Smart TSO-DSO interaction schemes, market architectures and ICT Solutions for the integration of ancillary services from demand side management and distributed generation

Cost-benefit analysis of the selected national cases

D4.3

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About SmartNet

The project SmartNet (http://smartnet-project.eu) aims at providing architectures for optimized interaction between TSOs and DSOs in managing the exchange of information for monitoring, acquiring and operating ancillary services (frequency control, frequency restoration, congestion management and voltage regulation) both at local and national level, taking into account the European context. Local needs for ancillary services in distribution systems should be able to co-exist with system needs for balancing and congestion management. Resources located in distribution systems, like demand side management and distributed generation, are supposed to participate to the provision of ancillary services both locally and for the entire power system in the context of competitive ancillary services markets.

Within SmartNet, answers are sought for to the following questions:

- Which ancillary services could be provided from distribution grid level to the whole power system?
- How should the coordination between TSOs and DSOs be organized to optimize the processes of procurement and activation of flexibility by system operators?
- How should the architectures of the real time markets (in particular the markets for frequency restoration and congestion management) be consequently revised?
- What information has to be exchanged between system operators and how should the communication (ICT) be organized to guarantee observability and control of distributed generation, flexible demand and storage systems?

The objective is to develop an ad hoc simulation platform able to model physical network, market and ICT in order to analyse three national cases (Italy, Denmark, Spain). Different TSO-DSO coordination schemes are compared with reference to three selected national cases (Italian, Danish, Spanish).

The simulation platform is then scaled up to a full replica lab, where the performance of real controller devices is tested.

In addition, three physical pilots are developed for the same national cases testing specific technological solutions regarding:

- monitoring of generators in distribution networks while enabling them to participate to frequency and voltage regulation,
- capability of flexible demand to provide ancillary services for the system (thermal inertia of indoor swimming pools, distributed storage of base stations for telecommunication).

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List of Abbreviations and Acronyms

Acronym	Meaning
aFRR	Automatic Frequency Restoration Reserve
AMS	Advanced Metering System
AS	Ancillary Services
BRP	Balancing Responsible Party
CAPEX	CAPital Expenditure
CBA	Cost-Benefit Analysis
CBR	Cost-Benefit Ratio
CCGT	Combined Cycle Gas Turbines
CHP	Combined Heat and Power
COCOMO	COnstructive COst Model
CO_2	Carbon dioxide
CS	Coordination Scheme
CS A	Centralized ancillary services market model
CS B	Local ancillary services market model
CS C	Shared balancing responsibility model
CS D	Common TSO-DSO ancillary services market model. Centralized variant.
DER	Distributed Energy Resources
DLMP	Distribution Locational Marginal Pricing
DMS	Distribution Management System
DSO	Distribution System Operator
EAC	Equivalent Annual Costs
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
HV	High Voltage
ICT	Information and Communication Technologies
IRR	Internal Rate of Return
ISGAN	International Smart Grid Action Network
JRC	Joint Research Centre
KPI	Key Performance Indicator
MCDM	Multi Criteria Decision Making
MDCU	Meter Data Collection Unit
mFRR	Manual Frequency Restoration Reserve
NIS	Network Information Systems
NPV	Net Present Value

NRA	National Regulatory Authority
OPEX	OPerating EXpenditure
OTS	Operator Training Simulator
PM	Person Months
PV	Photovoltaic
RES	Renewable Energy Sources
RTCM	Real Time Congestion Management
RTU	Remote Terminal Units
RR	Replacement Reserve
SCADA	Supervisory control and data acquisition
SG-MCA	Smart Grid Multi-Criteria Analysis
TCL	Thermostatically Controlled Loads
ToU	Time of Use
TRL	Technology Readiness Levels
TSO	Transmission System Operator
T&D	Transmission & Distribution
TYNDP	Ten Year Network Development Plan
VAT	Value Added Tax

Executive Summary

This deliverable describes the cost benefit analysis (CBA) performed within the H2020 SmartNet project aimed at determining which of the TSO-DSO coordination schemes (CSs) proposed during the project is the most suitable one to be deployed in each of the demo countries (Denmark, Italy and Spain) by 2030.

The growing penetration of medium and small-scale generation, flexible demand and storage systems in distribution networks requires an exhaustive analysis to determine to which extent the distributed energy resources (DER) can replace traditional generation in the provision of the network services; the resources should be aggregated effectively and an appropriate coordination between transmission system operators (TSOs), distribution system operators (DSOs) and aggregators is necessary.

SmartNet compares four TSO-DSO interaction schemes and different real-rime market architectures, with the aim of finding out which one could deliver the best compromise between costs and benefits for the system. For that purpose, an ad-hoc platform was developed to carry out simulations and perform a CBA to compare the benefits drawn by the system with the costs needed to implement each TSO-DSO interaction scheme, mainly the investments in information and communication technologies (ICT).

As a first step of the process, the analysis of several investment alternatives led to a CBA instead of Multi Criteria Decision Making (MCDM) process. The main advantages of CBA method compared to MCDM are that this method is most acknowledged and widely-used tool for assessing costs and benefits of industrial projects and that it includes detailed sector-specific guidelines which provide results by easy-to-read economic metrics. However, the main key issue of CBA method is identified as the high risk of double counting. Therefore, this preliminary analysis results in a list of metrics to be calculated:

1. **Total mFRR cost**: This metric includes the total balancing cost of the market defined in SmartNet. The energy activated is remunerated at the nodal price resulting from the clearing process. The mFRR activations in the SmartNet balancing market are aimed to solve the network imbalance and to avoid congestions predicted in advance for the next time step.
2. **Total aFRR cost**: This is the cost of re-balancing the system after the mFRR market. In this case, the bids submitted to the SmartNet market are ordered according to a system-wide merit order and the resulting price will be applied as marginal price (off-line simulation of aFRR market).
3. **Cost of unwanted measures**: this is the cost of emergency actions taken by network operators caused by unpredicted network congestions. They are valued at the bid price.
4. **ICT costs:** These costs comprise the communications and information technologies, including the software for the aggregation and market clearing process. Only those ICT costs that are directly related to the implementation of each coordination scheme have been considered. In this sense, communication costs have been assumed to be very similar in all coordination schemes and, therefore, differences stem from the software needed for aggregation and market clearing.

These metrics are calculated for Denmark, Italy and Spain. The obtained results are shown below:

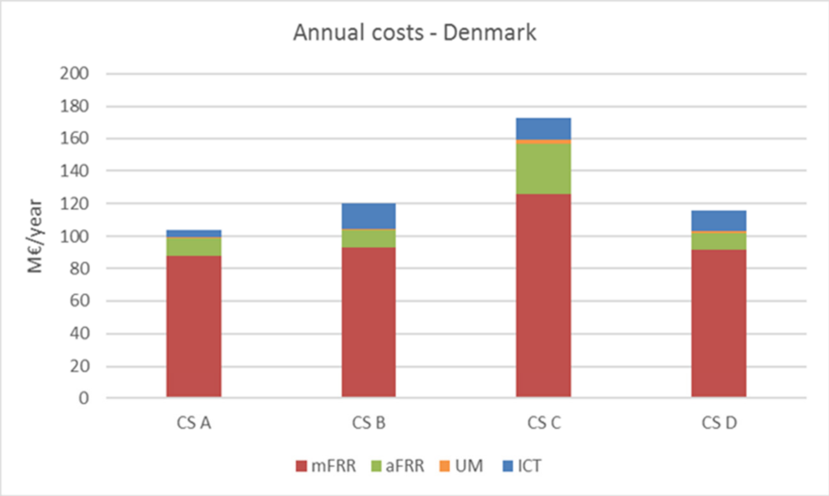


Figure 1: Annual costs for the Danish scenario

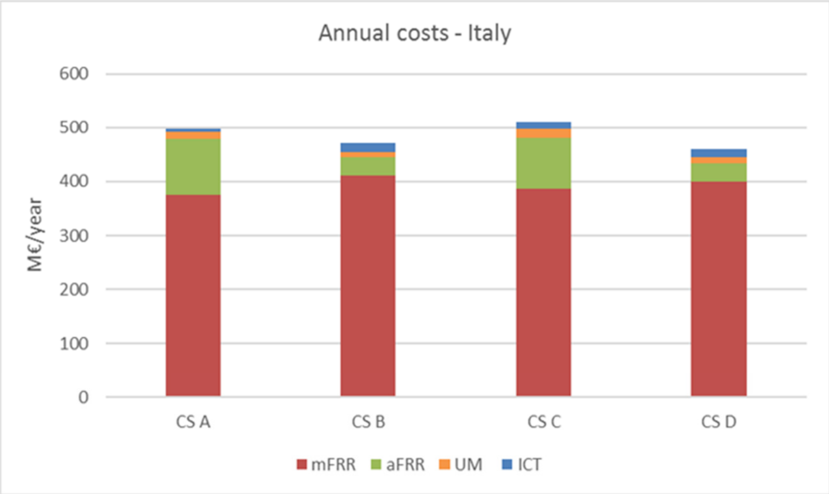


Figure 2: Annual costs for the Italian scenario

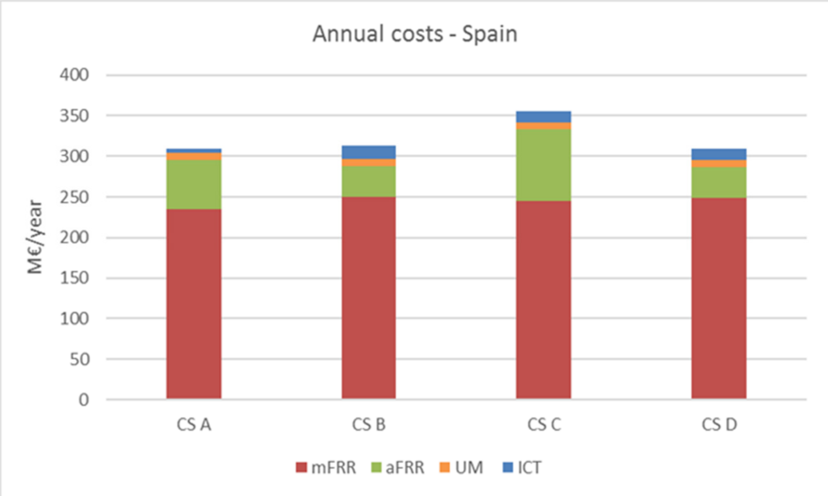


Figure 3: Annual costs for the Spanish scenario

As demonstrated in the figures above, mFRR is the biggest cost component, the cost of unwanted measures is negligible and ICT costs only represent a very small part of total costs. Moreover, the effectiveness of the TSO-DSO coordination schemes depends on the level of services requested by the DSO and, hence, CS A performs best when there are few congestions at distribution level (as in the Danish case), but CS D is the most efficient one when there are frequent congestions at distribution level (as in the Italian case). In general, two-step markets (CS B and CS C) are less efficient than markets optimising in a single step (CS D) and may suffer from scarcity and/or illiquidity of resources; this effect is even more notorious in the case of CS C, where an additional constraint is introduced by fixing the active power exchange in the TSO-DSO interconnection and, thus, further taking the solution away from the overall optimum obtained in CS D. However, in rare circumstances (i.e. severe congestions at transmission level) the selection of two-step market architectures can be more beneficial than other schemes, as market separation potentially prevents the spreading of high nodal prices among distribution and transmission systems.

These indicators represent the economic impact of the different coordination schemes at power system- level, therefore their efficiency is assessed through the described CBA. However, CSs must also allow the involved actors to have a profitable business case, that is, CSs must lead to an appropriate allocation of costs and benefits among them. As an example, it is expected that aggregators will bear a large portion of ICT costs (communications with DERs, aggregation software, etc.), so they should be able to obtain a high enough return in order to pay for those investments. Therefore, a business-level analysis (also called "micro-level analysis") is needed to assess the economic impact of the different CSs for all the relevant actors.

However, many of the specific data and financial parameters required to be used in these calculations are difficult to estimate, mainly due to two reasons:

i) The deployment of the proposed coordination schemes implies regulatory changes which are not defined yet. These modifications can take years, so, some of the estimated values could imply a considerable inclusion of inherent uncertainty on the long-term forecast.

ii) For the business-level economic analysis, the annual cash flows must be calculated. The obtained results from the SmartNet simulations can be considered representative for the system as a whole, but the results obtained with the number of time step simulated are less likely to be representative of the exchanges among the actors over a complete year.

Consequently, the business-level analysis developed only includes the identification of relationships and the formulas to be applied, but the specific data to be used is specified. Nevertheless, several theoretical boundary conditions (minimum set of economic parameters) are detailed in order to establish the issues which may strengthen or threaten the deployment of the proposed coordination schemes.

As a summary of the main findings by the CBA developed in the SmartNet project, it could be settled that in a more than likely scenario in which the fit-and-forget reinforcement remuneration approach is abandoned and the forecasting errors are more accurately calculated (on the one hand by the improvement in the calculation and on the other hand by shifting the gate closure toward real-time), the CS D could be the most feasible approach between the ones proposed. However, due to complexity reasons, the network observability cannot be pushed till single low-voltage nodes and, hence, it will be necessary to determine, for each specific case and country, the observability level to be deployed, assessing that the observability provision to the distribution grids implies new important investments by the system.

1 Introduction

The main objective of the SmartNet project is to provide optimised architectures for Transmission System Operator (TSO) – Distribution system operator (DSO) interaction [1][2]. Such optimisation must take into account the economic behaviour of each different coordination scheme (CS) and, thus, a cost-benefit analysis (CBA) is of utmost importance. Since the main objective of this deliverable is the analysis of the CSs from an economic perspective, an exhaustive definition of these CSs has not been included in it. However, sections from 5.3.1 to 5.3.4 show a brief overview of their main characteristics. For a more detailed information on the CSs definition, please see SmartNet deliverable 1.3 [1].

The CBA is oriented to identify the impacts at system-level (also called "macro-level analysis"), since the aim of the economic assessment was to identify which CS provides more efficient results in each country. Additionally, coordination schemes must also allow the involved actors to have a profitable business case, that is, that costs and benefits are properly allocated among them, which required a business-level analysis (also called "micro-level analysis").

In order to carry out such CBA, an ad-hoc simulation platform was developed [3], where different scenarios were analysed for the three countries where SmartNet focuses: Italy, Denmark and Spain [4]. The flexibility market considered in the SmartNet project, which is called "Integrated Reserve Market", is aimed at solving real-time imbalances and congestions between gate closure of intraday markets and real time until the opening of the next intraday market session [2], [3], [4], [5]. Its operation time is compatible with the timings of existing manual Frequency Restoration Reserve (mFRR) and Replacement Reserve (RR) markets [6], depending on the country. Although more details can be found in [2], for simplification purposes, the reader can understand that Integrated Reserve Market, SmartNet market, tertiary regulation market and mFRR market are the same kind of market. Likewise, automatic Frequency Restoration Reserve (aFRR) market can be assumed to be the same as secondary regulation market.

The results obtained in the simulation environment were the core input for the CBA described in this report. However, these results required an appropriate methodology to be applied. In a first step, a review of the literature related to economic assessment methodologies was performed, with a view to select the metrics to be considered within the CBA described in this report.

As shown in Figure 1.1, the CBA, which is highlighted in light blue, is an integral part of the long-term analysis performed for the three countries considered within SmartNet. In parallel to the development of the simulation software [3] and the definition of the 2030 scenarios [4], the most appropriate metrics were selected. Then, based on the results of simulations, which were also used for the laboratory tests [7], metrics were calculated and monetised to feed the system-wide CBA. The value chain was identified in parallel to the system-wide CBA, so that some guidelines on how to run a business-level CBA could also be extracted.

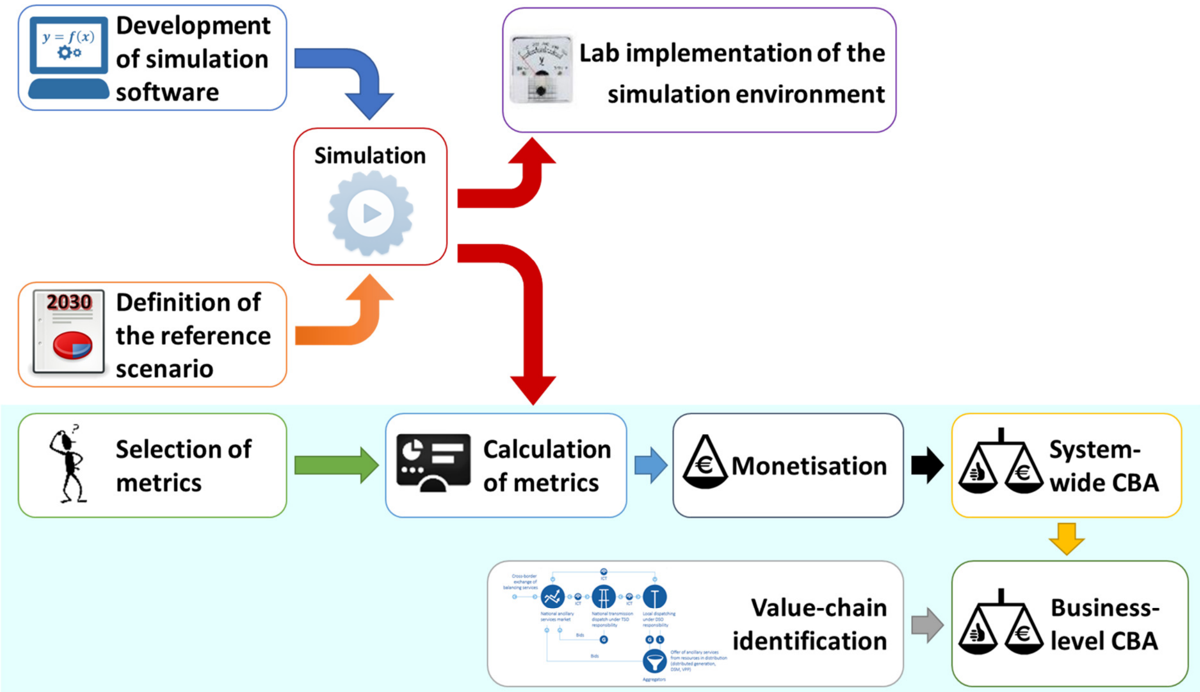


Figure 1.1: Approach for CBA in SmartNet project

Next chapters describe the process to select the metrics (chapter 2), the methodologies to calculate and monetise them (chapter 3) and present the results of the CBA (chapter 4). Then, chapter 5 provides an overview of the process to perform the business-level analysis and chapter 6 summarises the main conclusions.

2 Selection of metrics for the CBA

2.1 Cost-Benefit Analysis and Multi-Criteria Decision Making

The selection of the best alternative in complex investment processes, like the selection of the most appropriate CS, requires a deep analysis of the different implications that each of them has on the final result of the project. The best way to identify such implications is to use a set of metrics and to assign a weight to each of them. Defining the criteria (and their respective metric) is critical, because they must fulfil several characteristics to ensure that they really represent the complexity of the analysis. Furthermore, defining the weights is even more critical and controversial, since it needs to consider the whole conception of values, which is inherently subjective. The most important characteristics that the metrics must have is to be complete, non-overlapping, applicable, system-oriented, simple, reproducible, realistic, objective and documentable. Metrics can be of technical, social, environmental or economic nature, but the assessment described here focuses on the economic performance of the different coordination schemes and, hence, only the economic scope is relevant.

The use of metrics for analysing investment alternatives may lead to a cost-benefit analysis (CBA) or to a Multi Criteria Decision Making (MCDM) process.

On the one hand, a CBA is an analytical method for evaluating the costs and the benefits of a decision to determine the economic advantages and disadvantages of implementing that decision and to assess whether its benefits outweigh the costs or not. The basic assumption underlying CBA is the rationality of decision making. Cost benefit analysis can be performed either form a societal perspective which consider cost and benefits of a decision for the whole society or from a single or a group of stakeholders' perspectives. Most common applications of CBA are to find optimal resource allocation between different alternatives and to find most profitable investment option among a set of different alternatives. The most widely used indicators of CBA results are Net Present Value (NPV), Internal Rate of Return (IRR), and Cost Benefit Ratio (CBR). NPV is equal to discounted benefits minus discounted costs over a specific time span and defined in equation (1). In this equation, t is time, T is the time span, r is discount rate, B_t is the benefits at time t and C_t is the costs at time t. A positive NPV means that the decision has added value for decision makers and negative NPV means that the decision would bring losses to the decision makers.

$$NPV = \sum_{t=0}^{T} \frac{B_t - C_t}{(1+r)^t} \tag{1}$$

When there is only one single investment at the beginning of the project and the expected incomes are the same during all the years of its lifetime, the NPV can be replaced by a comparison between the annual incomes and the annuitisation of the initial investment. In that case, the investment is economically

attractive if the annual cash-flow (B) is bigger than the investment (C) multiplied by the uniform capital recovery factor, as described in equation (2).

$$B > \frac{r * (1+r)^T * C}{(1+r)^T - 1} \tag{2}$$

IRR is the rate of return or discount rate that sets the NPV of a decision equal to zero. A higher IRR would be more favourable for decision makers. Another metric for cost benefit analysis is CBR which is the ratio of total discounted costs of a decision over its life span divided by total discounted benefits over the same life span.

On the other hand, MCDM is mainly a qualitative approach for evaluating costs and benefits in complex decision-making problems and identifying the best decision among a set of alternatives [8]. In [9], the main advantages of MCDM are mentioned as: a) assessing mutually conflicting criteria, b) assessing simultaneously both tangible and intangible impacts, c) allowing probabilistic modelling of decision making problem, d) encouraging problem decomposition, e) involving stakeholders' view directly in decision making process, f) allowing quantitate evaluations. A MCDM problem can be expressed in matrix format as:

$$D = \begin{array}{c} \\ A_1 \\ A_2 \\ \vdots \\ A_m \end{array} \begin{array}{cccc} C_1 & C_2 & \dots & C_n \\ x_{11} & x_{12} & \dots & x_{1n} \\ x_{21} & x_{22} & \dots & x_{mn} \\ \vdots & \vdots & \dots & \vdots \\ x_{m1} & x_{m2} & \dots & x_{mn} \end{array} \tag{3}$$

$$W = [\, w_1 \; w_2 \dots w_n \,] \tag{4}$$

Where A_1, A_2,..., A_m are possible alternatives among which decision makers have to choose. C_1, C_2,..., C_n are criteria which demonstrate alternative performance, x_{ij} is the rating of alternative A_i with respect to criterion C_j and w_j is the weight of criterion C_j. [8]

2.2 Literature review

The first step to find the optimal interaction between TSO and DSO was to determine which approach, i.e. CBA or MCDM, was the most appropriate for this project. To this aim, several existing sector specific CBA and MCDM methodologies in the literature were reviewed.

The main advantages of CBA method compared to MCDM are that this method is most acknowledged and widely-used tool for assessing costs and benefits of industrial projects and that it includes detailed sector-specific guidelines which provide results by easy-to-read economic metrics [9]. However, the main key issue of CBA method is identified as the high risk of double counting.

In the following subsections, some of the most important CBA methodologies in the smart grids sector and their characteristics are described. However, since the CBA seemed to provide advantages over MCDM, more CBA methodologies were taken into account.

2.2.1 JRC method

Joint Research Centre (JRC) method provides a general guideline for CBA in smart grid projects. This approach has three main steps including definition of the boundary conditions, performing the CBA and performing a sensitivity analysis on the main parameters [10]. Defining the boundary conditions refers to identifying the conditional and parameters which are influential on the cost and benefit evaluations, identify the uncertainty of the available data for parameters and determining the time horizon for the CBA.

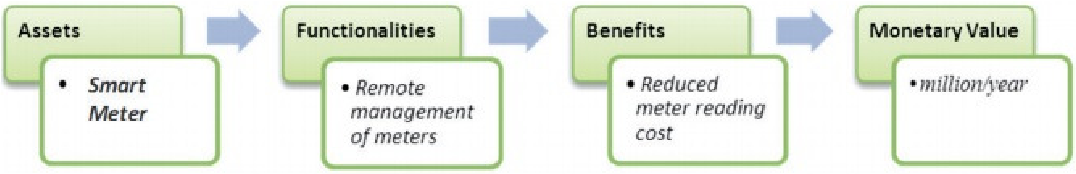


Figure 2.1: JRC approach for CBA in smart grid projects [10]

The main approach of JRC method is to define assets, map them to different functionalities and map these functionalities into associated costs and benefits. Then, these costs and benefit are monetized and compared with a predefined baseline scenario. This step is followed by performing the CBA, which is shown in Figure 2.1. The third (and last) step of JRC method is to perform a sensitivity analysis on the key parameters to evaluate the impact of a variation in these parameters on the final CBA results.

The JRC method was based on the EPRI method, which is described in the next subsection.

2.2.2 EPRI method

The CBA framework proposed by Electric Power Research Institute (EPRI) for smart grid demonstration projects mainly consists of three main sections, including project overview documentation, developing a research plan, and estimating project impacts, costs and benefits [11]. The cost and benefit estimation of a project consists of four steps including estimating physical impacts from measurements, monetising estimated physical impacts, estimating the annual costs for customers and utilities in the project and baseline scenario, and summarising total costs and benefits.

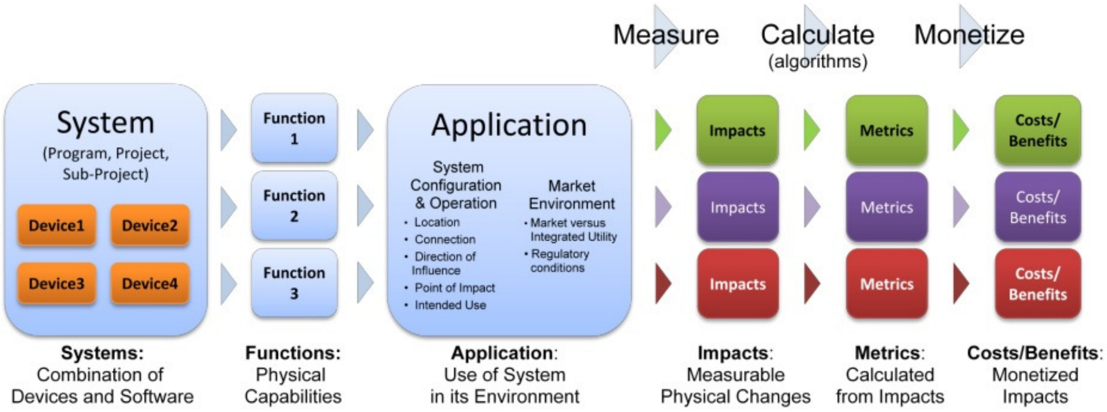


Figure 2.2: EPRI approach for CBA in smart grid demonstration projects [11]

Figure 2.2 shows the process to interpret the costs and benefits of specific devices, such as components of a system or project. First, each device is mapped to one or more functionalities according to their capabilities. A selection of these functions is defined as a set of applications which are classified into different branches. Then, measurable physical changes derived from a defined set of applications are translated as a set of impacts. Impact can be either direct, which means that they are confined to the project environment, or indirect, which means that they are out of the project scope. Metrics are calculated either directly from measurements or from impacts using relevant algorithms. Finally, both costs and benefits are derived by monetising associated impacts and metrics.

2.2.3 SG MCA method

Smart Grid Multi-Criteria Analysis (SG-MCA) is a method developed by State Grid cooperation of China and combines fuzzy logic with Analytic Hierarchy Process to assess costs and benefits of a smart grid project. This method is using a hierarchical structure so that, in each hierarchy, a set of metrics is assigned with a set of associated weights determined by experts. This method evaluates the projects based on four main categories of metrics including technical, social, economic, and practical. As a result, the performance of the project in terms of both four categories and as an entity is calculated in a final score [12].

2.2.4 ISGAN method

International Smart Grid Action Network (ISGAN) method for CBA aims to develop a global framework to identify, define, and quantify in a standardized way the costs and benefits which can be realized from the demonstration and deployment of smart grids technologies and related practices in electricity systems. By using this tool, analysts, regulators, utilities and other electricity system stakeholders can define and decide on system needs and priorities for smart grid system investment and regulatory changes. The results generated by the benefit-cost tools could be used to develop specific business cases,

considering specific regulatory and market structures, as well as current system status, available generation assets and resources and demand profiles [13].

2.2.5 Task specific methods

Additionally, there are CBA methods which are specific to some decisions and tasks in power systems:

- **Investment project appraisal** [14]: Figure 2.3 shows the main steps of this approach to evaluate investment decisions or project appraisal. These steps include i) definition of the socio-economic, institutional and political context, ii) definition of main objectives, iii) identification of project activities and responsibilities, iv) evaluation of technical feasibility and environmental sustainability, v) financial cost and befit analysis, vi) (only in case of negative financial values) economic analysis and re-evaluating market and non-market aspects, vii) risk assessment.

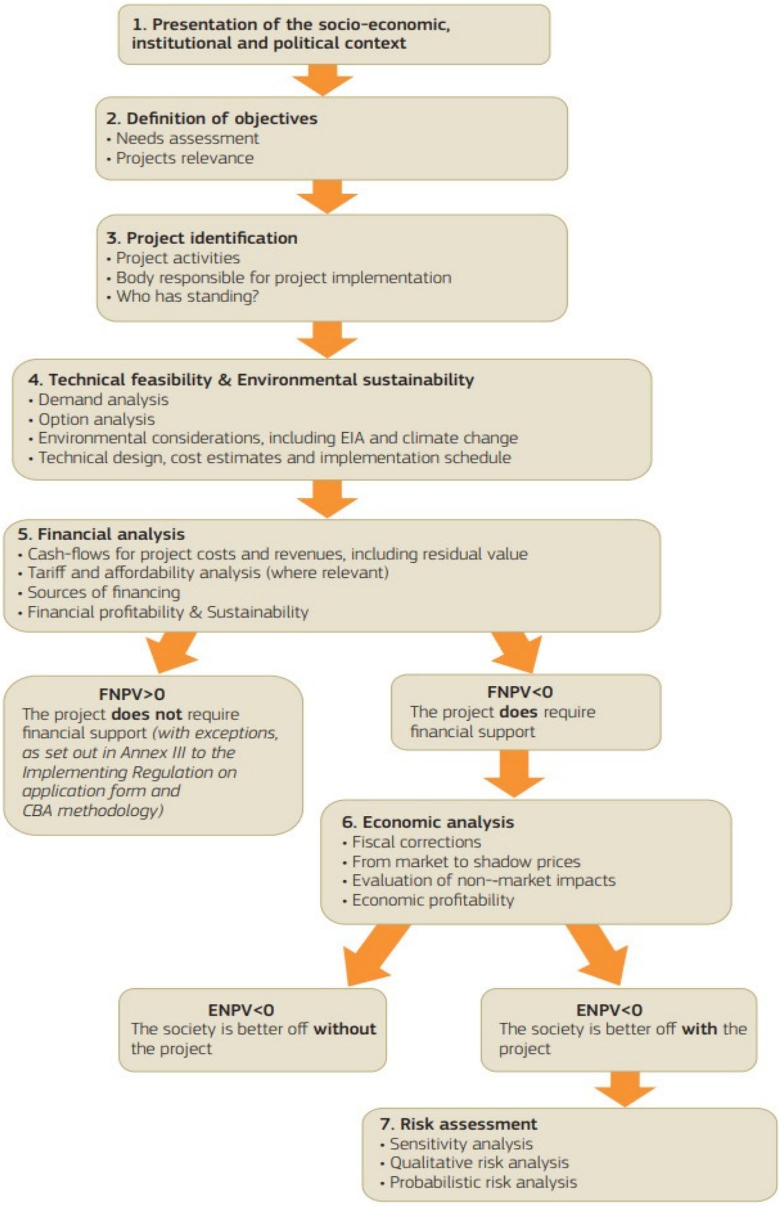


Figure 2.3: CBA approach for investment project appraisal or investment decision making

- **Grid development projects**: The European Network of Transmission System Operators for Electricity (ENTSO-E) presents a guideline for CBA in grid development projects [15] and proposes a combined CBA and MCDM approach for regional grid investment plans to develop the Europe-wide Ten Year Network Development Plan (TYNDP). The goal is to characterise the impact (including added values and costs) of transmission grid extension projects for society. This study defines the benefit categories including improved security of supply, socio-economic welfare, RES integration, variation in losses, variation in carbon dioxide (CO_2) emissions, technical resilience and flexibility. The cost category is defined as total project expenditure.

Besides, a multi-criteria cost-benefit analysis for the assessment of transmission grid expansion is proposed in [16]. This study defines a top-down tree structure to avoid double counting of criteria. On the top of the tree, a rough classification of domains such as economic or environmental criteria are defined. Each of these domains is branching down to represent measurable criteria such as social welfare, CO_2 emissions and so on. An example of the tree structure to determine Key Performance Indicators (KPIs) for transmission grid expansion project is shown in Figure 2.4. Then, all criteria and different alternatives are sorted in an evaluation matrix. The next step is to convert all criteria indicators into a utility value that represent the value of the indicator to the society. This task can be done by defining a utility function. The utility values of the indicators relevant to a single alternative can be combined in a weighted linear way to calculate the ranking parameter of that alternative. In the weighed linear combination, the weights vector incorporates the importance of one criterion (for decision makers or society) with respect to the others.

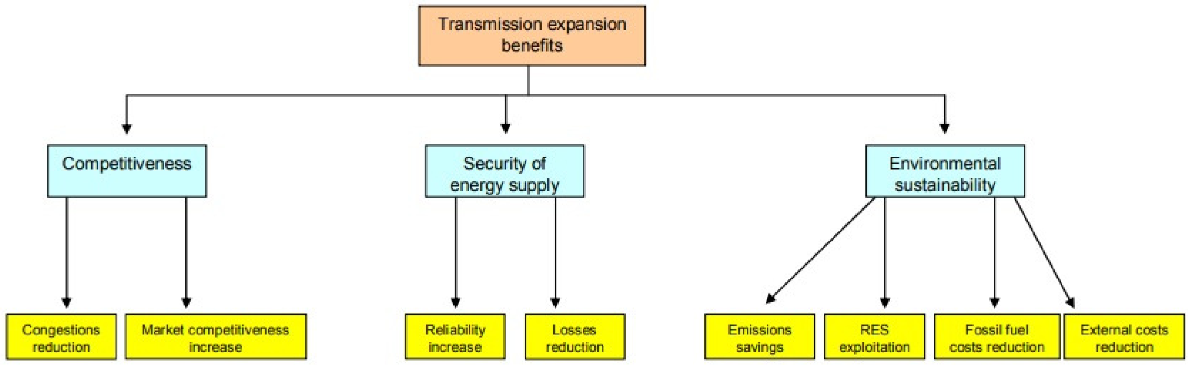


Figure 2.4: Top-down tree approach to determine KPIs for transmission expansion projects [16]

2.3 Preliminary list of metrics and consultation

As stated above, there was a preference for CBA before the literature review, which was confirmed during the process. The literature review process also resulted in a preliminary list of metrics, which are listed below:

i. Increased utilisation and hosting capacity of renewable energy sources (RES), i.e. less curtailment of RES
ii. Reduced Network losses
iii. System Congestion Reduction
iv. Reduced Ancillary service cost (Voltage Quality and Frequency Stability improvement)
v. System balancing improvement
vi. Avoided and deferred network investment
vii. Emissions savings

viii. Information and Communication Technology (ICT) cost

This list was further elaborated by grouping or re-naming some of the initial metrics. In the case of "vi. Avoided and deferred network investment", the time span of network and reserve investments is much longer than that of the operational real time markets. The combined optimisation problem of long-term investment and short-term operation is very stiff and, thus, numerically very difficult to solve accurately and efficiently without splitting. Moreover, the combined optimisation problem does not change much if the fast and slow parts are solved separately and, in order to solve the investment problem, it is necessary to consider the operational optimisation problem. Therefore, it was decided that SmartNet should focus on developing the fast, operational time span solutions and, thus, this metric was converted into "d) Cost attributable to network limitations".

Then (July 2017), a consultation to the Advisory Board was organised, *Ideas and alternatives for the cost-benefit analysis performance*, with the aim to support the decision-making process for the system level analysis. The complete consultation document and its corresponding analysis can be found in the Appendix I. The metrics and monetisation methods proposed in the consultation document, are described below:

a) **Enhanced provision of ancillary services:** The TSO-DSO coordination schemes investigated in SmartNet are aimed at increasing the competitiveness of ancillary service provision, by extending their related markets to distributed energy resources (DER), i.e., where the centre of mass of power flexibility is expected to be in a near future. In particular, SmartNet simulations are focused on the real-time market devoted to the activation of the flexible DER for the energy balance of the system (mFRR and RR depending on the country) taking into account also the network limitations (congestion management). The proposed metric to evaluate this aspect is the balancing cost which can be monetised by multiplying the cleared balancing cost and the activated volume, for each node 'n' and each time-step 't'.

b) **Reduction of unwanted measures adopted by network operators in order to solve congestions:** As anticipated above, the real-time market simulated in SmartNet includes the network models and limits. Depending on the TSO-DSO coordination scheme, this model is limited to transmission network or extended to the distribution grid. In addition, the market architecture impacts on the ability of the market operator in predicting network congestions and to, consequently, activate the right resources to avoid them. Having considered that the simulated coordination schemes are expected to solve congestions with different effectiveness, network operators will inevitably deal with some critical situations (unexpected congestions) to be immediately solved with dedicated (unwanted) measures, such as:
    - Immediate curtailment of load/RES generation.
    - Blocking of activation signals.

- Inhibition of bidding of non-prequalified resources. This case is of special importance in the Centralised Market Model, where the DSO does not have access to DER flexibility and the constraints in the distribution grid are not taken into account by the market clearing algorithm; however, the DSO can pre-qualify DER to bid into markets, after checking that those bids will not create constraints in the distribution grid.

Even in this case, the monetization of the unwanted measures can be easily performed. In particular, since these actions inevitably[1] cause an imbalance in the system, a good metric can be represented by the consequent imbalance price. However, when such imbalance price does not represent the price to compensate for curtailment, the compulsory limitation of flexibility can be evaluated according to the associated resource costs.

When monetising this metric several approaches were proposed in the consultation; i) considering the flexibility cost (the cost of the resources affected), ii) considering the average imbalance price or iii) considering the free market approaches.

c) **Reduced network losses:** Because of the non-ideal behaviour of network components, energy losses are an unavoidable element of power systems and it may have a significant impact on the management of both transmission and distribution grids. Taking into account the market architectures investigated within SmartNet, there is a concrete potential of reducing energy losses by approaching supply and demand of ancillary services. The proposed CBA will compare the effects of each TSO-DSO coordination scheme on the energy losses by processing the simulation results. Their associated cost can be calculated by multiplying them by the energy price profile (resulting from the market). Thanks to this integration, the CBA will also consider the coordination scheme ability of selecting the optimal energy paths depending on the current price of energy.

d) **Cost attributable to network limitations:** The real-time market simulated in SmartNet takes into account complete network models and it guarantees that the final activations are selected in order to avoid (voltage and loading) congestions and to keep energy losses limited. Depending on the TSO-DSO coordination scheme, the market effectiveness in taking into account network limitations is expected to be different and, consequently, the activated resources as well (with a direct impact on the cleared balancing price). Network operators are carefully considering the occurrence/severity of congestions and losses in order to evaluate grid refurbishment actions which, in turn, are inversely proportional to the effectiveness of the market in solving undesired situations. This effectiveness can be evaluated by comparing the cleared balancing price of the following two situations:

[1] Obviously, there is a minimum threshold under which compensations should not be compulsory. Likewise, some flexibility activations might cancel each other (as it is already the case in the integration of the EU balancing markets).

- Real situation, in which the entire physics of the network (losses, transmission capacity) is simulated.
- Ideal situation (busbar simulation), in which electricity network is simulated disregarding the physics and with zero losses.

It is immediate to deduce that the price difference between these two situations corresponds to the cost attributable to congestion management and to network losses compensation (an intermediate situation could be performing a copperplate simulation, where the electricity networks have infinite transmission capacity, but network losses are taken into account, so that only the cost of congestion management could be derived from the price difference). This difference also directly returns a monetary value and it is a valuable metric for the profitability evaluation of refurbishment investments[2].

e) **Emissions savings:** A more efficient cooperation between TSOs and DSOs, together with the integration of network/resources models in the market clearing algorithms, is expected to be beneficial in the optimal management of available flexibility, including the one provided by low-carbon generation technologies (which are gradually replacing conventional plants with higher carbon emissions). Generation dispatch and unit commitment model is used for calculation of emissions savings in each coordination scheme compared to the reference scheme. Standard emission rates for each generation technology will be taken into account.
The monetization of CO_2 costs is based on forecasted CO_2 prices for electricity in the studied horizon. The price can be derived from official sources such as the International Energy Agency.
In this case, the volume of CO_2 emissions will be based on the generation mix resulting in the simulation of each coordination scheme.

f) ICT costs. Since there were several aspects to be asked to the advisory group, the questions related to this metric are described below.

In general, respondents agreed with the proposed metrics and monetisation methods, although they proposed different approaches for the analysis of some metrics. This feedback was used as an important input for the discussions leading to the selection of the final metrics to be considered and which are described in section 2.4.

Since the aim is to identify the most efficient TSO-DSO coordination scheme, i.e. the one with the lowest implementation and operational costs, in each of the countries under investigation (Italy, Denmark, Spain), the same metrics have been used, but the results of simulations are different for each country and, thus, also their calculation and monetisation results, leading to different CBA results in each

[2] A detailed analysis should consider the situation after each grid refurbishment investment, so that the economically sound refurbishments would be identified (there may be some bottlenecks which only appear in very extreme situations and, hence, whose removal would not be economically efficient), but it is not the aim of this analysis to be so detailed.

country. It is assumed that any kind of coordination between TSO and DSO will be more efficient than having no coordination at all, so there is no baseline scenario against which the different coordination schemes are compared.

However, the participation of DER in the provision of ancillary services for TSO and DSO requires the existence of an advanced communication infrastructure, which can also be used for additional applications, either for the DSO (billing, monitoring of grid status in real-time, etc.) or for the participation in other markets (day-ahead or intraday). Therefore, when considering ICT costs, it is worthwhile to consider that part of such communication infrastructure will already be there, as an evolution of present communication systems, as described in section 0. Since the centralized ancillary service market model (CS A), is the closest one to present situation, it has been taken as the baseline scenario as well. The topic of the baseline was also included in the consultation to the Advisory Board and the answers received supported the decision made.

An additional consequence of having such ICT infrastructure is that the ICT cost is one of the obvious metrics to be included in the CBA. Therefore, the consultation also included some questions about the ICT costs to be considered. The answers requested to include the following items, both in capital and operational expenditures:

- Supervisory control and data acquisition (SCADA):
    - Main control centre software, licenses, etc. for SCADA, Energy Management System (EMS) and Distribution Management System (DMS).
    - Operator Training Simulator (OTS), either in house or outsourced.
    - Remote Terminal Units (RTUs) and local substation hardware.
    - Telecommunication systems between substation RTUs and distribution control centre.
    - Front-end at control centre.
- Operational planning applications:
    - Network applications.
    - Market applications – system services.
    - Forecast applications.
    - Regional coordinator (which can be outsourced).
- Metering cost (if needed):
    - Meters, either at consumers' or producers' facilities.
    - Telecommunications (dial up).
    - Database.
    - Applications.
- Other costs:
    - Building.

- Staff in ICT for maintaining the database and applications.
- Staff in ICT team for development of new applications.
- Uninterrupted Power Supply.

In general, there was a preference of outsourcing ICT services, although cyber-security is a critical point and the DSOs must be aware of this challenge. Cyber-security and interoperability were expected to be the most critical aspects to be considered in ICT costs.

Based on the results of the consultation to the advisory board and on several internal discussions, some modifications were made to the preliminary set of metrics. On the one hand, some of them were disaggregated to a lower level, so that the CBA analysis can provide more accurate and detailed results. To this end, the metric ***Enhanced provision of ancillary services*** was disaggregated into two metrics: i) provision of mFRR service, and ii) provision of aFRR service. Likewise, the r***eduction of unwanted measures adopted by network operators in order to solve congestions*** metric was divided in two metrics: i) unwanted measures, and ii) forecasting errors. On the other hand, ***Reduced network losses*** affect the relative value of the bids when calculating the nodal prices in the mFRR market, so it is included into the first metric and, thus, it was excluded from the list. Likewise, ***Emissions savings*** was removed from the CBA, because aggregators already include a cost for CO_2 emissions when they create the bids to be sent to the mFRR market. As a result, CO_2 emissions were calculated and compared for the different coordination schemes but were not monetised and added to the cost of the rest of metrics.

The resulting list of metrics was presented in different dissemination activities during the Autumn in 2018 [17], [18], [19], [20], [21]:

A. **Total mFRR cost**: This metric includes the total balancing cost of the market defined in SmartNet [2]. The energy activated is remunerated at the nodal price resulting from the clearing process[3]. The mFRR activations in the SmartNet balancing market are aimed to solve the network imbalance and to avoid congestions predicted in advance for the next time step.
B. **Total aFRR cost**: This is the cost of re-balancing the system after the mFRR market. In this case, the bids submitted to the SmartNet market are ordered according to a system-wide merit order and the resulting price will be applied as marginal price (off-line simulation of aFRR market).
C. **Cost of unwanted measures**: Each coordination scheme results in a different market setup. Depending on the market setup adopted, the grid model included in the market clearing process, which aims at solving and avoiding congestion issues in the network, is more or less detailed. For example, the centralised AS market model (CS A) does not consider congestions at distribution level and, thus, the distribution grid model considered in the market clearing process is very simple. These simplifications, which allow a faster execution of the market clearing algorithm,

[3] Nodal prices were obtained for MV nodes at distribution level. The details on how the simulations were performed can be found in D4.2 [4].

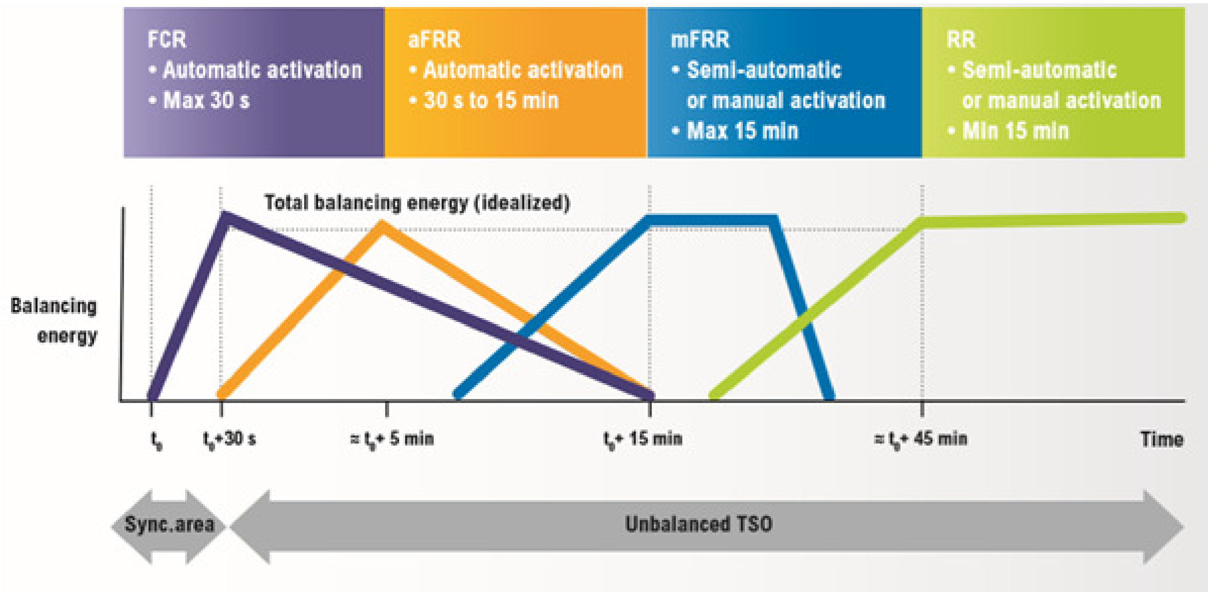
may create infeasibilities when dispatching units cleared in the market. This way, some bids accepted in the market may create congestions not identified by the grid model used. In this case, grid operators may need to take emergency actions to re-dispatch some resources aiming to solve real congestions in the grid. They 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).

D. **Cost of forecasting errors**: This term also refers to deviations between market activations (mFRR) and actual activations, but in this case, they are 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 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).

E. **ICT costs:** The term ICT cost comprises the communications and information technologies, including the software for the aggregation and market clearing process. Only those ICT costs that are directly related to the implementation of each coordination scheme have been considered[4]. In this document, the term implementation is used to refer to the work in designing, specifying, coding, testing, validating and documenting software.

The CO_2 emissions were also presented as an additional metric, but not monetised, as described above.

For clarification purposes, Figure 2.5 below presents the characteristics of the different frequency regulation processes, as described by ENTSO-E.



[4] See section 2.4 for the final definition of this metric.

Figure 2.5: Timing for different frequency regulation processes [22]

The questions received during the dissemination activities led to a final reflection about the suitability of the proposed metrics. In particular, the impact of the cost of forecasting errors was unclear for the audiences. Forecasting errors are caused by deviations between mFRR market activations and real activations, because the requested flexibility cannot be physically activated due to either flexibility modelling errors and/or flexibility forecasting errors. Forecasting errors may result in partial activations of accepted bids or in activations of non-accepted bids. As the CBA is focused at system level (and not at the business-case level), imbalance penalties were deemed not to be advisable, because they usually express the cost of the aFRR required to solve them and it has already been accounted for in the second metric. Hence, it was first decided to monetise this metric as the mFRR cost of the flexibility affected by the forecasting errors, that is, since some bids were matched in the mFRR market (and increased the mFRR cost) but did not provide the promised flexibility, leading to a need to dispatch the same amount of flexibility in the aFRR market (with its associated cost), it was decided to subtract the cost of those bids from the total mFRR cost, to account for the cost of that flexibility for the system only once.

However, subtracting these costs would have prevented the analysis to really account for the capacity of coordination schemes to deal with uncertainty. Although forecasting errors when calculating the available flexibility should not be widespread in AS markets, the decarbonisation of power systems will lead to progressive dismantling of firm-capacity, fossil fuel-based, big power plants, which will be replaced by intermittent, renewable, smaller power plants. Whatever coordination scheme is implemented in the future, it must deal with the intermittent nature of renewable-based power plants, so the impact of forecasting errors should not be removed from the scoring of CSs.

2.4 Final metrics selection

As a result, the final list of metrics in the following one:

1. **Total mFRR cost**: This metric includes the total balancing cost of the market defined in SmartNet [2]. The energy activated is remunerated at the nodal price resulting from the clearing process. The mFRR activations in the SmartNet balancing market are aimed to solve the network imbalance and to avoid congestions predicted in advance for the next time step.
2. **Total aFRR cost**: This is the cost of re-balancing the system after the mFRR market. In this case, the bids submitted to the SmartNet market are ordered according to a system-wide merit order and the resulting price will be applied as marginal price (off-line simulation of aFRR market).
3. **Cost of unwanted measures**: this is the cost of emergency actions taken by network operators caused by unpredicted network congestions. These measures are activated on available flexibility and they are valued at the correspondent bid price.

4. **ICT costs:** The term ICT cost comprises the communications and information technologies, including the software for the aggregation and market clearing process. Only those ICT costs that are directly related to the implementation of each coordination scheme have been considered. In this sense, communication costs have been assumed to be very similar in all coordination schemes and, therefore, differences stem from the software needed for aggregation and market clearing[5].

Figure 2.6 shows the evolution of the metrics to be used in the CBA along the different stages. Since the cost of CO_2 emissions is already included in the bids sent by aggregators to the mFRR, the metric was not monetised in the final list, but included as a complementary metric for informative purposes (that is why it is included in yellow). Likewise, network losses affect the relative value of the bids when calculating the nodal prices in the mFRR market, so it is included into the first metric and, thus, it was excluded from the final list.

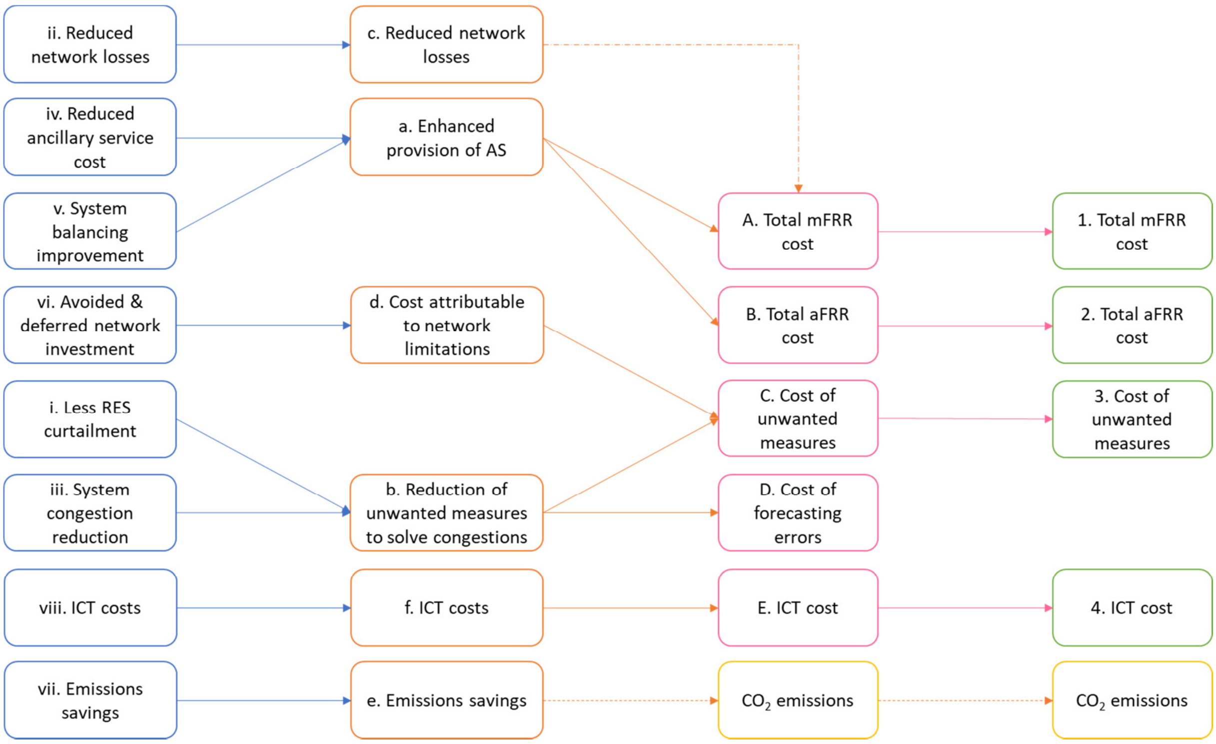


Figure 2.6: Evolution of the metrics considered within the different stages of the CBA

It is important to highlight that the scenarios simulated in SmartNet, which provide the input for the CBA in this report are aimed at analysing normal situations in the operation of the power systems. Therefore, they represent three typical days for each of the countries under analysis and, thus, exceptional situations are not included in this analysis. Ancillary services are critical especially in exceptional situations in terms of system stability and resilience against abnormal conditions. However,

[5] This assumption allows for scalability of the results obtained because communication costs are the only ones which increase directly with the number of DER units involved.

exceptional situations must have been excluded from SmartNet studies in order to keep the task manageable.

3 Methodologies for calculating the metrics for the CBA

The CBA was selected as the most suitable approach for the calculation of the macro-level analysis since this method tries to reduce the complexity of the problem by converting all metrics into a monetary unit (no need to assign weights as such, but just converting all the metrics into money). The CBA method allows a more straightforward comparison between the different alternatives and, for some metrics, the monetisation process in the CBA is more objective than assigning subjective weights as requested in the multi-criteria analysis.

In the SmartNet macro-level analysis, each TSO-DSO coordination scheme was assessed for Denmark, Italy and Spain and the results compared against a baseline (the centralised AS market model, CS A). Metrics were elaborated and applied for comparing the TSO-DSO interaction schemes for each national case and, as result, the different schemes were independently scored for each country, so that the most convenient architecture, which is different for each national case, could be identified.

Figure 3.1 shows the macro analysis synthesis, in which it can be seen that most of the metrics take the simulation results as a basis, but the ICT costs related to the coordination schemes were managed separately from the rest of the costs directly linked to the coordination schemes deployment. The reason is that most of the metrics result in operational costs, while ICT costs have a predominant investment component. As a result, the selected approach for the calculation of each operational metric is detailed in section 3.1, while the procedure for the ICT costs estimation is detailed in section 0.

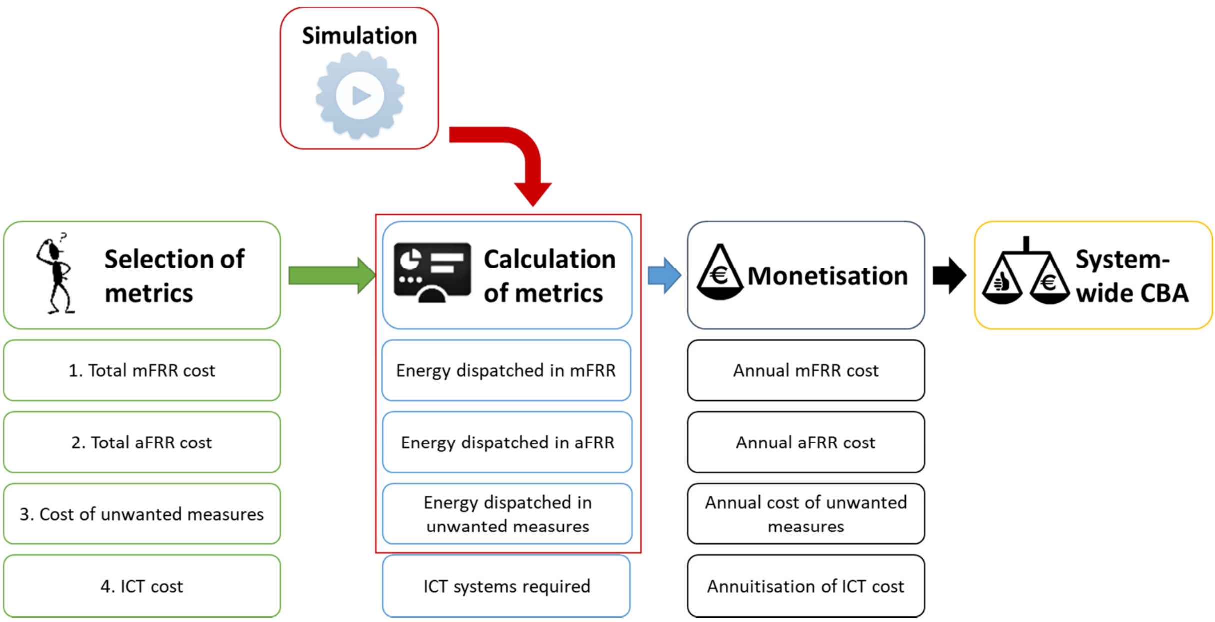


Figure 3.1: Macro analysis synthesis

In addition to the metrics monetised and included in the system-wide CBA, CO_2 emissions were investigated as a complementary metric (and included in section 3.1), because they can provide extra

information for the CBA. However, CO_2 emissions were not monetised because the bids sent by aggregators to the mFRR market already include an estimation of the cost of the CO_2 ton.

3.1 Operational metrics calculation

The flexibility market considered in the SmartNet project, which is called "Integrated Reserve Market", is aimed at solving real-time imbalances and congestions between gate closure of intraday markets and real time until the opening of the next intraday market session [2], [3], [4], [5]. The market horizon can vary as a function of the market requirements, but in general it would last from 15 minutes to 1 hour. When a market session is opened, bidders, which can be conventional and/or distributed energy sources at transmission and distribution networks, are asked to submit their flexibility bids. These can be in both directions, positive or negative, depending if they contribute to upward or downward balancing, respectively. Complex bids including temporal and/or logical constraints are also allowed.

Other important characteristics of the market clearing algorithm are that it considers a pay-as-clear approach and that it calculates nodal prices. In the pay-as-clear approach, all the activated bids receive the same price, which corresponds to the most expensive activated flexibility (as opposite to the pay-as-bid approach, where each activated bid receives the price they bid), so that the risk of market participants bidding in terms of what they want to receive instead of their real cost of flexibility is removed [23]. Likewise, nodal pricing is the most granular pricing approach, i.e. each node in the considered network has a different price, so that the effect that network losses and limitations in grid elements have in the price creation can be accounted for.

As described in [3], the simulation environment has been divided into three main layers:

1. Market layer: This layer integrates the market clearing algorithms, which process the bids proposed by the different market players and returns the optimal activations aimed at restoring the system balance and solving/avoiding network congestions.
2. Bidding and dispatching layer: In this layer the bids that different agents (both traditional producers and retailers and aggregators that represent the numerous flexible resources connected in distribution) send to the market layer are created. For that purpose, market players use different algorithms to process the available flexibility of energy resources into bids and to translate market results into activations.
3. Physical layer: This layer simulates the physical processes of the electrical network (transmission and distribution) as well as the generation, consumption and storage equipment connected to it. Therefore, it simulates the effects of the activations on transmission and distribution networks, including the physics of each (flexible and non-flexible) device connected to them.

With the data corresponding to each of the scenarios, as described in sections 4.2.1, 4.3.1, 4.4.1, the appropriate simulations have been carried out for the five coordination schemes in the three countries. In

this way, it has been possible to calculate the foreseen productions by the different types of technology, the consumptions and the prices in each one of the network nodes for each programming period.

3.1.1 Total mFRR cost

This indicator includes the total balancing cost in the SmartNet market. The mFRR activations are the result of the SmartNet balancing market. They are aimed at solving the network imbalance and congestions predicted for the next time steps.

As the motivation of the SmartNet market is to allow a fair and cost-efficient competition between different sources of flexibilities, including the ones located at the distribution level, it appears natural to use the most economically efficient approach of the marginal price. In the SmartNet market, network constraints, both at transmission and distribution levels, have to be taken into account. Marginal pricing can be adapted to a system with network constraints in different ways, becoming a Locational Marginal Price (LMP). This is the approach applied in the SmartNet market [2].

Therefore, the cost of the SmartNet market will be valued multiplying the energy matched in the SmartNet market by the corresponding nodal marginal price.

3.1.2 Total aFRR cost

Real power systems and energy resources are affected by forecasting errors and, for this reasons, mFRR activations are not typically capable of perfectly balancing the system and a residual imbalance is constantly experienced. In addition, actual power exchanges of resources, as well as unforeseen congestions, may require the intervention of network operators in re-dispatching programmable units (with a consequent impact on the mFRR balancing effectiveness – see section 3.1.3). Especially for this last motivation, TSO-DSO coordination schemes are expected to have an impact on the imbalance after the mFRR activation.

CBA needs to consider the residual imbalance to accurately evaluate (and compare) the performance of each TSO-DSO coordination scheme and to convert it into a cost. A possible approach consists of calculating the cost of activated aFRR, reserve that groups all the resources responsible of restoring the balance of the system after the mFRR activations.

aFRR resources are often experiencing economic losses in managing a regulation reserve (e.g. conventional generators cannot produce up to their technical limits, since a given percentage of power flexibility needs to be reserved for aFRR). For this reason, aFRR is typically more expensive than mFRR and the three reference countries are adopting different remuneration schemes:

- in order to take into account these losses, Denmark and Spain are recognizing a reward for the allocated capacity;

- Italy, since reserve capacity is not remunerated, flexibility resources are submitting aFRR bids more expensive than mFRR ones (Figure 3.2).[6]

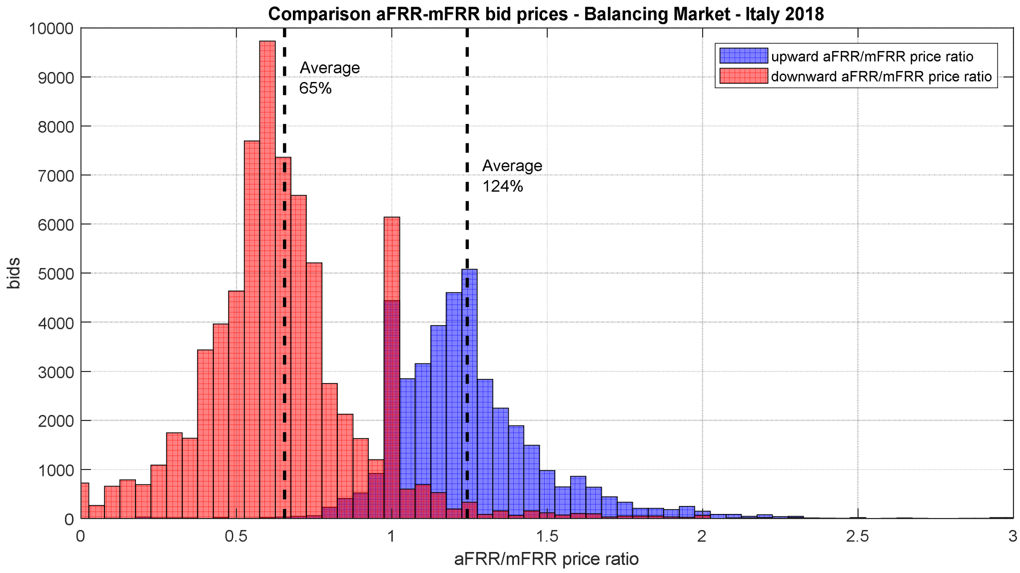


Figure 3.2: Comparison between mFRR and aFRR flexibility prices

By 2030, these remuneration schemes are expected to change, but it is difficult to predict their evolution. For the sake of simplicity, an evolution of the Italian procurement method is supposed to be functional in all the considered countries with the following structure:

1. aFRR dimensioning at each balancing market session;
2. Construction and submission of aFRR bids by flexible resources;
3. Selection of aFRR participating resources on the basis of a merit order list;
4. Calculation of the aFRR cost on the basis of the actual aFRR activations and cleared price (cost of the most expensive selected resource).

3.1.2.1 aFRR dimensioning at each balancing market session

At each balancing market session, the aFRR total needs (downward and upward separately) are calculated for the next time steps. In theory, aFRR is dimensioned by using dedicated tools [24], with the role of anticipating the balancing reserve necessities. SmartNet is not dealing with the reserve dimensioning problem and, for this reason, aFRR procurement and activations are considered in an approximated way.

The simulation platform returns the residual imbalance after the selected mFRR activations and the application of re-dispatch measures by network operators for each time step[7]. This imbalance

[6] In general, aFRR price is also more expensive than mFRR price in Denmark and Spain.

corresponds to the theoretical aFRR activation needs, and the resulting profile can be used for the dimensioning of aFRR volumes. This, of course, cannot be happening in the real world since activated volumes of aFRR are not known *a priori*. However, for the SmartNet investigations, the actual imbalance is considered a reasonable approximation of its prediction (the one used by a real reserve dimensioning tool). At this point, taking into account some simple safety margins (a minimum amount of reserve $aFRR_{min}$ and a coverage factor k_{aFRR}), aFRR between the generic time instants t_1 and t_2 is dimensioned as:

$$\begin{cases} aFRR_{upward}\ (t_1 \div t_2) = \min\{aFRR_{min}\ , -\min[negative\_imbalance(t_1 \div t_2)] \times k_{aFRR}\} \\ aFRR_{downward}\ (t_1 \div t_2) = \max\{-aFRR_{min}\ , \max[positive\_imbalance(t_1 \div t_2)] \times k_{aFRR}\} \end{cases} \quad (5)$$

Figure 3.3 reports an example of aFRR dimensioning based on the simulation results achieved for one day of Denmark. From the figure it is evident how aFRR is recalculated every hour, i.e. at each balancing market session, on the basis of the experienced residual imbalance.

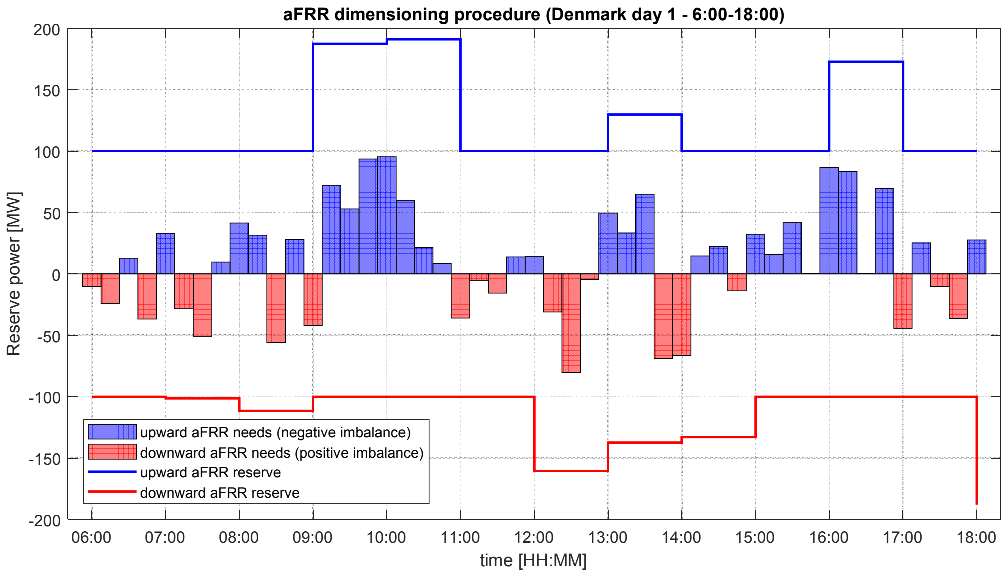


Figure 3.3: aFRR dimensioning based on residual imbalance returned by simulations (kaFRR=2 and aFRRmin=100 MW

3.1.2.2 Flexibility resources submit aFRR participation bids

According to the SmartNet investigations reported in [25], all the simulated flexible resources can theoretically participate in aFRR services. Since the simulation platform is not considering the

[7] The simulation platform includes aFRR, but the selected activations are aimed at maintaining the stability of the system, rather than the full restoration of the residual imbalance. In addition, the aFRR resources are selected with practical criteria oriented to maintain a simple simulation structure. For these reasons, aFRR activations returned by the simulator are not always a realistic representation of the residual imbalance cost.

procurement of the resources, the available flexibility to be offered for aFRR has to be calculated in post-processing. A possible way of creating aFRR bids consists of:

- looking at the submitted mFRR bids (mFRR bids are describing in an accurate way the available flexibility in every single simulated time step);
- hypothesizing aFRR flexibility identical to a fixed portion $k_{a/mFRR}$ of the submitted mFRR bids (this portion has to be selected in order to make the available aFRR resources higher than the dimensioned aFRR needs – it might be varying country by country);
- applying penalization coefficients to aFRR flexibility costs in order to make it more expensive than mFRR (according to the data reported in Figure 3.4, possible choices are $k_{positive}$=1.24 and $k_{negative}$=0.65 – to be applied to positive and negative costs respectively).

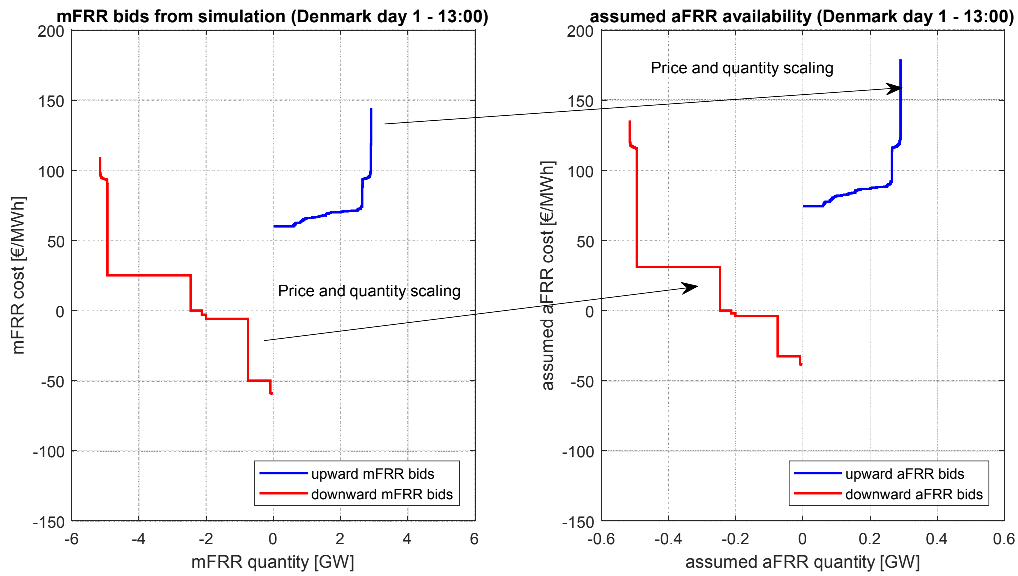


Figure 3.4: Comparison between mFRR and aFRR bidding curves for ka/mFRR=0.1, kpositive=1.24 and knegative=0.65

3.1.2.3 Selection of aFRR participating resources

Once the aFRR bids are generated, the balancing market is assumed to process them by means of a merit order based procedure. While mFRR is used for both balancing and congestion management, its activation is beneficial for both transmission and distribution networks, and TSO DSO coordination schemes are affecting the selection procedure of the mFRR resources. On the contrary, aFRR is called to support balancing (which is not a distribution service) and the selection of the participating resources can be based on an independent/unique procedure:

The submitted flexibility quantities are compared with the reserve needs for the next time intervals, and the less expensive resources are selected to participate in aFRR services (Figure 3.5). Since SmartNet has adopted a pay as clear pricing for energy balancing, aFRR is remunerated with the marginal price of the most expensive selected resource. Figure 3.6 reports the resulting aFRR marginal price for (the simulated day of one scenario).

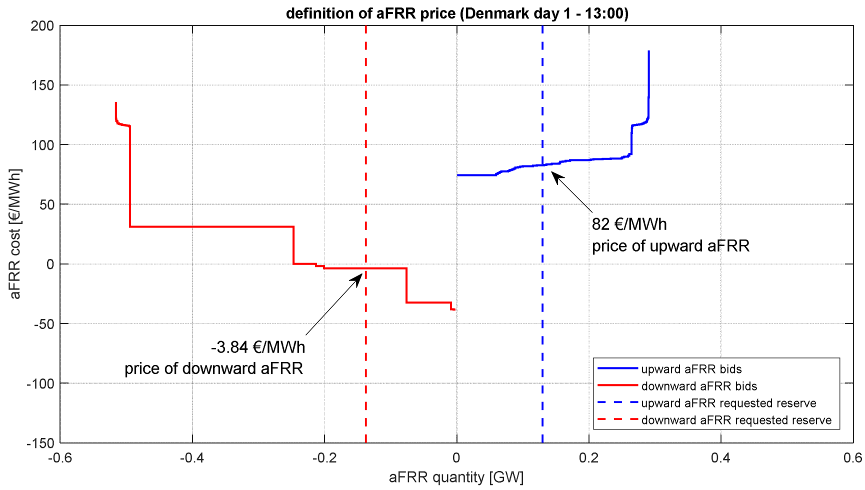


Figure 3.5: Comparison between the aFRR bidding curves and the reserve needs for a given time instant

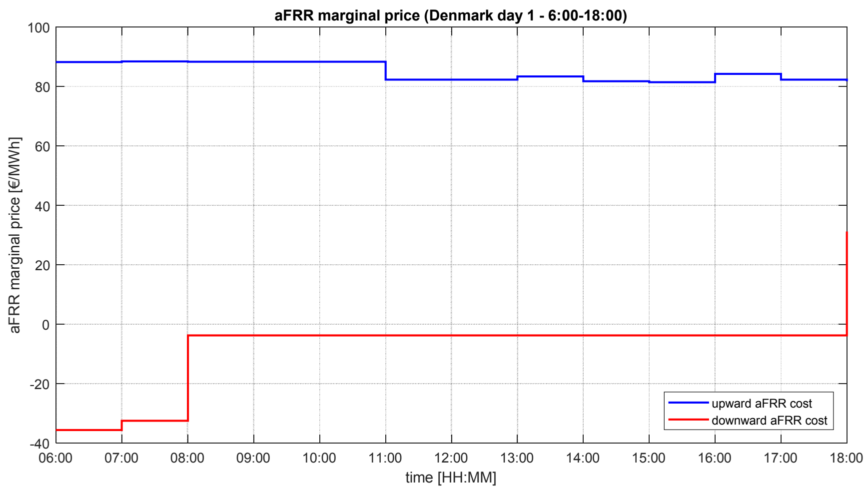


Figure 3.6: Resulting aFRR marginal price for each simulated time instant (ka/mFRR=0.1, kpositive=1.24 and knegative=0.65)

3.1.2.4 Calculation of the aFRR cost

At this point, all the details of aFRR dimensioning, procurement and activation have been defined and the total cost of this service can be easily calculated. As anticipated above, the aFRR activated volume for a given scenario is assumed to be the residual imbalance returned by the simulator (Figure 3.3). By

multiplying, for each time instant, the aFRR energy with the marginal price returned by the hypothesized balancing market (Figure 3.6), the total cost of aFRR can be finally calculated (Figure 3.7).

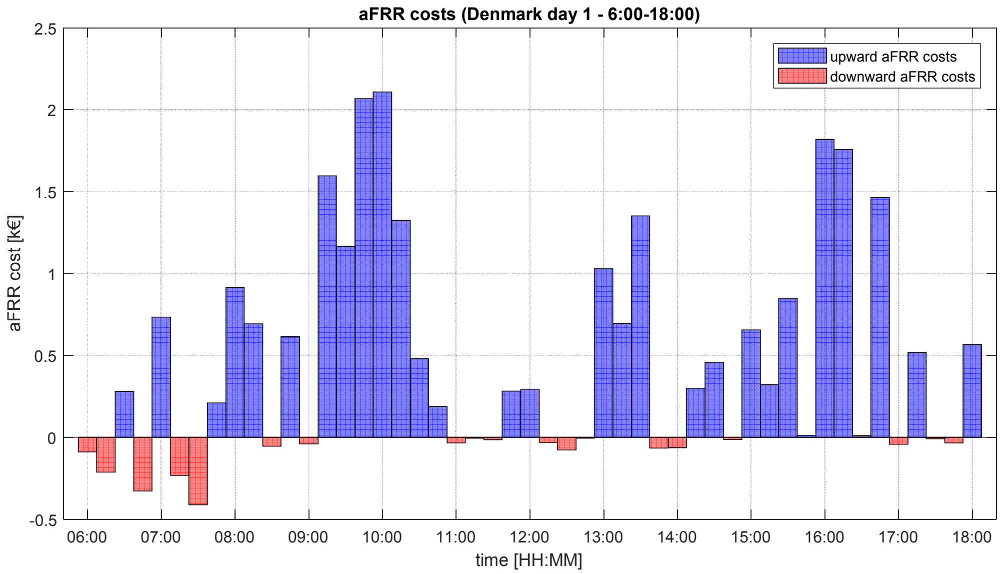


Figure 3.7: Resulting total cost of activated aFRR

3.1.3 Cost of unwanted measures

Market clearing and bidding algorithms result in activations decided on the basis of a forecasted situation. This means that, in addition to a residual imbalance after mFRR activations, network operators could also face unexpected congestions that have to be promptly solved by re-dispatching flexible resources in order to avoid the intervention of grid protections. Most of the time, re-dipatching consists of renewables curtailment, storage units and conventional generation rescheduling. These “unwanted measures” has a cost for the system and are dependent on the applied TSO-DSO coordination scheme[8]:

- Unwanted measures require the activation of flexibility, which is paid by the network operator (TSO or DSO depending on the re-dispatching competency) to the activated resources. It is assumed that re-dispatched resources are remunerated according their actual cost for reaching the requested set-point (pay as bid).
- From the cost perspective, unwanted measures have a more significant impact on the system imbalance. In fact, emergency re-dispatching is not operated in consideration of network balancing, increasing the requested volumes of aFRR (with a significant effect on the system total costs).

[8] TSO-DSO coordination scheme A does not consider distribution network limitations and, in case of activation of distributed flexibilities, congestions at this level have to be solved separately with unwanted measures. This is not happening with market architectures including distribution grid modelling.

3.1.4 CO_2 emissions assessment

A more efficient cooperation between TSOs and DSOs can enable low-carbon generation technologies to replace conventional plants with higher carbon emissions, thus facilitating the necessary energy transition. A detailed network and resources model, in combination with the generation dispatch and unit commitment model, is used to evaluate the management of the available flexibility, including the one provided by low-carbon generation technologies in each coordination scheme. Standard emission rates for each generation technology are taken into account [26].

The achieved savings in CO_2 emissions can be calculated from the difference between dispatched power of conventional generators and Combined Heat and Power (CHP) plants before and after SmartNet market is dispatched, and the CO_2-emissions factors for the different technologies. For all conventional and CHP devices (power plants):

i. To calculate the dispatch of these devices before SmartNet market, the nominal power for each device is multiplied by the active power injection of that device. The result is the time series of injected power by each device within the simulated period.

$$A_i = nomP_i * \ activePowerInjection_i \qquad i: device \tag{6}$$

ii. To calculate the dispatch of these power plants after SmartNet market, the set points for the devices in the physical layer, which represent the active power injection after the SmartNet market, are considered. As a result, a time series of injected power by each device is obtained.

$$B_i = phyP_i \qquad i: device \tag{7}$$

iii. The difference between A_i and B_i is the (either upward or downward) activation of conventional devices. By multiplying this value by the emission coefficient of each device, the additional CO_2 emissions for each coordination scheme are calculated.

$$CO_2\ Emission\ Difference = \sum_i (B_i - A_i) * EmissionFactor_i \qquad i: device \tag{8}$$

The CO_2 emission factor is assumed to be 0.2015 ton/MWh for the Combined Cycle Gas Turbines (CCGT) and CHP plants and 0.3388 ton/MWh for the coal power plants [26][9].

[9]Since this analysis looks at the conditions in 2030, the emission factors considered take into account recent improvements in CCGT, CHP and coal power plants, which used to be higher in the past.

3.2 ICT costs

The main goals of the estimation of ICT costs are:

- To discover cost differences in terms of ICT systems for upgrading the centralized AS market model (CS A) to alternative CSs, under the assumption that the centralized AS market model (CS A) will be implemented by 2030.
- To analyse future requirements of a general ICT system (market and aggregation platforms and bidding systems), the amount of communication, and the requirements in the coordination schemes.

3.2.1 Assumptions, framework and limitations of ICT cost estimation

The ICT cost estimation task was formulated as follows:

> *Based on current arrangements and developments in the electricity markets, and under the assumption that the centralized ancillary service (AS) market model (CS A) will be in use by 2030, the ICT costs discussed here are estimated costs of upgrading from the centralized AS market model to i) Local AS market model (CS B), ii) Shared balancing responsibility model (CS C), or iii) Common TSO-DSO AS market model (CS D).*

Since the communication systems required to have the centralized AS market (CS A) in operation by 2030 are the same as for the rest of the coordination schemes, the estimation of ICT costs concentrated on IT systems required to implement bidding and market clearing functionalities in different coordination schemes. The systems and communications that are not directly related to coordination schemes were left outside the scope of this analysis. Note that this ICT cost estimation involves large uncertainties on technology and cost development, since energy markets and grids are currently changing and the target year 2030 is relatively far, at least from the ICT development cycle point of view.

In practice, this analysis consisted of estimating what kind of ICT infrastructure will be applied to the baseline scenario and how the baseline infrastructure will be upgraded in order to realize other market model alternatives. Assuming that the centralized AS market model will exist in 2030 implied a number of consequences. Also, focusing the analysis on 2030 required predictions about technology and cost developments that needed to be pointed out explicitly. Thus, the assumptions about the framework during the process of estimating ICT cost are listed below.

1) The communication requirements for all relevant DERs to participate in AS markets will already exist by 2030. Thus, there will be a communications connection to each flexible DER of any size and type and its cost will be low enough so that participation in CS A will provide benefits to the

DER owner. There is no certainty if this assumption will apply in 2030[10]. Adequate technological solutions already exist now, but it is highly uncertain if they will be implemented everywhere by 2030, because unbundling of the electricity market fractionalises the business case and separates the benefits and costs to different actors. Meeting the minimum compulsory requirements of the AS communication needs is one possible solution.

2) Aggregation services will be in place by 2030 and aggregators will have algorithms to aggregate devices in distribution grids in order to bid in the TSO AS market. There will be functional AS markets in which even small entities will benefit from participating (directly or indirectly). Again, there is no certainty about the existence in the future of aggregation services suitable for very small DERs in the SmartNet real-time market.
3) The central market clearing will be implemented and therefore all necessary communications, data management and other services will exist at the level needed for the centralized AS market in 2030.
4) The central AS market clearing will have access to and information of the transmission network, to solve congestions and imbalances. It was assumed that, in the CS D, access to similar information of the connecting distribution networks will be possible.
5) There could be service providers that implement SmartNet coordination schemes and offer, for example, all services needed to run local AS markets to DSOs. This will be particularly relevant if there is a large number of small DSOs.
6) Only the ICT costs directly associated with the coordination schemes were compared. Note that the coordination schemes will have different indirect costs and benefits, e.g. they may need different amounts of investments to compensate for their weaknesses. Some of these investments may even be alternative ICT solutions. For example, the performance of the centralized AS market (CS A) regarding DER hosting capacity etc. can be improved, if the distribution network constraints are managed via dynamic grid tariffs [28], [29], [30]. Such differences were not considered here.
7) No investments or development costs were included in the analysis regarding systems, facilities or communication connections that will exist in 2030, regardless of the studied coordination schemes. These were assumed to be available for the purposes of a coordination scheme. Hence, the usage of a coordination scheme will not require new machine rooms or such facilities. The existing communications were assumed to accommodate messages related to a coordination scheme as the data amount will be low.

[10] System Operation Guideline UE/2017/1485 and the European gird connection codes set mandatory requirements for the real time information and remote controllability of distributed generation and will be developed to cover smaller DERs.

The requirements and standards do not define adequately the critical details for the control connectivity of very small DERs. Thus, it is not certain yet to what extent these requirements facilitate the needed fast control communications to all DER sizes and types crucial for the fast SmartNet ancillary services. Very small flexible resources (roughly down to 1kW) including loads, embedded generation and storage may be needed to make sure that each node has adequate market liquidity.

8) The cost of all ICT needed to monitor and control own systems or assets, in order to participate in the AS markets, was considered as an internal cost for monitoring and asset management. This also includes the cost of making decisions on what and when to bid, as well as receiving activation instructions. Thus, such costs were not included in the implementation cost estimation of the coordination schemes.
9) Some costs were not included in the costs estimation, as the IT system cost estimation was expected to contain uncertainty that is higher than the share of these costs. These costs include:
    a. Solver license costs: It was assumed that optimisation problem solver can be used in server mode to solve local markets for several DSOs. Hence, the solver costs will be very low in comparison to the cost of developing aggregation and market clearing implementations.
    b. Cost of multiple computing sites: It was assumed that DSOs and TSO will already have multiple computing sites that can be utilized for coordination scheme computations without additional investment on machine rooms or equivalent infrastructure.

Abnormal and restorative energy grid/market or telecommunications situations were left out of the scope of the analysis (see [31], [32] and [33] for concepts in grid security). Typically, for an electricity grid, N-1 security standard is assumed, which means that normal operation functionality can be securely maintained during any single fault in the grid by provisions of ancillary services or other available resources. The abnormal events are typically related to technical system operation. However, it is also important to have means to address an unusual market situation and maintain grid functionality and security. Also, ICT failures or cyber reasons can lead to an abnormal situation. It was assumed that ICT systems for implementing the coordination schemes will be built according to standard reliability practices. However, further analysis of abnormal and restorative power grid states may provide information that affects ICT systems and thus their costs.

The ICT cost estimation work focuses on capital expenditure (CAPEX) costs. According to a common practise, operating expenditure (OPEX) costs can be assumed to be proportional to CAPEX costs [27]. Annual OPEX costs can be considered as 20% of CAPEX contemplating the current rate of maintenance fees of commercial solvers[11].

Furthermore, real purchase costs of IT systems can be very different from the development costs due to various reasons. In general, market opportunity, cost estimate uncertainty, contractual terms, requirements diversity, and financial health are listed as main factors affecting software pricing in [34]. The estimates provided in this work considered development costs of IT systems, but this does not change the relations of candidate coordination schemes (CS B, CS C, and CS D) with each other. It was very hard to predict what will be the actual purchase costs related to one particular coordination scheme

[11] See: https://ampl.com/products/standard-price-list/

in the future when the implementation of the coordination scheme takes place. Recall that the word *implementation* is used to refer to the work in designing, specifying, coding, testing, validating and documenting software.

3.2.2 The COCOMO method

Estimation of a work effort needed to implement IT systems is generally very difficult. According to software engineering literature, the software development process usually consists of five main phases, whose relative shares are [34]:

1. analysis 15%,
2. design 25%,
3. coding 20%,
4. testing 30%, and
5. documentation 10%.

There are some functional methods to derive rough estimates of software development efforts, even though they contain a large uncertainty. One of the classic and the best-known methods is the COnstructive COst MOdel (COCOMO) [35], which estimates the number of person months (PM) as a function of source code lines:

$$PM = A \times KLOC^b \tag{9}$$

where KLOC stands for thousand (kilo) lines of source code and A, b are adjustable parameters, which depend on the IT system environment.

In an embedded system, where other hardware, software, regulation and operational procedures are already in place, the suggested values for the adjustable parameters are A=3.6 and b= 1.2 [34]. This environment corresponds best to the environment of TSO-DSO coordination schemes, but PM estimates in a less demanding environment were calculated as well for performing a sensitivity analysis.

Note that there are more advanced versions of COCOMO and other estimation methods [34], but those were not considered to be feasible in the context of the SmartNet project, as they require more expertise and effort. Moreover, the simple COCOMO model expresses well the fact that the development efforts depend exponentially on application conditions. For example, IT systems for critical infrastructures are typically estimated to be much more expensive, as the testing and validation processes require more efforts and care.

However, the SmartNet project was a research project, not a software project, and therefore the COCOMO method needed to be adjusted to correct differences between research and real-life implementation activities. The final outcome was a hybrid approach utilising both the available data

sources and the COCOMO method with necessary adjustments to infer actual real-life implementations based on research implementations, as presented in subsection 3.2.3 below.

3.2.3 A hybrid estimation method

The simple COCOMO method estimation needed to be adjusted for the comparison of coordination schemes, because the SmartNet simulator implementation was not equivalent to a comprehensive IT system that includes all functions needed in aggregation, bidding and market clearing. For example, the simulator used a large common database for all the data, with unlimited access. In addition, the simulator was implemented for research purposes only, without additional efforts on user-friendly interfaces, reporting function as requested by regulation or such. The modifications to the COCOMO estimate and their justifications are provided below:

- The work for a complete IT system was estimated to be four times as large as the SmartNet simulator work. This work was further divided into 25% of higher-cost work by senior experts and 75% of lower-cost work (by non-experts).
- The objective of SmartNet was to bring technology from Technology Readiness Level (TRL) [36] 2 to TRL 4-5. Although this objective has been achieved, TRL is still below the level required for commercial applications (TRL 9). Therefore, further analysis and software development will be needed to validate candidate coordination schemes before they can be taken into real-life use. It was assumed that this additional work requires twice as much the effort of the SmartNet simulator, because it must be more detailed (in terms of DSO networks) and it should provide information on handling abnormal events either in grids, markets or ICT. Moreover, changing the regulation to accommodate a new coordination scheme requires a massive amount of work in administrative or legal aspects (that affect ICT costs), which is out of the scope of the SmartNet project. Therefore, ICT costs estimates focused on the work required for developing a simulator for assessing the functionalities of a new coordination scheme. Additionally, an analysis to gain an understanding of abnormal situations was also needed, although those are outside the scope of SmartNet.
- The market clearing process in the common TSO-DSO AS market model (CS D) became critical and hence its cost increased. In CS D, the process clears the market for the whole country at both TSO and DSO level. A highly fault tolerant and dependable market clearing solution is needed, because local market clearing is not performed (i.e. DSO resources are cleared in the centralized market). A feasible market clearing solution needs to be obtained for all time steps and market/grid conditions. High dependability software costs more due to increased efforts in validation and testing [34]. Thus, a criticality cost increase was added to the cost estimate of CS D.

Figure 3.8 illustrates the work flow of the SmartNet ICT cost estimation. The first step was to estimate person-month efforts, based on the number of computer programme code lines in the SmartNet simulator by using the simple COCOMO method. Based on an internal consultation within the project consortium, the work efforts required for aggregation and market clearing were further split into implementing the base-line centralized AS market model (CS A) and the alternative coordination schemes (CS B, CS C, and CS D). Moreover, the work efforts were further divided into smaller tasks in order to estimate the effort of upgrading the centralized AS market (CS A) into alternative coordination schemes (CS B, CS C and CS D). At this point, the adjustments explained above were performed as well. Finally, the cost estimation for the base-line (CS A) and the upgrades to the four alternative schemes (CS B, CS C, and CS D) were calculated by estimating the costs of person months.

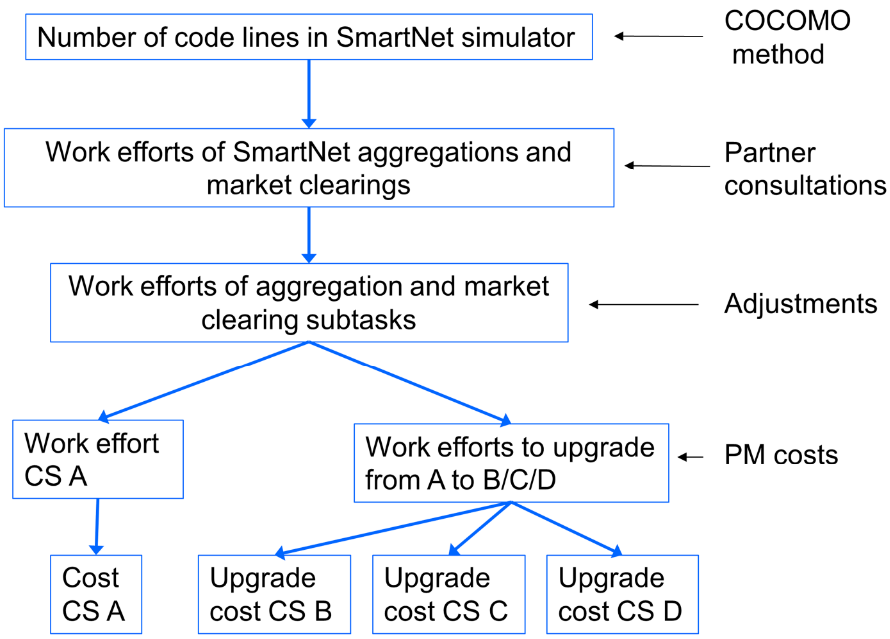


Figure 3.8: Illustration of the hybrid cost estimation method

3.2.4 Data sources

Once the research methodology was established, the data to feed the calculations had to be selected. However, the required data are seldom publicly available, so a detailed research work had to be carried out to find information sources that can be related to the systems needed in coordination schemes. In this case, the relationship between some DSO grid management information systems and the grid management system was investigated in the common TSO-DSO AS market model (CS D).

Additionally, communications of smart metering and various cost analyses were related to DER communications for discussing the feasibility of assuming the centralized TSO AS markets (CS A) in 2030 in such a way that DSO level DERs are aggregated to the TSO market.

3.2.4.1 SmartNet simulator

First of all, the data gathered from the SmartNet simulator were considered to estimate the required ICT investments, based on the COCOMO method. The simulator was implemented in Python and AMPL languages, and CPLEX solver was used to solve complex optimization problems, in order to compare the different TSO-DSO coordination schemes. The simulation models described flexible energy resources at a physical level from large units down to domestic white appliances and electric vehicles and separate aggregation algorithms were developed for different types of DER units [37]. Therefore, the simulator implementation [3] contains all aggregation algorithms (Thermostatically Controlled Loads (TCL), conventional generators, storage, CHP, curtailable generation / load and atomic loads) for various types of resources and all market clearing algorithms (central market, local market and common market) needed in the coordination schemes [2].

The simulator used a common database for all the data, which is not the expected procedure for real-life systems. This implies that the simulator implementation contained fewer interfaces among different systems than in real life, so it reduced the amount of coding to some extent. However, the simulator also required some data processing to analyse the results.

However, the SmartNet simulator provided valuable information on estimating work efforts of implementing aggregation and market clearing. The COCOMO method was used to relate the SmartNet simulator implementation efforts to real-life work effort estimates, and further to ICT costs. For that purpose, the numbers of code lines in the aggregation and market clearing components were taken as an input. The numbers of code lines were approximately 36 000 and 21 000 for aggregation and market clearing components, respectively (calculated on Jan 24, 2019).

3.2.4.2 Efforts estimated by implementation partners

Although the SmartNet simulator provided very valuable information, it was built for research purposes, so some adjustments were needed in order to estimate real-life systems. As a result, the partners who developed the simulator were contacted to provide estimates of real-life implementation. The SmartNet aggregation and market clearing components of the simulator were developed by six project partners, four of which provided estimates of required person-months for real life implementation (to be utilised by commercial aggregators, DSOs, and TSOs) of aggregation and market clearing algorithms. It turned out that partners were rather optimistic about the work effort needed. However, partners’ inputs provided valuable insights for estimating the work share of the aggregation and market clearing developments required:

- It was assumed that the total work of SmartNet aggregation tasks (excluding DSO aggregation) consisted of i) implementing aggregation to bid into the centralized AS markets (CS A), i.e. the TSO market and ii) upgrading the aggregation algorithm for offering bids to

local markets. The share of the aggregation work done in SmartNet to bid into TSO markets was estimated to be 56 %, with the remaining 44 % to allow aggregators to bid into local markets.

- It was considered that the market clearing work included TSO market clearing (CS A), upgrading market clearing for local markets, and DSO aggregation, whose cost shares were 40 %, 30 %, and 30 %, respectively.

3.2.4.3 IT system costs in national DSO regulation

DSOs in Europe are regulated by National Regulatory Authorities (NRAs). To the best of our knowledge, Finland is the only country in which the DSO regulation model includes publicly available minimum functional requirements and explicit upper bound costs for general IT systems needed in distribution grid operation by the DSOs. According to the Finnish Energy Authority, the IT system cost estimation was based on a report by Empower Ltd and an assessment of their field experts in 2010. These estimates were updated by the Finnish Energy Authority for the regulation period 2016- 2023. In addition, the regulator has made unit cost inquires to DSOs during 2014 and 2015. The IT system estimations correspond to "traditional" systems that meet normal customer service requirements and fulfil functionalities required by laws and regulations. Investment duration is 10 years for all grid IT systems and 20 years for telecommunications in network control, respectively.

The maximum cost recognized by the Finnish Energy Regulation [38] are presented in Table 3.1:

Network Information System	
System, standard unit	112 500 €
Scaling by number of customers	+ 6.6 € per customer
Customer Information System	
System, standard unit	75 500 €
Scaling by number of customers	+ 9.5 € per customer
Energy metering for settlement and billing in the distribution network (includes the cost of meter reading systems)	
Energy meter, remotely read, up to 3x63 A	200 € each
Energy meter, remotely read, over 3x63 A	570 € each

Energy meter, locally read, up to 3x63 A[12]	180 € each
System for management of metering data and calculating metered electricity market balances	
System, standard unit	138 000€
Scaling by energy usage locations	+ 6.6 € per location

Supervisory control and data acquisition (SCADA)	
System, standard unit	301 300€
Scaling by substations	+ 9 800 € per substation
Scaling by remotely controllable secondary substations and switchgear	+ 2 200 € each
Distribution Management System (DMS)	
System, standard unit	21 900 €
Scaling by other integrated grid systems	+ 21 900 € per system
Scaling by substations	+ 1 100€ per substation
Scaling by remotely controllable secondary substations and switchgear	+ 550 € each
Telecommunications for network control	
Communication network	89 800 €
Scaling by substations	+ 5 500 € per substation

Table 3.1: Maximum cost recognized by the Finnish regulation [38]

Many cost items were used (due to similarities) as pieces of background information for estimation of costs of aggregation (CIS, System for management of metering data and calculating metered electricity market balances, SCADA) and last kilometre communications (Billing metering). The cost of Network Information Systems (NIS) was considered as a suitable reference to estimate the cost of handling a large amount of grid data in the common TSO-DSO market (CS D). The regulation cost model was also used as a benchmark and sanity checker in the SmartNet ICT cost estimation. For example, IT system cost estimates based on the work efforts provided by researchers were compared to these costs approved by regulators. This comparison confirmed that the work efforts estimated by researchers were likely to underestimate the ICT costs of coordination schemes, but cost estimates derived by the COCOMO method were more realistic.

[12] The number of meters allowed by the authority in this category is very small.

3.2.4.4 Information on last kilometre communications

SmartNet ICT cost analysis gathered information from various smart metering system requirement specifications and CBA reports, in order to assess the cost of communications to households with DER capability. For example, a good recent overview of smart metering systems and requirements is in chapter 3 of [39]. The cost benefit analyses considered in [40] were done prior to roll outs and do not tell the actual realised costs and benefits. In addition, the project received anonymized data on DSOs' smart meter deployment costs in 2016 in Norway. These data referred to 111 DSOs, which represent over 2.9 million metering locations. Out of these, about 2.3 million locations were households, 0.3 million summerhouses or equivalents and 0.3 million industry locations (each industrial site consumes over 100 MWh annually). Unfortunately, this kind of data concerning existing systems was not available from Italy, Spain, or Denmark. The ICT cost estimates do not include any last kilometre data as a direct input. Rather, the role of last kilometre data was to help in assessing the feasibility to the working assumptions of the ICT cost estimation.

The following conclusions can be drawn regarding the communications costs of distribution-related ancillary services (AS).

1) The functional requirements of the metering system have a much smaller impact on the costs than the installation costs of the meters.
2) The smart metering systems will not adequately support distributed AS, unless the functional requirements for smart meters are amended accordingly. The most important missing capability is to adequately and quickly activate AS provided by many small DERs. The capabilities to support verification of the responses must also be upgraded. In some vertically integrated utilities outside Europe, smart metering systems already support distributed AS.
3) The smart metering systems have many properties that are needed by distributed AS. These include measurements for billing, verification and, to some extent, voltage quality, reasonable existing cyber-security requirements, adequate independence from third parties that may suddenly stop their service, etc.
4) Existing communication requirements for smart metering systems, especially in Europe, are typically not comparable to the communication requirements for the ancillary services provision and, thus, the analysis of costs for smart metering systems does not provide much information about the expected communication costs of distributed ancillary services. Some useful general observations regarding highly distributed systems can be made. For small distributed end devices, the installation and integration costs tend to dominate as functionality in mass produced end devices is inexpensive. With relatively modest additional costs, the communication networks can be made to support fast control actions. Implementing own communication infrastructures for functionalities tends to be relatively expensive compared to implementing a generic common infrastructure for all the functionalities needed. In the distributed systems, integrating many

functionalities is often cost efficient compared to doing the same with separate dedicated systems and devices. Dedicated, last-kilometre ICT infrastructure can be too expensive for the provision of AS from small flexible DER.

The analysis of the last kilometre is further described in Appendix III, section 10.

Last kilometre communication costs were outside the main scope of the SmartNet project and its ICT cost comparison. They are briefly discussed here, because the development of these costs depends very much on integration of services and technologies and related regulations. They have a significant impact on the minimum size of flexible DER that are feasible to be aggregated in the SmartNet integrated reserve markets. The aggregation costs and the last kilometre costs were estimated to be roughly as big as the ICT costs included in the comparison.

3.2.4.5 Summary of ICT cost estimation input sources

The use of various information sources in the ICT cost estimation is summarised in Table 3.2:

Input	Utilization in cost analysis
The number of programming code lines for aggregations and market clearing modules in the SmartNet simulator	Primary input for estimating work effort in creating aggregation and market clearing systems for real implementations.
Consultations to SmartNet partners on work efforts for implementing aggregation and market clearing algorithms that are ready to be used in network operations. Input on work efforts of various subtasks.	Partner input allowed splitting the total work effort derived from SmartNet simulator implementation into subtasks of implementing the base line coordination scheme (CS A) and upgrading that to future coordination scheme candidates (CS B, CS C and CS D).
Finnish DSO regulation's explicit upper bound costs for the ICT systems commonly needed in distribution grid operation.	The regulation cost model is based on the reported DSO costs and expert estimates. In SmartNet, this served as a collection of reference systems and a sanity checker in estimating costs of the solutions proposed by SmartNet. Although there are considerable differences between DSOs common IT systems and SmartNet solutions, the regulation model may provide lower bound estimates for costs in many cases. NIS was used as a reference for estimating costs of grid data processing in CS D.
Real anonymized costs on smart metering reported by DSOs in 2016. This included communications costs and cost of smart meter data processing. The latter category may also include other costs.	The real data illustrates the variability of communications and data processing costs. It was reasonable to approximate DER communications by smart metering communications costs. Thus, this real communication cost information provided input for assessing the feasibility of the working assumptions of ICT cost estimation.

Table 3.2: Summary of ICT cost estimation inputs and utilization

3.2.5 ICT cost calculation

Calculating ICT cost estimates began with listing IT systems and upgrades that were needed when the base line implementation of the centralized AS market model (CS A) is upgraded to each of alternative candidate coordination schemes (CS B, CS C and CS D). The main cost sources are listed in Table 3.3.

Upgrade from the centralized AS markets (CS A) to local AS markets (CS B)
Aggregation services for aggregators to submit bids to local markets
Implementation of local AS markets according to the coordination scheme
DSO smart aggregation and disaggregation implementation based on parametric optimization
Upgrade from the centralized AS markets (CS A) to shared balancing responsibility (CS C)
Aggregation services for aggregators to submit bids to local markets
Implementation of local AS markets according to the coordination scheme
Note that the DSO and TSO market information exchanges between the market and Common TSO-DSO profile scheduler is assumed to be at low costs and hence included in the general estimate of interface costs
Upgrade from the centralized AS markets (CS A) to a common TSO-DSO market (CS D)
Aggregation services for aggregators to submit bids to local markets
Implementation of the TSO-DSO common market
Interfaces and robust handling of all DSO grid data in market clearing
Solution to calculate effectively the market clearing optimization problem

Table 3.3: Main IT system cost sources in estimating the costs of coordination schemes

Then, as described in Figure 3.8, the numerical COCOMO-estimates of SmartNet simulator work were calculated. These general level estimates are provided in Table 3.4, where the SmartNet simulator coding was split into sections of coordination scheme, simulation scenarios, implementing transmission or distribution networks, DER aggregation, market clearing and emulating the physical electric grids. For the ICT cost estimation, the most relevant estimates were the work efforts required to derive costs of aggregation and the market clearing IT systems. However, the complete SmartNet simulator work, excluding the physical layer, provided information on the effort of testing and verifying the functionality of a TSO-DSO coordination scheme with real networks before it was taken into network operations. Market clearing and aggregation tasks were split into smaller tasks, as explained in the methodology section 3.2.3, in order to calculate the efforts for the above-listed essential upgrades.

The next step was to calculate the ICT costs, based on the equations provided in Appendix II - ICT costs equations. These equations used some variables and a few adjustable parameters, whose meaning and values are given in a tabular form in Table 3.5 and Table 3.6. The values of the variables were derived from the input data according to the ICT cost estimation methodology.

The number of aggregation solution providers and local market service providers were both considered to be three in Italy, Spain and Denmark, as the numbers were expected to be small. Moreover, values below three would mean either a monopoly or an unhealthy market situation. If the number of aggregators or local market service providers increases, the system-level costs for aggregation and local markets become large.

The last step in the calculation of ICT costs was to provide the numerical estimates for national cases, which is presented in section 4.1. The cost estimates of the IT system implementations are presented in NPV, assuming that Denmark has 66 DSOs, Italy has 638 DSOs and Spain has 397 DSOs, as shown in Table 3.6.

Simulator topic	COCOMO simplest version		
	KLOC = kilo lines of code	PM estimated by COCOMO in an embedded environment, A=3.6 and b=1.2	PM estimated by COCOMO in a less demanding[13] (semi-detached) environment, A=3 and b=1.12
scenario	27.5	192	123
network	5.40	27	20
aggregation	36.0	265	166
market	21.0	139	91
physical layer	44.2	339	209

Table 3.4: Effort estimates derived from SmartNet simulator and COCOMO method.

Name	Value	Explanation
highPMCost	25 000€	PM cost of senior specialist work [41]
lowPMCost	22 000€	PM cost of specialist work derived from the senior specialist estimate [41]
nAggregators	3	Number of aggregation solution providers in Italy, Spain and Denmark
nLocalMarketPlatforms	3	Number of service providers offering local market clearings in Italy, Spain, and Denmark

Table 3.5: Parameters in the ICT cost model

[13] COCOMO estimates for a less demanding environment were calculated only for illustrating sensitivity on the usage environment.

Name	Value	Explanation
CocomoCost	666 × highPMCost	Cost of the SmartNet simulator (without physical layer implementation) estimated by the COCOMO method in an embedded environment. Simulator work requires senior specialist level skills.
SimulatorStudyCost	2 ×CocomoCost	Cost of verifying a new TSO-DSO coordination scheme before taking it into use.
marketClearAlgPM	55.6	PM needed for CS A market clearing algorithm development, based on COCOMO and partner consultations.
marketClearOtherPM	3 × marketClearAlgPM	PM needed for developing market clearing, excluding the algorithm development.
localMarketAlgPM	41.7	PM needed for local market clearing algorithm development, based on COCOMO and partner consultations.
localMarketOtherPM	3× localMarketAlgPM	PM needed for developing local market clearing, excluding the algorithm development.
DSOaggregAlgPM	41.7	PM needed for DSO aggregation algorithm development, based on COCOMO and partner consultations.
DSOaggregOtherPM	3 × DSOaggregAlgPM In CS_B only 0.5x DSOaggregOtherPM - costs is taken[14].	PM needed for developing DSO aggregation, excluding the algorithm development.
aggregAlgPM	148	PM needed for aggregation algorithm development, based on COCOMO and partner consultations.
aggregOtherPM	3 × aggregAlgPM	PM needed for aggregation development, excluding the algorithm development.
locAggregAlgPM	116	PM needed in aggregation algorithm development for local markets, based on COCOMO and partner consultations.
locAggregOtherPM	3 × locAggregAlgPM	PM needed in aggregation development for local markets, excluding the algorithm development.
marketClearRTPM	26	PM needed to solve real time requirements of central market clearing in CS D.

[14] This is because locally there is market clearing and DSO aggregation and it can be assumed that data management of local market clearing can be used for managing DSO aggregation data with adding only half of the costs.

DcriticalityCost	(marketClearAlgPM× marketClearRTPM) highPMCost / 2	In common TSO-DSO market model, the central market clearing becomes critical and its implementation cost is increased. This factor reflects both criticality and real-time challenges.

nDSO	nDSODenmark = 66;
	nDSOItaly = 638;
	nDSOSpain = 397;
		Number of DSOs. The cost of central market clearing in CS D depends of how many DSO grids it handles in the optimization process.

nodesForDSO	50	Typical DSO grid model in market clearing algorithm consists of nodesForDSO nodes.

nodesTSO	nodesTSODenmark = 144;
	nodesTSOItaly = 3x3648;
	nodesTSOSpain = 1493;
		The number of nodes to model TSO grid in market clearing of CS D. For Italy, the number of nodes is three times the nodes used to model the Northern-Italy in simulations, while it is the number of nodes in the simulation models for Spain and Denmark.

NISunit	138 000 €	Estimated base-line cost for handling grid data in the market clearing of CS D. The numerical value is the DSO regulation upper bound cost of Network Information System's unit cost.
NISperNode	6.6 €	Scaling factor of the grid handling cost. Numerical value is the scaling factor of the DSO regulation upper bound cost of Network Information Systems.
interfaceCost	22 000 €	The upper bound cost in the DSO regulation for connecting different network management systems.

Table 3.6: Variables in the ICT cost model

4 Results

Before assessing the obtained results in this CBA, it is necessary to summarize the main characteristics of the scenarios considered by the simulations. More detailed information on the main scenario setups and simulation results are developed in deliverable D4.2 [4], specifically, the characteristics of each scenario datasets are detailed. Next paragraphs summarize the data provided in that deliverable, but, for a deeper understanding of how the scenarios are created and simulations carried out, a thorough reading of the document is recommended.

Table 4.1 shows the key characteristics of the final scenario datasets, including the number of flexible devices as well as the number of network elements.

Category	IT (503)	DK (401)	SP (301)	Comment
Photovoltaic (PV)	655 323	203 502	59 943	
Wind	31	3 472	1 053	
CHP	1 531	3	922	Large CHP
Hydro	1 833	0	555	Run or river hydro
Conventional	1 774	67	596	
Storage	212 717	139 355	200 033	EV and pumped hydro
Wet	1 236 325	3 206 570	1 847 500	Domestic appliances
TCL	68 481	74 688	124 539	Domestic heat pumps
Sheddable load	33 783	3 383	43 501	Street lights
Nodes (transmission)	3 648	144	1 493	Transmission network
Nodes (distribution)	2 410	3 388	2 799	Distribution network
Branches (transmission)	4 230	199	2 231	Transmission network
Branches (distribution)	2 410	3 387	2 755	Distribution network
Distribution grids	638	66	397	Primary substations

Table 4.1: Key characteristics of datasets

4.1 ICT cost estimates

The relation between implementation costs and purchase costs is complex, since purchase costs depend on politics, markets, and other issues, as explained in section 3.2.1. Based on the approach described in section 0, it was assumed that the costs related to most CSs (all except CS D) do not depend on the country.

To illustrate results and give some reference figures we list some estimated unit system costs. The coordination scheme consists of multiple such systems and their modifications. For an aggregator, the cost model estimates the IT system costs of aggregating flexibilities to the TSO market to be 13.5 M€ and the cost of upgrading the aggregation to bid in local markets to be 10.6 M€. The IT system cost of

implementing TSO market clearing is estimated to be 5.1 M€. Moreover, the cost of implementing a platform service for local market clearings in the local AS market model is estimated to be as high as 11.3 M€. The DSO aggregation implementation is included in the local AS market model (CS B), which increases the complexity of the IT system and, thus, its cost. Note that upgrading aggregation to local markets can be more expensive than making the local market clearing service. In general, aggregators will have high costs as they require complex IT systems.

However, the centralized market clearing in CS D handles large amounts of DSO grid data and suffers from real-time challenges (the market must be cleared with the appropriate frequency to provide the results for providing the services requested by TSOs and DSOs). Therefore, its cost depended on the simulation model and on the complexity of the market clearing optimisation, which is affected by the amount of grid data and the number of nodes. This yielded different cost estimates for Denmark, Italy and Spain. The cost of the commons TSO-DSO market clearing was estimated to be 20.4 M€ and 14.9 M€, and 7.5 M€ for Denmark, Italy and Spain, respectively.

In each CS, estimates for higher and lower costs were calculated as cost boundaries, which depended on the implementation effectiveness of local aggregation and/or markets. If each aggregation solution provider and market clearing service provider implemented their own solution without any additional support, the costs would be the highest. However, if there were certain national support to develop algorithms for advanced functionalities, such as DSO aggregation, and the results were available for all parties, the cost of implementing local market aggregation and market clearing would be lower. At the lowest total cost level, it was assumed that general implementations could be achieved with a 50% increase to a single implementation cost.

The cost structure in each coordination scheme is illustrated in Table 4.2 by splitting the costs into aggregation and market clearing costs. Recall that estimates for CS B, CS C and CS D were upgrading costs from the existing CS A (which are provided for information purposes in the column in grey), meaning that the components already present in CS A were assumed to be available also for these coordination schemes. Some estimates are provided as lower and upper bounds. This refers to how effectively local aggregation and/or market clearing can be implemented, as discussed earlier. It was also assumed that upgrading from CS A to any of the alternative schemes requires additional work on simulating how the coordination schemes behave in different real-world situations.

The illustration of aggregation and market clearing costs in Denmark is provided in Figure 4.1, followed by the illustration of Italy in Figure 4.2 and Spain in Figure 4.3. The cost of the base line centralized AS market implementation (CS A) is illustrated on the left and the additional costs to upgrade to candidate coordination schemes (CS B, CS C and CS D) are provided on the right. The coordination schemes are denoted as follows: the centralized AS market model (CS A), the local AS market model (CS B), the shared balancing responsibility model (CS C), and the common TSO-DSO AS market model (CS D). In the figures below, the difference between the high and low estimates of the table are illustrated by

lighter colour. The light blue bar illustrates the effectiveness of implementing local markets as explained above.

(M€)	CS A	CS B	CS C	CS D
Aggregation cost – For the TSO market	20.2 – 40.4	N/A	N/A	N/A
Aggregation cost – For the DSO market	N/A	15.8 – 31.7	15.8 – 31.7	N/A
Aggregation cost – For the common TSO-DSO market	N/A	N/A	N/A	15.8 – 31.7
Market clearing cost – TSO market	5.1	N/A	N/A	N/A
Market clearing cost – DSO market	N/A	16.9 – 33.8	9.2 – 18.3	N/A
Market clearing cost – Common TSO-DSO market	N/A	N/A	N/A	20.3 (IT) 14.9 (SP) 7.5 (DK)
Validation studies[15]	N/A	33.3	33.3	33.3
TOTAL (UPGRADE) COST PER CS	**25.2 – 45.5**	**66.0 – 98.8**	**58.3 – 83.3**	**69.4 – 85.3 (IT)** **64.0 – 79.8 (SP)** **56.6 – 72.4 (DK)**

Table 4.2: Summary of main IT cost components in CS A, CS B, CS C and CS D (M€)

[15] The test and validation of this type of critical systems may imply more costs than coding them.

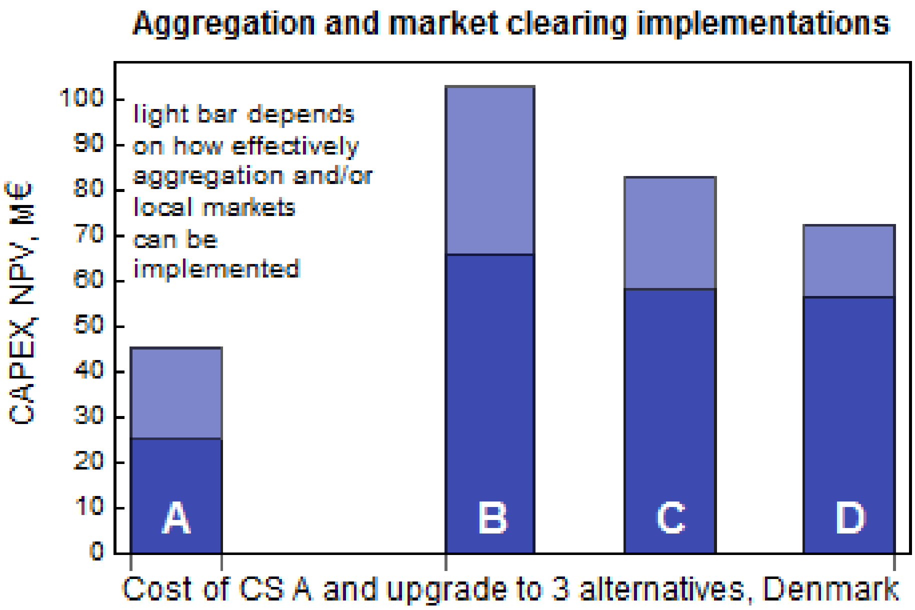


Figure 4.1: Cost estimates of aggregation and market clearing implementations in Denmark.[16]

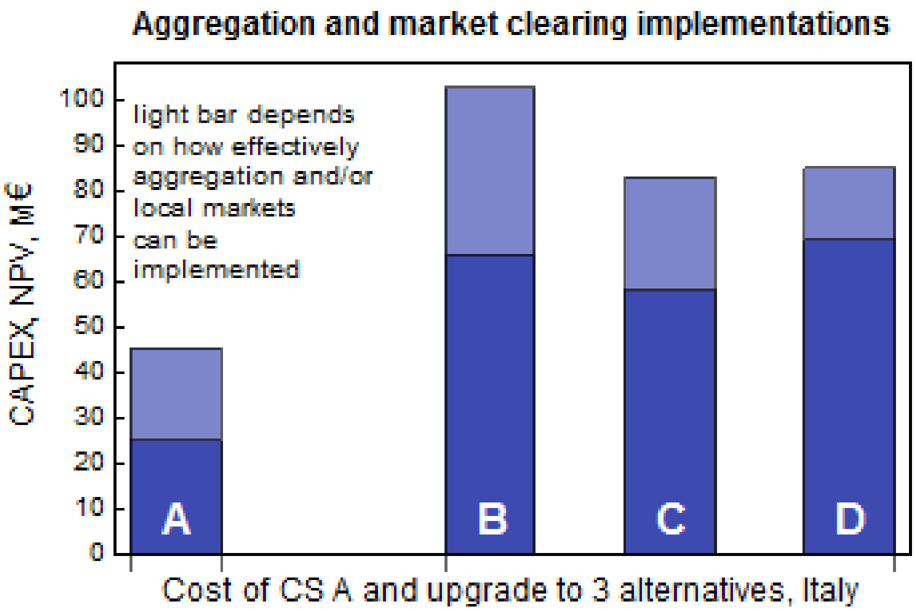


Figure 4.2: Cost estimates of aggregation and market clearing implementation in Italy

[16] The costs for coordination schemes B, C and D are the costs for updating the existing CS A to each alternative scheme. It was assumed that CS A will be in use by 2030. The cost of CS A is for reference purposes only. This comment applies to Figure 4.2 and Figure 4.3 as well.

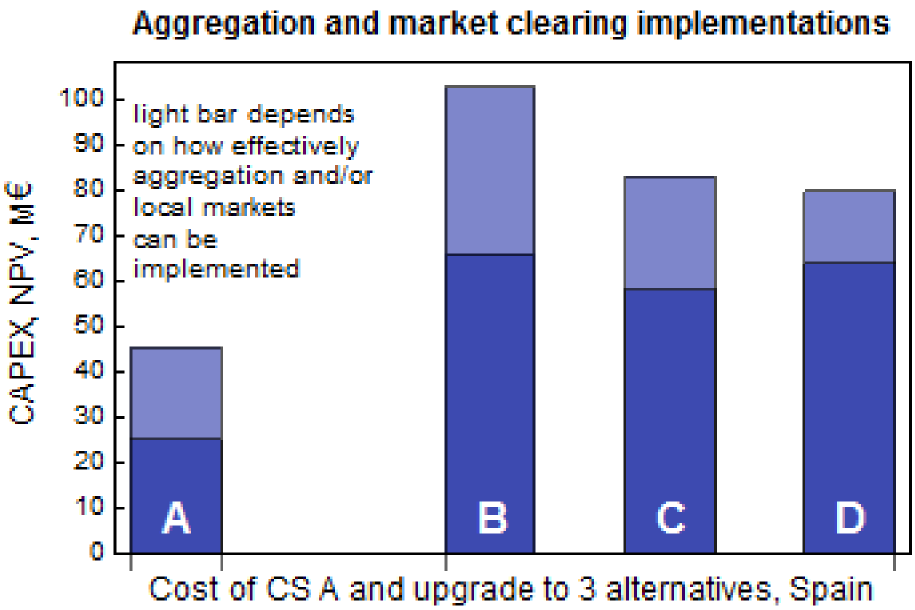


Figure 4.3: Cost estimates of aggregation and market clearing implementations in Spain

The data presented in the three figures above are provided in a numerical form in Table 4.3. Note that the cost of the centralized AS markets (CS A) only covers the cost of implementing IT systems for market clearing and aggregation. These costs are taken as the baseline for the rest of the costs, because it was assumed that CS A will be in place by 2030, and the aim of this ICT cost assessment is to estimate the costs required to upgrade CS A to the other CSs. As a result, the first column is highlighted in grey to represent the baseline costs (CS A), while the consecutive columns correspond to the cost required to upgrade such baseline to the four alternative TSO-DSO coordination schemes (CS B, CS C and CS D).

	NPV (M€)			
	CS A	**CS A → CS B**	**CS A → CS C**	**CS A → CS D**
Low estimates	25.3	66.0	58.3	69.5 (Italy) 64.0 (Spain) 56.6 (Denmark)
High estimates	45.5	103.0	83.3	85.2 (Italy) 79.8 (Spain) 72.4 (Denmark)

Table 4.3: Cost estimates of aggregation and market clearing implementations in national scenarios

The equivalent annual costs (EAC) can be calculated according to equation (10)[17]:

$$EAC = \frac{r\ (NPV)}{1-(1+r)^{-n}} \tag{10}$$

where NPV = net present value, r = interest rate[18], and n = number of periods.

The investment ICT cost recovery period was assumed to be 10 years, to coincide with the hold time of DSO network management systems in the Finnish DSO regulation model. In order to estimate the interest rate for the investment, inflation rates and 10-year bond rates for Denmark, Italy and Spain were used. Considering that inflation rates were 0.8%, 1.7% and 1.7%[19] and the 10-year bond rates were 0.24%, 3.13% and 1.47%[20] for Denmark, Italy and Spain, a conservative interest estimate of 5% was made. For a 10-year period, with an interest rate of 5%, the annual costs are presented in Table 4.4.

Under the scope restrictions and the formulation of the ICT cost estimation problem, the main finding was that ICT costs in different market arrangements are almost the same (subject to uncertainties) and much lower than the operational costs, as demonstrated in next sections. Therefore, estimated ICT costs are not the key elements to be considered in selecting the AS market arrangements and, hence, monetarized values are not transformed to a given future target year at this point.

[17] https://en.wikipedia.org/wiki/Equivalent_annual_cost. This formula is equivalent to the Capital Recovery factor (https://en.wikipedia.org/wiki/Capital_recovery_factor)

[18] Considering long-term impacts, this term should be really low.

[19] Data for November 2018 taken from: https://tradingeconomics.com/country-list/inflation-rate?continent=europe

[20] Data taken from: https://www.investing.com/rates-bonds/italy-government-bonds?maturity_from=40&maturity_to=310. Consultation date: 2018/12/11

	Equivalent Annual Cost (M€) 10-year investment with 5% interest rate			
	CS A	CS A → CS B	CS A → CS C	CS A → CS D
Low estimates	3.28	8.55	7.55	9.00 (Italy) 8.29 (Spain) 7.33 (Denmark)
High estimates	5.89	13.34	10.79	11.03 (Italy) 10.33 (Spain) 9.38 (Denmark)

Table 4.4: Equivalent Annual costs of ICT investments with a 10-year period and a 5% interest rate.

4.2 Comparison of coordination schemes in Denmark

4.2.1 Denmark dataset

The Danish simulated scenario includes Western Denmark as shown in Figure 4.4, which is fed by the transmission network part synchronously connected to Continental Europe, but with connections to Eastern Denmark as well as neighbouring countries.

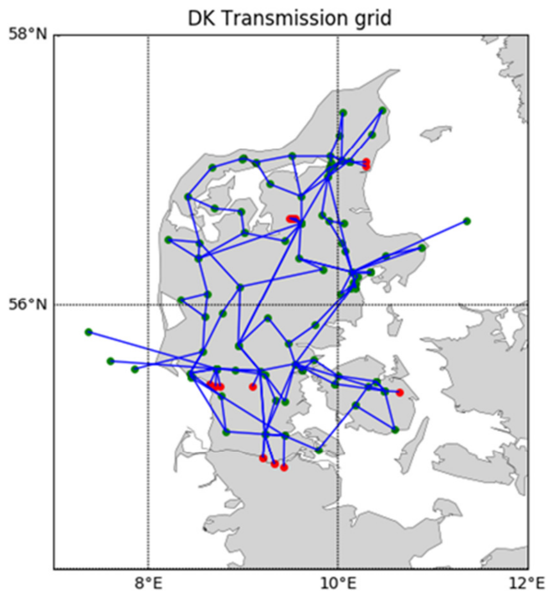


Figure 4.4: Danish transmission grid

In the Danish case, the wind power is of great importance and the main contributor to the imbalances. For more details, see D4.2 [4].

For each of the simulated scenario, different days for simulations have been selected in order to represent different operating conditions. What make the difference are mainly the power demand, PV and wind power availability. Normalised time-series for PV and wind power availability on the selected dates for the Danish scenario are shown in Figure 4.5. In addition, the considered number of occurrences of each day throughout a whole year is indicated, based on a comparison of the actual renewable generation mix in Denmark during 2018.

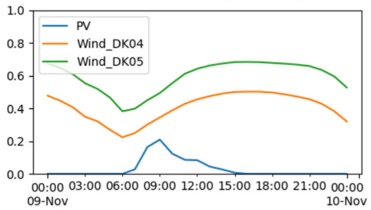
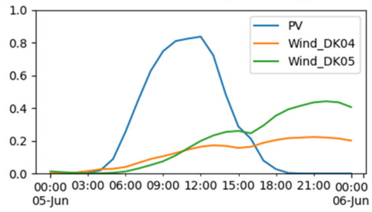
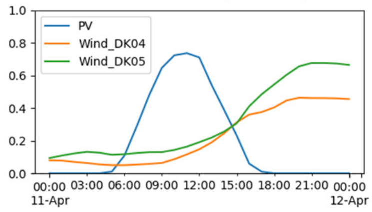
Denmark		
Scenario 401 (9 Nov)	Scenario 402 (5 June)	Scenario 403 (11 Apr)
		
No. occurrences/year: 94	No. occurrences/year: 221	No. occurrences/year: 50

Figure 4.5: Normalised PV and Wind power availability in the Danish scenario

As it can be deduced from the graphs, the main differences between the selected days are:

- Day 1 (Scenario 401 - 9 Nov): Low PV generation + High wind generation (over the day).
- Day 2 (Scenario 402 - 5 June): High PV generation (midday hours) + Wind generation (afternoon).
- Day 3 (Scenario 3 - 11 Apr): High PV generation (midday hours) + High wind generation (afternoon).

4.2.2 mFRR provision cost

As described above, three different days were simulated for each country. Table 4.5 to Table 4.7 recall the amounts of energy dispatched in each of them (in GWh) and summarise their associated cost (in k€) for the four simulated TSO-DSO coordination schemes. In all the cases, the results are divided into transmission and distribution, as well as in upward and downward activated mFRR.

Day 1		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	4.11	1.11	4.10	1.31	4.65	2.83	4.10	1.24
	Down	-0.48	-0.96	-0.41	-1.21	-3.13	-1.21	-0.42	-1.14
	Total	**4.59**	**2.07**	**4.51**	**2.52**	**7.78**	**4.04**	**4.52**	**2.38**
Cost (k€)	Up	309.76	33.68	336.80	46.96	447.71	192.71	327.81	42.04
	Down	-19.50	-10.47	-18.93	-11.94	-0.08	-25.93	-19.32	-12.59
	Total	**290.26**	**23.21**	**317.87**	**35.02**	**447.63**	**166.78**	**308.49**	**29.45**

Table 4.5: mFRR provision costs for the Danish scenario – Day 1

Day 2		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	3.31	0.06	3.28	0.09	2.42	1.07	3.28	0.09
	Down	-0.34	-0.16	-0.32	-0.18	-1.03	-0.15	-0.32	-0.18
	Total	**3.65**	**0.22**	**3.60**	**0.27**	**3.45**	**1.22**	**3.60**	**0.27**
Cost (k€)	Up	237.01	4.79	236.09	7.62	181.77	83.89	236.40	7.69
	Down	-19.50	-8.08	-18.94	-8.26	-54.07	-6.71	-18.93	-8.96
	Total	**217.51**	**-3.29**	**217.15**	**-0.64**	**127.7**	**77.18**	**217.47**	**-1.27**

Table 4.6: mFRR provision costs for the Danish scenario – Day 2

Day 3		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	4.08	0.14	4.06	0.19	3.78	2.20	4.06	0.18
	Down	-1.38	-0.72	-1.33	-0.81	-3.42	-0.83	-1.33	-0.79
	Total	**5.46**	**0.86**	**5.39**	**1.00**	**7.20**	**3.03**	**5.39**	**0.97**
Cost (k€)	Up	291.89	12.07	305.67	18.63	342.84	176.98	305.46	17.24
	Down	-67.69	-18.02	-66.01	-17.94	-36.23	-28.15	-66.78	-19.28
	Total	**224.20**	**-5.95**	**239.66**	**0.69**	**306.61**	**148.83**	**238.68**	**-2.04**

Table 4.7: mFRR provision costs for the Danish scenario – Day 3

Cost values are graphically represented in Figure 4.6 to Figure 4.8. Again, values are provided for transmission (red bars) and distribution (purple bars) and for upward (dark colour) and downward (light colour) activations.

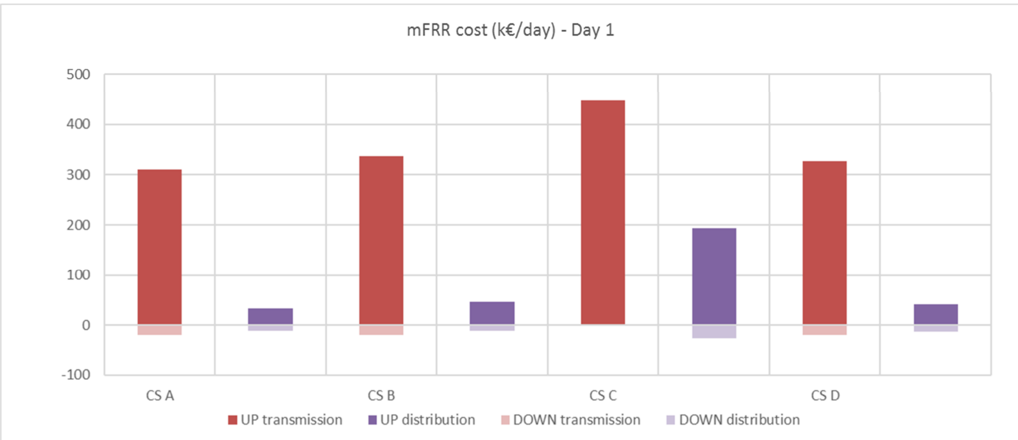


Figure 4.6: mFRR provision cost in the Danish scenario – Day 1

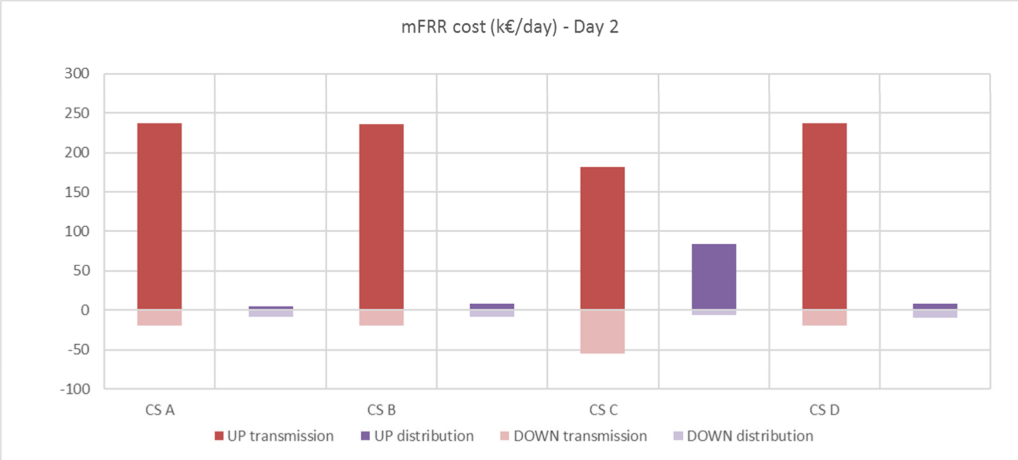


Figure 4.7: mFRR provision cost in the Danish scenario – Day 2

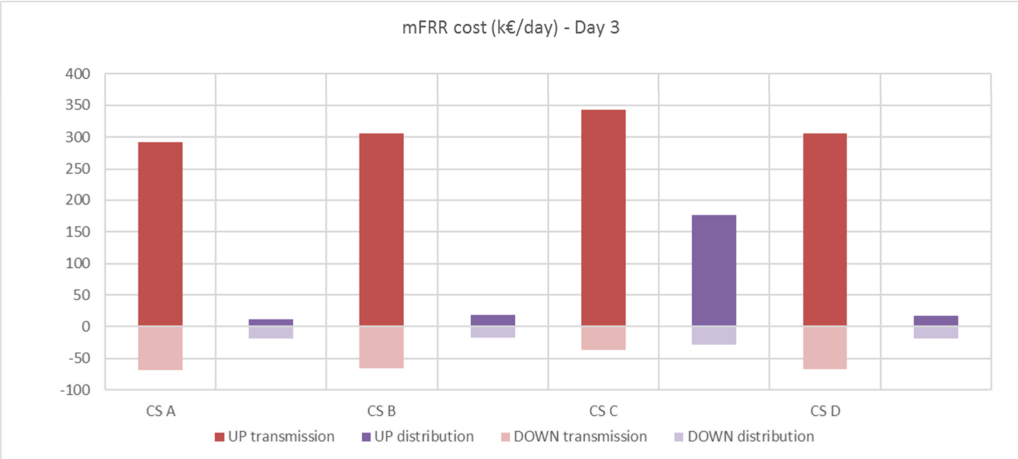


Figure 4.8: mFRR provision cost in the Danish scenario – Day 3

4.2.3 aFRR provision cost

As for the case of mFRR provision, activation (in GWh) are obtained from simulation results [4] and the related cost (in k€) for each coordination scheme are calculated for the three days. However, there is no shared balancing responsibility when dispatching aFRR and the TSO is assumed to be always responsible to keep the overall system balance. Therefore, the values are divided into upward and downward balancing, but not into transmission and distribution in Table 4.8 to Table 4.10 below.

These cost values are graphically represented in Figure 4.9 to Figure 4.11, distinguishing the values for upward (dark colour) and downward (light colour) activations.

			CS A	CS B	CS C	CS D
Day 1	Energy (GWh)	Up	0.39	0.38	1.00	0.37
		Down	-0.34	-0.35	-0.05	-0.37
		Total	**0.73**	**0.73**	**1.05**	**0.74**
	Cost (k€)	Up	32.81	32.17	84.72	30.51
		Down	-0.33	-1.17	-0.17	-1.22
		Total	**32.48**	**31.00**	**84.55**	**29.29**

Table 4.8: aFRR provision results for the Danish scenario – Day 1

			CS A	CS B	CS C	CS D
Day 2	Energy (GWh)	Up	0.47	0.48	1.00	0.48
		Down	-0.48	-0.48	-0.17	-0.48
		Total	**0.95**	**0.96**	**1.17**	**0.96**
	Cost (k€)	Up	42.50	43.02	92.28	43.16
		Down	-13.58	-13.40	-4.46	-13.41
		Total	**28.92**	**29.62**	**87.82**	**29.75**

Table 4.9: aFRR provision results for the Danish scenario – Day 2

			CS A	CS B	CS C	CS D
Day 3	Energy (GWh)	Up	0.40	0.40	0.84	0.39
		Down	-0.41	-0.40	-0.14	-0.39
		Total	**0.81**	**0.80**	**0.98**	**0.78**
	Cost (k€)	Up	33.93	34.02	71.87	33.75
		Down	-0.92	-2.70	-3.38	-2.61
		Total	**33.01**	**31.32**	**68.49**	**31.14**

Table 4.10: aFRR provision results for the Danish scenario – Day 3

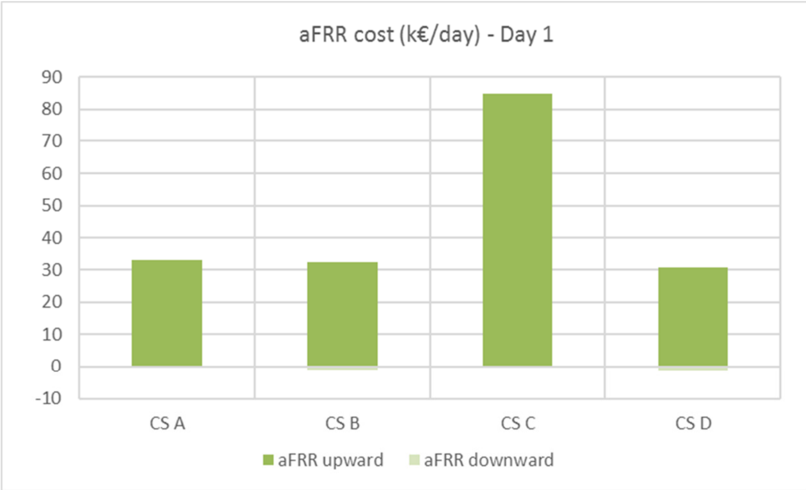


Figure 4.9: aFRR provision cost in the Danish scenario – Day 1

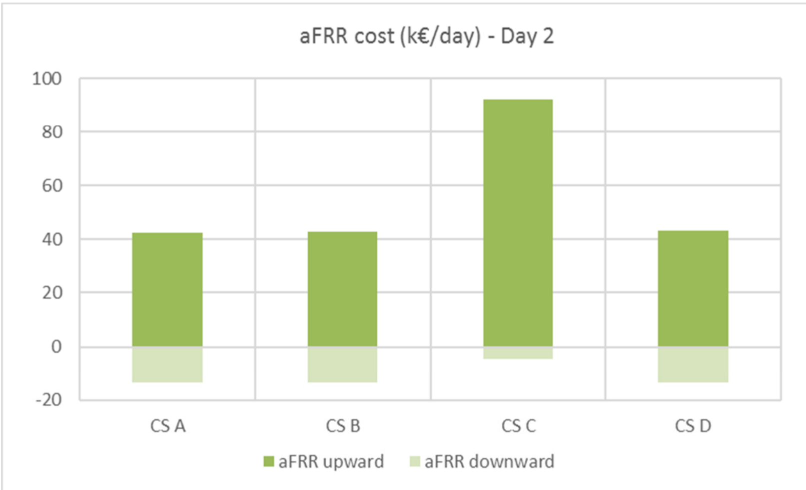


Figure 4.10: aFRR provision cost in the Danish scenario – Day 2

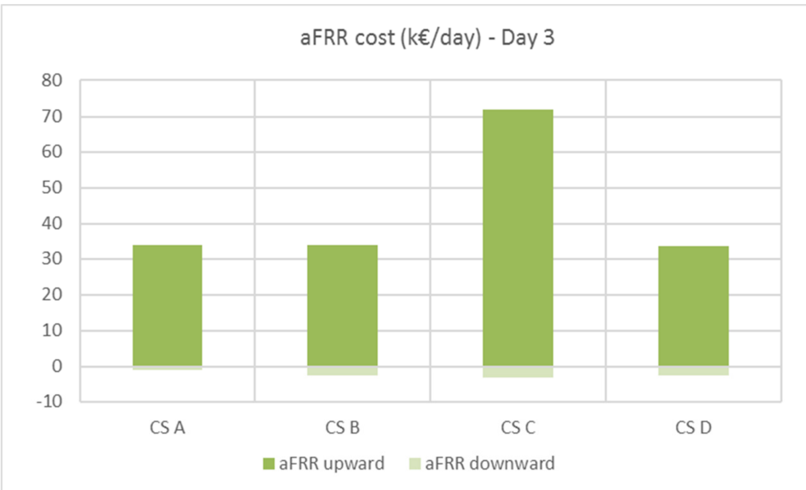


Figure 4.11: aFRR provision cost in the Danish scenario – Day 3

4.2.4 UM provision cost

As for the cases of mFRR and aFRR provisions, unwanted measures and related costs are calculated starting from the simulation results [4] for each coordination scheme. The values are divided into upward and downward balancing, but not into transmission and distribution in Table 4.11 to Table 4.13 below.

			CS A	CS B	CS C	CS D
Day 1	Energy (GWh)	Up	0.22	0.21	0.87	0.22
		Down	-0.02	-0.02	0.00	-0.02
		Total	**0.24**	**0.23**	**0.87**	**0.24**
	Cost (k€)	Up	3.48	3.41	14.64	3.37
		Down	0.00	0.00	0.00	-0.01
		Total	**3.48**	**3.41**	**14.64**	**3.36**

Table 4.11: UM provision results for the Danish scenario – Day 1

			CS A	CS B	CS C	CS D
Day 2	Energy (GWh)	Up	0.06	0.06	0.20	0.06
		Down	-0.06	-0.06	-0.02	-0.06
		Total	**0.12**	**0.12**	**0.22**	**0.12**
	Cost (k€)	Up	1.07	1.07	3.46	1.07
		Down	0.10	0.10	0.03	0.10
		Total	**1.17**	**1.17**	**3.49**	**1.17**

Table 4.12: UM provision results for the Danish scenario – Day 2

			CS A	CS B	CS C	CS D
Day 3	Energy (GWh)	Up	0.04	0.04	0.75	0.04
		Down	-0.17	-0.17	-0.05	-0.17
		Total	**0.21**	**0.21**	**0.80**	**0.21**
	Cost (k€)	Up	0.69	0.67	12.07	0.64
		Down	2.01	2.00	0.56	2.02
		Total	**2.70**	**2.67**	**12.63**	**2.66**

Table 4.13: UM provision results for the Danish scenario – Day 3

These cost values are graphically represented in Figure 4.12 to Figure 4.14, distinguishing the values for upward (dark colour) and downward (light colour) activations.

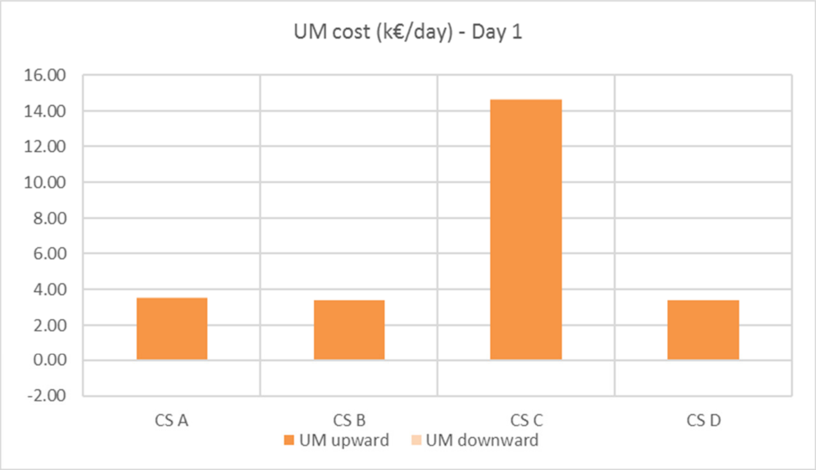


Figure 4.12: UM provision cost in the Danish scenario – Day 1

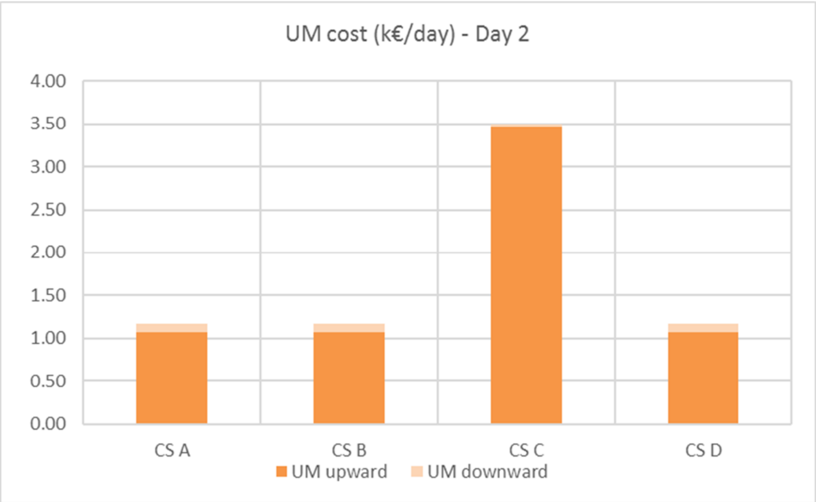


Figure 4.13: UM provision cost in the Danish scenario – Day 2

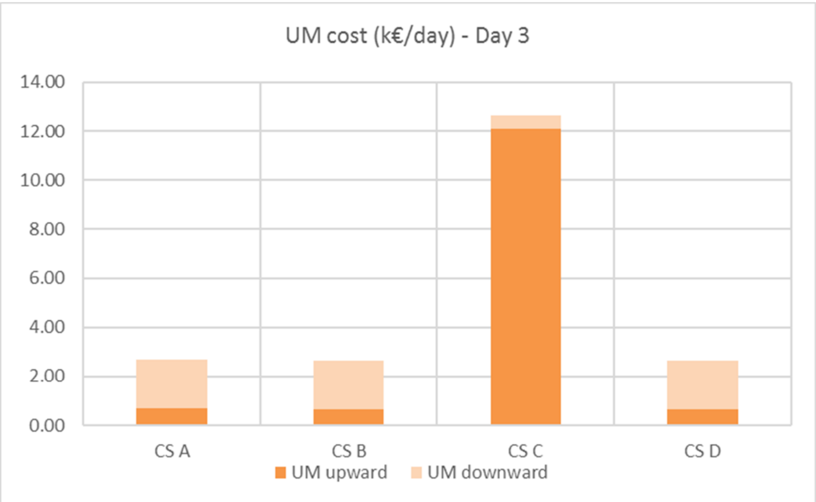


Figure 4.14: UM provision cost in the Danish scenario – Day 3

4.2.5 Cost results for Denmark

The daily values for mFRR (section 4.2.2), aFRR (section 4.2.3) and UM (section 4.2.4), together with the daily allocation of ICT costs (section 4.1) are shown together in Table 4.14 in order to allow the comparison and assessment of the impact that the different day typologies has on the obtained results. The daily cost of the ICT for each day is calculated simply by dividing the annualized value by the 365 days of a year. In Table 4.14, the cheapest CS is highlighted in green and the most expensive one in red, while the same results are graphically represented from Figure 4.15 to Figure 4.17.

	(k€/day)	mFRR	aFRR	UM	ICT	TOTAL
Day 1	CS A	313.47	32.48	3.48	12.56	**361.99**
	CS B	352.89	31.00	3.41	42.53	**429.83**
	CS C	614.40	84.55	14.64	37.68	**751.27**
	CS D	337.94	29.29	3.37	35.45	**406.05**
Day 2	CS A	214.22	28.92	1.17	12.56	**256.87**
	CS B	216.51	29.61	1.17	42.53	**289.82**
	CS C	204.88	87.82	3.49	37.68	**333.87**
	CS D	216.19	29.74	1.17	35.45	**282.55**
Day 3	CS A	218.26	33.01	2.70	12.56	**266.53**
	CS B	240.35	31.32	2.66	42.53	**316.86**
	CS C	455.45	68.49	12.63	37.68	**574.26**
	CS D	236.63	31.14	2.66	35.45	**305.88**

Table 4.14: Daily costs (k€/day) for the Danish scenario

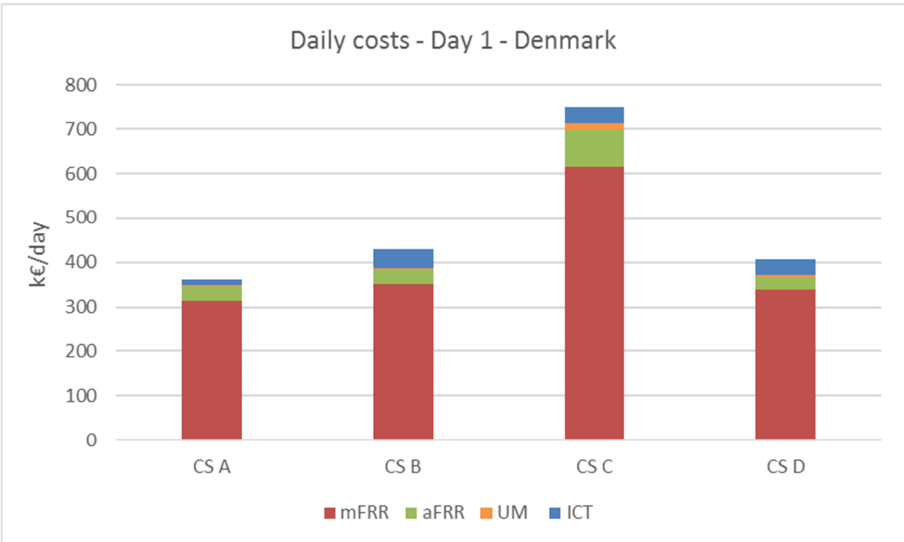


Figure 4.15: Daily costs for the Danish scenario – Day 1

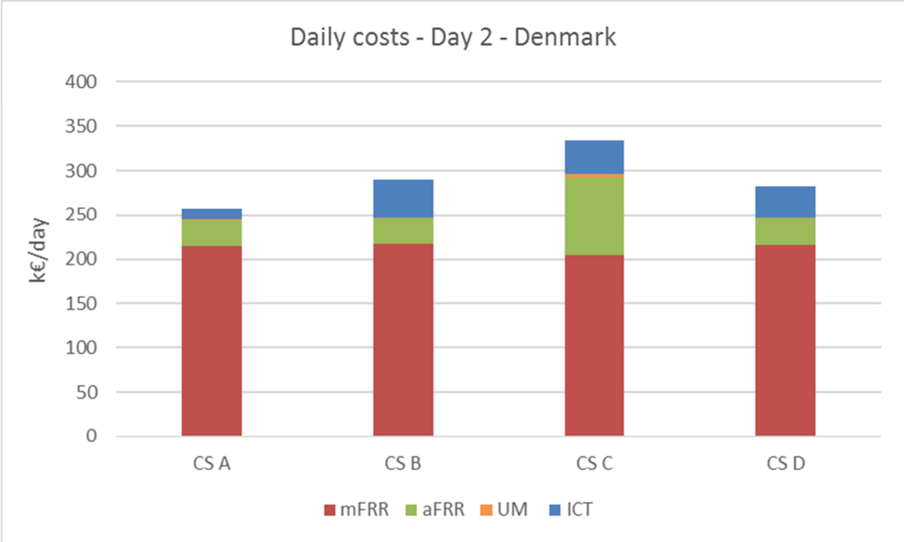


Figure 4.16: Daily costs for the Danish scenario – Day 2

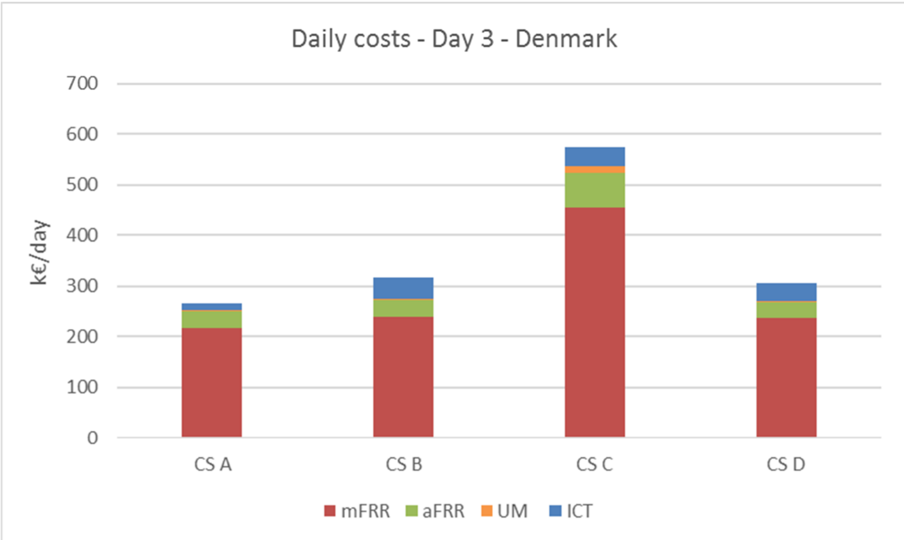


Figure 4.17: Daily costs for the Danish scenario – Day 3

Considering the number of occurrences of each day (detailed in section4.2.1), the annual cost Figure 4.18values for each CS have been calculated and reported in Table 4.15 and Figure 4.18.

(M€/year)	mFRR	aFRR	UM	ICT	**TOTAL**
CS A	87.72	11.09	0.72	4.59	**104.12**
CS B	93.04	11.02	0.71	15.53	**120.30**
CS C	125.80	30.78	2.78	13.76	**173.12**
CS D	91.38	10.88	0.71	12.94	**115.91**

Table 4.15: Annual costs for the Danish scenario

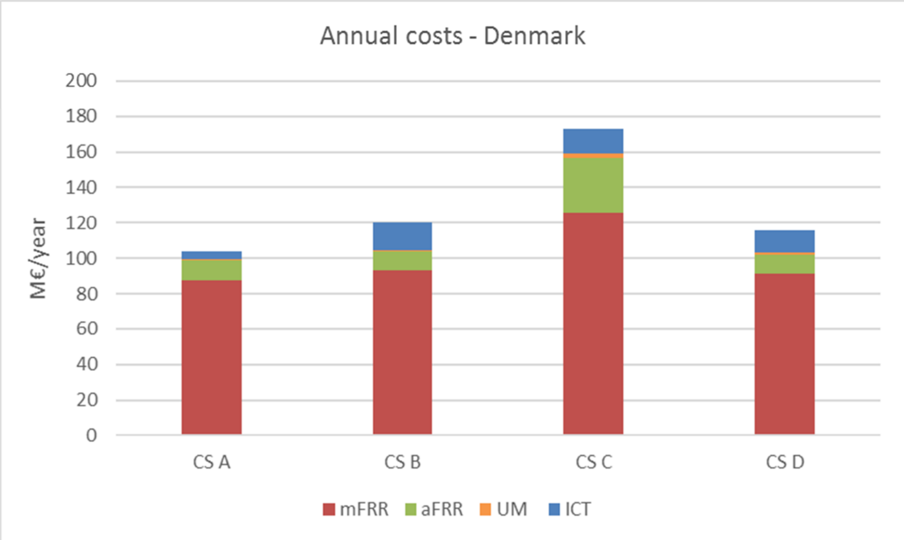


Figure 4.18: Annual costs for the Danish scenario

From the analysis of the obtained results, some conclusions can be observed:

- The cheapest coordination scheme in Denmark is the CS A, regardless of the type of day. Something similar happens with the most expensive coordination scheme, which is always CS C.
- In general, this behaviour is due to the great amount of mFRR energy managed in each CS in comparison with the amount of aFRR. In Day 1 and Day 3, mFRR accounts for 75 % - 85 % of the total costs of each CS, while aFRR only justifies about 10 % of it. In the Day 2, though, aFRR makes CS C the most expensive coordination scheme since its cost is considerable higher (~90 k€/day) than in the rest of CSs (~30 k€/day). In this type of days, the mFRR cost for all coordination schemes is very similar, so the most expensive coordination scheme is determined by the aFRR activations.
- In general, the annual results for CS A, CS B and CS D are very similar, the merit order is driven by the ICT costs. This is reasonable since the ICT system complexity is higher in CS D and CS B than in CS A.
- The UM costs are negligible in comparison with the rest of costs in all coordination schemes.

4.2.6 CO_2 emissions savings

The CO_2 emission for the Danish scenario in each day are represented from Figure 4.19 to Figure 4.21 .

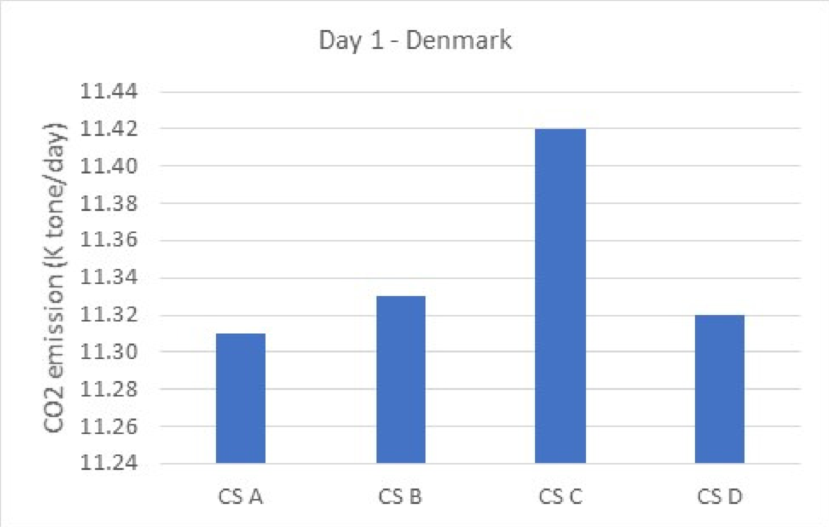


Figure 4.19: Daily CO_2 emission for the Danish scenario – Day 1

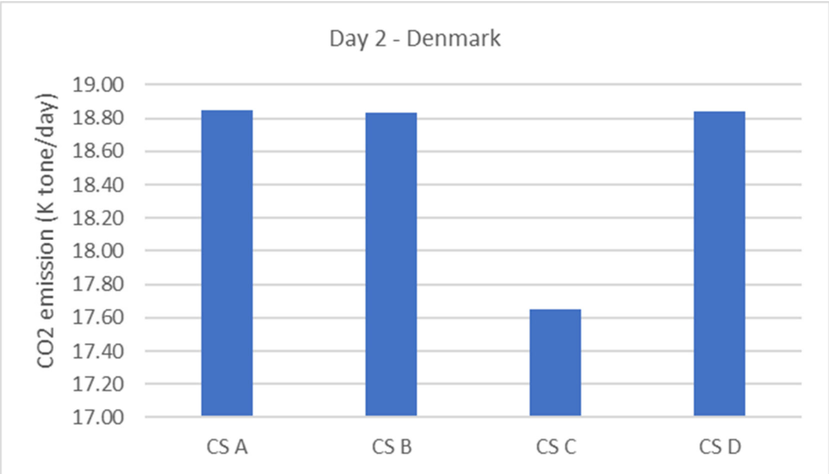


Figure 4.20: Daily CO_2 emission for the Danish scenario – Day 2

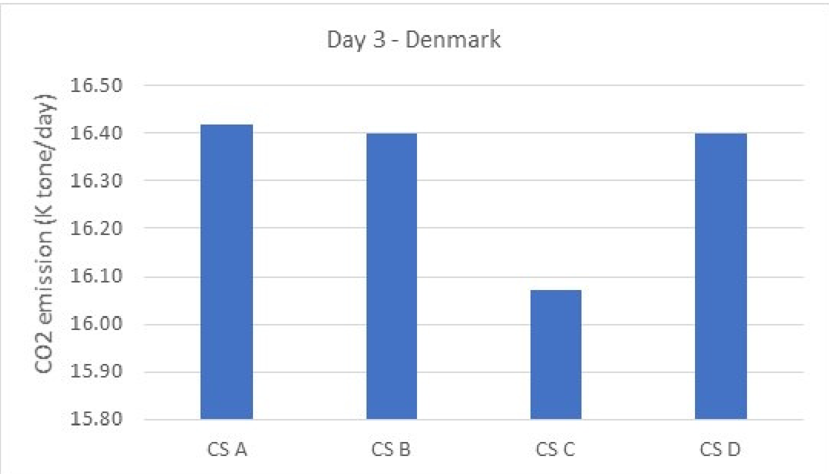


Figure 4.21: Daily CO_2 emission for the Danish scenario – Day 3

Figure 4.22 represents the annual CO_2 emissions from all conventional and CHP devices at physical layer for the Danish scenario. The results show that CS C has the lowest emission in comparison to other schemes. However, the difference between coordination schemes is less than 4 %, which is quite low (note that the Y axis scale goes from 5 400 up to 6 100 ktons/day).

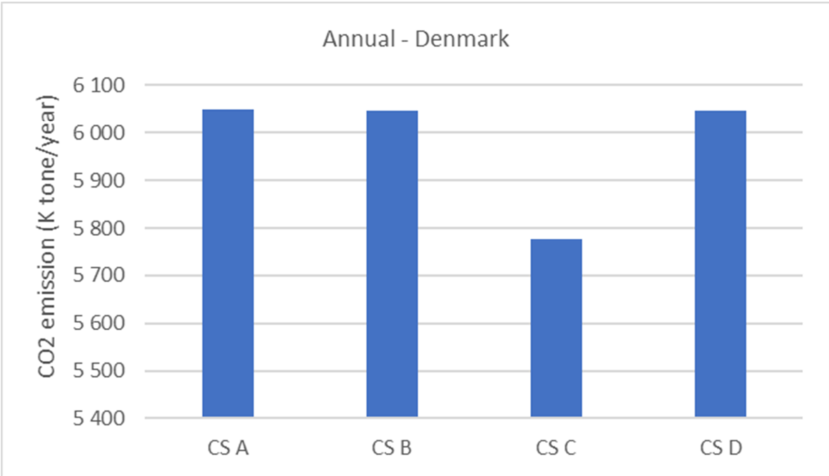


Figure 4.22: Annual CO_2 emission for the Danish scenario

4.3 Comparison of coordination schemes in Italy

4.3.1 Italy dataset

The transmission grid considered in the Italian scenario dataset includes Northern and Central Northern parts of Italy (Figure 4.23). The transmission grid data includes information about generators (location, power capacity, and type), and information about which nodes are primary substations for distribution grids. The data includes 3648 nodes and 638 primary substations.

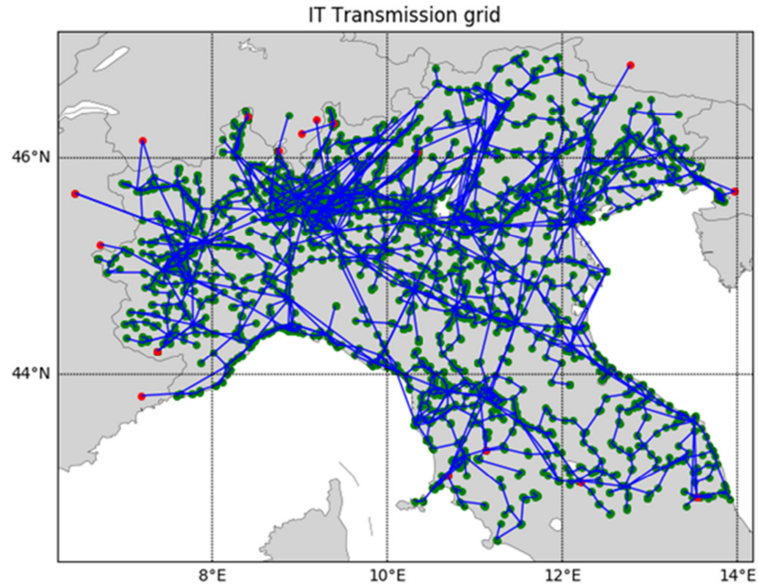


Figure 4.23: Italian transmission grid

In the Italian case, the main contribution to the imbalances comes from solar power, with some contribution also from net demand, and minor ones from wind and run-of-river hydro. For more details, see D4.2 [4].

For each of the simulated scenarios, different days have been selected in order to simulate the most common operating conditions. What make the difference are mainly the power demand, PV and wind power availability. Normalised time-series for PV and wind power availability on the selected dates for the Italian scenario are shown in Figure 4.24. In addition, the considered number of occurrences of each day throughout a whole year is indicated, based on a comparison of the actual renewable generation mix in Italy during 2018.

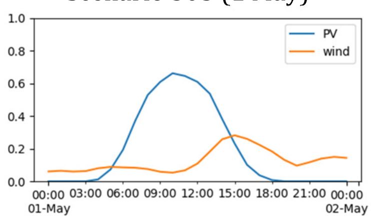
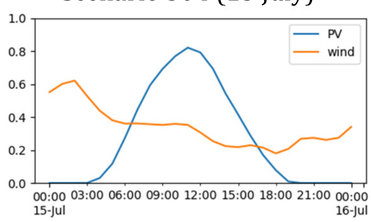
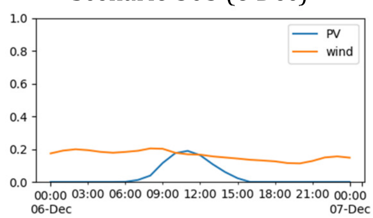
Italy		
Scenario 503 (1 May)	Scenario 504 (15 July)	Scenario 505 (6 Dec)
		
No. occurrences/year: 121	No. occurrences/year: 190	No. occurrences/year: 54

Figure 4.24: Normalised PV and Wind power availability in the Italian scenario

As it can be drawn from the graphs above, the main differences between the selected days are:

- Day 1 (Scenario 503 - 1 May): High PV generation (midday hours) + Low wind generation (mainly in the afternoon).

- Day 2 (Scenario 504 - 15 July): High PV generation (midday hours) + High wind generation (mainly in the first hours of the day).
- Day 3 (Scenario 505 - 6 Dec): Very low PV generation (midday hours) + Low and constant wind generation (over the day).

4.3.2 mFRR provision cost

As described in section 4.3.1, three different days were simulated for each country. Table 4.16 to Table 4.18 recall the amounts of energy dispatched in each of them (in GWh) and summarise their associated cost (in k€) for the four coordination schemes. In all the cases, the results are divided into transmission and distribution, as well as in upward and downward activated mFRR.

Day 1		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	26.60	5.40	29.08	4.26	29.08	2.55	29.17	4.13
	Down	-27.35	-0.46	-27.45	-1.80	-27.91	-2.16	-27.43	-1.76
	Total	53.95	5.86	56.53	6.06	56.99	4.71	56.6	5.89
Cost (k€)	Up	2 028	341	2 160	323	2 179	194	2 168	309
	Down	-1 757	-11	-1 762	-10	-1 785	-33	-1 761	-14
	Total	**271**	**330**	**398**	**313**	**394**	**161**	**407**	**295**

Table 4.16: mFRR provision costs for the Italian scenario – Day 1

Day 2		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	26.28	4.81	29.38	2.86	27.40	3.50	29.54	2.64
	Down	-21.39	-2.22	-21.46	-3.38	-22.81	-4.27	-21.46	-3.31
	Total	47.67	7.03	50.84	6.24	50.21	7.77	51.00	5.95
Cost (k€)	Up	1 847	227	1 952	183	2 000	218	1 956	170
	Down	-1 200	-14	-1 172	-9	-1 168	-61	-1 182	-18
	Total	**647**	**213**	**780**	**174**	**832**	**157**	**774**	**152**

Table 4.17: mFRR provision costs for the Italian scenario – Day 2

Day 3		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	50.78	3.51	52.01	2.31	53.63	1.11	52.10	2.16
	Down	-48.83	-1.36	-48.71	-1.16	-49.29	-0.99	-48.73	-1.02
	Total	99.61	4.87	100.72	3.47	102.92	2.10	100.83	3.18
Cost (k€)	Up	4 362	227	4 475	210	4 604	94	4 447	193
	Down	-2 046	43	-2 047	41	-2 213	-44	-2 073	24

	Total	2 316	270	2 428	251	2 391	50	2 374	217

Table 4.18: mFRR provision costs for the Italian scenario – Day 3

Cost values are graphically represented in Figure 4.25 to Figure 4.27. Again, values are provided for transmission (red bars) and distribution (purple bars) and for upward (dark colour) and downward (light colour) activations.

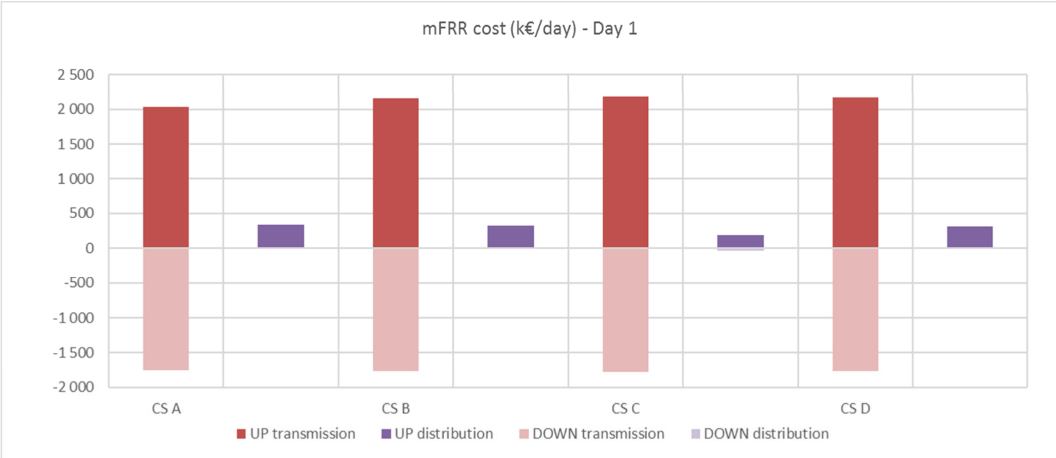


Figure 4.25: mFRR provision cost in the Italian scenario – Day 1

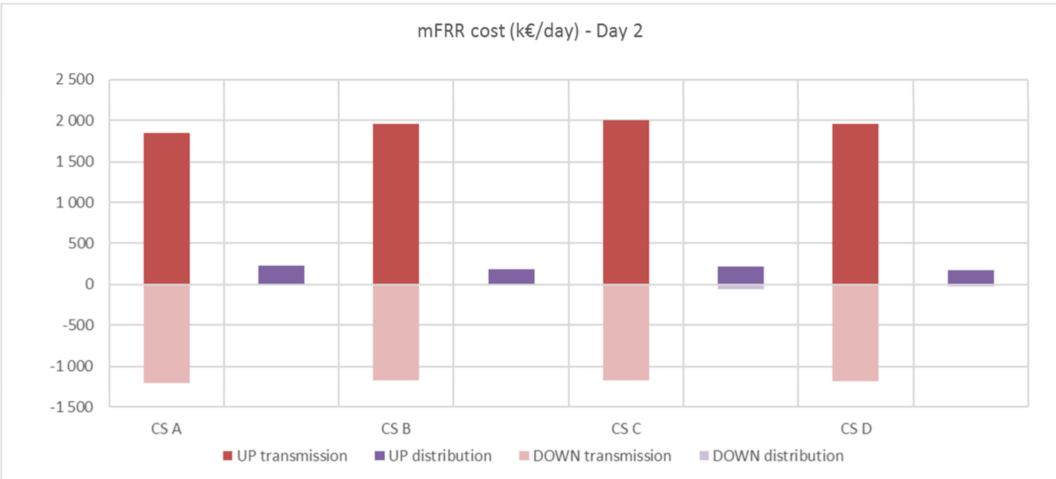


Figure 4.26: mFRR provision cost in the Italian scenario – Day 2

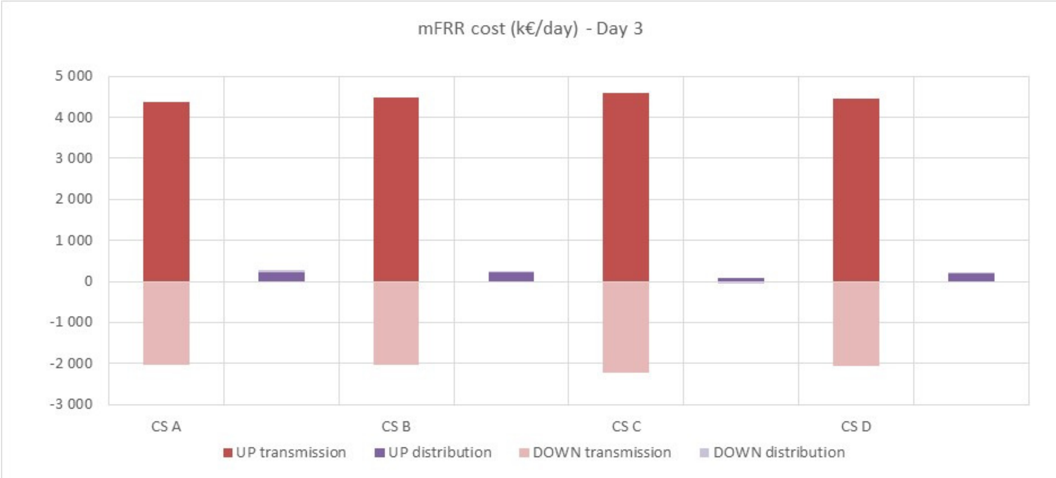


Figure 4.27: mFRR provision cost in the Italian scenario – Day 3

4.3.3 aFRR provision cost

As for the case of mFRR provision, energy activation volumes (in GWh) are obtained from [4] and their related cost (in k€) for each coordination scheme are calculated for the three days. However, there is no shared balancing responsibility when dispatching aFRR and the TSO is assumed to be responsible of the management of this reserve. Therefore, the values are divided into upward and downward balancing, but no distinction is made between transmission and distribution resource (see Table 4.19 to Table 4.21).

			CS A	CS B	CS C	CS D
Day 1	Energy (GWh)	Up	3.74	2.14	4.04	2.14
		Down	-1.38	-2.14	-1.69	-2.14
		Total	5.12	4.28	5.73	4.28
	Cost (k€)	Up	326.72	186.89	349.20	186.74
		Down	-55.07	-84.39	-67.52	-83.79
		Total	**271.65**	**102.5**	**281.68**	**102.95**

Table 4.19: aFRR provision results for the Italian scenario – Day 1

			CS A	CS B	CS C	CS D
Day 2	Energy (GWh)	Up	4.41	1.83	4.28	1.84
		Down	-0.99	-1.85	-1.31	-1.84
		Total	5.40	3.68	5.59	3.68
	Cost (k€)	Up	353.89	146.05	338.42	147.09
		Down	-38.53	-59.17	-49.92	-58.28
		Total	**315.36**	**86.88**	**288.5**	**88.81**

Table 4.20: aFRR provision results for the Italian scenario – Day 2

			CS A	CS B	CS C	CS D

Day 3	Energy (GWh)	Up	2.77	1.52	1.81	1.56
		Down	-1.03	-1.57	-1.60	-.1.56
		Total	3.80	3.09	3.41	3.12
	Cost (k€)	Up	250.63	138.52	165.05	140.82
		Down	-41.20	-61.31	-62.33	-61.24
		Total	**209.43**	**77.21**	**102.72**	**79.58**

Table 4.21: aFRR provision results for the Italian scenario – Day 3

These cost values are graphically represented in Figure 4.28 to Figure 4.30, distinguishing the values for upward (dark colour) and downward (light colour) activations.

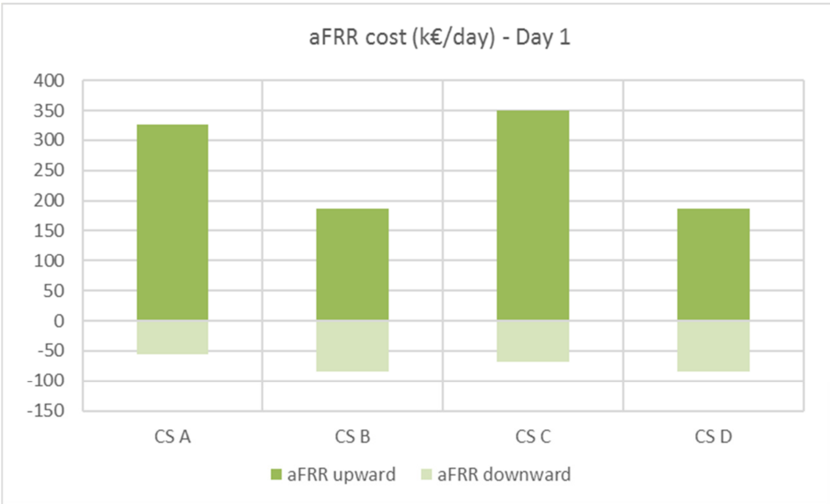


Figure 4.28: aFRR provision cost in the Italian scenario – Day 1

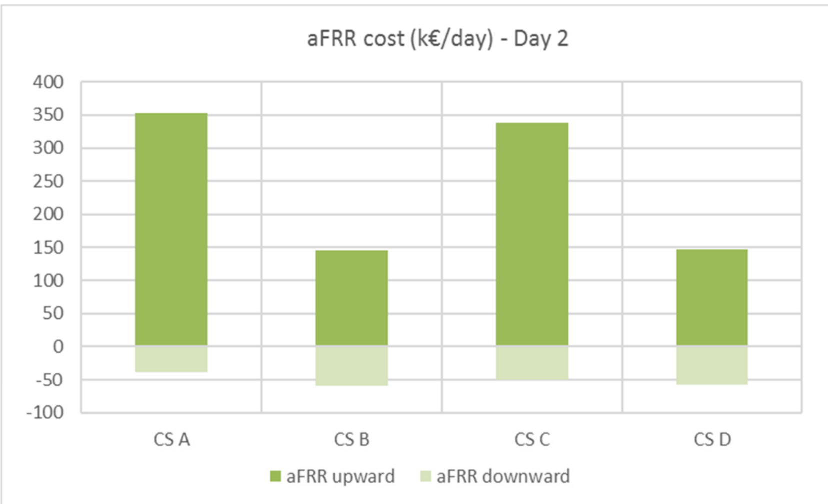


Figure 4.29: aFRR provision cost in the Italian scenario – Day 2

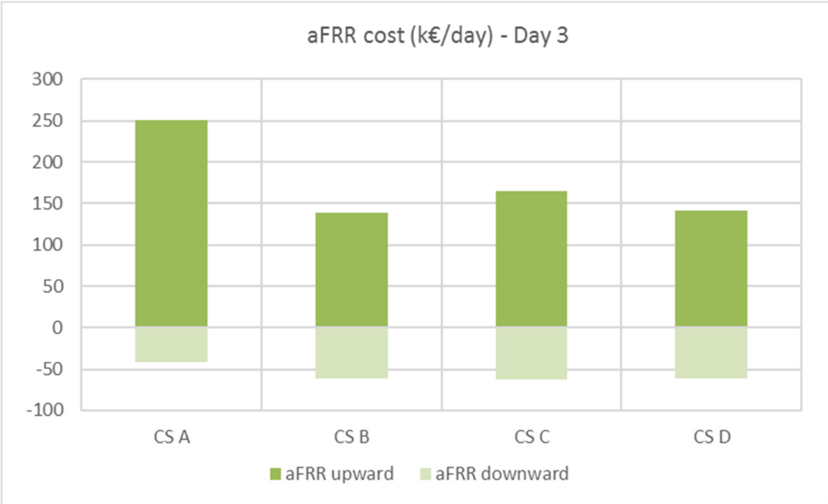


Figure 4.30: aFRR provision cost in the Italian scenario – Day 3

4.3.4 UM provision cost

As for the cases of mFRR and aFRR provisions, unwanted measures and related costs are calculated starting from the simulation results [4] for each coordination scheme. The values are divided into upward and downward balancing and reported in in Table 4.22 to Table 4.24 below.

			CS A	CS B	CS C	CS D
Day 1	Energy (GWh)	Up	0.35	0.24	0.96	0.25
		Down	-0.79	-0.08	-0.23	-0.09
		Total	1.14	0.32	1.19	0.34
	Cost (k€)	Up	6.75	4.62	17.43	4.73
		Down	0.21	-1.51	-1.52	-1.61
		Total	**6.96**	**3.11**	**15.91**	**3.12**

Table 4.22: UM provision results for the Italian scenario – Day 1

			CS A	CS B	CS C	CS D
Day 2	Energy (GWh)	Up	1.64	1.25	2.32	1.25
		Down	-2.50	-1.40	-1.90	-1.40
		Total	4.14	2.65	4.22	2.65
	Cost (k€)	Up	26.71	20.60	34.49	20.62
		Down	16.32	12.26	19.39	12.15
		Total	**43.03**	**32.86**	**53.88**	**32.77**

Table 4.23: UM provision results for the Italian scenario – Day 2

			CS A	CS B	CS C	CS D
Day 3	Energy	Up	2.31	2.27	2.45	2.33

	(GWh)	Down	-3.03	-2.94	-3.35	-3.04
		Total	5.34	5.21	5.80	5.37
	Cost (k€)	Up	43.35	41.91	46.30	44.01
		Down	29.33	28.91	32.89	28.87
		Total	**72.68**	**70.82**	**79.19**	**72.88**

Table 4.24: UM provision results for the Italian scenario – Day 3

These cost values are graphically represented in Figure 4.31 to Figure 4.33, distinguishing the values for upward (dark colour) and downward (light colour) activations.

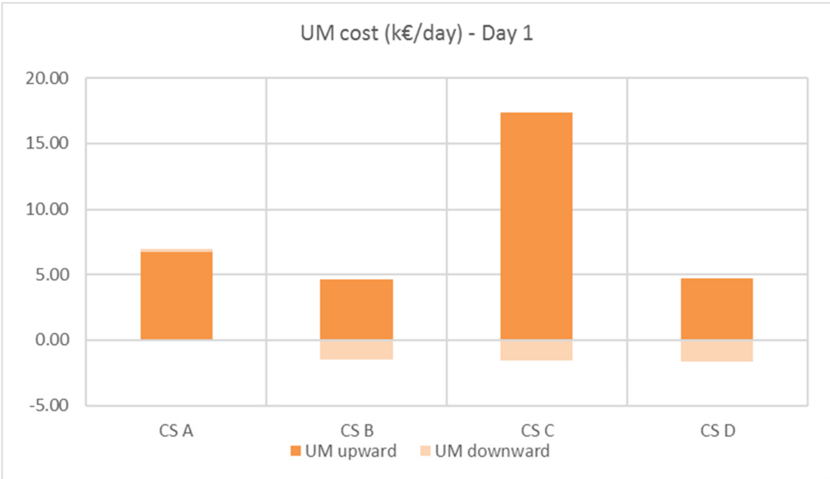


Figure 4.31: UM provision cost in the Italian scenario – Day 1

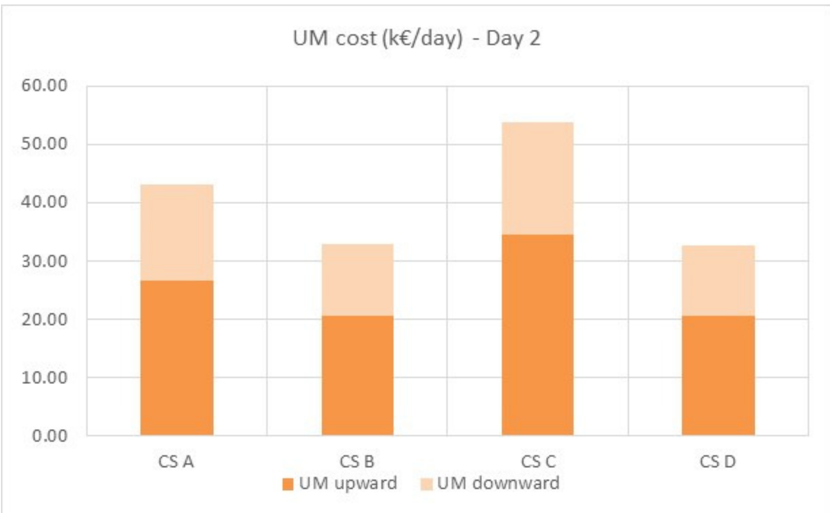


Figure 4.32: UM provision cost in the Italian scenario – Day 2

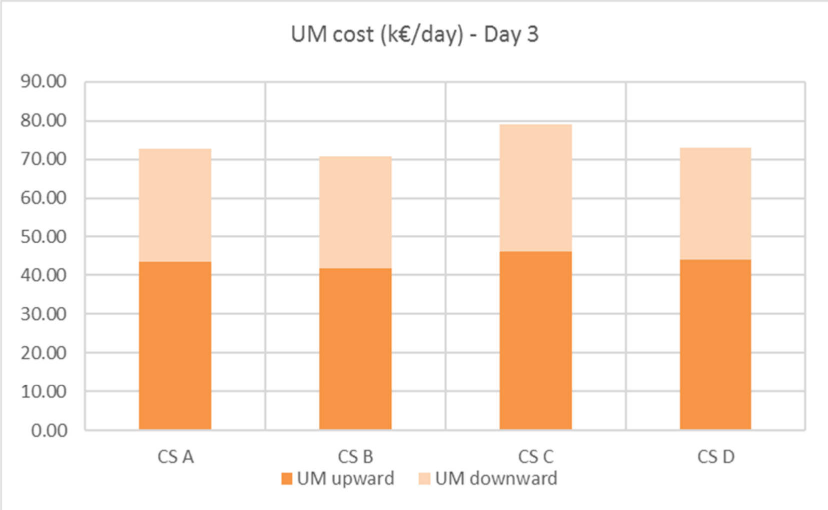


Figure 4.33: UM provision cost in the Italian scenario – Day 3

4.3.5 Cost results for Italy

The daily values for mFRR (section 4.3.2), aFRR (section 4.3.3) and UM (section 4.3.4), together with the daily allocation of ICT costs (section 4.1) are shown together in Table 4.25 in order to allow the comparison and assessment of the impact that the different day typologies has on the obtained results. The daily cost of the ICT for each day is calculated simply dividing the annualized value by the 365 days of a year. In Table 4.25, the cheapest CS is highlighted in green and the most expensive one in red, while the same results and graphically represented from Figure 4.34 to Figure 4.36.

	(k€/day)	mFRR	aFRR	UM	ICT	TOTAL
Day 1	CS A	600.74	271.64	6.97	12.56	**891.91**
	CS B	710.11	102.50	3.11	42.53	**858.25**
	CS C	554.61	281.69	15.91	37.68	**889.89**
	CS D	701.68	102.77	3.12	40.00	**847.57**
Day 2	CS A	858.64	315.35	43.03	12.56	**1 229.58**
	CS B	953.45	86.88	32.87	42.53	**1 115.73**
	CS C	988.71	288.50	53.88	37.68	**1 368.77**
	CS D	925.53	88.82	32.77	40.00	**1 087.12**
Day 3	CS A	2 585.47	209.42	72.68	12.56	**2 880.13**
	CS B	2 679.16	77.21	70.83	42.53	**2 869.73**
	CS C	2 440.59	102.72	79.19	37.68	**2 660.18**
	CS D	2 591.09	79.57	72.88	40.00	**2 783.54**

Table 4.25: Daily costs (k€/day) for the Italian scenario

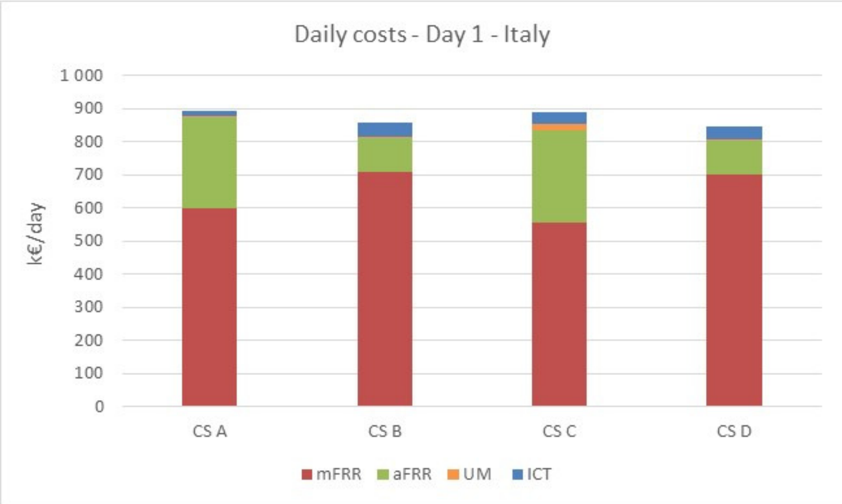


Figure 4.34: Daily costs for the Italian scenario – Day 1

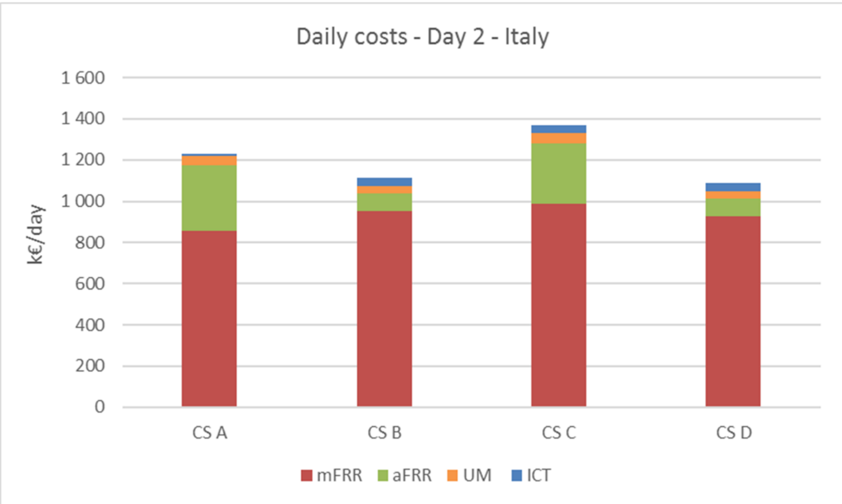


Figure 4.35: Daily costs for the Italian scenario – Day 2

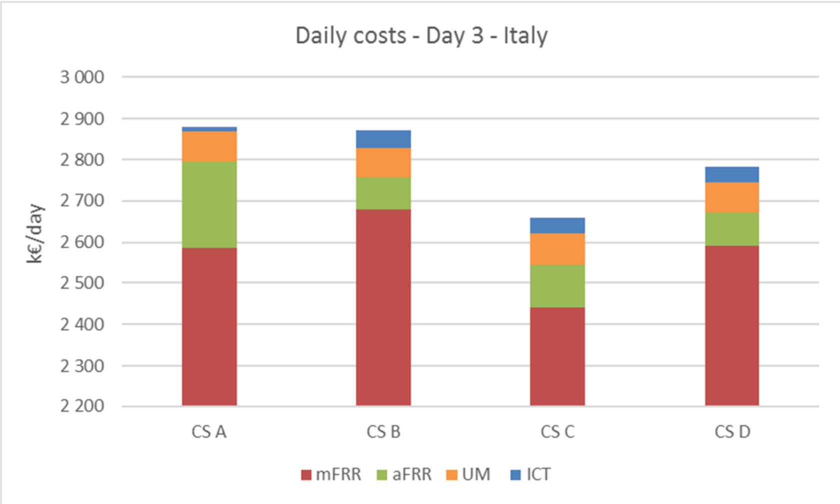


Figure 4.36: Daily costs for the Italian scenario – Day 3

Considering the number of occurrences of each day (detailed in section 4.3.1), the annual cost values for each CS have been calculated and reported in Table 4.26 and Figure 4.37.

(M€/year)	mFRR	aFRR	UM	ICT	**TOTAL**
CS A	375.45	104.09	12.94	4.59	**497.07**
CS B	411.75	33.08	10.45	15.53	**470.81**
CS C	386.76	94.45	16.44	13.76	**511.41**
CS D	400.67	33.61	10.54	14.60	**459.42**

Table 4.26: Annual costs for the Italian scenario

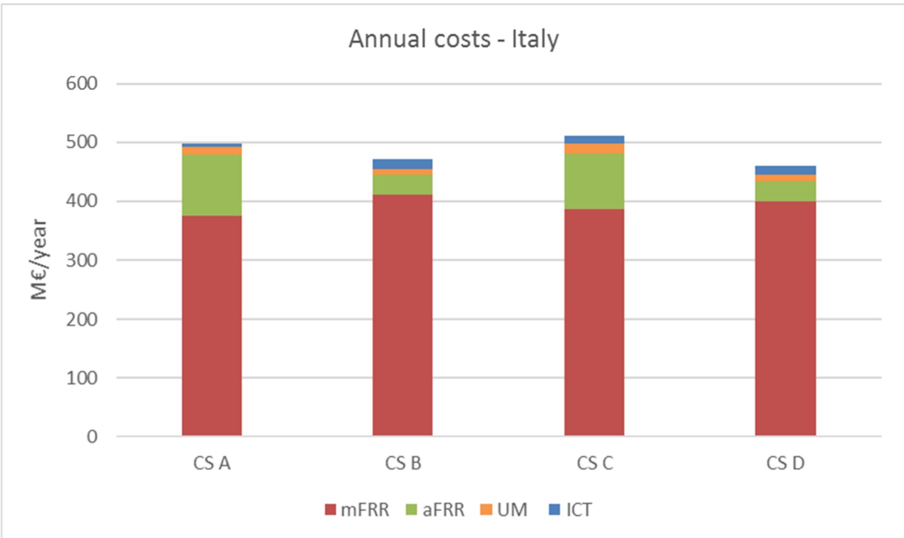


Figure 4.37: Annual costs for the Italian scenario

From the analysis of the obtained results, the following conclusions can be observed:

- The main component of the CBA is the mFRR cost and this cost is very similar in all CSs.

- The UM and ICT costs are a small part of the total costs.
- The main difference between CSs is determined by the aFRR cost.
- In the considered scenario, the most efficient CSs are CS B and CS D, although the total costs obtained for all CSs are very similar.
- It is noteworthy the big amount of energy managed by the mFRR in the days type Day 3 (very low PV and wind generations) in comparison with the other two types. The low amount of renewable generation causes severe congestions at the distribution level, with a consequent impact on the activated reserves.

4.3.6 CO_2 emissions savings

The CO_2 emission for the Italian scenario in each day are represented from Figure 4.38 to Figure 4.40.

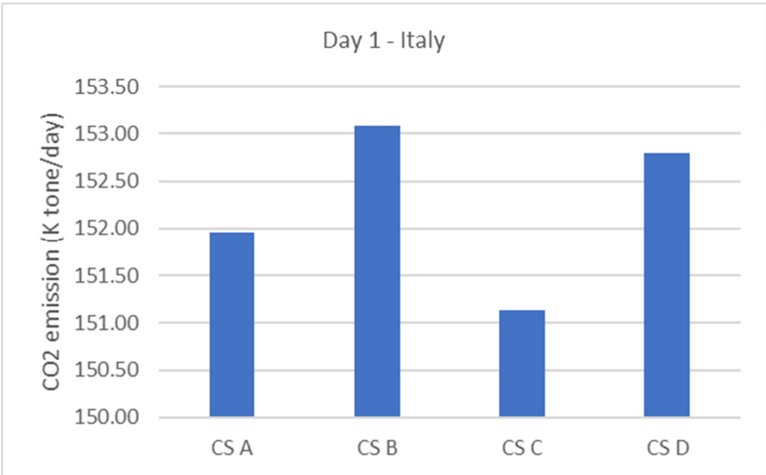


Figure 4.38: Daily CO_2 emission for the Italian scenario – Day 1

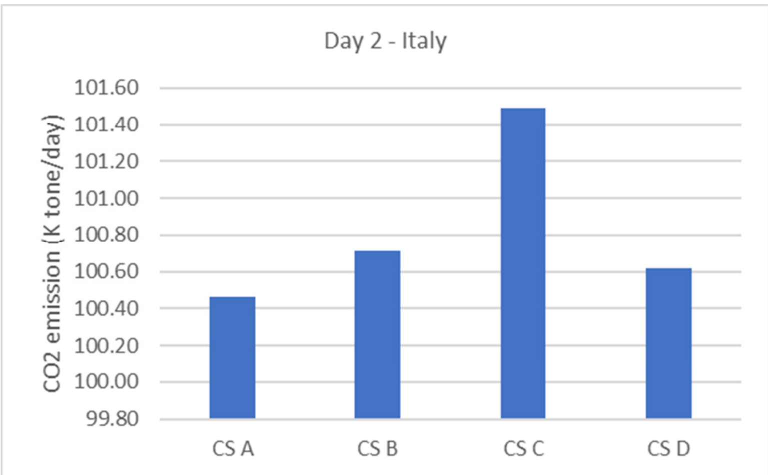


Figure 4.39: Daily CO_2 emission for the Italian scenario – Day 2

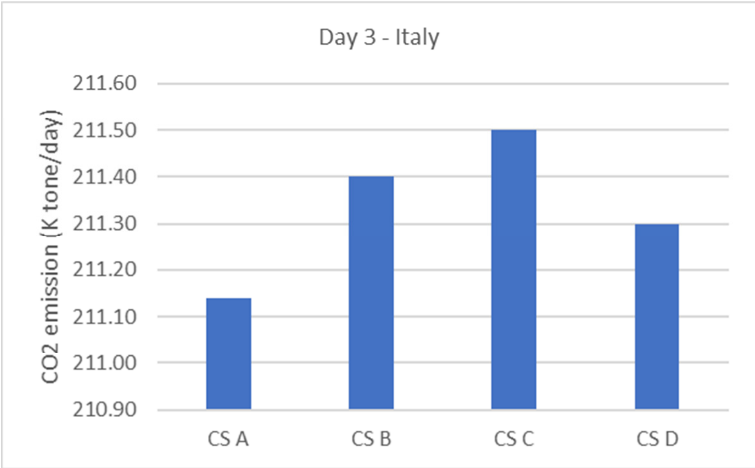


Figure 4.40: Daily CO_2 emission for the Italian scenario – Day 3

Figure 4.41 represents the annual CO_2 emissions from all conventional and CHP devices at physical layer for the Italian scenario. The results show that CS B has the lowest emission while CS C has the highest one. However, the difference between coordination schemes is less than 1 %, which is very low (note that the Y axis scale goes from 48 000 up to 49 200 ktons/day).

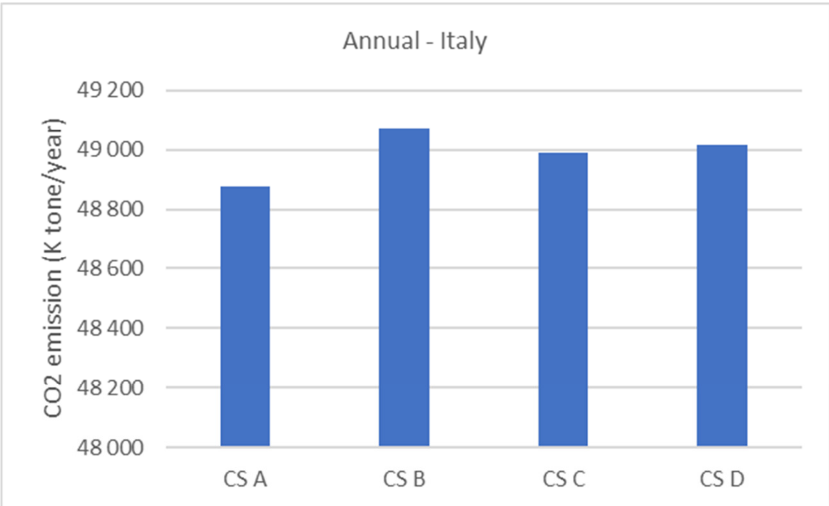


Figure 4.41: Annual CO_2 emission for the Italian scenario

4.4 Comparison of coordination schemes in Spain

4.4.1 Spain dataset

The transmission grid of the Spanish dataset is shown in Figure 4.42.

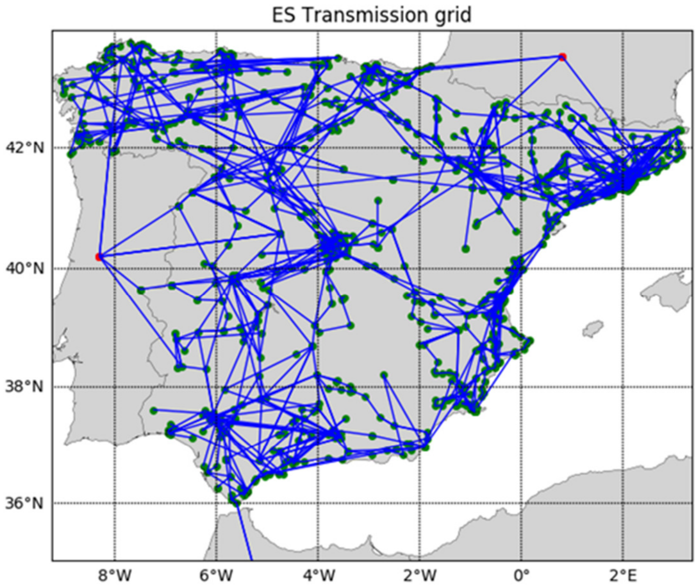


Figure 4.42: Spanish transmission grid

In this case, net load, wind and PV have similar contributions to the imbalances, while run-of-river hydro contributions are one order of magnitude lower. For more details, see D4.3 [4].

For each of the simulated scenarios, three different days have been simulated in order to represent the most common operating conditions. What make the difference are mainly the power demand, PV and wind power availability. Normalised time-series for PV and wind power availability on the selected dates for the Spanish scenario are shown in Figure 4.43. In addition, the considered number of occurrences of each day throughout a whole year is indicated, based on a comparison of the actual renewable generation mix in Spain during 2018.

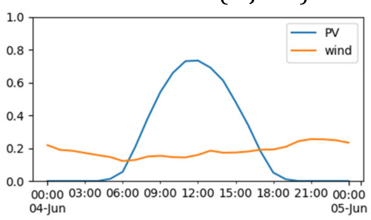
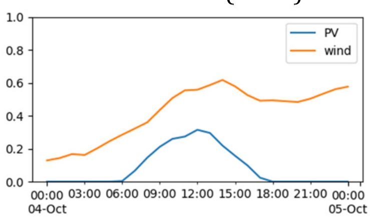
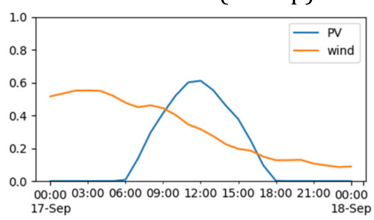
Spain		
Scenario 301 (4 June)	Scenario 302 (4 Oct)	Scenario 303 (17 Sep)
		
No. occurrences/year: 216	No. occurrences/year: 96	No. occurrences/year: 53

Figure 4.43: Normalised PV and Wind power availability in the Spanish scenario

As it can be noticed from the graphs above, the main differences between the selected days are:

- Day 1 (Scenario 301 - 4 June): High PV generation (midday hours) + Low wind generation (constant over the day).
- Day 2 (Scenario 302 - 4 Oct): Low PV generation (midday hours) + High wind generation (increasing over the day).

- Day 3 (Scenario 303 - 17 Sept): High PV generation (midday hours) + High wind generation (decreasing over the day).

4.4.2 mFRR provision cost

As described in section 4.4.1, three different days were simulated for each country. Table 4.27 to Table 4.29 recall the amounts of energy dispatched in each of them (in GWh) and summarise their associated cost (in k€) for the four coordination schemes. In all the cases, the results are divided into transmission and distribution, as well as in upward and downward activated mFRR.

Day 1		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	10.10	0.76	10.85	0.85	7.68	3.79	10.92	0.77
	Down	-0.35	-0.03	-0.35	-0.88	-0.01	-3.08	-0.35	-0.88
	Total	**10.45**	**0.79**	**11.20**	**1.73**	**7.69**	**6.87**	**11.27**	**1.65**
Cost (k€)	Up	504.33	43.17	539.71	48.78	390.93	213.11	543.18	44.03
	Down	-16.71	-1.47	-16.85	-4.04	-0.20	-42.46	-16.65	-4.73
	Total	**487.62**	**41.70**	**522.86**	**44.74**	**390.73**	**170.65**	**526.53**	**39.30**

Table 4.27: mFRR provision costs for the Spanish scenario – Day 1

Day 2		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	14.32	0.87	14.66	1.14	10.60	4.67	14.90	0.87
	Down	-0.35	-0.16	-0.34	-0.78	-0.01	-2.85	-0.32	-0.76
	Total	**14.67**	**1.03**	**15.00**	**1.92**	**10.61**	**7.52**	**15.22**	**1.63**
Cost (k€)	Up	851.20	56.21	871.25	80.70	634.27	305.72	884.91	56.82
	Down	-17.04	-8.71	-16.72	-9.62	-0.10	-49.89	-15.74	-9.15
	Total	**834.16**	**47.5**	**854.53**	**71.08**	**634.17**	**255.83**	**869.17**	**47.67**

Table 4.28: mFRR provision costs for the Spanish scenario – Day 2

Day 3		CS A		CS B		CS C		CS D	
		Tx	Dx	Tx	Dx	Tx	Dx	Tx	Dx
Energy (GWh)	Up	10.56	2.32	11.23	2.54	8.59	4.36	11.46	2.31
	Down	-0.18	-0.35	-0.19	-1.24	-0.01	-3.10	-0.19	-1.23
	Total	**10.74**	**2.67**	**11.42**	**3.78**	**8.60**	**7.46**	**11.65**	**3.54**
Cost (k€)	Up	597.93	151.96	604.63	167.19	475.16	279.98	615.45	151.11
	Down	-10.17	-28.77	-11.10	-30.93	-0.16	-45.59	-11.06	-31.86
	Total	**587.76**	**123.19**	**684.68**	**593.53**	**475.00**	**234.39**	**604.39**	**119.25**

Table 4.29: mFRR provision costs for the Spanish scenario – Day 3

Cost values are graphically represented in Figure 4.44 to Figure 4.46. Again, values are provided for transmission (red bars) and distribution (purple bars) and for upward (dark colour) and downward (light colour) activations.

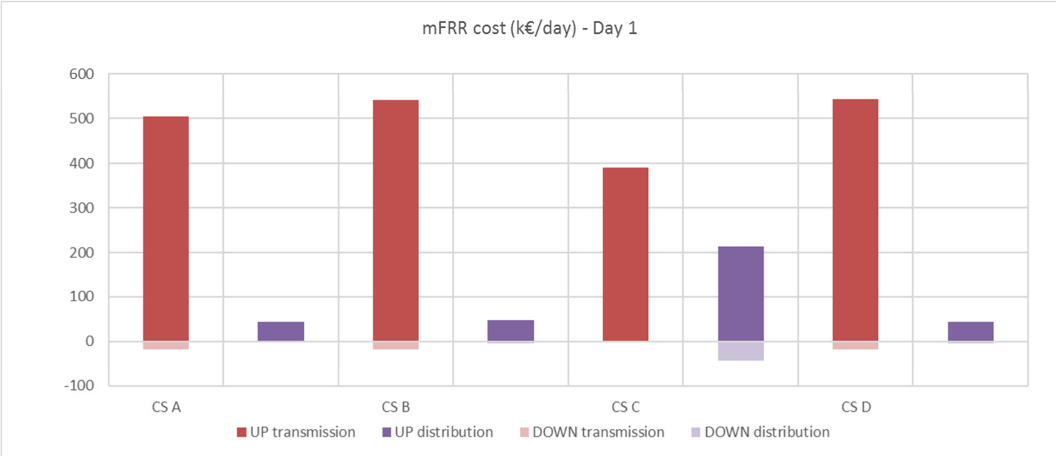


Figure 4.44: mFRR provision cost in the Spanish scenario – Day 1

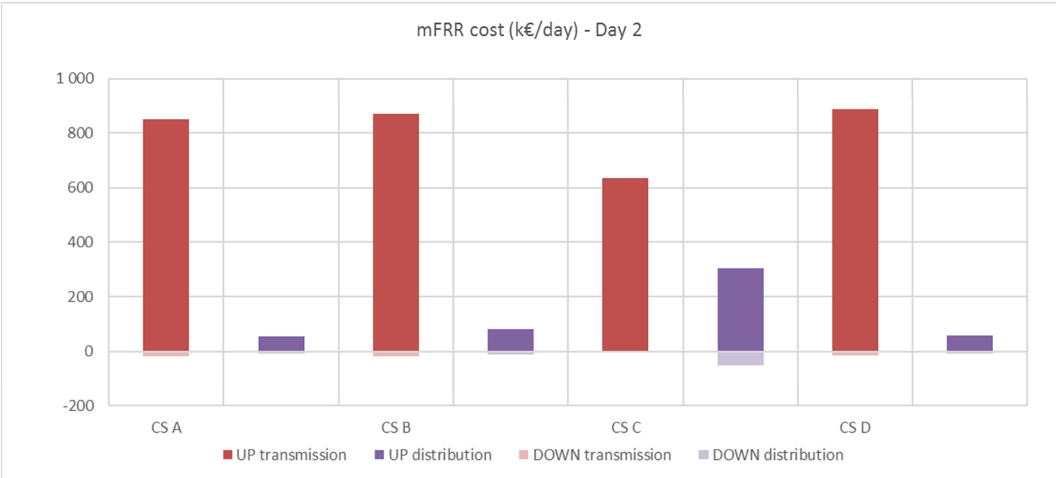


Figure 4.45: mFRR provision cost in the Spanish scenario – Day 2

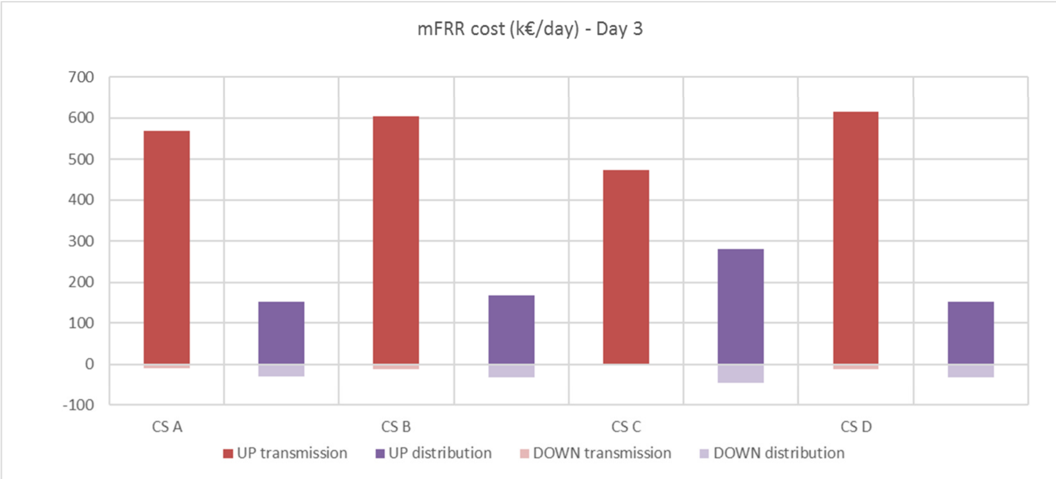


Figure 4.46: mFRR provision cost in the Spanish scenario – Day 3

4.4.3 aFRR provision cost

As for the case of mFRR provision, energy activation volumes (in GWh) are obtained from [4] and their related cost (in k€) for each coordination scheme are calculated for the three days. However, there is no shared balancing responsibility when dispatching aFRR and the TSO is assumed to be always responsible to keep the overall system balance. Therefore, the values are divided into upward and downward balancing, but not into transmission and distribution in Table 4.30 to Table 4.32 below.

			CS A	CS B	CS C	CS D
Day 1	Energy (GWh)	Up	2.54	1.64	3.36	1.74
		Down	-1.15	-1.73	-0.93	-1.74
		Total	**3.69**	**3.37**	**4.29**	**3.48**
	Cost (k€)	Up	162.99	106.02	216.17	111.92
		Down	-18.13	-25.82	-14.86	-25.89
		Total	**144.86**	**80.20**	**201.31**	**86.03**

Table 4.30: aFRR provision results for the Spanish scenario – Day 1

			CS A	CS B	CS C	CS D
Day 2	Energy (GWh)	Up	2.79	2.15	3.99	2.05
		Down	-1.54	-1.82	-0.83	-2.05
		Total	**4.33**	**3.97**	**4.82**	**4.10**
	Cost (k€)	Up	208.53	159.18	300.03	152.36
		Down	-12.99	-15.33	-7.61	-16.92
		Total	**195.54**	**143.85**	**292.42**	**135.44**

Table 4.31: aFRR provision results for the Spanish scenario – Day 2

			CS A	CS B	CS C	CS D
Day 3	Energy (GWh)	Up	2.57	1.86	3.87	1.90
		Down	-1.53	-1.82	-0.89	-1.90
		Total	**4.10**	**3.68**	**4.76**	**3.80**
	Cost (k€)	Up	209.68	149.46	326.89	151.25
		Down	-20.98	-25.43	-9.17	-27.43
		Total	**188.70**	**124.03**	**317.72**	**123.82**

Table 4.32: aFRR provision results for the Spanish scenario – Day 3

These cost values are graphically represented in Figure 4.47 to Figure 4.49, distinguishing the values for upward (dark colour) and downward (light colour) activations.

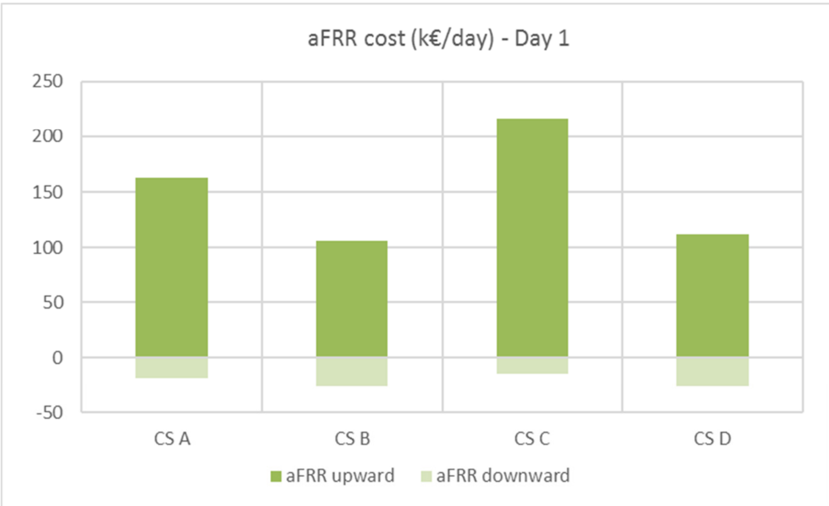


Figure 4.47: aFRR provision cost in the Spanish scenario – Day 1

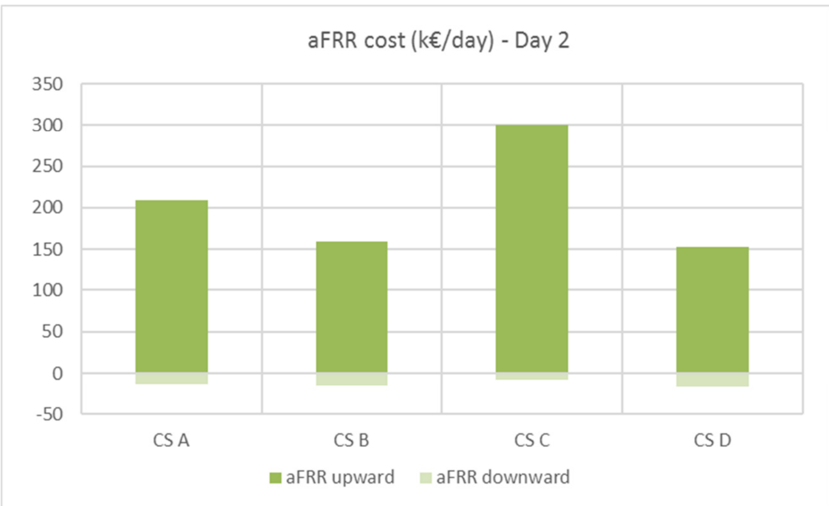


Figure 4.48: aFRR provision cost in the Spanish scenario – Day 2

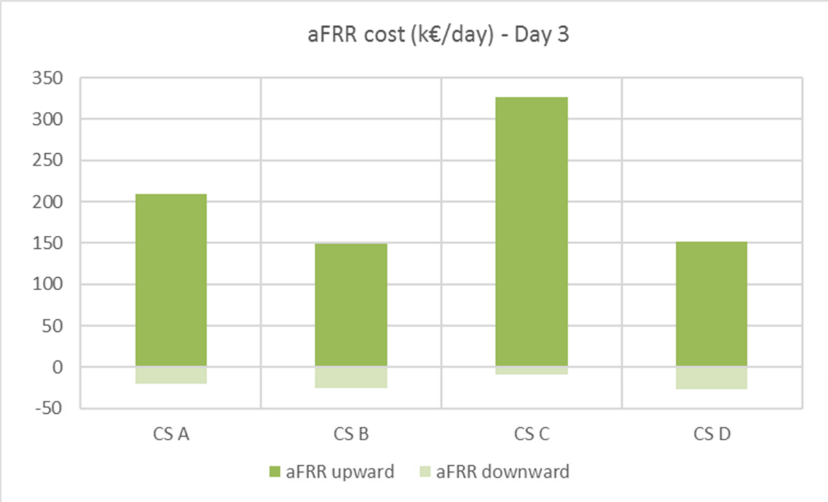


Figure 4.49: aFRR provision cost in the Spanish scenario – Day 3

4.4.4 UM provision cost

As for the cases of mFRR and aFRR provisions, unwanted measures and related costs are calculated starting from the simulation results [4] for each coordination scheme. The values are divided into upward and downward balancing, but not into transmission and distribution in Table 4.33 to Table 4.35 below.

			CS A	CS B	CS C	CS D
Day 1	Energy (GWh)	Up	0.30	0.32	0.33	0.31
		Down	-0.66	-0.17	-0.15	-0.27
		Total	**0.96**	**0.49**	**0.48**	**0.58**
	Cost (k€)	Up	4.45	4.77	5.06	4.55
		Down	0.83	0.26	0.21	0.40
		Total	**5.28**	**5.03**	**5.27**	**4.95**

Table 4.33: UM provision results for the Spanish scenario – Day 1

			CS A	CS B	CS C	CS D
Day 2	Energy (GWh)	Up	2.78	2.82	2.82	2.86
		Down	-3.89	-3.61	-3.21	-3.32
		Total	**6.67**	**6.43**	**6.03**	**6.18**
	Cost (k€)	Up	59.81	60.70	57.86	61.20
		Down	7.11	6.75	6.29	6.30
		Total	**66.92**	**67.45**	**64.15**	**67.50**

Table 4.34: UM provision results for the Spanish scenario – Day 2

			CS A	CS B	CS C	CS D
Day 3	Energy	Up	0.90	0.92	0.96	0.92

	(GWh)	Down	-1.07	-0.61	-0.54	-0.58
		Total	**1.97**	**1.53**	**1.50**	**1.50**
	Cost (k€)	Up	20.19	20.69	22.80	20.88
		Down	3.20	3.06	2.99	2.35
		Total	**23.39**	**23.75**	**25.79**	**23.23**

Table 4.35: UM provision results for the Spanish scenario – Day 3

These cost values are graphically represented in Figure 4.50 to Figure 4.52, distinguishing the values for upward (dark colour) and downward (light colour) activations.

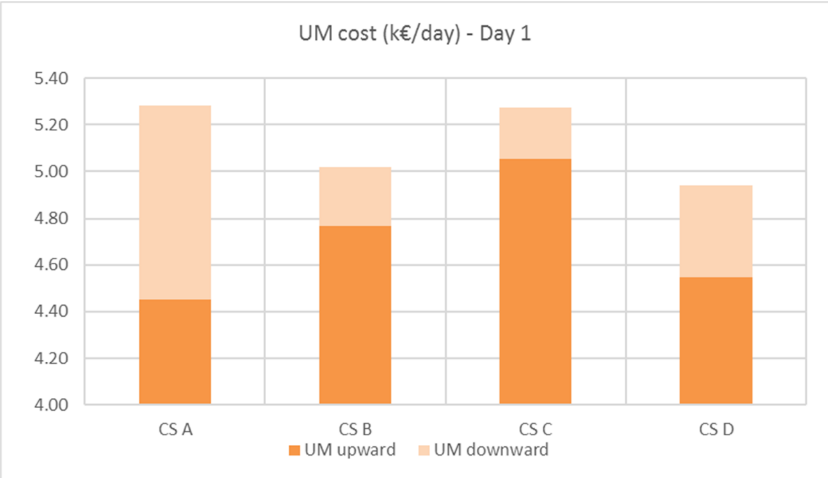


Figure 4.50: UM provision cost in the Spanish scenario – Day 1

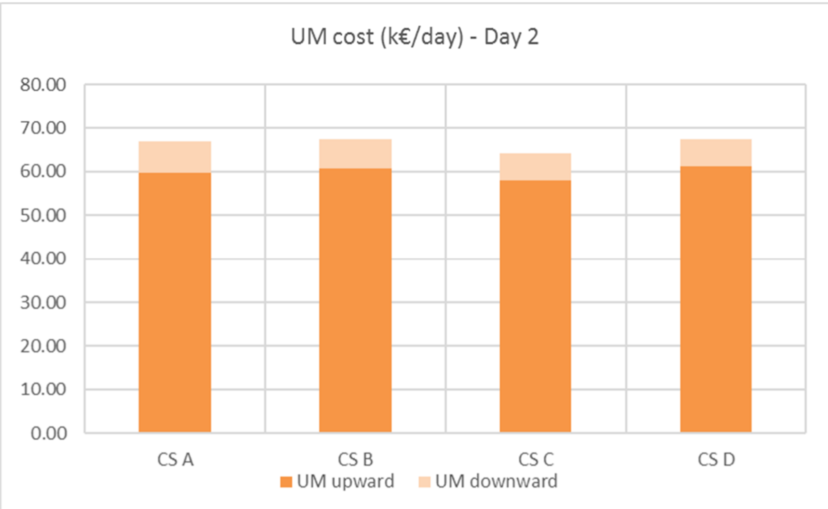


Figure 4.51: UM provision cost in the Spanish scenario – Day 2

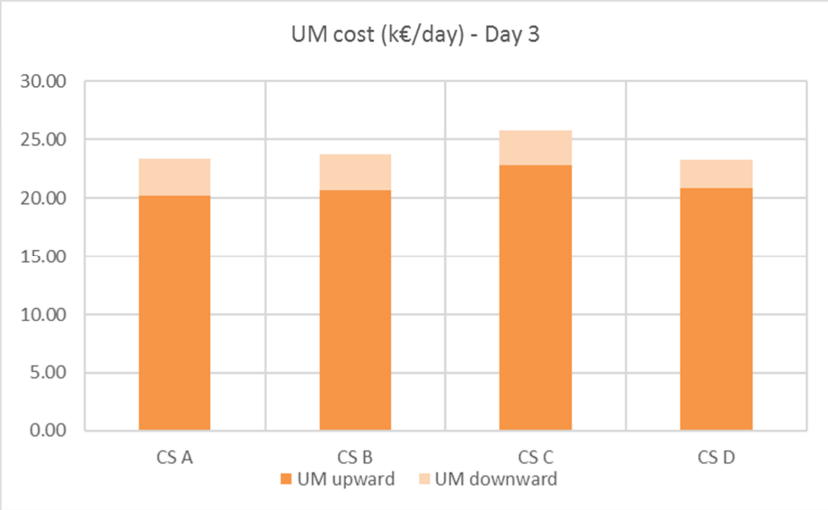


Figure 4.52: UM provision cost in the Spanish scenario – Day 3

4.4.5 Cost results for Spain

The daily values for mFRR (section 4.4.2), aFRR (section 4.4.3) and UM (section 4.4.4), together with the daily allocation of ICT costs (section 4.1) are shown together in Table 4.36 in order to allow the comparison and assessment of the impact that the different day typologies has on the obtained results. The daily cost of the ICT for each day is calculated simply dividing the annualized value by the 365 days of a year. In Table 4.36, the cheapest CS is highlighted in green and the most expensive one in red, while the same results are graphically represented from Figure 4.53 to Figure 4.55.

	(k€/day)	mFRR	aFRR	UM	ICT	**TOTAL**
Day1	CS A	529.32	144.86	5.28	12.56	**692.02**
	CS B	567.60	80.20	5.02	42.53	**695.35**
	CS C	561.59	201.31	5.27	37.68	**805.85**
	CS D	565.83	86.03	4.94	38.07	**694.87**
Day2	CS A	881.66	195.54	66.93	12.56	**1 156.69**
	CS B	925.61	143.85	67.45	42.53	**1 179.44**
	CS C	890.00	292.43	64.15	37.68	**1 284.27**
	CS D	916.85	135.44	67.49	38.07	**1 157.85**
Day3	CS A	680.95	188.69	23.39	12.56	**905.59**
	CS B	729.79	124.03	23.75	42.53	**920.1**
	CS C	709.39	317.73	25.79	37.68	**1 090.59**
	CS D	723.64	123.82	23.23	38.07	**908.76**

Table 4.36: Daily costs (k€/day) for the Spanish scenario

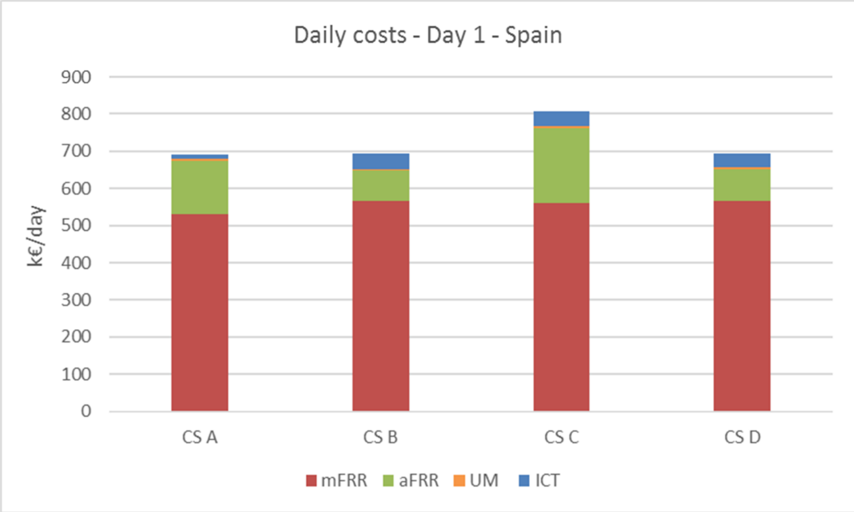


Figure 4.53: Daily costs for the Spanish scenario – Day 1

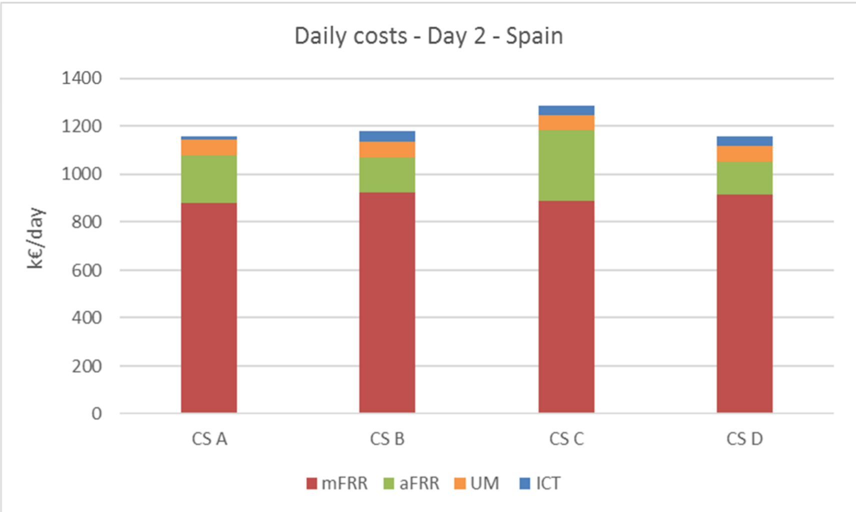


Figure 4.54: Daily costs for the Spanish scenario – Day 2

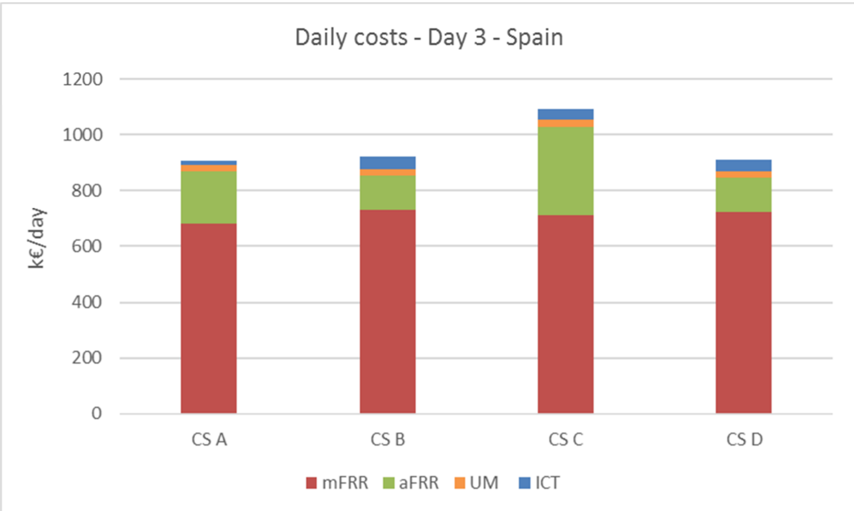


Figure 4.55: Daily costs for the Spanish scenario – Day 3

Considering the number of occurrences of each day (detailed in section 4.4.1), the annual cost values for each CS have been calculated and reported in Table 4.37 and Figure 4.56.

(M€/year)	mFRR	aFRR	UM	ICT	**TOTAL**
CS A	235.06	60.06	8.81	4.59	**308.52**
CS B	250.14	37.71	8.82	15.53	**312.20**
CS C	244.34	88.40	8.66	13.76	**355.16**
CS D	248.59	38.15	8.78	13.90	**309.42**

Table 4.37: Annual costs for the Spanish scenario

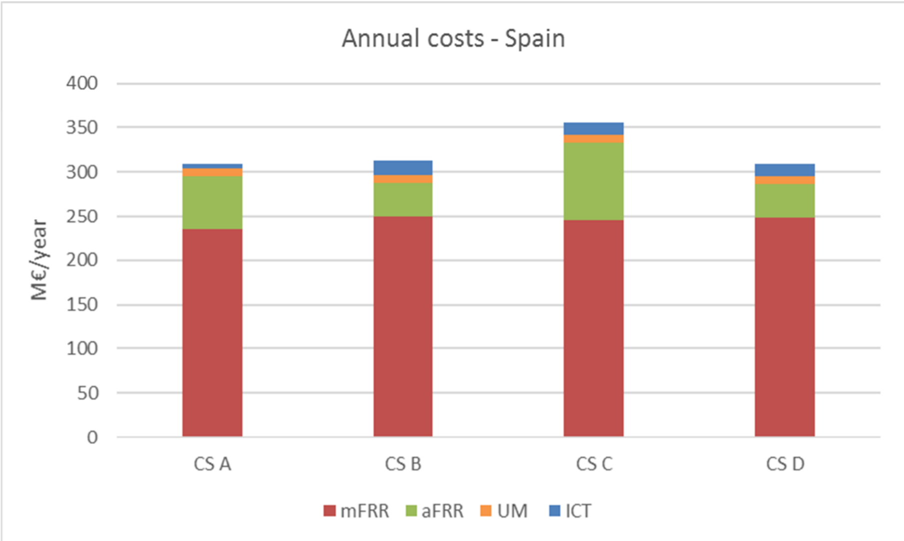


Figure 4.56: Annual costs for the Spanish scenario

From the analysis of the obtained results, the following conclusions can be observed:

- CS A, CS B and CS D are very similar and the cheapest coordination schemes, for all the considered day typologies. The most expensive one is CS C.
- In general, the annual costs of the UM are negligible in comparison with the rest of costs. However, when there is poor PV generation (Day 2), the UM cost is a bit higher than in the other day typologies.
- The ICT costs are almost negligible if compared to the mFRR cost.
- Being the total costs of CS A, CS B and CS D practically equal and the mFRR costs very similar in all coordination schemes (around 240 M€/year), the difference between these coordination schemes is determined by aFRR, UM and ICT cost figures.
- mFRR cost accounts for the larger share in total costs, but its influence is a bit lower than in Denmark (e.g. mFRR contribution to total cost in CS C is about 65÷70% in the three days).

- aFRR is making CS C as the most expensive coordination scheme, demonstrating the ineffectiveness of the simulated scenario in allowing a separated management of the balancing services.

4.4.6 CO_2 emissions savings

The CO_2 emission for the Spanish scenario in each day are represented from Figure 4.57 to Figure 4.59.

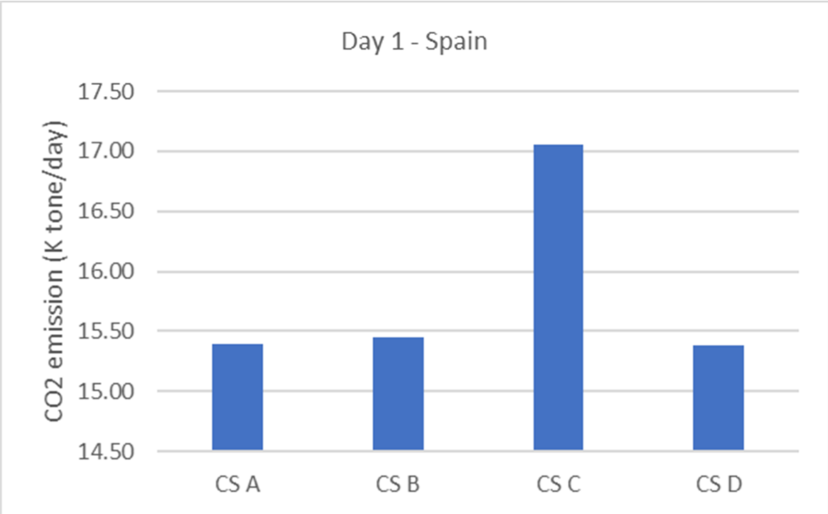


Figure 4.57: Daily CO_2 emission for the Spanish scenario – Day 1

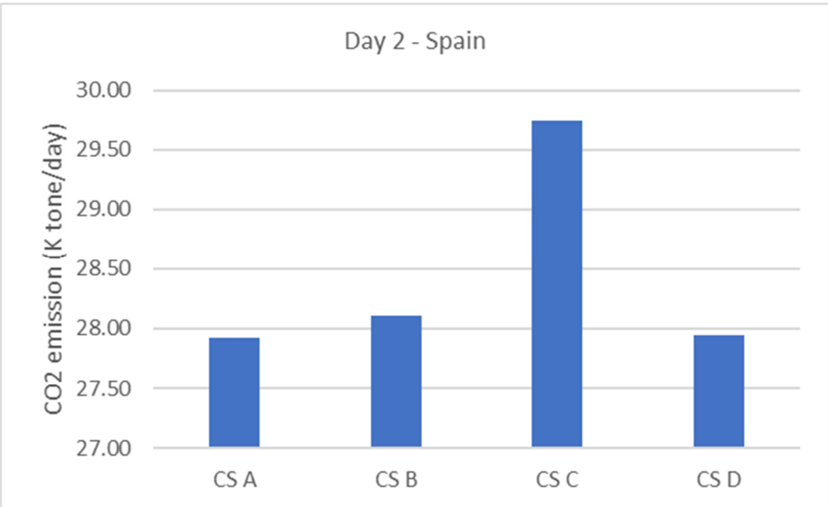


Figure 4.58: Daily CO_2 emission for the Spanish scenario – Day 2

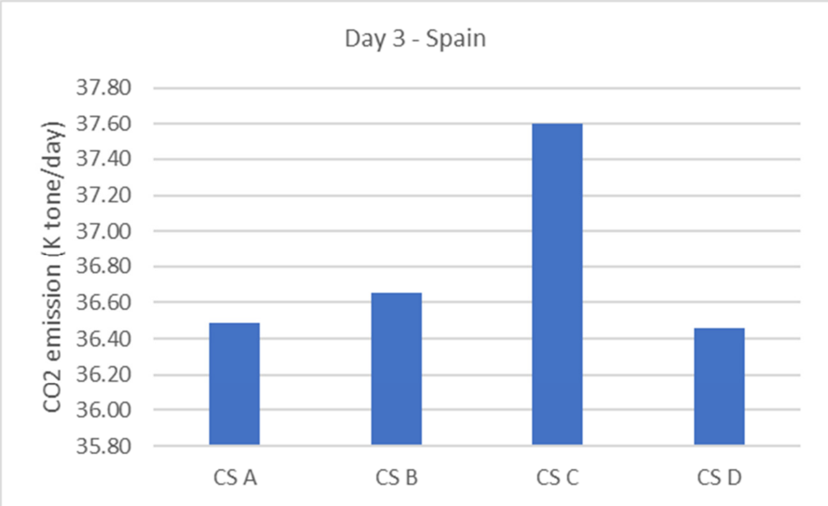


Figure 4.59: Daily CO_2 emission for the Spanish scenario – Day 3

Figure 4.60 represents the annual CO_2 emissions from all conventional and CHP devices at physical layer for the Spanish scenario. The results show that CS C has the highest emissions in comparison to CS A, CS B and CS D, which have very similar results. However, the difference between coordination schemes is less than 7 %, which is quite low (note that the Y axis scale goes from 7 000 up to 8 800 ktons/day).

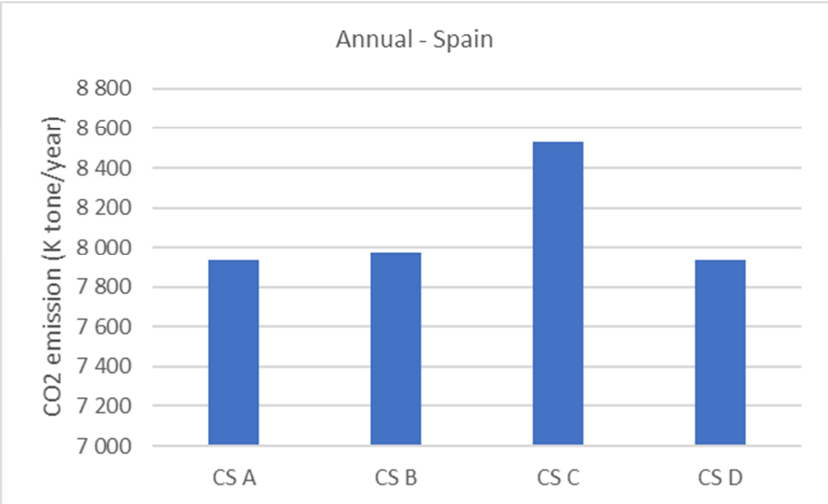


Figure 4.60: Annual CO_2 emissions in the Spanish scenario

4.5 Discussion of results

From the obtained results (which are reported in sections 4.2.5, 4.3.5 and 4.4.5 for Denmark, Italy and Spain respectively) some general conclusions can be summarized as follows:

1) The effectiveness of the TSO-DSO coordination schemes depends on the level of services requested by the DSO:

- In case of few congestions at distribution level (forecasting errors are comparable to the possibility of having congestions in distribution grid), CS A has higher economic performance with respect to CS B and CS D. This is the case of Denmark, where the uncertain contribution of wind power (mostly located at transmission level) is higher than the contribution from PV (at distribution level). Therefore, forecasting errors are expected to be higher, while the congestions at distribution level are likely to be less common.
- When distribution congestions are significant (and predictable), the adoption of CS B or CS D results to be beneficial. This is the case of Italy, where generation located in distribution grids, such as PV, contributes more to the electricity supply and, hence, congestions are expected to happen more frequently.
- In any case, the most relevant cost component is mFRR in all the cases, while UM and ICT costs only account for a small share. Moreover, results discourage the investigation of new methods for dispatching aFRR, because higher complexity would result in higher IT costs.

2) The implementation of two-step markets (CS B and CS C) is generally less efficient than optimising in a single step (CS D):
   - Regarding CS B, the results are pretty similar to the ones returned by CS D, although slightly more expensive in the scenarios simulated. This is something to be expected because CS D obtains an overall optimum, while CS B solves distribution and transmission services separately.
   - On the contrary, CS C is clearly the least efficient CS in all the countries. In addition to optimising in two steps, CS C introduces an additional constraint by fixing the active power exchange on the TSO-DSO interconnection, which further decreases the solution efficiency.
   - Both CS B and CS C may suffer from scarcity and/or illiquidity of resources, which would further decrease their efficiency.
   - However, in rare circumstances (i.e. severe congestions at transmission level) the selection of two-step market architectures can be more beneficial than other schemes, as market separation potentially prevents the spreading of high nodal prices among distribution and transmission systems.
3) Under the scope restrictions and the formulation of the ICT cost estimation problem, the main finding was that the technological costs in upgrading market architectures from CS A to CS B, CS C, or CS D are almost the same (subject to uncertainties) and much lower than operation costs. Variation between countries is minor.
4) In addition to these general conclusions, some country-specific deductions can be extracted:

- For the specific case of Italy, in which there are big congestions at distribution level, the upgrade from CS A to CS B/D is convenient and not jeopardized by ICT costs.
    - In Spain, with average congestions at distribution level, the ICT costs are comparable to the benefits brought by adopting CS B/D rather than maintaining CS A.
    - In Denmark, with low congestions at distribution level and high forecasting errors, the implementation of DSO-inclusive CSs failed.
5) The aggregators will bear a large portion of ICT costs (communications with DERs, aggregation software, etc.). Therefore, the related cost analysis indicates that the aggregator's IT systems will be the most expensive ones. Additionally, it must be taken into account that the problem with the last kilometre DER communications was assumed to be solved, since that is part of the base line of the centralized AS market (CS A). However, it may be possible that DER communication/activation costs turn out to be too large for a profitable aggregation business, but this issue is applicable to all CSs.
6) Regarding the CO_2 emissions, the main conclusions achieved by the analysis are:
    - Italy is characterized by large CO_2 emissions if compared to other countries (one order of magnitude higher), because Denmark has small demand and mostly renewable energy mixes, and the energy mix in Spain is predominantly carbon-free (nuclear and large portions of renewables).
    - All CSs features similar emissions, being the difference less than 7%. The mFRR activations are small if compared to the total energy demand. In the specific case of CS C, the sub-optimal mFRR activations drive to more visible impacts on CO_2, except when forecasting errors are comparable to the probability of having congestions in distribution (Denmark), as CS C becomes more efficient, also in terms of CO_2 emissions.

5 Business-level analysis

The efficiency of the different TSO-DSO coordination schemes was assessed through the CBA described in previous chapters. However, CSs must also allow the involved actors to have a profitable business case, that is, CSs must lead to an appropriate allocation of costs and benefits among them. Therefore, a business-level analysis (also called “micro-level analysis”) was needed to assess the economic impact of the different CSs for all the relevant actors.

As the reader will discover when reading this chapter, the complexity of a business-level analysis is out of the scope of the economic assessment performed with the project SmartNet. However, due to its relevance when making regulatory decisions, this chapter is intended to provide guidance on how to conduct this kind of analysis.

Based on the experience of the partners in the project, the e^3value methodology [42] was selected as the most suitable approach to perform the economic analysis of the SmartNet coordination schemes. The two main reasons were that it presents the whole picture of the business case and that it focuses on the concept of economic value, which allows an easy comparison of different arrangements, country regulations, scenarios, etc. Additionally, the e^3value is not intended to identify a new business idea, but it aims at clarifying and evaluating such idea more thoroughly. Therefore, the e^3value can be very useful when going a step forward, i.e. when the business case has been identified and a specific analysis of its profitability is required.

The business-level analysis is composed of several main steps to determine, at the end of the process, whether coordination schemes are economically attractive for all actors, i.e. whether the benefits seen by each of them outweigh their costs. The following topics will be developed through the next sections:

1. **Definition and representation of the value models.**

   When developing a business idea, it must be taken into account that each entity involved should be able to make profit or, at least, increase positively its economic results. This must be clear, since no stakeholder is willing to adopt new products or services if their added value is not obvious. The aim of this analysis is to present the whole picture, so, it will not only focus on the actors who want to provide a new service, but also on the rest of the parties they need to fulfil such business.

   Two of the main characteristics of the e^3value methodology are that it is a graphical approach and that it focuses on the economic value. Therefore, the representation of the business idea takes the shape of a value model. A value model represents a number of actors who exchange objects of economic value with each other. The value models include all actors that participate in the business and who must collaborate with each other, so that all of them benefit. These actors are directly or indirectly connected, so, the required relationships can result in a dense network.

In this case, each coordination scheme was represented as a value model. All actors must contribute to the success of the business, regardless of their size, strength or role. This means that they must establish relationships and exchange value objects which are of value for them. The value model is a bi-dimensional representation of the value exchanges between the different actors, so, it is quite simple to draw what is offered to whom and what is requested for it in return.

It is worthwhile to indicate that **an exchange between actors is included in the graphic representation only if there is a recurrent payment associated to it**. If there is a cost, but only a one-time payment, the issue will be considered in the subsequent investment analysis, but not in the graphics.

2. **Identification of the relationships between actors.**

When comparing the value models for the different coordination schemes, it must be taken into account that they refer to the same type of service, but which is provided in different ways. Therefore, most of the actors and their relationships are common to all of them. As a result, it is important to highlight the differences among them, because those differences were the ones which resulted in different behaviour for each coordination scheme.

3. **Theoretical formulas definition.**

Once the exchanges are identified, the next step is to quantify them via simple formulas, which represent the relationships between the actors and which need to be fed with the appropriate data. Most of the times, the formulas which represent the money flows between actors, are a multiplication between a price and an energy volume.

The formulation developed in this step aimed to provide an appropriate tool to calculate the numeric results if all the required data had been available, in as much detail as it is required by these formulas. However, due to the results and the level of detail obtained from the SmartNet simulations, these formulas had to be adjusted to adapt them to the available data.

4. **Formulation adjustments**

As indicated above, from the theoretical formulation (optimal case) some adjustments may be necessary. The formulation was updated, according to the results obtained by the SmartNet simulation environment and the data format (e. g. time-step, disaggregation level of the results, detail level of the input-data, etc.) used there.

5. **Actor's cash-flow calculation.**

The cash-flows are calculated by the addition of money in-flows and the subtraction of money out-flows. Although the settlement period in most European countries is one hour, this period will be reduced in the future, as established in Article 53 of the Guideline on Electricity Balancing [43]. In the specific case of SmartNet, the time-step was established in 15 minutes, so the annual cash-flow

should be calculated as the sum of the 15-minute values, i.e. 4 periods of 15 min in each hour and 8, 760 hours per year.

6. **CBA, including investments, for each actor.**

Once annual cash-flows are obtained, an investment profitability analysis must be performed for those actors who need to make a specific investment for the deployment of each coordination scheme. In the SmartNet analysis, only specific ICT costs should be assessed, since they were expected to be the only new investment required for the operating of the coordination schemes.

In this last step, a comparison between the calculated annual cash flows and the annualization of the required investment for each actor must be performed in order to determine the most attractive coordination scheme for each of them.

All these steps are described in detail in this document, after describing both the e³value methodology (section 5.1) and the specific description of participants in the SmartNet coordination schemes (section 5.2). The creation of the value models is described in section 5.3, while the relationships between the actors and the formulas to be used are presented in Appendix IV – Business-level analysis formulation.

5.1 e³ value methodology

e³value is a conceptual modelling approach aimed at facilitating the statement, communication and understanding of the value proposition of an innovative business idea. In addition, it is also designed to allow for a rigorous evaluation of its economic feasibility. As a third goal, it also intends to build the bridge between the expression of the business idea and the identification of the required supporting information systems, in order to avoid the usual thinking of ICTs as an expense only, rather than as a tool to create value for customers and the company itself.

All the stakeholders involved in a business idea must be able to make profit or to increase their economic utility, and all of them must have a common understanding of the value proposition.

Two of the main characteristics of e³value are that it is a graphical approach and that it focuses on the **economic value**. Therefore, the representation of the business idea takes the shape of a value model. A value model represents a number of actors who exchange objects of economic value with each other, i.e. **it represents what objects of economic value are exchanged by whom**. In fact, it represents what is offered to whom and what is requested for it in return (in the economic sense).

The main concepts to express the model are:

- Actor: An actor is perceived by its environment as an independent economic (and often also legal) entity. Economically independent means that it is profitable after a reasonable period of time (when referring to companies) or that it increases its economic utility (when referring to end

customers). In a sound and sustainable business model each actor should be capable of making profit or increasing its utility.

- Value Activity: Actors perform value activities in order to increase their profit or economic utility. Therefore, the execution of a value activity must yield profit for, at least, one actor. In addition, each value activity must be completely assignable to an actor.
- Value Object: Actors exchange value objects, which are services, products, money, or even consumer experiences. The important point here is that a value object is of value for one or more actors.
- Value Port: An actor uses a value port to show to its environment that it wants to provide or request value objects. The concept of ports allows of abstracting away from the internal business processes and focusing only on how external actors and other components of the business model can be 'plugged in'.
- Value Offering: A value offering models what an actor offers or requests from its environment. The closely related concept 'value interface' (see below) models an offering to the actor's environment and the reciprocal incoming offering, while the value offering models a set of equally directed value ports exchanging value objects. It is used to model e.g. bundling: the situation that some objects are of value for an actor only when they are offered in combination.
- Value Interface: Actors have one or more value interfaces, grouping individual value offerings. A value interface shows the value object that an actor is willing to exchange for another value object via its ports. The exchange of value objects cannot be divided at the level of the value interface.
- Value Exchange: A value exchange is used to connect two value ports with each other. It represents one or more potential trades of value objects between value ports.
- Market Segment: The market segment shows a set of actors that, for all of their value interfaces, give the same economic value to objects.

The concepts above can be used to model value exchanges between actors or market segments, but do not give the idea of which value activities or value exchanges must take place, so that some other value activities or value exchanges can also take place. In other words, they do not represent the order in which value exchanges must take place. To that end, some other concepts are used:

- Scenario path: A scenario path consists of one or more segments, related by connection elements, and both start and stop stimuli. A path indicates via which value interfaces objects of value must be exchanged, as a result of a start stimulus, or as a result of exchanges via other value interfaces.
- Stimulus: A scenario path starts with a start stimulus, which represents a consumer's need. The last segment(s) of a scenario path is connected to a stop stimulus. A stop stimulus indicates that the scenario path ends.

- Segment: A scenario path has one or more segments. Segments are used to relate value interfaces with each other (e.g. via connection elements) to show that an exchange on one value interface causes an exchange on another value interface.
- Connection: Connections are used to relate individual segments. Each fork splits a scenario path into two or more sub-paths, while each join collapses sub-paths into a single path. In AND forks/joins, all incoming and outgoing paths have the same number of occurrences, while in OR forks (joins) the number of occurrences of the incoming (outgoing) path equals the addition of the number of occurrences of the outgoing (incoming) sub-paths. An implosion (AND connection with only one incoming and one outgoing port) shows a change in the number of occurrences within a sub-path.

Table 5.1 shows the graphical representation of the main e³value concepts.

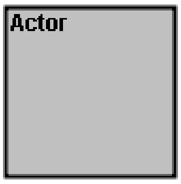
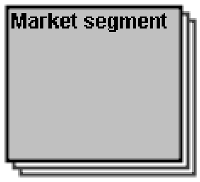
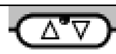
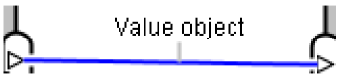
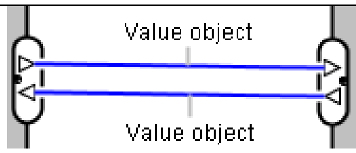
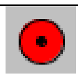
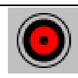
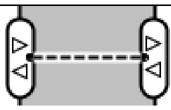
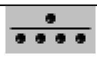
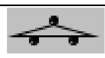
Concept	Graph	Concept	Graph
Actor		Market segment	
Value port		Value interface	
Value object		Value exchange	
Start stimulus		End stimulus	
Segment		Implosion	
AND fork/join		OR fork/join	

Table 5.1: Graphical representation of main e3value concepts

The goal of the e³value is to evaluate a business idea, and discover a business scenario, which consists of the value model and the scenario path, which is feasible for every stakeholder. Therefore, e³value assumes that business developers already have a business idea in mind and, thus, it aims at clarifying and evaluating such idea more thoroughly.

In order to create the business scenario, a number of sequentially-executed steps are needed. The result of each step is an input for the following step, and the outcome of the whole process is a business model, including a graphical representation and the corresponding financial profitability sheets, which facilitate the sensitivity analysis of the business case.

1. Step 1 – Business idea description: Write down a short business case description to express the business idea. The value model is a representation of the real world and, hence, such a representation cannot include all the objects of the real world, but the basic rule is to include all involved actors and activities in the value model process.
2. Step 2 – Goal selection: The first consideration to be taken when modelling the business is specifying all the goals that stakeholders want to satisfy with that business, even if they may be in conflict with the goals of another stakeholder(s).
3. Step 3 – Technology selection: Once the goals are identified, the next step is to select an appropriate technology to achieve both operational (short-term) and strategic (long-term) goals.
4. Step 4 – Value activity selection: In this step, value activities to be included in the model are selected.
5. Step 5 – Value interface selection: In this step all value interfaces necessary to model the business case are selected from a library of interfaces [42], where general and optional interfaces are provided for each activity.
6. Step 6 – Ports connection: The value interfaces must be connected to obtain a connected value model.
7. Step 7 – Actor selection: Each activity should be performed by an actor, but this is not a strict one to one relation. Some actors perform more than one activity, and in some cases an activity should be divided over two actors.
8. Step 8 – Scenario path identification: A scenario path is used to explain cause-effect relationships by travelling over paths through a system. Scenario paths allow to count the number of value exchanges in a given time-period, which is very important to perform the profitability analysis.
9. Step 9 – Information system model construction: Once a correct value model has been constructed, the information system needed to support such a model must be addressed. This step is performed only when the expenses to maintain such an information system are substantial; otherwise they will be included as O&M costs.
10. Step 10 – Base-line profitability sheets calculation: The evaluation of a business model focuses on the question whether it is feasible from an economic point of view, and whether a scenario is profitable for each actor involved in the value model. The impact of the business model in the different actors is assessed by creating profitability sheets for each actor involved, where economic value is assigned to objects delivered and received.
11. Step 11 – Sensitivity analysis: Since it is not possible to predict the future, the important result of the analysis is not the numbers on profitability themselves, but the reasons behind them. Therefore, a sensitivity analysis is very useful to check the robustness of the results obtained when different assumptions are taken.
12. Step 12 – Investment analysis: After a scenario is chosen, a detailed analysis of financial aspects must be made. There are several standard criteria for investment analysis (e.g. NPV and IRR).

For a more detailed explanation, see e^{3}value website (http://e3value.few.vu.nl/) and [42].

5.2 Description of participants

The definition of actor in e^{3}value, i.e. an independent economic (and often also legal) entity, cannot be completely translated into actors in the power system. Many times, real actors in power systems perform more than one role, which are translated as "actors" in value models. For example, an electricity supplier may perform the roles of retailer, aggregator and Balancing Responsible Party (BRP) at the same time. Therefore, participants described here are linked to archetypical roles in power systems (e. g. one role for retailer, another one for aggregator and a third one for BRP).

This section includes a brief description of the participants represented graphically in the e^{3}value models (section 5.3).

Consumers (entities purchasing electricity for powering their own loads) can buy electricity directly in the market or through a retailer/aggregator. Likewise, producers can sell electricity directly or through an aggregator. If consumers or producers trade directly in the market, they are called "Direct" and, if not, they are called "Non-direct". In order to be consistent with the assumptions in the simulations, consumers connected at transmission level are considered to be "Direct".

Moreover, consumers can provide flexibility or not (it is assumed that DER producers will always provide flexibility). If they do, they are called "Active" and, if not, they are called "Passive". Therefore, active consumers can change their consumption patterns if properly incentivised, while passive consumers do not change their baseline consumption. Although all consumers connected at transmission are direct, not all of them are active and, equally, some direct active consumers are connected at distribution level.

The different types of consumers are presented in Table 5.2 below.

Actors	Description
Non-direct passive consumers	– These consumers are connected at distribution level. – They are Passive, so they determine their consumption entirely with respect to their own needs, even if they may use Time of Use (ToU) tariffs. – They are Non-direct, so they acquire their electricity through a retailer.
Non-direct active consumers	– These consumers are connected at distribution level. – They are Active, so they participate in active demand activities providing flexibility through their aggregator. – They are Non-direct, so they acquire their electricity through an aggregator.

Actors	Description
Direct passive consumers	– These consumers are connected at transmission level. – They are Passive, so they determine their consumption entirely with respect to their own needs, even if they may use ToU tariffs. – They are Direct, so they acquire their electricity directly in the wholesale market.
Direct active consumers-distribution	– These consumers are connected at distribution level. – They are Active, so they participate in active demand activities providing flexibility through their aggregator. – They are Direct, so they acquire their electricity directly in the wholesale market.
Direct active consumers-transmission	– These consumers are connected at transmission level. – They are Active, so they participate in active demand activities providing flexibility through their aggregator. – They are Direct, so they acquire their electricity directly in the wholesale market.

Table 5.2: Description of participants - Types of consumers

The rest of the participants presented in the e^3value models are detailed in Table 5.3 below.

Actors	Description
Retailers of non-direct passive consumers	The main commercial activity of retailers is the wholesale purchase of electricity and the subsequent resale to their customers (non-direct passive consumers). In this model, retailers are not willing to buy any active demand service.
Aggregators of non-direct active consumers	These aggregators buy the wholesale electricity for their customers (non-direct active consumers) and, additionally, manage the active demand services provided by them. Aggregators act as intermediaries between several active consumers and other players in the system, by aggregating each consumer's demand flexibility and offering it to other players (e. g. DSO, TSO) through the corresponding market.
Central producers	Producers with generator(s) connected to the high-voltage transmission grid.
Direct DER Producers	They manage their own needs and participation in the different markets, i.e. sale of electricity in the wholesale market, management of their imbalances through the corresponding BRP, balancing provision taking part in balancing markets, etc. These DER producers are assumed to be connected at distribution level.
Non-direct DER producers	They contract an aggregator for the management of all their activities. These DER producers are assumed to be connected at distribution level.
Aggregators of non-direct DER producers	These aggregators sell the wholesale electricity of their customers (non-direct DER producers) and, additionally, manage the rest of their activities, e. g. participation in the wholesale market, payment of Transmission and Distribution (T&D) fees, participation in balancing markets, etc. Aggregators act as intermediaries between non-direct DER producers and other players in the system, by aggregating production and flexibility and offering it to other players.

Actors	Description
Wholesale market operator	The market operator is responsible for wholesale electricity trade and it will be the sole counterparty for all market transactions, so, it receives offers and bids and clears the market. Therefore, market participants do not trade with each other, but through the market platform organized/managed by the market operator.
DSO	The DSO, as defined by 2009/72/EC, is a natural or legal person responsible for operating, maintaining, and – if necessary – developing the distribution system in a given area, and – where applicable – its interconnections with other systems. The DSO as a regulated entity is subject to unbundling requirements. In the long term, the DSO ensures the ability of the distribution system to meet future demand for the distribution of electricity or gas. The DSO is responsible for the connection of grid users at the distribution level and for the connection of the DSOs within the TSO area of responsibility (control area).
TSO	The TSO, as defined by 2009/72/EC, is a natural or legal person responsible for operating, maintaining, and – if necessary – developing the transmission system in a given area, and – where applicable, its interconnections with other systems. The TSO as a regulated entity is subject to unbundling requirements. It is the responsibility of the TSO to safeguard the normal operation of the electric power system. In the long term, the TSO ensures the ability of the system to meet future demand for the transmission of electricity. Moreover, the TSO is responsible for connecting grid users at the transmission level and for connecting all DSOs within the TSO control area.”
Rest of the system	Other regulated entities who take part in the electricity system and receive a payment for this. Since the process to solve all these payments is quite complex and does not provide further details for the business case under analysis, they have all been included under this black box.

Table 5.3: Description of participants – Other participants

However, all market participants must be assigned to BRP (they can be their own BRP). BRPs are responsible for keeping the scheduled program (as a result of market trade) in real-time and, if they cannot, they will face the imbalances assigned by the TSO. If the producers represented by the BRP generate more electricity than scheduled (or if consumers demand less), the BRP is assigned an upward imbalance and, thus, will receive that amount at a lower price than the day-ahead market price (being the difference between both prices the imbalance cost). On the contrary, if BRP’s producers generate less (or if consumers demand more), the TSO will charge a downward imbalance and the BRP will pay a price which is higher than the day-ahead price (again, being the difference the imbalance cost). More details can be found in section 11.2.6. The different types of BRP are described in Table 5.4 below.

Actors	Description
BRP: Direct passive consumers	This BRP has a balancing contract with the direct passive consumers for the management of the imbalances caused by them.

Actors	Description
BRP: Retailers of non-direct passive consumers	This BRP has a balancing contract with the retailers of non-direct passive consumers for the management of the imbalances caused by them.
BRP: Central producers	This BRP has a balancing contract with the central producers for the management of the imbalances caused by them.
BRP: Direct active consumers-transmission	This BRP has a balancing contract with the direct active consumers-transmission for the management of the imbalances caused by them.
BRP: Direct active consumers-distribution	This BRP has a balancing contract with the direct active consumers-distribution for the management of the imbalances caused by them.
BRP: Aggregators of non-direct active consumers	This BRP has a balancing contract with the aggregators of non-direct active consumers for the management of the imbalances caused by them.
BRP: Direct DER producers	This BRP has a balancing contract with the direct DER producers for the management of the imbalances caused by them.
BRP: Aggregators of non-direct DER producers	This BRP has a balancing contract with the aggregators of non-direct DER producers for the management of the imbalances caused by them.

Table 5.4: Description of participants - BRPs

In addition to these roles which appear in all coordination schemes, the management of the SmartNet market requires different roles in each coordination scheme:

Role	Description	Coordination scheme (CS)
Balancing Market Operator	The TSO manages the instantaneous imbalances (that BRPs are not able to control), by making use of balancing energy supplied by the providers to the balancing market[21]. The balancing costs are transferred to the BRPs. The BRPs, in turn, charge the costs of their imbalances to the actors that have a balancing contract with them (consumers, producers, retailers).	CS A CS B CS C
Local Market Operator	There is a separate local market, which is managed by the DSO. Resources from the distribution grid can only be offered to the TSO via the local market and after the DSO has selected resources needed to solve local congestions. The DSO aggregates and transfers bids to the balancing market, operated by the TSO. The DSO assures that only bids respecting the DSO grid constraints can take part in the balancing market.	CS B

[21] The market clearing algorithm aims not only to procure balancing, but also to avoid congestions in real-time.

	There is a separate local market, which is managed by the DSO. Flexibility for both congestion management and balancing of the distribution grid needs to be contracted in this local market. Resources from the distribution grid cannot be offered to the TSO grid and vice versa.	CS C
Common Balancing Market Operator	There is a common market for both the TSO and the DSO with flexibility from resources connected at transmission and distribution levels. The TSO and the DSO are both responsible for the organization and operation of the market. The DSO constraints are integrated in the market clearing process.	CS D

Table 5.5: Description of participants - SmartNet market managers

5.3 Creation of the value models

Next sections present and explain the value models for each coordination scheme (detailed explanation of each coordination scheme can be found in Deliverable 1.3 [1]). As previously mentioned, these models represent the money exchanges between the different stakeholders (and not other exchanges of information etc. which are not linked to an economic exchange).

Although the value models presented here take the Spanish regulation as a basis, it was considered that they represent the likely situation in 2030 in the three countries under analysis (Italy, Denmark[22] and Spain).

For the sake of clarity, each subsection has been written aiming to provide a complete overview of the specific coordination scheme, in such a way that each section can be read independently. For that reason, some information may be repeated. In all CSs, there are two main paths for the money flows: the traditional electricity supply path (path 1) and the path for providing AS (path 2). Path 1 is common to all the CSs, so it is only described in CS A, but it also appears in the rest of CSs.

5.3.1 Coordination scheme A

In this coordination scheme, the TSO contracts ancillary services (AS) directly with DER owners connected to the distribution grid. The DSO can procure and use resources to solve local grid issues, but the procurement takes place in other timeframes (different from near real time, e.g. long-term ahead) than the centralized AS market. Resources in distribution are subject to DSO pre-qualification to be allowed to bid into the centralized AS market [5].

Figure 5.1 has been extracted from D1.3 [1]. It illustrates the role played by relevant stakeholders and, additionally, it shows a high-level view of the market architecture and interactions among players.

[22] The only significant difference detected is the payment for market access, based on a fixed subscription rate in Denmark.

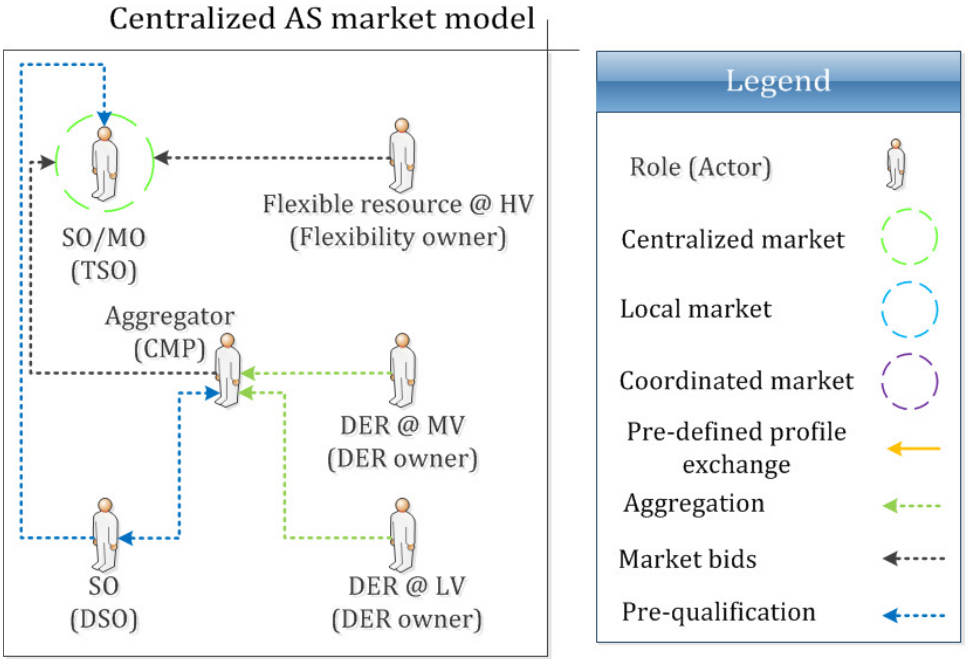


Figure 5.1: Centralized AS market model

The value model for CS A is presented in Figure 5.2.

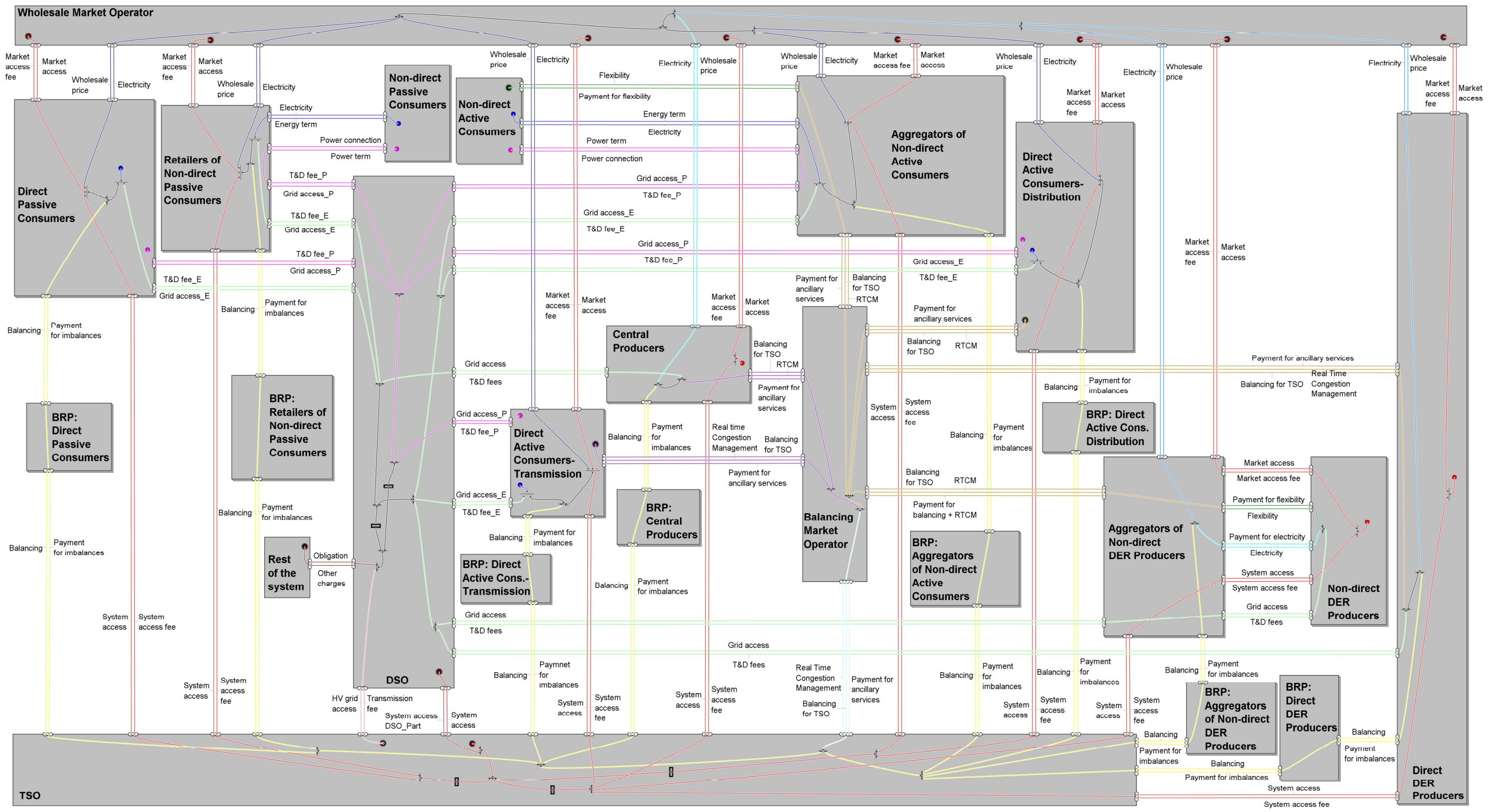


Figure 5.2: Value model of CS A

The money flows in the value model take two main paths, which are described below.

Path 1- Traditional electricity supply path (Dark blue, fuchsia, light green and red exchanges)

Consumers demand electricity, so they will pay for it to their respective providers. The retail price was assumed to be an "all-inclusive" price, made up of different components, so consumers receive just one invoice with all the different components of the price detailed in such invoice. For clarity reasons the electricity demand has been divided into two terms:

- Fuchsia start stimuli: It represents the contracted power term (kW), i.e. the size of the connection to the grid. Consumers need a connection to the grid and will pay (on a monthly basis) for the size of the connection to the grid.
- Dark blue start stimuli: It represents the energy demand term (kWh). Consumers require electricity to satisfy their needs and will pay for it. They may obtain such electricity from:
    - Retailers, in the case of the non-direct passive consumers
    - Aggregators, in the case of non-direct active consumers.
    - Their own participation in the wholesale electricity market, in the case of the direct passive consumers, direct active consumers-transmission and direct active consumers-distribution.

Electricity itself refers to the actual electricity consumption (dark blue exchanges). Retailers and aggregators buy the electricity for their non-direct consumers in the electricity market, while the direct consumers participate themselves in the wholesale market. In this case, for simplicity reasons, it has been assumed that the wholesale market operator is the sole counterparty for all market transactions: market participants do not trade with each other, but through the wholesale market operator, so, somehow, it is as if the market operator sells electricity to the retailers, aggregators and direct consumers (blue marine exchanges) and buys it from the central producers (cyan exchanges), from the direct DER-Producers and from the aggregators representing the non-direct DER producers (blue exchanges) who, in turn, will pay for this electricity to the corresponding DER producer (light blue exchanges).

Three different payments for the access to the network and participation in the wholesale electricity market were assumed to exist:

- **Grid access (T&D fees)**. The payment will be based on the T&D fees (this fee includes: transmission and distribution costs, retribution for the NRA and other regulated payments.). The price is regulated. For consumers this fee includes a power term and an energy term. In the case of producers, they pay for energy produced (only energy term).
- **System access**: All participants in the power system must contribute to the System Operator's remuneration. The price is regulated. For consumers/retailers this payment is based on the traded amount in the wholesale market, while producers must pay according to their available capacity.

- **Market access**: All participants in the wholesale electricity market must contribute to the Market Operator's remuneration. The price is regulated. For consumers/retailers this payment is based on the traded amount in the wholesale market, while producers must pay according to their available capacity.

Retailers and aggregators, on behalf of consumers, buy **grid access** from the DSO[23]. With that purpose, they collect T&D fees from consumers, which are included in the power and energy terms of the retail electricity price, and transfer them to the DSO. Likewise, direct consumers must pay for grid access directly to the DSO, based on their contracted type of tariff. Additionally, all producers also have to pay the grid access to the DSO for the energy actually produced. Central producers and direct DER producers will pay directly to the DSO, while non-direct DER producers will make this payment through their aggregators (light green exchanges).

The T&D fees collected by the DSO are composed of three main items, whose shares in the total fee are defined by the NRA: DSO remuneration, TSO remuneration (pink exchanges and end stimulus) and other system charges to be paid to the "Rest of the system" (brown exchanges and end stimulus).

It must be noted that, in addition to the other system charges included in the T&D fees, the government will also receive the taxes payment collected by retailers from consumers, such as Value Added Tax (VAT). But, as the objective of the current analysis is not the assessment of profitability for the "Rest of the system", such as the government, these charges are not included in the analysis. As this approach is taken in all the coordination schemes, it does not affect to the CBA analysis.

Additionally, retailers, aggregators, direct consumers, central producers and direct DER producers must pay for the costs incurred by the regulated actors in charge of the economic and technical management of the system, i.e. the market operator and the system operator. As a result, they will pay for **market access** to the wholesale market operator and for **system access** to the TSO (red start stimuli, exchanges and end stimuli). In the case of central producers, direct DER producers and aggregators representing the non-direct DER producers, the amounts to be paid depend on the available power, while the retailers, direct consumers and aggregators representing the non-direct active consumers, will pay depending on the amount they traded in the market.

In all coordination schemes, it has been represented that part of the system access fees collected by the TSO is transferred to the DSO (dark red exchanges)[24].

It is important to highlight the amounts of energy used in the different payments: consumers pay for real electricity consumption; the T&D fees are also based on real consumption, but wholesale electricity,

[23] For simplicity reasons, in these graphs the grid access is always paid to the DSO and then, the corresponding part is transferred to the TSO (High Voltage (HV) grid access). In reality, DSOs and TSOs collect the access fees from consumers and producers connected to their grids.

[24] Currently, this payment from TSO to DSO, does not happen, since DSOs are not operating the system. It is expected that the situation represented here will be the standard case in 2030.

market access and system access are based on the traded amount. Producers pay T&D fees based on their real production, but market and system access payments depend on their available capacity.

Path 2 – Provision of balancing and congestion management (Yellow and light blue exchanges)

Retailers, aggregators of non-direct active consumers and direct consumers buy electricity, but the amount they purchase will not always match the amount actually consumed, since imbalances in real-time may arise[25]. In the same manner, the production schedule foreseen by the producers do not match exactly with the energy that they finally can produce. This difference is the imbalance that needs to be solved (yellow exchanges).

The TSO is responsible for keeping the balance between production and consumption in its control area and, thus, it has established a balancing mechanism in order to cope with imbalances. With that purpose, the balancing market operator opens the balancing market. The market clearing algorithm aims not only to procure balancing, but also to avoid congestions in real-time. For that reason, the represented exchanges include both ancillary services: real-time congestion management (RTCM) and the balancing for TSO (light blue exchanges). Then, the balancing market operator receives bids from potential providers of ancillary services.

In this model, it was considered that the bids submitted to the balancing market for the provision of these ancillary services (balancing for TSO + RTCM) come from:

i) central producers (purple exchanges),
ii) direct active consumers–transmission (purple exchanges),
iii) direct active consumers–distribution (ochre exchanges),
iv) direct DER producers (ochre exchanges),
v) aggregators of non-direct active consumers (ochre exchanges), who, in turn, acquire the flexibility from their consumers (green exchanges), and
vi) aggregators of non-direct DER producers (ochre exchanges), who, in turn, acquire the flexibility from their DER producers (green exchanges).

However, the costs involved in the use of these ancillary services are not borne by the TSO but transferred to the actors who have caused the imbalances. In these models, the imbalance management role is performed by the Balancing Responsible Parties (BRP), who, in turn, will transfer the corresponding penalties to the actor causing the imbalance (yellow exchanges).

In this coordination scheme, non-direct active consumers and non-direct DER producers, both connected at distribution level, can participate in the balancing market through their respective

[25] Even without forecasting errors, these amounts are not the same, because retailers must cope with the expected losses along the system (in other countries, it is the DSO who must procure the energy it uses to cover energy losses in its system).

aggregators. The aggregators acquire the flexibility and submit the corresponding bids in the balancing market on behalf of them.

5.3.2 Coordination scheme B

In this coordination scheme, the TSO can contract DER only indirectly. First, the DSO, via a local market, may procure resources for solving local problems and, then, an aggregation of the remaining resources is transferred to the TSO AS market [5].

Figure 5.3 has been extracted from D1.3 [1]. It illustrates the role played by relevant stakeholders and, additionally, it shows a high-level view of the market architecture and interactions among players.

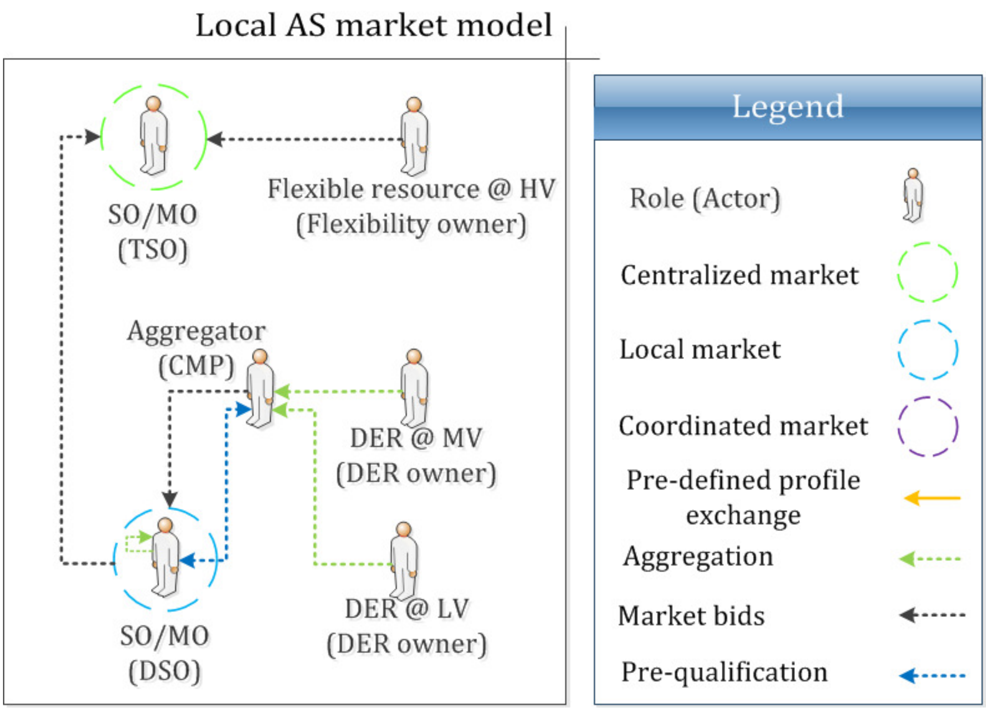


Figure 5.3: Local AS market model

The value model for CS B is presented in Figure 5.4.

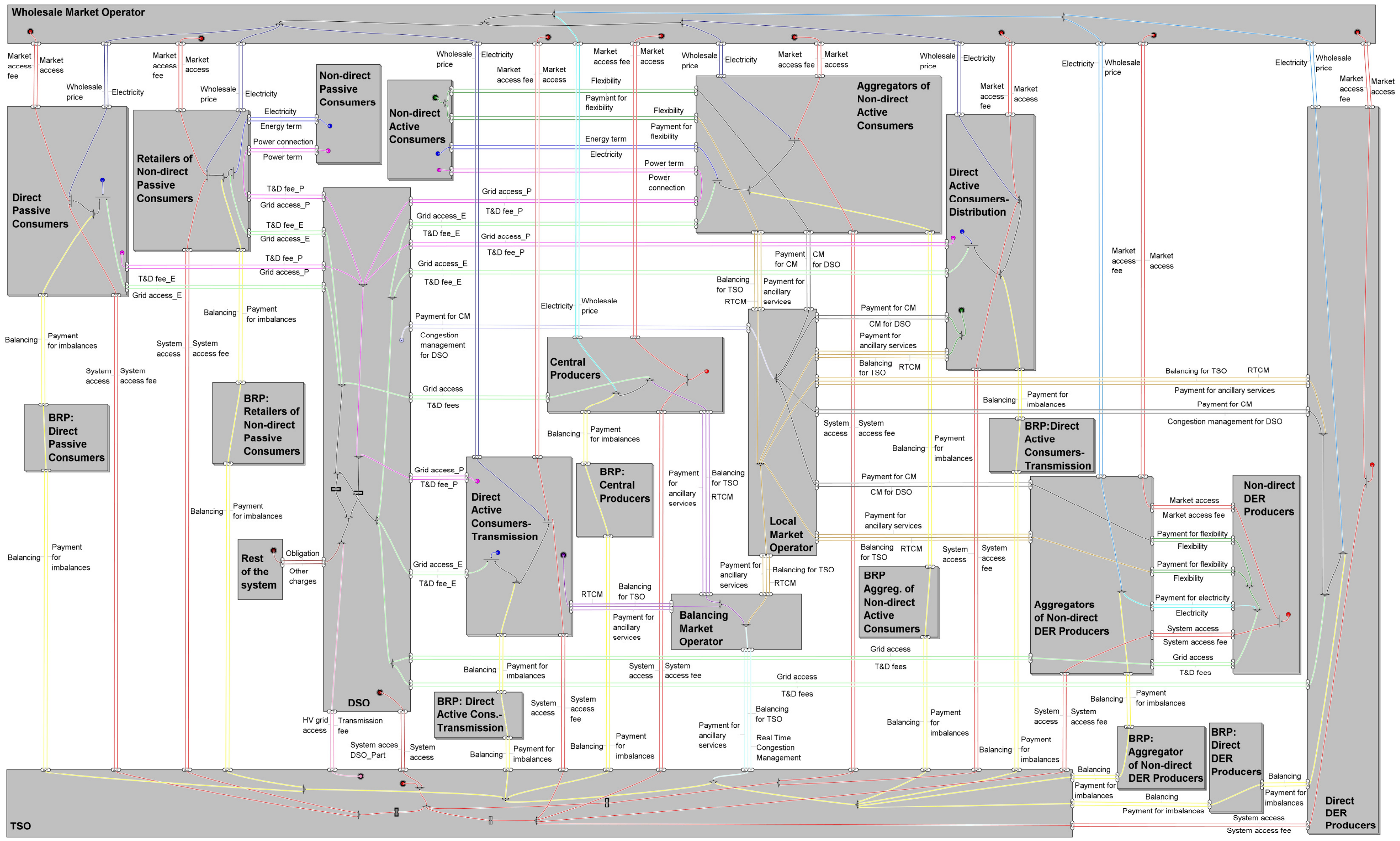


Figure 5.4: Value model of CS B0

The money flows in the value model take two main paths: path 1 (as described in section 5.3.1) and path 2 described below.

Path 2 – Provision of balancing and congestion management (Yellow and light blue exchanges)

Retailers, aggregators of non-direct active consumers and direct consumers buy electricity, but the amount they purchase will not always match the amount actually consumed, since imbalances in real-time may arise[26]. In the same manner, the production schedule foreseen by the producers do not match exactly with the energy that they finally can produce. This difference is the imbalance that needs to be solved (yellow exchanges).

This coordination scheme includes the operation of a local market by the DSO for the resolution of its own congestions. The DSO communicates its requirements to manage congestions (violet start stimulus) to the local market operator (violet exchanges). The local market operator will use the bids submitted by:

i) direct active consumers-distribution (black exchanges),
ii) direct DER producers (black exchanges),
iii) aggregators of non-direct active consumers (black exchanges), who, in turn, acquire the flexibility from their consumers (green exchanges) and
iv) aggregators of non-direct DER producers (black exchanges), who, in turn, acquire the flexibility from their DER producers (green exchanges).

Once the congestions from the DSO have been solved, the local market operator aggregates the remaining bids coming from these providers and transfers this aggregated flexibility to the balancing market operated by the TSO (ochre exchanges). The aggregators of non-direct active consumers and aggregators of non-direct DER producers, once again, will acquire the flexibility from their customer, the non-direct DER producers and the non-direct active consumers (green exchanges). The DSO has priority to use the flexibility from the local grid. The DSO sends an aggregated bid to the balancing market, making sure that only bids respecting the DSO grid constraints can take part in this market.

The TSO is responsible for keeping the balance between production and consumption in its control area and, thus, it has established a balancing mechanism in order to ensure the balance of its grid and to cope with imbalances. With that purpose, the balancing market operator opens the balancing market. The market clearing algorithm aims not only to procure balancing, but also to avoid congestions in real-time. For that reason, the represented exchanges include both RTCM and the balancing for TSO (light blue exchanges). The balancing market operator will use the resources offered by the central producers and direct active consumers-transmission in the balancing market (purple exchanges) and the bids coming from the local market (ochre exchanges).

[26] Even without forecasting errors, these amounts are not the same, because retailers must cope with the expected losses along the system (in other countries, it is the DSO who must procure the energy it uses to cover energy losses in its system).

However, the costs involved in the use of these services are not borne by the TSO but transferred to the actors who have caused the imbalances. In these models, the imbalance management role is performed by the BRP, who, in turn, will transfer the corresponding penalization to the actor causing the imbalance (yellow exchanges).

5.3.3 Coordination scheme C

In this coordination scheme, there is a shared balancing responsibility. The TSO transfers the balancing responsibility from the distribution grid to the DSO. The DSO has to respect a pre-defined schedule and uses local DER (obtained via a local market) to fulfil its balancing responsibilities. The pre-defined schedule is based on the nominations of the BRPs, possibly in combination with historical forecasts at each HV/MV interconnection point [5].

Figure 5.5, which has been extracted from D1.3 [1], illustrates the role played by relevant stakeholders and, additionally, it shows a high-level view of the market architecture and interactions among players.

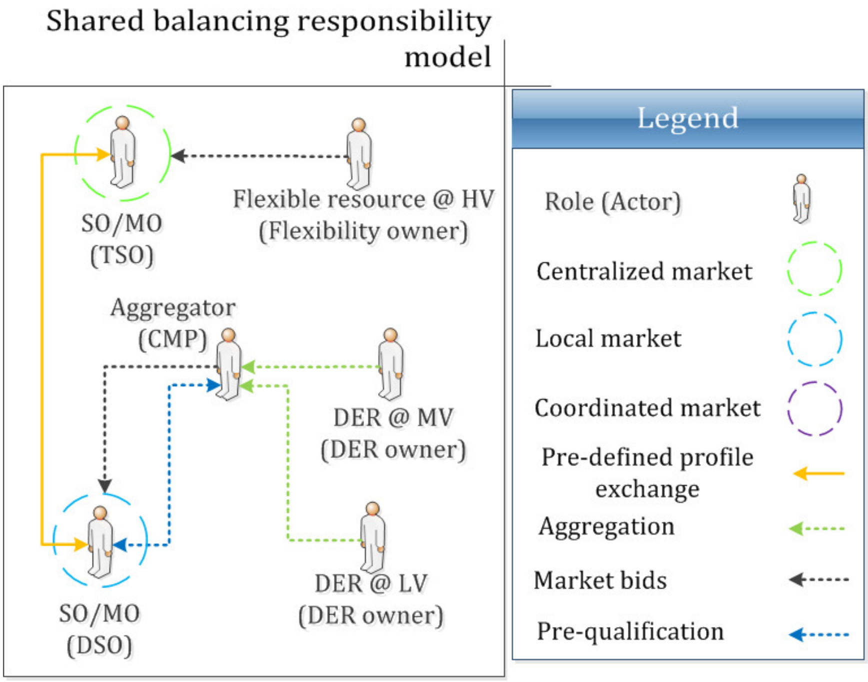


Figure 5.5: Shared balancing responsibility model

The value model for CS C is presented in Figure 5.6.

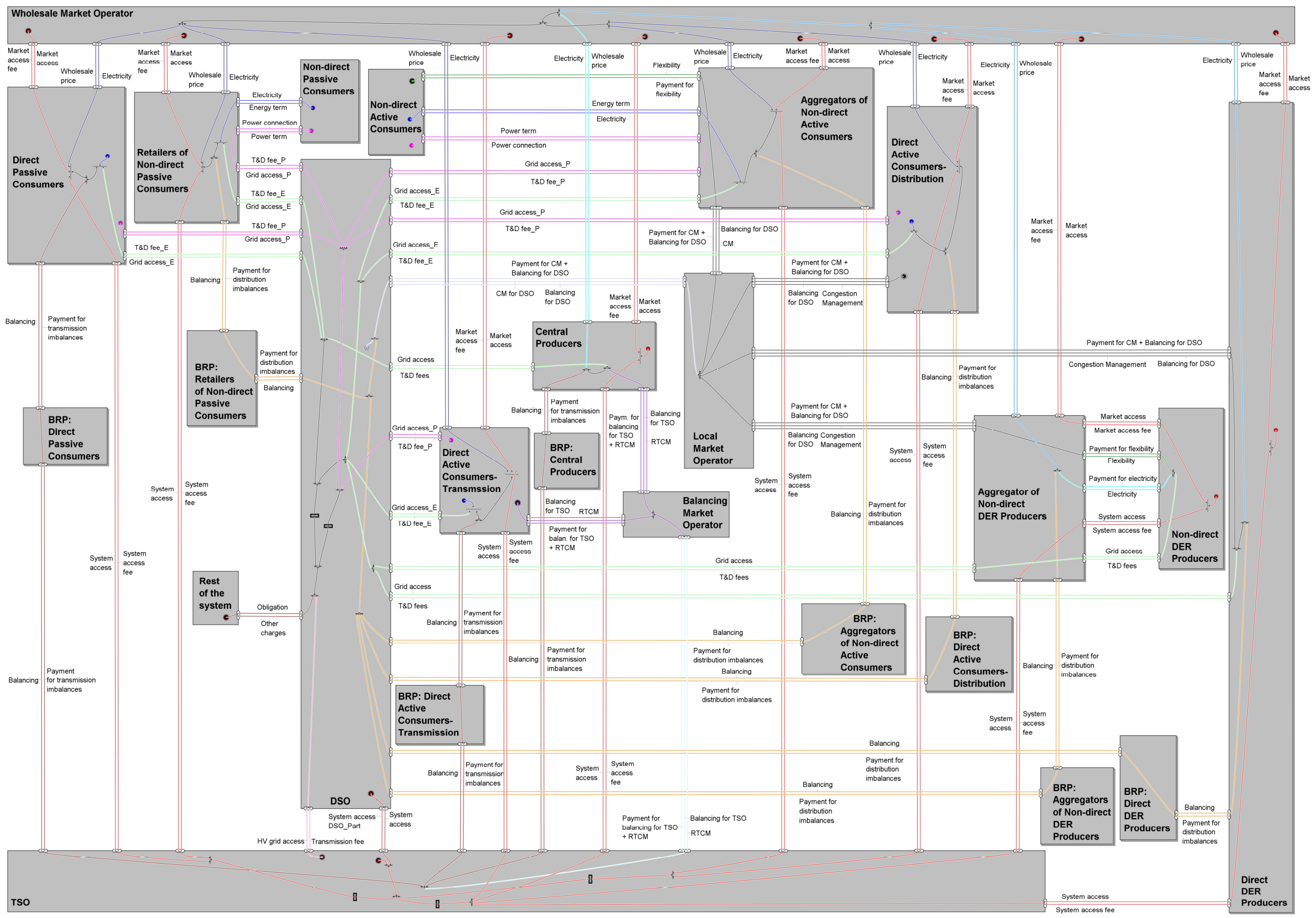


Figure 5.6: Value model of CS C

The money flows in the value model take two main paths: path 1 (as described in section 5.3.1) and path 2 described below.

Path 2 – Provision of balancing and congestion management (Yellow and light blue exchanges)

Retailers, aggregators of non-direct active consumers and direct consumers buy electricity, but the amount they purchase will not always match the amount actually consumed, since imbalances in real-time may arise[27]. In the same manner, the production schedule foreseen by the producers do not match exactly with the energy that they finally can produce. This difference is the imbalance that needs to be solved. In this coordination scheme, the imbalances are disaggregated into imbalances at distribution level (orange exchanges) and imbalances at transmission level (brown exchanges).

In this coordination scheme, the TSO transfers the balancing responsibility partially to the DSO, by means of a setpoint agreed between TSO and DSO, in such a way that there is a local market managed by the DSO, for resources connected to the distribution grid, and a balancing market managed by the TSO, for resources connected to the transmission grid.

The DSO communicates to the local market operator (violet exchanges) its own requirements for solving congestions (violet start stimulus) and, additionally, the balancing needs to cover imbalances occurring at distribution level (orange exchanges) caused by BRPs representing:

i) retailers of non-direct passive consumers,
ii) aggregators of non-direct active consumers,
iii) aggregators of non-direct DER producers,
iv) direct active consumers-distribution and
v) direct DER producers.

This necessity of balancing and congestion management for the distribution grid will be solved by means of the bids submitted by:

i) direct active consumers-distribution (black exchanges),
ii) direct DER producers (black exchanges),
iii) aggregators of non-direct active consumers (black exchanges), who, in turn, acquire the flexibility from their customers (green exchanges) and
iv) aggregators of non-direct DER producers (black exchanges), who, in turn, acquire the flexibility from their DER producers (green exchanges).

The TSO is responsible for keeping the balance between production and consumption in its control area and has therefore established a balancing mechanism in order to ensure the balance of its grid and to

[27] Even without forecasting errors, these amounts are not the same, because retailers must cope with the expected losses along the system (in other countries, it is the DSO who must procure the energy it uses to cover energy losses in its system).

cope with imbalances. In this case, the TSO must solve the imbalances caused at transmission level (brown exchanges) by:

i) central producers,
ii) direct passive consumers and
iii) direct active consumers-transmission.

Additionally, the TSO must also avoid congestions in real-time. With those purposes, the balancing market operator opens the balancing market (light blue exchanges) which can make use of the bids submitted by the central producers and the direct active consumers-transmission (purple exchanges).

5.3.4 Coordination scheme D

In this coordination scheme, there is a common AS market for TSOs and DSOs. TSOs and DSOs contract DER in the common flexibility market. The main goal is the minimization of total procurement costs of flexibilities contracted by TSO and DSO [5]. The common market uses flexibilities from resources connected at transmission and distribution level to solve both TSO and DSO needs. Consequently, both TSO and DSO are responsible for the organization and operation of the market. DSO constraints are integrated in the market clearing process.

Figure 5.7, which has been extracted from D1.3 [1], illustrates the role played by relevant stakeholders and, additionally, it shows a high-level view of the market architecture and interactions among players. Out of the two alternatives considered in D1.3, centralized/decentralized variants, only the centralized variant is considered in this business-level approach.

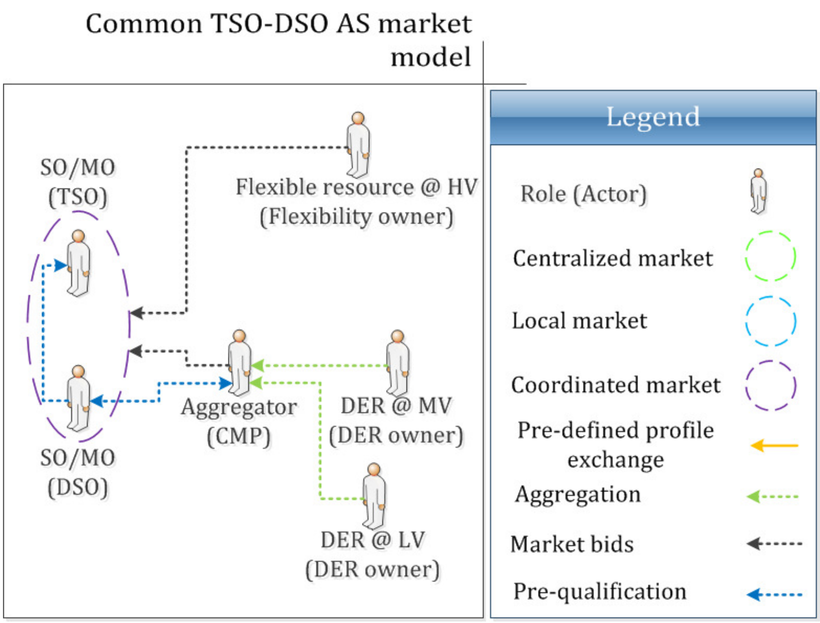


Figure 5.7: Common TSO-DSO AS market model

The value model for CS D is shown in Figure 5.8.

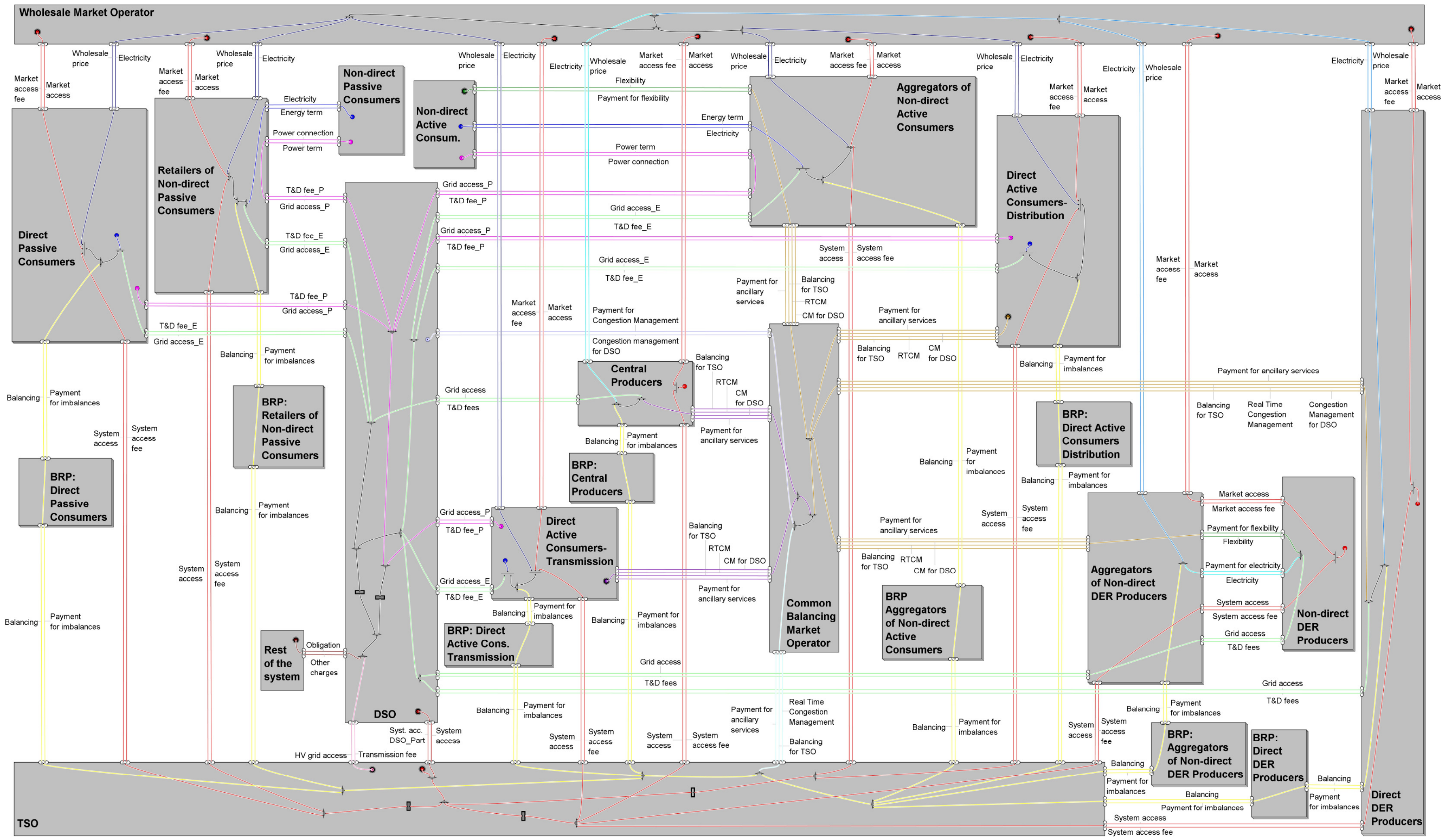


Figure 5.8: Value model of CS D

The money flows in the value model take two main paths: path 1 (as described in section 5.3.1) and path 2 described below.

Path 2 – Provision of balancing and congestion management (Yellow and light blue exchanges)

Retailers, aggregators of non-direct active consumers and direct consumers buy electricity, but the amount they purchase will not always match the amount actually consumed, since imbalances in real-time may arise[28]. In the same manner, the production schedule foreseen by the producers do not match exactly with the energy that they finally can produce. This difference is the imbalance that needs to be solved. In this coordination scheme, the imbalances are disaggregated into imbalances at distribution level (orange exchanges) and imbalances at transmission level (brown exchanges).

This coordination scheme promotes a common flexibility market for DSOs and TSO. The procurement of resources made under this coordination scheme has as main goal to minimize total procurement cost of flexibility. There is a common market for TSO and DSO with resources connected to transmission and distribution level. The TSO and the DSO are both responsible for the organization and operation of the market. In this case, all constraints are integrated in a single process that includes both transmission and distribution grid constraints. The DSO and TSO attend the common balancing market to solve congestions and to balance the system, respectively. Actions to solve issues at distribution level are presented as violet start stimulus and exchanges, while actions at transmission level are represented as light blue exchanges. The clearing process will consider the submitted bids from:

- i) central producers (purple exchanges),
- ii) direct active consumers-transmission (purple exchanges),
- iii) direct DER producers (ochre exchanges),
- iv) direct active consumers-distribution (ochre exchanges),
- v) aggregators of non-direct active consumers (ochre exchanges), who, in turn, acquire the flexibility from their consumers (green exchanges) and
- vi) aggregators of non-direct DER producers (ochre exchanges), who, in turn, acquire the flexibility from their DER producers (green exchanges).

The costs involved in the use of these services are not borne by the TSO and DSO but transferred, through the corresponding BRP, to the actors who have caused the imbalances.

5.3.5 Main differences in the value models

The main differences in the value models come from the provision of balancing and the management of congestions (path2). As summary, Table 5.6 indicates which these differences are, especially those

[28] Even without forecasting errors, these amounts are not the same, because retailers must cope with the expected losses along the system (in other countries, it is the DSO who must procure the energy it uses to cover energy losses in its system).

regarding type of service required, who causes the imbalances to be solved by each market and the available providers.

CS A	**Balancing market**		
	Services	**Resolution of imbalances caused by**	**Providers**
	Balancing for TSO RTCM	All participants; i) retailers of non-direct passive consumers, ii) aggregators of non-direct active consumers, iii) aggregators of non-direct DER producers, iv) direct active consumers-distribution, v) direct DER producers, vi) central producers, vii) direct passive consumers, viii) direct active consumers-transmission	i) central producers (transmission) ii) direct active consumers–transmission iii) direct active consumers–distribution iv) direct DER producers v) aggregators of non-direct active consumers, who, in turn, acquire the flexibility from their consumers vi) aggregators of non-direct DER producers, who, in turn, acquire the flexibility from their DER producers
CS B	**Local market**		
	Services	**Resolution of imbalances caused by**	**Providers**
	CM at distribution level	n.a.	i) direct active consumers-distribution ii) direct DER producers iii) aggregators of non-direct active consumers, who, in turn, acquire the flexibility from their consumers iv) aggregators of non-direct DER producers, who, in turn, acquire the flexibility from their DER producers.
	Balancing market		
	Services	**Resolution of imbalances caused by**	**Providers**
	Balancing for TSO RTCM	All participants; i) retailers of non-direct passive consumers, ii) aggregators of non-direct active consumers, iii) aggregators of non-direct DER producers, iv) direct active consumers-distribution, v) direct DER producers, vi) central producers, vii) direct passive consumers, viii) direct active consumers-transmission	i) central producers (transmission) ii) direct active consumers-transmission iii) local market operator: aggregated bid respecting the DSO grid constraints
CS C	**Local market**		
	Services	**Resolution of imbalances caused by**	**Providers**
	Balancing for DSO CM at distribution	i) retailers of non-direct passive consumers ii) aggregators of non-direct active consumers iii) aggregators of non-direct DER producers iv) direct active consumers-distribution v) direct DER producers	i) direct active consumers-distribution ii) direct DER producers iii) aggregators of non-direct active consumers, who, in turn, acquire the flexibility from their customers iv) aggregators of non-direct DER producers, who, in turn, acquire the flexibility from their DER producers
	Balancing market		
	Services	**Resolution of imbalances caused by**	**Providers**
	Balancing for TSO RTCM	i) central producers, ii) direct passive consumers iii) direct active consumers-transmission	i) central producers (transmission) ii) direct active consumers-transmission
CS D	**Common balancing market**		

	Services	Resolution of imbalances caused by	Providers
	Balancing + CM at system level	All participants; i) retailers of non-direct passive consumers, ii) aggregators of non-direct active consumers, iii) aggregators of non-direct DER producers, iv) direct active consumers-distribution, v) direct DER producers, vi) central producers, vii) direct passive consumers, viii) direct active consumers-transmission	i) central producers (transmission) ii) direct active consumers-transmission iii) direct DER producers iv) direct active consumers-distribution v) aggregators of non-direct active consumers, who, in turn, acquire the flexibility from their consumers vi) aggregators of non-direct DER producers, who, in turn, acquire the flexibility from their DER producers

Table 5.6: Summary of differences between coordination schemes

5.4 Criteria for a successful business-level analysis

The SmartNet project assesses the efficiency of the different TSO-DSO coordination schemes through the CBA described and calculated in previous chapters. However, CSs must also allow the involved actors to have a profitable business case, that is, CSs must lead to an appropriate allocation of costs and benefits among them. Therefore, a business-level analysis is needed to assess the economic impact of the different CSs for all the relevant actors.

The business-level analysis is composed of several main steps to determine, at the end of the process, whether coordination schemes are economically attractive for all actors, i.e. whether the benefits seen by each of them outweigh their costs. Throughout this chapter 5, the steps to be followed when developing this type of analysis have been detailed; from the initial theoretical analysis with the definition of the methodology to be used, definition of participants and creation of value models up to the definition of the specific formulas to be calculated (which are presented in detail in Appendix IV – Business-level analysis formulation). Based on the graphical models developed for the coordination schemes (Figure 5.2, Figure 5.4, Figure 5.6 and Figure 5.8) and the formulas detailed for each value exchange, the annual flows of funds for all the actors can be calculated. These flows can then be used as an input to deduce each actor's annual cash flow, by considering all other expenses they would need for launching the business model (e.g. ICT costs) too. Once the annual cash flows are obtained, the profitability of the investments that each actor needs to perform, if any, has to be checked.

Many of the specific data and financial parameters to be used in these calculations are difficult to estimate, for two main reasons:

i) The deployment of the proposed coordination schemes implies regulatory changes which are not defined yet and which may take from few to several years. Therefore, some of the values to be included in the business-level must be estimated in the medium- to long-term, which implies a considerable inclusion of inherent uncertainty on the long-term forecast.
ii) For the business-level economic analysis, the annual cash flows must be calculated. The obtained results from the SmartNet simulations can be considered representative for the system as a

whole, but the results obtained with the number of time step simulated are less likely to be representative of the exchanges among the actors over a complete year.

Consequently, the business-level analysis developed in this deliverable only includes the identification of relationships, the formulas to be applied and the type of data to be used. Explicitly, these issues are developed in detail in the Appendix IV – Business-level analysis formulation. Section 11.1 presents the actors who are relevant for the different coordination schemes and the relationships between them, section 11.2 shows the formulas to be used in the business-level analysis to calculate the numeric results when all the data are available as detailed as required by these formulas and, finally, section 11.3 details specific issues regarding each coordination scheme.

Nevertheless, several theoretical boundary conditions (minimum set of economic parameters) are detailed in order to establish the issues which may strengthen or threaten the deployment of the proposed coordination scheme.

Specifically, in the case of the DSO, in order to determine under which circumstances the use of a local market may represent an improvement, it is necessary to perform a comparison between the DSO's current cash flow and the one obtained when each coordination scheme is deployed. In addition, the costs to be taken into account in each coordination scheme include; (i) the investment in network elements and in ICTs for the development of each CS and (ii) the flexibility acquisition by the DSOs.

Taking the Spanish case as a basis, the law 24/2013 [46] and the Royal Decree 1048/2013 [47] establish the criteria of remuneration to the investment to be perceived by the DSOs:

1) The methodologies for the remuneration of the distribution activities are established by the regulator, on the basis of the required costs to build, operate and maintain the associated infrastructure, according to the criterion of minimum cost for the system.
2) The remuneration to the investment is perceived for the assets in service and which have not been amortized yet.
3) The methodology to remunerate the distribution activity includes economic incentives, both positive and negative, for the improvement of the supply quality, for reducing losses and for decreasing fraud.
4) The established remuneration parameters are in force for 6 years.
5) There is a maximum limit to the amount of eligible investment costs. The retribution is calculated via formulas that allow for achieving efficiency gains both in the construction of infrastructures and in the operation and maintenance of networks.
6) The rate of return payable from the electric system is linked to the return of the Spanish ten-year bond increased by an appropriate differential. This differential is 200 points for investments performed after January 2014 according to [46].

Once the DSO's cash flow in the specific coordination scheme and the remuneration to the investment to be perceived is known, two considerations must be fulfilled simultaneously;

1) On one hand, from the system perspective, it must be fulfilled that the cost for the system is reduced by the deployment of the specific CS.

$$Annual\ remuneration\ for\ DSO_{CS} < Current\ annual\ remuneration\ for\ DSO$$

2) On the contrary, from the DSO perspective, its final result should be improved with the deployment of a new coordination scheme.

By assessing these two conditions for each coordination scheme, the minimum value of return to be perceived by the DSO for acquisition of flexibility can be calculated. Therefore, although the annual remuneration for the DSO should be reduced (from the system perspective) such reduction must be lower than the cost reduction for the DSO (the operational cost of procuring flexibility must be lower than the annuitized cost of the capital cost for reinforcing the grid).

6 Conclusions

In view of the obtained outcomes during the project, and taking into account the scenarios analysed within it, the adoption of CS C results to be the least efficient CS in all the countries and, therefore, technical reasons could advise to continue centralizing balancing responsibility to TSOs. However, depending on the impact of the congestions at distribution level, the congestion management responsibility could be shared between TSOs and DSOs, as it has already been addressed by the *Clean Energy for All Europeans* package [48]:

- Traditional TSO-centric schemes could stay optimal if distribution networks do not show significant congestions, which is likely in the very near-future scenarios where the distribution grid planning continues affected by the fit-and-forget reinforcements policy. However, in the future, this regulatory trend may be modified, so that the DSOs' remuneration will give more importance to their investments in intelligence (OPEX) rather than on investments in grid elements (CAPEX). Then, a more advanced coordination between TSO-DSO, like the proposed CS B or CS D, should be deployed for a more efficient management of the system.
- More advanced centralized schemes incorporating distribution constraints show higher economic performances, but their performance could be undermined by big forecasting errors. Hence, it is of paramount importance to improve the forecasting techniques, to increase the market clearing frequency and to shift the gate closure as much as possible towards real-time.
- The two-step optimization process implies that the decentralized schemes are less efficient than single-step processes. Scarcity of liquidity and potential impact of local market power (not investigated in SmartNet), along with extra constraints introduced to avoid counteracting actions between local congestion market and balancing market (e.g. increasing the system imbalance while solving local congestions), negatively affect economic efficiency of decentralized schemes. The effect of these inefficiencies is especially important in CS C, which is further affected by additional rigidities (i.e. fixed power flow at the TSO-DSO electrical interface).
- The local congestion markets should have a "reasonable" size and guarantee a free competition by enough actors, in order to prevent scarcity of liquidity and the power exercise by the local markets. This may create the need for small DSOs to pool-up to ensure the required market size.

As a summary of the main findings by the CBA developed in the SmartNet project, in a more than likely scenario in which the fit-and-forget reinforcement remuneration approach is abandoned and the forecasting errors are more accurately calculated (on the one hand by the improvement in the forecasting techniques and, on the other hand, by shifting the gate closure closer to real-time), CS D could be the most efficient of the coordination schemes proposed. However, due to complexity reasons, the network observability cannot be pushed till single low-voltage nodes and, hence, it will be necessary to determine, for each specific case and country, the observability level to be deployed, taking into account that increasing the observability of distribution grids implies new important investments by the system.

Once the most advisable CS at system-level is selected, a business-level analysis is needed to assess the economic impact of the different CSs for all the relevant actors in order to guarantee that all the involved participants have a profitable business case. The appropriate allocation of costs and benefits among the actors is of utmost importance when selecting the CS, since this issue may strengthen or threaten the deployment of the proposed CS.

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8 Appendix I - Consultation

This section presents the consultation document [49], as it was made available to stakeholders.

1. Cost-benefit analysis (CBA) of the different schemes

With the results obtained from the simulations, one of the main goals is the elaboration of a CBA methodology for the analysis of TSO-DSO interaction schemes[29] and the assessment of the best TSO-DSO interaction for each national case. With that purpose, next steps will be followed:

1) Development of a CBA procedure:
   - State of the art of metrics for CBA.
   - Selection of SmartNet metrics.
2) Macro-level CBA (at system level):
   - Calculation of values for metrics with the data input from the simulations.
   - Once the metrics have a value, that value needs to be monetised.
   - Cost calculation of the required information and communication technologies (ICTs).
   - Evaluation of every coordination scheme in all countries.
3) Micro-level CBA (at business case level):
   - Identification of the value chain.
   - Allocation of costs and benefits per stakeholder.
   - Sensitivity analysis.

The objective of the micro-level analysis is to define a business scenario which allows all the involved actors to have a profitable business case. Therefore, it aims at properly allocating costs and benefits to the different stakeholders. Since the details for the micro-level analysis are not sufficiently developed for a consultation yet, this consultation is oriented to help guide the process to perform the macro-level CBA.

1.1 CBA methodology – Literature review

Several methodologies have been reviewed in order to determine their applicability to the SmartNet analysis. The analysis included:

- **Electric Power Research Institute method** (available at: https://www.epri.com/#/pages/product/000000000001020342/)
- **Joint Research Centre methodology** (available at: https://ses.jrc.ec.europa.eu/sites/ses/files/documents/guidelines_for_conducting_a_cost-benefit_analysis_of_smart_grid_projects.pdf)

[29] Basics for coordination schemes and market design are available at: http://smartnet-project.eu/wp-content/uploads/2017/06/2-SmartNet-PowerTech-20170619-TSO-DSO-CS-Six-V2.pptx and http://smartnet-project.eu/wp-content/uploads/2017/06/3-20170619_SmartNet-G.Leclercq-Presentation-VF.pptx.

- **International Smart Grid Action Network method** (available at: http://www.sasgi.org.za/wp-content/uploads/2.21_ISGAN_Annex3_-Issue2.0_28Sept2011.pdf)
- **Pacific Northwest National Laboratory method** (available at: http://epe.pnnl.gov/capabilities/cba.stm)
- **U.S. Department Of Energy/Federal Energy Regulatory Commission method** (available at: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-02.LBL_.DR-Cost-Effectiveness.11-106A.pdf)
- **REALISEGRID project** (available at: http://realisegrid.rse-web.it/content/files/File/Publications%20and%20results/Deliverable_REALISEGRID_3.3.1.pdf)
- **e-Highway 2050 project** (available at: http://www.gridinnovation-on-line.eu/Articles/Library/E-Highway-2050-A-New-Multi-Criteria-Cost-Benefit-Methodology-To-Compare-New-Transmission-Investments.kl)

The analysis of further CBA methods continues in parallel to this consultation.

1.2 Macro level CBA analysis

The evaluation of different investment alternatives needs to define:

- A set of criteria (metrics). They need to be complete, non-overlapping, applicable, system-oriented, simple, reproducible, documentable, realistic and objective.
- A set of weights that establish the importance of those metrics.

The definition of metrics is a very critical issue, but the assignment of weights to them is even more critical and controversial.

Two approaches exist for the assessment of the alternatives:

1) The multi-criteria analysis approach consists in; defining a set of criteria for classifying alternative investment variants, providing quantitative indicators to quantify the selected criteria, converting indicators into one only utility value (possibly a-dimensional), performing a weighed linear combination of utility values (weights incorporate the importance of the different criteria).
2) The cost-benefit analysis approach. It tries to reduce the problem complexity by converting all indicators into a monetary unit (no need to assign weights as such, but just converting all the metrics into money). In SmartNet, we opted for this approach, since it allows a more straightforward comparison between the different alternatives and, for some metrics, the monetisation process (CBA) is more objective than assigning subjective weights (multi-criteria).

In the macro analysis each coordination scheme will be assessed for Denmark, Italy and Spain and the results compared against a baseline. The definition of this baseline is one of the questions included in this consultation. Metrics will be elaborated and applied for comparing the TSO-DSO interaction schemes for each national case and, as result, the different schemes will be independently scored for each country. Then, the most convenient architecture, different for each national case, will be highlighted.

Figure 8.1 shows the macro analysis synthesis, in which it can be seen that the ICT costs related to the coordination schemes will be managed separately from the rest of the costs directly linked to the coordination schemes deployment. The procedure for the ICT costs estimation is detailed in section 1.3.

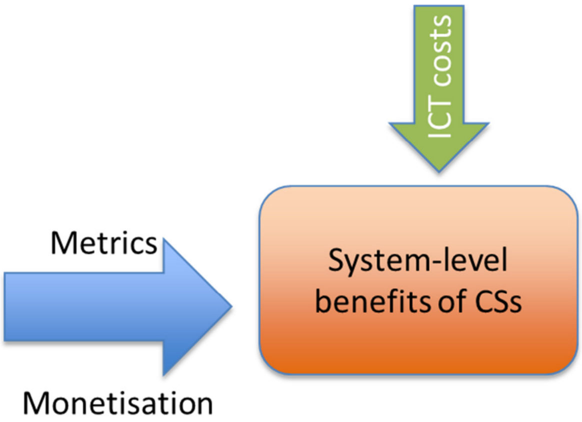

Figure 8.1: Macro analysis synthesis

In general, the metrics may be divided into three categories[30]:

1) **Core elements:** Typical CBA ingredients, e.g. lifecycle costs, overall system social welfare, CO_2 emissions, system reliability, etc.
2) **Experimental items:** Innovative items or elements difficult to assess, e.g. extra costs due to distribution investments, extra costs due to market power, socio-environmental costs of new lines, etc.
3) **Sensitivity factors**: Extra elements to enrich decision maker's knowledge, e.g. social welfare split, renewable energy sources (RES) curtailment costs, etc.

The main proposed metrics to quantify the costs and benefits of the different SmartNet coordination schemes are:

a. **Enhanced provision of ancillary services**: The TSO-DSO coordination schemes investigated in SmartNet are aimed at increasing the competitiveness of ancillary service provision, by extending their related markets to distribution energy resources (DER), i.e. where the centre of mass of power flexibility is expected to be in a near future. In particular, SmartNet simulations will be focused on the real-time market devoted to the activation of the flexible DER for the energy balance of the system (manual Frequency Restoration Reserve –mFRR– and Replacement Reserve –RR– depending on the country) taking into account also the network limitations

[30] As defined in http://www.e-highway2050.eu/fileadmin/documents/Results/D6.1_A_comprehensive_long_term_benefit_cost_assessment.pdf

(congestion management). The proposed metric to evaluate this aspect is balancing cost[31], which can be monetised by multiplying the cleared balancing cost and the activated volume..

b. **Cost attributable to network limitations:** The real-time market simulated in SmartNet takes into account complete network models and it guarantees that the final activations are selected in order to avoid (voltage and loading) congestions and to keep energy losses limited. Depending on the TSO-DSO coordination scheme, the market effectiveness in taking into account network limitations is expected to be different and, consequently, the activated resources as well (with a direct impact on the cleared balancing price). Network operators are carefully considering the occurrence/severity of congestions and losses in order to evaluate grid refurbishment actions which, in turn, are inversely proportional to the effectiveness of the market in solving undesired situations. This effectiveness can be evaluated by comparing the cleared balancing price of the following two situations:
   - Real situation, in which the entire physics of the network (losses, transmission capacity) is simulated.
   - Ideal situation (busbar simulation), in which electricity network is simulated disregarding the physics and with zero losses.

   It is immediate to deduce that the price difference between these two situations corresponds to the cost attributable to congestion management and to network losses compensation (an intermediate situation could be performing a copperplate simulation, where the electricity networks have infinite transmission capacity, but network losses are taken into account, so that only the cost of congestion management could be derived from the price difference). This difference also directly returns a monetary value and it is a valuable indicator for the profitability evaluation of refurbishment investments[32].

c. **Reduction of unwanted measures adopted by network operators in order to solve congestions:** As anticipated above, the real-time market simulated in SmartNet includes the network models and limits. Depending on the TSO-DSO coordination scheme, this model is limited to transmission network or extended to distribution too. In addition, the market architecture impacts on the ability of the market operator in predicting network congestions and to consequently activate the right resources to avoid them. Having considered that the simulated coordination schemes are expected to solve congestions with different effectiveness, network operators will inevitably deal with some critical situations (unexpected congestions) to be immediately solved with dedicated (unwanted) measures, such as:

[31] We think that social welfare is not a suitable metrics because there could be cases when an arbitrage between bids could get a better social welfare but we have instead only to minimize the cost to activate resources to solve congestion and imbalance (optimizing social welfare is the aim of the previous energy markets).

[32] A detailed analysis should consider the situation after each grid refurbishment investment, so that the economically sound refurbishments would be identified (there may be some bottlenecks which only appear in very extreme situations and, hence, whose removal would not be economically efficient), but it is not the aim of this analysis to be so detailed.

- Immediate curtailment of load/generation.
- Blocking of activation signals.
- Inhibition of bidding of non-prequalified resources.

Even in this case, the monetization of the unwanted measures can be easily performed. In particular, since these actions inevitably cause an imbalance in the system, a good indicator can be represented by the consequent imbalance price. However, when it does not represent the price to activate curtailment, the compulsory limitation of flexibility can be evaluated according to the associated resource costs.

d. **Reduced network losses**: Because of the non-ideal behaviour of network components, energy losses are an unavoidable element of power systems and it may have a significant impact on the management of both transmission and distribution grids. Taking into account the market architectures investigated within SmartNet, there is a concrete potential of reducing energy losses by approaching supply and demand of ancillary services. The proposed CBA will compare the effects of each TSO-DSO coordination scheme on the energy losses by processing the simulation results. Their associated cost can be calculated by integrating them with the energy price profile (resulting from the market). Thanks to this integration, the CBA will also consider the coordination scheme ability of selecting the optimal energy paths depending on the current price of energy.

e. **Emissions savings**: A more efficient cooperation between TSOs and DSOs, together with the integration of network/resources models in the market clearing algorithms, is expected to be beneficial in the optimal management of available flexibility, including the one provided by low-carbon generation technologies (which are gradually replacing conventional plants with higher carbon emissions). Generation dispatch and unit commitment model is used for calculation of emissions savings in each coordination scheme compared to the reference scheme. Standard emission rates for each generation technology will be taken into account.

The monetization of CO_2 costs is based on forecasted CO_2 prices for electricity in the studied horizon. The price can be derived from official sources such as the International Energy Agency.

1.3 ICT costs

The term ICT cost comprises the communications and information technologies, including the software for the market clearing process. Only those ICT costs that are directly related to the implementation of a coordination scheme will be considered. The main goals of this estimation are:

- To discover differences between coordination schemes in terms of ICT.
- To analyse requirements of ICT systems (market arrangement system and bidding system), the amount of communication, and its requirements in the coordination scheme.
- To estimate the ICT costs (in 2030) in each national case and coordination scheme.

For the definition of the ICT costs the following steps will be carried out:

1) Functionalities definition (e. g. data handling, security, reliability, etc.). Comparison of the coordination schemes in terms of functionalities in its ICT systems.
2) Convert each ICT system in a coordination scheme into a current cost. Estimation of ICT system cost development from current costs to year 2030.

This ICT estimation involves large uncertainties on technology and cost development since the details of year 2030 are currently unknown. The main focus of the analysis will be on issues that can make differences between coordination schemes.
The systems and communications not directly related to coordination schemes are left outside the scope of this analysis, and the use of existing communication for low capacity traffic will be assumed to be free.

Questions

Baseline

1. What scenario should be considered as baseline for the SmartNet analysis? Should we stick to the two options below, or would you suggest another one?
   a) Option 1: Only resources connected to transmission level can provide ancillary services.
   b) Option 2: Coordination scheme A, in which resources connected to distribution level can provide ancillary services (when certain preconditions are met). This is the current situation in Denmark and in Spain, and it will also probably be the case in Italy in the near future.
2. If option 1 is selected, can we ensure that the resources connected to transmission network will be enough to provide all the ancillary services required by the system? If not, what actions should be taken? How would the congestions at distribution level be solved?
3. If option 2 is selected, some costs/benefits may not be adequately addressed and not easily compared. For instance, let's assume that the costs of implementing a control system for coordination scheme A is 100 and the costs of implementing a control system for coordination scheme B is 130. Since these control systems are not scalable, it is not immediate to state that passing from A to B would cost 30 but, in principle, it can be any value between 30 and 130. Do you have experience with this kind of issues?

Metrics

The following metrics have been preselected for the analysis (see short description in the accompanying document). Please, answer the questions for each of them.

4. Enhanced provision of ancillary services.
   4.1 Is this metric suitable for the analysis in SmartNet?
   4.2 Do you agree with the proposed monetization method?
   4.3 Would you propose another monetization method for this metric?

4.4 Should we consider marginal price or pay-as-bid?

4.5 Do you agree with our statement about social welfare?

5. Cost attributable to network limitations

 5.1 Is this metric suitable for the analysis in SmartNet?

 5.2 Do you agree with the proposed monetization method?

 5.3 Would you propose another monetization method for this metric?

 5.4 Should we divide the costs of congestion management and losses (copperplate), or have both costs together (busbar)? How would you propose to avoid overlapping with "Reduced network losses" (see question 7 below)?

6. Reduction of unwanted measures adopted by network operators in order to solve congestions.

 6.1 Is this metric suitable for the analysis in SmartNet?

 6.2 Which monetization method do you prefer: imbalance price or flexibility cost?

 6.3 Would you propose another monetization method for this metric?

 6.4 What kind of prices should be used; average price (in which periods), marginal price, etc.

7. Reduced network losses.

 7.1 Is this metric suitable for the analysis in SmartNet?

 7.2 Do you agree with the proposed monetization method?

 7.3 Would you propose another monetization method for this metric?

 7.4 What kind of prices should be used; average price (in which periods), marginal price, etc.

8. Emission savings.

 8.1 Is this metric suitable for the analysis in SmartNet?

 8.2 Do you agree with the proposed monetization method?

 8.3 Would you propose another monetization method for this metric?

 8.4 What kind of prices should be used; average price (in which periods), marginal price, etc.

9. Some indicators have been intentionally selected in order to be partially overlapping. For instance, the 'cost attributable to network limitations' considers both losses and congestion management, while losses are specifically addressed in 'reduced network losses'. We are confident that, by processing both the indicators, it is possible to discriminate the cost of congestion management. The latter, otherwise, would not be easily extractable from the simulation results, since it is processed internally by balancing market clearing algorithm. Do you detect any overlapping or possible combinations between these metrics that can be eventually avoided? If so, which one(s) do you consider to be the most relevant(s)? Why?

ICT costs

10. Do you have any experience in the ICT costs monetization? If so, please explain.

11. Should the DSOs invest in their own ICTs or, on the contrary, should they outsource this service to a third party?

12. What are the most relevant issues when a DSO changes its ICT solution from one technology to another? In what situations will such technology changes occur? (Consider both communications and data systems.)
13. Please estimate the share of ICT costs in energy network/service investments a) currently and b) in 2030. (Consider both CAPEX and OPEX.)
14. Any critical aspect to be considered in the ICT costs?
15. Should the DSOs have redundant systems? Which ones?

Summary

1. Overview of respondents

A consultation was organized with the aim to support the decision-making process for the system-wide cost-benefit analysis. In particular, the metrics to be considered, their monetization methods and the relevant ICT costs were the main attention points for the consultation.

Respondents could provide answers via the website or by email for a period of 2 months and a half (4 August 2017-17 October 2017). Three answers were received in total, but all of them were incomplete. Therefore, the conclusions in this report may have been extracted from only one or two answers in some cases. The answers came from 3 different countries. Figure **8.2** gives an overview of the respondants per country.

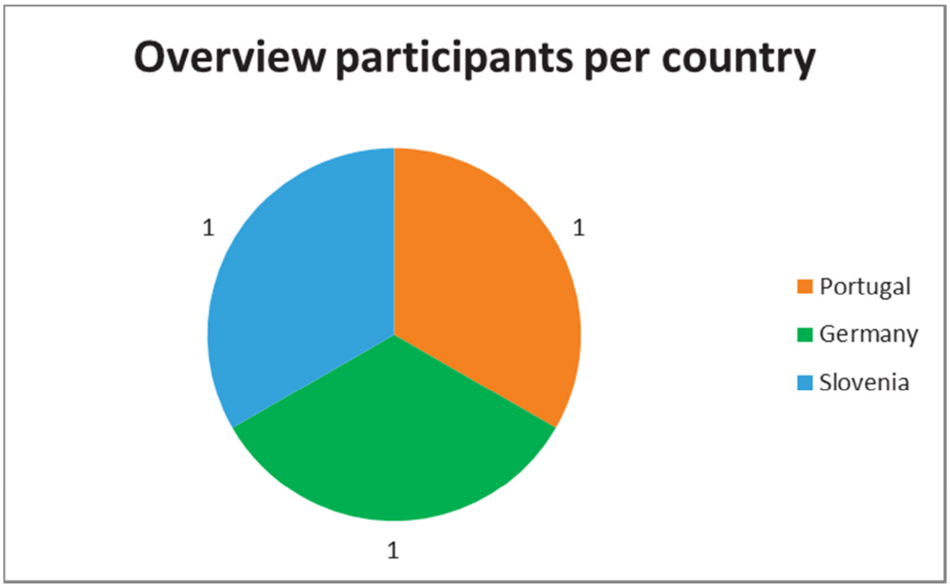

*Figure **8.2:** Overview participants per country*

The background of the respondents was mostly from the consulting sector (2), being the third respondent the R&D centre of a TSO.

2. Main feedback from respondents

The consultation asked specific questions related to the baseline to be considered, the different indicators that may be included in the cost-benefit analysis (CBA) and the relevant costs of the information and communication technology (ICT). A summary of the answers is presented in the sections below.

1.1 Baseline

Although not clearly stated by respondents (no one responded directly to the question about the option they prefer), the answers to the potential problems in each option showed a preference for considering Coordination Scheme A as the baseline for the CBA, rather than the case in which only the resources connected at transmission can provide ancillary services. The main reason for this is that the increased contribution by distributed energy resources (DER) in the future will result in higher balancing needs and in the decommissioning of several traditional power plants. Therefore, the balancing resources at transmission level only may not be enough to guarantee the required stability for the system.

However, there is no answer to how to consider, in the system-level CBA, the cost synergies[33] between coordination schemes if Coordination Scheme A is taken as the baseline.

1.2 Metrics

In general, respondents agree with the proposed metrics and monetization methods, except for "Reduction of unwanted measures adopted by network operators in order to solve congestions", which is rejected by two respondents. This metric is further discussed below.

When asked about potential overlapping between them, respondents did not know what to answer, although one of them identified a likely interdependence of prices for the different indicators.

Although respondents would not propose different monetization methods, they proposed different approaches for the analysis in some indicators:

- In "Enhanced provision of ancillary services", one respondent states that it would be interesting to evaluate the impact of coordination schemes in the provision of reactive power / voltage control services or other ancillary services. They also state that it would be important to assess the improvements in the liquidity of balancing markets (*"higher liquidity means that if a part of aggregators cannot participate in balancing markets, the prices will still not vary significantly because there is still additional supply from DER at lower prices"*). As a final remark, one of the

[33] For instance, let's assume that the costs of implementing a control system for coordination scheme A is 100 and the costs of implementing a control system for coordination scheme B is 130. Since these control systems are not scalable, it is not immediate to state that passing from A to B would cost 30 but, in principle, it can be any value between 30 and 130.

respondents highlighted the need to explain very well why we are not considering "social welfare", because regulators tend to be in favour of maximizing it.

- In "Reduction of unwanted measures adopted by network operators in order to solve congestions", one respondent requests to avoid unwanted measures through a market for specific grid services. They also propose that, instead of blocking activation signals, network operators should provide in advance grid state information to flexibility providers.
- In "Reduced network losses", respondents prefer to split the costs of congestion management and losses, for greater transparency and for having additional information. In addition, one respondent proposes to use long-term prices (at least one month or even one year), because the losses can be statistically well forecasted.

Regarding the pricing for the services, there is wide variability among answers and among metrics:

- For "Enhanced provision of ancillary services", pay-as-bid is the preferred option, although it is also mentioned the interest of performing a comparison between this method and marginal pricing.
- For "Reduced network losses", two respondents prefer average price and another one marginal price.
- For "Emissions savings", average price is preferred.

The major discrepancy is for the metric "Reduction of unwanted measures adopted by network operators in order to solve congestions", which is rejected by two respondents. The main reason for this seems to be that the consultation document did not clearly explain how the SmartNet market works, because they think that these unwanted measures should be avoided by means of a market approach (which is the case of SmartNet). Regarding the monetization method, one answer prefers flexibility cost (the cost of the resource(s) affected), another one the average imbalance price and the third one the free market, although a flexibility cost with a random premium could be used for simulation purposes.

1.3 ICT costs

Based on one of the answers, the ICT costs to be included (both in capital and operational expenditures) are:

- SCADA:
    - Main control centre software, licenses, etc. for SCADA, Energy Management System (EMS) and Distribution Management System (DMS).
    - Operator Training Simulator (OTS), either in-house or outsourced.
    - Remote Terminal Units (RTUs) and local substation hardware.
    - Telecommunication systems between substation RTUs and distribution control centre.
    - Front-end at control centre.

- Operational planning applications:
    - Network applications.
    - Market applications - system services.
    - Forecast applications.
    - Regional coordinator (which can be outsourced).
- Metering cost (if needed):
    - Meters, either at consumers' or producers' facilities.
    - Telecommunications (dial up).
    - Database.
    - Applications.
- Other costs:
    - Building (€/m2).
    - Staff in ICT team for maintaining the database and applications.
    - Staff in ICT team for development of new applications.
    - Uninterrupted Power Supply.

In general, there is a preference for outsourcing ICT services, especially as the importance of DER grows. One critical point is cyber-security and, thus, although ICT may be outsourced, DSOs must be really aware of this challenge.

When changing from one ICT solution to another, the most important issues of concern are the lack of interoperability between ageing and new systems, the need to ensure continuity of supply and security concerns. However, if ICT service is outsourced, the DSO only needs to care about the service received and not about the underlying technology.

One respondent expects cyber-security and interoperability to be the most critical aspects to be considered in ICT cost, another respondent thinks that ICT systems are easier and cheaper to adapt than the traditional DSO business (ICT systems are more flexible than power systems) and the third one thinks that, due to the difference of characteristics of DSO core business and ICT, it is better to outsource this service. However, only one provides an estimate of ICT costs when compared to the overall energy network/service investments: 25 % today and 60 % in 2030.

Regarding redundant systems, the three answers are different. One respondent thinks that "*ICTs that ensure communication with TSOs and other energy market entities must be uninterruptable to not compromise security of supply and ensure adequate quality of service to energy consumers*", another one thinks that redundancy is only required for the transition phase if there is a major ICT system change and the third one thinks that outsourcing allows the DSO to forget about it (even if the subcontractor will need to have redundant systems to ensure the continuity of supply of the ICT service).

9 Appendix II - ICT costs equations

The equations for ICT cost estimates in terms of parameters and variables are given below:

Low estimates:

$$\text{Low cost of CS A} = \text{marketClearAlgPM} \times \text{highPMCost} + \text{marketClearOtherPM} \times \text{lowPMCost} + 0.5\,\text{nAggregators} \times (\text{aggregAlgPM} \times \text{highPMCost} + \text{aggregOtherPM} \times \text{lowPMCost})$$

$$\begin{aligned}\text{Low update cost from CS A to CS B} &= 0.5\,\text{nAggregators} \times (\text{locAggregAlgPM} \times \text{highPMCost} + \text{locAggregOtherPM} \\ &\times \text{lowPMCost} + \text{marketClearAlgPM} \times \text{highPMCost} + \text{marketClearOtherPM} \times \text{lowPMCost} \\ &+ \text{localMarketAlgPM} \times \text{highPMCost} + \text{localMarketOtherPM} \times \text{lowPMCost} \\ &+ \text{DSOaggregAlgPM} \times \text{highPMCost} + 0.5 \times \text{DSOaggregOtherPM} \times \text{lowPMCost}) \\ &+ \text{SimulatorStudyCost}\end{aligned}$$

$$\begin{aligned}\text{Low update cost from CS A to CS C} &= 0.5\,\text{nAggregators} \times (\text{locAggregAlgPM} \times \text{highPMCost} + \text{locAggregOtherPM} \\ &\times \text{lowPMCost} + \text{marketClearAlgPM} \times \text{highPMCost} + \text{marketClearOtherPM} \times \text{lowPMCost} \\ &+ \text{localMarketAlgPM} \times \text{highPMCost} + \text{localMarketOtherPM} \times \text{lowPMCost}) \\ &+ \text{SimulatorStudyCost}\end{aligned}$$

High estimates:

$$\begin{aligned}\text{High cost of CS A} &= \text{marketClearAlgPM} \times \text{highPMCost} + \text{marketClearOtherPM} \times \text{lowPMCost} \\ &+ \text{nAggregators} \times (\text{aggregAlgPM} \times \text{highPMCost} + \text{aggregOtherPM} \times \text{lowPMCost})\end{aligned}$$

$$\begin{aligned}\text{High update cost from CS A to CS B} &= \text{nAggregators} \times (\text{locAggregAlgPM} \times \text{highPMCost} + \text{locAggregOtherPM} \times \text{lowPMCost}) \\ &+ \text{nLocalMarketPlatforms} \times (\text{marketClearAlgPM} \times \text{highPMCost} + \text{marketClearOtherPM} \\ &\times \text{lowPMCost} + \text{localMarketAlgPM} \times \text{highPMCost} + \text{localMarketOtherPM} \times \text{lowPMCost} \\ &+ \text{DSOaggregAlgPM} \times \text{highPMCost} + \text{DSOaggregOtherPM} \times \text{lowPMCost}) \\ &+ \text{SimulatorStudyCost}\end{aligned}$$

$$\begin{aligned}\text{High update cost from CS A to CS C} &= \text{nAggregators} \times (\text{locAggregAlgPM} \times \text{highPMCost} + \text{locAggregOtherPM} \times \text{lowPMCost}) \\ &+ \text{nLocalMarketPlatforms} \times (\text{marketClearAlgPM} \times \text{highPMCost} + \text{marketClearOtherPM} \\ &\times \text{lowPMCost} + \text{localMarketAlgPM} \times \text{highPMCost}) + \text{SimulatorStudyCost}\end{aligned}$$

Cost estimates of CS D:

$$\text{DTSODSODependentCost}\begin{pmatrix}\text{nDSO, nodesForDSO, nodesForTSO,}\\ \text{NISunit, NISperNode, interfaceCost}\end{pmatrix}$$

$$= \text{NISunit} + (\text{nDSOnodesForDSO} + \text{nodesForTSO}) \times \text{NISperNode} + \text{interfaceCost} \times (\text{nDSO} + 1)$$

$$\text{D MarketClearItaly} = \text{DcriticalityCost} + \text{localMarketAlgPM} \times \text{highPMCost} + \text{localMarketOtherPM} \times \text{lowPMCost} + \text{marketClearRealTime} \times \text{highPMCost} + \text{DTSODSODependentCost}\begin{pmatrix}\text{nDSOItaly, nodesForDSO, nodesTSOItaly,}\\ \text{NISunit, NISperNode, interfaceCost}\end{pmatrix}$$

$$\text{DMarketClearSpain} = \text{DcriticalityCost} + \text{localMarketAlgPM} \times \text{highPMCost} + \text{localMarketOtherPM} \times \text{lowPMCostmarketClearRealTime} \times \text{highPMCost} + \text{DTSODSODependentCost}\begin{pmatrix}\text{nDSOSpain, nodesForDSO, nodesTSOSpain,}\\ \text{NISunit, NISperNode, interfaceCost}\end{pmatrix}$$

$$\text{DMarketClearDenmark} = \text{DcriticalityCost} + \text{localMarketAlgPM} \times \text{highPMCost} + \text{localMarketOtherPM} \times \text{lowPMCost} + \text{marketClearRealTime} \times \text{highPMCost} + \text{DTSODSODependentCost}\begin{pmatrix}\text{nDSODenmark, nodesForDSO, nodesTSODenmark,}\\ \text{NISunit, NISperNode, interfaceCost}\end{pmatrix}$$

$$\text{DItalyLow} = 0.5\ \text{nAggregators} \times (\text{locAggregAlgPM} \times \text{highPMCost} + \text{locAggregOtherPM} \times \text{lowPMCost}) + \text{DcriticalityCost} + \text{localMarketAlgPM} \times \text{highPMCost} + \text{localMarketOtherPM} \times \text{lowPMCost} + \text{marketClearRealTime} \times \text{highPMCost} + \text{DTSODSODependentCost}\begin{pmatrix}\text{nDSOItaly, nodesForDSO, nodesTSOItaly,}\\ \text{NISunit, NISperNode, interfaceCost}\end{pmatrix} + \text{SimulatorStudyCost}$$

$$\text{DSpainLow} = 0.5\ \text{nAggregators} \times (\text{locAggregAlgPM} \times \text{highPMCost} + \text{locAggregOtherPM} \times \text{lowPMCost}) + \text{DcriticalityCost} + \text{localMarketAlgPM} \times \text{highPMCost} + \text{localMarketOtherPM} \times \text{lowPMCost} + \text{marketClearRealTime} \times \text{highPMCost} + \text{DTSODSODependentCost}\begin{pmatrix}\text{nDSOSpain, nodesForDSO, nodesTSOSpain,}\\ \text{NISunit, NISperNode, interfaceCost}\end{pmatrix} + \text{SimulatorStudyCost}$$

DDenmarkLow

$$= 0.5\ \mathrm{nAggregators}\ \times (\mathrm{locAggregAlgPM}\ \times\ \mathrm{highPMCost} + \mathrm{locAggregOtherPM}\ \times\ \mathrm{lowPMCost}) + \mathrm{DcriticalityCost} + \mathrm{localMarketAlgPM} \times\ \mathrm{highPMCost} + \mathrm{localMarketOtherPM} \times\ \mathrm{lowPMCost} + \mathrm{marketClearRealTime}\ \times\ \mathrm{highPMCost} + \mathrm{DTSODSODependentCost}\begin{pmatrix}\mathrm{nDSODenmark}, \mathrm{nodesForDSO}, \mathrm{nodesTSODenmark}, \\ \mathrm{NISunit}, \mathrm{NISperNode}, \mathrm{interfaceCost}\end{pmatrix} + \mathrm{SimulatorStudyCost}$$

$$\mathrm{DItalyHigh} = \mathrm{nAggregators}\ \times (\mathrm{locAggregAlgPM}\ \times\ \mathrm{highPMCost} + \mathrm{locAggregOtherPM}\ \times\ \mathrm{lowPMCost}) + \mathrm{DcriticalityCost} + \mathrm{localMarketAlgPM} \times\ \mathrm{highPMCost} + \mathrm{localMarketOtherPM} \times\ \mathrm{lowPMCost} + \mathrm{marketClearRealTime}\ \times\ \mathrm{highPMCost} + \mathrm{DTSODSODependentCost}\begin{pmatrix}\mathrm{nDSOItaly}, \mathrm{nodesForDSO}, \mathrm{nodesTSOItaly}, \\ \mathrm{NISunit}, \mathrm{NISperNode}, \mathrm{interfaceCost}\end{pmatrix} + \mathrm{SimulatorStudyCost}$$

$$\mathrm{DSpainHigh} = \mathrm{nAggregators}\ \times (\mathrm{locAggregAlgPM}\ \times\ \mathrm{highPMCost} + \mathrm{locAggregOtherPM}\ \times\ \mathrm{lowPMCost}) + \mathrm{DcriticalityCost} + \mathrm{localMarketAlgPM} \times\ \mathrm{highPMCost} + \mathrm{localMarketOtherPM} \times\ \mathrm{lowPMCost} + \mathrm{marketClearRealTime}\ \times\ \mathrm{highPMCost} + \mathrm{DTSODSODependentCost}\begin{pmatrix}\mathrm{nDSOSpain}, \mathrm{nodesForDSO}, \mathrm{nodesTSOSpain}, \\ \mathrm{NISunit}, \mathrm{NISperNode}, \mathrm{interfaceCost}\end{pmatrix} + \mathrm{SimulatorStudyCost}$$

$$\mathrm{DDenmarkHigh} = \mathrm{nAggregators}\ \times (\mathrm{locAggregAlgPM}\ \times\ \mathrm{highPMCost} + \mathrm{locAggregOtherPM}\ \times\ \mathrm{lowPMCost}) + \mathrm{DcriticalityCost} + \mathrm{localMarketAlgPM} \times\ \mathrm{highPMCost} + \mathrm{localMarketOtherPM} \times\ \mathrm{lowPMCost} + \mathrm{marketClearRealTime}\ \times\ \mathrm{highPMCost} + \mathrm{DTSODSODependentCost}\begin{pmatrix}\mathrm{nDSODenmark}, \mathrm{nodesForDSO}, \mathrm{nodesTSODenmark}, \\ \mathrm{NISunit}, \mathrm{NISperNode}, \mathrm{interfaceCost}\end{pmatrix} + \mathrm{SimulatorStudyCost}$$

10 Appendix III – Potential of smart meters to support the provision of distributed ancillary services

10.1 Introduction

SmartNet ICT cost analysis (section 0) gathered information from various smart metering system requirement specifications and CBA reports, in order to assess the cost of communications to households with DER capability. The SmartNet ICT cost estimates do not include any last kilometre costs, because they are nearly independent on the coordination scheme and also highly uncertain as shown below. In the worst case they can be even higher than the other ICT costs and thus a possible significant cost barrier for the provision of AS using very small DERs. The information on last kilometre costs was also an important input for assessing the feasibility of the working assumptions of the ICT cost estimation

According to the cost analysis, a last kilometre communication system with small DERs dedicated to ancillary services only tends to become too expensive compared to the benefit of the ancillary services. There are low-latency, one-way multicasting technologies and services which can be used for demand respond in some areas. Some of them are based on radio broadcasts and some use power lines as the communication channel and they are briefly discussed in this document in a separate section on the topic. These technologies have adequate performance for the ancillary services considered but they are not readily ubiquitously available. They also need a receiver and thus an expensive site visit if separately implemented. Thus, there is a need to study the possibility to use those communication infrastructures that will be available for some other reasons. The SmartNet project focuses on FRR type ancillary services. These require high availability and low latency multicasting of control commands to the energy resources that provide the flexibility. (These are functional performance requirements and do not define in any way how and on which communication stack layer the required low latency multicasting performance is to be implemented.) The aggregator may find synergies with other building, energy and DG management, and security applications that need low latency and high availability remote controllability. That may enable sharing the investment.

In addition, smart meters have potential to provide a cost-efficient solution, because nearly every relevant customer connection in Europe is going to be equipped with them. EU Directive 2009/72/EC [50] is the EU legislative on the Third Internal Market Package which stipulates all EU member states equip 80% of their consumers with smart meters by 2020 to assist the active participation of consumers in the electricity and gas supply markets. Some other EU documents such as the EC Recommendation no. 148/2012 [51] also promote smart metering. A review of the rollout situation in 2015 or 2016 is in [52], but both [52] and a recent demand response-oriented report [53] ignore that the transmission of time critical control signals is important in DR in general and especially when using them for ancillary services.

Thus, they do not help in assessing to what extent the smart metering systems communication capabilities support and will support distributed ancillary services.

If the communication for ancillary services is integrated in the smart metering systems, additional installation costs can be avoided, and the communication capability stays over the lifetime of the metering system. The costs of site visits are biggest individual cost item so avoiding them enables cheaper service. For the smart metering cost benefit case, it is very important to include real-time communication from the meter to the customers' systems via a standardized interface that is, in modern requirements and implementations, a one-way interface to some standard communication bus. Thus, every reasonable smart meter and related functional requirement set nowadays includes the interface readily and there is no need to add it for the provision of ancillary services.

This annex analyses 1) the possibility to include multicasting fast control commands in the smart metering system requirements and 2) the suitability of the future smart meters in metering for verification and settlement of the DERs responses for the SmartNet ancillary services.

As described in next sections, 1) Fast control command communication capabilities to support distributed ancillary services are not included in most of the next generation smart metering functional requirements existing or under development in Europe and thus they will not be implemented in the smart metering systems, although many rather cost efficient possible technical solutions exist and 2) The suitability of the future smart meters in metering for verification and settlement of the DER responses for the SmartNet ancillary services was found to be easily made adequate, especially, if included in the metering requirements.

10.2 Control signal broadcasting technologies

Many technologies can be used for broadcasting control signals from the DSO or TSO to DERs. All these technologies have reasonably adequate performance for multicasting control signals to DERs in ancillary service provision. Implementation details may set some performance limitations. Many (but not all) of the technologies are able to communicate directly from the central location to a receiver integrated in the DER, but the receivers have typically been integrated to certain types of smart meters that distribute the control signals via local, real-time communication to DER.

The main limitation of these technologies is that another complementing communication network is needed for two-way communication and for transferring large amounts of data. Three main technologies are used for this purpose:

1. Radio broadcasting for multicasting and broadcasting control signals: The use of control systems based on radio broadcasting is quite common. In several countries in central Europe radio ripple control systems [54] are in use. In the UK, the BBC Radio 4 Longwave Radio tele switch [55] is used, although stopping the service is planned by 2020, because it is assumed that smart meters can

replace the functionality. However, in the smart meter requirements of UK there are no requirements regarding the latencies of control signals so the still existing capability to broadcast control signals for ancillary services will most likely disappear.

2. Power line communication for multicasting and broadcasting control signals: Various narrow band power line communication technologies have been used for the purpose. Brief descriptions and references to more detailed information can be found in an overview of different power line communication technologies [56]. In addition, also more power line communication technologies are being developed and piloted for DR signal broadcasting. Even multicasting from the central TSO location directly to controllable household appliances has been piloted. The most common power-line-based control signal communication technology is the power line ripple control, which has been used and is still in use in many countries around the world (the first versions were developed during the Second World War).
3. New technologies for control signal communications: The above examples are mainly such existing systems for fast load control signal communications that are already being phased out or replaced by other technologies. Current and future communications technologies that are applicable for Smart Grid needs are described in SmartNet Deliverable D3.2 [57], more specifically, in chapter 7 on enabling technologies. The requirements for control signal communications are defined in terms of criticality, latency, availability, resilience, power autonomy, typical data volume, minimum bandwidth and cost. Depending on their implementation, future technologies, such as 5G, are anticipated to meet these requirements even better than the earlier mentioned multicasting and broadcasting. They can also enable new services and functionalities that benefit ancillary services and Smart Grids.

10.3 Reviews of European functional requirements of smart metering

A rough comparison of planned functional requirements can be found in the report [40]. When looking it for comparable reference systems in the cost analysis, it was observed that only in some countries, namely the Netherlands, UK and Germany, the smart metering system requirements include capability to send load control commands. In NL and UK, they do not set any performance requirements but only define technical implementations (see [58] and [59], for example). Thus, it is not easy to see how close the performance will be to the level needed by the markets defined within SmartNet. The specification of the Netherlands is such that, together with a suitable configuration, it may nearly or even adequately meet the time-critical communication needs of SmartNet. The cost of using GPRS may also become relatively high when the technology is widely substituted by newer technologies. Further analysis is needed before clear conclusions can be reached.

The cost-benefit analysis [40] (in pp. 33 -34) states that controlling low-voltage devices, such as heat pumps, electrical vehicles and other controlled energy applications, provides no additional benefit, as the net present value decreases slightly. The main reason is that the increase in telecommunication cost

cannot be compensated by the additional benefit. However, the report recommends including them in the mandatory smart metering installations, because it considers the controllability of such devices important for the future decentralized energy supply systems. For the minimum requirements of the telecommunication infrastructure, it mentions in particular that control signals must be sent and received at least every 15 minutes.

In most of the countries in EU, the smart metering systems are not at all adequate for SmartNet control signal communication needs. This can also be seen from a review of the smart metering requirements in 8 countries comprising Sweden, Norway, Denmark, Germany, the Netherlands, United Kingdom, Italy and Estonia. The review was included in a recent study of the requirements of next generation smart metering systems for Finland reported in Finnish by Pöyry Consulting [60], that almost completely lacks transparency regarding the references and other sources of information. It does not recommend any load control capabilities. This is surprising, because in a small cost-benefit analysis, it finds (in spite of overly high-cost estimates of local control interface) that the inclusion of load control functionalities in the smart meter requirements is profitable. It also found that the alternative home-automation-based approaches that have adequate performance still in most small houses tend to be too expensive compared to the benefits, if the smart metering systems include the load control interfaces. Thus, there seems to be an unexplainable conflict of interest that, in some countries, may prevent the inclusion of the needed control interfaces in the requirements for smart meters.

The Dutch Smart Meter Requirements [58] defines adequate and standardized interfaces for external service providers for sending control commands to appliances in the customers' premises. In the Dutch metering network, GPRS is used. The GPRS Companion Standard to Dutch Smart Meter Requirements [59] defines the requirements for the GPRS communication for the Dutch smart meters. In this case, the data connection has priority, which is good for activating ancillary services, on the contrary to normal GPRS networks, where speech has priority over a data connection and, hence, are not acceptable when activating ancillary services. It is notable that functional performance requirements are not defined.

A recent dissertation [39] includes a good review and summary of the situation regarding smart metering requirements and rollout plans around the world. It compares the functional requirements and guidelines for smart metering systems presented by different national and international authorities, such as EC, ERGEG, SMCG and the Swedish Ei. The review covers almost the whole world, with the notable omissions of the situation, requirements and plans in New Zealand and Australia (Australia is in some respects clearly ahead Europe). The dissertation finds that, for example, most requirement include the possibility to switch remotely the power supply on and off and to limit power remotely and that the requirement to support demand response commands is included in 12 EU states (including also Sweden) and ERGEG. Another interesting observation here is that the dissertation studies by simulations how the data communication and other latencies of control activation can be reduced in order to meet the TSO requirement of 15-minute activation time. The simulation is based on a smart metering system in

Gothenburg that has a ZigBee-based last kilometre communication system. The result is that switching the power supply off in all the meters can be done in 6 minutes by adding more meter data collection units (MDCUs) so that each MDCU has 50 meters at maximum. That was considered adequate for the purpose and allowing enough time for planning the switching. Nowadays, each MDCU has 144 meters at maximum and the simulated time to switch off all the meters is 20 minutes, being 14 minutes the time to switch off 90% of the meters.

Also, in many other existing smart metering technologies and systems the control communication performance can be improved by adding more MDCUs. The cost of improving the performance is rather similar to the Gothenburg case simulated in [39] and even after the improvements, the activation times may be somewhat too long for fast ancillary services. New communication technologies have potential to provide better control communication performance with smaller costs.

10.4 Costs of smart metering

The smart metering cost benefit analysis study [40] provides useful information on the components of the smart metering system costs. In addition, the project SmartNet received anonymized information on the smart metering costs in Norway and the regulatory information on costs is available from Finland. It is good to notice that typically it is taken into account by subtracting that the old meters need to be changed or taken to calibration anyhow. Unfortunately, cost data from Denmark, Italy or Spain was not available.

SmartNet ICT cost analysis received from Norway anonymized data on DSOs' Smart Meter deployment costs on 2016. These 111 DSOs represent over 2.9 million metering locations, out of which about 2.3 million locations are households, 0.322 million summerhouses or equivalents, and 0.3 million industry locations (site annual consumption over 100 MWh).

Figure 10.1 illustrates the variation of the reported total costs per Advanced Metering System (AMS) and the share of communications and other costs. The category "other costs" contains mainly the costs of IT-systems needed for processing smart metering data.

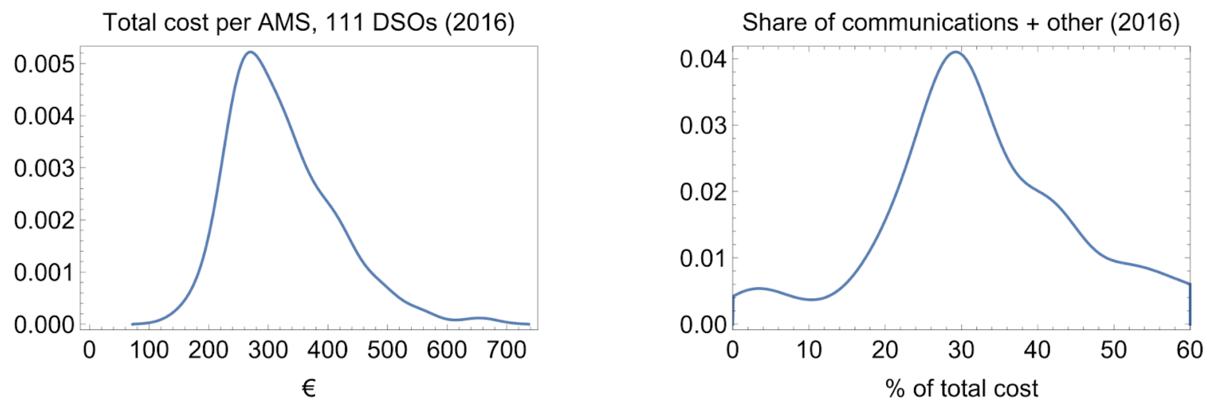

Figure 10.1: Histogram model for total costs and the share of ICT costs.

As an initial approximation, the share of communication and other costs is estimated to be around 30% (mean value of the share is 32.7%, but "other" category contains also non-IT-system costs). This can be split between communications and "other", with proportions 14% and 16%, by studying the mean values of communication costs and "other" costs, after removing 5% of the lowest and highest values. Therefore, by using the weighted total cost average EUR 385 per metering location, the share of telecommunications would be EUR 54 and the share of data collection system would be EUR 62. Typically, the lifetime of a smart metering investment is 10-15 years.

In the cost benefit analysis study [40], cost averages per metering point are given for 12 countries, which are given in Euros in Table 10.1.

GB	NL	RO	BE-BR	BE-FL	BE-WL	CZ	DE	HU	LT	PT	SK
281.65	240.28	97.73	527.92	569.30	685.82	436.46	492.12	242.42	163.27	116.51	171.15

Table 10.1: Cost average per metering point in different countries

Some explanations can be found by studying the analyses and the requirements closer. In Germany, the costs are higher due to different requirements for the implementation details of the ICT and cyber-security architecture requirements. It would be much more cost efficient to specify functional requirements; not how to implement them. In Belgium and in the Czech Republic, the costs are high because the costs of the meters have been estimated to be very high when compared to the requirements. Both the age of the studies and the estimated high installation costs may be the mains reason for this. The report states that experience from the large-scale rollouts from Italy and Spain shows costs per meter that are closer to the ones in Portugal than the ones in Belgium. In Finland, the Energy Market Authority allows EUR 200 per meter for the lifetime 10-20 years in its regulation model. That is rather close to the actual costs in Finland in large-scale rollouts.

In the Netherlands and in Great Britain, electricity-metering systems are required to support gas metering, which may slightly increase the costs. Since the analysis, the required functionalities have become more common and the costs lower. Now smart 3x64A meters meeting the functional requirements of most of the countries in the cost benefit reports are commonly available for EUR 70 when bought individually and they are much cheaper when bought in very large quantities. Thus, the costs of the meters and their interfaces and internal processing are less than 25 % of the total cost of an installed smart metering system. Data communication solutions are not expensive either, but that is because low-priority and long-latency communication is used. Thus, it does not tell anything about the costs of communication needed for the control signals of ancillary services.

There are many possible reasons that can explain why the costs in Norway are higher than in Great Britain, the Netherlands, Italy, Spain and Finland: the national differences in work costs, difficult geographical conditions that increase the communication system costs, difficult access to install the

meters, not using the alternative costs of not making the investment as a reference, increase of the costs due to approaching regulatory deadlines, etc.

In Finland, the regulating authority has defined in the regulation model the upper cost for smart metering systems per metering point that can be included in the distribution tariffs of the customers. Such upper limit tends to act as a target cost for DSOs, but real costs are higher in many cases. For example, many rural DSOs see support to low-voltage distribution automation so profitable that they are willing to make the small additional investment to a system that better supports that functionality. Poor timing or implementation of the investment also increases the costs.

From the smart metering cost analyses, the following conclusions can be drawn regarding the costs of distribution of ancillary services:

1) The metering system functional requirements have much smaller impact on the costs than the installation costs of the meters. 2) The smart metering systems will not support distributed AS unless the functional requirements for smart meters are amended accordingly. 3) Existing smart metering system communication requirements are not comparable to the communication requirements of ancillary services and thus the smart metering system cost analyses do not provide much information about estimating the communication costs of distributed ancillary services. 4) For our purposes, the best individual overview is in [39] but also the other sources help to get a more complete picture.

10.5 Adequacy of the smart metering requirements from the ancillary service point of view

From ancillary service point of view, it would be necessary to have roughly such requirements as maximum latencies shall not exceed 1 minute and minimum aggregated availability shall be at least 99.9% of the time in a year for 90% of the controlled sites. When controlling small flexible resources, it is not important to reach nearly every site nearly always. More important is to focus the requirements to the availability and latency of the aggregated responses. It is also important that the messages include activation times, because too much delayed commands must never be allowed to cause any responses.

If the smart metering systems were required to have low latency, high availability multicast of small group control signals that would likely cause only rather modest cost increases compared to the potential benefits. Several technologies are suitable for the purpose, and there is a long experience on some of them. For example, in Finland before 1997 power line ripple control systems were controlling the loads in very many electricity utilities and they were able to transmit simultaneously sent control signals within 3 seconds to all meters. For typical ancillary services, even 10-30 second latencies could be sufficiently short. These power line-based communication systems controlled large amounts of houses that had more or less storage heating. In central Europe, there is a radio ripple control system with similar capabilities in use, but due to the costs, it is not applied to small customers. These are just examples. The

communication technologies have advanced much during the last 20 years, so it can be expected that the costs of large-scale implementation with the new technologies could be less expensive than then. For example, the 5G network technologies seem to support the needed functionalities and are being studied in control and protection applications that also require efficient multicasts and with even much smaller latencies. Increasingly the DSOs start to need the possibilities to remotely control first the type B DER and with time also smaller ones. Thus, the DSOs gradually start to need such a communication system. Therefore, it is recommended that the smart metering system requirements will be analysed and reconsidered regarding the low latency group control capabilities as well as the capabilities of the potential communication technologies in the future. It would be a surprise, if the result of the analysis turns out that technical development was not proceeding in this respect.

10.6 Conclusions

The following conclusions can be drawn regarding the communication costs of distribution ancillary services.

1. The functional requirements of the metering system have a much smaller impact on the costs than the installation costs of the meters.
2. The smart metering systems will not adequately support distributed AS, unless the functional requirements for smart meters are amended accordingly. The most important missing capability is to adequately and quickly activate AS which are provided by many small flexible DERs. Also, the capabilities to support verification of the responses must be upgraded. In some vertically integrated utilities outside Europe, smart metering systems already support distributed AS.
3. The smart metering systems have many properties that are needed by distributed AS. These include measurements for billing, verification and, to some extent, voltage quality, reasonable existing cyber-security requirements, adequate independence from such third parties that may suddenly stop their service, etc.
4. Existing communication requirements for smart metering systems, especially in Europe, are typically not comparable to the communication requirements for the ancillary services provision and, thus, the analysis of costs for smart metering systems does not provide much information about the expected communication costs of distributed ancillary services. Some useful general observations regarding highly distributed systems can be made. For small, distributed end devices, the installation and integration costs tend to dominate, as functionality in mass-produced end devices is inexpensive. With relatively modest additional costs, the communication networks can be made to support fast control actions. Implementing own communication infrastructures for functionalities tends to be relatively expensive compared to implementing a generic common infrastructure for all the functionalities needed. In the distributed systems, integrating many functionalities is often cost-efficient, when compared to doing the same with separate dedicated systems and devices. Dedicated

last-kilometre ICT infrastructure can be too expensive for the provision of AS from small flexible DERs.

11 Appendix IV – Business-level analysis formulation

11.1 Relationships between actors

Next tables (Table 11.1, Table 11.3, Table 11.5 and Table 11.7) present the actors who are relevant for the different coordination schemes and the relationships between them. These relationships are easily drawn from the e³value models, that is, the value model of each coordination scheme (Figure 5.2, Figure 5.4, Figure 5.6 and Figure 5.8). Due to format restrictions, the relationships (what is exchanged between two actors) are indicated with a number. Therefore, following those tables, an extra table has been included to explain the meaning of each number (Table 11.2, Table 11.4, Table 11.6 and Table 11.8). The concepts explained in these tables are the same as those ones represented graphically in the value models.

For clarity purposes, in the tables corresponding to coordination schemes B, C, and D, new financial exchanges, in comparison with coordination scheme A, are highlighted in green. Likewise, in the explanatory tables of the exchanges, a shaded cell means that the exchange is the same as an exchange already performed in CS A.

The cash-flows for the different actors are obtained by adding all the terms in their respective column and subtracting all the terms in their respective row. As an example, equation (11) shows the cash flow for the actor Non-direct DER producers (the superscript of the addends indicates who performs the payment):

$$\begin{aligned} \mathit{Annual\ cashflow}\ _y^{\mathit{Non\ direct\ DER\ Producers}} \\ &= \mathit{Payment\ for\ electricity}_y^{\mathit{Aggregator}} + \mathit{Payment\ for\ flexibility}_y^{\mathit{Aggregator}} \\ &- \mathit{Grid\ access}_y^{\mathit{Non\ direct\ DER\ Producers}} - \mathit{System\ access}_y^{\mathit{Non\ direct\ DER\ Producers}} \\ &- \mathit{Market\ access}_y^{\mathit{Non\ direct\ DER\ Producers}} \end{aligned} \tag{11}$$

Each relationship detailed in these table results in a formula which is described in sections 11.2 and 11.3.

WHO / TO WHOM	Non-direct passive consumers	Direct passive consumers	Non-direct active consumers	Direct active consumers-Distr.	Direct active consumers-Trans.	Retailers of Non-direct passive consumers	Aggregators of Non-direct active consumers	Central producers	Direct DER producers	Non-direct DER producers	Aggregator of non-direct DER producers	Wholesale market operator	Balancing market operator	BRP: Direct passive consumers	BRP: Retailers of non-direct passive consumers	BRP: Direct active consumers-Distr.	BRP: Direct active consumers-Trans.	BRP: Aggregators of non-direct active consumers	BRP: Central producers	BRP: Direct DER producers	BRP: Aggregators of non-direct DER producers	DSO	TSO	Rest of the system
Non-direct passive consumers						1 2																		
Direct passive consumers												3 4		8								6 7	5	
Non-direct active consumers							1 2																	
Direct active consumers-Distr.												3 4				8						6 7	5	
Direct active consumers-Trans.												3 4					8					6 7	5	
Retailers of Non-direct passive consumers												3 4			8							6 7	5	
Aggregators of Non-direct active consumers			9									3 4						8				6 7	5	
Central producers												3							8			7	5	
Direct DER producers												3								8		7	5	
Non-direct DER producers											3 5 7													
Aggregator of non-direct DER producers										9 10		3									8	7	5	
Wholesale market operator								4	4		4													
Balancing market operator				11	11		11	11	11		11													
BRP: Direct passive consumers																							8	
BRP: Retailers of non-direct passive consumers																							8	
BRP: Direct active consumers-Distr.																							8	
BRP: Direct active consumers-Trans.																							8	
BRP: Aggregators of non-direct active consumers																							8	
BRP: Central producers																							8	
BRP: Direct DER producers																							8	
BRP: Aggregators of non-direct DER producers																							8	
DSO																							12	13
TSO													11									14		

Table 11.1: Exchanges performed in CS A

No.	What	Who	To whom
1	Retail electricity	Non-direct passive consumers	Retailers of non-direct passive consumers
		Non-direct active consumers	Aggregators of non-direct active consumers
2	Power connection	Non-direct passive consumers	Retailers of non-direct passive consumers
		Non-direct active consumers	Aggregators of non-direct active consumers
3	Wholesale market access	Direct passive consumers	Wholesale market operator
		Direct active consumers-Distribution	Wholesale market operator
		Direct active consumers-Transmission	Wholesale market operator
		Retailers of non-direct passive consumers	Wholesale market operator
		Aggregators of non-direct active consumers	Wholesale market operator
		Central producers	Wholesale market operator
		Direct DER producers	Wholesale market operator
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	Wholesale market operator
4	Wholesale electricity	Direct passive consumers	Wholesale market operator
		Direct active consumers-Distribution	Wholesale market operator
		Direct active consumers-Transmission	Wholesale market operator
		Retailers of non-direct passive consumers	Wholesale market operator
		Aggregators of non-direct active consumers	Wholesale market operator
		Wholesale market operator	Central producers
		Wholesale market operator	Direct DER producers
		Wholesale market operator	Aggregators of non-direct DER producers
5	System access	Direct passive consumers	TSO
		Direct active consumers-Distribution	TSO
		Direct active consumers-Transmission	TSO
		Retailers of non-direct passive consumers	TSO
		Aggregators of non-direct active consumers	TSO
		Central producers	TSO
		Direct DER producers	TSO
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	TSO
6	Grid Access Power term	Direct passive consumers	DSO
		Direct active consumers-Distribution	DSO
		Direct active consumers-Transmission	DSO
		Retailers of non-direct passive consumers	DSO
		Aggregators of non-direct active consumers	DSO
7	Grid Access Energy term	Direct passive consumers	DSO
		Direct active consumers-Distribution	DSO
		Direct active consumers-Transmission	DSO
		Retailers of non-direct passive consumers	DSO
		Aggregators of non-direct active consumers	DSO
		Central producers	DSO
		Direct DER producers	DSO
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	DSO
8	Imbalances	Direct passive consumers	BRP: Direct passive consumers
		Direct active consumers-Distribution	BRP: Direct active consumers-Distribution
		Direct active consumers-Transmission	BRP: Direct active consumers-Transmission
		Retailers of non-direct passive consumers	BRP: Retailers of non-direct passive consumers

No.	What	Who	To whom
		Aggregators of non-direct active consumers	BRP: Aggregators of non-direct active consumers
		Central producers	BRP: Central producers
		Direct DER producers	BRP: Direct DER producers
		Aggregators of non-direct DER producers	BRP: Aggregators of non-direct DER producers
		BRP: Direct passive consumers	TSO
		BRP: Retailers of non-direct passive consumers	TSO
		BRP: Direct active consumers-Distribution	TSO
		BRP: Direct active consumers-Transmission	TSO
		BRP: Aggregators of non-direct active consumers	TSO
		BRP: Central producers	TSO
		BRP: Direct DER producers	TSO
		BRP: Aggregators of non-direct DER producers	TSO
9	Flexibility	Aggregators of non-direct active consumers	Non-direct active consumers
		Aggregators of non-direct DER producers	Non-direct DER producers
10	Payment for electricity	Aggregators of non-direct DER producers	Non-direct DER producers
11	Ancillary services for TSO[34]	Balancing market operator	Direct active consumers-Distribution
		Balancing market operator	Direct active consumers-Transmission
		Balancing market operator	Aggregators of non-direct active consumers
		Balancing market operator	Central producers
		Balancing market operator	Direct DER producers
		Balancing market operator	Aggregators of non-direct DER producers
		TSO	Balancing market operator
12	HV grid access	DSO	TSO
13	Obligations	DSO	Rest of the system
14	System access_ DSO part	TSO	DSO

Table 11.2: Information on exchanges performed in CS A

[34] The term ancillary services includes the balancing and the real-time congestion management.

WHO \ TO WHOM	Non-direct passive consumers	Direct passive consumers	Non-direct active consumers	Direct active consumers-Dist.	Direct active consumers-Trans.	Retailers of Non-direct passive consumers	Aggregators of Non-direct active consumers	Central producers	Direct DER producers	Non-direct DER producers	Aggregator of non-direct DER producers	Wholesale market operator	Local Market Operator	Balancing market operator	BRP: Direct passive consumers	BRP: Retailers of non-direct passive consumers	BRP: Direct active consumers-Dist.	BRP: Direct active consumers-Trans.	BRP: Aggregators of non-direct active consumers	BRP: Central producers	BRP: Direct DER producers	BRP: Aggregators of non-direct DER producers	DSO	TSO	Rest of the system
Non-direct passive consumers						1 2																			
Direct passive consumers												3 4			8								6 7	5	
Non-direct active consumers							1 2																		
Direct active consumers-Dist.												3 4					8						6 7	5	
Direct active consumers-Trans.												3 4						8					6 7	5	
Retailers of Non-direct passive consumers												3 4				8							6 7	5	
Aggregators of Non-direct active consumers			9 9									3 4							8				6 7	5	
Central producers												3								8			7	5	
Direct DER producers												3									8		7	5	
Non-direct DER producers											3 5 7														
Aggregator of non-direct DER producers										9 9 10		3										8	7	5	
Wholesale market operator								4	4		4														
Local Market Operator				11 15			11 15		11 15		11 15														
Balancing market operator					11			11					11												
BRP: Direct passive consumers																								8	
BRP: Retailers of non-direct passive consumers																								8	
BRP: Direct active consumers-Distribution																								8	
BRP: Direct active consumers-Transmission																								8	
BRP: Aggregators of non-direct active consumers																								8	
BRP: Central producers																								8	
BRP: Direct DER producers																								8	
BRP: Aggregators of non-direct DER producers																								8	
DSO													15											12	13
TSO														11									14		

Table 11.3: Exchanges performed in CS B

No.	What	Who	To whom
1	Retail electricity	Non-direct passive consumers	Retailers of non-direct passive consumers
		Non-direct active consumers	Aggregators of non-direct active consumers
2	Power connection	Non-direct passive consumers	Retailers of non-direct passive consumers
		Non-direct active consumers	Aggregators of non-direct active consumers
3	Wholesale market access	Direct passive consumers	Wholesale market operator
		Direct active consumers-Distribution	Wholesale market operator
		Direct active consumers-Transmission	Wholesale market operator
		Retailers of non-direct passive consumers	Wholesale market operator
		Aggregators of non-direct active consumers	Wholesale market operator
		Central producers	Wholesale market operator
		Direct DER producers	Wholesale market operator
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	Wholesale market operator
4	Wholesale electricity	Direct passive consumers	Wholesale market operator
		Direct active consumers-Distribution	Wholesale market operator
		Direct active consumers-Transmission	Wholesale market operator
		Retailers of non-direct passive consumers	Wholesale market operator
		Aggregators of non-direct active consumers	Wholesale market operator
		Wholesale market operator	Central producers
		Wholesale market operator	Direct DER producers
		Wholesale market operator	Aggregators of non-direct DER producers
5	System access	Direct passive consumers	TSO
		Direct active consumers-Distribution	TSO
		Direct active consumers-Transmission	TSO
		Retailers of non-direct passive consumers	TSO
		Aggregators of non-direct active consumers	TSO
		Central producers	TSO
		Direct DER producers	TSO
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	TSO
6	Grid Access Power term	Direct passive consumers	DSO
		Direct active consumers-Distribution	DSO
		Direct active consumers-Transmission	DSO
		Retailers of non-direct passive consumers	DSO
		Aggregators of non-direct active consumers	DSO
7	Grid Access Energy term	Direct passive consumers	DSO
		Direct active consumers-Distribution	DSO
		Direct active consumers-Transmission	DSO
		Retailers of non-direct passive consumers	DSO
		Aggregators of non-direct active consumers	DSO
		Central producers	DSO
		Direct DER producers	DSO
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	DSO
8	Imbalances	Direct passive consumers	BRP: Direct passive consumers
		Direct active consumers-Distribution	BRP: Direct active consumers-Distribution
		Direct active consumers-Transmission	BRP: Direct active consumers-Transmission
		Retailers of non-direct passive consumers	BRP: Retailers of non-direct passive consumers

No.	What	Who	To whom
		Aggregators of non-direct active consumers	BRP: Aggregators of non-direct active consumers
		Central producers	BRP: Central producers
		Direct DER producers	BRP: Direct DER producers
		Aggregators of non-direct DER producers	BRP: Aggregators of non-direct DER producers
		BRP: Direct passive consumers	TSO
		BRP: Retailers of non-direct passive consumers	TSO
		BRP: Direct active consumers-Distribution	TSO
		BRP: Direct active consumers-Transmission	TSO
		BRP: Aggregators of non-direct active consumers	TSO
		BRP: Central producers	TSO
		BRP: Direct DER producers	TSO
		BRP: Aggregators of non-direct DER producers	TSO
9	Flexibility	Aggregators of non-direct active consumers	Non-direct active consumers
		Aggregators of non-direct active consumers	Non-direct active consumers
		Aggregators of non-direct DER producers	Non-direct DER producers
		Aggregators of non-direct DER producers	Non-direct DER producers
10	Payment for electricity	Aggregators of non-direct DER producers	Non-direct DER producers
11	Ancillary services for TSO[35]	TSO	Balancing market operator
		Local market operator	Direct active consumers-Distribution
		Local market operator	Aggregators of non-direct active consumers
		Local market operator	Direct DER producers
		Local market operator	Aggregators of non-direct DER producers
		Balancing market operator	Central producers
		Balancing market operator	Direct active consumers-Transmission
		Balancing market operator	Local market operator
12	HV grid access	DSO	TSO
13	Obligations	DSO	Rest of the system
14	System access_ DSO part	TSO	DSO
15	Congestion management for DSO	DSO	Local market operator
		Local market operator	Direct active consumers-Distribution
		Local market operator	Aggregators of non-direct active consumers
		Local market operator	Direct DER producers
		Local market operator	Aggregators of non-direct DER producers

Table 11.4: Information on exchanges performed in CS B

[35] The term ancillary services includes the balancing and the real-time congestion management.

WHO \ TO WHOM	Non-direct passive consumers	Direct passive consumers	Non-direct active consumers	Direct active consumers-Dist.	Direct active consumers-Trans.	Retailers of Non-direct passive consumers	Aggregators of Non-direct active consumers	Central producers	Direct DER producers	Non-direct DER producers	Aggregator of non-direct DER producers	Wholesale market operator	Local Market Operator	Balancing market operator	BRP: Direct passive consumers	BRP: Retailers of non-direct passive consumers	BRP: Direct active consumers-Dist.	BRP: Direct active consumers-Trans.	BRP: Aggregators of non-direct active consumers	BRP: Central producers	BRP: Direct DER producers	BRP: Aggregators of non-direct DER producers	DSO	TSO	Rest of the system
Non-direct passive consumers						1 2																			
Direct passive consumers												3 4			16								6 7	5	
Non-direct active consumers							1 2																		
Direct active consumers-Dist.												3 4					17						6 7	5	
Direct active consumers-Trans..												3 4						16					6 7	5	
Retailers of Non-direct passive consumers												3 4				17							6 7	5	
Aggregators of Non-direct active consumers			9									3 4							17				6 7	5	
Central producers												3								16			7	5	
Direct DER producers												3									17		7	5	
Non-direct DER producers											3 5 7														
Aggregator of non-direct DER producers										9 10		3										17	7	5	
Wholesale market operator								4	4		4														
Local Market Operator				18			18		18		18														
Balancing market operator					11			11																	
BRP: Direct passive consumers																								16	
BRP: Retailers of non-direct passive consumers																							17		
BRP: Direct active consumers-Dist.																							17		
BRP: Direct active consumers-Trans.																								16	
BRP: Aggregators of non-direct active consumers																							17		
BRP: Central producers																								16	
BRP: Direct DER producers																							17		
BRP: Aggregators of non-direct DER producers																							17		
DSO													18											12	13
TSO														11									14		

Table 11.5: Exchanges performed in CS C

No.	What	Who	To whom
1	Retail electricity	Non-direct passive consumers	Retailers of non-direct passive consumers
		Non-direct active consumers	Aggregators of non-direct active consumers
2	Power connection	Non-direct passive consumers	Retailers of non-direct passive consumers
		Non-direct active consumers	Aggregators of non-direct active consumers
3	Wholesale market access	Direct passive consumers	Wholesale market operator
		Direct active consumers-Distribution	Wholesale market operator
		Direct active consumers-Transmission	Wholesale market operator
		Retailers of non-direct passive consumers	Wholesale market operator
		Aggregators of non-direct active consumers	Wholesale market operator
		Central producers	Wholesale market operator
		Direct DER producers	Wholesale market operator
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	Wholesale market operator
4	Wholesale electricity	Direct passive consumers	Wholesale market operator
		Direct active consumers-Distribution	Wholesale market operator
		Direct active consumers-Transmission	Wholesale market operator
		Retailers of non-direct passive consumers	Wholesale market operator
		Aggregators of non-direct active consumers	Wholesale market operator
		Wholesale market operator	Central producers
		Wholesale market operator	Direct DER producers
		Wholesale market operator	Aggregators of non-direct DER producers
5	System access	Direct passive consumers	TSO
		Direct active consumers-Distribution	TSO
		Direct active consumers-Transmission	TSO
		Retailers of non-direct passive consumers	TSO
		Aggregators of non-direct active consumers	TSO
		Central producers	TSO
		Direct DER producers	TSO
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	TSO
6	Grid Access Power term	Direct passive consumers	DSO
		Direct active consumers-Distribution	DSO
		Direct active consumers-Transmission	DSO
		Retailers of non-direct passive consumers	DSO
		Aggregators of non-direct active consumers	DSO
7	Grid Access Energy term	Direct passive consumers	DSO
		Direct active consumers-Distribution	DSO
		Direct active consumers-Transmission	DSO
		Retailers of non-direct passive consumers	DSO
		Aggregators of non-direct active consumers	DSO
		Central producers	DSO
		Direct DER producers	DSO
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	DSO
9	Flexibility	Aggregators of non-direct active consumers	Non-direct active consumers
		Aggregators of non-direct DER producers	Non-direct DER producers
10	Payment for electricity	Aggregators of non-direct DER producers	Non-direct DER producers

No.	What	Who	To whom
11	Ancillary services for TSO[36]	Balancing market operator	Central producers
		Balancing market operator	Direct active consumers-Transmission
		TSO	Balancing market operator
12	HV grid access	DSO	TSO
13	Obligations	DSO	Rest of the system
14	System access_ DSO part	TSO	DSO
16	Transmission imbalances	Direct passive consumers	BRP: Direct passive consumers
		Direct active consumers-Transmission	BRP: Direct active consumers-Transmission
		Central producers	BRP: Central producers
		BRP: Direct passive consumers	TSO
		BRP: Direct active consumers-Transmission	TSO
		BRP: Central producers	TSO
17	Distribution imbalances	Retailers of non-direct passive consumers	BRP: Retailers of non-direct passive consumers
		Aggregators of non-direct active consumers	BRP: Aggregators of non-direct active consumers
		Aggregators of non-direct DER producers	BRP: Aggregators of non-direct DER producers
		Direct DER producers	BRP: Direct DER producers
		Direct active consumers-Distribution	BRP: Direct active consumers-Distribution
		BRP: Retailers of non-direct passive consumers	DSO
		BRP: Aggregators of non-direct active consumers	DSO
		BRP: Aggregators of non-direct DER producers	DSO
		BRP: Direct DER producers	DSO
		BRP: Direct active consumers-Distribution	DSO
18	Ancillary services for DSO[37]	DSO	Local market operator
		Local market operator	Direct active consumers
		Local market operator	Aggregators of non-direct active consumers
		Local market operator	Direct DER producers
		Local market operator	Aggregators of non-direct DER producers

Table 11.6: Information on exchanges performed in CS C

[36] The term ancillary services for TSO includes the balancing for TSO and the real-time congestion management.
[37] The term ancillary services for DSO includes the balancing for DSO and the congestion management for DSO.

WHO \ TO WHOM	Non-direct passive consumers	Direct passive consumers	Non-direct active consumers	Direct active consumers-Dist.	Direct active consumers-Trans.	Retailers of Non-direct passive consumers	Aggregators of Non-direct active consumers	Central producers	Direct DER producers	Non-direct DER producers	Aggregator of non-direct DER producers	Wholesale market operator	Common Balancing Market Operator	BRP: Direct passive consumers	BRP: Retailers of non-direct passive consumers	BRP: Direct active consumers-Dist.	BRP: Direct active consumers-Trans.	BRP: Aggregators of non-direct active consumers	BRP: Central producers	BRP: Direct DER producers	BRP: Aggregators of non-direct DER producers	DSO	TSO	Rest of the system
Non-direct passive consumers						1 2																		
Direct passive consumers												3 4		8								6 7	5	
Non-direct active consumers							1 2																	
Direct active consumers-Dist.												3 4				8						6 7	5	
Direct active consumers-Trans.												3 4					8					6 7	5	
Retailers of Non-direct passive consumers												3 4			8							6 7	5	
Aggregators of Non-direct active consumers			9									3 4						8				6 7	5	
Central producers												3							8			7	5	
Direct DER producers												3								8		7	5	
Non-direct DER producers											3 5 7													
Aggregator of non-direct DER producers										9 10		3									8	7	5	
Wholesale market operator								4	4		4													
Common Balancing Market Operator				19	19		19	19	19		19													
BRP: Direct passive consumers																							8	
BRP: Retailers of non-direct passive consumers																							8	
BRP: Direct active consumers-Dist.																							8	
BRP: Direct active consumers-Trans.																							8	
BRP: Aggregators of non-direct active consumers																							8	
BRP: Central producers																							8	
BRP: Direct DER producers																							8	
BRP: Aggregators of non-direct DER producers																							8	
DSO													15										12	13
TSO													11									14		

Table 11.7: Exchanges performed in CS D

No.	What	Who	To whom
1	Retail electricity	Non-direct passive consumers	Retailers of non-direct passive consumers
		Non-direct active consumers	Aggregators of non-direct active consumers
2	Power connection	Non-direct passive consumers	Retailers of non-direct passive consumers
		Non-direct active consumers	Aggregators of non-direct active consumers
3	Wholesale market access	Direct passive consumers	Wholesale market operator
		Direct active consumers-Distribution	Wholesale market operator
		Direct active consumers-Transmission	Wholesale market operator
		Retailers of non-direct passive consumers	Wholesale market operator
		Aggregators of non-direct active consumers	Wholesale market operator
		Central producers	Wholesale market operator
		Direct DER producers	Wholesale market operator
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	Wholesale market operator
4	Wholesale electricity	Direct passive consumers	Wholesale market operator
		Direct active consumers-Distribution	Wholesale market operator
		Direct active consumers-Transmission	Wholesale market operator
		Retailers of non-direct passive consumers	Wholesale market operator
		Aggregators of non-direct active consumers	Wholesale market operator
		Wholesale market operator	Central producers
		Wholesale market operator	Direct DER producers
		Wholesale market operator	Aggregators of non-direct DER producers
5	System access	Direct passive consumers	TSO
		Direct active consumers-Distribution	TSO
		Direct active consumers-Transmission	TSO
		Retailers of non-direct passive consumers	TSO
		Aggregators of non-direct active consumers	TSO
		Central producers	TSO
		Direct DER producers	TSO
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	TSO
6	Grid Access Power term	Direct passive consumers	DSO
		Direct active consumers-Distribution	DSO
		Direct active consumers-Transmission	DSO
		Retailers of non-direct passive consumers	DSO
		Aggregators of non-direct active consumers	DSO
7	Grid Access Energy term	Direct passive consumers	DSO
		Direct active consumers-Distribution	DSO
		Direct active consumers-Transmission	DSO
		Retailers of non-direct passive consumers	DSO
		Aggregators of non-direct active consumers	DSO
		Central producers	DSO
		Direct DER producers	DSO
		Non-direct DER producers	Aggregators of non-direct DER producers
		Aggregators of non-direct DER producers	DSO
8	Imbalances	Direct passive consumers	BRP: Direct passive consumers
		Direct active consumers-Distribution	BRP: Direct active consumers-Distribution
		Direct active consumers-Transmission	BRP: Direct active consumers-Transmission
		Retailers of non-direct passive consumers	BRP: Retailers of non-direct passive consumers

No.	What	Who	To whom
		Aggregators of non-direct active consumers	BRP: Aggregators of non-direct active consumers
		Central producers	BRP: Central producers
		Direct DER producers	BRP: Direct DER producers
		Aggregators of non-direct DER producers	BRP: Aggregators of non-direct DER producers
		BRP: Direct passive consumers	TSO
		BRP: Retailers of non-direct passive consumers	TSO
		BRP: Direct active consumers-Distribution	TSO
		BRP: Direct active consumers-Transmission	TSO
		BRP: Aggregators of non-direct active consumers	TSO
		BRP: Central producers	TSO
		BRP: Direct DER producers	TSO
		BRP: Aggregators of non-direct DER producers	TSO
9	Flexibility	Aggregators of non-direct active consumers	Non-direct active consumers
		Aggregators of non-direct DER producers	Non-direct DER producers
10	Payment for electricity	Aggregators of non-direct DER producers	Non-direct DER producers
11	Ancillary services for TSO[38]	TSO	Common balancing market operator
12	HV grid access	DSO	TSO
13	Obligations	DSO	Rest of the system
14	System access_ DSO part	TSO	DSO
15	Congestion management for DSO	DSO	Common balancing market operator
19	Ancillary services for TSO & DSO[39]	Common balancing market operator	Direct active consumers-Distribution
		Common balancing market operator	Direct active consumers-Transmission
		Common balancing market operator	Aggregators of non-direct active consumers
		Common balancing market operator	Central producers
		Common balancing market operator	Direct DER producers
		Common balancing market operator	Aggregators of non-direct DER producers

Table 11.8: Information on exchanges performed in CS D

[38] The term ancillary services for TSO includes the balancing for TSO and the real-time congestion management.

[39] The term ancillary services for TSO & DSO includes the real-time congestion management and balancing for TSO and the congestion management for DSO.

11.2 General formulas

Next sub-sections show the formulas to be used in the business-level analysis. As described in the introduction to section 5.3, it was considered that the likely situation in 2030 will be similar in the three countries under analysis (Italy, Denmark[40] and Spain). Therefore, although the current regulatory conditions in Spain were taken as a basis for this section, they are assumed to be applicable to the other two countries as well. In case future conditions are not in line with the formulas described here, enough details are provided so that the reader can adapt the formulas to the specific conditions he/she wants to describe.

As it was previously mentioned, the formulation developed in this step aims to provide an appropriate tool to calculate the numeric results when all the data are available as detailed as required by these formulas.

The formulas included in this section are applicable in all coordination schemes. Specific issues regarding each coordination scheme are detailed in section 11.3.

Since several subscripts are used, Table 11.9 summarizes all of them.

Letter	Description
a=1, . . . A	Number of active consumers
b=1, . . . B	Number of actors buying in the wholesale market
d=1, . . . D	Number of Non-direct DER Producers having a contract with the same aggregator
i=1, . . . n	Number of periods of a ToU tariff
j=1, . . . J	Number of actors selling in the wholesale market
m	Month
p=1, . . . P	Number of flexibility services providers in the balancing market/local market
q=1, . . . Q	Number of parties creating imbalances in the system
r=1, . . . R	Number of Non-direct DER Producers
t=1, . . . T	Number of periods in a whole year
y	Annual value

Table 11.9: Subscript meaning

[40] The only significant difference detected is the payment for market access, based on a fixed subscription rate in Denmark.

11.2.1 Retail electricity

The income that a retailer obtains for the electricity sale depends on two concepts:

- Power connection[41]: Each consumer pays a fixed tariff per kW and year. Considering the general case of a n-period ToU tariff, the contracted power and the power term price per period that can be different, the payment for the contracted power on an annual basis (subscript y) is calculated as:

$$Power\ connection_y(€) = \sum_{i=1}^{n} Contracted\ Power_i\ (kW) * Period\ Tariff_i\ (€/kW) \tag{12}$$

- Electricity: The retail price of that electricity (which can be different in different hours of the day) and the energy demanded by the customers will determine the earnings for the retailer.

$$Retail\ electricity_y\ (€) = \sum_{t=1}^{T} Final\ electricity\ demand_t\ (kWh) * Retail\ Price_t\ (€/kWh) \tag{13}$$

In this case, consumers pay for both concepts to their retailers and the active consumers acquire the electricity through an aggregator. The tariffs to be applied will depend on the specific arrangements agreed between the parties.

11.2.2 Wholesale electricity

Regarding the electricity acquisition, it is assumed that electricity is bought by the retailers, aggregators, direct passive consumers and direct active consumers through the day-ahead market. The payment received by the wholesale market operator for the electricity is transferred to the central producers, direct DER producers and aggregators of non-direct DER producers depending on the energy traded and the price agreed as a result of the day-ahead market clearing. Therefore, the total cost for the buyers of the wholesale electricity depends on the day-ahead market price and on the energy traded (based on the expected demand). So, the annual payment from each actor *b* buying in the wholesale market is:

$$\begin{aligned} &Payment\ for\ wholesale\ electricity_{y,b}\ (€) \\ &= \sum_{t=1}^{T} Electricity\ traded_{t,b}\ (MWh) * Day\ ahead\ market\ price_t\ (€/MWh) \end{aligned} \tag{14}$$

[41] The contracted power term is a money flow because somebody is willing to pay for this power connection and there is a recurrent payment linked to it.

As indicated above, this payment received by the wholesale market operator will be transferred to the electricity sellers depending on the energy traded in the market by each of them, in such a way that the payment from the wholesale market operator to each actor *j* selling in the wholesales market is:

$$Payment\ for\ wholesale\ electricity_{y,j}\ (€) = \sum_{t=1}^{T} Electricity\ traded_{t,j}\ (MWh) * Day\ ahead\ market\ price_t\ (€/MWh) \quad (15)$$

In the case of aggregators of non-direct DER producers, the aggregators transfer the payment received for the wholesale electricity to the *d* non-direct DER producers, with which they have a contract, according to the energy traded for each of them and the prices agreed between the parties. As a general case, it was considered that the agreed price (electricity price) could be different to the day-ahead market price, so, for each specific aggregator the following formula would be applicable:

$$Payment\ for\ electricity_y (€) = \sum_{d=1}^{D}\sum_{t=1}^{T} Electricity\ traded_{t,d}\ (MWh) * Electricity\ price_t\ (€/MWh) \quad (16)$$

11.2.3Market access

All participants in the wholesale electricity market must contribute to the Market Operator's retribution. The price is regulated.

In the case of central producers, direct DER producers and non-direct DER producers (through their aggregators) the payment is based on the available power of each installation and it is calculated on a monthly basis. The availability term for each technology and the price are set by the NRA.

$$Market\ access\ Producers_y\ (€) = \sum_{m=1}^{12} Installed\ power\ (MW) * Availability\ term\ (\%) * Market\ access\ fee_m\ (€/MW\ per\ month) \quad (17)$$

Direct consumers, retailers and aggregators, as retailers of active consumers, have to pay a market access fee for buying electricity in the market. The amount to be paid depends on the energy traded for each hour. The price is set by the NRA for each MWh traded in the market.

$$Market\ access\ Buyers_y\ (€) = \sum_{t=1}^{T} Electricity\ traded_t\ (MWh) * Market\ access\ fee\ (€/MWh) \quad (18)$$

11.2.4System access

All participants in the electrical system have to contribute to the System Operator's retribution, according to a regulated price set by the NRA.

Specifically, central producers, direct DER producers and non-direct DER producers (through their aggregators) pay depending on the available power of each installation and it is calculated on a monthly basis. The availability term for each technology and the price are set by the NRA.

$$\begin{aligned} System\ access\ Producers_y(€) \\ = \sum_{m=1}^{12} Installed\ power\ (MW) * Availability\ term\ (\%) \\ * System\ access\ fee_m\ (€/MW\ per\ month) \end{aligned} \tag{19}$$

Direct consumers, retailers and aggregators, as retailers of active consumers, also have to pay a system access fee for the finance of the electricity system and the system operator's retribution. In this case, the amount to be paid by these buyers of electricity is based on the traded amount in the wholesale market. The price is set by the NRA for each MWh traded.

$$\begin{aligned} System\ access\ Buyers_y\ (€) \\ = \sum_{t=1}^{T} Electricity\ traded_t\ (MWh) * System\ access\ fee\ (€/MWh) \end{aligned} \tag{20}$$

Although this is not the current real situation in Spain, in the graphical models it has been considered that the system access fees collected by the TSO could be shared with the DSO (*System access DSO part)*:

$$\begin{aligned} System\ access\ DSO\ part_y\ (€) \\ = \left(System\ access\ Producers_y(€) + System\ access\ Buyers_y\ (€)\right) \\ * \%\ DSO\ part \end{aligned} \tag{21}$$

11.2.5Grid access

In general, in the EU Member States, the electricity supply is made up of the cost of electricity generation, the cost of electricity transmission and distribution, other costs of the electricity system and taxes.

The grid access is regulated by the NRA, who fixes the prices for T&D fees. For the different types of consumers this fee was assumed to include a power term and an energy term:

- Grid access_power term: For a n-period ToU tariff the total annual cost must be calculated multiplying the price of each period i in €/kW/year (T&D PowerTerm Price) by the contracted power[42] in kW.

$$Grid\ access\ Power\ Term_y(€) = \sum_{i=1}^{n} Contracted\ Power_i\ (kW) * T\&D\_PT\ Price_i\ (€/kW) \quad (22)$$

- Grid access_energy term: The cost depends on the price of that fee, which can be a ToU tariff (T&D_EnergyTerm Price), and on the energy demanded.

$$Grid\ access\ Energy\ Term_y(€) = \sum_{t=1}^{T}\sum_{i=1}^{n} Final\ electricity\ demand_{i,t}\ (kWh) * T\&D\_ET\ Price_{i,t}\ (€/kWh) \quad (23)$$

Equation (22) and (23) will be applicable to; i) direct passive consumers, ii) direct active consumers, iii) retailers of non-direct passive consumers and iv) aggregators of non-direct active consumers. Although in some countries the consumer may receive different bills from the retailer and from the DSO, in most of the cases, when the electricity is acquired through a retailer, the retailer sells electricity to consumers and pays for T&D fees to the DSO.

Likewise, central producers, direct DER producers and non-direct DER producers, through their aggregators, must pay the grid access. It was assumed that they must pay for each MWh fed into the grid[43], according to a price set by the NRA.

$$Grid\ access\ producers_y\ (€) = \sum_{t=1}^{T} Real\ electricity\ generation_t\ (MWh) * T\&D\ Producers\ fee\ (€/MWh) \quad (24)$$

The money obtained through T&D fees is used to pay for transmission, distribution, and other costs, which may include the retribution for the NRA, subsidies for renewables, etc. Therefore, the T&D fees collected by the DSO must be shared among several parties. As an example, the whole amount of T&D fees collected in Spain in 2017 was distributed as indicated below [44]:

- DSO part (DSO_{part}): 30.37% of the T&D fees collected during 2016 were paid to DSOs.
- TSO part (TSO_{part}): 10.03% were paid to the TSO. This transference is indicated as H*igh voltage grid access* in the graphical models.
- Other electric regulated actors part ($Others_{part}$): The rest of the T&D fees, 59.60%, is shared among other regulated actors. This concept is indicated as Obligations in the graphical models.

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[42] In Spain the tariffs type 3.1 (3 periods) and type 6 (6 periods) allow contracting different power for each period. These tariffs are for connection voltages > 1 kV.

[43] Real generation. This includes the expected losses, although it will be the retailers who must cope with the expected losses along the system.

Therefore, from the whole amount transferred to the DSO (equation (22) + (23) + (24)) for the payment of T&D fees, the DSO should keep its corresponding part (equation (25)) and transfer the remaining quantity to the TSO for the HV grid access (equation (26)) and to the rest of the system for the payment of the obligations (equation (27)):

$$\begin{aligned} &T\&D\ fees\ DSO\ part_y \\ &\quad = \big(Gris\ access\_PowerTerm_y\ (€) + Grid\ access\_EnergyTerm_y (€) \\ &\quad + Grid\ access\_Producers_y\ (€)\big) * DSO_{part} (\%) \end{aligned} \tag{25}$$

$$\begin{aligned} &High\ Voltage\ grid\ access_y \\ &\quad = \big(Gris\ access\_PowerTerm_y\ (€) + Grid\ access\_EnergyTerm_y (€) \\ &\quad + Grid\ access\_Producers_y (€)\big) * TSO_{part} (\%) \end{aligned} \tag{26}$$

$$\begin{aligned} Obligations_y\ &= \big(Gris\ access\_PowerTerm_y\ (€) + Grid\ access\_EnergyTerm_y (€) \\ &+ Grid\ access\_Producers_y (€)\big) * Others_{part} (\%) \end{aligned} \tag{27}$$

This part transferred to the other regulated actors, equation (27), will have to be shared among them according to the criteria fixed by the NRA.

11.2.6Balancing

Electricity balancing is one of the key roles of the TSO, who needs to act in order to ensure that the generation coming from producers is equal to the energy demanded by consumers in real time.

In general, the TSO can open the balancing market to manage the arisen balancing necessities coming both from production (central producers, direct DER producers, aggregators of non-direct DER producers) or consumption side (direct passive consumers, direct active consumers, retailers of non-direct passive consumers, aggregators of non-direct active consumers). So, the amount of energy to be balanced by the TSO through the balancing market will be:

$$\begin{aligned} Balancing\ energy_{y,TSO} (MWh) &= \sum_{t=1}^{T} Balancing_{t,TSO}\ (MWh) \\ &= \sum_{t=1}^{T} (Imbalances\ Production_t\ (MWh) \\ &+ Imbalances\ Consumption_t\ (MWh)) \end{aligned} \tag{28}$$

Additionally, the TSO needs to solve the real-time congestions. The addition of the balancing for TSO and real-time congestion management is named *ancillary services* in Figure 5.2. Therefore, the payment

from the TSO for these ancillary services will be the multiplication of the amount of energy by the *SmartNet balancing price.*

The definition of this price is detailed in the SmartNet deliverable D2.2 [2]. As a summary, the inputs to the clearing and pricing algorithm are the forecasted injection at the different nodes of the network prior the activation decisions, the available flexibility bids and the transmission and distribution network models. Then the market optimization decides which bids are activated. The market associates a specific price for upward and downward flexibility for each node at transmission or distribution level, using the approach of distribution locational marginal pricing (DLMP). For more information see section 2.3 and 5.4 of Deliverable D2.2 [2] :

$$Payment\ for\ ancillary\ services_{y,TSO}(€) = \sum_{t=1}^{T}(Balancing_{t,TSO} + RTCM_{t,TSO})\,(MWh) + * SmartNet\ balancing\ price_t\ (€/MWh) \quad (29)$$

The balancing market operator clears the market[44] and, as result, the balancing necessities are allocated between the participants in the balancing market; i) central producers, ii) direct DER producers, iii) aggregators of non-direct DER producers, iv) direct active consumers-distribution, v) direct active consumers-transmission and vi) aggregators of non-direct active consumers, depending on the price offered by each of them. The sign convention used here is in line with D2.1 [37] and with the agreements reached in the project to create the future European mFRR platform [45]: balancing providers should bid a positive price for upward balancing when they want to be remunerated for an increase in their generation output (or a decrease in their consumption) and a positive price for downward balancing when they would be willing to pay to be able to reduce their output (or increase consumption). If they are willing to pay to increase output (or reduce consumption) or if they want to be remunerated to reduce output (or increase consumption), they should bid a negative price instead.

So, the payment made by the TSO for ancillary services to the balancing market operator is shared between the P flexibility services providers mentioned above, in such a way that each provider p will be remunerated based on the energy provided and the balancing price:

$$Payment\ for\ ancillary\ services_{y,TSO}(€) = \sum_{p=1}^{P}\sum_{t=1}^{T}(Balancing\ energy_{t,p}\ (MWh) * SmartNet\ balancing\ price_t\ (€/MWh) \quad (30)$$

[44] The market clearing algorithm aims not only to procure balancing, but also to avoid congestions in real-time.

According to this formula, the amount to be paid by the balancing market operator is positive when the provision is upward balancing (positive balancing energy), and it is negative if the provision is downward balancing (negative balancing energy) and, hence, the providers must pay for it to the balancing market operator. This is not a penalty, but a sign agreement. When a bid submitted by a producer is matched in the day-ahead market, the producer receives the day ahead market price for the traded energy. After that, in the balancing market, the producer can submit a bid for downward energy. If that bid is matched the producer will pay to the balancing market at a price that is lower than the day-ahead market price. So, the benefit comes from (Day-ahead market price-Downward energy price) * Energy traded in the balancing market.

From equation (30) the payment that each provider receives for the provision of ancillary services can be drawn.

It was assumed that the imbalance price is calculated in such a way that the TSO does not earn or lose money for doing the balancing, so, the price to be paid or received will depend on the total imbalance of the system. The imbalance price is calculated based on the balancing energy, and its associated price, used in each time step to cope with the imbalances. For the calculation of the imbalance price, the total balancing cost is shared among the parties creating the imbalances according to their share in the creation of the total imbalance.

The ancillary services cost in each time step is allocated among the q parties which created the imbalances in the system in that specific time, so:

$$\begin{aligned} &Payment\ for\ ancillary\ services_{y,TSO}(€) \\ &= \sum_{q=1}^{Q}\sum_{t=1}^{T} Imbalance\ energy_{t,q}\,(MWh) * Imbalance\ price_{t}\,(€/MWh) \end{aligned} \tag{31}$$

Again, the funds can flow in both directions: if the imbalance is negative (more electricity consumption/less electricity generation than expected, so, there is a necessity of increase the production), balancing will be positive (upward balancing energy is required) and, thus, the money will flow from the party causing the imbalance to the TSO, through the corresponding BRPs, and then from TSO to the balancing market operator. On the contrary, if the imbalance is positive (lower electricity consumption/more electricity generation than expected, so, there is a necessity of decrease the production), balancing will be negative (downward balancing energy is required) and the money will flow on the contrary way, i.e. from the balancing market operator to the TSO and from the TSO to the party causing the imbalance, through the corresponding BRPs. Every time step, the imbalance price to be applied will be based on the sign of the whole system imbalance, in order to disincentive the aggravation of the system imbalance:

- When the imbalance has the same sign as the whole system imbalance, the imbalance is aggravating the whole system imbalance. Therefore, the imbalance price to be applied will be

related to the average price of the balancing energy activated at that time-step, including all balancing means (i. e. SmartNet balancing and aFRR).

- On the contrary, when an imbalance is in the opposite direction to the system imbalance, that imbalance is softening the whole system imbalance and it will be economically valued at the day-ahead market price.

In summary, a dual-price system for imbalances was considered: the one who generates more (or consumes less) is remunerated for such excess, but the price is not higher than the day-ahead price: the BRP who involuntarily reduces system imbalance (because the system is short) receives the day-ahead price and the BRP who increases system imbalance (because it is long) receives a price which is lower. On the contrary, the BRP who produces less (or consumes more) must pay for the difference: if it involuntarily reduces system imbalance (because the system is long), it pays day-ahead price, but if it increases system imbalance (because the system is short), the BRP pays a price which is higher than day-ahead price

In summary, each time step equation (32) must be fulfilled:

$$\begin{aligned} &Ancillary\ services\ cost_t(€) \\ &\quad = Imbalance\ reducer_t(MWh) * Dayaheadprice_t(€/MWh) \\ &\quad + Imbalance\ creator_t(MWh) * Imbalance\ price_t(€/MWh) \end{aligned} \tag{32}$$

It has been considered that the management of the energy imbalances is performed by external parties, so, a separate role of BRP has been graphically represented for each actor creating imbalances. The BRP only manages the imbalances appearing within the balancing group it is responsible for. The payment for imbalances will be made through these entities and, depending on the contractual agreement between both parties, the penalties might be transferred to the party causing the imbalance.

Finally, the aggregators acquire the flexibility from both the non-direct active consumers and the non-direct DER producers for the submission of bids in the balancing market. The flexibility acquisition in each time step will follow equation (33) in which the subscript r indicates the different types of existing non-direct DER producers and the subscript a indicates the different types of non-direct active consumers.

$$Aggregated\ flexibility_t\ (MWh) = \sum_{r=1}^{R} Flexibility_{t,r}\ (MWh) + \sum_{a=1}^{A} Flexibility_{t,a}\ (MWh) \tag{33}$$

The total aggregated flexibility for a whole year will be the sum of equation (33) for the T periods.

$$Aggregated\ flexibility_y\ (MWh) = \sum_{t=1}^{T} Aggregated\ flexibility_t(MWh) \tag{34}$$

The payments for this flexibility will depend on the particular agreements between the parties. For example, the aggregation service could be remunerated by means of the payment of an annual subscription fee, agreed between the involved parties, in such a manner that the remuneration for the aggregator is:

$$Aggregation\ service_y(€) = Subscription\ fee_y(€) \tag{35}$$

Likewise, the BRP's remuneration could be based on annual subscription fees paid by its customers.

11.3 CS-Specific formulas

In addition to the general formulas described in the previous section and which apply to all CSs, each CS has specific formulas, which are described in next subsections.

11.3.1 Coordination scheme B

In this case, the DSO opens the local market in order to solve its own congestions and it will pay for this service to the local market operator:

$$\begin{aligned} &Payment\ for\ Congestion\ Management_y\ (€) \\ &= \sum_{t=1}^{T} Congestion\ management_t\ (MWh) \\ &* Congestion\ management\ price_t\ (€/MWh) \end{aligned} \tag{36}$$

The local market operator allocates this necessity between the available flexibility providers at distribution level:

i) direct DER producers,
ii) aggregators of non-direct DER producers,
iii) direct active consumers-distribution and
iv) aggregators of non-direct active consumers.

Each provider will be remunerated according to the energy traded and the congestion management price and, in the case of the aggregators, they will have to, in turn, acquire flexibility from the active consumers and the DER producers.

Once the local market has solved the congestions coming from the DSO, the non-used flexibility bids in this local market will compete against the bids by central producers and active consumers-transmission to satisfy the balancing and the real-time congestions necessities (named *ancillary services* in Figure 5.4)

transferred from the TSO[45] to the balancing market. So, in this case, the payment for ancillary services from the TSO to the balancing market will be shared between the P providers (central producers, the active consumers-transmission and the local market operator), who, in turn, will distribute the payment among its providers at distribution level, so:

$$Payment\ for\ ancillary\ services_y^{TSO}\ (€) = \sum_{p=1}^{P}\sum_{t=1}^{T} Balancing\ energy_t\ (MWh) * SmartNet\ balancing\ price_t\ (€/MWh) \quad (37)$$

The main characteristics of the SmartNet price calculation are briefly explained in section 11.2.6.

Likewise, the payment from the balancing market operator to the local market operator will be shared among the providers through this local market, which are, once again the four flexibility providers listed above. Each provider will be remunerated according to the energy traded and the SmartNet balancing price and, in the case of the aggregators, they will have to, in turn, acquire flexibility from the active consumers and the DER producers.

In this coordination scheme, the payment for the flexibility received by the non-direct active consumers and the non-direct DER producers will be the sum of the corresponding part from the provision of congestion management (CM in equation (38)) and the provision of ancillary services for the TSO.

$$Remuneration\ for\ flexibility_y (€) = \sum_{t=1}^{T} (Payment\ forflexibility\ for\ CM_t + Payment\ for\ flexibility\ for\ ancillary\ services_t)\ (€) \quad (38)$$

Next, it should be agreed how each flexibility provider will be remunerated. Several approaches can be considered; discounts in the electricity bill for consumers, €/kWh for every pattern modification, etc.

11.3.2Coordination scheme C

In this coordination scheme, the TSO partially transfers the balancing responsibility to the DSO in such a way that there is a local market managed by the DSO for resources connected to the distribution grid and a balancing market managed by the TSO for resources connected to the transmission grid.

The DSO has to manage the imbalances caused at distribution level by the different actors connected to the distribution grid (retailers of non-direct passive consumers, aggregators of non-direct active

[45] The market clearing algorithm aims not only to procure balancing, but also to avoid congestions in real-time.

consumers, direct active consumers-distribution, direct DER producers and aggregators of non-direct DER producers). Additionally, the DSO uses the local market for its own necessity of congestion management. The addition of the balancing for DSO and the congestion management by the DSO is named *ancillary services* in Figure 5.6. As in the case of TSO, it is considered that the DSO does not earn or lose any money for doing the balancing, so, the price to be paid or received will depend on the total imbalance of the system. So, the corresponding payment from the DSO to the local market operator for the provision of these services (congestion management and balancing for DSO) is:

$$Payment\ for\ ancillary\ services_{y,DSO}\ (€) = \sum_{t=1}^{T} (Balancing\ for\ DSO_t + Congestion\ management_t)(MWh) * SmartNet\ balancing\ price_t\ (€/MWh) \quad (39)$$

The main characteristics of the SmartNet price calculation are briefly explained in section 11.2.6.

The local market allocates this payment among the available flexibility providers at distribution level[46]. Each provider will be remunerated according to the energy traded and the resulting price from the clearing process for the congestion management and balancing for DSO. In the case of the aggregators, they acquire, in turn, flexibility from active consumers and the DER producers.

On the other hand, the TSO solves the congestions arisen in real time and the imbalances caused at transmission level (named *ancillary services* in Figure 5.6) by central producers, direct passive consumers and direct active consumers-transmission through the balancing market[47], in which only the central producers and the active consumers-transmission can submit bids. So, the payment from the TSO for the ancillary services will be shared between the P providers participating in the balancing market based on the energy traded and the balancing clearing price.

$$Payment\ for\ ancillary\ services_{y,TSO}\ (€) = \sum_{t=1}^{T} (Balancing\ for\ TSO_t + RTCM_t)(MWh) * SmartNet\ balancing\ price_t\ (€/MWh) \quad (40)$$

11.3.3 Coordination scheme D

This coordination scheme promotes a common flexibility market for DSOs and TSO, with resources connected to transmission and distribution level. The TSO and the DSO are both responsible for the organization and operation of the market. The DSO attends the common balancing market to solve its

[46] Direct DER producers, Aggregators of non-direct DER producers, Direct active consumers-distribution and Aggregators of non-direct active consumers.

[47] The market clearing algorithm aims not only to procure balancing, but also to avoid congestions in real-time.

own congestions and the TSO to balance the transmission network and to solve the real-time congestions (named ancillary services in Figure 5.8).

The equations in section 11.2.6 are applicable to all coordination schemes and, for that reason, they are included within the G*eneral formulas* section. However, in the case of the CS D, a specific formula needs to be reformulated in order to take into account specific issues regarding only to the common balancing market deployed in this CS. Specifically, when calculating the results for CS D, equation (29) should be replaced by equation (41).

$$\sum_{t=1}^{T} Payment\ for\ ancillary\ services_{t,TSO}\ (€) + \sum_{t=1}^{T} Payment\ for\ congestion\ management_{t,DSO} (€) = \sum_{t=1}^{T} (Balancing\ for\ TSO_t + RTCM_t + Congestion\ management\ for\ DSO_t)\ (MWh) * SmartNet\ balancing\ price_t\ (€/MWh) \tag{41}$$

Therefore, the payment from DSO for the congestion management and from TSO for balancing its network is allocated between the providers of the service, which may be either connected at transmission (central producers and direct active consumers-transmission) or at distribution level (direct DER producers, aggregators of non-direct DER producers, direct active consumers-distribution and aggregators of non-direct active consumers). Each provider will be remunerated according to the energy traded and the resulting price from the clearing process for the congestion management for DSO and balancing for TSO. In the case of the aggregators, they acquire, in turn, flexibility from the active consumers and the DER producers.