Deliverable D6.1

Ex-post evaluation of the demonstrations

V 1.0

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D6.1 – Ex-post evaluation of the demonstrations

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Executive summary

This task describes and compiles the results of the first task of WP6 thus deals with the ex-post evaluation of the demonstrations of the COORDINET project. This deliverable includes an evaluation of the tested combinations of products for grid services and coordination schemes for each demonstration site, in terms of technical, economic and social KPIs, as identified in WP1. In this document a summary of the calculated KPIs as resulted from all demonstration sites in the three countries, namely Spain, Sweden and Greece is presented.

The obtained KPI results gathered from all demo sites led to a profound analysis carried out from the perspective of each demo separately, taking into account their special network characteristics and peculiarities. This assessment paves the way to a deeper understanding of how the flexibility mechanisms can be well exploited from the network operators through several suitable market model schemes in order to alleviate different types of network problems. In this front, the technical, economic, environmental and social KPIs were used to quantify and evaluate the impact of the tested solutions in different demonstration sites with different network characteristics. Moreover, KPIs showing the progress of the demonstrations during the project execution were utilized.

Although all the demonstrators focused on developing a platform to enable the marked-based information exchange and all the tools needed to implement a flexibility market, the three demonstrations display quite different characteristics in terms of the type of the participating sources of flexibility, as well as the national market and regulatory framework which is vastly differentiated among the demos. Hence, the comparison between them is not reasonable and therefore such an analysis has not been conducted.

Since it is acknowledged that the combination of coordination schemes and products affects the implementation and the efficiency of the flexibility market, a meaningful analysis conducted is presented in order to facilitate the selection approach of the preferred coordination schemes and products based on the KPI results of the project.

This document alongside the rest of the WP6 deliverables complements the analysis and the evaluation of coordination mechanisms and market models schemes for the provision of flexibility services in three demonstration countries. It serves as the key starting point for the evaluation of the applicability of flexibility mechanisms among distribution and transmission system operators.

The methodology adopted for the analysis of the KPIs and the preparation of this deliverable included the close collaboration among the involved partners through weekly meetings during task's execution. The assessment of each demo KPI calculation was performed by various partners and confirmed by the rest of the demo leaders, who were responsible to validate the accuracy and the methods utilised for the extraction of the obtained results. NTUA/ICCS, as the responsible partner for Deliverable 6.1, has refined the content, structure and presentation style of the inputs obtained from the partners, thus produced the final version of this document.

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Abbreviations and Acronyms

Acronym	Definition
ANN	Artificial Neural Network
BaU	Business as Usual
BUC	Business Use Case
CAPEX	Capital Expenditures
DA	Day-ahead
DER	Distributed Energy Resource
DSO	Distribution System Operator
FSP	Flexibility Service Provider
ICT	Information and Communications Technology
ID	Intraday
KPI	Key Performance Indicator
mFRR	Manual Frequency Restoration Reserve
MO	Market Operator
NRT	Near real-time
OPEX	Operational Expenditures
O&M	Operations and Maintenance
RES	Renewable Energy Sources
RR	Replacement Reserves
SGU	Significant Grid User
SO	System Operator
TSO	Transmission System Operator
WF	Wind Farm

Table 1: Acronyms list

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 demonstrates 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 demonstrations. The CoordiNet project is centred around three key objectives:

1. To demonstrate to which extent coordination between TSO/DSO will lead to a cheaper, more reliable and more environmentally friendly electricity supply to the consumers through the implementation of three demonstrations 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 energy services and opens up new revenue streams for consumers providing system services.

In total, ten demonstration campaigns have been carried out in three different countries, namely Spain, Sweden and Greece. In each demonstration activity, different products are tested, in different time frames. Figure 1 presents the overview of (standardized) products, system services, and coordination schemes implemented in the CoordiNet demonstration activities. More details about the defined basis, in the form of designated Business Use Cases (BUCs) tested in CoordiNet, can be found in deliverable D1.5 [1].

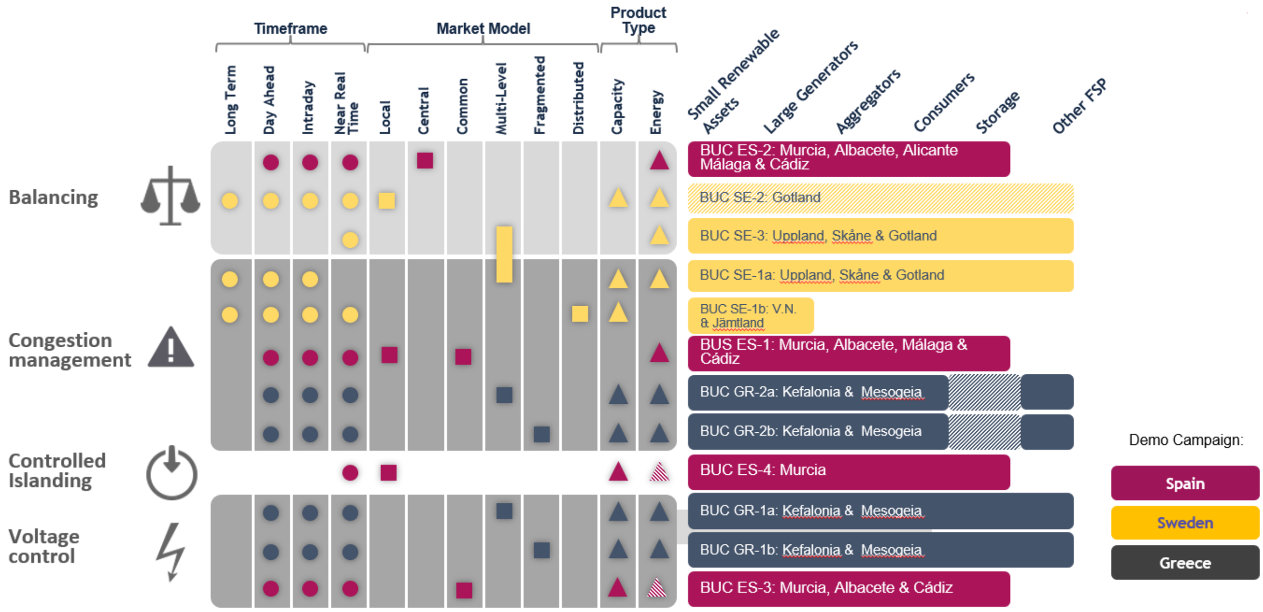

Figure 1: Overall CoordiNet approach: Services, timeframes, coordination schemes and products that will be demonstrated in different countries (Spain in pink, Sweden in yellow, and Greece in grey)

1.2 Objective and scope

This deliverable reports on task 6.1 "Ex-post evaluation of the demonstrations" of the CoordiNet project, which aims to analyse the results of the different demonstrations in Spain, Sweden and Greece. The KPIs defined in D1.6 [2] were used to analyse the results of the three demonstrations. These KPIs were defined before starting the demonstrations. As the demonstrations progressed [1], [2], [3], slight changes were made to the definition and calculation formulas of some KPIs to adapt them to the tests performed by the demonstrations and to present the demonstration results in the most effective way.

Technical, economic, environmental and social KPIs were used to quantify and evaluate the impact of the tested solution in the demonstration sites. Moreover, KPIs showing the progress of the demonstrations during the project were used. Although all the demonstrations focused on developing a platform to enable the marked-based procurement of system services by the TSO and DSOs and all the supporting tools needed, the three demonstrations are quite different. Hence, the comparison between them is not reasonable and has not been conducted.

Furthermore, the deliverable also provides an approach that could be followed in the market planning phase to select the preferred coordination scheme and products, using the most critical KPIs. In addition, the factors that should be taken into account for the selections are presented.

The scope of this document is to analyse the KPIs calculated by the three demonstrations in order to draw conclusions based on their outcomes and discuss the selection of preferred coordination schemes and products to address system needs.

1.3 Methodology

This section describes the methodological approach followed to analyse the KPIs provided by all the demonstrators and draw conclusions. The steps that were followed are presented in Figure 2.

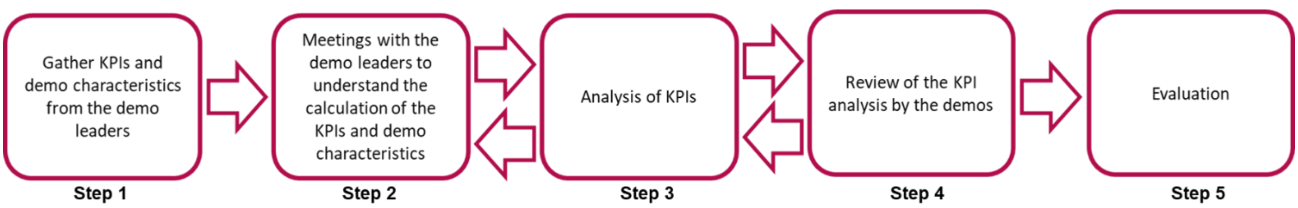

Figure 2: Steps followed to analyse the KPIs and conduct the evaluation

Steps 1-4 were performed for each demo run of all the demonstrators. Step 5 was performed after steps 1-4 were completed for all demo runs.

Step 1: Initially the characteristics of each demo run were gathered. Then the calculated KPIs by the demonstrators and some data used for their calculation were collected. The characteristics of the demos and the data utilised for KPI calculation were used to interpret the KPI results and conduct the analysis.

Step 2: After the collection of the necessary data from the demonstrators, meetings with the demo leaders were held to understand demo characteristics and the methodology followed by the demos to calculate the KPIs, as well as the assumptions made for the calculation of the KPIs.

Step 3: The next step was the analysis of the calculated KPIs by the partners involved in T6.1. During the analysis several meetings with the demo leaders took place, to address any question that arose. The demo leaders provided continuous support to perform a proper KPI analysis. This is shown by the two-way arrows between steps 2 and 3 in Figure 2.

Step 4: Once the KPIs analysis was completed, the demo leaders reviewed the analysis to make sure that they agree with the analysis conducted. In case the demo leaders had comments on the analysis, the necessary modifications were applied to address their comments. This is shown by the two-way arrows between steps 3 and 4 in Figure 2.

Step 5: The final step is the evaluation of the results. Based on the KPI analysis, conclusions were drawn.

1.4 Structure

The rest of the document is organized as follows. Chapter 2 provides a brief description of the three demonstrators to help the reader understand the problems faced by the system operators and how they are addressed through the implementation of the flexibility markets. In addition, details on the tested BUCs are presented. Chapter 3 includes the KPI analysis based on the KPIs values provided by the three demonstrators. Chapter 4 summarizes the KPI analysis to draw conclusions thus offer a meaningful approach to support the proper selection of coordination schemes and products according to network needs. Furthermore, the conclusions of other deliverables of WP6 are used in combination with the KPI analysis to evaluate the tested combinations of products for system services and coordination schemes. Finally, chapter 5 concludes the deliverable, summarizing the most interesting conclusions.

2 Demonstration sites

In this chapter, a brief description of the demonstrators is provided to make it easier for the reader to follow the analysis of the results. The tested services, products and coordination schemes are presented. Additionally, the major differences between the demo runs (demonstration phases), that affect the analysis of the results and the conclusions, are highlighted. Demo runs took place at different times. While the aim of demo run 1 was mainly to test that all developed tools work properly and identify areas for improvement, in the Spanish demo some BUCs were fully demonstrated from the first demo run. The next demo runs were full scale demonstrations with the aim to collect data in order to evaluate the results and draw conclusions. Two demonstration phases took place in the Spanish and Greek demonstrations, while three phases took place in the Swedish demonstration. The differences between the demo runs in each demonstration are presented in the following sections.

2.1 Spanish demonstrator

Currently, congestions at DSOs' networks are not frequent, as, traditionally before reaching technical limits according to planning criteria, the DSOs invest in grid assets to continue providing system security and quality of service to their customers as established in the current regulation. However, currently the DSO has 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 both at transmission and distribution levels, it is expected that congestions could also increase at the distribution level [3]. From a TSO's perspective, balancing and congestion management services are procured from resources connected both at the transmission and the distribution networks, as HV level networks (e.g., 132 kV) are operated by DSOs in Spain. In this context, the activation of flexibility connected at the distribution 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 can help SOs cope with network violations.

In the Spanish demonstrator, four system services, congestion management, balancing, voltage control and controlled islanding were tested. The services were tested under different coordination schemes. Congestion management was tested under the common and local market models, balancing services under the central market model, voltage control under the common market model and controlled islanding under the local market model. Energy products were considered for congestion management and balancing, while both, energy and capacity products, were considered for voltage control and controlled islanding. An overview of the Spanish demonstrator is presented in Figure 3, which shows the locations and the FSPs of each pilot site, the DSO of each location and the services, products and coordination schemes tested. More details are provided in the following tables.

Within the Spanish demonstration campaign, two demonstration phases have been organized, demo run 1 and demo run 2, which include four Business Use Cases (BUCs). Demo run 1 is focused on testing the coordination schemes for 'BUC ES1a: Common Congestion Management', 'BUC ES2: Balancing' and 'BUC ES4: Controlled Islanding'. Demo run 1 took place from October 2020 to June 2021. Demo Run 2 is focused on testing the coordination schemes for 'BUC ES1b: Local Congestion Management' and 'BUC ES3: Voltage Control'. In addition, it also included tests for 'BUC ES1a: Common Congestion Management', in the case of Malaga demonstration site. Demo Run 2 started in September 2021 and ended in March 2022. In this context, the main difference between Demo Runs 1 and 2 are the BUCs being tested, and consequently the services procured by SOs and voltage levels where FSPs were connected to.

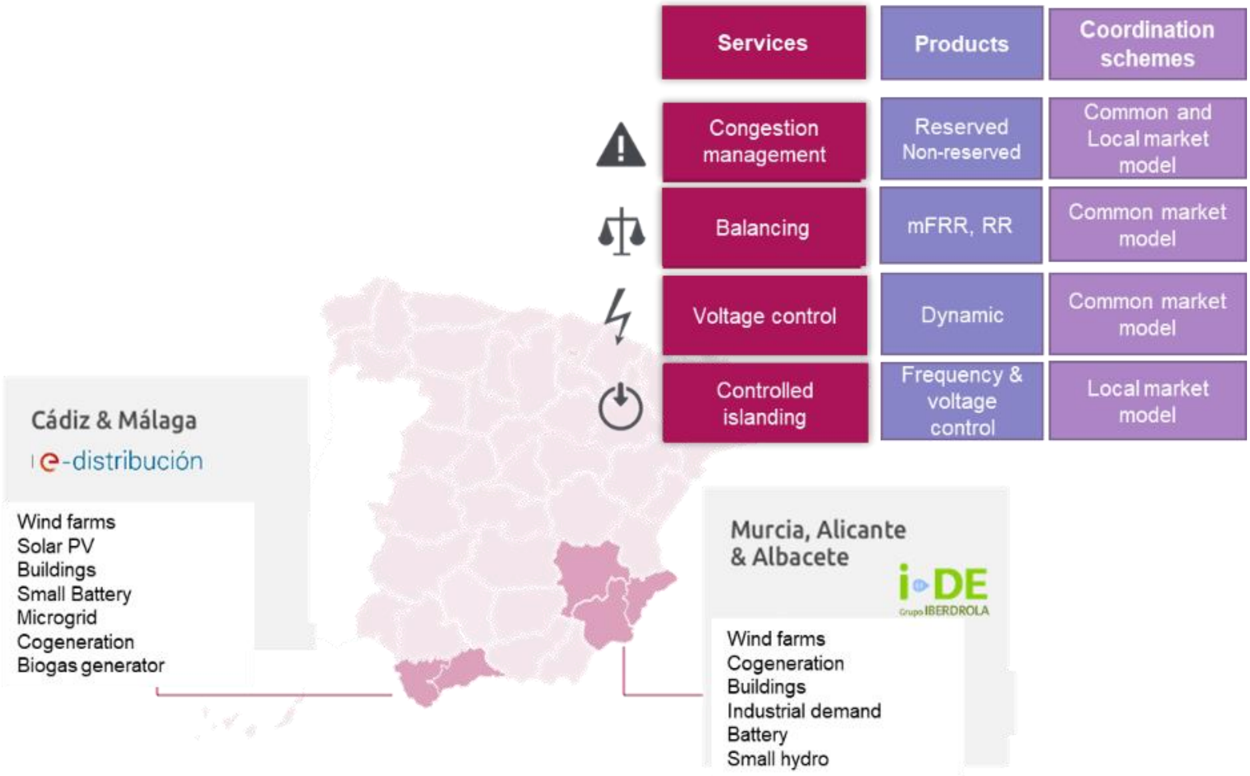

Figure 3: Map of the Spanish demonstrator areas.

The FSPs in the Spanish demonstrator include distributed generation, demand response, and storage systems. The predominant type of FSP varies according to BUC and voltage level. When testing the common balancing and congestion management BUCs, wind farms, small hydropower plant and cogeneration where the main types of FSPs, as these BUCs focused on resources connected to HV levels. For BUCs tested in lower voltage levels, demand response, micro grids and storage systems were used in addition. That is the case of the islanding BUC, that used a combination of PV panels and a battery. The local congestion management market was composed primarily by a micro-grid and demand response. About 300 MW of total flexible capacity and 20 FSPs were considered in the two demo runs of the Spanish demonstration. More detailed figures about the FSPs are provided in Table 4.

Renewable generation units considered are connected at e-DI, i-DE and REE networks at high, medium and low voltage levels. Demand-side resources considered are connected at low and medium voltages networks of e-DI in Malaga and of i-DE in Murcia, and at the high voltage network of i-DE in Alicante. Cádiz and Albacete pilot sites involve renewable sources, mainly wind power. In both locations, Voltage Control, Common Congestion Management and Balancing BUCs were tested. For these resources, as most of the units currently already participate in the market, the specific developments required for the demos are not numerous. However, voltage control is a new service where the product and the market framework have been defined and agreed between the TSO and DSO as part of CoordiNet.

The products that were tested are given in Table 2. The Table shows the provided system service, whether they are capacity or energy products, the coordination scheme under which the provision of the system service was tested and in which BUC the product was tested. Energy products were procured for congestion management and balancing services (mFRR and RR), while both, capacity and energy products were tested for voltage control and controlled islanding. Congestion management was tested under the common (BUC ES1-a) and local (BUC ES1-b) coordination schemes. The central market mechanism was applied for both products for balancing (BUC ES-2). Voltage control was tested considering the common market model (BUC ES-3). The two products for controlled islanding were procured through a local market (BUC ES-4).

Table 2: Products tested in the Spanish demonstrator.

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

Further insights on the design of the seven products through standard attributes for product definition (see D1.3 [4] for more details on product attributes) can be found in D6.3 [5] and D3.1 [3].

The market timeframes tested for each product, the system to which the service is provided and the pilot sites where the products were tested are shown in Table 3. Day-ahead (DA) and near real-time (NRT) market timeframes were considered for non-reserved congestion management products procured in common and local markets. The procured flexibility product in the common market was tested in distribution and transmission systems, while the product procured in the local market was only tested in the distribution system. Both products were procured in Malaga and Murcia-Alicante. The product of the common market was also procured in Albacete and Cadiz. NRT market timeframe was considered for balancing products that were procured in distribution and transmission system in Albacete, Cadiz and Murcia-Alicante. The product for voltage control was tested for DA and NRT in the distribution systems of Albacete and Cadiz. Finally, controlled islanding products were tested for long-term and NRT market timeframes in the distribution system of Murcia-Alicante.

Table 3: Market timeframes of product procurement, system using the product and pilot site tested in the Spanish demonstrator.

Product ID	Long-term	Day-ahead	Intraday	Near real-time	Distribution	Transmission	Pilot site
Non-reserved congestion management (Common market	-	✓		✓	✓	✓	Albacete Cádiz Málaga Murcia-Alicante
Non-reserved congestion management (Local market	-	✓		✓	✓		Málaga Murcia-Alicante
mFRR	-		-	✓	✓	✓	Albacete Cádiz Murcia-Alicante
RR	-		-	✓	✓	✓	Alabacete Cádiz Murcia-Alicante
Steady-state reactive power	-	✓ (week ahead, capacity)	-	✓ (energy)	✓	✓	Albacete Cádiz
Programmed island	✓ (capacity)		-	✓ (energy)	✓		Murcia-Alicante
Outage island	✓ (capacity)		-	✓ (energy)	✓		Murcia-Alicante

To help the reader understand the Spanish demonstrator's KPI analysis, the key features of the two demo runs are presented in Table 7.

Table 4: Characteristic of the two demo runs of the Spanish demonstrator

	Demo run	
	1	2
Year	2020-2021	2021-2022
Time period	October 2020 to June 2021	September 2021 to March 2022
Operating days	12 November 2020 2 February 2021 22 and 23 April 2021 11 and 18 June 2021	17 and 24 November, 16 December 2021 2, 3, 7, 11, 14, 15, 16, 22 and 24 March 2022
Weather conditions	First part - early winter Second part - early summer	First part - early winter Second part - early spring
System service	Congestion management Balancing Controlled islanding	Congestion management Voltage control

	Demo run	
	1	2
Coordination scheme	Congestion management: Common Balancing: Common Controlled islanding: Local	Congestion management: Common and local Voltage control: Common
Market timeframe	Congestion management: DA and NRT Balancing: DA and RT Controlled islanding: DA and NRT	Congestion management: DA and NRT Voltage control: Week ahead
Capacity of FSPs	Cadiz – 103 MW Malaga – 14.5 MW Albacete – 143 MW Murcia - 90 MW	Cadiz – 42 MW Malaga – 15 MW Albacete 126 MW Murcia - 90.8 MW
Number of resources	Cadiz – 5 units Malaga – 7 units Albacete – 7 units Murcia - 1 unit	Cadiz – 1 unit Malaga – 8 units Albacete – 7 units Murcia - 2 units
Days / hours with cleared flexibility	One hour per demo test	From 15 minutes to an hour per demo test

2.2 Swedish demonstrator

The Swedish demonstration uses a multi-level market coordination scheme with three layers due to a three-layered system operation: local DSO, regional DSO and the TSO. The regulated tariff model employed by Svenska kraftnät (SvK, the Swedish TSO) [7] introduces costs to constrain the capacity, which influences the operational business of the underlying system operators. With the tariffs, both local DSOs and regional DSOs subscribe to fixed capacity charges, which guarantees the regional and local energy consumption at the interfacing grid nodes up to the subscribed limit. In recent years, the annual subscription level has been surpassed more and the risk to be denied a temporary increase of the subscription has increased. This causes higher accumulated costs, which are due to the increasing urban development and electrification of transport and industry sectors. In addition to the capacity issues, referred to as congestion management, balancing and reserve markets are expected to benefit from standardized flexibility products and new market schemes in Sweden. The Swedish demo ran during 3 winters. In winter congestions occur due to the increase in load demand as a result of low temperatures.

In the Swedish demonstrator, two services, congestion management and balancing were tested. Congestion management was tested under the Multi-level market Model and Distributed Market Model, through a Peer-2-Peer (P2P) market, while balancing services were tested under the Multi-level Market Model. If not dispatched in the regional DSO congestion market, qualified unused bids can be further forwarded to the mFRR market to support the balancing needs of the TSO. An overview of the Swedish demonstrator is presented in Figure 4, which shows the locations and the FSPs of each pilot site and the services, products and coordination schemes tested. More details are provided in the following tables.

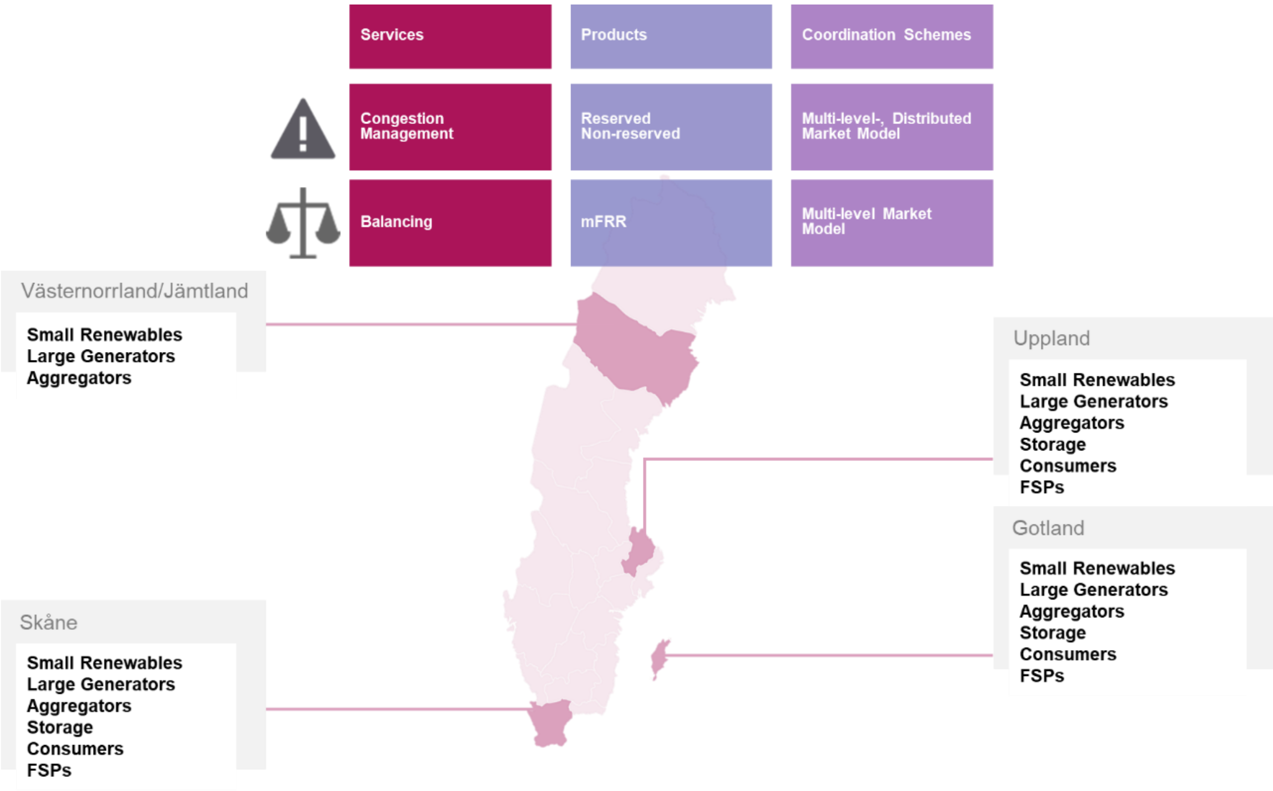

Figure 4: Map of the Swedish demonstrator areas.

The FSPs in the Swedish demonstrator are of many different kinds including industry, commercial buildings, reserve power gensets, energy storages and aggregated domestic heat pumps with different degrees of controllability on the consumer's end. Flexibility was also considered from larger local district heating (electric boilers, gas turbine and waste combustion). Additionally, EV charging is a flexible resource investigated in the demonstration. In Uppland, 9, 14 and 23 FSPs participated in demo run 1, 2 and 3, respectively, representing a total capacity of 96 MW, 172 MW and 103 MW in the three demo runs. In Skåne, 7, 11 and 7 FSPs participated in the three demo runs with a total capacity of 76 MW, 200 MW and 24 MW, while in Gotland, 3, 4 and 4 FPSs with a total capacity of 24 MW, 25 MW and 24 MW participated in the three demos. The FSPs that participated in each demo run of the Swedish demo can be found in D4.7.1 [6] and D6.6 [8].

In Table 5, the targeted products are given. The table shows the provided system service, whether they are capacity or energy products, the coordination scheme under which the provision of the system service was tested and in which BUC the product was tested. Reserved capacity and non-reserved energy products were employed for congestion management purposes through a multi-level market mechanism (BUC SE-1a). Additionally, a distributed P2P market was applied to procure energy products for congestion management services (BUC SE-1b). Also, balancing services were procured as a capacity product for frequency support (mFRR) under the multi-level market mechanism (BUC SE-3).

Table 5: Products tested in the Swedish demonstrator.

Product name	System service	Capacity/Energy	Coordination Scheme	BUC
Reserved congestion management	Congestion management	Capacity	Multi-level	SE-1a
Non-reserved congestion management	Congestion management	Energy	Multi-level	SE-1a
Congestion management P2P	Congestion management	Energy	Distributed (P2P market – Block chain application)	SE-1b
mFRR	Balancing	Capacity	Multi-level	SE-3

Further insights on the design of the four products through standard attributes for product definition (see D1.3 [4] for more details on product attributes) can be found in D4.1 [9] and D6.3 [5].

The market timeframes tested for each product, the system to which the service is provided and the pilot sites where the products were tested are shown in Table 6. Log-term, DA and intraday (ID) market timeframes were considered for reserved congestion management, while non-served congestion management was tested for DA and ID market timeframes. Both products were procured in the distribution system in Uppland, Skåne and Gotland.

Table 6: Market timeframes of product procurement, system using the product and pilot site tested in the Swedish demonstrator

Product name	Long-term	Day-ahead	Intraday	Near real-time	Distribution	Transmission	Pilot site
Reserved congestion management	✓	✓	✓	-	✓	-	Skåne, Uppland Gotland
Non-reserved congestion management	-	✓	✓	-	✓	-	Skåne, Uppland Gotland
Congestion management P2P	-	✓	-	-	✓	-	Gotland Västernorrland Jämtland
mFRR	-	-	-	✓	-	✓	Skåne Uppland

To help the reader understand the Swedish demonstrator's KPI analysis, the key features of the three demo runs are presented in Table 7. More details can be found in D4.7.1 [6].

Table 7: Characteristic of the three demo runs of the Swedish demonstrator

	Demo run		
	1	2	3
Year	Winter 2019/2020	Winter 2020/2021	Winter 2021/2022
Time period	Uppland: January 8 - March 31 Skåne: November 5 - March 31 Gotland: January 14 - March 31	Uppland: November 2 - March 31 Skåne: November 2 - March 31 Gotland: November 2 - March 31	Uppland: November 1 - March 31 Skåne: November 1 - March 31 Gotland: November 1 -March 31
Operating days	Uppland: 83 days Skåne: 147 days Gotland: 78 days	Uppland: 120 days Skåne: 150 days Gotland: 150 days	Uppland: 151 days Skåne: 151 days Gotland: 151 days
Weather conditions	Mild winter	Colder winter compared to demo run 1	Coldest winter but high electricity prices reduced usage and therefore bids from key flex resources
System service	Congestion management	Congestion management	Congestion management Balancing
Coordination scheme	Multi-level	Multi-level Distributed (P2P)	Multi-level Distributed (P2P)
Market timeframe	DA	Multi-level: Day-ahead & Intraday Distributed (P2P): Day-ahead	Multi-level: Day-ahead & Intraday Distributed (P2P): Day-ahead
Capacity of FSPs	Uppland: 96 MW Skåne: 76 MW Gotland: 24 MW	Uppland: 172 MW Skåne: 200 MW Gotland 25 MW	Uppland: 103 MW Skåne: 24 MW Gotland: 25 MW
Number of resources	Uppland: 9 Skåne: 7 Gotland: 3	Uppland: 14 Skåne: 11 Gotland: 4	Uppland: 23 Skåne: 7 Gotland: 4
Days / hours with cleared flexibility	Uppland: 16 days / 172 hours Skåne: 8 days / 26 hours Gotland: 3 days / 58 hours	Uppland: 41 days / 412 hours Skåne: 16 days / 35 hours Gotland: 12 days / 29 hours	Uppland: 23 days / 71 hours Skåne: 15 days / 30 hours Gotland: 2 days / 4 hours

In demo run 2, the volume of bids but also the volume of cleared flexibility increased compared to demo run 1. This was partly due to the colder winter during demo run 2 compared to the record warm one during demo run 1. Also, in demo run 2, the cleared volume increased by 65 % in Skåne and 102% in Uppland. In Gotland the cleared volume reduced, reflecting the higher pricing of some FSPs. In demo run 3, even though it was during the coldest winter of the three demo runs, the cleared volume decreased by between 2% and 12% compared to demo run 2. This was due to the high prices as the low cost FSPs were not available in times of congestion.

In general, it was observed that the submitted bids and the cleared flexibility are mainly affected by three factors; The weather conditions, as they affect the demand, the behaviour of the Significant Grid Users (SGUs), as their deviation from normal consumption has a great impact on flexibility markets both in terms of DSO grid needs and the quality of the forecasted grid needs, and the electricity prices, as they affect bidding strategy and demand [6].

When comparing the results of the demonstration over the different periods, it should be noted that there were strong differences between them. The first winter was a record warm winter with only few and relatively short colder periods. The second winter started even milder but had a strong cold spell in February 2021, during which flexibility on the market was insufficient to meet congestion needs. The third winter was the coldest winter, but the electricity prices were very high affecting the use of flexibility to avoid surpassing the subscription [6].

2.3 Greek demonstrator

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, faces network issues in some network areas due to the increased penetration of RES.

The aim of the Greek demonstrator is to investigate how unlocking flexibility from the distribution system can help the TSO and DSO to address these issues. The flexibility could be used to speed up the connection of the users to the distribution system and solve the network issues in the transmission system. Given that in the foreseeable future the RES penetration in the distribution system will increase significantly, reverse power flows will occur, resulting in congestions and voltage violations. These network issues will be mainly detected when RES generation is very high and the demand is low, but also in the opposite scenario, when the demand is high and the RES penetration is low.

In order to improve quality of supply, while avoiding the curtailment of RES generation and the reinforcement investments required to alleviate the networks issues, the improved TSO-DSO coordination and the use of flexibility through two market-based mechanisms are examined in the Greek demonstrator, in order to achieve this in the most cost-efficient way. A local market and the relevant platform were developed in order for the DSO to buy flexibility from Distributed Energy Resources (DERs) connected to the distribution system [10]. In the Greek demo, two services were examined, congestion management and voltage control, under two coordination schemes. When the Multi-level market model is implemented, the unused bids of the local market are forwarded to the TSO market. On the other hand, when the Fragmented market model is implemented, each system operator can buy flexibility only from the resources connected to its own system. An overview of the Greek demonstrator is presented in Figure 5, which shows the locations and the FSPs of each pilot site and the services, products and coordination schemes tested. More details are provided in the following tables.

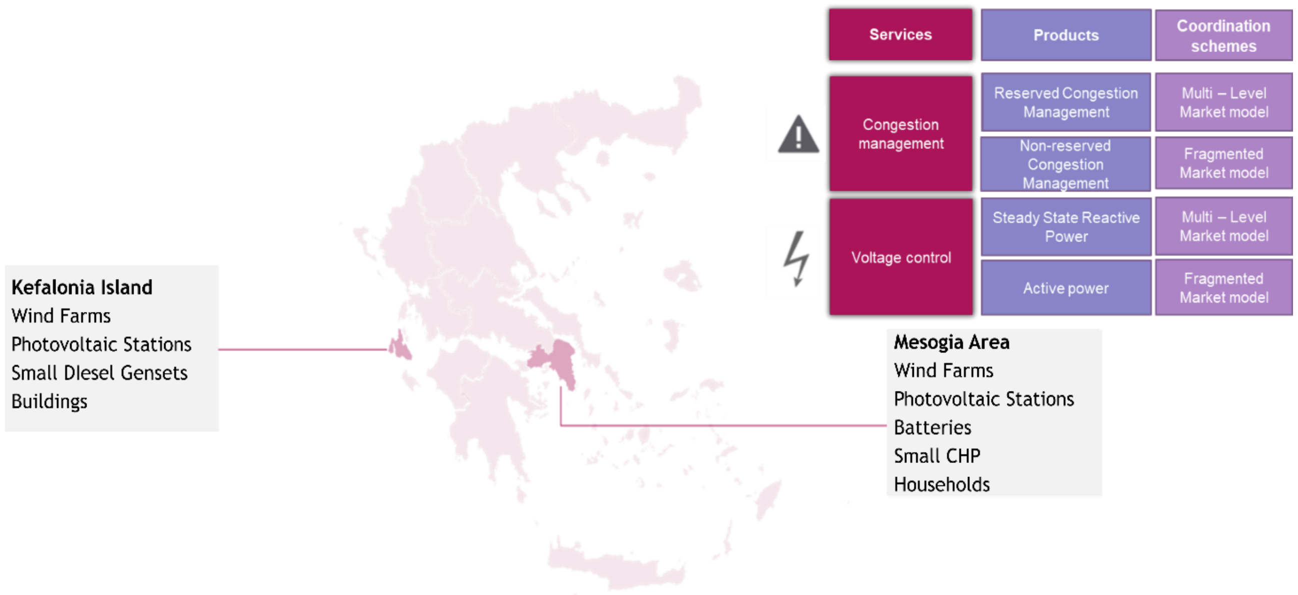

Figure 5: Map of the Greek demonstrator areas.

The implementation of a real flexibility market in Greece is not feasible for congestion management and voltage control, as the relevant regulation is not in place. The objective of the Greek demo was therefore to test the configuration of the developed market platforms, while making sure that all the necessary components for a market implementation are in place and all the communications work properly, as well as identify the advantages and disadvantages of such a market platform. The FSPs participating in the demonstrator do not submit bids, therefore virtual bids are created by a developed software. Regarding the Renewable Energy Sources (RES) and loads, the virtual bids are determined considering forecasts, which are based on real measurements. The bid price is set higher than the feed-in tariffs for RES and consumption tariffs for demand.

The bids are submitted to the market platform and the market is cleared to eliminate the network violations identified by the system operator. In order to create network issues in the distribution system, (as previously explained there are currently no such issues) scenarios with different increased RES penetration and load demand have been considered [11]. Based on the market results, activation signals are sent to the FSPs, but in reality, they are not activated. This is done to test that all the functions and communications work properly. In addition, the local market outcomes are integrated and tested with the TSO validation tool developed by IPTO, which emulates the operation of the TSO balancing market (not with the actual TSO balancing market). The TSO validation tool aims to assess the impact of the local market on the existing wholesale balancing market.

The list of FSPs in the Greek demonstrator consists of a small CHP, a residential battery, irrigation pumps, diesel gensets, loads and RES. Measurements of RES (Wind Farms and PVs) and loads are used to forecast RES production and load demand, respectively. A percentage of the production and demand is submitted to the market platform as a "virtual" bid. RES and loads are monitored but not controlled. More details about the FSPs that participated in the Greek demonstrator can be found in D5.1 [12] and D6.6 [8].

Table 8 presents the products of the Greek demonstrator. The table shows the provided system service, whether they are capacity or energy products, the coordination scheme under which the provision of the system service was tested and in which BUC the product was tested. For congestion management, capacity and energy products were procured under the multi-level (BUC GR-2a) and fragmented (BUC GR-2b) market models. Capacity and energy products were also procured for voltage control under the multi-level (BUC GR-1a) and fragmented (BUC GR-1b) market models. The capacity product of active power for voltage control is provided by generation units (e.g., PVs) and the energy product is provided by consumers.

Table 8: Products tested in the Greek demonstrator.

Product name	System service	Capacity/Energy	Coordination Scheme	BUC
Reserved congestion management	Congestion management	Capacity	Multi-level Fragmented	GR-2a&b
Non-reserved congestion management	Congestion management	Energy	Multi-level Fragmented	GR-2a&b
Steady state reactive power	Voltage control	Energy	Multi-level Fragmented	GR-1a&b
Active power	Voltage control	Capacity Energy	Multi-level Fragmented	GR-1a&b

Further insights on the design of the four products through standard attributes for product definition (see D1.3 [4] for more details on product attributes) can be found in D6.3 [5] and D5.2 [10].

The market timeframes tested for each product, the system to which the service is provided and the pilot sites where the products were tested are shown in

Table 6. It is observed that all products were tested for DA and ID market timeframes. Except for the reserved congestion management product, all the other products were also tested for the NRT market timeframe. All products were tested in the distribution system and the non-activated bids were forwarded to the transmission system for balancing services in the balancing market operated by IPTO. All products were tested in both pilot sites, Kefalonia and Mesogia.

Table 9: Market timeframes of product procurement, system using the product and pilot site tested in the Greek demonstrator.

Product ID	Long-term	Day-ahead	Intraday	Near real-time	Distribution	Transmission	Pilot site
Reserved congestion management	-	✓	✓	-	✓	✓	Kefalonia Mesogia
Non-reserved congestion management	-	✓	✓	✓	✓	✓	Kefalonia Mesogia
Steady state reactive power	-	-	-	✓	✓	-	Kefalonia Mesogia
Active power	-	✓	✓	-	✓	✓	Kefalonia Mesogia

To help the reader understand the Greek demonstrator's KPI analysis, the key features of the two demo runs are presented in Table 10. More details can be found in D5.6 [13] and D5.8 [14].

Table 10: Characteristic of the two demo runs of the Greek demonstrator

	Demo run	
	1	2
Year	2020-2021	2022
Time period	Mesogia: November 2020-May 2021	Mesogia: September 2021-April 2022 Kefalonia: September 2021-April 2022
Operating days	Mesogia: 30 days	Mesogia: 65 days Kefalonia: 65 days
Weather conditions	Do not affect the demonstration	
System service	Congestion management	Congestion management Voltage control
Coordination scheme	Congestion management: Multi-level	Congestion management: Multi-level & Fragmented Voltage control: Multi-level & Fragmented
Market timeframe	Congestion management: DA	Congestion management: DA, ID, NRT Voltage control: DA, ID, NRT
Capacity of FSPs	Mesogia: PVs - 28.61 MW Loads - 3.66 MW (Peak load) Small CHP: 4kW Residential battery: 10kW Diesel Genset: 80kW	Mesogia: PVs - 28.61 MW Loads - 3.7 MW (Peak load) Small CHP: 4kW Residential battery: 10kW Diesel Genset: 500kW Kefalonia: PVs - 4 MW Pumps - 5 MW
Number of resources	Mesogia: PVs - 73 Loads - 461 Small CHP: 1 Residential battery: 1 Diesel Genset: 1	Mesogia: PVs - 73 Loads - 480 Small CHP: 1 Residential battery: 1 Diesel Genset: 1 Kefalonia: PVs - 45 Pumps - 5MW
Days / hours with cleared flexibility	Multiple scenarios with different DER penetration and load demand were considered.	Multiple scenarios with different DER penetration and load demand were considered. 5 different scenarios were created depicting the future condition of the network with high penetration of RES and increased demand driven by the electrification of various sectors such as heating and transportation

3 KPIs of demonstrated BUCs

In this chapter, the calculated KPIs provided by the three demonstrators are presented and analysed. A sub-chapter has been created for each KPI. Since the three demonstrations are quite different and the comparison between them is not reasonable, these sub-chapters are further divided to discuss and analyse the KPIs for each demonstration separately.

3.1 KPI analysis

Some KPIs have been calculated by all the demos, while some other have not. This has been determined during the definition of the KPIs in D1.6 [2]. The demonstrations determined the KPIs to be calculated based on the network issues addressed, the implemented coordination schemes and the aspects that each demonstration seeks to investigate. Table 11 shows which KPIs have been calculated by the demonstrators during each demo run. N/A means that the KPI is Not Applicable in this demonstrator and therefore has not been calculated. It is noted that the values of some KPIs are the same for all the demo runs. For instance, the value of KPI 20 which measures the CAPEX cost for developing the CoordiNet platform is calculated once and is the same one for all the demos runs. For that case, the term “same” has been used.

Table 11: KPIs that have been calculated in each demonstrator in each demo run

KPI	Demo run 1			Demo run 2			Demo run 3
	Demonstrators						
	Spanish	Swedish	Greek	Spanish	Swedish	Greek	Swedish
1	Yes	N/A	N/A	Yes	N/A	N/A	N/A
2	No	N/A	N/A	Yes	N/A	N/A	N/A
3	Yes	No	No	No	Yes	Yes	Yes
4	Yes	No	Yes	Yes	Yes	Yes	Same
5	Yes	Yes	Yes	Yes	Yes	Yes	Yes
6	Yes	Yes	Yes	Yes	Yes	Yes	Yes
7	Yes	N/A	No	No	N/A	Yes	N/A
8	Yes	No	No	No	Yes	Yes	No
9	No	No	N/A	Yes	Yes	N/A	Yes
10	Yes	N/A	Yes	Yes	N/A	Yes	N/A
11	Yes	N/A	Yes	Yes	N/A	Yes	N/A
12	No	N/A	No	Yes	N/A	Yes	N/A
13	Yes	N/A	N/A	No	N/A	N/A	N/A
14	Yes	N/A	N/A	No	N/A	N/A	N/A
15	Yes	N/A	N/A	No	N/A	N/A	N/A
16	Yes	N/A	No	Yes	N/A	Yes	N/A
17	Yes	N/A	No	Yes	N/A	N/A	N/A
18	Yes	Yes	Yes	Yes	Yes	Yes	Yes
19	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20	Yes	No	Yes	Same	Yes	Yes	Same
21	Yes	N/A	N/A	No	N/A	N/A	N/A
22	Yes	N/A	N/A	Yes	N/A	N/A	N/A
23	N/A	N/A	Yes	N/A	N/A	Yes	N/A
24	Yes	N/A	No	Yes	N/A	Yes	N/A
25	Yes	N/A	No	Yes	N/A	Yes	N/A
26	N/A	N/A	No	N/A	N/A	N/A	N/A
27	N/A	Yes	N/A	N/A	Yes	N/A	Yes
28	N/A	No	N/A	N/A	Yes	N/A	Yes
29	No	N/A	N/A	Yes	N/A	N/A	N/A
30	No	N/A	N/A	No	N/A	N/A	N/A
31	Yes	N/A	N/A	Yes	N/A	N/A	N/A

KPI	Demo run 1			Demo run 2			Demo run 3
	Demonstrators						
	Spanish	Swedish	Greek	Spanish	Swedish	Greek	Swedish
32	Yes	N/A	N/A	No	N/A	N/A	N/A
33	Yes	N/A	N/A	No	N/A	N/A	N/A
34	Yes	Yes	Yes	Yes	Yes	Yes	Yes
35	N/A	Yes	N/A	N/A	Yes	N/A	Yes
36	Yes	N/A	Yes	Yes	N/A	Yes	N/A
37	Yes	Yes	Yes	Yes	Yes	Yes	Yes
38	Yes	Yes	Yes	Yes	Yes	Yes	Yes
39	Yes	No	Yes	Yes	Yes	Yes	Yes

3.1.1 KPI 1 – Cost of counteractions needed based on the activated flexibility

This KPI measures the redispatch cost aiming to solve congestions and voltage violations caused by the activation of accepted bids or the partial activation of accepted bids or by the activation of non-accepted bids (i.e flexibility requested to be activated even if the market did not select the related bid [2]). The cause of such issues depends on several parameters, such as the market set up, the grid model used in the market clearing, etc.

3.1.1.1 Spanish demo

Table 12: KPI 1 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	0 €	510.88 € (Málaga)
	ES-1b		0 €
	ES-2	0 €	

The BUCs tested during the demo run 1 related to congestion management and balancing services are based on existing markets, so, no simplifications have been adopted. This coordination between TSO and DSOs guarantees that the accepted bids in the markets are compatible in both transmission and distribution level. Therefore, no congestions nor voltage violations were identified afterwards and no-redispatch was necessary [15]. The KPI was not calculated for BUCs ES-3 and ES-4. The services provided at BUCs ES-3 and ES-4 do not generate redispatches, as the delivery of the services is not based on active power and no counteraction was needed.

During demo run 2, no counteractions were necessary when testing the congestion management local markets (BUC ES-1b), both at e-DI and i-DE demo sites. Therefore, the cost due to counteractions for this BUC ES-1b, is equal to zero. However, the redispatch was necessary for the test of the common congestion management market (BUC ES-1a) in Málaga. Specifically, according to [15], 3.06 MW were redispatched, which corresponds to a total cost of 510.88 €.

3.1.2 KPI 2 – Estimation of the increment of reactive power flexibility for the network operators (TSO and DSO)

This indicator measures the increment of reactive power provided when the CoordiNet solution is implemented compared to the Business as Usual (BaU) scenario.

3.1.2.1 Spanish demo

Table 13: KPI 2 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-3		e-DI: 50% - 500% i-DE: 10% - 160%

This KPI, related to the voltage control (BUC ES-3), was calculated by both Spanish DSOs, e-DI and i-DE, but only in demo run 2.

e-DI estimated the increment of reactive power flexibility using the PQ curve obtained in the prequalification test for the FSP located in Cádiz, PESUR (wind technology). Based on such curve, and taking into account the compulsory active and reactive power that a generation facility has to provide, the maximum reactive power that can be reached for different active power values can be determined. The values of the estimated increment, for both inductive and capacitive products, are detailed in [15]. As summary, it can be stated that in the case of the inductive product, the calculated Increment Reactive Power Flexibility is between 150% - 500%. For the capacitive product, this value is estimated at 50% - 500%.

i-DE performed three voltage control tests with three different FSPs:

- FSP ALB_WIND 132 - The increment of reactive power was 4 MVAr, meaning an increase of 160%.
- ALB_CHP132 - It provided an increment of 1 MVAr (up and down), meaning an increase equal to 50%.
- MUR CHP132 - It provided an increment of 0.5 MVAr (up and down) with an increase of 10% with respect to the BaU approach.

3.1.3 KPI 3 – Cost of R&I solution vs alternative grid solution

In BAU scenario, new investments in the distribution/transmission grid are needed in order to solve Congestion or Voltage problem. The investment cost covers the cost of DSO for upgrading or installing new distribution lines and the additional investment cost at the transmission level for upgrading the HV/MV substation. This indicator is used in the Spanish and the Greek demos to compare the CoordiNet solution with the investment cost required to apply alternative solution on an annual basis. In the Swedish demo, it is used to compare the cost for flexibility with avoided exceeding subscription cost.

3.1.3.1 Spanish demo

Table 14: KPI 3 value - cost reduction of the R&I solution vs alternative grid solution in the Spanish demonstrator

Demo	BUC	Demo run 1
Spanish	ES-1a	**e-DI:** Total Cost per year: -1.1% CAPEX variation: 94.34% **i-DE:** CAPEX variation: 97.27%
	ES-2	
	ES-3	
	ES-4	**i-DE:** CAPEX variation: 83.13%

This KPI was calculated only in demo run 1 of the Spanish demonstration. For e-DI, the simulations performed for the network of Cadiz pilot site (BUC ES-1a and BUC ES-2) have shown that two transformers (66/220 kV) are congested for an increased share of RES. To avoid congestions, the installation of an additional transformer is required. According to the Spanish Grid Code Orden *IET/2659/2015* [16], the CAPEX cost for such a reinforcement is equal to 13,190 €/MVA. The investment cost for a transformer with a capacity of 120 MVA will be equal to 1,582,800 €. Considering a Weighted Average Cost of Capital equal to 5.58% [17] and an asset life of 40 years [18], the annual cost is 99,679 € [19].

Concerning the implementation of the CoordiNet solution, the CAPEX is equal to 89,442 €. This includes the expenses for the necessary software and equipment. The annual OPEX cost is equal to 88,156 € (summation of KPI 4 and KPI 5 values). Considering an asset life of 12 years, the annual cost is 98,580 €. Therefore, a reduction of 1.1% is observed. Comparing only the CAPEX cost of the two solutions, the reduction is equal to 94.34%

For i-DE, for BUC ES-1a and BUC ES-2, in order to avoid congestions, the reinforcement of a 132 kV line and two positions in a substation transformer is required. The line length is 50 km and the cost of the reinforcement is 178,344 €/km, while the cost for the substation transformer is 401,554 €/unit. Therefore, the CAPEX cost is 9,720,308 €. For BUC ES-4, the reinforcement of a medium voltage line and one position in a substation transformer is required. The line length is 20 km and the cost of the reinforcement is 74,773 €/km, while the cost for the substation transformer is 75,456 €/unit. This results in a CAPEX equal to 1,570,916 €.

The CAPEX for the necessary developments to implement the CoordiNet solution in all the BUCs (BUC ES-1a, ES-2 and ES-4) was equal to 265,000 €. The cost assigned to the development itself can be estimated at 220,000 € and the system maintenance in the cloud is estimated at 45,000 €. i-DE did not have the data on OPEX for service procurement available in demo run 1. Therefore, the annual cost of the two solutions cannot be compared. Only the CAPEX can be compared. For BUCs ES-1a and ES2-a, a reduction of 97.27% is observed, while for BUC ES-4 the reduction is equal to 83.13%.

3.1.3.2 Swedish demo

Table 15: KPI 3 value - cost reduction of the R&I solution vs alternative grid solution in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	**SE-1a**		**Uppland:** 634.5 k€ **Skåne:** 15 k€	**Uppland:** 226.5 k€ **Skåne:** -0.8 k€

In the Swedish demo, this KPI compares the cost for buying flexibility with the avoided penalty costs, which the DSO should pay to the TSO when the subscription level increase is denied. The KPI was calculated in demo run 2 and 3 and in two pilot sites, Uppland and Skåne. In Gotland, this KPI has not been calculated as the principle of subscription fees differs in local networks compared to that of regional networks. It is noted that the hypothetical case where the temporary subscription is not granted by the TSO is considered in order to investigate the cost reduction that the use of flexibility entails.

In Uppland, two substations participated in the pilot site of Uppland, the Bredåker and Plenninge Substations. The combined subscription level is a few hundred MW with 2/3 of this capacity in Bredåker.

In demo run 2, concerning the Bredåker Substation, if the DSO was not able to buy flexibility, the subscription level would have been violated 375 hours and the total imported energy above the subscription level would be 4,770 MWh. This corresponds to a penalty of 1,258 k€ (13,356 kSEK). The use of flexibility reduced the hours of subscription level violation to 290 hours and the imported energy above the subscription level to 3,135 MWh. This corresponds to a penalty of 827.1 k€ (8,778 kSEK).

Concerning the Plenninge Substation, if the DSO could not buy flexibility, the subscription level would have been violated 132 hours and the total imported energy above the subscription level would be 669 MWh. This corresponds to a penalty of 176.5 k€ (1,873.2 kSEK). The use of flexibility reduced the hours of subscription level violation to 62 hours and the imported energy above the subscription level to 259 MWh. This corresponds to a penalty of 68.3 k€ (725.2 kSEK).

The above costs refer to the case where the two substations are investigated individually. When the subscription levels of the two substations are summed up, if the DSO was not able to buy flexibility, the subscription level would have been violated 274 hours and the total imported energy above the subscription level would be 4,096 MWh. This corresponds to a penalty of 1,080 k€ (11,469 kSEK). The use of flexibility reduced the hours of subscription level violation to 181 hours and the imported energy above the subscription level to 2,264 MWh. This corresponds to a penalty of 596.9 k€ (6,339 kSEK). Therefore, the penalty was reduced by 483.1 k€ (5,130 kSEK) by using flexibility.

It is observed that when the subscription levels are summed up, the penalty was reduced by 298.5 k€ (3,164 kSEK). Taking into account that the cost for buying flexibility was 146.7 k€ (1,557.7 kSEK), the total savings are 634.5 k€ (6,735 kSEK).

During demo run 3, concerning the Bredåker Substation, the hours over subscription level and the total imported energy above the subscription level, assuming the DSO is not able to buy flexibility, reduced significantly (160 hours – 1,970 MWh). Regarding the Plenninge Substation, these number increased (138 hours – 1,267 MWh). As explained in Section 2.2, due to high electricity prices the use of flexibility from key FSPs reduced. Hence, the purchased flexibility reduced the total imported energy above the subscription level slightly (Bredåker Substation: 158 hours and 1,952 MWh, Plenninge Substation: 136 hours & 1,259 MWh). Summing up the subscription levels of the two substations, the hours over subscription level reduced from 115 to 114 hours (so just 1 hour) the total imported energy above the subscription level from 2,345 to 2,343 MWh. Following the same approach mentioned for demo run 2 and given that the cost for buying flexibility was 2.975.8 k€ (31,605 kSEK), the total savings were 226.5 k€ (2,404.4 kSEK).

During demo run 2, in Skåne, three substations participated in the pilot site of Skåne, the Söderåsen, Sege-Arrie and Barsebäck Substations. There was no violation of the subscription level at the Barsebäck Substation.

Concerning the Söderåsen and Sege-Arrie Substations, the use of flexibility reduced the total imported energy above the subscription level, but not the total hours with subscription violation. In particular, the subscription level was violated for 397 and 92 hours at Söderåsen and Sege-Arrie Substations, respectively. Concerning the Söderåsen Substation, the total imported energy above the subscription level with and without the use of flexibility was 14,338 MWh and 14,378 MW. These two violations correspond to a penalty cost equal to 3,782.7 k€ (40,146.4 kSEK) and 3,793.2 k€ (40,258.4 kSEK), respectively.

Regarding the Sege-Arrie Substation, the total imported energy above the subscription level with and without the use of flexibility was 4,680 MWh and 4,762 MW. These two violations correspond to a penalty cost equal to 1,234.7 k€ (13,104.0 kSEK) and 1,256.3 k€ (13,333.6 kSEK), respectively.

It is observed that for both substations, the penalty costs have been reduced by 32.2 k€ (341.6 kSEK) due to the use of flexibility, while the total cost for buying flexibility was 17.2 k€ (182.9 kSEK). Therefore, the total cost savings were 15 k€ (158.7 kSEK).

In demo run 3, in Skåne, the amount of total imported energy above the subscription level was not reduced at the Söderåsen and Barsebäck Substations. At the Sege-Arrie Substation, the use of flexibility did not reduce the hours above the subscription level (26 hours), but it reduced the total imported energy above the subscription level from 703 MWh to 693 MWh. Hence, the penalty reduced with 27,4 kSEK from 185.2 k€ (1,966.7 kSEK) to 182.7 k€ (1,939.3 kSEK). The cost for buying the flexibility was (36.2 kSEK). Therefore, an increase in the total cost by 0.8 k€ (8.7 kSEK).

In Uppsala, the use of flexibility reduced the total hours with subscription violation, while in Skåne only the amount of the energy above the subscription level was reduced. It is observed that the here calculated reduction of the total cost by using flexibility is hypothetical and assumes that a temporary subscription is not granted by the TSO. In reality temporary subscription was granted during the studied winter in both pilot sites.

3.1.3.3 Greek demo

Table 16: KPI 3 value - cost reduction of the R&I solution vs alternative grid solution in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a		**Kefalonia:** 66% **Mesogia:** 62%
	GR-1b		**Kefalonia:** 29% **Mesogia:** 16%
	GR-2a		**Kefalonia:** 15% **Mesogia:** 39%
	GR-2b		**Kefalonia:** -71% **Mesogia:** -40%

In the Greek demonstration KPI 3 has been calculated only in demo run 2 and it reaches a high value of up to 66% in Kefalonia demo area and 62% in Mesogia demo area for the voltage control with the Multi-Level Market Model. On the one hand voltage problems are not that common in the distribution networks in Greece, on the other hand the required investment to overcome these problems are really high. Therefore, for such cases of services and network problems the proposed in CoordiNet local Platform brings advantages to the efficiency of the overall network. These advantages are severely reduced when considering the Fragmented Market Model, since the DSO has the balancing responsibility of the distribution network. Therefore, for any procured flexibility for voltage control the DSO requires to procure the same amount of flexibility in the opposite direction which increases the flexibility cost. As a result, the value of KPI 3 is still positive but hardly reduced when considering the Fragmented Market Model for voltage control.

Regarding the congestion management uses cases, KPI 3 is calculated at 15% (for Kefalonia demo area) and 39% (for Mesogia demo area) for the Multi-level Market Model and -71% (for Kefalonia demo area) and -40% (for Mesogia demo area) for the Fragmented Market Model. The negative values of this KPI indicate that it is more preferable to invest in transmission and distribution grid capacity compared to procuring flexibility from the local market. The reduction of the value of KPI 3 is driven by the large amount of flexibility which is required to be procured from the DSO to balance the distribution network, thus fulfil the balancing responsibility at the TSO-DSO interface. Nevertheless, the introduction of a local market appears to bring a lot of advantages in the distribution system operation and therefore the planning strategies of system operators require adaptations in order to take under consideration the flexibility provision for investment deferral.

3.1.4 KPI 4 – OPEX – OPerational EXpenditures

This indicator calculates the recurrent costs that are required in order to operate and maintain the installed equipment, i.e. the operational cost of all actors using the CoordiNet Platform, communication tools and metering devices, weather prediction services. The total operational cost of the CoordiNet Platform composes of three elements, namely the operational cost of the local market operator, the operational cost of the DSO and the operational cost of the TSO.

3.1.4.1 Spanish demo

Table 17: KPI 4 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI (Cadiz):** 28,650 € (sum over ES-1A en ES-2) **i-DE:** 42,880 €	**e-DI (Malaga and Cadiz)** 147,406.5 € **i-DE:** 42,880 €
	ES-1b		**e-DI (Malaga and Cadiz)** 147,406.5 €
	ES-2	**e-DI (Cadiz):** 28,650.00 € (sum over ES-1A en ES-2) **i-DE:** 268 €	**i-DE:** 268 €
	ES-3		**e-DI (Malaga and Cadiz)** 147,406.5 € **i-DE:** 268 €
	ES-4	**i-DE:** 268 €	**i-DE:** 268 €

For the Spanish demonstration, the OPEX includes the service management cost by the DSO. This cost differs between e-DI and i-DE.

For e-DI, in demo run 1, the cost mainly includes outsourcing costs to implement certain aspects and tests in the demo. Reported total costs for this demo run are 28,650 € over all BUCs in Cadiz pilot site. This value represents the proportional part of the e-DI OPEX in the CADIZ site. In demo run 2, the cost for E-DI increased up to 147,406.5 € for Cadiz and Malaga combined. This is because the BUCs tested in the first demo run required less developments and efforts by e-DI. The Voltage control BUC (ES-3) and the local congestion management market (ES-1b) required most efforts. These BUCs were performed at both locations (Cadiz and Malaga).

For the i-DE cases, i-DE is doing everything inhouse. The cost calculation is therefore different as it depends on estimated costs based on the duration and the number of activations needed to manage the process of a service. Within one BUC, costs are common to all demo sites and the above table therefore does not distinguish between the different sites. In the case of i-DE, the number of activations per year was estimated (80 activations for BUC ES-1a, 1 activation for BUCs ES-2, ES-3 and ES-4, and 54 activations for BUC ES-1b). BUC ES-1a aims to solve a structural problem of congestion that could happen 80 times per year, while BUCs ES-2 and ES-4 aim to solve untimely failures that may happen between 0 to 1 time per year. The OPEX cost considered includes the cost of service management by an operator. Depending on the duration of the activations the cost can be different. But as an average, 4 hours are needed to manage the process of a service. There are other OPEX expenditures for setting up the service (prequalification, software test, etc), but they are not recurrent.

For i-DE, it can thus be seen that the activation costs in BUC ES-1a (Non-reserved congestion management (Common market)) are significantly higher than for ES-2 (balancing) and ES-4 (outage island). This is due to the higher number of hours of work needed in BUC ES-1a. BUC ES-1a requires to manage forecasts and to program certain actions, while the other two are associated to actions in real-time. 8 hours are needed in BUC ES-1a and 4 hours in BUC ES-2 and BUC ES-4.

The costs between e-DI and i-DE are therefore hard to compare, as both are calculated in a different way and are based on different assumptions.

3.1.4.2 Swedish demo

Table 18: KPI 4 value in the Swedish demonstrator

Demo	BUC	Annual demo cost
Swedish	SE-1a	**Uppland:** 84,950 € **Skåne:** 31,560 € **Gotland:** 18,700 €

For the Swedish demo, this KPI is only calculated for BUC SE-1a (congestion management). This is because the P2P market (BUC SE-1b) is relatively small and utilises the same infrastructure. As such, it would only be an arbitrary self-assessed percentage of the total cost that would be ascribed to them. For a similar reason, this KPI is also not calculated for BUC SE-3 (the balancing market). mFRR is operated by the TSO and therefore the CoordiNet trial would only be a fraction of the total cost for the national market. In addition, it would probably be hard to estimate the costs attributable to 1 of the 6 products present in the national mFRR market.

Furthermore, the operational expenditures are only calculated for one phase/year of the demo. This is because the main operational expenditures are IT related subscriptions which are present in all demo runs/years. As such, it would make more sense to evaluate differences in costs between demos and markets, rather than within a demo.

As such, operational expenditures are only calculated for BUC SE-1a. The cost is presented as an annual OPEX cost for the demo as the differences over the years are rather small. The main difference can be found in the OPEX for the last winter, where Vattenfall needed an additional 21,000 € to keep metering up and to run the demo over summer to gain additional data for the forecast machine-learning algorithms.

The OPEX can be split up for the Flexibility market platform (Market tool) and for the Flex tool [20]. The Flexibility market platform is the interface for the FSPs. It is where they submit bids (manually or through API), upload production plans and receive market information (when available), receive notification of clearing and where they can see records of their cleared bids. The Flex tool, on the other hand, is an internal tool for the DSO, used in the DSO control room. This allows visualization of resource metering, of forecasts (from their external supplier Expektra or RWTH Aachen), and of the aggregated flexibility. The Flex tool is also used by the DSO to calculate the impact of the cleared bids on the forecasted power flow at the substation level and select the bids to be activated.

The cost of the Flexibility market platform and the Flex tool are divided over the different pilot sites, and are different for the system and the market operator (even though in practice, in CoordiNet the DSO is both the system and the market operator). With regard to the **Flexibility market platform**, for the **system operator** (Gotland area), the cost for the common platform is split based on 4 out of 35 resources. The remainder of the cost for the system operator is shared equally between Uppland and Skåne (that is 15.5 out of 35 resources). Costs for the system operator are linked to platform costs related to hosting (Azure cloud), licenses, security and data classification. For the **market operator**, the Uppland and Gotland pilot sites have Vattenfall as market operator. They endure metering costs related to cloud service and export and service of meters; costs related to communication (e.g., mobile subscriptions); and other market operation costs, such as: those related to forecasting (models, Expektra), security and data classification costs and data hub costs. These costs are divided between both demo areas. Uppland is responsible for 19 out of 23 resources and Gotland for the remaining 4 out of 23 resources. For the Skåne pilot site, E.ON is the market operator. They face costs related to the installation and service of the meters, communication of the meters and forecasting. Table 19 gives the split up cost per demo area for each operator.

Table 19: Flex market platform and Flex tool costs per pilot site

Asset	Demo area	System operator	Market operator
Flex market platform	**Uppland**	7.28 k€	47.29 k€
	Gotland	1.94 k€	9.96 k€
	Skåne	7.28 k€	5.60 k€
Flex tool	**Uppland**	7.28 k€	23.10 k€
	Gotland	1.94 k€	4.86 k€
	Skåne	7.28 k€	11.40 k€

The costs related to the **Flex tool** are divided in a similar way for the **system operator** and **market operator** between the different demo areas. For the system operator, the division of 4, 15.5 and 15.5 out of 35 resources is considered for Gotland, Uppland and Skåne, respectively. For the system operator the division of 19 and 4 out of 23 is considered for Uppland and Gotland, respectively, while Skåne has separate costs. Cost components (such as hosting, licenses, metering, cloud service) are also the same for both operators.

The additional costs of the data hub and meters explain the differences between the Vattenfall and E.ON demonstrations. For Uppland and Gotland the costs for real-time data acquisition is higher than for Skåne due to the fact that Vattenfall needed to procure and security assess the complete IoT solution, while E.ON could utilise an internal IoT box not requiring additional security review. Finally, costs for data communication increase when the number of customers increases. Uppland has more customers than Skåne, and Skåne has more customers than Gotland. This is also reflected in the cost differences. The aforementioned costs are presented in Table 19. Summing up per demo area the costs for the Flex market platform and the Flex tool leads to the total values in Table 18.

3.1.4.3 Greek demo

Table 20: KPI 4 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	**GR-1a**	626,000.00 €/year	626,000.00 €/year
	GR-1b	626,000.00 €/year	626,000.00 €/year
	GR-2a	626,000.00 €/year	626,000.00 €/year
	GR-2b	626,000.00 €/year	626,000.00 €/year

In both demo runs of the Greek demonstration, the recurrent costs required to operate and maintain the installed equipment to run the flexibility market are over €600,000.00. This value contains costs for the market operator, the DSO and the TSO. The cost for the market operator mainly consists of the operational market platform (€ 252,000.00) and the weather prediction license (€60,000.00). It should be pointed out that these costs refer to the whole country, and not only for the demo. The cost for only the demo would therefore be lower. The operational cost is calculated based on seven people needed for a full year. Other costs are linked to data handling, updating licenses and communication with the TSO, DSO and FSPs. Costs for the DSO and TSO are also mostly linked to operating the tools (€ 144,000.00 for each system operator for the whole country), while some other are linked to communication and in case of the DSO there are also costs linked to metering. Finally, note that all costs are the same for both the Greek pilot sites as the same platform is used.

3.1.5 KPI 5 – OPEX for service procurement

This indicator measures the cost for services procurement consisting of the cost of reserved capacity and the cost of energy.

3.1.5.1 Spanish demo

Table 21: KPI 5 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	**ES-1a**	**e-DI:** 59,506.13 €	**e-DI:** 129,329.96
	ES-1b		**e-DI:** 161,941.78 €
	ES-2		
	ES-3		**e-DI:** 0 € **i-DE:** 0 €
	ES-4		

For the Spanish demo, in demo run 1, this KPI is only calculated for BUC ES-1a and the Cadiz pilot site (e-DI). i-DE cases were not included as they did not have the data on OPEX for service procurement available in demo run 1. Specifically, for the calculation of this KPI, the total activated energy per FSP and per year in the Cadiz pilot site has been considered. The MWh/year values are multiplied by the Variable Cost of the FSP which includes the Operation and Maintenance (O&M) of the power plants, amongst others. To this value other external administrative costs related with the market representation and management of the units are added. Summing up the OPEX for service procurement per year for all the different FSPs in the Cadiz pilot site (see Table 76 in D3.4 of CoordiNet [19]), leads to a total OPEX for service procurement of 59,506.13 € per year.

For this calculation, the cost (€/MWh) is the same for every windfarm but the re-dispatched energy is different in every case. Therefore, the higher the re-dispatched energy in BUC ES-1a, the higher the OPEX for service procurement. Additionally, there is an extra cost in €/MW for market representation which is also included in the final OPEX for service procurement. The extra cost depends on the nominal power of the generator. The higher the nominal power, the higher the market representation cost. For this reason, even though almost all FSPs are windfarms, they have quite different costs.

For e-DI, in demo run 2, the OPEX for Common Congestion Management (ES-1a) increased significantly, since some aggregator and FSPs' additional costs have been added in comparison with the demo run 1. The cost includes the aggregator's and physical unit cost to provide the service, multiplied by the total amount of MWh provided at the market. The OPEX also includes the OPEX for the operation of the software necessary to monitor and control the FSPs, which is equal for each FSP considered. Additionally, the cost per FSP related to the aggregation platform development is included. For BUC ES-1b (local congestion management BUC), the same costs are included in the calculation of the KPI. These costs are higher than for the common market because (as also indicated in KPI 4) since more efforts were needed from e-DI side for this.

For ES-3 (the voltage control BUC), for both i-DE and E-DI, the OPEX for service procurement is calculated based on the active power that the FSP is not able to provide because of providing a reactive power output. Given the conditions[1] of the FSP, no variations in the active power were necessary to absorb reactive power from the grid and therefore there is no cost related to this product.

3.1.5.2 Swedish demo

Table 22: KPI 5 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 67,557.38 € **Skåne:** 11,683.56 € **Gotland:** 49,089.81 €	**Uppland:** 146,771.8 € **Skåne:** 17,233.6 € **Gotland:** 12,392.1 €	**Uppland:** 3,015.11 € **Skåne:** 3,392.00 € **Gotland:** 7.54 €
	SE-1b		**Gotland:** 101.76 € **VästerNorrland/Jämtland:** 0 €	
	SE-3			

As can be seen in Table 22, procurement costs differ significantly between the different demo runs and between the pilot sites. For both Skåne and Uppland, participating flexibility increased significantly (from 76 to 120 MW for Skåne and from 96 to 256 MW for Uppland). Indeed, for the second winter of 2020/2021 (demo run 2) the number of FSPs doubled in Skåne and Uppland to total 24 over the three markets. As such, the volume of bids increased. The increase in procurement costs is, however, explained by the volume of cleared flexibility. The cleared volume increased by 65 % in Skåne and 102% in Uppland. This is explained by the fact that the winter 2020/2021 (demo run 2) was colder compared to the record warm winter in 2019/2020 (demo run 1).

For Gotland, it should be noted that the market was not operated frequently enough to draw general conclusions. With regard to procurement costs, the situation was also different due to the fact that pricing of some FSPs increased, implying that the DSO reduced the cleared flexibility volumes. Participating flexibility was, however, kept at 24 MW in Gotland. Furthermore, the sharp decrease in costs in Gotland for demo run 2 is explained by the fact that in the first winter a single extreme event occurred over two days, leading to clearing of flexibility for 24 hours. Due to the fact that flexibility in winter 2019/2020 was only

[1] Conditions e-DI: the operation point of the PQ curve in which the FSP operated during the tests.
Conditions i-DE: Some FSPs need to exchange some active power to provide reactive power. Others can provide reactive power without involving their active power curve. This may cause additional costs.

procured during three days, a single event/cold spell period like this, significantly influenced the KPI in such a relatively small market.

Comparing the different pilot sites, it should also be noted that Uppland has significantly higher procurement costs than the other two demos. This can be explained by KPI 6 (the average cost per service for the examined period). As it will be detailed in the analysis of KPI 6, Uppland has flexibility available at a lower cost than the fee for temporary subscription from the TSO, which explains that they clear more flexibility than the other pilot sites, explaining the higher total procurement costs.

For the P2P market, 4 MW was procured with an average cost of €25.44 /MWh. Only one call for flexibility had been made in the demonstration.

In demo run 3, on the other hand, there was a large increase in electricity prices implying that low cost flexibility resources were not operated during periods of congestion and thus not available to provide their flexibility. Although there was a need for flexibility, cleared volumes reduced between 1% and 12% compared to the winter in demo run 2 due to the high electricity prices. This also explains the significantly lower OPEX for service procurement.

3.1.5.3 Greek demo

Table 23: KPI 5 value in the Greek demonstrator for scenario no 3

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a		Mesogia: 481.8 € Kefalonia: 1462.69 €
	GR-1b		Mesogia: 873.5 € Kefalonia: 2692.398 €
	GR-2a	Mesogia: 29,433.49 €	Mesogia: 1286.92 € Kefalonia: 4242.87 €
	GR-2b		Mesogia: 2246.73 € Kefalonia: 7992.919 €

Currently, there are no congestion and voltage problems in the network of the Greek pilot sites because RES penetration is limited to a specified level (for each distribution network) to avoid any network violations. The DSO does not allow for connection of any producer or consumer that their operation will lead to violation of the network constraints. For the demo, congestions were therefore created in the examined feeders based on different future scenarios, by increasing grid injection under low load conditions. Depending on the scenario, the load (demand) was also increased. Two types of regulations were tested: upward and downward flexibility (regulation 1 and 2, respectively). Downward flexibility implies increasing demand or curtailing PV generation in order to solve reverse flows and congestion.

Multiple scenarios were made in order to test when congestion violations occurred, however, in this deliverable, only the most interesting scenarios are reported. These scenarios are shown in Table 24. In total, 40 feeders were tested, yet, the demo is focusing on only the 7 feeders indicated in the table below. The reason for this was that in demo run 1, the topology manager could only characterize these 7 feeders. Later in the project, all feeders were modelled. In the scenarios, demand and/or generation were increased to identify the limits in the different feeders. Only the interesting scenarios were used to calculate the KPIs. Note that in the overview table above, scenario 3 is shown as this is the scenario with the highest increase in renewables. For the Greek demo, the most challenging congestion is the one caused by the increase in renewables. In the text below, however, other scenarios are also discussed.

It can be seen that in scenario 2, 3, 5 (feeder 7) and 6 (feeder 7), when congestion is created due to an increase in generation without a load increase, only downward flexibility is required. The prices of this downward flexibility differ between 102.80 and 111.42 €/MWh. In case that the loads are also increased in some feeders (see scenario 5 and 6), upward regulation is needed. Prices of upward flexibility range between 81,37 and 88,56 €/MWh. The marginal price of the majority of resources (PVs and Loads) are zero, as they do not have any fuel cost. To overcome this issue, the price of the flexibility bids is determined using the feed-in tariffs (for flexibility provided by RES) and consumption tariffs (for flexibility provided by demand) as a reference. Prices for the flexibility are set higher than the feed-in tariffs for RES and consumption tariffs for Demand. These explain minor price fluctuations.

We should be careful in attempting to compare the size of the load increase with the height of the price per service or the total quantity per service asked. A percentage increase on a feeder with an already low load might result in the same absolute load increase as a lower percentage increase on a feeder with an already high load. We can compare feeder 2, however, in scenario 5 and 6. The average price per service increases with almost 7 euros (almost a 9% increase in price). An increase in RES and load therefore has a significant influence on the price. In addition, the total quantity of service needed increases from 3.12 MWh to 56.88 MWh. This increase in needs together with the average price increase imply that total costs increase from 3,806.60 € to 75,551.97 €. Looking at feeder 7 in scenario 3 and 6, it can however be seen that feeder 7 has identical grid needs in both scenarios. However, prices are different as in each scenario the bid-generator tool is used again to create bids based on the assumptions explained above (consumption tariffs and feed-in tariffs). This explains minor price differences.

Table 24: Scenarios of the Greek demonstration in demo run 1

	Scenario 2	Scenario 3	Scenario 5		Scenario 6			
RES increase	400%	500%	400%		500%			
Load increase	-	-	200%		1500%	300%	400%	-
Feeder	7	7	2	7	1	2	5	7
Average price per service in EUR/MWh (Regulation 1)	0	0	81.37	0	85.08	88.56	84.72	0
Total quantity per service in MWh (Regulation 1)	0	0	3.12	0	2.10	56.88	22.31	0
Average price per service in EUR/MWh (Regulation 2)	106.45	104.43	0	102.80	0	0	0	111.42
Total quantity per service in MWh (Regulation 2)	5.51	18.80	0	5.60	0	0	0	18.98
Total cost (EUR/day)	586.06	1962.90	253.77	574.93	178.74	5036.80	1890.56	2114.28
Total cost (EUR/year)	8790.88	29,443.49	3806.60	8623.91	2681.03	75,551.97	28,358.38	31,714.17

The cost for service procurement was determined based on both technical and economic assumptions. In the demo run 1 of the Greek demonstration, FSPs did not place real bids but virtual bids were simulated for PVs and demand. Increased controllability of such devices was also assumed, as it is not currently the reality for most of them. The current regulation does not allow DERs to offer flexibility services and most DERs do not have smart meters which measure at sufficient granularity. For the demo, additional equipment was, however, installed to measure more frequent consumption (SLAMs) and generation data.

As explained above, the price for flexibility was set based on the assumption that it needs to be higher than feed-in tariffs for RES that are curtailed and higher than consumption tariffs for demand in case you want them to consume more in given time period. The latter is necessary to compensate their higher consumption cost which they need to pay to their retailer. In reality, these prices might change and different prices might exist for upward and downward regulation in the demo run 2 or after the demo has been finalized.

Table 25: Yearly values over all scenarios per BUC per region for the Greek pilot in demo run 2

	BUC GR-1a		BUC GR-1b		BUC GR-2a		BUC GR-2b	
	Mesogia	Kefalonia	Mesogia	Kefalonia	Mesogia	Kefalonia	Mesogia	Kefalonia
OPEX for service procurement in EUR	3,479.53	5,240.57	7,795.70	10,900.15	68,108.87	62,735.18	155,797.09	132,330.03
Average cost per service for the examined period in EUR/MWh	89.62	98.88	100.40	102.83	90.28	96.07	103.26	101.32
Volume of transactions in MWh	38.82	53.00	77.65	106.00	754.43	653.02	1.508.85	1.306.04
Number of transactions	658	513	1,001	1,075	12,703	4,614	15,320	6,208

For demo run 2, four scenarios were selected in addition to Scenario 1 which represents the current situation: Scenario 2 and 3 with a high RES increase, scenario 4 with a load increase and scenario 5 with an extreme load increase. The probability of occurrence for each scenario is calculated as follows:

Scenario 1: 27.4% which represents 100 days in one year.
Scenario 2: 4.1% which represents 4 days in one year.
Scenario 3: 1.4% which represents 5 days in one year.
Scenario 4: 4% which represents 15 days in one year.
Scenario 5: 0.5% which represents 2 days in one year.

Taking into account the frequency of occurrence of the different scenarios, the table above gives the yearly values per BUC.

As one can see, within these scenarios, the operation of the local market with the multi-level market (BUC GR-1a and BUC GR-2a) seems to achieve the most efficient result, since the local market model operated by the DSO solves the “local” network problems (congestion (GR-2) and voltage (GR-1)) and at a second stage transfers the balancing responsibility to the upper level along with the remaining flexibility offers. In such a way the flexibility offers of the whole system are pooled to cover imbalances from the whole network in the transmission level which results in a higher efficiency. OPEX costs are clearly lower.

The fragmented market model (BUC GR-1b and BUC GR-2b) appears to be the easiest to be applied since the interaction and communication between the system operators is similar to the current operational practices. Nevertheless, the fragmented market model requires adequate liquidity and the OPEX cost of the local market is higher.

3.1.6 KPI 6 – Average cost per service for the examined period

This indicator measures the average cost for providing system services in the different markets. This indicator is used to measure the average cost of the reserved capacity and provided energy.

3.1.6.1 Spanish demo

Table 26: KPI 6 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI:** 9.97 €/MWh	**e-DI:** 176.59 €/MWh
	ES-1b		**e-DI:** 73.02 €/MWh **i-DI:** 25 €/MWh
	ES-2		
	ES-3		**e-DI:** 0 €/Mvar **i-DI:** 0 €/Mvar
	ES-4		

For this first demo run, similar to KPI 5, this KPI is only calculated for BUC ES-1a and the Cadiz pilot site (e-DI). i-DE cases were not included as they did not have the data on OPEX for service procurement available in demo run 1. The average cost per service for the examined period differs between the different FSPs. The minimum cost is 7.82 €/MWh per year, while the maximum cost is 63.63 €/MWh. The average cost per service over all FSPs for the examined period is 9.97 €/MWh. Reasons for these differences are explained under KPI 5. The re-dispatched energy is different for the different windfarms and there are extra costs increasing with nominal power.

For demo run 2, there is no OPEX cost for the Voltage Control service as mentioned in KPI 5. For i-DE, there is only one FSP in the Local Congestion Management BUC (ES-1b). For e-DI, there are multiple FSPs for which the average cost is presented in Table 26. As discussed under KPI 5, this cost takes into account aggregator's and physical unit costs to provide the services, the OPEX for the operation of the software necessary for monitoring and controlling the FSPs, etc. [4]

3.1.6.2 Swedish demo

Table 27: KPI 6 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 20.73 €/MWh **Skåne:** 157.35 €/MWh **Gotland:** 61.62 €/MWh	**Uppland:** 22.14 €/MWh **Skåne:** 141.61 €/MWh **Gotland:** 151.68 €/MWh	**Uppland:** 27.32 €/MWh **Skåne:** 346.83 €/MWh **Gotland:** 18.84 €/MWh
	SE-1b		**Gotland:** 25.44 €/MWh	
	SE-3			

As indicated previously, in KPI 5, Uppland has the lowest average procurement cost. The availability of relatively high volumes of low-priced flexibility, compared to the other pilot sites of the Swedish demonstration, results from a Significant Grid User with a historic contract with built-in availability compensation. Therefore with 22.14 €/MWh, Uppland clears relatively large volumes of flexibility when the regular subscription limit is violated (Uppland cleared 6.2 GWh in demo run 2). The price in the Uppland market is in effect capped by the cost of a temporary raise of the subscription level to the TSO. As such, Uppland markets clear flexibility below the cost per MWh for temporary subscription from the TSO. This is in contrast to the markets in Skåne and Gotland where the market has not been used to avoid cost for temporary subscriptions.

On the contrary, the Skåne market included purchases aimed at the situation in which a temporary increase in subscription level by the TSO is denied. As a result, for Skåne, as the temporary subscription is not granted, the average price of the cleared flexibility is considerably higher explaining why less flexibility is cleared. In addition, temporary subscription is not often denied, explaining as well why corresponding volumes are small. Furthermore, for Gotland as well, average price of cleared flex is considerably higher explaining why less flexibility is cleared. Gotland is similar to Skåne although it technically has no TSO connection: it has a similar cost / subscription method towards the Vattenfall operated HVDC link. Gotland was only tested in the second winter (2020/2021 – demo run 2).

As such, two business cases exist: when temporary increase in subscription level is granted by the TSO, bids should be below the price of the temporary subscription (around 20-25 €/MWh); in case there is no temporary subscription increase by the TSO, price for cleared bid can increase significantly but the buyer will only purchase flexibility seldom (in case of the CoordiNet project, they will be activated in case of test bids and when winter is severe). Price fluctuations in Skåne and Gotland are explained by the weather dependent nature of the markets as well as price effects that are influenced by the availability of some flexibility resources during the last winter.

3.1.6.3 Greek demo

Table 28: KPI 6 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	**GR-1a**		Mesogia **Downward flex: 111,63 €/MWh** **Upward flex: 86,87 €/MWh** Kefalonia **Downward flex: 105,99 €/MWh** **Upward flex: 96,37 €/MWh**
	GR-1b		Mesogia **Downward flex: 113,49 €/MWh** **Upward flex: 87,30 €/MWh** Kefalonia **Downward flex: 111,18 €/MWh** **Upward flex: 94,48 €/MWh**
	GR-2a	**Downward flex:** 105.24 €/MWh **Upward flex:** 84.46 €/MWh	Mesogia **Downward flex: 117,83 €/MWh** **Upward flex: 89,87 €/MWh** Kefalonia **Downward flex: 112,62 €/MWh** **Upward flex: 95,06 €/MWh**
	GR-2b		Mesogia **Downward flex: 116,67 €/MWh** **Upward flex: 89,85 €/MWh** Kefalonia **Downward flex: 107,33 €/MWh** **Upward flex: 95,31 €/MWh**

As explained in the analysis of KPI 5, currently, there is no congestion in the network of the Greek pilot sites because RES penetration is limited to a specified level (for each distribution network) to avoid any network violations. For the demo, congestions were created in the examined feeders based on different future scenarios (see KPI 5). Average procurement costs per service increase when more loads / RES are included in different feeders. This is discussed in more detail under KPI 5.

In the scenarios, congestions were created by increasing grid injection (increased RES penetration) under low load conditions or by increasing load under low RES production. Two types of regulations were tested: upward and downward flexibility (regulation 1 and 2 respectively). Based on the assumptions made, the average cost per service in demo run 1 was 105.24 €/MWh and 84.46 €/MWh for downward and upward flexibility, respectively. In demo run 2 as well, it seems that downward regulation is always more expensive than upward regulation. For the Mesogia region, the differences between downward and upward flex are, however, bigger than for the Kefalonia region. Comparing the average cost per service between the two market models tested in the Greek demonstrator, the differences between Multi-Level and Fragmented market are relatively low. Despite the increased needs for flexibility in the fragmented market model, due to the additional need for balancing each distribution network separately, the average cost per service is similar to the Multi-Level Market Model, since the available flexibility from the local resources is mainly affected by the feed-in tariffs of the resources such as demand and solar PVs.

3.1.7 KPI 7 – Increase RES and DER hosting capacity

This indicator measures the potential increase of hosting capacity for DERs with the innovative system services tested in CoordiNet compared to the baseline situation where no “smart” actions are performed on the network. The indicator gives a statement about the additional DERs that can be installed in the network thanks to innovative system services without the need for conventional reinforcements (i.e., new grid lines).

3.1.7.1 Spanish demo

Table 29: KPI 7 value in the Spanish demonstrator

Demo	BUC	Demo run 1
Spanish	**ES-1**	0%
	ES-2	
	ES-3	
	ES-4	

No improvement is observed in the increase of the RES and DER hosting capacity. The implementation of the flexibility markets has an impact on the steady state capacity, however, due to the dynamic capacity and short circuit level the capacity of the installed RES and DERs cannot be increased. Therefore, the use of flexibility alone does not allow the increase of RES and DER hosting capacity.

3.1.7.2 Greek demo

Table 30: KPI 7 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-2a		0%
	GR-2b		0%

This KPI is calculated only in demo run 2. In the scope of the CoordiNet project and especially for the Greek demonstration, the hosting capacity was estimated through the calculation of availability of hardware assets in both the distribution and transmission system. The calculation of hosting capacity is conducted based on the principle of operational safety. To reproduce IPTO's estimation of the hosting capacity just for the demonstration area of Kefalonia, an assumption for minimum load conditions is made while maximizing RES generation at transmission and distribution level. This created the necessary conditions to recreate a power flow from the island interconnected system of the Ionian islands, part of which is Kefalonia, to the mainland.

In the Table 31 below, the conditions for the minimum netload and maximum generation are described:

Table 31: Installed Capacity and minimum netload of interconnected Ionian Islands for the minimum netload and maximum generation scenario

Characteristics	Island Complex		
Island	Kefalonia	Zante	Lefkada
Minimum netload (MW)	5	13	8.5
RES Installed Capacity (MW)	101.5	No RES available	No RES available

According to Table 31 the interconnected island complex of the Ionians is divided in three islands, specifically Kefalonia, Zante and Lefkada. Among those, Kefalonia has the lowest minimum netload, amounting to 5 MW. The quantities in Table 31 represent the historical minimum observed in the past 10 years and represents the value during spring months. Kefalonia's power system is a small part of the western Greek interconnected power system and its load is served mainly by the plants of this area, where the biggest part of its power fleet consists of hydro plants. Moreover, the large-scale wind potential of the island is the reason why there are a lot of wind farms. Specifically, on the island of Kefalonia wind farms with a total established rated power of 101.5MW are operating today, while connection offers with an aggregated power of 46.7MW on Kefalonia and Lefkada islands, have already been granted.

To conclude with the calculation of the BaU, the island complex described has two transmission lines, interconnecting it with mainland Greece. These lines start from Zante and Lefkada. Their characteristics are available in Table 32.

Table 32: Transmission System power lines transfer capability of interconnected western complex of Ionian Islands

Characteristics	Island Complex	
Island	Lefkada	Zante
Transfer Capability (MW)	138	150

Kefalonia does not have an immediate interconnection with mainland Greece and is reliant on its interconnections with Lefkada on the North and Zante on the South. To conduct the analysis under N-1 conditions, the power line between Lefkada and mainland Greece is considered out of service. The estimation for the hosting capacity of BaU is calculated at 63MW. The hosting capacity, considering the introduction of local market, remains unchanged, since the RES hosting capacity is dependent on the technical parameters of minimum net load, the capacity of transmission lines and the already installed RES capacity. Therefore, the results from a local market do not modify these key parameters in the equation for the calculation of the KPI and the shift in the hosting capacity is 0MW as depicted in Table 30. From the analysis of the Greek demonstration, it becomes clear that the methodologies for estimating the RES and DER hosting capacity of both transmission and distribution system needs to be updated, to consider either implicitly or explicitly the impact of various types of flexible resources connected at different voltage levels.

3.1.8 KPI 8 – Reduction in RES curtailment

This indicator measures the reduction in the amount of energy from Renewable Energy Sources (RES) that is not injected to the grid (even though it is available) due to operational limits of the grid, such as voltage violations or congestions

3.1.8.1 Spanish demo

Table 33: KPI 8 value in the Spanish demonstrator

Demo	BUC	Demo run 1
Spanish	**ES-1a** **ES-2** **ES-4**	**e-DI, i-DE:** 10%
	ES-1b	
	ES-3	

For both DSOs, e-DI and i-DE, it has been estimated that the RES curtailment due to network constraints could be reduced by 10% due to a more appropriate use of resources and improved coordination between the TSO and DSO that was realized in CoordiNet. The developed DSO platforms assist in improving the system operation, as they enable a better communication between the DSOs and TSO. Since the calculation of the KPI is based on an estimation, it has been calculated only in demo run 1.

3.1.8.2 Swedish demo

Table 34: KPI 8 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Swedish	**SE-1b**		**Gotland:** 4 MW

The P2P market applied in Gotland resulted in a reduction in RES curtailment of 4 MW. This shows that a market that allows the system users to optimize their resources can lead to a higher penetration of RES, reducing their curtailment during congestions. Due to the low number of FSPs that participated in the market and the very short duration that the market was open, broader conclusions cannot be drawn about RES curtailment. However, it is shown that a P2P market is a viable solution for energy transactions between system users thus can result in a reduction of RES curtailment.

3.1.8.3 Greek demo

Table 35: KPI 8 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-2a		N/A
	GR-2b		N/A

On the transmission system level, the curtailment of RES is only allowed when critical situations concerning the security of supply arise. To this day, this practice is avoided and has never occurred in the past. This changed on 2-3 April 2022 where a small amount of RES was curtailed for the first time in transmission system's history. This situation emerged as the result of two incidents occurring at the same time.

First of all, the RES generation was at an all-time high, covering for 68% of the total aggregated national generation, and, on the other hand, the electricity consumption was at a yearly low point, since, needs in electricity tend to minimize during spring months.

Given the above factors and the fact that Greece's target of 67% generation from RES until 2030, the above situation is an outlier event. Although, in absence of large infrastructure for storage, it is not improbable to come across a similar situation to arise again in the future, but, currently, no sufficient data exists to measure the impact of RES curtailment in the Greek power system.

3.1.9 KPI 9 – Share of fossil-based activated energy

This indicator measures the ratio of activated energy bids that are fossil-fuel based with respect to the total amount of activated energy bids in the different demo sites and BUCs. The KPI is calculated for the Spanish BUC of ES-1a and ES1b and for the Swedish BUC of SE-1a and SE-1b.

3.1.9.1 Spanish demo

Table 36: KPI 9 value in the Spanish demonstrator

Demo	BUC	Demo run 2
Spanish	ES-1a	**e-DI:** 5.22%
	ES-1b	**e-DI:** 0% **i-DE:** 0%

In demo run 1 of the Spanish demo, for the BUC ES-1, only renewable FSPs have participated. The share of fossil-based activated energy was therefore considered zero and not calculated. In demo run 2, in the grid of e-DI and the BUC ES-1a, common congestion management, one unit that participated in the market was considered fossil-based since it uses natural gas as fuel. When finishing demo run 2, the unit had provided 0.16 MWh out of a total of 3.06 MWh, resulting in a share of fossil-fuel based activated energy of 5.22%.

In BUC ES-1b, local congestion management, the pilot developed in the Malaga site did not include any FSP that was considered fossil-fuel based, therefore resulting in 0%. For i-DE, another local congestion management market was tested in the pilot site of Murcia. Neither in this site, any FSP was considered fossil-fuel based, resulting in a share of 0% of activated fossil-fuel based energy.

3.1.9.2 Swedish demo

Table 37: KPI 9 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 0% **Skåne:** 42% **Gotland:** 0%	**Uppland:** 0% **Skåne:** 2% **Gotland:** 0%	**Uppland:** 0% **Skåne:** 56% **Gotland:** 0%
	SE-1b		**Gotland:** 0% **Jämtland/Västern:** 0%	

This KPI has been calculated for all three pilot sites in BUC SE-1a, as well as for the two pilot sites in BUC SE-1b. Due to the fact that the P2P market (BUC ES-1b) was tested only during demo run 2, the KPI has not been calculated in demo run 1 and 3. For the congestion management service tested in BUC SE-1a, the KPI has been calculated for all three demo runs.

In the Uppland pilot site, the ratio of fossil-fuel based activated energy in all demo runs was 0%. In the mix of units delivering flexibility in demo run 1, there were only two fossil-fuel based units, a waste incineration plant of 10 MW and a gas turbine of 16 MW. In demo run 2 and 3, also a hospital reserve diesel generator of 8 MW in the region was set up as an FSP, but was running on biodiesel and is therefore not fossil-fuel based [9]. The gas turbines are considered reserve power in case of major black outs and thereby were not activated. The waste incineration plant also did not offer flexibility in demo run 2 and 3. Although the unit placed bids on the market occasionally in demo run 1, this was during days when no flexibility was required.

In Skåne, in BUC SE-1a, the ratio of the activated fossil-fuel based flexibility during demo run 1,2 and 3 was 42%, 2% and 56%, respectively. In the mix of FSPs in demo run 1, there were two diesel gensets (60 MW and 0.5 MW) that are fossil-fuel based. These were activated due to their low bid price. In demo run 2, the fuel was switched for both diesel gensets to biodiesel, leaving a waste incineration plant as the only activated fossil-fuel based unit due to its low bid price. In demo run 3, this waste incineration plant was forced to leave the market due to environmental restrictions limiting the ability to provide flexibility, and a district heating plant joined the market. Between the demo runs, the fossil-fuel based activated energy decreased to only 2% in demo run 2 from the initial 42% in demo run 1, mainly due to this fuel switch. An additional fossil-fuel based unit joined the market in demo run 2, a diesel genset of 0.75 MW, but it was not activated. In demo run 3, the activated fossil-fuel based flexibility ratio became 56% as a new district heating plant joined.

In Gotland, in BUC SE-1a, two fossil-fuel based power units participated in demo run 2 and 3. A gas turbine of 40 MW and a diesel genset of 40 MW participated, on top of the fossil-free unit mix of demo run 1. The units were however never activated, resulting in a ratio of 0% in all demo runs. In BUC SE-1b, a mix of heat pumps, electric boilers and wind power units were included. Therefore, the ratio of fossil-fuel based activated bids of the P2P market was 0%.

In the pilot site of Jämtland/Västernorrland, the units providing flexibility in the P2P market of SE-1b were non-fossil-based. The mix of units consists of hydropower and wind power units. Hence, the ratio of fossil-fuel based activated energy was 0%.

3.1.10 KPI 10 – Accuracy of the RES production forecast calculated 1 hour in advance

This indicator measures the Normalized Mean Absolute Error (NMAE) of RES forecast 1 hour in advance in transmission and distribution systems. Different indicators are calculated per production type (Wind, photovoltaic).

3.1.10.1 Spanish demo

Table 38: KPI 10 value in the Spanish demonstrator

<table>
<tr><th>Demo</th><th>BUC</th><th>Demo run 1</th><th>Demo run 2</th></tr>
<tr><td rowspan="3">Spanish</td><td>ES-1a
ES-2
ES-4</td><td>e-DI: 6.962 %
i-DE: 0.547 %
REE: 0.9%</td><td></td></tr>
<tr><td>ES-1b
ES-3</td><td></td><td>i-DE: 0.1845 %</td></tr>
<tr><td>ES-2</td><td></td><td></td></tr>
</table>

Concerning e-DI, in demo run 1, five FSPs (4 wind farms and 1 PV) participated in the Cadiz pilot site for BUCs ES-1a and ES-2. The Normalized Mean Absolute Value (NMAE) has been calculated for each FSP. The minimum and the maximum NMAE values are 3.78% and 8.31%, respectively. The average value of all the FSPs is 6.96%.

For i-DE, two FSPs participated in BUCs ES-1a, ES-2 and ES-4. The average value of the NMAE was 0.547%.

A typical accuracy of REE tools for 1 hour in advance is about 0.9%

In demo run 2, concerning e-DI, there was no forecasting one hour in advance, as there is no available data for the FSPs participating in the demonstration.

For i-DE, four FSPs participated in BUCs ES-1b and ES-3. The average value was 0.1845%

In general, a good performance of all forecasting tools is observed, which is critical for the system operators in order to detect potential network issues, such as congestions. High accuracy is also important for the FSPs, as it assists in developing a proper bidding strategy.

3.1.10.2 Greek demo

Table 39: KPI 10 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	**GR-1a** **GR-1b** **GR-2a** **GR-2b**	2.3%	Kefalonia demo area: 1.8% Mesogia demo area: 1.5%

In demo run 1, 73 PVs participated in the Mesogia pilot site for BUCs GR-2a. Although in demo run 1, the demonstration did not take place in the Kefalonia pilot site, the PV generation forecasting was tested for 45 PVs in this pilot site. Hence, the NMAE has been calculated for a total of 118 PVs connected to medium voltage and was equal to 2.3% for 1 hour ahead using the Artificial Neural Network (ANN) based PV generation forecasting tool developed by the Greek demonstrator. In particular, the RES forecasting tool had already been developed in previous EU-funded projects and its accuracy was improved in CoordiNet.

In the demo run 2, the demonstration took place in both demo sites, Kefalonia and Mesogia. The acquired results from the demo site in Mesogia indicate that the RES production forecast has been further improved by minimizing the forecast error from 2.3% to 1.5% thus improving the accuracy, while in the Kefalonia demo area the results were also satisfying, achieving a deviation of 1.8% between forecasted and real values for 1 hour in advance.

A good performance of the RES forecasting tool was observed. As also mentioned for the Spanish demo, this is important for the system operator to detect potential network issues and for the FSPs to develop a proper bidding strategy. The same tool is used for all the BUCs. Although BUCs GR-1a&b and GR-2b were not tested in demo run 1, since the RES forecasting tool was in place and tested in both pilot sites, the accuracy was calculated for all the BUCs.

3.1.11 KPI 11 – Accuracy of the RES production forecast calculated 24 hours in advance

This indicator measures the Normalized Mean Absolute Error (NMAE) of RES forecast 24 hours in advance in transmission and distribution systems. Different indicators are calculated per production type (Wind, photovoltaic).

3.1.11.1 Spanish demo

Table 40: KPI 11 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a ES-2 ES-4	**e-DI:** 8.31 % **i-DE:** 0.6 % **REE:** 2.13%	
	ES-1b		
	ES-2		

To investigate the accuracy of RES forecasting 24 hours in advance, the NMAE was calculated for the FSPs already mentioned for KPI 10. For e-DI, the minimum and maximum values were 4.09% and 10.13%, respectively, while the average value was 8.31% which is slightly higher than the one calculated for 1 hour in advance. For i-DE, the average value was 0.6 %. A typical accuracy of REE tools for 24 hours in advance is about 2.13%.

As for RES forecasting 1 hour in advance, the performance of the forecasting tools is good which is very important for the same reasons mentioned in the analysis of KPI 10.

3.1.11.2 Greek demo

Table 41: KPI 11 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a GR-1b GR-2a GR-2b	4.7%	Kefalonia demo area: 3.4% Mesogia demo area: 4%

The accuracy of the RES forecasting tool was tested for the demo run 1 in Mesogia for a prediction of 24 hours ahead. The same PVs, as for KPI 10, were considered. The NMAE was equal 4.7% for all the PVs, using the ANN based PV generation forecasting tool. The performance of the tool is thus also good for 24 hours ahead. In the demo run 2, the demonstration took place in both demo sites, Kefalonia and Mesogia. The acquired results from the demo site in Mesogia indicate that the RES production forecast has been further improved by minimizing the forecast error from 4.7% to 4% thus improving the accuracy, while in the Kefalonia demo area the results were even better, achieving a deviation of 3.4% between forecasted and real values for 24 hours in advance.

3.1.12 KPI 12 – Voltage variation

This indicator measures the decrease in the deviation of the voltage on the network nodes as a result of using the market platform and products proposed by CoordiNet. As a basis, the nominal voltage per node has been used.

3.1.12.1 Spanish demo

Table 42: KPI 13 value in the Spanish demonstrator

Demo	BUC	Demo run 2
Spanish	**ES-3**	**e-DI (Cadiz):** 84.2%

This KPI was calculated only in demo run 2 and in BUC ES-3 which focuses on voltage control. Due to the additional reactive power that is used to control voltage a reduction of 84.2% in voltage variation compared to the BaU scenario was achieved. Therefore, the results show that the use of additional reactive power can significantly reduce voltage violations.

3.1.12.2 Greek demo

Table 43: KPI 12 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	**GR-1a, GR-1b**		**Kefalonia:** 37.59% (during winter day with increased RES) **Kefalonia:** 28.87% (during summer day with increased RES) **Mesogia:** 11.58% (during winter day with increased RES) **Mesogia:** 26.22% (during summer day with increased RES)

This KPI has been calculated in demo run 2 for both demo sites (Kefalonia and Mesogia) and tested under multiple scenarios with increased load and RES penetration. The results demonstrate that with the proper utilisation of flexibility assets through the Coordinet platform, voltage variations are significantly mitigated thus the absolute deviation is decreased. Hence the Coordinet Platform is used efficiently by providing significant benefits comparing to the BaU scenario.

3.1.13 KPI 13 – Criticalities Reduction Index

This indicator measures the reduction of the number of criticalities on the network under consideration in terms of overvoltage and overcurrent.

3.1.13.1 Spanish demo

Table 44: KPI 13 value in the Spanish demonstrator

Demo	BUC	Demo run 1
Spanish	ES-1a	**e-DI & i-DE:** 20%
	ES-2	
	ES-4	

This KPI was only calculated during demo run 1 and its calculation was based on estimations, taking into account the historical number of criticalities observed in the networks of the pilot sites and estimating how the CoordiNet solution could improve this number. This KPI is supposed to consider criticalities caused by overvoltage and overcurrent.

Both DSOs taking part in the Spanish demonstrator have valued this KPI at 20% [19].

In the specific case of e-DI, analysing the historical data of 2020, 5 and 3 criticalities were detected in Cádiz and Málaga, respectively. All criticalities were due to overcurrent, since no overvoltage criticalities are registered. However, considering the expected increase of RES connected at distribution networks, these criticalities are also expected to increase. With the CoordiNet solution, a 20% reduction in the criticalities is estimated, since the DSO platform will allow the detection of these criticalities and the anticipation of the corresponding solution. Therefore, the number of criticalities could be reduced from 5 to 4.

The other Spanish DSO, i-DE, considers that there are no criticalities during the normal exploitation of the grid. However, around 5 times per year, compromising situations can happen due to extraordinary events in the surrounding grid. They are not really critical solutions, but situations in which reinforcement or flexibility could support the DSO. This is an estimation based on the fact that flexibility is not 100% available all the time, while reinforcement would provide a long-term solution.

3.1.14 KPI 14 – Islanding duration

This indicator measures the capacity of islanding event to last as long as required. This indicator is calculated as the relation (in %) between the duration of a single islanding event and the required duration of an islanding event after an intentional or unintentional disconnection from the grid.

3.1.14.1 Spanish demo

Table 45: KPI 14 value in the Spanish demonstrator

Demo	BUC	Demo run 1
Spanish	ES-4	**i-DE:** 100%

This KPI was solely calculated during demo run 1 by i-DE, since it is the only DSO that tested the controlled islanding BUC. The energy required for the islanding was delivered when required (1.5 hours) under different tests considering scheduled and non-scheduled disconnections. Therefore, the value of the KPI is 100% [19].

3.1.15 KPI 15 – TIEPI - Equivalent interruption time related to the installed capacity

This indicator measures the total amount of TIEPI avoided, measured in hours, as result of using the market Platform and products proposed by CoordiNet.

3.1.15.1 Spanish demo

Table 46: KPI 15 value in the Spanish demonstrator

Demo	BUC	Demo run 1
Spanish	ES-1	
	ES-2	
	ES-3	
	ES-4	**i-DE:** 0.10835 minutes

The TIEPI is an indicator of continuity of supply. It is an acronym in Spanish: *Tiempo de Interrupción Equivalente de la Potencia Instalada*. It is in practice similar to the Average System Interruption Duration Index (ASIDI) defined by the IEEE standard 1366-2003, although instead of using the kVA served, the MV/LV transformation capacity and the power contracted by MV consumers are considered as weighting factors. Thus, any fault affecting the LV grid exclusively would not be included in these reliability indicators.

Besides being a technical indicator of continuity of supply, TIEPI also has economic implications. The DSOs in Spain are subject to an economic incentive mechanism over the TIEPI and the NIEPI[2]. These indicators are calculated separately every year for four different types of areas: urban, semi-urban, concentrated rural and scattered rural. The incentive is a symmetric bonus/malus scheme. The total annual incentive/penalty for a DSO is capped to +2%/-3% of the base DSO remuneration (without incentives) in the previous year.

In the Spanish demonstration, this KPI was exclusively calculated for the Islanding BUC (BUC ES-4), considering that an islanding situation results in a direct avoidance of TIEPI for the DSO. The implementation of other BUCs could also lead to the avoidance of TIEPI, although in such cases this would be achieved only indirectly (e.g., congestions avoided preventing a possible outage). For this reason, this KPI is only calculated in demo run 1, considering that the controlled islanding BUC was only demonstrated during the first Spanish demo run.

The TIEPI indicator is equal to 0.10835 minutes for BUC ES-4, which means that the islanding operation would have avoided an impact in the DSO's TIEPI of approximately 0.11 minutes.

[2] *Número de Interrupciones Equivalente de la Potencia Instalada:* The NIEPI measures the frequency of interruptions, similary to the ASIFI defined by the IEEE standard 1366-2003.

3.1.16 KPI 16 – Potential Offered flexibility

This indicator measures the potential offered flexibility. This is the potential amount of flexibility that all flexible resources of the portfolio are able to offer to the market platform.

3.1.16.1 Spanish demo

Table 47: KPI 16 value in the Spanish demonstrator

<table>
<tr><th>Demo</th><th>BUC</th><th>Demo run 1</th><th>Demo run 2</th></tr>
<tr><td rowspan="5">Spanish</td><td>ES-1a</td><td rowspan="2">e-DI:
Congestion Management:
231,038.78 MWh
Balancing:
37,539.3 MWh
i-DE:
Congestion Management:
20,201.4 MWh</td><td rowspan="2">e-DI:
Common Congestion Management: 3.06 MWh
Local Congestion Management: 0.21425 MWh

i-DE:
Local Congestion Management:
0.2 MWh</td></tr>
<tr><td>ES-1b</td></tr>
<tr><td>ES-2</td><td></td><td></td></tr>
<tr><td>ES-3</td><td></td><td></td></tr>
<tr><td>ES-4</td><td></td><td></td></tr>
</table>

In demo run 1, the potential offered flexibility has been estimated based on 2020 data collected from the actual congestion management and balancing markets. It has been calculated for each of the FSPs participating in the Spanish demonstration. For each market, based on the total capacity of the FSPs participating in the market and the capacity of each FSP participating in BUCs ES-1a and ES-2, the percentage contribution of each FSP to the offered energy was estimated. By multiplying the percentage contribution of each FSP with the total energy offered by the agent bidding in each market, the potential offered flexibility from each FSP is calculated.

For e-DI, the total potential offered flexibility in the common congestion management (BUC ES-1a) and balancing (BUC ES-2) markets of the FSPs participating in the Spanish demonstrator is equal to 231,038.78 MWh and 37,539.3 MWh, respectively.

For i-DE, the total potential offered flexibility in the common congestion management market (BUC ES-1a) has been calculated equal to 20,201.4 MWh.

In demo run 2, the potential flexibility was calculated differently. For e-DI, the calculation was based on the different demonstrations performed and the flexibility offered to the market account for the flexibility cleared in the market. The potential flexibility was equal to 3.06 MWh and 0.21425 MWh in the common and the local congestion markets respectively, thus higher in the common market compared to the local one.

For i-DE, the potential flexibility that was offered during the tests was equal to 0.2 MWh.

3.1.16.2 Greek demo

Table 48: KPI 16 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a, GR-1b, GR-2a, GR-2b,		**Kefalonia:** 370,758.4 (during winter day with increased RES) **Kefalonia:** 404,718.5 (during summer day with increased RES) **Mesogia:** 319,543.7 (during winter day with increased RES) **Mesogia:** 321,453.7 (during summer day with increased RES)

This KPI calculates the potential flexibility which can be offered to the market platform. Future scenarios with increased load and increased RES are considered in order to calculate the total amount of potential flexibility from flexible resources for both demo sites.

In both demo sites for the future scenarios with increased RES, it is obvious that the amount of potential offered flexibility is also increased substantially.

3.1.17 KPI 17 – Increase in the amount of load capacity participating in DR

This indicator measures the increase in the amount of load that participates in demand response in order to offer flexibility to system operators as a result of using the market platform and products proposed by CoordiNet.

3.1.17.1 Spanish demo

Table 49: KPI 17 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI**: 361.2 kW	**e-DI**: 448.2 kW **i-DE:** 400 kW
	ES-1b		
	ES-2		
	ES-3		
	ES-4		

This KPI has been calculated for BUC ES-1a. For e-DI, three loads with a total peak demand equal to 361.2 kW participated in demo run 1. Considering that before CoordiNet no loads participated in the demand response, there is an increase of 361.2 kW. This shows that CoordiNet gave the opportunity to evaluate the participation of demand response in the provision of flexibility. For i-DE, demand flexibility did not participate in demo run 1, so this KPI has not been calculated for i-DE.

In demo run 2, the demand engaged through the use of cascading funds and monitored by the aggregator Bamboo Energy was also considered. Hence, concerning e-DI, the load capacity participating in DR response in BUCs ES-1a and ES-1b was 488.2 kW. An increase of 35% compared to demo run 1 is observed.

Concerning i-DE, the capacity of loads participating in BUC ES-1b was 400 kW.

Given that there was no load capacity which participated before CoordiNet, the increase is equal to the capacity participating in the CoordiNet demonstrations.

3.1.18 KPI 18 – Volume of transactions

This indicator measures the volume of transactions in MW or MWh depending on the service that is provided. This indicator will be used in order to measure the volume of cleared bids for each service.

3.1.18.1 Spanish demo

Table 50: KPI 18 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI (Cadiz):** 237,009.42 MWh **i-DE (Albacete and Murcia):** 7.6 MWh	**e-DI (Malaga):** 6.12 MWh
	ES-1b		**e-DI (Malaga):** 0.4 MWh **i-DE:** 0.02 MWh
	ES-2	**e-DI (Cadiz):** 18,051.87 MWh	
	ES-3		**e-DI (Malaga):** 557 MVarh **i-DE:** 13.5 MVarh
	ES-4		

For the first demo run, i-DE has based the calculation of this KPI on the sites performed in demo run 1 (Albacete and Murcia). Therefore, the volume of transactions (in MWh) for the 2 FSPs during i-DE Congestion Management Test was 7.6 MWh. This was based on a test that took place on February 2nd, from 1:00 pm to 2:00 pm.

For e-DI, the volume of transactions is based on all transactions done in 2020, so the calculation is performed by estimating the total annual volume. For the Common Congestion Management Cadiz BUC (BUC ES-1a), there are 237,009.42 MWh of transactions. For the Balancing BUC Cadiz scenario (BUC ES-2), there are 18,051.87 MWh of transactions.

For the second demo run, which is calculated taking into account only Coordinet demo transactions, when it comes to BUC ES-3 focusing on voltage control, it should be noted that the volume of transactions is expressed in Mvarh, as there was no impact on the active power (MW). For the other BUCs, there are comparatively low volumes of transactions in the second demo run. This is because in demo run 1 this KPI is calculated based on total annual volumes, while in demo run 2 it is calculated taking into account only Coordinet demo transactions. Specifically, the calculated volume of transactions for e-DI in Malaga was 6.12 MWh for ES-1a, 0.4 MWh for ES-1b and 557 MVarh for ES-3, while for i-DE was 0.02 MWh for **ES-1b** and 13.5 MVarh for **ES-2**.

3.1.18.2 Swedish demo

Table 51: KPI 18 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 3,260.00 MWh **Skåne:** 74.00 MWh **Gotland:** 797.00 MWh	**Uppland:** 6,596.32 MWh **Skåne:** 121.70 MWh **Gotland:** 81.70 MWh	**Uppland:** 109 MWh **Skåne:** 9.8 MWh **Gotland:** 0.4 MWh
	SE-1b		**Gotland:** 4 MWh	
	SE-3			

Table 51 gives the volume of cleared transactions. For Uppland and Skåne, it can be seen that there is an increase in cleared volumes in demo run 2. This is explained by the more severe winter period 2020/2021 (demo run 2) compared to 2019/2020 (demo run 1), explaining the higher need for flexibility. For Uppland, the increase in cleared flexibility is, however, significantly higher. This is, as explained previously in KPI 6, due to the fact that in Uppland TSO buys flexibility to lower costs from temporary subscription increases by the TSO, implying that the price of flexibility is capped. During the three demos in Uppland temporary subscription was denied during one day and a handful of days in Skåne. For Skåne, MWh costs of bids are much higher because bids cleared much more rarely and not to avoid for temporary subscription. In Skåne the focus has been to clear flexibility when the TSO denies temporary subscription.

Gotland, as explained previously is a special case in the sense that the market is not operated a lot. Because of this, the results were highly influenced by one single event/cold spell period in demo run 1 that led to the need to buy flexibility for 24 hours. Due to the small size of the market, this had a large influence on demo run 1 implying that the results of demo run 1 and 2 for Gotland should not be compared.

It is useful to interpret KPI 18 together with KPI 19, which shows the number of cleared bids and number of days the market was open. Here it can be seen that in demo run 2, Uppland clearly had a higher need for flexibility, resulting in more bids being cleared and the market being open more frequently. The Uppland market is also dominated by a few larger companies, even though smaller resources are also active in bidding (49 out of 538 cleared hourly bids). The Gotland market was only open for 3 days in the first winter, and 12 days in the second winter, while the Skåne market doubled its opening days in the second winter.

During the third winter (demo run 3), the volume of transactions decreased significantly due to the subsequent factors: firstly, the winter of 2021-2022 was generally warmer than the winter of 2020-2021 and secondly it seems that consumers and producers changed their behaviour due to the high electricity prices occurred in the winter of the third demo run. Cleared volumes were reduced significantly. It is worthwhile to point out that the analysis above focusses only on cleared bids, and not on offered bids. Offered bids were analysed for the last two winters. Several FSPs made assumptions when flexibility was likely to be cleared (e.g., warm period) and did not provide bids continuously, while others had automatic bidding in place and bided irrespective of prospect activation.

3.1.18.3 Greek demo

Table 52: KPI 18 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a		Mesogia: 38.82 MW Kefalonia: 53.00 MW
	GR-1b		Mesogia: 77.65 MW Kefalonia: 106 MW
	GR-2a	Mesogia: 18.80 MWh (downward)	Mesogia: 754.43 MW Kefalonia: 653.02 MW
	GR-2b		Mesogia: 1508.85 MW Kefalonia: 1306.04 MW

This indicator measures the volume of transactions in MW or MWh depending on the service that is provided. For the Greek demo, congestion management services are provided through upward and downward regulation depending on whether there are load increases or not. In the tested scenarios for demo run 1, it is clear that when load increases, upward regulation is needed. This implies that either more generation is needed, or that consumption decreases are needed. In case there is an increase in renewables, downward regulation is required. This implies that more consumption or generation curtailment is needed. KPI 5 zooms in more detail on the differences between the scenarios and highlights some changes in flexibility needs between the scenarios. More details on the scenarios for demo run 1 are shown in Table 24 presented in the framework of the analysis of KPI 5. Nevertheless, comparing the different feeders is hard as percentage differences do not necessarily give indications on absolute load/RES increases. Concerning the volume of transactions, as explained in the analysis of KPI 5, scenario 3 is presented here as this is the scenario with the highest increase in renewables.

For demo run 2, we can compare between the different BUCs as more BUCs have been tested. Clearly, higher volumes of transactions are needed for congestion management (GR 2) than for voltage control (GR1). The values presented in the table above for demo run 2 are yearly values. Furthermore, it is also evident that the fragmented market leads to higher volumes of transactions than the multilevel market, since in the fragmented market model, each DSO is also responsible for balancing each own network, using only local resources.

3.1.19 KPI 19 – Number of transactions

This indicator measures the number of transactions. This indicator will be used in order to measure the number of offered and cleared bids for each service. Note that for the Spanish demo, for e-DI, the number of transactions was not available and the number of hours that each FSP has participated in each market during 2020 was used.

3.1.19.1 Spanish demo

Table 53: KPI 19 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI (Cadiz):** 281 hours **i-DE (Albacete and Murcia):** 2 transactions	**e-DI (Malaga):** 6 transactions
	ES-1b		**e-DI (Malaga):** 12 transactions **i-DE:** 1 transaction
	ES-2	**e-DI (Cadiz):** 77.71 hours **i-DE:** 5 transactions	
	ES-3		**e-DI (Malaga):** 12 transactions **i-DE:** 3 transactions
	ES-4		

During demo run 1, the demo mostly tested technical aspects regarding the activation of the FSPs. For this purpose, it was sufficient to have one bid per FSP. However, outside the demo, these FSPs were active in real markets. For this KPI, e-DI and i-DE, used different approaches to indicate the number of transactions. e-DI reported the total number of hours with transactions in real markets, while i-DE presented the results of the tests executed in the demonstrator. As such, the results of e-DI and i-DE cannot be compared.

2 and 5 are the number of transactions carried out in the test period for the i-DE demonstrator for ES-1a and ES-2, respectively during demo run 1. For demo run 2, i-DE had 1 transaction in ES-1b and 3 transactions in ES-3. These were the number of transactions necessary to be able to carry out the tests. It was not possible to reproduce a market due to the regulatory context. There was no competition and the idea was merely to test the functionality of the tool.

For e-DI, data on the number of transactions were not available in demo run 1. As such, the number of hours that each FSP has participated in each market during 2020 was used as the closest alternative approach. For the ES-1a congestion management BUC, more hours of transactions (281 hours) were registered than for the balancing BUC ES-2 (77.71 hours). For demo run 2, e-DI had 12 transactions in Malaga for BUC ES-3 and ES-1b, while 6 for BUC ES-1a. It can be assumed that 1 hour of transaction is similar to 1 transaction. In this respect, there seems to be a decrease in transactions between demo run 1 and 2. This is because in demo run 1 transactions were determined based on an annual horizon, while in demo run 2, they are only calculated for the demos themselves.

3.1.19.2 Swedish demo

Table 54: KPI 19 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	
Swedish	SE-1a	**Uppland:** 196 bids cleared (172 hours and 16 days with transaction) **Skåne:** 26 bids cleared (26 hours and 8 days with transaction) **Gotland:** 70 bids cleared (58 hours and 3 days with transaction)	**Uppland:** 538 bids cleared (412 hours and 41 days with transaction) **Skåne:** 38 bids cleared (35 hours and 16 days with transaction) **Gotland:** 33 bids cleared (29 hours and 12 days with transaction)	**Uppland:** 74 bids cleared (71 hours and 23 days with transaction) **Skåne:** 30 bids cleared (30 hours and 15 days with transaction) **Gotland:** 4 bids cleared (4 hours and 2 days with transaction)
	SE-1b		**Gotland:** 1 bid	
	SE-3			

In demo run 1, it can be seen that the Gotland market had transactions for 3 days. This is explained by the lower congestion management requirements due to the mild winter. In demo run 2, flexibility requirements increased as of which the market was open for more days. Nevertheless, the total amount of cleared bids decreased from demo 1 to demo run 2 due to an outlier in demo run 1. Indeed, one single event/cold spell period caused the need to clear 24h of flexibility which had a large influence on the small market (see also explanation in the previous KPI). During the third winter, the number of transactions decreased again because the largest flexibility provider, a heat pump from the district heating company, was taken out of service due to a fault that needed repair.

For Uppland and Skåne, however, this KPI confirms previous findings of KPI 18 as the number of cleared bids increased going from demo run 1 to demo run 2. This is explained by the mild winter in demo run 1. In addition, as explained in the introduction of the Swedish demo explanation (see Chapter 2), during the first winter, the Uppland flexibility market was operated for 83 days, and during the second winter for 120 days. In the first winter, flexibility was cleared during 16 days and 172 hours during the period of combined power outtake from the two TSO grids. In the second winter, there was a TSO maintenance work implying that the subscription violated charges were removed. During this period, flexibility was cleared during 41 days and 412 hours. As can be seen in KPI 19, even though the length of the demo run period only doubled, the number of cleared bids tripled, while the price remained rather stable. These larger volumes were needed due to a significant cold spell in February 2021 but they were still not sufficient to stick to the subscription limit as well as in the first demo run. For the third demo run, however, the number of cleared bids decreased again due to the warmer winter and the higher electricity prices. For Skåne, this was also due to the increased capacity in Sege-Arrie. For reasons explained in D4.7.1 [6], the interest in participating at this market decreased since there no longer was a real need for the flexibility in this point. This, in combination with the new requirements on the procurement process in Söderåsen (due to the sharp need of flexibility there), caused a decrease in both number of FSPs and therefore also in the amount of MWs. For Uppland, the electric boilers from the district heating companies were offering less bids due to a threefold increase in average spot market price for electricity. The boilers were therefore not used during hours with peak consumption, which happened to coincide with times of high electricity prices.

Combining the results of KPI 18 and 19 leads to the average cleared volume per bid. This is presented in Table 55.

Table 55: Average cleared volume per bid

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 16.6 MWh per bid **Skåne:** 2.846 MWh per bid **Gotland:** 11.38 MWh per bid	**Uppland:** 12.26 MWh per bid **Skåne:** 3.202 MWh per bid **Gotland:** 2.476 MWh per bid	**Uppland:** 1.47 MWh per bid **Skåne:** 0.326 MWh per bid **Gotland:** 0.1 MWh per bid
	SE-1b		**Gotland:** 4 MWh per bid	
	SE-3		**Jamtland/Vastern:** 0	

Table 55 shows that for Uppland, but also for Gotland and Skåne, on average cleared volumes per bids are rather higher, indicating the participation of some large-scale FSPs. Although total liquidity was good, liquidity in terms of competition among bids was not good enough with lower levels of bids available for some FSPs [21]. Several FSPs underestimated the effort and time needed to prepare for providing flexibility.

3.1.19.3 Greek demo

Table 56: KPI 19 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a		Mesogia: 658 Kefalonia: 513
	GR-1b		Mesogia: 1001 Kefalonia: 1075
	GR-2a	Mesogia: 16 transactions	Mesogia: 12703 Kefalonia: 4614
	GR-2b		Mesogia: 15320 Kefalonia: 6208

For the Greek demo, the transactions are summarized in Table 57 for the different scenarios, making a distinction between upward and downward regulation. Downward regulation is mainly offered by RES, while upward is offered by demand. The number of RES is considerably lower than the demand resources, while on the other hand their capacity is higher than consumption. This is also depicted in the flexibility offers. There is a small number of downward flexibility offers with large quantity offered by PVs and a higher number of upward flexibility offers with relatively smaller quantity offered by demand resources.

As indicated, it is hard to link the load increase with the number of transactions. A load increase of 1500% only requires 11 transactions, while a load increase of 200% on feeder 2 requires 92 transactions.

Table 57: Number of transactions in demo run 1 of the Greek demonstration

	Scenario 2	Scenario 3	Scenario 5		Scenario 6			
RES increase	400%	500%	400%		500%			
Load increase			200%		1500%	300%	400%	
Feeder	7	7	2	7	1	2	5	7
Upward regulation	0	0	92	0	11	975	135	0
Downward regulation	6	16	0	8	0	0	0	10

For demo run 2, the transactions on a yearly basis per BUC and per pilot site confirm the findings of KPI 18. More transactions are needed for the fragmented market than for the multi-level market and congestion management requires more transactions than voltage control. As already explained before, the comparison between the two market models indicates that the multilevel market model requires lower amounts of flexibility since the balancing responsibility of the whole network (transmission and distribution) is transferred to the TSO, compared to the fragmented market model where each system operator is responsible for balancing each own network using only resources, located in their own network.

3.1.20 KPI 20 – ICT Cost

This indicator was defined in D1.6 [2] as a KPI that "measures the ICT costs that are directly related to the implementation of each coordination scheme". However, taking into consideration the evolution of the project during the last years, it has been necessary to adapt this definition according to the real deployment of the demonstrators. It may be more realistic to say that the ICT costs will be determined for each market developed within the CoordiNet project, than for each coordination scheme, since no demonstrator has done such calculation by coordination scheme.

The term implementation is used to refer to 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. This KPI considers only 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 cost of the already existing systems is not considered.

Since this KPI is related to the CAPEX of the ICT solutions implemented in the CoordiNet demonstrations, there is no difference between the demo runs. Once the ICT solutions are integrated into the demonstrations, no further capital expenditures are required. It is noted that the operational expenditures to operate and maintain the installed equipment are analysed and discussed in KPI 4.

3.1.20.1 Spanish demo

Table 58: KPI 20 value in the Spanish demonstrator

Demo	BUC	CAPEX*
Spanish	ES-1a	e-DI: 181,660 € i-DE: 265,000 € REE: 112,694 €
	ES-1b	
	ES-2	
	ES-3	
	ES-4	

** CAPEX included in Table 58 only gathers the costs incurred by TSO (REE) and DSOs (e-DI and i-DE). Since it is difficult to specify a value for each demo run/BUC, the total amounts are shown in this table and, when possible, more details are explained below.*

In the case of the Spanish demo, part of the data related to this KPI was provided after demo run 1, while other after demo run 2.

The demo run 1 in the Spanish demonstrator focused on testing three BUCs, specifically: BUC ES-1a (common congestion management), BUC ES-2 (central balancing) and BUC ES-4 (controlled islanding). According to [19], the total ICT costs in the Spanish demonstrator for demo run 1 were 459,354 €.

In the case of the Spanish TSO, REE, the incurred costs are based on the required adaptations to the already existing platform in order to incorporate the DSO limitations in the balancing process and to modify the congestion management process from the current centralised approach to the common one. These modifications and updates have been valued at 112,694 € [19].

The two Spanish DSOs taking part in the Spanish demonstrator, e-DI and i-DE, estimated the costs for the modifications and developments necessary to test the BUCs evaluated in demo run 1 at 181,660 €, in the case of e-DI, and 265,000 € is the estimation by i-DE. It must be noted that i-DE was the only DSO testing BUC ES-4, but the specific cost of testing the controlled islanding service was not provided, as a single value gathering the costs for all BUCs was provided in [19]. Therefore, it can be assumed that the difference between the two values may be due to this fact. After demo run 2, pending information regarding the incurred ICT costs was provided. However, the information, and also its degree of detail, provided by each partner is different in each case. Next paragraphs summarize all the information related to this KPI provided both in [19] and [15] by each participant. In addition, REE specified internally the incurred cost, about 100,000 €, for the development of the voltage control platform. Therefore, the total CAPEX identified by REE for CoordiNet [19] could be summarized as follows:

Role	BUC	Cost
Spanish TSO (REE)	ES-1a	8,847 €
	ES-2	3,847 €
	ES-3	100,000 €

i-DE, the Spanish DSO, identified a total cost of 265,000 € for testing all BUCs. However, no more details are provided in [19] or [15].

Role	BUC	Cost
Spanish DSO (i-DE)	ES-1a	265,000 €
	ES-1b	
	ES-2	
	ES-3	
	ES-4	

Finally, e-DI indicated a total cost of 181,660 € for the development of its own platform, which allowed testing all BUCs (excluding controlled islanding, since this BUC ES-4 was not tested by e-DI). In addition, other costs incurred by other partners participating in the demonstrator (e.g. development of the aggregation and local market platforms) were also considered. Thus, next table summarizes the data incurred by e-DI specified in [19] and [15], but also those ones indicated on behalf of other partners taking part in the tests of the BUCs:

Table 59: KPI 20 value in the Spanish demonstrator

Role	BUC	Cost
Spanish DSO (e-DI) / DSO platform	**ES-1a**	**181,660 €**
	ES-1b	
	ES-2	
	ES-3	
Aggregator / aggregation platform	**ES-1a**	**320,000 €**
	ES-1b	
Market operator / Local market platform	**ES-1b**	**160,000 €**

3.1.20.2 Swedish demo

Table 60: KPI 20 value in the Swedish demonstrator

Demo	BUC	ICT Cost
Swedish	**SE-1a**	**Uppland:** 555,888 € **Skåne:** 454,750 € **Gotland:** 237,522 €
	SE-1b	166,500 €

This KPI has been calculated for BUCs SE-1a and SE-1b.

In BUC SE-1a, 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 the systems to the new DSO platform.

The ICT cost (CAPEX) in the Swedish demonstrator has been firstly calculated at system level, including the costs related to the system operation and the market operation. Then, the costs have been split into costs related to the Market tool used by FSPs and the Flex tool used by DSO staff, which have been developed and used in the Swedish demonstrator. Lastly, these costs have been specified for each pilot site based on several considerations and an assignation of percentages. Next paragraphs summarize and explain the different considerations taken into account in the mentioned steps.

Firstly, the main functionalities and their related ICT costs have been identified, valued and assigned to the pertinent actor (DSO, market operator (MO) and the Swedish TSO). Table 61 shows such costs and their allocations:

Table 61: ICT costs allocation per actor - Sweden

	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 €		
	1,013,558 €	858,976 €	75,378 €
	Total cost = 1,947,913 €		

The calculated total ICT costs, including those related to the system operation, market operation and the costs assumed by the TSO for updating its own systems, are 1,947,913 €. Specifically, the concepts included in the calculations are:

- Distribution system operation costs (1,013,558 €): It includes the development of different applications, such as the grid monitoring, load forecasting, the integration with other elements, the metering, forecasting, security & data classification and data hub.
- Market operation costs (858,976 €): These costs include market engine and security & data classification.
- TSO's updating costs (75,378 €): This concept includes the modifications performed in the SvK's own systems.

As it was already explained in section 3.1.4.2, the Swedish demonstrator has developed two different tools: the flex tool, which allows the visualization of different kind of information and eases the understanding of the grid necessities, and the market tool, in which the market clearing is executed.

Starting from the functionalities shown and valued in Table 61, the costs have been assigned to the flex tool and/or the market tool. In some cases, the costs have been shared between both tools, since the functionality should be performed by both of them. It must be noted that, in this case (see Table 62), the costs assumed by the Swedish TSO for the updating of its own systems have not been included in the sharing (i.e. the incurred cost for the development of both platforms is 1,872,534 €), since these costs are not purely assignable to the platform costs itself. Linked to Table 61, Table 62 shows the distribution of costs between the tools based on the functionalities performed by each one:

Table 62: ICT costs allocation per developed tool

	Flex tool	Market tool
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)	208,125 €	208,125 €
Meters at consumer/producer facilities	16,074 €	64,296 €
Forecasting (models, Expektra)	41,234 €	
Security & data classification	26,476 €	26,476 €
Data Hub	16,489 €	16,489 €
	724,648 €	**1,147,886 €**

Therefore, the total estimated costs for the development of the tools are: 724,648 € for the flex tool and 1,147,886 € for the market tool.

Finally, when calculating the ICT costs to be assumed by each pilot site, it is considered that the cost for the development of the flex tool should not be assumed as a CAPEX of the pilot sites.

When splitting the costs among the pilot sites, several considerations must be taken into account:

Two different DSOs participate in the Swedish demonstrator (i.e., E.ON and Vattenfall), which have valued individually several of the mentioned functionalities in Table 61. Specifically:

	E.ON	Vattenfall
Meters at consumer/producer facilities	6,500 €	73,870 €
Forecasting (models, Expektra)	32,000 €	9,234 €
Security & data classification		52,953 €
Data Hub		32,978 €
	38,500 €	**169,035 €**

As it was already explained in section 3.1.4.2 where the OPEX costs are analysed, the difference in costs related to metering solutions is also due to the fact that the metering devices are kept running over the summer 2021 in order to acquire additional data for the forecast machine-learning algorithms.

In the case of E.ON, it is only responsible for the demo in Skåne, so, the amount of 38,500 € should be assigned directly to demo-site. On the other hand, Vattenfall is responsible for Uppland and Gotland. The split of costs assumed by Vattenfall are shared between both demo-sites based on the number of resources available in each demo-site; 19 resources in Uppland and 4 in Gotland. Therefore, for Uppland a cost of 139,638 € is assumed, while for Gotland the remaining cost of 29,397 € is considered.

The costs of the market platform to be shared among the three demo-sites (i. e. market engine and integration) will be assigned according to the following percentages: 40% for Uppland, 40% for Skåne and the remaining 20 % for Gotland. Therefore, out of the 1,040,625 €, 416,250 € would be assumed by Uppland, 416,250 € would be assumed by Skåne and 208,125 € by Gotland.

It must be noted that some of the functionalities of the flex tool (grid monitoring, load forecasting and integration) should not be assigned specifically to the demo sites, since such functionalities can be used for many other purposes. Therefore, the 624,375 € assigned to these functionalities are not shared among the demo sites.

Summarizing, the costs to be assigned to each demo-site would be as follows:

- Uppland: 139,638 € + 416,250 € = 555,888 €
- Skåne: 38,500 € + 416,250 € = 454,750 €
- Gotland: 29,397 € + 208,125 € = 237,522 €

These final results are the ones included in Table 58.

This KPI has also been calculated for the BUC SE-1b, the development of the P2P market. It has been stated by E.ON that the cost for the development of the P2P markets can be estimated at 10% of the total development cost in the flex and market tools performed by E.ON, which includes the following functionalities: the grid monitoring, the market engine, load forecasting and integration.

Therefore, and taking into account that this development of the platforms was estimated at 1,665,000€, the development of the P2P market is valued at 166,500 €.

3.1.20.3 Greek demo

Table 63: KPI 20 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a	1,352,000 € (Mesogia)	1,368,000 (Mesogia) 1,356,000 (Kefalonia)
	GR-1b		
	GR-2a		
	GR-2b		

The ICT costs gathered in this section for the Greek demonstrator include the incurred costs considering the four BUCs deployed in the demonstrator; congestion management (BUCs GR-2a&b) and voltage control (BUCs GR-2a&b) being tested each one of them under two different coordination schemes, multi-level and fragmented models. During demo run 1 only the multi-level congestion management service was tested in Mesogia, while demo run 2 tested the congestion management and the voltage control services, for the multi-level and fragmented approaches, both in Mesogia and Kefalonia (see more details in Table 10). However, as it was previously indicated, this KPI is based on the cost of the ICT solutions implemented in the demonstrator, so, there should be no relevant differences between the demo runs.

Next paragraphs provide a detailed explanation of components and incurred costs mainly for the development of the required platform identified after demo run 1. In the Greek case, during demo run 2, some minor differences have been detailed for each location, mainly related to the number of substations considered at each location/demo run. Therefore, at the end of the section, the differences between demo run 1 and demo run 2 are clarified.

The CoordiNet deliverable D5.1 [12] specifies how the TSO/DSO communication platform is developed in order to *allow the integration of the Operation technology and Information Technology systems of TSOs and DSOs, by using an Enterprise Service Bus (ESB) approach*. Specifically, the KPI 20 considers the ICT costs directly related to the deployment of such communication platform, which is responsible for coordinating the necessary functions (such as 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, communicating of market results, communicating activated bids to FSPs and grid operators and performing the settlement process) to implement the BUCs.

Focusing on the development of such a platform, the components that should be considered in the software development were identified [12]:

- Forecasting provider: Prediction of total demand and renewable energy production (PV and wind farms).
- Wide area monitoring: Identification of congestions or voltage violations both in transmission and distribution levels.
- Market platform (multi-level and fragmented): Platforms where bids are submitted, TSO and DSO cooperate for system services and the market is cleared.
- Aggregator tool: Application for, among others, giving access to the market platform to the users performing aggregation.
- TSO/DSO tool for participating in the market platform: Web application allowing TSO and DSO to operate in the market.
- Monitoring services: Tool to collect data.
- Reporting services: Tool to generate reports (using Business Intelligence).
- Common HV&MV Network: The Common Information Model (CIM) for the representation of the HV & MV networks.

On the basis of this first approach in the initial phase of the project, [10] reports on software development activities for the Greek pilot. It categorises the software tools into three main categories:

- Market clearing tools, which comprise the design of the system services including the new local market operated by the DSO and the existing NRT balancing market operated by the TSO.
- Decision support tools, which increase the observability and controllability of the network components (e. g. forecasting, state estimation, data visualization, topology management, etc).
- Communication tools, which provide market access to market participants and enable the data exchange between system operators (the communication is achieved via an ESB).

The tools, algorithms, communication infrastructures, etc. finally used and developed in the Greek demonstrator are listed and valued in Table 64. The total cost is estimated at 1,352,000 €, out of which 347,000 € should be assigned to the DSO, 740,000 € to the market operator and the remaining 265,000 € to the TSO. Moreover, Table 64 specifies in detail, which concepts are assignable to each role. It is noted that these costs would not change significantly if the flexibility market was implemented for the whole country. This is due to the fact that the cost of the developed tools and software, which is the largest percentage of the total cost, would only slightly change.

Table 64: ICT costs allocation per actor - Greece

	DSO	MO	TSO
Load forecasting algorithms (considering 3 substations)	6,000 €		
RES forecasting algorithms (considering 3 substations)	6,000 €		
Data storage for forecasting tools	60,000 €		
Power flow and state estimation tool	50,000 €		
Topology Manager	70,000 €		
Enterprise Service Buse (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 congestion management 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 €
	347,000 €	**740,000 €**	**265,000 €**
	Total cost = 1,352,000 €		

The total cost of 1,352,000 € was based on demo run 1 which considered three substations for the tests in Mesogia. The total cost indicated after demo run 2 for Mesogia was 1,368,000 € (Table 63). The difference is just caused by the number of substations considered; while during demo run 1 three substations were included, demo run 2 covered seven substations. Since the assigned costs to the load and RES forecasting algorithms were calculated based on the number of substations (2,000 €/substation), the final cost for Mesogia after demo run 2 was 1,368,000 €. Likewise, and taking the value of 1,352,000 € as the basis for the platform development, the costs indicated for Kefalonia, 1,356,000 €, included four substations, instead of the three previously considered during demo run 1 (Table 63).

3.1.21 KPI 21 – Deviation between accepted and actual activated mFRR

This indicator measures the deviation between the accepted and actual activation of flexibility for mFRR system service. The non-activation is not due to limitations in the grid models used, but because the requested flexibility cannot be physically activated due to either flexibility modelling errors and/or flexibility forecasting errors. They latter can be caused by the partial activation of accepted bids or by the activation of non-accepted bids (flexibility requested to be activated even if the market did not select the related bid).

3.1.21.1 Spanish demo

Table 65: KPI 21 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1		
	ES-2	**e-DI:** Positive deviation: 975.17 MWh/month Negative deviation: 297.86 MWh/month **i-DE:** 4 MWh	
	ES-3		
	ES-4		

In the Spanish demonstration, this KPI is exclusively applied to BUC ES-2, calculating the deviations in mFRR markets caused by flexibility modelling errors and/or flexibility forecasting errors. e-DI and i-DE, used different approaches to indicate the deviation between the accepted and actual activated mFRR.

e-DI reported the deviation between market activated energy and actually measured energy based on data of June 2021. The data has been grouped in positive (measured energy>market program) and negative deviation (measured energy<market program). i-DE recorded a positive deviation of 4 MWh, considering the wind farms participating in the ES-2 BUC [5].

Although these values may not capture the effects of the complete implementation of BUC ES-2, they signal that those deviations (mostly positive) do exist for wind farms. Such deviations should be considered, especially by DSOs, when considering the implementation of flexibility mechanisms for congestion management.

This KPI is only calculated in the Spanish Demo Run 1, considering that the BUC ES-2 was only demonstrated at the first demonstration period.

3.1.22 KPI 22 – Requested flexibility

This indicator measures the amount of flexibility requested by the platform for system services from all the flexible resources of the portfolio.

3.1.22.1 Spanish demo

Table 66: KPI 22 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**REE (DA):** 41,467 MWh **REE (NRT):** 107,010 MWh	e-DI: 6.12 MWh
	ES-1b		e-DI: 0.1818 MWh i-DE: 0.3 MWh
	ES-2	**REE:** 1,848,707 MWh	
	ES-3		e-DI: 500 MW*Mvar i-DE: 17.5 Mvarh

During demo run 1 this KPI was only calculated by REE, the Spanish TSO, taking into account the amount of flexibility managed in the already existing congestion management and balancing markets. Since such demo run focuses on demo areas of high-voltage networks managed by the DSO, the FSPs connected to such grids are already participating in the markets managed by the TSO [22]. Therefore, the data has been gathered at system-level from the already existing markets for the first semester of 2021.

The data included only the RES technologies, that is why the value for the congestion management in NRT is considerably higher than the energy in the DA congestion management (while in the real situation, considering all the technologies, the amount of energy managed in the DA congestion market is much higher than the energy required for the NRT congestion management).

During demo run 2, the flexibility requested by the platform was analysed by the Spanish DSOs for the tested BUCs. In the case of e-DI, the requested flexibility by the market platform to the specific FSPs located in Málaga in the common congestion market was 6.12 MWh (BUC ES-1a), 0.1818 MWh in the local congestion market (BUC ES-1b) and 500 MW*Mvar for the voltage control (BUC ES-3). In the case of the voltage control product tested by e-DI, it was internally decided that the units of the offered, cleared and dispatched volumes were expressed in MW*Mvar for one hour (i. e. the voltage product was defined as the additional reactive capacity offered by the providers, which is determined by an area in MW*Mvar) [15]. Likewise, i-DE required 0.3 MWh in the local congestion market (ES-1b) and 17.5 Mvarh in the voltage control tests (ES-3) [15]. This KPI was not calculated for BUC ES-4.

3.1.23 KPI 23 – Data reliability ratio

This indicator measures the percentage of reliable data according to all the data received in the examined period

3.1.23.1 Greek demo

Table 67: KPI 23 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	**GR-1a**		**Kefalonia:** 100% **Mesogia:** 100%
	GR-1b		**Kefalonia:** 100% **Mesogia:** 100%
	GR-2a	**Mesogia:** 100%	**Kefalonia:** 100% **Mesogia:** 100%
	GR-2b		**Kefalonia:** 100% **Mesogia:** 100%

During both demo runs 1 and 2, all packages that were exchanged between the tools, used to identify network issues, clear the market and forward the unused bids of the local market to the TSO market, were received successfully. Thus, the data reliability ratio is 100%. Table 68 shows all at the packages exchanged between the aforementioned tools, as well as the description of the packages.

Table 68: Packages sent to the tools used in the Greek demonstration

Tool	Package name	Description of package	Successful (1=Yes, 0=No)
Grid Topology/Management			
1	Grid Topology Buses	Characteristics of network buses	1
2	Grid Management Bids	Data of submitted bids	1
3	Grid Topology Lines	Characteristics of network lines	1
4	Grid Topology Switches	Characteristics of network switches	1
5	Grid Management LTPVF	RES forecast	1
6	Select Feeders	Identification and name of feeders under consideration	1
7	preGrid_Load_Profile	DA hourly load profile	1
Market Clearing			
1	GRID_p_sensitivity_matrix	Sensitivity matrix of voltage to active power	1
2	GRID_q_sensitivity_matrix	Sensitivity matrix of voltage to reactive power	1
3	GRID_sensitivity_matrix	Sensitivity martix for congestion management	1
4	GRID_a_connectivity_matrix	Connectivity of bids to buses	1
5	GRID_b_connectivity_matrix	Data for bids	1
6	GRID_powerflow_results_lines	Line power flow results before market	1
7	GRID_powerflow_results_volt	Voltage power flow results before market	1
8	GRID_max_thermal_limits	Capacity of network lines	1
9	GRID_ab_con_matrix_dim	Auxiliary package to execute market	1
10	GRID_powerflow_rslts_lines_dim	Auxiliary package to execute market	1
11	GRID_powerflow_results_vol_dim	Auxiliary package to execute market	1
12	GRID_bus_data	Auxiliary package to execute market	1
13	GRID_branch_data	Auxiliary package to execute market	1
After Clearing for IPTO			
1	Select Uncleared Bids for IPTO	Unused bids are sent to IPTO	1
		Reliability (%)	100

3.1.24 KPI 24 – Accuracy of load forecast calculated 1 hour in advance

This indicator measures the Mean Absolute Percentage Error (MAPE) of the load forecast 1 hour in advance in transmission and distribution systems.

3.1.24.1 Spanish demo

Table 69: KPI 24 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI:** 3.73% **i-DE:** Alicante: 5.18% Murcia: 1.78%	**e-DI:** 3.73%
	ES-1b		
	ES-2	**e-DI:** 3.73% **i-DE:** Alicante: 5.18% Murcia: 1.78%	
	ES-3		**e-DI:** 3.73%
	ES-4	**e-DI:** 3.73% **i-DE:** Murcia: 1.78%	

In demo run 1, e-DI took into account loads connected to 17 nodes to calculate this KPI for BUCs ES-1a and BUC ES-2. The Mean Absolute Percentage Error (MAPE) was equal to 9.53% when all the nodes are taken into account which is a high value for forecasting the load of the next hour. There were two nodes with very high values, in which can explain the high MAPE value. When these two nodes are not taken into account, MAPE is equal to 3.73% showing a good performance of load forecasting 1 hour in advance. Similar results were observed in dermo run 2, where the KPI was calculated for BUCs ES-1a, ES-1b and ES-3.

For i-DE, in demo-run 1, there were very few FSPs. The forecast was executed for one FSP in Murcia pilot site (BUCs ES-1a, ES-2 and ES-4) and one in Albacete pilot site (BUCs ES-1a, ES-2). The MAPE was calculated only for the period in which the test was performed and was equal to 5.18% for the FSP in Alicante and 1.78% for the FSP in Murcia.

3.1.24.2 Greek demo

Table 70: KPI 24 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a GR-1b GR-2a GR-2b		**Kefalonia:** 4.1% **Mesogia:** 3.6%

This KPI acts as an indicator which calculates a deviation metric between the estimated and the predicted values of load demand calculated 1 hour in advance. The metric used is the mean absolute percentage error, therefore, the error is given as a percentage of the real load value at each time step. The calculated error metrics, for both cases are similar to the state-of-the-art algorithms. The task of estimating the load demand 1 hour in advance, is mainly a very-short-term time-series based forecasting problem. That means that the forecasting process is using as input the temporal information of the time-series as well as very-short-term exogenous variables that might affect the energy consumption by end-users, such as temperature. Furthermore, the difference between the MAPE values of the two test cases is caused by the different location based human behavior and different local weather phenomena, but still within acceptable range of error.

3.1.25 KPI 25 – Accuracy of load forecast calculated 24 hours in advance

This indicator measures the Mean Absolute Percentage Error (MAPE) of the load forecast 24 hours in advance in transmission and distribution systems.

3.1.25.1 Spanish demo

Table 71: KPI 25 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI:** 9.45% **i-DE:** Alicante: 21.99% Murcia: 13.45%	**e-DI:** 9.45%
	ES-1b		
	ES-2	**e-DI:** 9.45% **i-DE:** Alicante: 21.99% Murcia: 13.45%	
	ES-3		**e-DI:** 9.45%
	ES-4	**e-DI:** 9.45% **i-DE:** Murcia: 13.45%	

The accuracy of load forecasting for 24 hours in advance was also investigated. The MAPE was calculated for the same FSPs, as for KPI 24. For e-DI, MAPE was equal to 190.57% when all the nodes are taken into account which is a very high value. However, this value is due to two nodes with extremely high values. When these two nodes are not taken into account, MAPE is equal to 9.45% showing a good performance of load forecasting 24 hours in advance. Similar results were observed in dermo run 2, where the KPI was calculated for BUCs ES-1a, ES-1b and ES-3.

For i-DE, as for KPI 24, the MAPE was calculated only for the period in which the test was performed and was equal to 21.99% for the FSP in Alicante and 13.45% for the FSP in Murcia.

3.1.25.2 Greek demo

Table 72: KPI 25 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a, GR-1b, GR-2a, GR-2b,		**Kefalonia:** 8.2% **Mesogia:** 6.36%

This KPI acts as an indicator which calculates a deviation metric between the estimated and the predicted values of load demand calculated 24 hours in advance. The metric used is the mean absolute percentage error, therefore, the error is given as a percentage of the real load value at each time step. The calculated error metrics, for both cases are aligned with the state-of-the-art algorithms. The task of estimating the load demand 24 hours in advance, is mainly a short-term time-series based forecasting problem. That means that the forecasting process is using as input the temporal information of the time-series as well as short-term exogenous variables that might affect the energy consumption by end-users, such as temperature.

Furthermore, the difference between the MAPE values of the two test cases is caused by the different location based human behavior and different local weather phenomena, but still within acceptable range of error.

3.1.26 KPI 26 – State estimation performance evaluation

This indicator consists of three sub-indicators: 1) The first sub-indicator will measure the Mean Absolute Error (MAE), the Root Mean Squared Error (RMSE) and the Maximum Error (ME) between the true (or the measured) and the estimated system state. 2) The second sub-indicator will measure the Autocorrelation Function (ACF) to evaluate the properties of a time series, which in this case is the estimated system state. It is, therefore, necessary to verify whether the residuals $\hat{y}_t - \hat{y}_{t-1}$ are noncorrelated, where $\hat{y}_t$ is the estimated system state at time-step t. If the residuals are non-correlated, the ACF should be within the noise margins $\pm 1.96/\sqrt{Ns}$ with 95% of probability, where Ns is the total number of time-steps. The ACF is plotted for the first $\sim\sqrt{Ns}$ lags. 3) The third sub-indicator will measure the Refresh Rate (RR) of the state estimation process.

Although this KPI was defined during the first stages of the project, it has not been calculated due to the absence of available measurements. In particular the state estimation tool was tested in the Greek demo. However, the number of available measurements where not sufficient for the convergence of the algorithm, therefore a load flow algorithm was used instead.

3.1.27 KPI 27 – Market utilization factor

This indicator measures the estimated number of times, more specifically the total duration that the market is being used annually but is limited to the examined period of time. Units are given in hours. This KPI has been calculated only for the BUCs SE-1a and SE-1b of the Swedish demonstration.

3.1.27.1 Swedish demo

Table 73: KPI 27 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 250 hours **Skåne:** 26 hours **Gotland:** 80 hours	**Uppland:** 631 hours **Skåne:** 35 hours **Gotland:** 29 hours	**Uppland:** 71 hours **Skåne:** 30 hours **Gotland:** 4 hours
	SE-1b		**Gotland:** 120 hours **Jämtland/Västern N.:** 240 hours	

The load in Uppland, but also in Skåne area, is strongly seasonal and the need for flexibility is restricted to the winter season when temperatures are low. To estimate the annual utilization of the flexibility market, KPI 19 serves as basis with the addition of two months representing the required flexibility for January and March. To set the estimation in the right context, it shall be noted that the winter 2019/2020 (demo run 1) was warmer (>+1°C on average) than any previous winter.

On this basis, the Uppland market has been utilized for 250 hours in the first demo run. This number is an estimated sum of the market outcome, described in KPI 19 of in total 235 unique hours of market utilization plus additional flexibility required to avoid subscription violations further detailed in [6].

Uppland experienced higher market utilization with 631 hours in the winter 2020/2021 (demo run 2), which can be explained by the colder winter during demo run 2 compared to demo run 1. This includes not only the transaction hours but also the hours in which a subscription violation occurred during times when the market was closed (i.e. November to December 2020, as described in [21]). 44% of the trades were caused by forecast errors. The numbers in Table 73 are the remaining 56% that would have been actually traded, given actual congestion and enough availability in the flexibility market. Thus, these numbers indicate the potential market utilization. This results in 71 hours in the third winter.

In Skåne, the market was used for 26 hours in the first winter and 35 hours in the second one. In the third winter, from November 1st 2021 to March 31st 2022, the purchase of flexibility has decreased in all the Swedish demo sites. This is due to high-priced flexibility purchases as few flexibility bids were available in the market due to high electricity prices, which affects the market activity of FSPs. While the average electricity price in SE4 (Skåne) between the month November to March was 28 SEK/MWh in 2019/2020, it increased to 39 SEK/MWh in the winter 2020/2021 and peaked in the winter 2021/2022 with an average price of 116 SEK/MWh. Thus, the prices have a negative impact on the market utilization, which is measurable with the indicator shown in Table 73.

In addition, in parallel to this last demo run, the sthlmflex market [6] was launched. This market operated actively with trades for 50 hours in parallel to the CoordiNet last demo run. In that sense, as CoordiNet was an enabler for sthlmflex and the identified flexibility need and the traded flexibility options are closely related, these values could be counted in addition to the market utilization identified for the Swedish Demo. All flexibility was procured on a day-ahead basis.

Gotland's demonstration periods differ slightly compared to the remaining Swedish pilot sites. The multi-level market was actively used in the first winter for 80 hours. In the second year, two weeks were selected as test periods. In the first test-week, in spring 2021, the flexibility market was utilized for 29 hours. During the second test period, in autumn 2021, wind power generators participated as FSPs. Due to high prices flexibility bids were not cleared in this second test week in Gotland. In the third winter, the market in Gotland was operated for 121 days with major transactions between December and March. As detailed in [21], flexibility providers were fewer in this last demo run due to maintenance and revision. Thus, for the remainder of the last winter period FSPs did not get active in the market, which explains the lower amount of market utilization in 2022.

The P2P market mechanism has been tested during the second winter. With that, 1 hour of flexibility have been contracted via the market for the Gotland pilot site in demo run 2 within the defined distributed market scheme. Furthermore, by means of the P2P market, also the Northern Swedish pilot site in Jämtland/Västern Norland experienced an active market utilization for 240 hours, in demo run 2.

Finally, in the third winter the P2P market was not actively used. Reasons such as low prices, fewer flexibility need and missing experience in the flexibility capacity of active peers, have led to a low interest in this market. This aspect is further elaborated in [21].

3.1.28 KPI 28 – Increased grid connections

This indicator measures the ratio of increased grid connections and serves as one measure to monitor an increased security of supply. The increased grid connection is given as new feasible grid connections (Unit: MW) which can be added to the underlying subscription level.

3.1.28.1 Swedish demo

Table 74: KPI 28 value in the Swedish demonstrator

Demo	BUC	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 20.4 MW **Skåne:** 0 **Gotland:** 0.7 MW	**Uppland:** 20.4 MW **Skåne:** 0 **Gotland:** *
	SE-1b	**Gotland: *** **Jamtland/Vastern: ***	**Gotland: *** **Jamtland/Vastern: ***

* KPI not possible to analyse due to small volumes of flexibility

Per decision by the DSO, Vattenfall in Nov 2020, additional connections of ~20,4 MW are allowed, considering the ability to handle congestion within CoordiNet. However, this does not inherently reflect the amount of additional connections that can be granted within the system. The actual amount of MW that can be connected depends on the specific load profiles and locations of the new customers. These two factors are determined by two aspects:

1. the similarity factor (Swedish "sammanlagringsfaktor") that determines the fraction a customer's peak load to coincide/be added to the overall peak load of the congested connection point.
2. the Power Transfer Distribution Factors (PTDF, also called impact factor or in Swedish "påverkansfaktor") which consider the power flow during peak loading and the amount of additional consumption that will be drawn from the connection point with congestion.

In Uppland, an increase of 20.4 MW could be realized with the CoordiNet activities during demo run 2. Also, in Gotland an increase in connection capacity by 0.7 MW was realized.

The reason for no increased grid connection in Skåne can be explained with the need to have a certainty of the flexibility delivery and its ongoing availability as well as its impact on the congested connected point (PTDF). With future higher liquidity, eventually the grid connection could be increased. Especially, with a mix of measures to mitigate congestions in the grid, also in Skåne area more customers will be connected. However, it is difficult to predict how many more customers could be connected, due to the new flexibility options alone. The experience with continued operation of the flexibility market for congestion management in the winters of 20/21 and 21/22 have contributed to increased confidence of the market as a concept utilized for allowing more grid connections. Even so, the market liquidity, and more specifically the availability of flexibility bids needs to improve in order to feel confident enough to allow additional connections solely based on the flexibility market.

As described in [6], in Sege-Arrie in Skåne, an increased grid capacity was arranged with the transmission system operator through non-CoordiNet related activities. Thus, while the same market solution as given in the second demonstration run was applied, the participation in the flexibility market was not necessary. However, at the same time, for the long run availability contracts have been discussed and tested under the term free bids [6] between FSPs and DSOs to develop a higher confidence in the flexibility service. By this design, an increase of grid capacity through flexibility utilization can be more likely in the future.

3.1.29 KPI 29 – Capacity increase with reactive management

This indicator measures the percentage difference, or in other words percentage increase, in capacity (Apparent Power) as result of using the market platform and products proposed by CoordiNet.

3.1.29.1 Spanish demo

Table 75: KPI 29 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1b		0 MVA
	ES-3		Inductive product: 17.57% Capacitive product: 11.81%

Regarding e-DI, the values of active and reactive power provided in KPI 2 were used to calculate the percentage difference between the BaU and R&I scenarios. The average percentage increase considering the inductive and capacitive product is presented in the above table. It is observed that in both cases the increase is over 10%. The largest increase is observed for the inductive product, where it is equal to 17.57%. Concerning i-DE and BUC ES-1b, no capacity increase was considered. Congestion management can reduce congestions. However, to consider a capacity increase, FPSs should be available when there is a need, which is not guaranteed.

3.1.30 KPI 30 – Peak load demand reduction

This indicator measures the maximum percentage decrease of peak load demand in an area by a flexibility provider resource.

3.1.30.1 Spanish demo

This KPI was expected to be only calculated by one DSO, e-DI. However, finally, it was not possible to perform such calculation, since the required data were not available.

3.1.31 KPI 31 – Total activation time of a product

The indicator measures the total time of product activation. It will allow knowing the use of a product.

3.1.31.1 Spanish demo

Table 76: KPI 31 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**REE (DA):** 1,312 h **REE (NRT):** 992 h	e-DI: 4.2 hours
	ES-1b		e-DI: 2.75 hours i-DE: 1 hour
	ES-2	REE: 9,260 h	
	ES-3		e-DI: 2 hours i-DE: 3.75 hours

The calculation of this KPI is directly linked to KPI 22 – Requested flexibility. While for KPI 22 the amount of requested flexibility is calculated, this KPI assesses the total activation time. The explanation provided in 3.1.22.1 is also applicable for this KPI. Table 76 shows the overall system results in demo run 1 and 2.

During demo run 1, this KPI was only calculated for BUCs ES-1a and ES-2 by REE, the Spanish TSO, considering that, since demo run 1 focuses on demo areas of high-voltage networks managed by the DSO, the FSPs connected to such grids are already participating in the markets managed by the TSO [22], It can be considered that the common congestion and the central balancing markets are those ones already existing in the Spanish system. Therefore, the values included in Table 76 for demo run 1 were gathered at system-level from the already existing markets for the first semester of 2021, considering only renewable technologies,

On the contrary, during demo run 2, e-DI and i-DE, the Spanish DSOs, activated the specific products developed within CoordiNet project in order to test BUCs ES-1a, ES1-b and ES-3 in their demo-sites. Thus, according to [15], e-DI activated the common congestion management market (BUC ES-1a) for 4.2 hours, the local congestion management market (BUC ES-1b) for 2.75 hours and the voltage control (BUC ES-3) for 2 hours. Likewise, i-DE indicates an activation time of 1 hour for the local congestion management (BUC ES-1b) and 3.75 hours for the voltage control (ES-3).

3.1.32 KPI 32 – Delivered energy in controlled islanding

This indicator measures the total energy supplied to the island. It is calculated as the sum of the net energy supplied by the FSPs and the net energy supplied by other generators. The net energy provided by the FSPs shows if the island lasted as requested, while net energy provided by other generators shows the increase in generation availability (in case of an outage).

3.1.32.1 Spanish demo

Table 77: KPI 32 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	**ES-1a**		
	ES-2		
	ES-3		
	ES-4	**i-DE:** 1,235 kWh	

During the Spanish tests of ES-4, once disconnected from the rest of the grid, the whole electrical island could be maintained by the FSPs, namely a PV generator and a battery. The PV provided the bulk of the energy required by the loads in the island, while the battery could act as a “local balancing” resource. It is worth mentioning that the battery played the crucial role of balancing the energy locally, maintaining stability within the island. The tests of BUC ES-4 demonstrated the technical feasibility of the islanding mode, maintaining the supply within technical limits.

This KPI is only calculated in the Spanish Demo Run 1, considering that the BUC ES-4 was only demonstrated at the first demonstration period.

3.1.33 KPI 33 – Maximum power (non-transient) in controlled island

This indicator measures the maximum power of the island, ignoring transients. This could be used to assess to which extent the service allows to create the island depending not only on the FSPs but also on other generation. The indicator is equal to the maximum of the sum of power provided by the FSP and other generators.

3.1.33.1 Spanish demo

Table 78: KPI 33 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a		
	ES-2		
	ES-3		
	ES-4	945 kW	

Together with KPI 32, this KPI helped gauge the performance of the islanding BUC in the Spanish demonstration. A maximum power (non-transient) of 945 kW was measured in the electrical island. At this particular time during the test, the output of the PV was 1,165 kW, while the battery absorbed (charging state) 220 kW in order to supply the 945 kW, representing 77% of the peak demand of the considered grid. This KPI, as KPI 32, highlights the complementarity between the two types of FSPs involved in the demonstration, as the PV delivered the necessary power for supplying the loads and the battery provided the flexibility to maintain stability.

This KPI is only calculated in the Spanish Demo Run 1, considering that the BUC ES-4 was only demonstrated at the first demonstration period.

3.1.34 KPI 34 – Percentage of tested products per demo

This indicator measures the percentage of products tested in the demos with respect to the number of products initially targeted by the demos.

3.1.34.1 Spanish demo

Table 79: KPI 34 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI:** 100% **i-DE:** 100%	**e-DI:** 100%
	ES-1b		**e-DI:** 100% **i-DE:** 100%
	ES-2	**e-DI:** 100% **i-DE:** 100%	
	ES-3		**e-DI:** 100% **i-DE:** 100%
	ES-4	**e-DI:** 100%	

For the Spanish demo, all targeted products were also tested. For balancing products (BUC ES-2) for e-DI, these were mFRR and RR. However, it should be noted that RR was not tested directly in the demos (only mFRR was tested directly). This is because the RR product is directly related to the LIBRA platform to which the TSO does not have direct access. Nevertheless, the type of message and platform interaction of this product is the same as for mFRR and therefore it has been considered that both products have been tested. For i-DE, mFRR was also tested in the Coordinet Common Platform testing environment. The results for RR are assumed to be similar.

For Common congestion management (BUC ES-1a), the non-reserved congestion management product was tested in NR and DA market timeframes as targeted for e-DI. For i-DE, non-reserved congestion management product was also tested as targeted, both in NRT and DA market timeframes.

For BUC ES-3, initially the steady-state reactive power product was targeted and it has been tested during the demos.

Finally, with regard to the controlled islanding BUC (ES-4) the product was tested in a testing environment, as there was no outage in the examined period.

3.1.34.2 Swedish demo

Table 80: Tested products in the demo run 1 of the Swedish demonstration

Demo Run 1	Uppland	Skåne	Gotland	Jamtland
Congestion reserved	1	1	1	NA
Congestion non-reserved	1	1	1	NA
Congestion P2P	NA	NA	0	0
Balancing	0	0	NA	NA
System services	NA	NA	1	NA

Table 81: Tested products in the demo run 2 of the Swedish demonstration

Demo Run 2	Uppland	Skåne	Gotland	Jamtland
Congestion reserved	1	1	1	NA
Congestion non-reserved	1	1	1	NA
Congestion P2P	NA	NA	1	1
Balancing	0	0	NA	NA
System services	NA	NA	1	NA

Table 82: Tested products in the demo run 3 of the Swedish demonstration

Demo Run 3	Uppland	Skåne	Gotland	Jamtland
Congestion reserved	1	1	1	NA
Congestion non-reserved	1	1	1	NA
Congestion P2P	NA	NA	1	1
Balancing	1	1	NA	NA
System services	NA	NA	1	NA

The products tested in the Swedish demonstration are summarized in Table 80-Table 82. They depend on pilot site and on demo run. It is observed that going from the first to the last demo run the number of tested products increases and in demo run 3 all the targeted products were tested. In demo run 1, only the DA markets are tested. From demo run 2 onwards, both the DA and the ID markets are tested. As can be seen in the tables below, the system services product is only tested in Gotland. While balancing services are only tested in Uppland and Skåne in the third demo run. P2P products are only tested in Gotland and Jamtland, but only starting from demo run 2. Congestion products (both reserved and non-reserved) are tested from the first demo run onwards in Uppland, Skåne and Gotland.

3.1.34.3 Greek demo

Table 83: KPI 34 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a		100%
	GR-1b		100%
	GR-2a	50%	100%
	GR-2b		100%

In total, there are 4 products in the Greek demo: reserved congestion management, non-reserved congestion management, steady state reactive power and active power. In the demo run 1, only congestion management was tested (both reserved congestion management and non-reserved congestion management) and therefore 50% of the products was tested. In demo run 2, all products are tested.

Table 84: Product per service for KPI 34 in the Greek demo

Service	Products	Demo run 1	Demo run 2
Congestion management	Reserved congestion management	Yes	Yes
Congestion management	Non-Reserved congestion management	Yes	Yes
Voltage control	Steady state reactive power	No	Yes
Voltage control	Active power	No	Yes
	Number of tested products	2	4
	Percentage of tested products (%)	50	100%

3.1.35 KPI 35 – Ratio of forwarded flexibility bids

This indicator measures:

a) the ratio of flexibility bids forwarded from a LV DSO market to a MV DSO market, and
b) the ratio of flexibility bids forwarded from HV DSO market to the central balancing market.

The total volume of the energy-based flexibility bids is given in MWh, of which certain volumes are forwarded for local or central services, i.e., congestion management or balancing purposes, thus realizing a multi-level market scheme. Thus, this KPI only considers the BUC SE-1a. This can be realized with a consecutive market procedure. Unused bids of earlier closing markets can be forwarded, if they fulfil technical and contractual requirements of the following markets. The main idea is here to commit to first local, then regional and then central market scopes.

3.1.35.1 Swedish demo

Table 85: KPI 35 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	**SE-1a**	**Uppland:** 100% **Skåne:** 100% **Gotland:** 100%	**Uppland:** 100% **Skåne:** 90% **Gotland:** 80%	**Uppland:** 100% **Skåne:** 100% **Gotland:** 100%

In demo run 1, all bids at the pilot sites of Uppland, Skåne and Gotland have been forwarded from a LV DSO to the MV/HV DSO market for congestion management, as there was the main flexibility need in the HV grid segment. Forwarding bids to the TSO domain did not take place, since the FSPs did not prequalify for the mFRR market. In demo run 2, not all bids, in total 90% and 80% have been forwarded in the demo in Skåne and Gotland, respectively. This shows, that in parts, also the local system operators have utilized flexibility in the area of Skåne and Gotland. Table 85 includes the values of the LV-MV forwarding only, which is 100% for each demo site in the third winter, too. Moreover, in the third demo, forwarding to a central market was tested, too. For instance, in Uppsala, a battery with 5 MW and 20 MWh was pre-qualified for the purpose of participating both, to the CoordiNet markets and the mFRR market. An integration and utilization of the battery could however not be finalized within the final CoordiNet demo due to pending security checks and thus no forwarding effectively happened for this asset.

However, a battery of 0.48 MW and 1 MWh in Skåne did successfully participate in CoordiNet in parallel to the TSO frequency balancing market with the so called FCR-D product, i.e., a minimum bid size of 0.1 MW with an activation of downward flexibility in shortest time. This successful test shows that the time coordination and thus optional forwarding between the markets is functional.

The forwarding option to the central markets that are relevant for the transmission system is specifically interesting for FSPs with high availability. With that, the potential liquidity in multiple levels of markets can be increased with a joint set of flexibility resources. From the FSP perspective, the amount of potential revenue streams increases likewise. However, as the minimum bid size is 1 MW for at least one hour, hardly FSPs from the lower-level grids did qualify for the mFRR market. In addition, the prequalification process is time-consuming, as described in [6], which is further hindering the previously designed forwarding concept. In summary, the market for frequency balancing has gained interest and offers potential for batteries, for instance in the FCR-D which allows a participation as of 0.1 MW for downward capacity. In the final stages of the CoordiNet demonstrations a parallel and not consecutive procurement was realized. The multiple levels of congestion and balancing markets is of higher interest for FSPs. This concept thus would allow a 100% forwarding of bids.

3.1.36 KPI 36 – Participant recruitment

This indicator measures the percentage of users which accepted their participation in the demo in relation with the total amount of users contacted to participate in the demo. This indicator is used to evaluate the user engagement plan.

3.1.36.1 Spanish demo

Table 86: KPI 36 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI:** 100% (2 out of 2 FSPs) **i-DE:** 66.66% (4 out of 6 FSPs)	
	ES-1b		**e-DI:** 100% **i-DE:** 66.66%
	ES-2	**e-DI:** 100% (2 out of 2 FSPs) **i-DE:** 66.66% (4 out of 6 FSPs)	
	ES-3		**e-DI:** 100% **i-DE:** 66.66%
	ES-4	**e-DI:** 100% (2 out of 2 FSPs) **i-DE:** 66.66% (4 out of 6 FSPs)	

In demo run 1, two FSPs were contacted to participate in the demonstrations of e-DI, Ayuntamiento de Malaga and Enel Green Power. Both accepted to participate. Enel Green Power has voluntarily accepted to participate in the demonstrations that took place in Cadiz and Malaga, while Ayuntamiento de Malaga accepted to participate in the demonstration that took place in Malaga. Both FSPs own several units. In particular, 5 and 2 units of Enel Green Power accepted to participate in Cadiz and Malaga pilot sites, respectively, while 4 units of Ayuntamiento de Malaga accepted to participate in the Malaga pilot sites.

In demo run 2, the two same FSPs (Ayuntamiento de Malaga and Enel Green Power) accepted to participate in the demo through cascading funds. Through the use of the cascading funds, further FSPs owned by the client Malaga Tech Park participated in the demonstration.

In demo run 1 and 2, 6 different types of FSPs, that are usually interested in innovation, were contacted to participate in the demonstrations of i-DE. In particular, a municipality, a big generation company, a cogeneration, a big industrial demand, a hotel owners association and ceramist factories were contacted. Four of them accepted to participate. It is noted that in demo run 1, no incentives could be offered and it was not possible to reimburse the provided service, making it difficult to engage the FSPs.

3.1.36.2 Greek demo

Table 87: KPI 36 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a GR-1b	**Mesogia:** 94.4%	95%

In demo run 1, a small CHP, a residential battery, 64 customers and 5 backup diesel gensets were contacted to participate in the Mesogia pilot site. Initially, it was planned that the gensets will participate in the Kefalonia pilot site. Due to the difficulties described in D5.5 [23], it was determined that the gensets will eventually participate in the Mesogia pilot site. However, only 1 out of 5 gensets that were contacted replied positively regarding its participation in Mesogia. The small CHP and the residential battery belong to NTUA and therefore their participation was certain. Moreover, 64 customers were contacted with the aim to install

SLAMs to public buildings, offices and schools. All of them expressed their interest in participating in the demonstrations. The aforementioned contacted users are presented in Table 88.

Table 88: Users contacted and accepted to participate in the Mesogia pilot site

	Small CHP	Residential battery	Customers	Diesel Genset	Total
Users accepted to participate in the demo	1	1	64	1	67
Users contacted to participate in the demo	1	1	64	5	71
				Percentage	94.4%

Similar results were observed in dermo run 2, where the contacted users who accepted to participate in the Mesogia pilot site's demonstration have been slightly raised.

3.1.37 KPI 37 – Active participation

This indicator measures the percentage of users actively participating in the CoordiNet demonstration activities with respect to the total users that accepted the participation. This indicator is used to evaluate the customer engagement plan. The KPI has been calculated for Spain, Sweden and Greece.

3.1.37.1 Spanish demo

Table 89: KPI 37 value in the Spanish demonstrator.

Demo	BUC	Demo run 1	Demo run 2
Spanish	**ES-1a**	**E-DI:** 100% (2 out of 2 FSPs) **I-DE:** 66.66% (2 out of 3 FSPs)	E-DI: 100% (3 out of 3 FSPs)
	ES-1b		E-DI: 100% (3 out of 3 FSPs) I-DE: 100% (3 out of 3 FSPs)
	ES-2	**E-DI:** 100% (2 out of 2 FSPs) **I-DE:** 66.66% (2 out of 3 FSPs)	
	ES-3		E-DI: 100% (3 out of 3 FSPs) I-DE: 100% (3 out of 3 FSPs)
	ES-4	**E-DI:** 100% (2 out of 2 FSPs) **I-DE:** 66.66% (2 out of 3 FSPs)	

This KPI has been calculated for the Spanish demo in an overall way of the FSPs connected to the grid of each of the two DSOs, E-DI and I-DE, for all BUCs tested in each demo run.

In demo run 1, the BUCs ES-1a, ES-2 and ES-4 were tested and with the same FSPs connected to each DSO grid. For e-DI, all FSPs, that accepted to participate, participated in the market tests actively. For i-DE, one FSP that accepted to participate, will participate only in demo run 2. Concerning the other FSPs, all but 1 FSP, participated in the market test actively. The FSP not participating was not able to do the prequalification following the new regulation changes for balancing but is expected to participate in demo run 2.

In demo run 2, the BUC of ES-1a, ES1b and ES-3 were tested. Both for E-DI and I-DE all 3 FSPs in each grid that have accepted to participate in the demonstration also did so actively. For the BUC ES-1a, I-DE made all tests in demo run 1 and did not repeat the tests is demo run 2.

3.1.37.2 Swedish demo

Table 90: KPI 37 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 83% (5 out of 6 FSPs) **Skåne:** 100% (5 out of 5 FSPs) **Gotland:** 100% (2 out of 2 FSPs)	**Uppland:** 82% (9 out of 11 FSPs) **Skåne:** 89% (8 out of 9 FSPs) **Gotland:** 75% (3 out of 4 FSPs)	**Uppland:** 45% (5 out of 11 FSPs) **Skåne:** 50% (3 out of 6 FSPs) **Gotland:** 33% (1 out of 3 FSPs)
	SE-1b		**Gotland:** 100% **Jämtland/Vastern:** NA	

The KPI has been calculated for all the pilot sites of BUC SE-1a, as well as for BUC SE-1b. As the P2P market tested in BUC SE-1b, was only tested during demo run 2, the KPI has not been calculated in demo run 1 and 3. Regarding BUC SE1-a, the tests were performed and the KPI has been calculated for all three demo runs.

In Uppland, in demo runs 1 and 2, only one and two participants, respectively, that had agreed to participate did not participate actively in the market. This had a higher impact on demo run 1 as there were only 6 participants that had agreed to participate, compared to 11 in demo run 2. The ratio of active participation stays at the same level, decreasing from 83% to 82%, even though the participants almost doubled between the demos runs. In demo run 3, only 5 of 11 FSPs participated actively. The explanation for this can be found in that the third winter was the coldest with the most hours below zero of the three winters. The electricity prices skyrocketed and became in average 3-4 times higher than the previous winter which reduced usage and hence availability of flexibility from some SGUs. This affected all the Swedish demo sites. In Uppland, one FSP also left the market as the FSP wanted a more capacity oriented market compared to the CoordiNet market.

In Skåne, the active participation decreased from demo run 1 to demo run 2 by 11%. This was mainly because one of the FSPs that had agreed to participate ultimately did not participate. However, the participants increased from 5 to 9. In demo run 3 the total number of FSPs decreased to 6, and of these only 3 participated actively in the demonstration, lowering the ratio to 50%. At one TSO connection point, a more formal way of procurement of capacity according to the national Public Procurement Act was required. This caused a high barrier for many potential FSPs in the area. At another TSO connection point a higher subscription with the TSO was established this winter and the interest in participating in this market decreased since there was no longer a real need for the flexibility. Also, an already registered FSP during the last winter left the market due to environmental restrictions limiting the ability to provide flexibility.

The island of Gotland had good results in actively participation in demo run 1 with 100%, as the 2 FSPs that had agreed to participate took part in the demonstration. In demo run 2, the accepted FSPs doubled with only one of these not actively participating, decreasing the ratio to 75%. Hence, the overall participation in the market increased. In demo run 3, 3 FSPs were registered for the market but only 1 of these participated actively. One reason for this was that the largest flexibility provider, a heat pump from the district heating company, was taken out of service due to a fault that needed repair.

In BUC SE-1b, the pilot site of Gotland had a 100% participation in demo run 2 when this BUC was tested. In Jämtland/Västernorrland P2P market, no bids from the 3 FSPs accepted to participate were cleared, since the planned maintenance, and thereby the reason for the reduced subscription, was cancelled shortly before the market launch.

Regarding the FSP engagement strategy and the factors that affected the FSP participation in the Swedish demonstration, more details can be found in D4.7.1 [5] , D4.5 [21] and D4.1 [9].

3.1.37.3 Greek demo

Table 91: KPI 37 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a GR-1b	**Mesogia:** 100%	Mesogia: 100% Kefalonia: 100%
	GR-2a GR-2b		Kefalonia: 100%

In demo run 1, only BUCs GR-1a and GR-1b at the Mesogia pilot site were tested. The active participation in this site was 100%, as all FSPs that have accepted to participate (see Table 88 in KPI 36), later also did so actively. The FSPs accepted and were active in the demo run were the following: 1 small CHP, 1 residential battery, 64 consumers and 1 diesel genset. To attract the consumers and diesel genset to the Mesogia demo site, the Greek demonstrator worked with emails and social media campaigns, as well as workshops and face-to-face meetings [12].

In demo run 2, both the Mesogia and Kefalonia pilot sites were tested for BUC GR-1a and GR-1b, as well as for GR-2a and GR-2b. The active participation for both sites was 100% as the FSPs that had accepted to participate in the demonstrations, later also did so. Besides the FSPs mentioned for demo run 1, 6 irrigation pumps participated actively in the pilot site of Kefalonia.

3.1.38 KPI 38 – Type of flexibility providers per demo

This indicator reflects how versatile the demonstrators are in leveraging flexibility from different technologies. The demonstrators aspire to make use of flexibility from different technologies. If and how different types of technologies can actually be accessed and utilized during the demo phase depends on the number of different technologies that are available in the region of the demos as well as on the general capabilities of the demo. This indicator is measured as the relation between the number of different technologies leveraged in the demo and the number of main types of technologies initially identified by the project. The following technologies are considered for the KPI calculation:

- Renewables
- Conventional generators connected to the distribution system
- Conventional generators connected to the transmission system
- Aggregators
- Consumers
- Storage
- Electrical vehicles

3.1.38.1 Spanish demo

Table 92: KPI 38 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	ES-1a	**e-DI:** Cadiz - 50% **i-DE:** 66%	**e-DI:** Cadiz - 50% Malaga - 83%
	ES-1b	**e-DI:** Cadiz - 50%	**e-DI:** Cadiz - 50% Malaga - 83% **i-DE:** 100%
	ES-2	**e-DI:** Cadiz - 50% **i-DE:**100%	**e-DI:** Cadiz - 50% Malaga - 83%
	ES-3	**e-DI:** Cadiz - 50%	**e-DI:** Cadiz - 50% Malaga - 83% **i-DE:**66%
	ES-4	**e-DI:** Cadiz - 50% **i-DE:** 100%	**e-DI:** Cadiz - 50% Malaga - 83%

For the Spanish demonstrator, for demo run 1, different technologies are available for e-DI and i-DE per region. The technologies are common to all BUCS for e-DI and i-DE respectively. For e-DI, in Cadiz, renewables (windfarms) and conventional generators connected to the distribution system are available. Yet, only RES have been utilized, leading to a 50% usage of available technologies. In Malaga, six technologies are available (renewables, conventional generators connected to the distribution system, aggregator, consumers, storage and electrical vehicles). All of them were used.

For i-DE, the FSPs implied in each BUC are the following: in the Balancing BUC (BUC-ES-2), target technologies were wind and hydro generation. However, due to lack of sufficient hydro capacity the day of the test, it was considered only one target technology. For the Congestion management BUC (BUC-ES-1), the target technologies were wind, hydraulic, CHP and demand. The hydraulic was disregarded for the same reason as in the previous case. Out of the other 3 technologies, the demand failed (it was not qualified as BSP in advance). For the Controlled islanding BUC, the only targeted technology was the battery.

For demo run 2, i-DE had 2 out of 3 wind farms and cogeneration resources that took part in the demo. Hydro generation was not operating during demo run 2 as it did not take place during the generating season. With regard to local congestion management, only demand through an aggregator participated in the demo. For e-DI, RES was connected to the distribution grid and has been utilized in Cadiz. In Malaga, EVs were not in scope leading to 5/6 technologies (83%) being tested. EVs were not used due to technical limitations.

3.1.38.2 Swedish demo

Table 93: KPI 38 value in the Swedish demonstrator

Demo	BUC	Demo run 1	Demo run 2	Demo run 3
Swedish	SE-1a	**Uppland:** 50% **Skåne:** 25% **Gotland:** 25%	**Uppland:** 75% **Skåne:** 50% **Gotland:** 25%	**Uppland:** 50% **Skåne:** 13% **Gotland:** 63%
	SE-1b		**Gotland:** 25% **Jamtland/Vastern:** 13%	
	SE-3			

Analysing Table 93, it is shown that most Swedish pilot sites have increased their usage of a wider variety of flexibility technologies. In the Swedish demonstrator, all types of flexibility providers, except generators connected to the transmission system are present, covering a large width of technology types. There are some differences between the demo sites. For instance, Gotland, being a small island, cannot be expected to cover all resources. Furthermore, the demo sites did efforts to attract new FSPs. For instance, Skåne did not have electrical vehicles in the first and second demo run, but they did in the third demo run. In the third winter, Skåne did see a significant decrease in FSPs due to the increased capacity in Sege-Arrie. For reasons explained in D4.7.1 [6], the interest in participating at this market decreased since there no longer was a real need for the flexibility at this point. This, in combination with the new requirements on the procurement process in Söderåsen, caused a decrease in both number of FSPs, due to the sharp need of flexibility there.

3.1.38.3 Greek demo

Table 94: KPI 38 value in the Greek demonstrator

Demo	BUC	Demo run 1	Demo run 2
Greek	GR-1a&b GR-2a&b	**Mesogia:** 83.33%	**Mesogia:** 100% **Kefalonia:** 100%

In the end, in Mesogia, there were mostly renewables and consumers who offered their flexibility. As can be seen in the Table 95, there are also other FSPs (A small CHP, a residential battery and a diesel generator). Electric vehicles and conventional gensets for the TSO were not present in the demo. As indicated in the introduction of the Greek demo, it should be noted that the RES FSPs are only monitored, but not controlled. A percentage of the production is submitted to the market platform as a 'virtual' bid. Measurements of RES (WFs and PVs) are used to forecast RES production.

Table 95: FSPs in Mesogia pilot site

FSP	No. of FSPs	
Renewables	118	PVs (Medium Voltage)
Conv. Gen. to DSO	1	small CHP
Conv. Gen. to TSO	0	
Aggregators	1	Aggregator for demand management
Consumers	64	Households Offices Schools
Storage	1	Residential battery
Gensets	1	Diesel Generator (JD 148 kVA)
Electrical vehicles	0	

In demo run 2, in Kefalonia, there are mostly renewables (PV installations at MV) and renewables, together with some irrigation pumps and back-up Diesel generators, as show in Table 96.

Table 96: FSPs in Kefalonia pilot site

FSP	No. of FSPs	
Renewables	45	PVs (Medium Voltage)
Conv. Gen. to DSO	0	
Conv. Gen. to TSO	0	
Aggregators	0	
Consumers	25	Households
Consumers	7	Irrigation pumps
Storage	0	
Gensets	6	Back up Diesel Generators
Electrical vehicles	0	

3.1.39 KPI 39 – Total computational runtime

This indicator measures the execution time of market clearance under different coordination schemes.

3.1.39.1 Spanish demo

Table 97: KPI 39 value in the Spanish demonstrator

Demo	BUC	Demo run 1	Demo run 2
Spanish	**ES-1a**	REE: <1 s	
	ES-1b		**e-DI:** <15 s **i-DE:** <1s
	ES-2	REE: <1 s	
	ES-3		
	ES-4	REE: <1 s	

The computational runtime of BUCs ES-1a, ES-2 and ES-4 is less than 1 second for all the TSOs platforms regarding the setpoint calculations and market clearance. This is according to the internal design of the REE platforms. This execution time is satisfactory even for a NRT market.

In demo run 2, the total computational runtime of the Local Market Platform to clear the market in BUC ES-1b was less than 15 seconds for e-DI and less than 1 second for i-DE, which is satisfactory.

It is expected that an increase in the number of bids would increase the computational time. However, this increase in computational time would not be critical and would not affect the implementation of the flexibility market.

3.1.39.2 Swedish demo

Table 98: KPI 39 value in the Swedish demonstrator

<table>
<tr><th>Demo</th><th>BUC</th><th>Demo run 1</th><th>Demo run 2</th><th>Demo run 3</th></tr>
<tr><td rowspan="2">Swedish</td><td>SE-1a</td><td></td><td>Uppland: <5 s
Skåne: <5 s
Gotland: <5 s</td><td>Uppland: <5 s
Skåne: <5 s
Gotland: <5 s</td></tr>
<tr><td>SE-1b</td><td></td><td>Gotland: <5s
Jamtland/Vastern: <5 s</td><td>Gotland: <5s
Jamtland/Vastern: <5 s</td></tr>
</table>

The computational time of the market algorithm was less than five seconds in demo run 2 and 3 at all pilot sites where BUCs SE-1a and SE-1b were tested. A centralized solution of the market was implemented at each voltage level in BUC SE-1a and a P2P market was implemented in BUC SE-1b. For both type of markets, the computational runtime was less than 5 seconds which is considered satisfactory even for a NRT market.

In BUC SE-1a, subscription level constraints have been taken into account using the impact factors. Each impact factor indicates the incremental change in real power flow of a substation due to the activation of 1 MW flexibility from a specific FSP downstream of the substation. Using the impact factors, power flow equations are not added in the market clearing problem. Additionally, constraints related to voltage and line capacity limits are not considered, as it has been tested that internal congestions and voltage violations do not occur with the activation of flexibility. This resulted in a mixed-integer linear programming problem with a low number of constraints and hence in the rapid solution of the problem. Although the increase in market participants will lead to a higher computational time, it is expected to remain within acceptable limits allowing the smooth operation of the market even for a large increase in market participants.

In BUC SE-1b, the decentralized solution of the problem led to the rapid solution of the market clearing problem. This BUC was tested with a low number of bids. However, due to the decentralized procedure followed to solve the market, the execution time is not expected to increase significantly with the increase of bids.

3.1.39.3 Greek demo

Table 99: KPI 39 value in the Greek demonstrator

<table>
<tr><th>Demo</th><th>BUC</th><th>Demo run 1</th><th colspan="2">Demo run 2</th></tr>
<tr><td rowspan="4">Greek</td><td>GR-1a</td><td></td><td rowspan="4">Total execution time for local market: 9.6 min</td><td>TSO: 2,86 s</td></tr>
<tr><td>GR-1b</td><td></td><td>TSO: 2.58 s</td></tr>
<tr><td>GR-2a</td><td>Mesogia: <30 s</td><td>TSO: 13.05 s</td></tr>
<tr><td>GR-2b</td><td></td><td>TSO: 10.98 s</td></tr>
</table>

In demo run 1, the computational time of the DA market clearing algorithm of the local market developed in the Greek demonstration is less than 30 seconds. The market algorithm was tested for BUC GR-2a in Mesogia pilot site. 27 feeders were tested, considering also a large number of bids for each feeder. The feeder with the highest number of nodes has 184 nodes. Using impact factors, the power flow equations can be removed from the optimization problem, speeding up the solution of the problem.

The market clearing problem is solved quite fast, even when the number of nodes and bids is large. Hence, it is shown that the developed market algorithm can be used for the implementation of a local market for procuring flexibility.

In demo run 2, the total computational time of the DA market clearing algorithm of the local market developed in the Greek demonstration lasted about 9.6 minutes. The market algorithm was tested for all BUCs in the Greek demo considering also a large number of bids for each demonstration's feeder. If local markets where to be implemented, proper parallelization of the algorithm should take place to ensure minimal toll on execution time.

4 Selection of preferred coordinated schemes and products for system services

The selection of coordination schemes and products for system services is critical for the TSOs and DSOs. The main objective should be to meet the grid needs in the most cost-efficient way.

As mention in D1.3 [4], a one-size-fits-all coordination scheme does not exist. The selection of the implemented coordination scheme depends on several factors, such as the local circumstances, market maturities, regulatory conditions, grid need to be addressed, type of DERs that can provide flexibility, etc. In D1.3 [4], a mapping of coordination schemes and a common nomenclature were proposed by introducing classification layers that highlight the differences between the coordination schemes. The different identified classification layers are:

NEED: "Which System Operator needs will be addressed?". In the classification layer describing the need to be fulfilled by flexibility, a distinction is made between local needs, central needs and the combination of both needs in a certain market set-up. Only needs which will be procured via a market-based approach need to be considered here.

BUYER: "Which stakeholder(s) buy(s) the flexibility to answer a certain need?" The TSO, DSO and commercial parties are typical candidates to buy flexibility. In addition, more distributed buying models could sprout in a future time horizon, in which peers are actually the sole buyers (and providers) in the market.

MARKETS: "How many markets are considered?" The third layer of the classification structure considers the number of markets. In the context of CoordiNet a distinction is made between a single market (i.e., 1), and the existence of multiple markets (i.e., >1).

RESOURCES: "Does the TSO have access to DER?" The answer can be yes or no. If the TSO is allowed to procure flexibility services outside its own monitored area of control, i.e., at the distribution level, the coordination actions between the DSO and TSO will be different and should be intensified.

The proposed coordination schemes are service-agnostic so that they can be applied to different services or even a combination of services, always maintaining a SO-viewpoint. Due to this classification, each coordination scheme presents different advantages and disadvantages leading to important differences in the market implementation. Even for the same coordination scheme, small differences in its implementation could result in a significant difference in the market result.

In addition, for each system service, capacity and energy products can be defined. Product attributes define different characteristics of the products [4]. The selection of power and/or energy products and of their attributes should aim at addressing the grid needs, utilizing the capabilities of the FSPs.

The combination of coordination schemes and products affects the implementation and the efficiency of the flexibility market. This chapter discusses the factors that should be taken into account in order to select the preferred combination of coordination schemes and products and proposes an approach that could be followed for the selection, using insights from the KPI analysis conducted in Chapter 3, as well as the analysis conducted in D6.2 [24] and D6.3 [5]. Furthermore, the most critical KPIs that could be used in this approach are discussed.

4.1 KPIs to support the selection of preferred coordination schemes and products.

Firstly, it is important to note that the choice of coordination scheme is strongly conditioned by local conditions in each country, such as:

•The voltage levels operated by each system operator. The level of coordination required for a meshed sub-transmission network is not the same as that required for a medium voltage network.

•The number and size of TSOs and DSOs. With a larger number of DSOs and TSOs, special coordination means may be necessary.

•Already existing market structure and legacy systems. There may be a pre-existing infrastructure to which the actors are already adapted and which facilitates the implementation of one coordination scheme, or which may even be a barrier to another.

•The case study considered. Network needs and available resources are different and priorities are not always focused on the same type of services.

Therefore, KPIs could be used in the market planning stage to help to determine the suitable combination of coordination schemes and products to address network needs, but they may not be conclusive. This section discusses the most critical KPIs that could be used for the development and implementation of a market-based solution and support the choice.

As mentioned above, the most critical objective is to meet network needs in the most cost-efficient way. Therefore, the first aspect that must be examined is whether the selected combination addresses the network issues (e.g., congestions, voltage limit violations, etc.). Depending on the network needs, different KPIs could be used to evaluate the effectiveness of the selected coordination schemes. For instance, **KPI 12**, that calculates the decrease in the deviation of the voltage on the network nodes, could be used in case the aim is the elimination of voltage limit violations. Furthermore, **KPI 13**, that measures the reduction of the number of criticalities on the network under consideration in terms of overvoltage and overcurrent, could be used when congestions and voltage violations should be addressed.

Assuming that several combinations are capable of meeting the system needs, the most cost-efficient one should be selected. **KPI 3**, that compares the cost of the flexibility market solution with the investment cost required to apply alternative solutions on an annual basis, could be used not only to select the most cost-efficient combination, but also to determine whether the implementation of the solution is economically superior to alternative solutions. Hence, KPI 3 could be calculated for different combinations in the market planning stage to be able to compare them and select the preferred one.

For the implementation of a flexibility market, the necessary ICT infrastructure should be developed to allow FSPs to submit bids and SOs to buy system services. The cost for developing this infrastructure should be taken into account before determining the structure of the market as well as the interactions between the markets. **KPI 20**, that measures the CAPEX of ICT costs that are directly related to the implementation of each coordination scheme, could be used to determine the configuration of the ICT infrastructure. In addition to CAPEX, the expenditures for operating and maintaining the ICT infrastructure should be taken into account. For this purpose, **KPI 4**, that calculates the recurrent costs required to operate and maintain the installed equipment, could be used.

However, ICT costs only represent a very small part of total costs when the market-based solution is implemented [25]. The system service procurement cost is the highest cost of market-based solutions. Thus, **KPI 5**, that measures the cost for services procurement consisting of the cost of reserved capacity and the cost of energy, could be used to analyse the procurement cost for each combination.

Moreover, it is important to examine the scalability of the market-based solution or assess its efficiency in the future. **KPI 6**, that measures the average cost for providing system services in the different markets, could be used to estimate the procurement cost of a scaled-up market or based on the grid needs expected in the future.

Another important aspect is whether market-based solutions assist in using clean energy to address grid needs. **KPI 7**, that measures the potential increase of hosting capacity for DERs and RES, **KPI 8**, that measures the reduction in the amount of energy from RES that is not injected to the grid (even though it is available) due to operational limits of the grid, and **KPI 9**, that measures the ratio of activated energy bids that are fossil-fuel based with respect to the total amount of activated energy bids, are indicators that could be used to check which combination promotes the use of clean energy more effectively.

4.2 Approach to select the preferred coordination schemes and products

The selection of the suitable combination of coordination schemes and products for grid services should take into account several factors. Using the analysis conducted in T6.2 [24] and T6.3 [5] the main factors are listed below:

- **Adequacy of market design in meeting specific needs:** Since the ultimate goal for the implementation of a flexibility market is to meet the grid needs, the most critical factor for the selection of the suitable combination scheme is whether it is able to meet the latter. This depends on the requirements, as well as the national grid characteristics, the maturity of the markets, the current regulatory framework, the type of the FSPs etc.

- **Need for network information sharing:** Depending on the coordination scheme, network information sharing is vital to avoid network constraint violations through the activation of flexibility. This need arises when the TSO can procure flexibility from the FSPs outside of its area of control (e.g., FSPs connected to distribution system). For instance, when a multilevel market model is implemented and the unused bids from the local market are forwarded to the TSO market, network constraints of the distribution system should be taken into account in market clearance to avoid the violation of grid physical limitations. Therefore, the possibility whether sharing network information or not, affects the selection of the appropriate coordination scheme or the appropriate variation of coordination scheme. For example, as presented in D6.2 [24], depending on the variation of the multilevel market model, the need of information sharing can be prevented. However, this requires enough liquidity to ensure that network constraints violations do not occur.
- **Direct or indirect sharing of flexibility:** When a System Operator (SO) can use flexibility bids submitted from FSPs connected outside of its control area, there is a direct sharing of flexibility. For instance, when the multilevel market model is implemented and the TSO can use the flexibility bids submitted from FSPs connected to distribution system, the TSO can use directly the flexibility of these FSPs. However, a SO can also benefit from the flexibility of FSPs connected outside of its control area indirectly. For example, if a DSO aims at solving grid issues without having to balance the total purchased flexibility, this will change the interface flow with the TSO and will create an imbalance to the TSO which has to be solved using the flexibility of the FSPs connected to the transmission system. In that case, the DSO benefits from the flexibility connected to the transmission system indirectly. Therefore, the decision of direct or indirect sharing of flexibility affects the selection of the coordination scheme. This decision depends on several factors. One of these factors is whether network information sharing in terms of grid characteristics or market bids is feasible . When there is a direct sharing of flexibility, network information sharing is necessary for most variations of coordination schemes in order to avoid network constraint violations.
- **Competitiveness**: Market fragmentation could reduce the number of bids available to SO and thus the competitiveness of each fragmented layer. This depends heavily on the liquidity of the market at each layer.

- **Guarantee avoidance of network operational constraints:** This factor is directly related to the network information sharing and the direct sharing of flexibility. If the TSO is able to use the bids from FSPs connected to distribution system and distribution network information is not available to TSO market, then the avoidance of network operation constraints is not guaranteed.

- **Technical and financial barriers to entry in the market:** The selection of coordination scheme should take into account the types and capabilities of FSPs. For example, if the aim is to boost the participation of small-scale FSPs, a local market could be a solution as the products of this market could be designed in order to utilize their capabilities.

- **Timing aspect:** The integration in the timing of the existing market chain of wholesale markets and balancing markets is critical to select the most suitable combination.

- **Economic efficiency of different schemes**: In the coordination schemes, the offers to fulfil the system operators' needs are provided by Flexibility Service Providers (FSPs), which are market participants seeking for sustainable profitability. As in any market, those participants usually act strategically: they behave in their self-interest when choosing their actions (e.g. entering a competition, setting bids, etc.), based on their subjective evaluation of likely events (e.g. market rules, grid status, etc.), and on the possible actions of competitors (e.g. other FSPs) (Geckil & Anderson, 2016). More specifically, FSPs acting strategically set their bid to maximize their profits, taking into account the market set-up (e.g. common, fragmented, multilevel, etc.) and the strategies of other participating FSPs. Thus, the efficiency of the coordination schemes depends on the strategic behaviour of those participants.

5 Conclusions

In this deliverable, an ex-post analysis followed by the final evaluation of the demonstrations is performed. It is based on the calculated KPIs as resulted from the performed demo runs and the respective analysis carried out with the involved demonstrations partners. Moreover, challenges and opportunities identified in the performed demo runs of all demonstrations are reported. As stated at the beginning of this document, the three demonstrations display quite different characteristics, hence, the comparison between them is not reasonable and therefore the conducted analysis and conclusions is presented for each demo separately.

Spanish demo

The conclusion of the KPIs for the Spanish demo highlights that the proposed TSO-DSO coordination schemes for 'BUC ES1a Common Congestion Management', 'BUC ES1b: Local Congestion Management' and 'BUC ES3: Voltage Control' show an effective procurement of these flexibility services, in the cases presented by both TSO and DSOs. The Spanish pilot is a clear example of what has been mentioned about voltage levels and the coordination required. For the lower voltage levels (MV and LV), a local market has been chosen, with the corresponding information to the TSO of the required data. For higher voltage levels, the common market has been chosen. These results unveil the successful execution of processes such as the limitation of the FSP units introduced by the DSOs and TSO to the Common CoordiNet Platform and the DSOs to the Local Market Platform, to the resolution of different congestion management and voltage control issues by changing the output of the FSPs, in both day-ahead and near real-time timeframes. Additionally, the KPIs uncover that providing these flexibility services from distributed resources proves more beneficial for the TSO and DSOs, compared to conventional practices.

The outcome for the Spanish demonstration in CoordiNet depicts that the latter is able to successfully contribute to the development and adaptation of market platforms so that both the TSO and the DSOs could procure flexibility services in an efficient and coordinated manner. Furthermore, the calculated KPIs depict that the FSPs have the opportunity to start providing flexibility through new platforms and aggregation solutions, while innovative markets for new services (e.g. local congestion management, islanding operation and voltage control) were implemented. Nevertheless, many indexes related to the Spanish demonstration indicate that several aspects are still to be improved or addressed in order for the solutions demonstrated to be further exploited up to their full potential.

Swedish demo

The Swedish CoordiNet demonstration showed a more dynamic and digitalised way for DSOs to utilise flexibility for the operation of their network. The use of flexibility has proven that it can successfully alleviate network congestions, given that market liquidity is high enough. The abilities of the FSPs through the suitable TSO/DSO coordination scheme are as vital as the marketplace itself in order to unlock the full potential of flexibility, thus enable a marketplace that provides a cost-efficient way for including local flexibility resources to provide ancillary services to TSO and DSOs. Furthermore, it is unveiled that when the coupling between the electricity and heating sector is increased, the utilization of the energy system as a whole is getting more efficient. TSO-DSO coordination has vividly enhanced the cooperation and innovation resulting in several activities to enhance the Swedish market structure for flexibility services.

The KPI results have revealed that flexibility procurement is not an overall solution for solving all DSO issues related to the increased demand, neither an easy step for a DSO to setup the market framework for flexibility resources to join. Flexibility service providers need longer time than anticipated to set up internal processes, legal contracts and agreements with DSO, their balance responsible parties and the energy traders. The remuneration-based energy compensation has not been sufficient for some flexibility providers, requiring experiments with different forms of capacity compensation and cascading funds to secure participation from certain resources. In a nutshell, obtaining a high enough liquidity of the local flexibility markets has proven to be a challenge.

Greek demo

The Greek demonstration of the CoordiNet project has implemented four different BUCs covering two different services for congestion management and voltage control of the distribution and transmission network using two market models for the interaction between TSO and DSO: the Multi-level Market Model and the Fragmented Market Model. In the Multi-Level Market Model, the flexible resources connected to the transmission and distribution system can provide flexibility to system operators to eliminate network violations through a market mechanism. On the contrary, in the Fragmented Market Model, the flexible resources connected to the transmission system can provide flexibility only to the TSO while the flexible resources connected to the distribution system can provide flexibility only to the DSO. Therefore, in this market model each system operator is also responsible for the balancing of each network, accounting only for resources located in each network.

The developed CoordiNet platform has been tested in two demonstration sites namely in Kefalonia and Mesogia, considering a variety of actors, including thermal FSPs, CHPs, renewable FSPs, battery, residential and industrial loads. The examined market models have been tested in three different timeframes including Day Ahead (DA), Intraday (ID) and Near Real-Time, in the two demonstration areas of the Greek demo, Mesogia and Kefalonia. In order to evaluate the impact of a local flexibility market to the operation of both transmission and distribution system, different scenarios with increasing RES integration and load demand were considered.

The outcomes of the Greek demonstration confirm that the introduction of a local electricity market in the distribution system could enable the procurement of ancillary services from resources located in the distribution grid to mitigate network issues such as over and under voltages as well as line thermal overloading. In addition, the introduction of flexibility services from distributed energy resources allows the DSO to have a more proactive role in the operation of the distribution system while increasing the integration of RES in the system. The ex-post analysis of the results indicate that the Multi-Level Market Model seems to have more advantages over the Fragmented Market Model since in this model, the TSO has access to the flexibility offered from resources in the distribution grid and can use these resources either for voltage control or for congestion management.

The differences between the Fragmented and the Multi-level Market Model are also depicted on the KPI calculation. More specifically, from the analysis of the economic KPIs, KPI 5 (OPEX for service procurement), KPI 6 (Average cost per service for the examined period), KPI 18 (Volume of transactions), KPI 19 (Number of transactions), the operation of the local market within the Multi-level Market Model seems to achieve most efficient results, since the local market model operated by the DSO solves the “local” network problems (congestion and voltage) and at a second stage transfers the balancing responsibility to the upper level along with the remaining flexibility offers. In such a way, the flexibility offers of the whole system are pooled to cover imbalances from the whole network in the transmission level which results to higher efficiency. The fragmented market model appears to be the easiest to be applied since the interaction and communication between the system operators is similar to the current operational practices. Nevertheless, the fragmented market model requires adequate liquidity and the OPEX cost of the local market is higher. KPI 3 (Cost of R&I solution VS alternative grid solution) indicates that the operation of a local market with the Multi-level Market Model may defer the transmission/distribution grid investments and lead to a CAPEX reduction. These advantages are severely reduced when considering the Fragmented Market Model since the operational cost for local flexibility procurement is increased.

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