grid such as generation, electric vehicle chargers, storage devices, heating devices, etc. All them are capable of providing energy and/or services to the grid by mobilizing the flexibility they have available (Lind and Chaves, 2019).

The FSPs can participate in the flexibility markets, being rewarded for the availability to provide flexibility during some time and/or the provision of flexibility, while it should cope with several costs for their business activity (i.e., remuneration for DERs, ICT & SW costs, BRP costs, etc.). Meanwhile, DERs sign generally a contractual agreement with and independent aggregator, which may include (non-exhaustive list):

- incomes for the availability to provide flexibility (specially, in case of capacity products),
- incomes for the provided flexibility,
- a subscription fee to fund MO,
- a reduction on their energy-based term or on their energy bills (contracted by the supplier),
- an amount of annual renewable electricity for free or lower cost (contracted by the supplier), or
- a reduced cost of additional technology or services (equipment acquisition or maintenance),

12.3.1 Spanish legal framework for FSP and DERs

In Spain, DSOs can use distributed generation to solve congestion, through the redispatching services operated by the TSO. The DSO could use DG for local congestion management through the TSO. As these requests are sent by the DSO to the TSO, ultimately is the TSO that solves the constraints and instructs the DER. As a last resort, the TSO and DSO can curtail renewable generation for security reasons in day-ahead on in the real time.

Regarding balancing services, in Spain, energy storage facilities and demand-side facilities can recently participate in the electricity markets and TSO balancing markets in equality and under no-discrimination (Spanish Government, 2020), being 1 MW the minimum size required to participate in such markets. The aggregation of resources by technology and market agent in order to reach that minimum size is allowed.

However, the legal figure of the independent aggregator, as defined by the European regulation (e.g. Clean Energy Package) is still not fully implemented in the Spanish regulation, although it is expected by the end of 2022. Moreover, there are still no consensus regarding the relationship and agreement conditions regarding transfer of energy rules between aggregators and BRPs. Other services (such as black start, voltage control and DSO flexibility services) may be addressed in the future (Spanish Government, 2021). This depends on the future European Regulation related with the deployment of flexibility markets in the Distribution grids.

12.3.2 Swedish legal framework for FSP and DERs

In Sweden, DER can provide ancillary services to the TSO (Lind and Chaves, 2019). It is not possible to provide aFRR from demand response (consumers) as from now, while they are able to participate in mFRR. Moreover, the FCR market was planned to be open in 2019 for demand response (centrally controlled and/or stepwise controlled). In case of congestions, the TSO can also redispatch and curtail DER in case of disturbances or planned outages. The DSO can also procure flexibility from DER, via bilateral contracts.

In 2020, the Swedish regulation states that financial compensation for congestion management when the DSO does not raise the subscription level. This compensation will be a pass-through cost in the coming years.

Regarding the aggregation of resources, in Sweden, independent aggregators are not allowed to act consent from BRP delivering services to existing markets (e.g. a retailer). That is, the retailer has to be the own BRP at the point of delivery. If the independent aggregator is not a BRP itself and it want to provide balancing services, they can cooperate with a BRP to provide flexibility.

12.3.3 Greek legal framework for FSP and DERs

In Greece, as of today, there is no regulatory framework which allows the participation of DER in ancillary services. Only, interruptible contracts for large consumers exist but do not include resources connected at the distribution grid, and the TSO can only activate these resources for security reasons. In the near future, DER's curtailments in real-time shall be allowed for both security and economic reasons. Thus, the DERs will be remunerated to provide downward balancing energy through market mechanisms (Lind and Chaves, 2019).

In Greece, the regulatory basis for the DSO to procure DER flexibility for local grid management already exists, but it has not been implemented yet. Currently, "Demand Control Contracts" can be signed with individual electricity consumers in congested network areas. According to the Hellenic Electricity Distribution Network Code, DER can already provide local congestion management and voltage control.

In order to provide services to the DSO in the future, DR will have to be equipped with smart meters capable of being remotely controlled. In the case of the provision of these DSO services, DR will be remunerated according to bilateral contracts. Moreover, curtailment of DER by the DSO is also foreseen, i.e. under emergency situations, as long as they are connected through a remotely controlled switch.

Regarding the aggregation, no aggregators are currently active. To the extent that the EU common market design is being implemented, aggregated RES and DR will be able to participate in the balancing market and, possibly, in the day-ahead and intra-day markets.