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

Ancillary service provision by RES and DSM connected at distribution level in the future power system

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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).

Partners

Table of Contents

List of Abbreviations and Acronyms

Acronym	Meaning
aFRR	Automatic – Frequency Restoration Reserve
ACER	Agency for Cooperation of Energy Regulators
AVR	Automatic Voltage Regulator
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CBI	Cross-border interconnection
CCS	Carbon Capture and Storage
CE	Continental Europe
CHP	Combined Heat and Power
CO_2	Carbon dioxide
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
DSM	Demand-Side Management
DSO	Distribution System Operator
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EV	Electric Vehicle
FACTS	Flexible Alternating Current Transmission System
FCR	Frequency Containment Reserve
FCR-D	Frequency Containment Reserve – Disturbance
FCR-N	Frequency Containment Reserve – Normal operation
FRP	Frequency Restoration Process
FRCE	Frequency Restoration Control Error
FRR	Frequency Restoration Reserve
FRT	Fault Ride Through
GHG	Greenhouse gases
HV	High Voltage
HVDC	High Voltage Direct Current
ICT	Information and Communication Technology
IGCC	International Grid Control Cooperation
IIASA	International Institute for Applied Systems Analyses
IPTS	Institute for Prospective Technologies Studies
JRC	Joint Research Centre

LFC	Load Frequency Control
LFCR	Load Frequency Control & Reserves
LOLP	Loss-of-load Probability
LV	Low Voltage
mFRR	Manual – Frequency Restoration Reserve
MB	Balancing Market in Italy
MI	Intraday Market in Italy
MIT	Massachusetts Institute of Technology
MSD	Dispatching Services Market in Italy
MV	Medium Voltage
NE	Northern Europe
PDBF	Daily Base Operating Schedule in Spain
PDD	Probability Density Distributions
PSS	Power System Stabiliser
PUN	System-wide single price in Italy
PV	Photovoltaic
RES	Renewable Energy Source
ROCOF	Rate Of Change Of Frequency
RMS	Root Mean Square
RR	Replacement Reserve
R&D	Research & Development
SDR	Strategic Demand Response
SGR	Strategic Generation Reserve
StatCom	Static Compensator
TSO	Transmission System Operator
T&D	Transmission & Distribution
UC	Use Case
UCTE	Union for the Coordination of the Transmission of Electricity
V2G	Vehicle to grid

Executive Summary

An ancillary service is a service necessary for the operation of a transmission or distribution system. The ancillary services are required in the system to keep the security and guarantee the power supply with high quality standards. They are needed in normal operating conditions, but also during disturbances, and have been traditionally provided by big generation units connected at transmission level. However, by 2030, which is the reference year for SmartNet project, a big part of the generation is expected to be displaced from transmission to distribution, renewable energy sources (RES) are expected to play an important role and new actors, such as aggregators, are expected to appear into the system to compete with traditional providers of ancillary services, by offering flexibility from demand side management (DSM) and other distributed energy resources (DER)[1].

The goal of this deliverable is to provide a view on the need for ancillary services within the future European power system, separated by products. Special attention has been given to the three countries where the SmartNet pilots are going to be deployed: Denmark, Italy and Spain. For that purpose, three main steps can be distinguished, which summarise and group the content of this deliverable:

- *Analysis of current status:* study of the existing products for the provision of ancillary services in Europe and the associated rules for the ancillary services market.
- *Description of the expected changes by 2030:* definition of high-level scenarios which describe the expected evolution of the existing ancillary services and the novel services/functionalities. The countries where the pilots will be implemented are also mapped into these scenarios.
- *Reserves dimensioning:* description of current methodologies for reserves sizing, estimation of needs at a European level and quantification of the future reserve needs.

In the first part of the deliverable, a detailed analysis of the current regulations in the European power systems has been accomplished. It gives a complete overview of the status of diverse ancillary services across Europe, by establishing the comparison about the existing frequency regulation, voltage control and other ancillary services, such as the black start capability or the interruptible load services. As an example, the comparative results from the analysis of existing frequency control services in some European countries are shown in the table below (same table as Table 2.1).

[1] The broader term DER encompasses generation resources, such as distributed generation (DG), storage resources and consumption resources. In this deliverable, the terms demand side management (DSM) and demand response (DR) are used interchangeably to refer to flexibility available from consumption resources.

Country	Frequency control services		
	Primary	Secondary	Tertiary
Austria	FCR	aFRR	mFRR
Belgium	FCR-R1	FRR-R2	R3-Production
			R3-Dynamic profile
			R3 ICH-Interruptible users
Denmark*	FCR (DK1)	aFRR (DK1)	mFRR (DK1 and DK2)
	FCR-N (DK2 normal op.)		
	FCR-D (DK2 disturbance)		
Finland	FCR-N normal operation	aFRR	--
	FCR-D disturbance	mFRR	
Italy	Primary frequency control	Secondary frequency control	Tertiary frequency control
Norway	FCR-N normal operation	aFRR	mFRR
	FCR-D disturbance		
Spain	FCR	FRR	RR

* Denmark is the only country in Europe that belongs to two synchronous areas: the Continental synchronous area and the Nordic synchronous area; different requirements apply in Western Denmark (DK1) and Eastern Denmark (DK2).

Apart from the services themselves, the markets associated to ancillary services have been analysed too, considering the timeframes for the billing/trading processes, the procurement and activation times for the different products, the requirements for providers of the services and the remuneration schemes. The ancillary markets mechanisms have been compared to see that the harmonization of the ancillary services markets around Europe in 2030 is still far away because nowadays, there are important differences concerning the bid sizes to participate in the markets, the provision criteria (sometimes mandatory, sometimes optional) or even different remuneration schema.

In order to estimate the reserves by 2030, it is also necessary to know how the European power system will change by 2030. For this purpose, ad-hoc high-level scenarios have been drafted from the ENTSO-E visions and adapting the e-Highway 2050. Based on them, three key factors related to the ancillary services procurement have been considered: (1) the RES implementation deployment in comparison with the one required for decreasing the CO_2 emissions to the maximum established by the European regulations, (2) DR programmes and (3) interconnections with neighbouring countries. As a result, four feasible high-level scenarios have been selected, and are shown in the following figure (Figure 17 in subsection 3.2.2).

Scenario 1	Scenario 2	Scenario 3	Scenario 4
RES **lower** than required to fulfil 2030 emissions targets	RES **lower** than required to fulfil 2030 emissions targets	RES **equal to or higher** than required to fulfil 2030 emissions targets	RES **equal to or higher** than required to fulfil 2030 emissions targets
Good cross-border interconnections	**Poor** cross-border interconnections	**Good** cross-border interconnections	**Poor** cross-border interconnections

Each of the three countries under study (Denmark, Italy and Spain) was then mapped to these scenarios, based on current and expected future development. This way, three different views of the future have been found, from the most optimistic ones for Denmark (Scenario 3) and Italy (Scenario 4) to the most pessimistic for Spain (Scenario 2). This is useful to identify how the evolution of the ancillary services could be, in order to match these scenarios, not only in terms of possible changes in the existing mechanisms but also considering that new products, services or functionalities could appear in the markets. Both the scenarios and the mapping to the countries under study will be further used along the project, especially for the simulations which will lead to the identification of the most suitable coordination schemes and their cost-benefit analysis.

To assess the changes (in terms of procurement, providers, etc.) that could take place, a wide literature review has been performed. From the information available from the regulatory bodies, system operators and energy consultancies, the new services/functions detected have been grouped into three categories:

A) Ancillary services already implemented, but currently provided only by the conventional generation units. They could be provided, according to the 2030 paradigm, by DER e.g. Frequency Containment Reserve (FCR).

B) Ancillary services which are not yet deployed in the whole Europe or those whose regulatory framework is unclear, such as the compensation of power losses.

C) New functionalities that could be implemented in DER units, in order to make them behave as conventional generation units do, so that they could effectively participate in the provision of ancillary services (e.g. inertia emulation). Other services included in this group are completely new, such as those related to power quality improvement (e.g. damping of power system oscillations, mitigation of flicker, etc.).

From all these innovative ancillary services, the ones which are of real interest in SmartNet have been selected, either because they match with the TSO/DSO interaction schemes that are going to be developed within the project, because they are suitable to be integrated in the existing market schemes or because

their implementation does not imply disruptive changes for the system/market operators that would be unlikely to happen in the short-term horizon.

Eventually, in order to calculate the future reserves' needs, the current forecasts by the system operators, together with the methodologies they applied, have been explored. This knowledge was used as the basis for projecting the evolution of reserves needs in the SmartNet horizon through a Reserves Dimensioning Tool. This tool takes into consideration the system imbalances, as well as the variability of the two main RES installed in Europe (wind and PV) and has been designed to be country-independent. As an example, the application of the tool to Denmark, Italy and Spain is also shown in this deliverable. It must be noted that calculation methods strongly depend on the grid topology, historical data, the generation mix, etc. and, thus, each TSO and DSO must use some coefficients to adjust the theoretical values to their real implementation. It is not the aim of this application to provide exact figures for each TSO/DSO, but rather to provide an example of the application of the tool, together with a rough estimate of the likely reserve needs in the future.

1 Introduction

1.1 Scope of the document

This document aims at identifying the needs for ancillary services[2] in the SmartNet horizon (2030+), considering which innovative services can be provided by the resources connected at distribution level, especially distributed generation (DG) and demand side management (DSM)[3] actions, based on the reserve needs that will be required at that horizon. With that purpose, current market structures for existing ancillary services mechanisms are taken into account from the regulatory, economic and technical perspective, in order to foresee how these markets should evolve to cope with these novel services. For the achievement of these targets, three main subtasks have been carried out:

- Analysis of the state of the art in current regulations for ancillary services provision, as well as the foreseen or required changes that would be necessary in the medium-term horizon (up to 2030) to introduce those new services in the electricity markets.
- Definition of the future scenarios and the relationship between those scenarios and the countries where the pilots are going to operate (Italy, Denmark, Spain). This has been made by the adoption of a proper methodology, based on the one by ENTSO-E, and considering the key factors that impact over SmartNet.
- Development of a dedicated tool for the estimation of needs for ancillary services reserves, as well as its application to the pilot countries.

1.2 Deliverable structure

The document has been divided into different chapters to present the results of the different steps taken to identify the future needs for ancillary services.

Chapter 2 provides a revision of the state of the art in current ancillary services for several European countries (those countries with partners involved in the task) and the comparison between them. The market regulations in several European regions are analysed too.

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[2] An ancillary service is a service necessary for the operation of a transmission or distribution system **Errore. L'origine riferimento non è stata trovata.**.

[3] The broader term distributed energy resources (DER) encompasses generation resources, such as distributed generation (DG), storage resources and consumption resources. In this deliverable, the terms demand side management (DSM) and demand response (DR) are used interchangeably to refer to flexibility available from consumption resources.

Chapter 3 gives a view about novel ancillary services that could exist in the future. It also drafts the new requirements to the current services in order to match with the expected trends by 2030 in terms of generation and consumption mix, inertia reduction, deployment of storage, etc. The methodology used to create the SmartNet high level scenarios, as well as the match between the scenarios and the future situations in the pilot countries, is also shown.

Chapter 4 focuses on the reserve needs that will be necessary in 2030. It starts by reviewing both the current methodologies used by system operators (SOs) for reserves sizing and the present needs for ancillary services across Europe, both separated by products and for every country. Also the development of a Reserves Dimensioning Tool to estimate the future reserves needs and its application to the pilot countries is shown.

Chapter 0 shows the conclusions and the future steps to be carried out in SmartNet, on the grounds of the results presented in this deliverable.

There are also three additional appendices. Appendix A collects the detailed information of the current schemes of ancillary services provision in the different countries. In order to harmonise, as much as possible, the information provided from the partners, an ad-hoc template was designed for this purpose. Appendix B includes the market mechanism of several countries, apart from the pilot countries analysed in detail in section 2.2. Appendix C reviews the most important methodologies dealing with scenario design used in other European projects or by some international regulatory agents. Appendix D details the information about the ancillary services that could exist in future power grids.

2 Review of existing ancillary services and market structures

Different electricity markets are executed in a sequential order, so that electricity and ancillary services are traded in periods which range from some years (futures) to real-time operation (balancing), as shown e.g. in Figure 3 and Figure 4. In general, generators compete in the wholesale electricity markets to sell electricity to large industrial consumers and to electricity suppliers; whereas suppliers compete in the retail electricity markets to sell electricity to final consumers. The main characteristics of a well-functioning wholesale market are accessibility and liquidity to ensure competition, in order to guarantee the long-term security of supply, economic competitiveness and environmental sustainability for current and future consumers.

The price for wholesale electricity can be pre-determined by a buyer and seller through a bilateral contract (a contract in which a mutual agreement has been made between the parties) or it can be set by organised wholesale markets in which a market operator establishes the electricity price by matching supply (what generators want to sell) and demand (what suppliers and customers want to buy).

The wholesale markets are based on the principle of market participants balancing their own physical and traded positions, so, this is the primary mechanism by which the electricity systems are balanced. Subsequently, system operators need to solve any imbalance and locational issues that remain after the market closure (i. e. forecasting errors, incidents) [2]. To that end, transmission system operators (TSOs) may contract ancillary services, which help balance the transmission system during the whole electricity route, from generating sources to ultimate consumers. Distribution system operators (DSOs) could use a similar approach when the regulation allows them to do so.

One of the main duties of TSOs and DSOs is to guarantee the security of supply with high quality standards in their transmission or distribution systems. Therefore, they are continuously monitoring the grid to keep the frequency and voltage within their respective safe bands and to push them back to their normal range after an incident [1]. In order to bring these magnitudes back to their nominal ranges, system operators use ancillary services.

A number of ancillary services are currently available in European Union (EU) countries. The restructuring and introduction of competition in the electricity markets made it necessary that these services are clearly defined and monetised [3]. Sections 2.1 and 2.2 provide a wide and detailed overview on how ancillary services and market mechanisms are currently in force in several European countries.

2.1 Overview of ancillary services

According to ENTSO-E, TSOs must act to ensure that demand is equal to supply (balancing) in and near real-time. Efficient balancing markets should ensure security of supply at the least cost, while guaranteeing the achievement of environmental benefits by reducing the need for back-up generation.

With that purpose, there is a desire to increase harmonisation of the rules for balancing and for using ancillary services across Europe, in order to extend effective pan-European competition in these markets. Consequently, the access to a broad range of services from a wide range of providers (generators, storage and flexible loads) would give TSOs flexible options, allowing them to make more efficient decisions. At present, there is no uniform or standardised categorisation of current ancillary services within European countries, so that they can be classified according to different criteria. In particular, for this review of ancillary services, they have been grouped into three main categories:

- Services supporting frequency control (section 2.1.1).
- Services supporting voltage control (section 2.1.2).
- Other ancillary services (section 2.1.3). The services for power quality, combined frequency/voltage control, restoration services, etc. available at each country are included.

2.1.1 Ancillary services for frequency control

According to the ENTSO-E definition, the frequency control is the capability of a power generating module or high-voltage direct current (HVDC) system to adjust its active power output in response to a measured deviation of system frequency from a set point, in order to maintain stable system frequency [4]. There are three control layers:

1) *Primary frequency control*. It maintains the balance between generation and demand in the network by using the turbine speed governors and other fast activation devices. Primary control is an automatic function of the turbine governor that adjusts the generator output of a unit as a consequence of a frequency deviation / offset in the synchronous area. By the joint action of all the interconnected undertakings, primary control ensures the operational reliability in the synchronous area. For primary frequency control the Frequency Containment Reserve (FCR) is used. FCR typically includes operating reserves with an activation time up to 30 seconds. In several systems, such as the Nordic, the FCR is divided into two categories: Frequency controlled normal operation reserve (FCR-N) and Frequency controlled disturbance reserve (FCR-D).
2) *Secondary frequency control.* It is a centralised automatic function to regulate the generation in a control area based on activation of secondary control reserves in order to maintain the power flow interchanges with all other control areas. At the same time, it has to restore the frequency in case of a frequency deviation within the control area to its set-point value in order to free the capacity needed by the primary control and to restore the primary control reserves. The reserve used for this secondary control is the Frequency Restoration Reserve (FRR) which is an operating reserve necessary to restore the frequency to the nominal value after a sudden disturbance and to replace FCR if the frequency deviation lasts longer than 30 seconds. This category includes operating reserves with an activation time typically between 30 seconds up to 15 minutes. The

function of secondary control is also to restore power cross-border exchanges to their programmed set-point values [5]. Operating reserves of this category are typically activated centrally and can be activated automatically (aFRR) or manually (mFRR).

3) *Tertiary frequency control* is any (automatic or) manual change in the operation set-points of the generators (mainly by re-scheduling), in order to restore an adequate secondary control reserve (FRR) at the right time. The reserves used for the tertiary control are the Replacement Reserves (RR). Tertiary reserves have an activation time from several minutes up to hours.

Figure 1 shows the frequency variations over time when an incident occurs and the acceptable frequency bands.

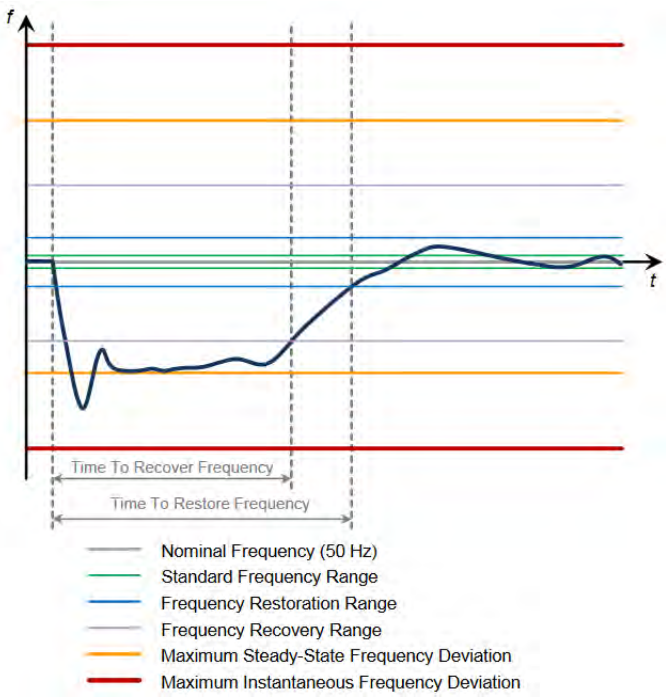

Figure 1 Frequency quality defining parameters [6]

The drop slope when the incident occurs is related to the system's inertia. The stabilisation in the lower part of the band is the result of the activation of FCR. The activation of FRR returns the frequency to the pre-fault value. The RR process RR reacts slower and replaces the FRR to in order to free them for future actions.

At ENTSO-E level, there is not a clear definition of mandatory requirements of each type of reserve, allowing each TSO to keep on using its present reserves requisites. In the ENTSO-E guideline [7], some minimum requirements related to frequency reserves are established, such as:

- Each TSO shall ensure the availability of at least its FCR obligations agreed between all TSOs of the same synchronous area.

- Each TSO of each continental Europe (CE) and Nordic load frequency control area shall implement an aFRR process and a mFRR process.
- All TSOs of a synchronous area shall have the right to implement a RR process.

In the case of FRR (aFRR/mFRR) and RR, the main differences between countries refer to the naming and the time horizons considered for each reserve. The only time specification is that FCR must be active for at least 15 minutes and that aFRR must be activated within 30 seconds. This has made it difficult the comparison of frequency control services within SmartNet.

Therefore, there are countries in which primary, secondary and tertiary control correspond to FCR, aFRR, mFRR, while other countries classify the reserves as FCR, FRR, RR. For purposes of clarity, the services analysed have been classified with the same name as they are defined in their respective country. In Table 2.1, the different denominations for frequency control services currently in force in each country are detailed. For more information and specific issues of these services, see section 7 (Appendix A).

Country	**Frequency control services**		
	Primary	**Secondary**	**Tertiary**
Austria	FCR	aFRR	mFRR
Belgium	FCR-R1	FRR-R2	R3-Production
			R3-Dynamic profile
			R3 ICH-Interruptible users
Denmark*	FCR (DK1)	aFRR (DK1)	mFRR (DK1 and DK2)
	FCR-N (DK2 normal op.)		
	FCR-D (DK2 disturbance)		
Finland	FCR-N normal operation	aFRR	--
	FCR-D disturbance	mFRR	
Italy	Primary frequency control	Secondary frequency control	Tertiary frequency control
Norway	FCR-N normal operation	aFRR	mFRR
	FCR-D disturbance		
Spain	FCR	FRR	RR

Table 2.1 Frequency control services

* It belongs to two synchronous areas, so different requirements apply in Western (DK1, CE) and Eastern Denmark (DK2, NE).

2.1.2 Ancillary services for voltage control

Voltage control includes the manual or automatic control actions designed to maintain the voltage set-points or the reactive power set-points in the system. This is achieved by balancing the respective reactive power requirements of the network and of customers. Voltage must be controlled continuously in order to ensure the power supply quality and to avoid the damage of the connected equipment.

Reactive power cannot be transmitted over long distances since it would require a large voltage gradient [8]. Therefore, voltage control has a local character. Additionally, the foreseen increase of DER penetration will lead to wider voltage variations, so DSOs will need to procure larger volumes of voltage control reserves.

Three different control layers are considered for voltage control, depending on the activation time:

1) *Primary voltage control* is the automatic local control performed in the range of milliseconds when a deviation of the voltage respect to the set-point is detected. This control maintains the voltage at the point of common coupling of the fast reacting devices close to their reference value by means of the automatic voltage regulators (AVRs). These values are fixed on the grounds of several criteria, such as the maximum reactive power to be provided by each device, security criterion, voltage drops, etc. The primary voltage control can last up to one minute.
2) *Secondary voltage control* maintains the voltage at given pilot nodes through the coordination of various regional reactive power resources. When the voltage at these buses is out of range, the operator changes the set-points of the voltage regulators in order to recover a voltage profile. The time of response of the voltage secondary control goes up to one minute and can be maintained for several minutes.
3) *Tertiary voltage control* acts on a system-wide basis and in a time scale of 10-30 minutes. Its objective is the optimisation of the network operation by minimising losses, maintaining the required voltage, and the replacement of reactive reserves. It also provides the reference set-point values of the secondary voltage control.

In the voltage control services, there is also a lack of homogenisation in the naming and requirements through the different European countries. In general, the countries do not differentiate the voltage control layers nowadays. Table 2.2 shows the name assigned for the voltage control services in each country. The detailed information and features for each country are shown in chapter 7 (Appendix A).

Country	Voltage control services
Austria	Voltage control
Belgium	Primary control
	Centralised control
Denmark	Voltage control
Finland	Voltage control
Italy	Primary voltage control
	Secondary voltage control
Norway	Voltage control
Spain	Voltage control – Transmission network
	Voltage control – Distribution network

Table 2.2 Voltage control services.

2.1.3 Other ancillary services

Additional ancillary services used in several countries are briefly described below:

- *Interruptible load service* (Belgium, Italy, Norway, Spain): It is a demand management tool operated by the TSO. Large consumers who purchase energy through the electricity market could establish bilateral contracts with the system operators to reduce their consumption to balance the system in exchange of some remuneration (discounts in their electricity bills or payments for the provision of the service). The regulation considers aspects such as the notice period, the duration and the number of disconnections per year. In Belgium this service is considered as part of the tertiary frequency control service. In Spain, the service is provided in a competitive environment, so that, once they have been pre-qualified, service providers compete with each other to provide the service to the TSO. More details about the provision of this service can be found in section 3.1.6.
- *Black start* (Belgium, Denmark, Italy, Spain): It is to provide the required service to execute the procedure to recover from a total or partial shutdown. Most power stations cannot restart without an extra external supply, so the ability of some station to perform a black start is necessary to achieve the reestablishment of the power supply. Once these power stations have been started, they can be connected to the rest of the network in order to assist and restore the stations with no black start capability. Although the black start capability is rarely used, the existence of black start providers is very important for the security of the system. Currently, this service exists in the majority of countries but it is seldom clearly defined, provided and remunerated as an ancillary service.
- *Grid losses compensation* (Austria, Belgium): During the transmission of electric power through the network, energy is lost due to several reasons, such as the heating of conductors or the windings in transformers, etc. In some countries, system operators are responsible for compensating these losses and, hence, they have already developed specific market mechanisms to purchase this extra energy (e.g. as Austria and Belgium).
- *Strategic reserve* (Belgium)/Peak load capacity reserve (Finland): This service consists of organising a strategic reserve mechanism to cover the structural shortages in generation in the winter period. It secures the electricity supply in situations where the planned electricity procurement is not sufficient to cover the expected electricity consumption [9]. The strategic reserve makes use of load shedding and market generation units. In Finland, the load capacity can consist of both power plants and facilities capable of providing DR.
- *Resolution of technical restrictions* (Spain): This is a mechanism integrated in the electricity market carried out by the TSO consisting in the resolution of the identified technical restrictions

by means of changes in the schedules of the programmed units and the subsequent process of re-balancing. This process is performed on a daily, an intraday and a real-time basis.

- *"Smoothed production"* (Norway): From the beginning of June 2015, Statnett (Norwegian TSO) introduced a new system service, "smoothed production". It aims at reducing the structural imbalances in the power system. These imbalances within operating hours due to a non-ideal fit in the planning between production and consumption and power exchanges or due to variations in the production/consumption profiles themselves are different. With the current one-hour resolution in the energy markets, the imbalances through different hours can be considerable. The power producers whose production changes regularly (usually weekly) ≥ 200 MW can participate in the service by delivering smoothed production based on orders from the TSO.

The extra services currently in force in each country are shown in the summary Table 2.3.

Country	Other ancillary services
Austria	Grid losses compensation
Belgium	Black start
	Grid losses compensation
	Strategic reserves for generation (SGR) and demand (SDR)
Denmark	Black start
Finland	Peak load capacity reserves
Italy	Interruptible load
	Black start
	Real time balancing
Norway	Interruptible load
	"Smoothed" production
Spain	Interruptible load
	Deviation management
	Black start
	Technical restriction resolution (day-ahead, intraday, real-time)

Table 2.3 Other ancillary services

The details, features and mechanisms of each of these services are available in section 7 (Appendix A).

2.1.4 Comparative analysis among several EU-countries

From Table 2.4 to Table 2.6 an overview of the different approaches for the main frequency control ancillary services (primary, secondary and tertiary control) is shown for the countries represented by SmartNet partners involved in this report. The naming, procurement (mandatory or optional submission of bids) and remuneration schemes, activation time and providers are compared below and differences among countries can be easily drawn.

Country	Primary control	Procurement/ Remuneration	Activation time/ Duration	Providers
Austria	FCR	Optional. Capacity (pay as bid).	0 s – 30 s. 15 min.	Production units > 5 MW.
Belgium	FCR-R1	Mandatory. Capacity remunerated.	0 s – 30 s. 15 min.	Base-load flexible units (gas, STEG[4]), Large industrial TSO grid users (aggregator), French generators.
Denmark	FCR (DK1)	Optional. Capacity (marginal price). Energy (imbalance price).	0 s – 30 s. 15 min.	Producers/consumers.
	FCR-N (DK2 normal operation)	Optional. Capacity (pay as bid). Energy (imbalance price).	50 % – 5 s. 100% – 25 s. *	Producers/consumers.
	FCR-D (DK2 disturbance)		150 s. *	Producers/consumers.
Finland	FCR-N normal operation	Optional. Capacity (marginal price).	< 3 min. *	Producers/consumers.
	FCR-D disturbance		30 s. *	Producers/consumers.
Italy	Primary frequency control	Mandatory. Remuneration depends on activation.	15 s – 30 s. 15 min.	Production units > 10 MW.
Norway	FCR-N normal operation	Mandatory (> 10 MW). Marginal price.	5 s – 30 s. 4/8/12 hours.	Producers/consumers.
	FCR-D disturbance		2 min – 3 min. 1 hour.	Producers/consumers.
Spain	FCR	Mandatory. Not remunerated.	0 s – 30 s. 15 min.	Production units.

* Duration of the service is not detailed

Table 2.4 Comparison. Primary frequency control services.

[4] STEG: Steam and gas turbine plants

Country	Secondary control	Procurement/ Remuneration	Activation time/ Duration	Providers
Austria	aFRR	Optional. Capacity and energy (pay as bid).	30 s. 15 min.	Production unit. Aggregators.
Belgium	FRR-R2	Optional. Capacity and energy (marginal price).	7.5 min (from 0 MW to maximum). No limit.	Base-load flexible units (gas, STEG).
Denmark	aFRR (DK1)	Optional. Capacity (fixed price). Energy (marginal price).	15 min. *	Production/consumption units.
Finland	aFRR	Optional. Capacity and energy remunerated.	30 s – 2 min. 15 min.	Production units. Consumers allowed but are not participating.
	mFRR	Optional.	15 min. *	Production units. Consumption (interruptible loads).
Italy	Secondary frequency control	Optional. Energy (pay as bid).	15 min. 2 hours.	Production units, but intermittent resources.
Norway	aFRR	Optional. Marginal price.	120 s – 210 s. *	Production units.
Spain	FRR	Optional. Capacity and energy (marginal prices).	30 s. 15 min.	Production units in a Regulation Area[5].

* Duration of the service is not detailed.

** Long term contract with Norway. Ad hoc procurement in DK1.

Table 2.5 Comparison. Secondary frequency control services

[5] A regulation area is a grouping of production units that can regulate under the management of an Automatic Generation Control system.

Country	Tertiary control	Procurement/ Remuneration	Activation time/ Duration	Providers
Austria	mFRR	Optional. Energy (pay as bid).	15 min. 15 min (minim.)	Production units. Aggregators.
Belgium	R3-Production	Optional. Capacity and energy remunerated.	15 min. No limit.	Turbo-jets, non-spinning units.
	R3-Dynamic Profile	Optional. Capacity (pay as bid)	15 min. 2 hour (40 times/year).	DSO connected loads / emergency generators.
	R3 ICH-Interruptible Load	Optional. Capacity and energy (regulated prices).	3 min 2 / 4 / 8 hours	Large industrial TSO grid users (via aggregator).
Denmark	mFRR (DK1 and DK2)	Optional. Capacity and energy (marginal prices).	15 min. *	Gas turbines, thermal power, heat boilers, CHP, and load shedding.
Finland	Not applied	--	--	--
Italy	Tertiary frequency control	Optional. Capacity (pay as bid).	15 min. *	Production units, but intermittent resources.
Norway	mFRR	Optional. Marginal price.	15 min. 1 hour.	Production/consumption units.
Spain	RR	Mandatory bidding. Energy (marginal price).	15 min. 2 hours.	Production units pre-qualified by the TSO.

* Duration of the service is not detailed

Table 2.6 Comparison. Tertiary frequency control services

As previously done for the frequency control services, from Table 2.4 to Table 2.6, the Table 2.7 summarises the main characteristics of the voltage control services.

Country	Denomination	Requirements	Providers	Procurement/ Remuneration
Austria	Voltage control	Generators connected at: - LV and MV: Power factor between 0.90 or 0.95, both inductive and capacitive depending on power and voltage. - HV: Provision of reactive power.	Generators, TSO, DSO, DG.	Mandatory. Not remunerated.
Belgium	Primary control	Reactive energy automatically activated. Producers > 25 MW take part in this control.	Producers. Only controlling units.	Payment for the reserved control bands based on: a unit price, the volume contracted in MVAr and the length of use.
	Centralised control	Reactive energy activated under system operator's request.	Producers. Controlling and non-controlling units.	
Denmark	Voltage control	Established power factor values based on generator's power.	Generators.	Mandatory. Not remunerated.
Finland	Voltage control	No requirements for P < 10 MW. - Synchronous generators > 10 MW: Power factor between 0.95 capacitive and 0.9 inductive. - Wind power plants > 10 MW: Power factor between 0.995 capacitive and 0.995 inductive or 0.95 capacitive and 0.95 inductive depending on rated active power.	Generators DSO	Mandatory non-remunerated minimal service. Optional service with fixed yearly remuneration for generators connected to 400 kV, 220 kV and 110 kV.
Italy	Primary control	Automatic provision of reactive on the basis of voltage deviation with respect to a reference value.	Generators. Maximum reactive power available (in delivery or absorption).	Mandatory. Not remunerated.
	Secondary control	Assignation depends on location of the generation unit and on the maintenance of voltage profiles on national network.		

Country	Denomination	Requirements	Providers	Procurement/ Remuneration
Norway	Voltage control	- Synchronous generators ≥1MVA: Power factor between 0.86 capacitive and 0.95 inductive. - Non-synchronous generators ≥ 0.5 MVA: Equipment for continuous voltage regulation. - Generators ≥ 25 MVA shall have power system stabilisers (PSS).	Generators.	Mandatory. Not remunerated.
Spain	Voltage control - Transmission network	- Generators: Power factor between 0.989 capacitive and 0.989 inductive. - TSOs: Reactances, capacitors, transformer regulation, etc. - DSO and users: Power factor value established for each hourly period. Bids can be submitted for a surplus band exceeding the mandatory requirements.	Generation units > 30 MW. RES connected at transmission level. TSO, DSO and qualified consumers (connected at transmission and contracted power > 15 MW).	Mandatory part: Not remunerated. Optional part: Remunerated at regular price. Four concepts included; reactive power generation/absorption band availability and reactive energy generated/absorbed for voltage control.
	Voltage Control - Distribution network	- Consumers: A reactive energy billing term is applied when reactive energy consumption is higher than the 33% of active energy consumption during the billing period (power factor < 0.95). - RES installations: Mandatory power factor between 0.98 inductive and 0.98 capacitive.	Consumers and RES connected at distribution level	Mandatory Not remunerated.

Table 2.7 Comparison of voltage control services.

2.2 Overview of electricity markets

In general terms, the Directive 2009/72/EC [1] states that the freedom of establishment and the freedom to provide services will be achievable only in a fully open market, which enables all consumers to freely choose their suppliers and all suppliers freely to deliver to their customers.

The Directive establishes the rules for the organisation of the electricity sector with the aim of developing a competitive, secure and environmentally sustainable market in electricity. However, at present, there are obstacles to the sale of electricity on equal terms and without discrimination or

disadvantages in the EU countries. Currently, different types of market organisation exist and EU countries may impose on electricity undertakings public service obligations which cover issues such as security of supply, power quality, price, and environmental protection (including energy efficiency, energy from renewable sources and climate protection).

EU countries have to define technical safety criteria to ensure the integration of their national markets at one or more regional levels. In addition, the national regulatory authorities are to cooperate to guarantee the compatibility of regulatory frameworks between regions. Moreover, countries must define criteria for the construction of generating capacity in their territory, taking into account aspects such as the contribution made by the units towards the Commission's '20-20-20' objectives. In order to secure competition and the supply of electricity at the most competitive price, cross-border access for new suppliers of electricity from different energy sources, as well as for new providers of power generation, has to be facilitated. Ultimately, in a single market, roles and responsibilities should converge across Member States.

With those purposes, the roles and responsibilities of each electricity market participant are described in this Directive. In particular, as regards the TSOs, the Directive states that the TSOs shall be responsible for ensuring a secure, reliable and efficient electricity system and, in that context, for ensuring the availability of all necessary ancillary services. In order to ensure effective market access for all market players, non-discriminatory and cost-reflective balancing mechanisms are necessary. TSOs should facilitate participation of final customers and final customers' aggregators in reserve and balancing markets. Regulatory authorities shall be responsible for fixing the methodologies used to establish the terms and conditions for the provision of these balancing services.

With regard to the DSOs, the Directive states that each DSO shall procure any service for its system according to transparent, non-discriminatory and market based procedures.

Member States should encourage the modernisation of distribution networks, which should be built in a way that they encourage decentralised generation and energy efficiency. The current market reality is that the ancillary services markets are designed around the limitations and properties of large centralised power plants. The regulatory environment affecting the distribution activity is still strongly in favour of traditional network investments and thus, in practise, it generally prevents using ancillary services from DERs as an alternative, even if they could offer better response speed, better combined reliability, lower losses and lower costs (variable and total). Currently, there are initiatives to enable better access of DERs to the ancillary services markets, but, at this time, it is unknown how these markets will eventually be developed in the long term.

Sections from 2.2.1 to 2.2.4 show the main characteristics and the analysis of current market mechanisms in some European countries (where the physical pilots will be established within SmartNet project, that is, Denmark, Italy and Spain). This is intended to envisage how the future development of

market regulations in the SmartNet horizon (2030) could be, since no disruptive changes in the market structures are foreseen. Additionally, other European countries have also been analysed and the results are shown in section 8 (Appendix B).

2.2.1 Market rules

The market rules are defined to facilitate the trading of products and services, and to improve the competition among the different stakeholders involved. At the same time, these rules are intended to reduce the investors' risks, by minimising uncertainties and defining the incentives in order to give support for an efficient operation of the system. Several common topics are gathered in the definition of market rules:

1) Power trading mechanisms:

- Type of product: FRR, RR, voltage control, load shedding service, etc.
- Market participants: All the participants are identified as well as the requirements for accessing to the market. Their responsibilities and scope of action are delimited too.
- Compulsory nature/Free submission of bids to the market.
- Arrangement of electricity trading in the wholesale market: Electricity pools (compulsory/voluntary) or bilateral contracts model.
- Matching process: Establishment of the algorithm and the process to select the best offers in order to optimise the costs for the provision of the ancillary services.
- Communication procedure to inform participants whether their offers have been accepted or not.
- Clearing: Calculation of the price to be paid to the service providers.

2) Power trading time frames: This part of the market rules mainly includes the definition of the times for the bidding process as well as the closure time where the contracts are fixed: day-ahead, intraday or balancing (for real-time provision of the services).

2.2.2 Electricity market – Denmark

Both Danish and EU authorities have supported the liberalisation of the electricity market in order to stimulate free competition in electricity production and trade. Some of the main consequences of this liberalisation were the unbundling of the transmission grid from electricity generation and the incorporation of many new players in the electricity market. The grid ownership and operation is now independent from generation activities, and all electricity market players have equal rights to use it.

The Danish wholesale market is a part of the Nordic market model and most of the electricity trading takes place on the common Nordic power exchange, Nord Pool, which is owned by the TSOs in the Nordic countries. The power exchange has two market places for electricity, namely Elspot and Elbas:

- Trading at Elspot (day-ahead market) is based on the auction principle, which means that once a day Nord Pool will find a market price for each hour of the next day for the various price areas by matching purchase and sales bids.
- In the Elbas market (intraday market), players can trade themselves into balance with continuous trading after Elspot is closed.

Nord Pool has divided the Nordic market area into bidding areas. All physical trading between these areas must take place via Nord Pool in order to optimise the flow, taking capacity restrictions in the transmission grid into consideration. In the spot market, Nord Pool uses implicit auction, which means that transfer capacity is allocated while electricity is traded.

Trading in the Nord Pool spot market follows a fixed time schedule that is repeated every day:

- Before 10:00, the Nordic TSOs announces how much capacity is available for the spot market for the next day.
- Before 12:00, the electricity suppliers and producers submit purchase and sales bids for the next day to Nord Pool.
- Subsequently, Nord Pool calculates the price. Initially, Nord Pool adds up all the buying and selling bids arriving at the price that strikes a balance between purchase and sale in the whole area (system price). If sufficient transfer capacity between the areas is available, a common market price equal to the system price will become effective in all the areas. This is seldom the case.
- In situations of insufficient transfer capacity (congestion), the Nordic countries are divided into different price areas (market splitting). For each Nordic country, the local TSO decides, which bidding areas the country is divided into. Eastern Denmark and Western Denmark are always treated as two different bidding areas.
- The different bidding areas help indicate constraints in the transmission systems, and ensure that regional market conditions are reflected in the price. Due to bottlenecks in the transmission system, the bidding areas may get different prices called area price. Figure 2 shows the current bidding areas in the Nord Pool market.

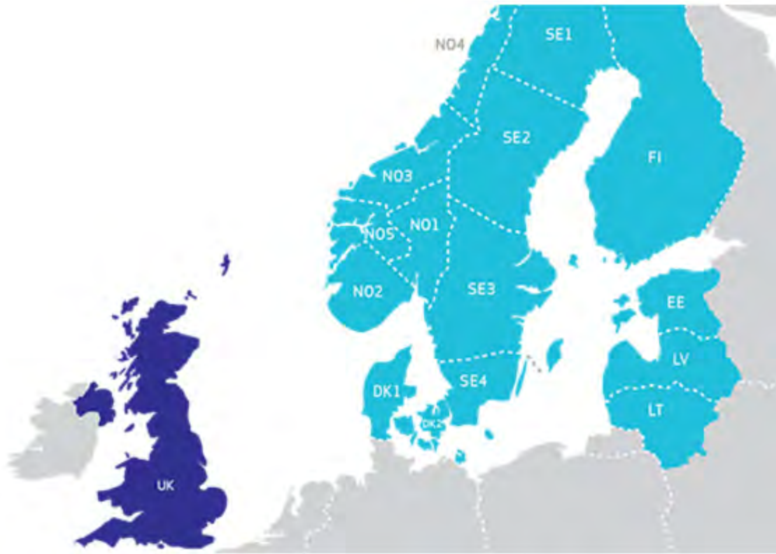

Figure 2 Nord Pool_Bidding areas

- Hourly prices and traded volumes for the following day of operation are typically announced to the market at 12:42 CET or later.

The intraday market takes place during the day of operation when the day-ahead market is closed. In the case of Denmark, these intraday markets exist on all Danish transmission interconnections to neighbouring areas (Norway, Sweden, Germany) and on the Great Belt Power Link[6]. At 14:00, capacities available for Nord Pool intraday trading are published. This is a continuous market and Elbas market allows trading until one hour before delivery time.

At last, in order to ensure a sustainable physical balance in the electricity system Energinet (Danish TSO) can make use of the regulating power and the reserve capacity:

1) Regulating power: Regulating power is production capacity or consumption offered by the market players to Energinet during the actual day of operation. In principle, the balance responsible party forwards bids for upward and downward reserve, stating the volume offered (MW) and the price of activating the power (DKK/MWh)[7]. Energinet forwards the Danish regulating power bids to NOIS (Nordic Operation Information System), which is a common Nordic list, including bids from Danish, Norwegian, Swedish, and Finnish players. When necessary for regulating the power in the Nordic countries, the cheapest bid placed on the common list will be activated, but always

6 The Great Belt Power Link (Storebælt HVDC) is a high voltage direct current interconnection across the Great Belt between Funen and Zealand connecting two power transmission systems in Denmark.

7 Danish Krone (DKK). 1 DKK = 0.134419891 euros (2016/10/24)

taking into consideration possible constraints in the interconnections between the countries. Energinet will always be responsible for activating the Danish regulating bids. Regulating power and balancing power are priced at marginal prices. Current regulating power and balancing power prices are published at Nord Pool Spot's webpage [10].

2) Reserve capacity (ancillary services): Reserve capacity is the production or the flexible consumption capacity offered in advance by the balance responsible parties to Energinet, who pays players a fixed availability payment for being available and for submitting bids for upward/downward regulation to the regulating power market. This allows Energinet to ensure that enough reserve capacity is available. Denmark is the only country in Europe that belongs to two synchronous areas (the Continental synchronous area and the Nordic synchronous area) and different requirements apply in Western Denmark (DK1) and in Eastern Denmark (DK2). For that reason, the requirements to be met by suppliers of ancillary services vary slightly depending on whether the services are to be supplied in Eastern or in Western Denmark. The ancillary services to be delivered in each zone are:
    - DK1:
        - FCR (Primary reserves)
        - aFRR (Secondary reserves, Load Frequency Control (LFC))
        - mFRR (Manual reserves)
    - DK2:
        - FCR-D (Frequency-controlled disturbance reserve)
        - FCR-N (Frequency-controlled normal operation reserve)
        - mFRR (Manual reserves)

Bids must be submitted as upward and downward regulation for FCR. FCR-N is procured symmetrically and FCR-D and mFRR is only procured as up regulation.

For more information about regulation of ancillary services in Denmark, see the *Continental Europe operation handbook. P1 – Policy 1: Load frequency control and performance* [11], the *Nordic System Operation Agreement* [12] and Energinet.dk's regulations for grid connection [13].

2.2.3 Electricity market – Italy

In Italy the regulation that controls the dispatching activity and the related ancillary services market is disciplined by deliberation 111/06 [14] of the national Regulatory Authority. The technical regulation for the operation of the system is instead provided by the Grid Code [15] for transmission, dispatching, development and security of grid issued by the TSO Terna. This document provides all technical regulations for access to the grid, development, management and maintenance of the grid, performance of

dispatching services, supply measurement and settlement services for financial charges connected to the aforementioned services and security of national electricity system.

The Day-Ahead Market (DAM), [16], hosts most of the electricity sale and purchase transactions and it is managed by the market operator (*Gestore Mercati Energetici*– GME). Participants submit offers/bids where they specify the quantity and the minimum/maximum price at which they are willing to sell/purchase. Bids/asks are accepted after the closure of the market sitting based on the economic merit-order criterion and taking into account transmission capacity limits between zones. The Italian transmission grid is divided into several zones: eleven foreign virtual zones, six geographical zones and five poles of limited production (national virtual zones)[8]. All the supply offers and the demand bids belonging to foreign virtual zones that are accepted in the day-ahead market (DAM) are valued at the marginal clearing price of the zone to which they belong. This price is determined, for each hour, by the intersection of the demand and supply curves. This is differentiated from one zone to another in case of congestion. The accepted demand bids pertaining to consumption units belonging to Italian geographical zones are valued at the "Prezzo Unico Nazionale" (PUN – national single price). This price is equal to the average of the prices corresponding to the geographical zones, weighted for the quantities purchased in these zones. The day-ahead market session relevant for the day D starts at 08:00 of D-9 and closes at 09:15 of the day D-1 (i.e. the day-ahead).

The intra-day spot market (also managed by GME), whose sessions take place after the closure of the day-ahead market session, has the purpose of adjusting the schedule output of the day-ahead market for several reasons. For example, the day-ahead market schedule could violate some technical constraints of generation/consumption units (e.g. ramp rates, start-up / shut-down times, etc.), making it not feasible. Moreover, since the intra-day market sessions take place closer to real-time, market players could benefit from new information that has become available after the closure of the day-ahead market session (e.g. failures of plants, new forecasts of renewable generation or of consumption, etc.) and that would make necessary to adjust the day-ahead market schedule, in order to avoid imbalances.

For these reasons, the intra-day market typically deals with volumes much lower than the day-ahead ones. The intra-day market (*Mercato Infragiornaliero* - MI) allows participants to change the schedules defined in the day-ahead market through additional demand bids or supply offers. This way, a generator can sell additional energy or buy-back part of the energy already sold in the day-ahead market, while a load can buy additional energy or re-sell part of the energy already bought in the day-ahead market.

[8] The current existing zones can be checked in: https://www.mercatoelettrico.org/en/mercati/MercatoElettrico/Zone.aspx

The MI consists of four sessions: MI1, MI2, MI3 and MI4. The sessions are organised in the form of implicit auctions of electric energy, like the day-ahead one, with different closure times and in sequence.

- The session of MI1 takes place after the results of the day-ahead market have been published: it opens at 10:45 of the day before the day of delivery and closes at 12:30 of the same day. The results of MI1 are notified to participants and published by 13:00 of the day before the day of delivery.
- The session of MI2, like MI1, opens at 10:45 of the day before the day of delivery, but closes at 14:40 of the same day. The results of MI2 are notified to participants and published by 15:10 of the day before the day of delivery.
- The session of MI3 opens at 16:00 of the day before the day of delivery and closes at 07:30 of the day of delivery. Offers / bids refer to the hours from noon to midnight of the day of delivery. The results of MI3 are notified to participants and published by 8:00 of the day of delivery.
- The session of MI4, like MI3, opens at 16:00 of the day before the day of delivery and closes at 11:45 of the day of delivery. Offers / bids refer to the hours from 16:00 to midnight of the day of delivery. The results of MI4 are notified to participants and published by 12:15 of the day of delivery.
- The sessions of the intra-day market are based on price-setting rules that are consistent with those of the day-ahead market, including zonal prices and congestion management. Nevertheless, unlike in the day-ahead market, the National Single Price (PUN) is not calculated and all purchases and sales are valued at the zonal price.

In the intra-day market it is also possible to submit the so-called “balanced offers”, composed of sale offers at a price equal to zero and purchase bids without price indication, submitted even by different market participants, but referring to the same hour and to “offer points” belonging to the same geographical or virtual zone, in such a way that the sold quantity is equal to the purchased one. “Balanced offers” are typically used by each large generation company to re-dispatch the amount of energy sold in the day-ahead market among its generators located in a specific zone, in order to better optimise the scheduling of its portfolio.

After the closure of each session of the intra-day market, GME (as done after the closure of the day-ahead market) notifies the Italian TSO Terna of the results that are relevant for dispatching: flows and updated injection and withdrawal schedules. These results are required by Terna to determine information about residual transmission capacities between zones for subsequent market sessions.

Once the intra-day sessions are closed the balancing markets are used. The ancillary services market (*Mercato per il Servizio di Dispacciamento* - MSD) is the market where Terna - as the Italian TSO - procures the resources needed to manage, operate, monitor and control the power system (relief of intra-zonal congestions, creation of power reserve, real-time balancing). In the MSD, Terna enters into

purchase and sale contracts with the aim of obtaining resources for dispatching services and acts as central counterpart to the transactions. Bids/offers must refer to offer points (i.e. generation units) qualified to provide ancillary services in the MSD and must be submitted by the respective dispatching users directly (without agents acting on their behalf). All accepted bids/offers are remunerated at the offered price (pay-as-bid methodology).

The MSD consists of a scheduling stage, ex-ante MSD, and a real time stage, the balancing market MB (MB-"Mercato del Bilanciamento"):

1) In the ex-ante MSD, Terna accepts energy demand bids and supply offers in order to relieve residual intra-zonal congestions and create reserve margins. In particular, the ex-ante MSD consists of four scheduling sub-stages: MSD1, MSD2, MSD3 and MSD4. In this phase, Terna accepts tertiary reserve bids and offers to define an optimal scheduling, relieving network congestions and creating suitable secondary and tertiary reserve margins for the real time operation.
2) The balancing market (*Mercato del Bilanciamento* - MB) takes place in different sessions, during which Terna selects bids/offers for the groups of hours of the same day on which the related MB session takes place. In the MB, Terna accepts energy demand bids and supply offers in order to provide secondary regulation and to balance energy injections and withdrawals into/from the grid in real time. The Balancing Market is currently divided into five sessions in which Terna selects offers referring to groups of hours the same day that takes place on the MB session. For the first session of the MB, tenders submitted by operators in the previous ex-ante MSD session are considered valid. For other sessions of the MB, the sessions for the submission of tenders are all opened at 22:30 of the day before the delivery day (and in any case not before the results of the previous ex-ante MSD session have been announced) and close one hour and a half before the first hour that can be traded at each session.

In Italy, only generating units can be qualified to provide ancillary services (no consumption units allowed), but they must have the following features: being a generation unit with a rated power greater than 10 MVA, not being a non-dispatchable renewable energy source (RES), not being a generation unit under test period, being able to increase/reduce at least 10 MW of power generation within 15 minutes from the start of the service and for hydro power plants, being able to produce at the maximum power for at least 4 hours.

Further technical details and limitations for the provision of ancillary services can be found in the grid code of the Italian TSO Terna [15].

As summary, Figure 3 shows the time schedule, gate closure and application horizon of the Italian electricity market sessions.

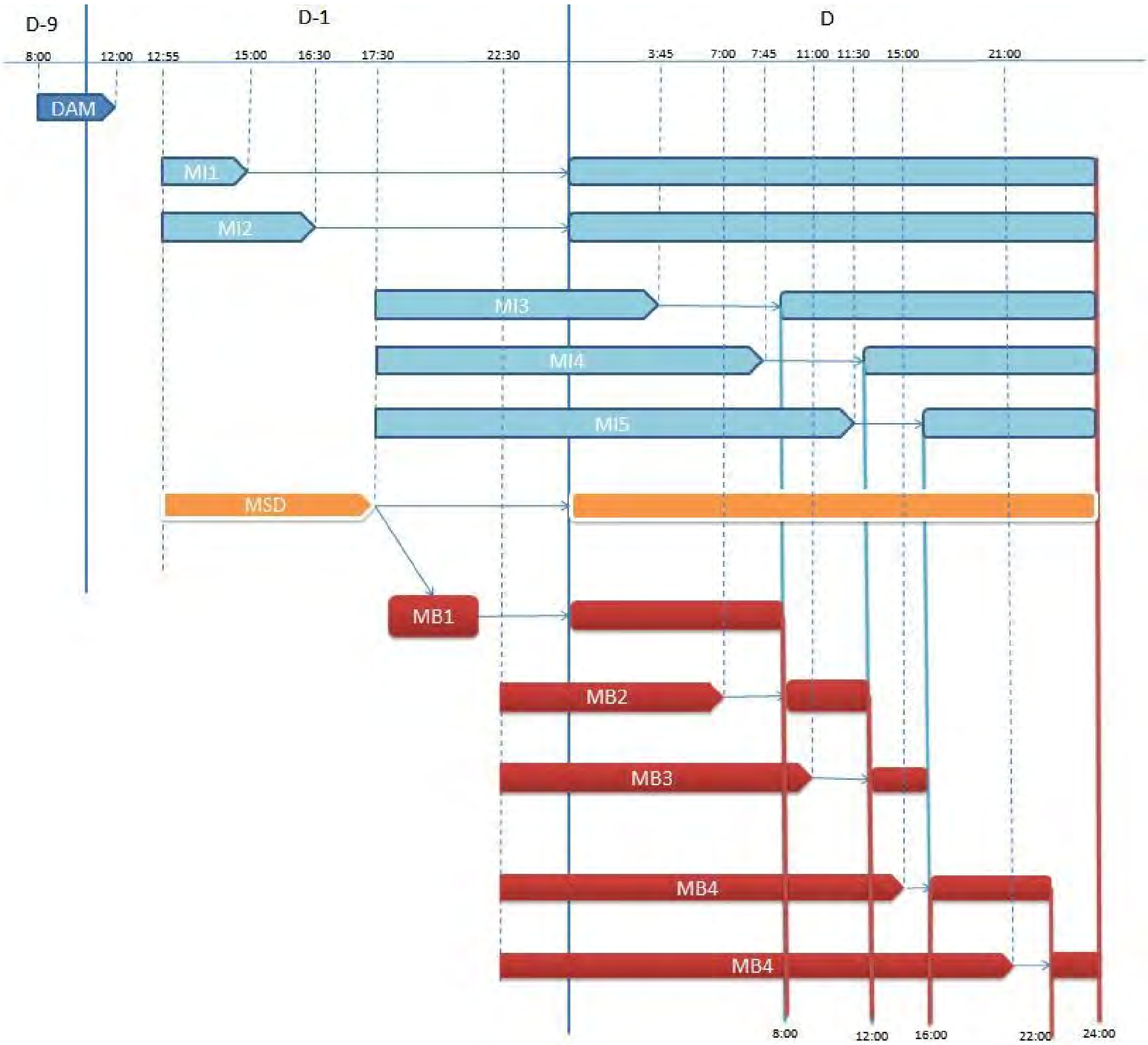

Figure 3 *Time schedule for electricity markets in Italy*

2.2.4 Electricity market – Spain

The purpose of the day-ahead market, as an integral part of electricity power production market, is to handle electricity transactions for the following day, through the presentation of electricity sale and purchase bids by market participants. OMIE (electricity market operator) manages the wholesale electricity market on the Iberian Peninsula [17]. Buying and selling agents may trade on the market regardless of whether they are in Spain or in Portugal. Their purchase and sale bids are accepted according to their economic merit order, until the interconnection between Spain and Portugal is fully occupied. When the interconnection permits the flow of the electricity traded by the agents, the price of electricity for that hour will be the same for Spain and Portugal. On the contrary, if the interconnection is fully occupied, the price-setting is run separately so that there will a different price for each country.

Every day, two hours before the closure of the day-ahead market (12:00 h), the TSO (REE) publishes the foreseen demand for every hour of the following day and the power exchanges between the Spanish grid and the neighbouring ones. Then, the market operator clears the market and sends the information of the base schedule to the TSO.

Based on this base schedule and including the information of the generation and consumption programs established by bilateral agreements, the TSO determines the Daily Base Operating Schedule (PDBF).

This program also needs to be feasible in physical terms, so a validation from the standpoint of technical viability is performed. This process is known as technical constraints resolution and it ensures that the market results can be technically accommodated. This means that the daily market results may be altered slightly, affecting around 4-5 % of the energy. To execute the technical restrictions process, the TSO analyses the generation programs of the units and the expected international exchanges in order to guarantee that energy is supplied with quality, safety and reliability. This process is repeated after every intra-day market session.

In order to participate in this technical constraints resolution, the generation power plants must have presented their corresponding upward and downward bids. This process has two stages:

- In the first stage, some generating units or pumping stations (upward/downward) are re-dispatched, considering the base case and the N-1 and N-2 criterion. The upward clearing price is the one offered in the bidding process for technical constraints. The downward clearing price is established according to the results of the day-ahead market.
- In the second stage, a new re-dispatching of the generation units and the pumping stations is done for balancing the global generation and demand programs. The upward clearing price is the one offered in the upward bid. The downward clearing price is the specific one of the downward bid.

Once the technical restrictions have been solved, the TSO publishes the provisional daily viable schedule, together with the limits to the generation units in order to avoid new restrictions. In parallel, the TSO also publishes the secondary reserve needs and several hours later the assignation of this reserve is carried out among the available production units.

After the day-ahead market, agents may once again buy and sell electricity on the intraday market, i.e. at different trading sessions some hours earlier than real time. There are six trading sessions based on auctions such as those described for the daily market, where the volume of energy and each hourly price are determined by the point where supply and demand meet. These sessions enable all the agents (especially small ones) to adjust their position easily and under the same conditions as any other operator within the same day as the physical delivery. In general, the Spanish intraday market records

similar prices to those arising in the day-ahead market. Intraday markets permit buying and selling agents to readjust their commitments up to four hours ahead of real time. After each intra-day session a new Final Hourly Schedule is launched.

Once each intra-day market session is closed, market parties cannot trade electricity to make adjustments to their schedules. However, they must notify any unavailability of generation units to the TSO. In addition, the TSO continuously monitors the real-time generation of wind power and real-time consumption, in order to check their differences to the traded volumes in the day-ahead and intraday markets. When these differences, together with the non-availabilities communicated by producers, create an imbalance of more than 300MWh during several hours, the TSO calls for the imbalance management market, where producers can send offers to compensate such expected imbalances. If the difference is not that high, the TSO can use the offers for tertiary regulation.

In real-time operation, frequency control services (first, the automatic secondary frequency mechanisms and, if they are not enough to restore nominal frequency, the tertiary reserve) act, cancelling the imbalances that come either from forecasting errors for production and/or demand, or from unexpected events in the production units, as well as from the deviations over the program in the interconnection between Spain and France.

The Spanish electricity market schedule [18] is shown in Figure 4, where the green bars represent the execution periods and the purple bars represent the application horizon for every market. The day-ahead and intraday markets are displayed in the upper area and the ancillary services' markets in the lower area.

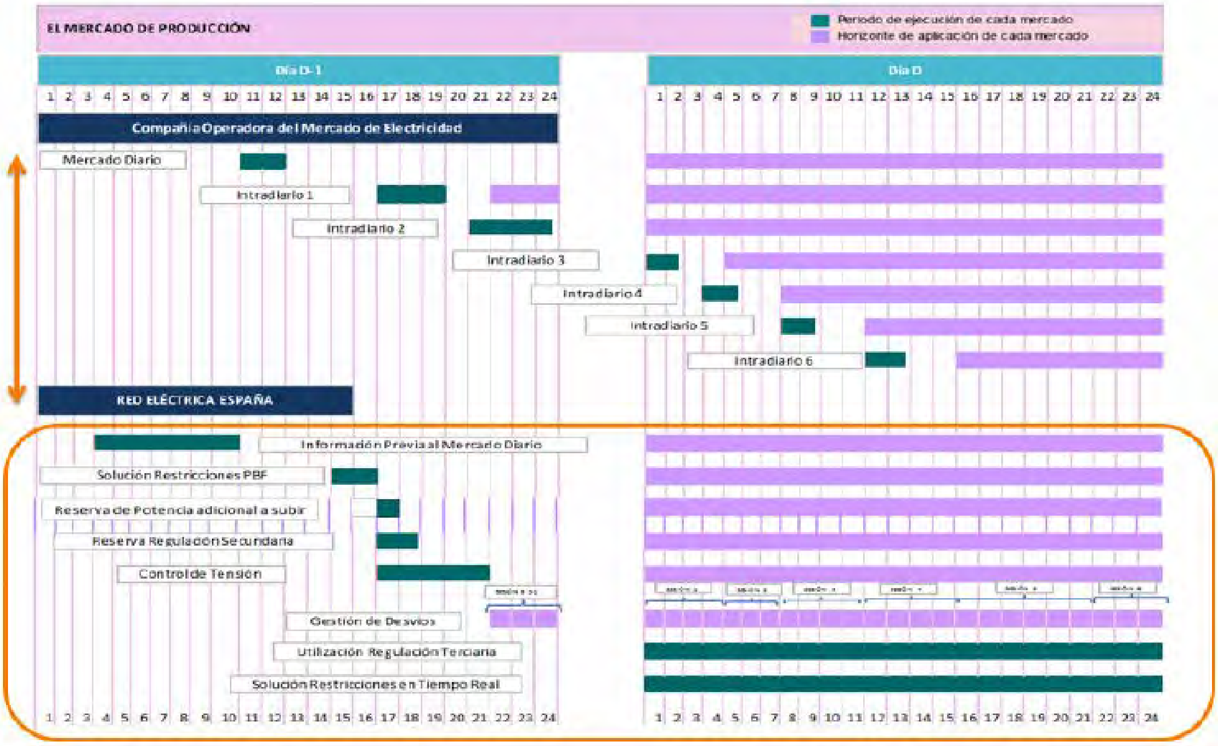

Figure 4 Time schedule for the Electricity markets in Spain

3 Identification of future needs of ancillary services

3.1 The SmartNet framework: expected trends in power systems up to 2030

In order to be able to provide a view on the need for reserves in 2030, it is necessary to know the expected changes in the European power system from the present situation. This is the aim of this chapter, which analyses not only generation, demand and storage planned evolution, but also the interconnections between the countries and the impact of the expected changes in the flexibility and stability of the system.

3.1.1 Electricity generation mix

The EU power generation mix is expected to change considerably over the projected period in favour of RES. Thus, electricity coming from RES is planned to increase (as a share of net power generation) from around 21% in 2010 to 44% in 2030 (see Figure 5). Wind onshore is expected to provide the largest contribution to this RES mix. Solar photovoltaic (PV) and biomass will also increase over time. Hydro and geothermal will remain roughly constant. In particular, variable RES (solar and wind) are expected to reach around 19% of total net electricity generation in 2020, 25% in 2030 and 36% in 2050, demonstrating the growing need for flexibility in the power system. With respect to nuclear energy, in spite of some life time extensions and the building of new power plants, its share is expected to decrease gradually over the projected period from 27% in 2010 to 22% in 2030, according to the EU Reference Scenario 2016 published by the European Commission [19]. This scenario considers that the legally binding GHG and RES goals will be fulfilled by 2030 and there will be a real implementation of the agreed policies between the EU and the Member States until December 2014.

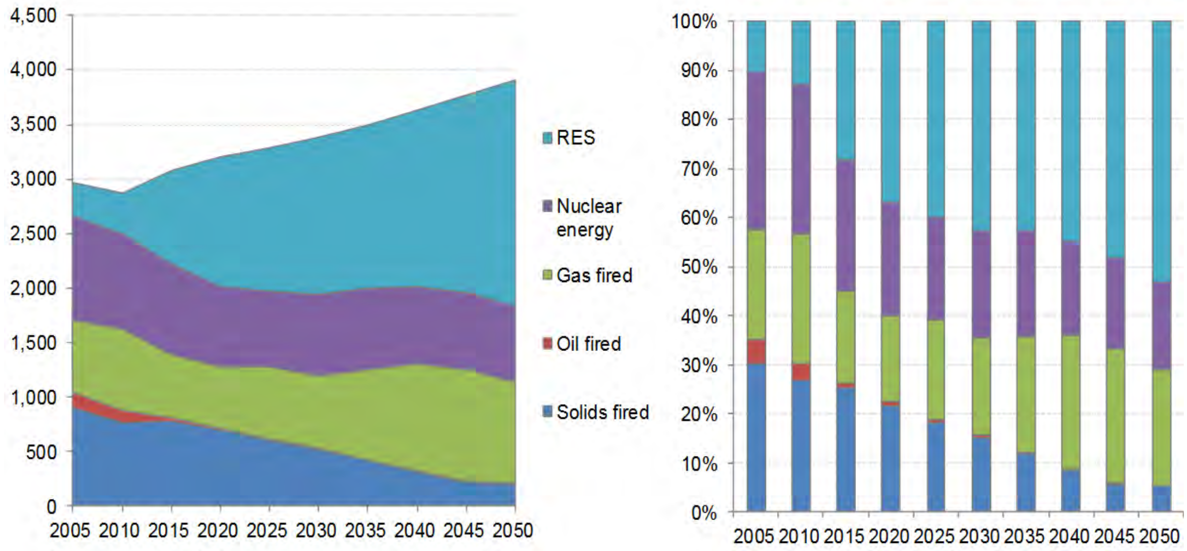

Figure 5 EU power generation (net) by fuel (TWh – left, shares – right) [19]

3.1.2 Electricity consumption mix

The distribution of final energy consumption across sectors will remain broadly similar to the current picture, all the way to 2050, with transport and residential sector comprising the lion's share of final energy consumption (32% and 27% of final consumption, respectively, in 2030). Industry sees its share in final energy demand decreasing, from 28% in 2005 to 23% in 2050, mostly due to improved energy efficiency in non-energy intensive industries. The tertiary sector (services and agriculture) will keep a stable share of about 17%.

With regard to the fuel mix in the final energy demand, as shown in Figure 6, a gradual increase of electricity is expected, from 21% in total final energy use in 2010 to 28% in 2050. The reason is a growth in electricity demand, as compared to other final energy use, due to some electrification of heating (heat pumps) and, to a limited extent, of the transport sector.

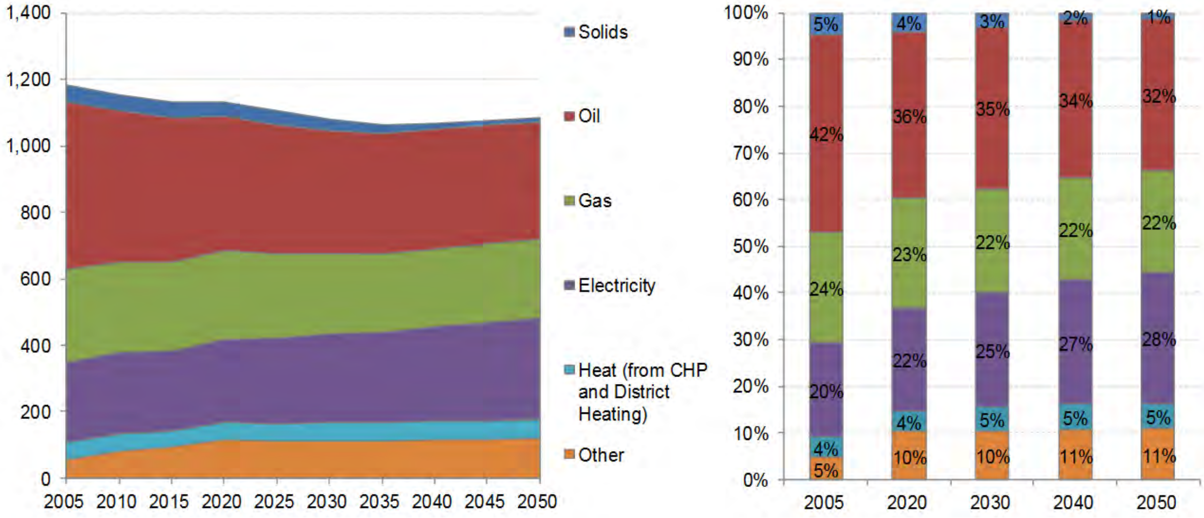

Figure 6 Evolution of final energy demand by fuel (Mtoe – left, shares – right) [19]

In the residential sector, final energy demand remains close to the 2015 level throughout the projection period. This is not the case in transport sector, which is expected to see a decrease until 2030 and, afterwards an increase, so that the final energy demand in 2050 is similar to the one in 2010 (Figure 7 Final energy demand in transport [19]).

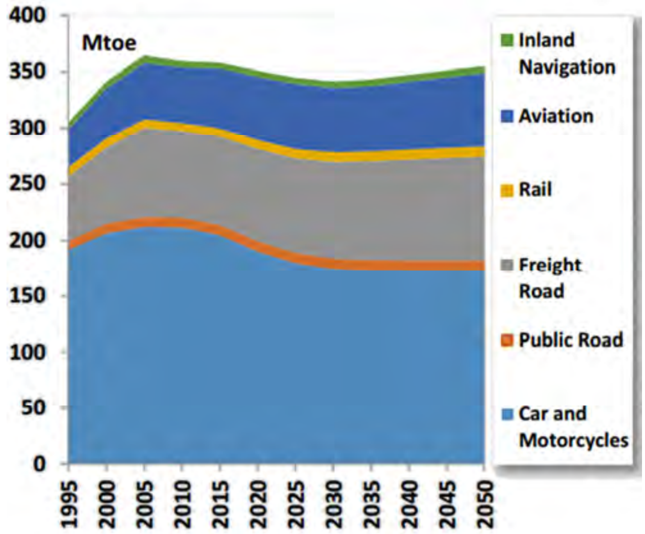

Figure 7 Final energy demand in transport [19]

However, in both sectors an increase of electricity consumption is expected in 2030. In particular, electricity is expected to contribute to 27% of final energy consumption in the residential sector (compared to 23% in 2010) (see Figure 8) and to 4% of the final energy consumption in the transport sector (compared to 2% in 2010) (Figure 9) [19] as a result of further electrification of rail and the uptake of electric vehicles (EVs).

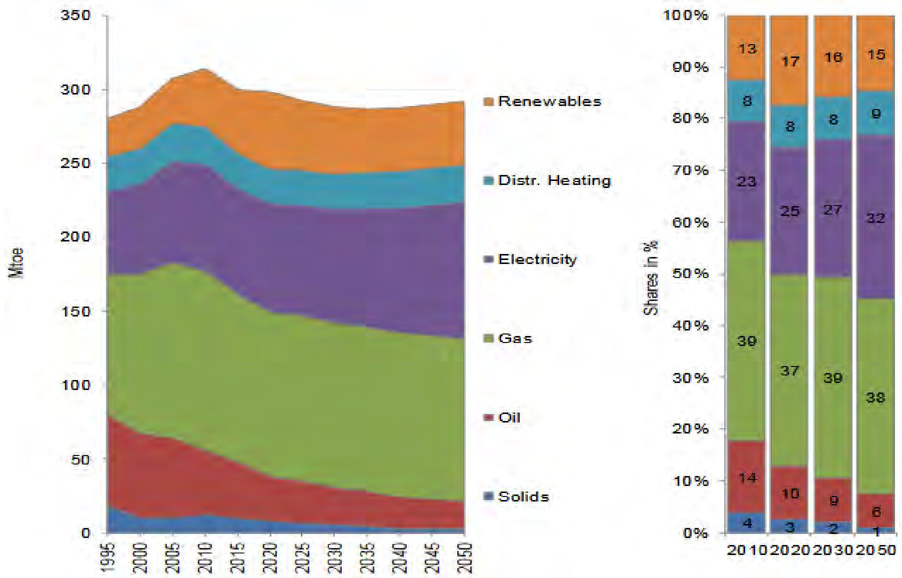

Figure 8 Final energy demand in the residential sector (Mtoe – left, shares – right) [19]

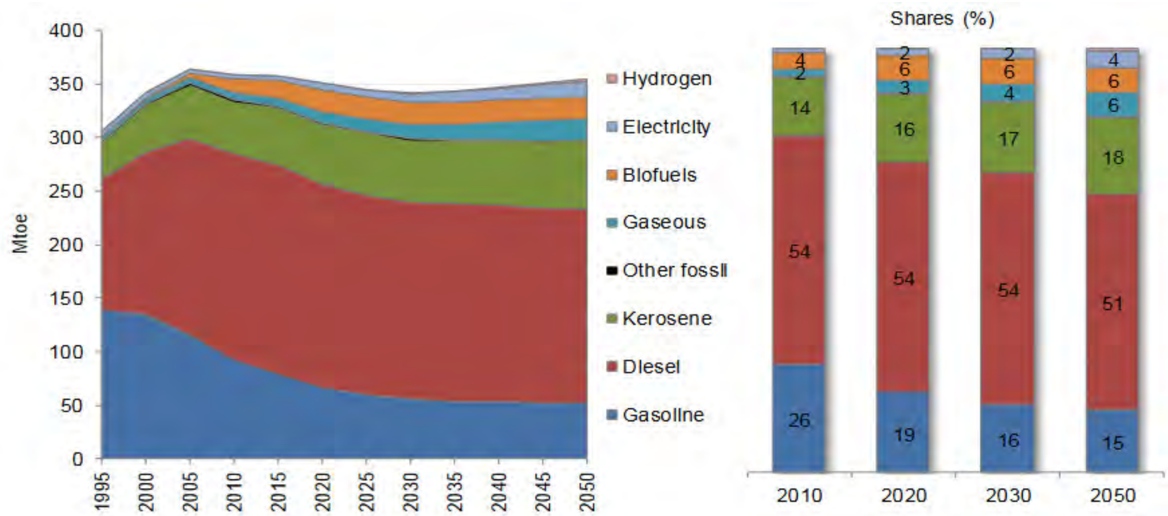

Figure 9 Final energy demand in transport by fuel type (Mtoe – left, shares – right) [19]

These changes in the consumption mix will have an impact in the power system, which can be summarised as follows:

- Electricity demand will rise, increasing (the risk for) congestion and local voltage problems. This will happen, in particular, in the distribution grid, where the majority of the mentioned additional load, resulting from the electrification of heating (domestic and tertiary sector) and transport, will be located, and where the distributed RES generation will be located as well.

- Due to the increased share of electric heating (increasingly by heat pumps), the consumption will become much more temperature-dependent (thus less predictable) and volatile. On the other hand, these loads will represent a large potential of flexibility in the grid.
- EVs consumption represents also a large potential of flexibility in the grid.
- A growth in volatile consumption, based on the weather conditions and mobility needs, will increase the risk of coincident consumption peaks, in turn causing large power flows and congestions. Moreover, power peaks may appear in distribution systems, if consumers are encouraged to consume electricity following the production pattern of RES production plants connected at transmission. Therefore, a closer collaboration will be required between TSOs and DSOs in order to mitigate the grid impact of such volatile consumption and generation. Some studies, such as [20] and [21] show that there are needs and possibilities to change the tariff structures to mitigate the congestion problems. Maybe, by the time horizon in SmartNet (2030) such capacity (subscribed power) based distribution tariffs that dynamically reflect the local grid costs will be allowed and introduced. However, grid congestion peaks are usually of short duration and with locational variation, which makes that the value of the responses on the market will not be significantly reduced by taking account of the grid constraints, even if transition from energy-based to capacity-based distribution tariffs can be very helpful.

3.1.3 Energy storage

Higher penetration of RES into distribution networks will increase the needs of reserves for ensuring system stability. Storage can help to decrease the requirements of back-up conventional energy with security of supply purposes. The energy excess proceeding from RES during high generation periods can be transformed back to electricity for balancing the power system in low demand periods. According to the recommendations for a European Energy Storage Technology Development Roadmap [22], prices of (electrical) storage are projected to drop, making distributed storage a competitive solution compared to traditional resources for reserve services. Moreover, the energy storage roadmap claims that distributed storage located at a utility substation on the distribution grid has a much higher value than central storage because it offers distribution upgrade deferral and stability control. The forecast in the 2030 horizon for energy storage by application is displayed in Figure 10.

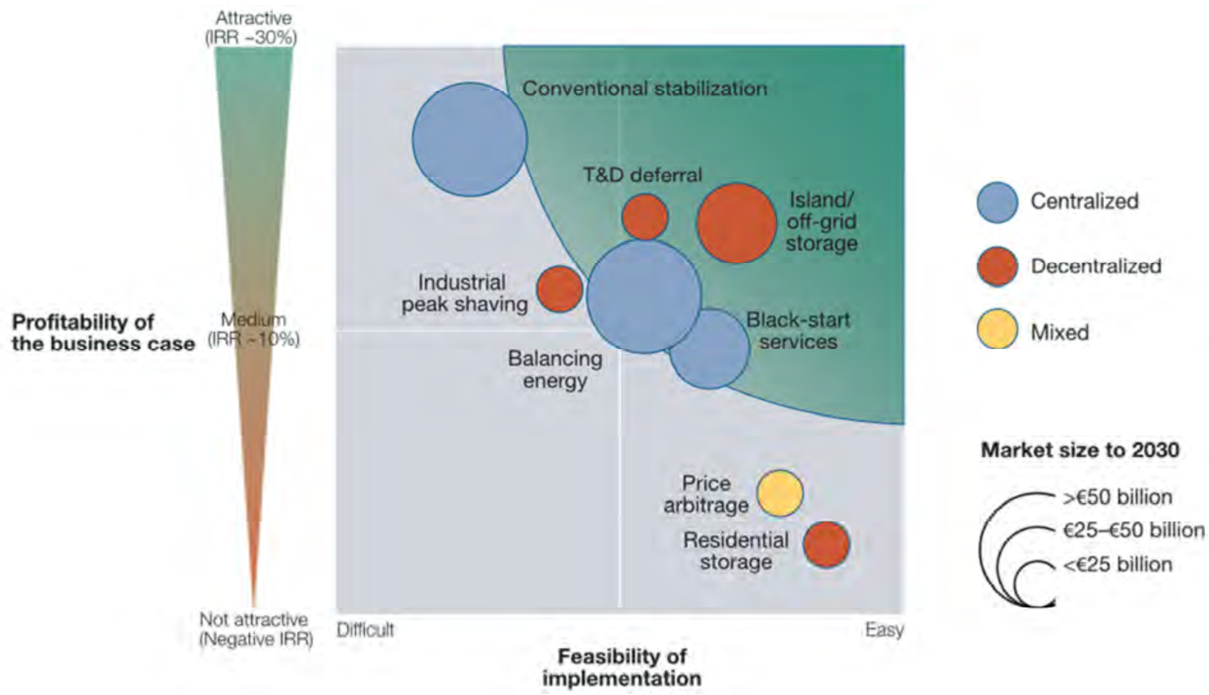

Figure 10 Electrical Energy Storage market forecast by application for 2030 [23]

Some characteristics of the energy storage integration in power systems are described below:

- Local electrical storage will be a common source of reserve services for balancing and voltage control. Storage is well suited to deal with continuous, small up and down fluctuations caused by intermittency and forecasting errors. Moreover, it has a larger flexibility range in both directions and a fast reaction time. As an example, Figure 11 [22] shows a comparison of the suitability of diverse battery technologies for grid operation applications.

Application	Pb acid	Ni/MH	Na/S	$Na/NiCl_2$	Redox Flow	Li/ion	Super capacitor
Time-shift	Suitable	Less suitable	Suitable	Suitable	Suitable	Less suitable	Unsuitable
Renewable integration	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable	Unsuitable
Network investment deferral	Less suitable	Less suitable	Suitable	Suitable	Suitable	Suitable	Unsuitable
Primary Regulation	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable	Unsuitable
Secondary Regulation	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable	Unsuitable
Tertiary Regulation	Suitable	Less suitable	Suitable	Suitable	Suitable	Suitable	Unsuitable
Power System start-up	Suitable	Suitable	Suitable	Suitable	Less suitable	Suitable	Suitable
Voltage support	Suitable	Suitable	Suitable	Suitable	Less suitable	Suitable	Suitable
Power quality	Less suitable	Unsuitable	Less suitable	Unsuitable	Less suitable	Less suitable	Suitable

Suitable **Less suitable** **Unsuitable**

Figure 11 Comparison among different electrochemical storage systems for the key grid applications

- The reactive power control capabilities of energy storage systems enable them to provide services such as voltage support control, improvement of voltage quality and RES insertion. The present global situation in energy storage installations is shown in [24], where the energy storage policies in different states in North America are described too.
- The improvements in electrochemical storage technologies and cost reductions will also contribute to increasing the amount of EVs. Controllable charging will enable these vehicles to be used as flexible loads and, thereby, to provide ancillary services.

3.1.4 Inertia reduction and increase of frequency deviations

Traditionally, inertia has been provided by the rotating masses in the generators. With an increasing share of converter-coupled devices [25], the total system inertia could be reduced to a level which would cause the frequency to change too fast, trip some protection relays and leave too little time for the FCR to kick in.

The decreasing amount of inertia in power systems has contributed in the last few years to the growth of frequency variations (see Figure 12 for example).

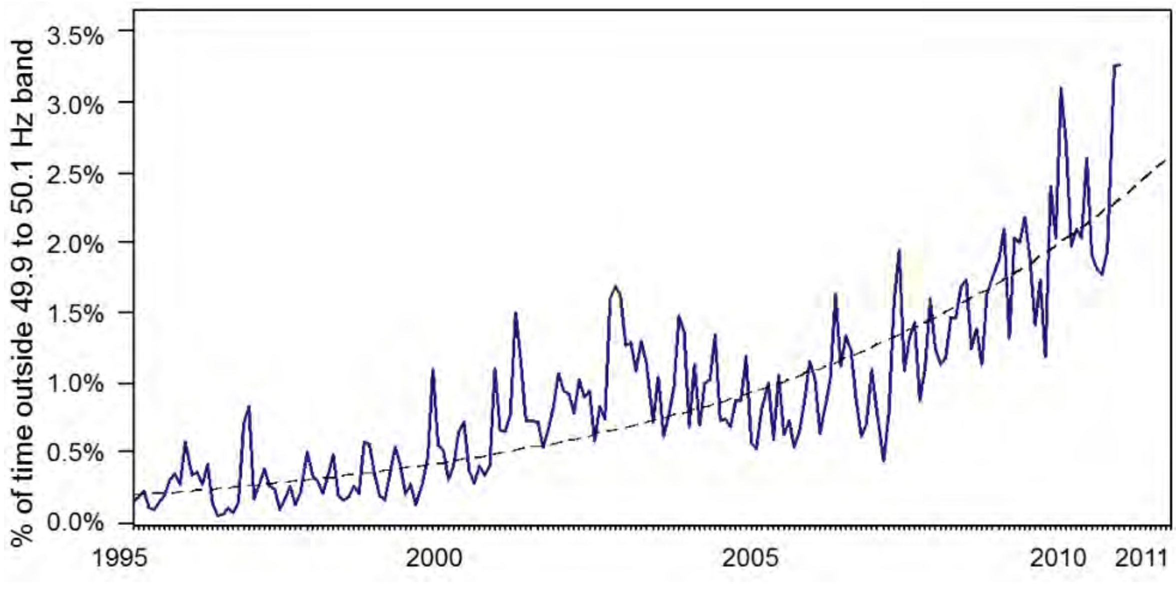

Figure 12 Evolution of frequency deviation in the Nordic power system up to 2011 [6]

Although the reduction of inertia in power systems and the resulting fast balancing challenges are global phenomena, there are few studies analysing its consequences. According to the Norwegian TSO, the increase of frequency deviations in the Nordic power system has had several reasons [26], although new cable connections to the continent and the existing design of the Nordic Power system (one-hour resolution of the market) are probably the main reasons.

The reduction of inertia and the subsequent increase of frequency deviations will negatively affect the reliability of the power system and it will also increase of balancing losses and costs, unless the ancillary services markets are developed to enable both better access of demand-side flexibilities to these markets and faster response times of the providers of the services.

An initial attempt to get a better understanding of the variation of kinetic energy in the Nordic power system [27] shows how the future changes will impact the inertia values in the system and how real time measurements of kinetic energy can be performed. Scenarios for 2020 and 2025 were developed from data provided by the Nordic TSOs in order to study future kinetic energy. As Table 3.1 shows, kinetic energy is expected to reach lower levels than today and, even, than any historical value.

Scenario	Production (MW)						Kinetic energy (GWs)
	Nuclear	Other thermal	Hydro (conventional)	Hydro (small)	Wind	Total	
2020	7 164	2 300	8 846	0	5 510	23 841	97
2020 part of conventional hydro: small-scale	7 164	2 322	6 346	2 500	5 510	23 841	90
2025	7 474	2 463	9 383	0	7 182	26 502	102
2025 part of conventional hydro: small-scale	7 474	2 463	6 883	2 500	7 182	26 502	95
2025 import, less nuclear	5 420	2 463	6 883	2 500	7 182	24 448	80

Table 3.1 Nordic power system inertia in extreme production scenarios for 2020 and 2025

The analysed scenarios considered the effect of reduced nuclear power and different levels of hydropower (replacing part of the conventional hydropower by small-scale hydropower -which has much lower inertia constant- in three of the minimum inertia scenarios).

To estimate the kinetic energy, average values for inertia constants were assumed (see Table 3.2) and the same power factor of 0.9 for all production. Moreover, full power was assumed for all the production except for conventional power that is operated with 80% of the maximum power.

Production type	H(s)
Nuclear	6.3
Other thermal	4
Hydro conventional	3
Hydro small-scale	1
Wind	0

Table 3.2 Average inertia constants assumed

Results from a dynamic analysis show that low amounts of power system kinetic energy are expected to have a significant impact on the minimum instantaneous frequency. Further studies are needed to reveal the potential challenges for the Nordic and European systems seen from the stability point of view.

The report [27] also recommends measures to handle future low kinetic energy situations, such as: synthetic inertia from resources connected through frequency converters and adjustable FCR parameters for FCR contributing resources.

Therefore, the importance of distributed FCR services will increase significantly in the future European power system. Moreover, the FCR also needs to be somewhat faster than today.

3.1.5 Increased flexibility

The fastest responding flexibility is in controllable loads, electricity storage systems and counverter-coupled energy sources, which are mainly distributed resources. The main limitation for controllable loads is that the duration of the responses is limited (depending on the case) and it often includes pay-back effects. Loads can be controlled upwards and downwards (solar and wind power mainly downwards).

The modern wind power plants are able to provide active and reactive power control. In addition to downward control, the upward control is also possible to a certain extent, if the wind generation is first curtailed (i.e. by modifying the pitch control of the blades to produce less than the available resource, even at lower speeds than the rated speed). The second option for upward regulation is to momentarily exploit the kinetic energy stored in the inertia of the rotor. This way, the wind power plants can momentarily contribute to supporting the system frequency.

At the moment, PV plants are able to provide voltage and they are also expected to contribute to frequency control in the future. Voltage control is normally implemented locally by reactive/active power droop control. PV plants have the potential to be aggregated in virtual power plants in order to participate in markets, including balancing markets.

Typical thermal power plants are condensing, combined heat and power (CHP), gas turbine, motor and nuclear power plants. The starting time of condensing power plant is related to the time when the plant was shut down (cold start or warm start). Frequency and voltage control can be provided at the same time, given that the working point of the synchronous machine and of the prime mover are within the capability limits [28]. It is possible to increase the flexibility of the CHP by using heat storages and, this way, reduce the dependence between electricity and heat production [29].

A comparison of the flexibility of different power plants is included in [30], when assessing future technical solutions for integrating higher amounts of RES production. It is also pointed out that there is currently (2012) a lack of metrics, methods and tools to measure the flexibility and its related cost of provision, evaluate the flexibility required, and optimise the generation resources to provide such flexibility at a minimum cost.

3.1.6 Demand response

DR may be defined as "the actual response/reaction of demand on certain signals or incentives to change their behaviour" [31].

Current developments and challenges (advanced metering and control technologies and the ever-increasing capacity of variable and distributed generation sources, respectively) have opened the door for a more active participation of customers.

Historically, DR was provided by large industrial loads, connected to the transmission grid, and mainly via interruptible load programs directly contracted with the TSO or with a BRP. Today, end-users are active customers, who are being empowered by technological breakthroughs to participate in the energy market.

Vision [32] on active customers includes the following views, for example:

- As demand response technology develops and human interactions are better understood, the availability, volume and response time of the demand-side resource will provide the flexibility necessary to respond to both peak demand and variable generation needs [33][34].
- The management of peak demand can enable better system planning throughout the entire electricity system, increasing options for new loads such as electric vehicles, for storage deployment and for generation technologies [34].
- While the smart meter is the interface between the distribution system and the customer's home, it is the HEMS or BEMS in home or business that can deliver the information and support the ability of the customer to adjust the use of electricity [35].
- Most consumers participate to electricity market based on economic incentives [29] [33]
- Customers use their own generation, energy storages and other controllable resources for DR [29]. Obviously, these DER must to be controlled automatically, because manual control is too unpredictable, expensive and slow for the intended electricity market purposes.
- The load profiles of the active consumers are totally different from the past passive consumers. The distribution tariffs are power-based and include products that give incentives to use flexibility to support distribution grid management [29].
- Many consumers have some emergency back-up power units, which are always switched on during power system outages. Own generation and electricity storages enable that [29].
- Standards and requirements on smart house/home properties are compulsory for all new buildings, thus enabling cost-efficient implementation of flexibility [29].

Even where aggregated distributed DR is allowed to participate to all markets for electricity and ancillary services, the volume of participation of DR can be small. This could be attributed to the design of

most wholesale markets, which could be hindering direct participation of DR. For instance, the minimum volume and response duration required by existing markets makes it difficult for small users or aggregators to take part in the day-ahead, intraday or ancillary service markets. Also, some products in the market of ancillary services are limited to resources connected at the transmission grid or to generation units. The introduction of smart grid technologies (home automation systems), new infrastructure (replacement of conventional meters by smart meters, smart appliances, etc.) and new market rules (products and processes that take into account the specificities of small aggregated load connected to the distribution grid) will enable a broader deployment of flexibility on the demand side.

An overview of different DR programs is provided in [31] and [36]. In these programs, it is common to observe demand participating in what is known as interruptible load contracts, as shown in section 2.1.3. The capacity for this service is usually procured on a yearly basis, but it is rarely used. Some countries have defined more advanced products. For instance, in Belgium demand can participate in the organised market mechanisms for primary and tertiary reserve and free flexibility energy; in particular, Elia (Belgian TSO) is already contracting loads connected at distribution system level for the tertiary reserve dynamic profile (R3-Dynamic profile, see Table 2.1).

Another example is France where the NEBEF (Notification d'Échange de Blocs d'Effacement) mechanism could be highlighted. This mechanism allows end-users (or their representatives) to sell the energy from a demand reduction action on the French day-ahead market. More information on this mechanism can be found in [37].

The electricity and ancillary services markets in Finland allow demand side participation, but the participation of demand side in ancillary services markets is still small. The structures of the ancillary services markets and their products are not suitable for small distributed flexible resources thus making prohibitively complex aggregation necessary for participation.

In Spain this service can be provided by electricity consumers connected at high voltage level through a yearly reverse auction managed by the TSO. It is an optional service and the participants can offer demand reduction blocks of 5MW or 90 MW, which have associated several options of execution depending on the prior notice time; without prior notice (immediate execution), 15 min (fast execution) and 2 hours (hourly execution).

Several challenges will need to be addressed in order to increase the participation of DR. At the level of the market design, a clear definition of the role and responsibilities of the aggregator will have to be determined. At the moment, in most countries, the role of aggregator is not defined, while in some others it is even forbidden. In addition, the impact on the portfolio of the balancing responsible party (BRP) due to activation by aggregators will have to be analysed and it has to be determined if compensation mechanisms need to be developed.

On the level of the data flow, it is important to have a safe, secure and efficient transfer and sharing of data with market parties which need of them. As an example, there is a discussion on data management at the level of DSOs and to what extent the DSO metering data could be used/ should be transferred to commercial market parties offering aggregation services.

Another element is that the newly developed products to increase DR at the distribution level should not hinder the safe and secure operation of the grid, meaning that clear control mechanisms and smart market clearing mechanisms have to be developed to ensure that no additional congestion or voltage violations are introduced by allowing more DR in the market.

3.1.7 Enhancement of cross-border interconnections

Sharing and exchange of balancing resources is expected to bring several benefits to the system. It will potentially improve the security of supply, increase competition on the balancing markets by better utilisation of the resources and, thus, provide TSO access to cheaper resources, reducing costs for the end-users.

At the moment, there are three main models in operation directly related to cross-border exchanges, although several alternative models and comparative evaluation of these can be found in [38]:

1. *TSO-TSO*: TSO-TSO model is a model for the exchange of balancing services exclusively by TSOs. In the TSO-TSO model, all interactions with a Balancing Service Provider (BSP) in another responsibility area are carried on through the connecting TSO. The TSO-TSO model is the standard one for the exchange of balancing services. It was decided that the European integration model for a future EU-wide balancing market should be based on a TSO-TSO model, where TSOs will cover all cross-border processes and obligations (if not delegated to a third party) [39].
2. *TSO-BSP*: TSO-BSP model is a model for the exchange of balancing capacity or the exchange of balancing energy where the contracting TSO has an agreement with a BSP in another responsibility or scheduling area. Under the TSO-BSP model, a BSP has a contractual relationship with another TSO than its connecting TSO. If the use of the TSO-BSP model is approved by the relevant national regulatory authority, the TSOs must define a set of rules which require, on the one hand, the adoption of the current processes and obligations and, on the other, the creation and development of new ones [38].
3. *Imbalance netting*: The Load Frequency Control & Reserves (LFCR) Network Code [40] defines the imbalance netting process as "*a process agreed between TSOs of two or more LFC Areas within one or*

more than one Synchronous Areas that allows for avoidance of simultaneous FRR activation in opposite directions by taking into account the respective FRCEs as well as activated FRR and correcting the input of the involved FRPs accordingly"[9]. The control target of the imbalance netting process is to reduce the amount of simultaneous counteracting FRR activation of different participating LFC Areas by imbalance netting power interchange. Each TSO shall have the right to implement the imbalance netting process for LFC areas within the same LFC block, between different LFC blocks or between different synchronous areas by concluding an imbalance netting agreement (see [40] for more details). The imbalance netting power interchange of LFC area should not exceed the actual amount of FRR activation, which is necessary to regulate the FRCE of the given LFC area to zero without imbalance netting power interchange. In a similar manner the interchange should not result in power flows exceeding the operational limits. The involved TSO should ensure that the sum of all interchanges is equal to zero. Several other formal requirements to TSOs involved in the same cross border activation for FRR and RR, imbalance netting and exchange of FCR, FRR and RR are defined in the LFCR Network Code [40].

Regardless of the model implemented, one of the main challenges for cross-border exchange is how to allocate the available transmission capacity at interconnectors, in order to make it in the most economically feasible way, and which allows an optimal utilisation of the available transmission capacity between the national transmission systems. Since cross-zonal capacities are a limited resource, capacity reservations are quite controversial, because they means that less cross-zonal capacity will be available for day-ahead and intraday trading. Because it is not possible to predict in advance how much of the contracted reserves will actually be used at a certain future time, there is a risk that the valuable transmission capacity will not be used. Since the interconnectors are likely to be congested in hours with high price differentials between bidding areas, the value of the trade lost is expected to be high. This was taken into consideration by the so-called EU Target Model, developed by ACER (Agency for Cooperation of Energy Regulators). This Target Model proposes a market design for balancing services that includes the management of cross-border exchanges at each timeframe (i.e. forward, day-ahead, intraday and balancing) and a coordinated approach for capacity calculation.

Another important issue is that cross-border trade shall not jeopardise system security, as stated by ERGEG (forerunner of ACER). Therefore, security of supply in each TSO's power system is the most important aspect that must be taken into account when the exchange of balancing services is considered [41]. This can be ensured by making available for being sold to other areas only the reserves beyond the

[9] FRCE means Frequency Restoration Control Error and FRP stands for Frequency Restoration Process.

defined reserve requirement for each part of the system. This implies that reserves covering both loss of the largest production unit and the expected forecast error with regard to consumption and wind production shall be kept for local purposes. It is also anticipated that only reserves bid into the balancing market are available for sale. Based on this, it was suggested [41] to estimate the available resources as shown in Equation (1):

$$BRexport = BRBid - BRSoS - BRFE \qquad (1)$$

Where:

BRBid - Resources bid into the Regulation Power Market

BRSoS - Resources kept for security of supply, referring to dimensioning fault

BRFE - Resources kept for potential Forecast Error

This is illustrated in Figure 13 below, suggesting that the most attractive (cheapest) resources are kept for "local" purposes, while more expensive resources that are not needed locally are made available for export. Although this is a natural starting point for cooperation, a more flexible approach should be aimed for in the longer run to optimise the use of common resources.

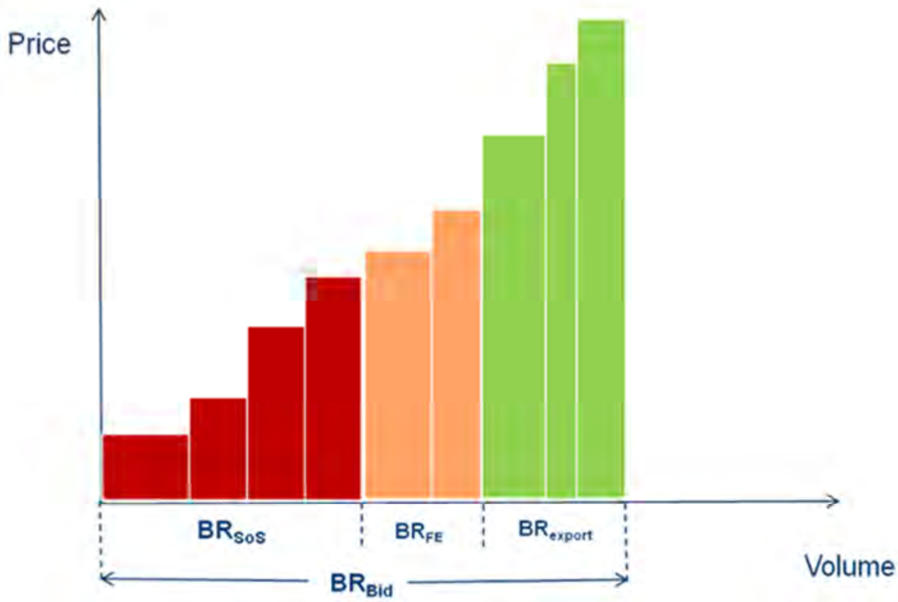

Figure 13 Balancing resources available for export [41]

It also must be taken into account that, within one synchronous system, the frequency is a common control signal, and if the whole synchronous system is one single control area (like the Nordic system), it is the only control signal that governs the load frequency control. If there are two or more control areas, the frequency is one of the two signals that together determine the area control error. Neither the area control error nor the frequency in the opposite system is a relevant control signals for the exchange of balancing power between separate synchronous systems. The frequency in each system is only

interrelated via the change of flow over the HVDC interconnections. It is therefore necessary to exchange explicit control signals to the HVDC terminals (and possibly generators) in the other system to enable the exchange of balancing services.

As an example of a real implementation of this advanced control of cross-border exchange of ancillary services, the recently commissioned HVDC cable between Norway and Denmark (Skagerrak 4) has the overall transmission capacity of 700 MW whereof 110 MW of the capacity have been contracted for provision of primary and secondary reserves (10 and 100 MW accordingly) from Norway to Denmark during a five-year period. It has been estimated that the value of this interconnection will be higher than the one obtained by taking this capacity away from the spot market. It is furthermore intended to trade automated ancillary services through the planned connections with Germany and UK. By reserving up to 300 MW of capacity to trading ancillary services, it is estimated that the Norwegian trading revenues could increase by approximately EUR 5 million per year and per cable. This situation presumes that the transmission capacity will be allocated to balancing services or to the spot market, depending on which the most feasible is in each case.

3.2 SmartNet high-level scenario

The expected changes in the European power system for the next years are drafted in section 3.1, but given the uncertainty linked to the definition of future behaviours, it is advisable to consider several scenarios, which represent different possible developments of certain issues into the future (some more optimistic and some others more pessimistic, considering factors such as the emission targets achievement or the RES and DR deployment). These scenarios are intended to cover not only such uncertainty, but also all the casuistry that can occur in different European countries.

Thus, in order to set the framework for the evaluation of future reserve needs, some SmartNet high-level scenarios have been defined. As described in the following subsections, they have been built both by adapting the e-Highway 2050 methodology and by considering the ENTSO-E visions.

3.2.1 Introduction to scenario design

When present situation needs to be defined in a certain field, quantifying all the parameters to characterise it may be an easy task. However, that is not the case when looking into the future, since many developments turn possible and several uncertainties should be managed.

In accordance to the definition of what a scenario is and how its design process should be addressed provided by the energy systems group of the International Institute for Applied Systems Analyses (IIASA), ”*In designing scenarios we devise images of the future, or better of alternative futures. Scenarios are neither predictions nor forecasts. Rather each scenario is one alternative image of how the future could unfold*” [42].

A scenario describes one possible development of certain issues into the future and it is defined according to a set of parameters and their evolution in time. When big changes take place, a modification in one parameter brings changes in many other variables. This is the situation where scenario planning is more useful, as it involves the analysis of the joint impact of various parameters, when several values are changed at a time, while keeping others constant [43]. The objective is to build representations of possible futures and the route to be followed to get there from the present.

The number of scenarios should be optimised to get a plausible, consistent and structurally different set of scenarios. They should also offer insights into the future and challenge the conventional wisdom about it. Four different approaches are possible to create these scenarios:

- Normative vs. exploratory scenarios:
    - Normative approach selects a possible future (optimistic/pessimistic/neutral) and evaluates the possibilities to get there from the present.
    - In the exploratory approach the present is the starting point, determining future scenarios by asking "what if" questions.
- Inductive vs. deductive scenarios:
    - Inductive approach (or bottom/up) starts with the data available and builds future scenarios by the combination of this information. This is particularly applied in developed markets, as macroeconomic variables are not expected to change dramatically in the short-term.
    - Deductive approaches (or top/down) are particularly used in emerging markets. In this case, the overall framework is imagined and the available data is then allocated where suitable.
- Qualitative vs. quantitative scenarios:
    - Qualitative approach uses visual symbols or words (storyline) to describe the scenarios, showing their main features.
    - Quantitative approach uses numerical information that is usually introduced in simulation tools.

For the development of the SmartNet high-level scenarios, some previous methodologies dealing with this topic have been analysed. They have been derived either by some international groups of interest (ENTSO-E, JRC, etc.) or by other projects (evolvDSO). The results of such literature review can be found in chapter 9 (Appendix C).

3.2.2 Generation of SmartNet high-level scenarios

The planning process of designing the SmartNet framework starts with the definition of scenarios that represent future projections over the 2030 time horizon. In these scenarios, all the elements that may have a direct or indirect impact on the need for and on the provision of ancillary services have to be taken into account.

The considered elements include policy and regulatory factors essentials to define the framework and sketch the boundaries of extreme scenarios. At European level, the European Commission (EC) published in March 2011 the communication "A roadmap for moving to a competitive low carbon economy in 2050" [44], where the role of electricity in the decarbonisation path was analysed. It was stated that, by 2050, electricity generation could almost totally eliminate CO_2 emissions (in a 93-99% below the 1990 level), as required for achieving the 79-82% economy-wide emissions reduction target established at the G8 in 2009 [45]. Mid-term emission reduction targets were also established by the EC, setting a 54-68% CO_2 reduction (compared to the 1990 level) for the power sector by 2030.

Several studies were published to analyse the progress needed in the power sector to get these objectives in 2050. One of them is *"Power Perspectives 2030: on the road to a decarbonised power sector"* [45], where the major challenges related to the decarbonisation transition were outlined, by taking into account several axes: generation technologies, transmission grid, demand side resources, etc.

Building on this information, SmartNet scenarios were drafted following a methodology based on the one deployed in e-Highway project (see subsection 9.6) and adapted to the needs and objectives of this project. According to this methodology, key uncertainties and options were defined and, then, linked to create possible futures and strategies respectively. Afterwards, futures and strategies were combined into possible and coherent scenarios. This set of scenarios is later investigated (detecting inconsistencies, similarities, etc.) in order to obtain a reduced number (4-6) scenarios that will be further analysed in the following tasks of the project.

For the application of the e-Highway methodology to the SmartNet project, ENTSO-E visions towards 2030 (see subsection 9.2, [46]) and the scenarios defined in the report *"Power Perspectives 2030: on the road to a decarbonised power sector"* [45] were taken as a reference.

The possible situations that could happen in the future are defined by parameters beyond our control, called uncertainties, such as the evolution of the economy, fuel prices, etc. For the definition of SmartNet scenarios, a number of key uncertainties were selected, based on the ENTSO-E European generation adequacy outlook [46]:

- Economic & financial conditions
- European framework

• Technological breakthroughs
• Energy efficiency breakthroughs
• Usage of DR potential
• Generation mix
• Transmission & distribution grids
• Smart grid implementation

Then, the ENTSO-E visions for 2030 have been considered as possible Futures (Vision 1: "Slow Progress", Vision 2: "Money Rules", Vision 3: "Green Transition", Vision 4: "Green Revolution"). They are not intended to be forecasts and, hence, there is no probability attached to them, so none of them is more probable to happen than any other. The main characteristics of these visions are graphically represented in Figure 14.

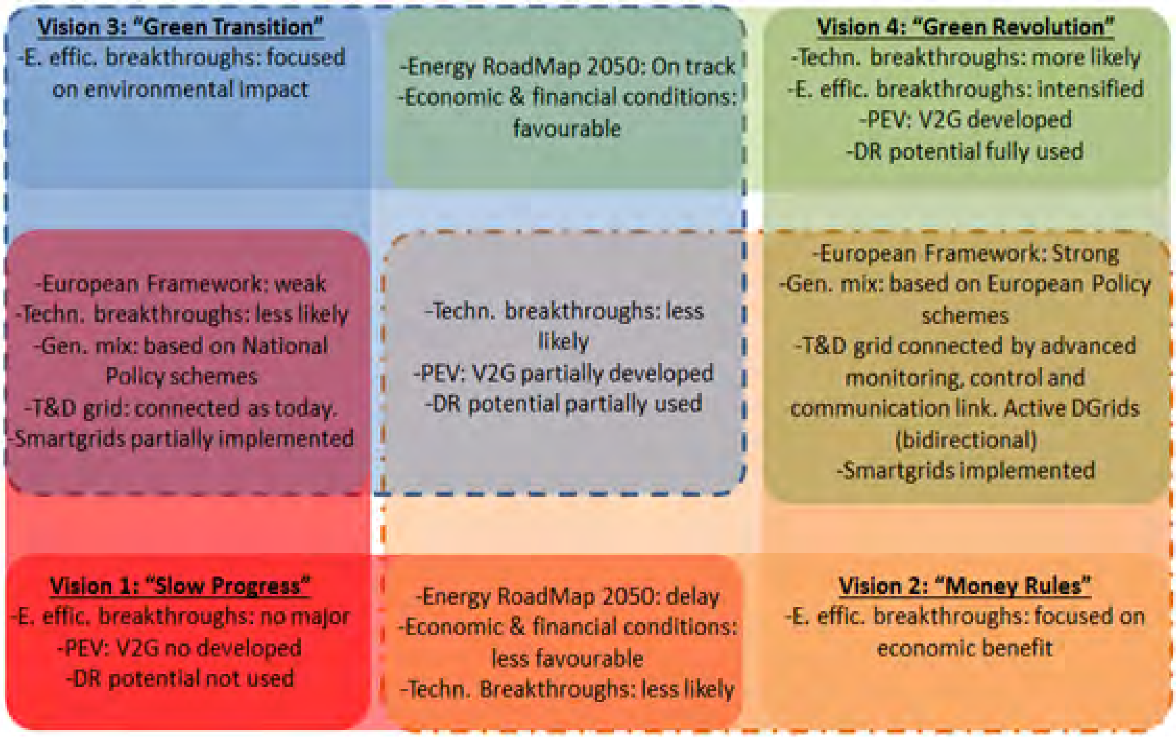

Figure 14 ENTSO -E visions for 2030

Visions are displayed in the corners of the Figure 14 starting from Vision 1, which can be considered as the most pessimist situation, to Vision 4, the most optimistic one. Moreover, some of the characteristics apply to several visions. These characteristics that are applicable to more than one vision are represented in spaces between two different visions. Common aspects to Visions 2 and 3 appear in the central region of the graph. According to this:

- Visions 1 and 2 present less favourable economic and financial conditions and they are delayed in the achievement of EC targets presented in the 2050 roadmap. Visions 3 and 4, on the other hand, are on track for getting these targets.
- Visions 1 and 3 share a weak European framework, with a generation mix based on national policies and no changes in transmission and distribution grid connections with respect to the present situation. Visions 2 and 4, however, are characterised by a strong European framework, with a generation mix based on European policies and on improved transmission and distribution grid connections.
- With respect to DR and vehicle to grid initiatives, Vision 1 is the only one that does not consider their use.

More detailed information on the characteristics of these Visions can be found in [46].

The next step includes the definition of options that will be combined to define possible strategies. Unlike uncertainties, options are parameters whose value can be chosen by the decision maker. It is obvious that, dealing with future scenarios, nothing is absolutely certain, but some assumptions are needed to advance in the scenario planning.

Strategies for SmartNet have been shaped based on existing studies dealing with the expected future and challenges. Among others, two studies carried out in the framework of the 2050 roadmap project have been mainly considered:

- *"Roadmap 2050: a practical guide to a prosperous, low-carbon Europe"* [47]: it is a guide to get the EC objectives for a low-carbon Europe in 2050. It analyses the technical and the economic feasibility of achieving this goal without jeopardising energy reliability and security, economic growth and prosperity.
- *"Power Perspectives 2030: on the road to a decarbonised power sector"* [45]: it is a technical assessment of the challenges and potential solutions in the transition to a fully decarbonised power sector from a European perspective. It analyses the next steps of development required in the European power sector by 2030 to achieve EC objectives in 2050.

The EC proposal on CO_2 reduction targets in power sector is shown in Figure 15.

In particular, three of the scenarios proposed on the latter [45] have been taken as a reference:

- A central scenario ("On Track"), which assumes:
    - the fulfilment of the current plans from ENTSO-E and the National Renewable Energy Action Plans up to 2020,
    - the compliance with the EC target of reducing emissions by 2030, and
    - the achievement of 50% RES share in 2030.

- A sensitivity scenario ("Business as Usual"), where current plans up to 2020 cannot be implemented and targets will not be achieved, involving 26% RES penetration.
- A sensitivity scenario ("High Renewable"), which is similar to the central scenario but considers 60% RES penetration, instead of 50%.

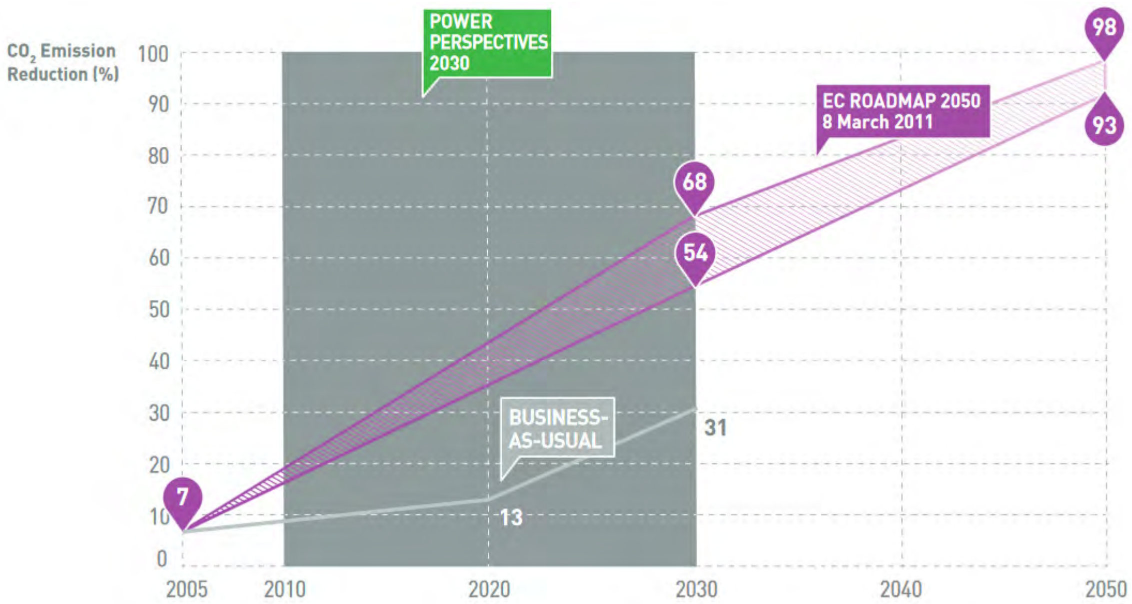

Figure 15 EC proposal on CO_2 reduction ranges in power sector [48]

The degree of compliance with EC emissions target by 2030 together with these alternatives for the massive integration of RES at European level have been considered in the definition of SmartNet strategies. But, apart from these issues, particular attention has been paid to those aspects especially able to provide the system with increased flexibility, both at grid level and on the demand side:

- On the one hand, the cross-border system expansion has been evaluated as a way to optimise the use of RES production while reducing the need for back-up power.
- On the other hand, actions on demand side were also analysed. DR initiatives and storage systems help to balance the system and to reduce the need for grid capacity expansion and back-up power.

Possible values assigned to these three variables were defined for 2030 as follows:

- For RES penetration, the main criterion was the degree of compliance with the requirements to achieve EC emissions target by 2050. Based on the report on power perspectives for 2030 [45], three possibilities were assumed:
    - RES share based on current plans:
        - On track for complying with the EC target of reducing emissions by 2050.

- Similar to "On Track" scenario, where 50% RES share was considered at European level.
  - Lower RES share:
    - Current plans are not fully implemented and, consequently, it is assumed that EC emissions target will not be achieved in 2050.
    - Similar to "Business as Usual" scenario, where 26% RES penetration was considered.
  - Higher RES share:
    - On track for complying with the EC target of reducing emissions by 2050.
    - Similar to "High RES" scenario where 60% RES share was considered at European level.
- For the cross-border interconnections status, two options were evaluated: improved interconnections and poor interconnections.
- For DR and Storage, the implementation degree was studied by the evaluation of two possibilities, one assuming that they are implemented and the other without this option.

Figure 16 shows all possible Strategies obtained by the combination of selected key Options.

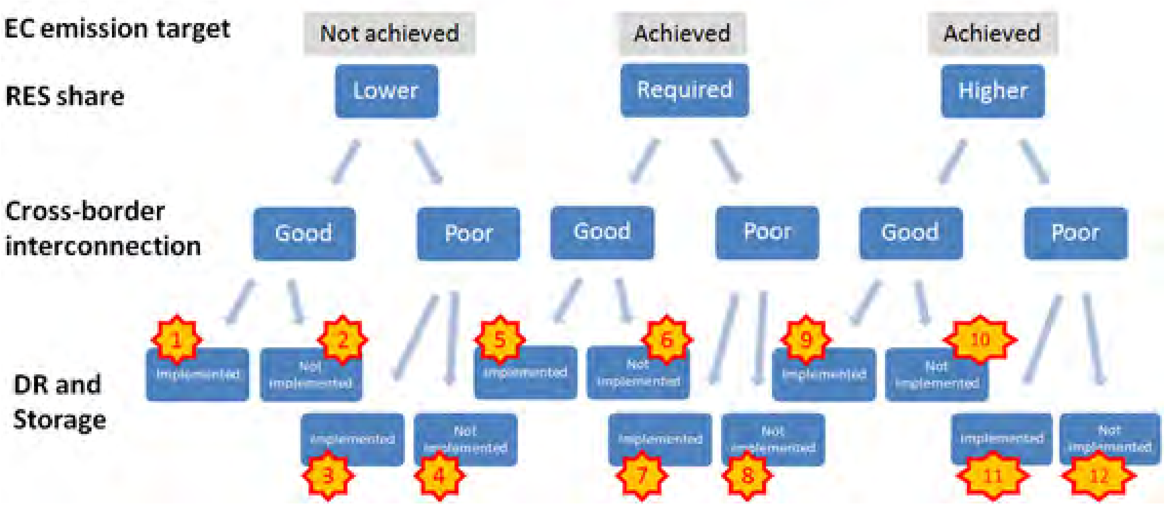

Figure 16 Possible Strategies in SmartNet

3.2.3 Selection of scenarios of interest

Next step in this process involves the combination of defined futures and strategies to generate a set of possible and coherent scenarios. These scenarios are first defined in a qualitative way and need to be optimised, in order to obtain 4-5 representative scenarios which can be used to perform the qualitative analysis to be carried out in subsequent tasks of the project. It is important to highlight that quantitative figures to be assigned to each parameter in further steps will depend on the country subject of study.

Thus, the figures should be set based on the national plans, the available resources and the characteristics of each country.

Table 3.3 shows all possible combinations and the scenarios obtained after discarding the ones where uncertainties and options did not match. In this table, the source of incompatibility is shown in each cell using these acronyms: RES (RES share), CBI (cross-border interconnection) and DR (demand response and storage).

		STRATEGIES											
		EC emission target not achieved				**EC emission target achieved**				**EC emission target achieved**			
		Lower RES share				**Required RES share**				**Higher RES share**			
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
FUTURES	**Vision 1**	CBI DR	CBI	DR	**SCN2**	RES CBI DR	RES	RES DR	RES	RES CBI DR	RES CBI	RES DR	RES
	Vision 2	**SCN1**	DR	CBI	CBI DR	RES	RES DR	RES CBI	RES CBI DR	RES	RES DR	RES CBI	RES CBI DR
	Vision 3	RES CBI	RES CBI DR	RES	RES DR	CBI	CBI DR	**SCN4**	DR	CBI	CBI DR	**SCN6**	DR
	Vision 4	RES	RES DR	RES CBI	RES CBI DR	**SCN3**	DR	CBI	CBI DR	**SCN5**	DR	CBI	CBI DR

Table 3.3 Combination of futures and strategies into possible SmartNet scenarios

In short, the following criteria were followed:

- Those strategies that assume the achievement of emission targets in 2030 (Strategies 5 to 12) are incompatible with Visions 1 and Vision 2 defined by the ENTSO-E. In this line, strategies based on the non-compliance with these targets (Strategies 1 to 4) are not compatible with Vision 3 and Vision 4.
- Good cross-border interconnections (Strategies 1, 2, 5, 6, 9, 10) are not compatible with Vision 1 and Vision 3 and, in the same way, poor interconnections (Strategies 3, 4, 7, 8, 11, 12) are incompatible with Vision 2 and Vision 4.
- The implementation of flexibility initiatives in the demand side (for instance, DR initiatives) (Strategies 1, 3, 5, 7, 9, 11) does not match with Vision 1 while strategies without this type of flexibility (Strategies 2, 4, 6, 8, 10, 12) are not compatible with the rest of the ENTSO-E visions.

This way, six final scenarios were obtained:

- Scenarios 1 and 2 (SCN1, SCN2) are based on the non-compliance with emission targets for 2030, assuming lower RES share than required to fulfil the 2050 energy roadmap. Moreover:
    - SCN1 falls within the scope of Vision 2 and it is characterised by the expansion of cross-border interconnections and the use of DR potential.
    - SNC2 takes place in the framework of Vision 1 and neither improved cross-border interconnections nor flexible demand are available.
- Scenarios 3, 4, 5 and 6 (SCN3, SCN4, CN5, SCN6) are based on the achievement of emission targets in 2030.
    - SCN3 and SCN5 are very similar, with the only difference on RES penetration, higher in SCN5. These scenarios take place in the framework of Vision 4 and they take into account both improved cross-border interconnections and flexible demand.
    - SCN4 and SCN6 are also very similar, with higher RES share in SCN6. They take place in the framework of Vision 3 and they assume no improvements in cross-border interconnections, but flexible demand is available.

In view of the similarities explained and in order to optimise the final scenarios, SCN3 and SCN5 (on the one hand) and SCN4 and SCN6 (on the other hand) are merged into two scenarios, where EC emission target is achieved or even improved in 2050. In this case, RES penetration is assumed to be, at least, the required by current plans for complying with this objective.

In this way, four scenarios can be finally defined for 2030, as reported in Table 3.4, where all the parameters (uncertainties and options) and their qualitative value are shown for each scenario.

Key parameters	Uncer-tainty	Opt.	Scenario 1 (SCN1)	Scenario 2 (SCN2)	Scenario 3 (SCN3+SCN5)	Scenario 4 (SCN4+SCN6)
Economic & financial conditions	X		Less favourable	Less favourable	Favourable	Favourable
European framework	X		Strong	Weak	Strong	Weak
Technological breakthroughs	X		Less likely	Less likely	More likely	Less likely
Energy efficiency breakthroughs	X		Focused on economic benefit	No major	Intensified	Focused on environmental impact
DR potential use	X	X	Partial (50%)	Not used	Total (100%)	Partial (50%)
Generation mix	X	X	Based on European Policy schemes	Based on National Policy schemes	Based on European Policy schemes	Based on National Policy schemes
Transmission & distribution grid	X	X	Advanced monitoring, control and communication link	Connected as today	Advanced monitoring, control and communication link	Connected as today
Smartgrid implemented	X		Yes	Partially	Yes	Partially
Distribution grids	X		Active (bidirectional)	As today	Active (bidirectional)	As today
RES share	X	X	Lower than required	Lower than required	The required or higher	The required or higher
Cross-border interconnections		X	Good	Poor	Good	Poor
DR and storage use		X	Implemented	Not implemented	Implemented	Implemented

Table 3.4 Qualitative definition of final SmartNet Scenarios

The more detailed descriptions of the SmartNet scenarios are presented below:

1. **Scenario 1 – Economic benefit search:** In the context of less favourable economic and financial conditions, this scenario assumes a situation where the lack of money does not allow the reinforcement of existing energy policies by national governments. Current permitting issues cause delays in construction of new infrastructures and lead to postponements in the fulfilment of the energy roadmap 2050.

European framework is strong, having influence on the definition of the generation mix. Nevertheless, due to the financial restrictions mentioned, RES penetration is lower than required for achieving EC emission targets in 2050. For base load electricity generation, hard coal is the preferred technology as a consequence of the carbon pricing level driven by existing policies.

This situation does not promote technological breakthroughs. There are no technology preferences and they compete in the market without specific support measures. Planned commercial deployments of carbon capture and storage (CCS) infrastructures are however boosted by European subsidies for their demonstration at full-scale.

Economic benefit drives the increase in the use of electricity in transport and heating/cooling sectors, as well as energy efficiency breakthroughs. Low growths are expected in electricity demand, particularly in view that energy efficiency improvements will partly compensate the increases caused by the assumed new uses of electricity.

With regard to electricity grids, advanced monitoring, control and communication links are considered in transmission and distribution (T&D) systems, together with bidirectional electricity flows in distribution. Vehicle-to-grid (V2G) approach is partially developed for electric vehicles and flexibility is assumed on charging side.

The need for additional back-up capacity has been reduced by the existence of a common European energy framework and the improvement of cross-border interconnections for electricity trading among European countries. In any case, when required, the pursuit of the economic benefit leads to the preferential use of the DR potential (the 50% of the maximum capacity of 10% is used due to no fundamental changes in current market design) rather than gas units.

2. **Scenario 2 – Pessimistic:** In the context of less favourable economic and financial conditions and a weak European framework, this scenario assumes a situation where the lack of money does not allow the reinforcement of existing energy policies by national governments. Current permitting issues cause delays in construction of new infrastructures and lead to delays in the fulfilment of the energy roadmap 2050.

   Due to the absence of a European framework, generation mix is defined by national policy schemes. RES penetration is lower than required for achieving EC emission targets in 2050. For base load electricity generation, hard coal is the preferred technology as a consequence of the carbon pricing level driven by existing policies.

   This situation does not promote technological or energy efficiency breakthroughs, as research and development (R&D) is financed by parallel national plans (very repetitive and not optimised), and planned commercial deployments of CCS infrastructures become non-realistic.

Negative or low growths are expected in electricity demand, particularly in view of the assumed low penetration of electricity in transport and heating/cooling sectors.

Even though no advanced T&D grid connections are assumed in this scenario, certain smart communications are considered that allow balancing in case of RES fluctuations. DR potential is not deployed and there are no improvements in cross-border interconnections for electricity trading among European countries. The additional back-up capacity needed will be provided by gas units.

3. **Scenario 3 – Optimistic**: In the context of more favourable economic and financial conditions and within a strong European framework, this scenario assumes a situation where national governments allocate money for the reinforcement of existing energy policies, mainly, in sustainable generation.

   The strong European framework has great influence on the generation mix, which is on track for the compliance with the defined EC emission targets in 2050. There are no technology preferences and all of them compete in the market without specific support measures. For base load electricity generation, gas is the preferred technology as a consequence of the carbon pricing level driven by the reinforcement of the existing policies.

   This situation promotes technological and energy efficiency breakthroughs, as R&D expenses are optimised and commercial deployment of CCS infrastructures is speed-up by means of European subsidies.

   The use of electricity in transport and heating/cooling sectors is intensified through additional subsidies. Increases in electricity demand caused by these new uses cannot be compensated by energy efficiency improvements, leading to growths in electricity demand.

   With regard to electricity grids, advanced monitoring, control and communication links are considered in T&D systems together with bidirectional electricity flows in distribution. V2G approach is fully developed for electric vehicles and flexibility is assumed on both, charging and generation sides.

   The need for additional back-up capacity for RES balancing is reduced by the existence of a common European energy framework and the improvement of cross border interconnections for electricity trading. In any case, when required, DR potential is fully available, with additional contributions from pumped hydroelectric storage and gas units.

4. **Scenario 4 – Ecological footprint reduction**: In the context of more favourable economic and financial conditions, this scenario assumes a situation where national governments allocate money for the reinforcement of existing energy policies.

   Due to the absence of a European framework, generation mix is defined by parallel national policy schemes without technology-specific support measures. Even though this mix is on track for the

compliance with the defined EC emission targets in 2050, it means higher costs caused by the need of higher back-up capacities, mainly covered by gas units with additional contributions from DR. For base load electricity generation, gas is the preferred technology as a consequence of the carbon pricing level driven by the reinforcement of the existing policies.

This situation does not promote technological breakthroughs, as R&D is financed by parallel national plans (very repetitive and not optimised), and planned commercial deployments of CCS infrastructures become non-realistic.

The minimisation of environmental impact drives the increase in the use of electricity in transport and heating/cooling sectors (intensified through additional subsidies) and energy efficiency breakthroughs. In the current market framework, the growths in electricity demand caused by these new uses cannot be compensated by energy efficiency improvements, leading to growths in electricity demand (higher than Scenarios 1 and 2 and lower than Scenario 3).

Even though no advanced T&D grid connections are assumed in this scenario, certain smart communications are considered that allow balancing in case of RES fluctuations. The lack of improvements in cross-border interconnections for electricity trading in Europe lead to higher back-up capacity needs that are covered by gas units. However, in this case, this need is somehow reduced by partially using DR potential (the 50% of the maximum capacity is used due to no fundamental changes in market design).

A summary of the four final scenarios selected is shown in Figure 17.

Scenario 1	Scenario 2	Scenario 3	Scenario 4
RES **lower** than required to fulfil 2030 emissions targets	RES **lower** than required to fulfil 2030 emissions targets	RES **equal to or higher** than required to fulfil 2030 emissions targets	RES **equal to or higher** than required to fulfil 2030 emissions targets
Good cross-border interconnections	**Poor** cross-border interconnections	**Good** cross-border interconnections	**Poor** cross-border interconnections

Figure 17 SmartNet high-level scenarios

3.3 Mapping of the scenarios to the pilot countries

By analysing the available predictions for the future situation in the three pilot countries (Denmark, Italy and Spain), the expected evolution of RES implementation to fulfil the emission targets in combination with the status of the cross-border interconnections by 2030 can be identified. This analysis allows the mapping of these countries to the defined high-level scenarios.

For *Denmark*, a higher amount of RES with respect to the required to fulfil the 2030-emission targets and good cross-border interconnections are foreseen. As described in [49], the Danish energy system has two main characteristics:

- On one side, a highly diversified and distributed energy system, based upon three major national grids (the power grid, the district-heating grid and the natural gas grid). The combined utilisation of these grids has implied that Denmark has a highly efficient supply system with a high share of CHP.
- On the other side, RES technologies (especially wind power) play a large and increasingly important role in the Danish energy system. As an example, it is worth to mention that, by 2015, the 42% of the power needs came from wind power, being one of the global front runners in the development of offshore wind farms. In this line, Denmark is currently implementing an ambitious energy plan with a progressive phase-out of fossil fuels, including their complete removal by 2050. As far as wind production is concerned, the 50% of the Danish electricity consumption must be produced by wind turbines by 2020.

From the point of view of cross-border interconnections, the analyses done by the ENTSO-E [50] state the fulfilment of the 10% interconnection capacity goal[10] (compared to the installed generation capacity) by 2020. This can be seen in Figure 18 for the whole Europe.

[10] Target interconnection rate established for 2020 for every European country.

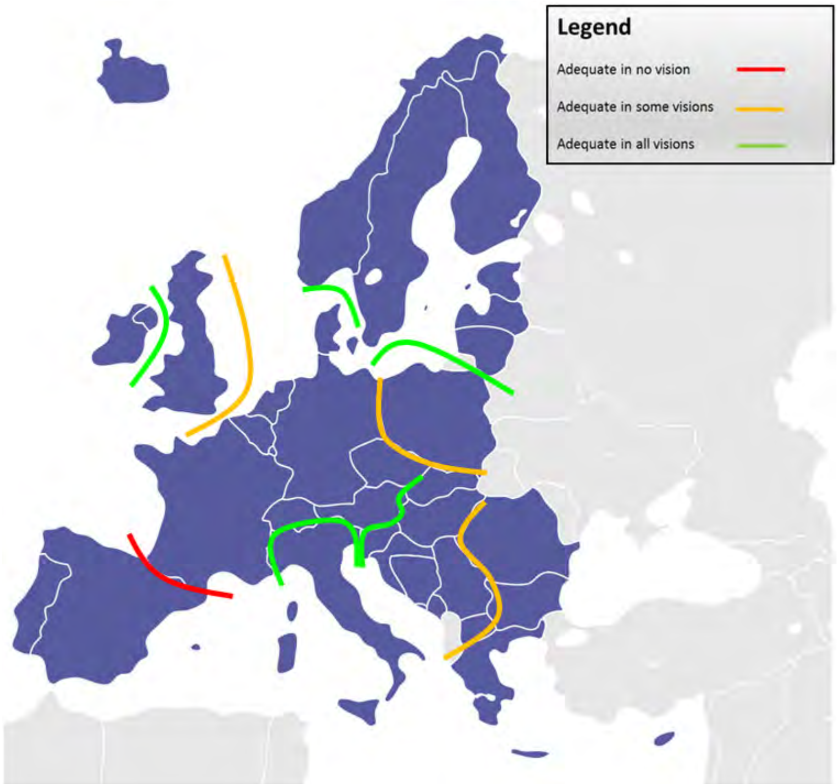

Figure 18 *2030 Transmission adequacy [50]*

On the basis of this information, the scenario that better suits for Denmark is *scenario 3*.

Regarding the Italian situation at 2030, different visions and ideas are present nowadays. The most updated and valuable forecasts are based on a work developed by RSE and ENEA for the Italian Ministry Economic Development [51]. According to this study, Vision 3 of ENTSO-E is the most adherent to the Italian situation, with a RES penetration slightly below the 50% targets. As it can be seen in Figure 19, the installed capacity in Italy has increased 50 GW in the last years, with more than 30 GW of RES (without taking into account hydro power systems). In 2030, installed RES capacity will reach around the 46.5% (70 GW) (in line with ENTSO-E Vision 3), maintaining only the 4% (7 GW) of hard coal-fired power plants and the 25% (37 GW) of combined cycle gas turbines.

With respect to cross-border interconnections, the situation is the same as the one described for Denmark, this is, the 10% interconnection capacity goal is expected to be achieved by 2020 [50] (see Figure 18).

For these reasons, the *scenario 4* of SmartNet is considered the one that better suits on the Italian situation.

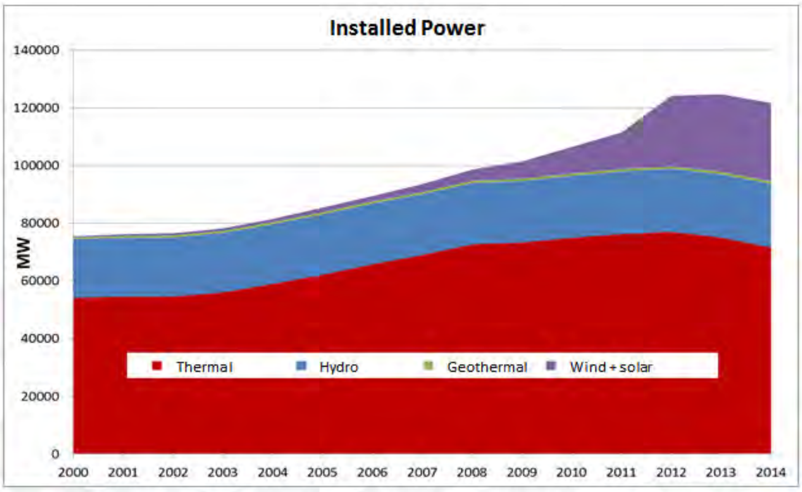

Figure 19 Installed capacity in Italy

Eventually, concerning *Spain*, prospects are more pessimistic regardless the recent results published for Spain and Portugal. These results show that the contribution of RES (mainly wind and hydro power) to the energy requirements was, for the first time ever, greater than the one of fossil fuel based sources. This has proven that RES can maintain the capacity market even as energy demand increases.

In any case, the 2030 framework will not actually encourage further investment in RES. This does not mean that CO_2 emissions reduction target will not be achieved, but that this objective will probably be reached not only by increasing RES capacity, but also by including the emissions trading mechanisms between different countries to fulfil the goal [52]. Nevertheless, it seems that this target is feasible at the whole EU level.

From an interconnection point of view, the boundary between Spain and France appears since many years as one of the most congested in Europe. The compliance with the target interconnection rate of 10% of installed generation capacity drives the grid development through this boundary, as current ratio for Spain is still far from the target. In March 2015, French, Spanish and Portuguese Governments signed the Madrid Declaration with the EC. This declaration showed the will to develop four projects to increase the capacity between France and Spain to 8 GW. Nonetheless, it is still not considered enough, even though this investment effort improves very much the interconnection ratio of Spain [50].

It seems quite clear that Spain will be unable to reach the needed interconnections targets established by the EU for 2030 (see Figure 18). For these reasons, *scenario 2* seems to be the most probable for Spain.

Both the scenarios and the mapping to the countries under study will be further used along the project, especially for the simulations which will lead to the identification of the most suitable coordination schemes and their cost-benefit analysis.

3.4 The evolution of the ancillary services in the 2030 horizon

Once the three pilot countries have been mapped into one of the four high-level scenarios, it is possible to identify the evolution required in the ancillary services in each of the countries, not only in terms of possible changes in the existing mechanisms but also considering that new products, services or functionalities could appear in the markets.

3.4.1 Novel ancillary services

The growth of new technologies (RES, DR, electricity storage) implies a major change in the power supply structure, which will require both the provision of new ancillary services and the evolution of the existing ones. According to the expected future changes, the traditionally main providers of ancillary services (conventional generators) will be proportionally less important, as a result of the increasingly important impact of novel resources in the grids. That is the reason why new ancillary services will be needed. The objective of this section is the identification of the expected, most relevant ancillary services to be provided in the future by DER units.

As a first step, these expected services have been identified and classified into four main categories; frequency control services, voltage control services, power quality improvement and other services (for other purposes or for combined frequency and voltage control), as shown in Table 3.5. In the technical literature concerning the future ancillary services provision, noticeable differences between several authors can be found in the definition of what a new ancillary service is. For clarification purposes, new ancillary services have been split into three categories:

A) Ancillary services that are currently widespread implemented, but only provided by conventional generation up to date. These novel services will be supplied by the DER/DSM that appear as new market participants in the time horizon considered in SmartNet (2030).
B) Ancillary services that are considered as "new" because they are not widely deployed. This is the case of voltage control or the black start capability. Primary, Secondary and Tertiary Voltage control ancillary services are commonly found in the literature. However, in many countries, such as in Spain, the voltage control service is simpler, so this distinction between the different control layers is not made.
C) New functions that will be implemented in DER in order to make them suitable for the provision of certain ancillary services. Some of them could be oriented to provide a certain service, e.g. a wind turbine with fault ride-through capability can contribute to restore the voltages during a fault by supplying reactive power to the system. This way, it could be used for primary voltage control. Some others can constitute a new ancillary service itself, such as the ones dedicated to the power quality improvement.

	A AS Widespread Today	B Emerging AS	C Future DER AS
Ancillary services for frequency control	FCR FRR RR		Fast frequency reserve: Inertia emulation Ramp margin: Ramp control
Ancillary services for voltage control	Congestion management through voltage control	Primary Voltage Control Secondary Voltage Control Tertiary Voltage Control	Fault ride-through capability
Ancillary services for power quality improvement			Injection of negative sequence voltages Damping of low-order harmonics Mitigation of flicker Damping of power system oscillations
Other ancillary services		Black start capability Compensation of power losses	Power factor control

Table 3.5 Future ancillary services/functions

Although all these services are expected to be developed in a future, the use cases (UC) definition within SmartNet project, Deliverable D1.3 [53], has only taken into account some of them; in particular, the ancillary services of frequency control (UC 1 and UC 2) and of voltage control (UC 3). Current market structures make very hard to predict the real implementation of a dedicated market the other novel ancillary services by 2030, because it would imply disruptive changes in the present trading mechanisms for ancillary services.

In spite of this selection, an assessment of existing literature on novel ancillary services/functions has been carried out and the information is available in chapter 10 (Appendix D) of this deliverable. It is oriented to compare the status of their actual deployment (mainly focused on the DG participation) and the main factors linked to the procurement of each service. Those belonging to category A have not been included in the appendix, since they were already analysed in the scope of section 2.1.

3.4.2 New requirements to the existing ancillary services

In addition to the new services described so far, it is also expected that current characteristics of ancillary services and the requirements for providing them will be adapted by 2030. This section describes the main trends in that direction.

As described in chapter 2, existing ancillary services market mechanisms favour the provision of the service by programmable (non-RES) generation units, especially by the big ones. As an example[11], the Italian regulation, which is based on deliberation 111/06 [54] of the national Regulatory Authority and on the Grid Code [15] for transmission, dispatching, development and security of grid issued by the TSO, limits the potential market participants to those which fulfil the following requirements:

- The unit must be a programmable relevant unit (i.e. greater than 10 MVA).
- It must be able to change the power output within 5 minutes after the instruction.
- It must have a gradient of 10 MW (for secondary reserve, tertiary reserve and congestion management) or of 3 MW (for balancing) in 15 minutes.
- For hydro power plants, the number of equivalent hours per year must be at least equal to 4.
- If it wants to provide secondary reserve, it must also:
    - have a device able to elaborate secondary signals,
    - provide a half band that is at least the maximum between (10MW, 6% Pmax) for thermal power plants and 15% of maximum output power for hydro power plant, and
    - be able to provide an output within 200 seconds and to keep the output power for at least 2 hours

Figure 20 gives an idea of the present limitations for the participation to ancillary services: only part of the programmable, relevant production can participate, while all the other units are excluded a priori.

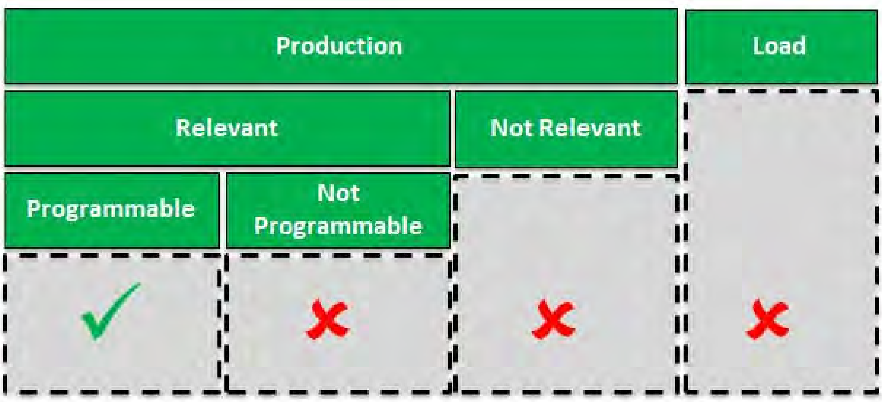

Figure 20 Present limitations to the participation in ancillary services

[11] The expected evolution in Norway is also presented in Appendix D (in section 10.5).

This means that, with the present regulation, there are some barriers to a non-discriminatory participation at the ancillary services market; in particular, there is a technology limitation, because there are explicit constraints on generation technologies: load and RES are excluded while the access should be allowed for all the resources that could potentially provide those services.

There are also limitations on sizing: the access is limited to power plants greater than 10 MVA with some requirements defined such as secondary margins, gradients, etc., that allow the access only to big power plants.

Finally, also the service is defined for upward/downward regulation, and this limits the possibility to provide a service for some actors (i.e. half secondary band for RES power plants).

There are several reasons to pursue for changing the existing situation. The most obvious are:

- Improve the process of procurement and activation of the reserves.
- Involvement of RES into the reserves whenever it is technically possible.
- Encourage harmonisation of balancing markets across Europe.

Following these, several changes have been proposed, based on the public consultation process in Italy and the intermediate conclusions from Market4RES project [55].

1. Timing of markets: Timing of markets could be modified in order to allow market participants to react faster to the changing conditions, caused by the intermittent generation. The European Commission recognises market participants' needs for "*adjusting their balances by trading in the intraday market time-frame as close as possible to real time*" [56] and establishes a maximum time of one hour between the intraday cross-zonal gate closure and the start of the relevant market time unit. Although this requirement is more demanding than the existing setups in some countries (see Figure 3 or Figure 4), some other countries are going even further by establishing shorter periods between intraday gate closure and real time operation[12]. These modifications of the present timing of markets will reduce the imbalance on reduce volumes necessary for provision of the ancillary services.
2. Minimum bid size requirements and aggregation of the bids: Minimum bid size refers to the minimum balancing power that must be offered by a single BSP in order to participate in balancing markets. Depending on the product minimum bid size, small generation and load units may be prevented from participating in balancing markets if aggregation of individual units' offers (for

12 https://www.epexspot.com/en/press-media/press/details/press/EPEX_SPOT_and_ECC_to_reduce_Intraday_lead_time_on_all_markets
https://www.epexspot.com/en/product-info/intradaycontinuous

compliance with minimum bid size) is not allowed. This is the case of balancing markets in Spain where bids must be sent by individual (generation) units. In several countries this obstacle however already does not exist e.g. at the Nordic Regulating Power market does not distinguish between a single-object or aggregated bid. Minimum bid size of 1 MW was proposed by Market4RES project [55] as a common target Europe.

3. Participation of demand products in balancing markets: Several European countries currently allow participation of demand in the balancing markets from single regulating objects or aggregated. However, there is no clear framework, which may encourage involvement of the end-users and design of the necessary market mechanisms.
4. The Imbalance settlement period: The imbalance settlement period refers to the period of time for which imbalances are calculated. Historically it is different practice in European countries, where settlement periods vary from 15 minutes (e.g. Belgium, the Netherlands, Germany, Switzerland, and Austria), 30 minutes (e.g. France), up to 1 hour (e.g. Portugal, Spain, and the Nordic countries). Short settlement periods contribute to a more cost-reflective imbalance settlement. This can be explained by the fact that BRPs that have been out of balance within a settlement period may be balanced over the whole period. Consequently, the costs incurred by the TSO to balance the system in real time cannot be properly allocated to the responsible market party. Reduction of the settlement period is also likely to reduce the activated volumes. It is interesting to mention that in EcoGrid EU project [57] 5 minutes was suggested as initial settlement period and tested in big-scale demonstration. The project however concluded that 15 minutes would probably be the most feasible alternative.

Based on these general recommendations, the specific recommendations for the Italian case described above can be summarised as:

- To enable not only large units, but also aggregation of the smaller ones;
- The gradient should not be expressed in absolute values (10 MW) but with a percentage of the maximum output power;
- The differentiations in upward and downward bids (no more symmetric as it is actually), so that also RES can participate to ancillary services market.

Moreover, current standard products traded in Italy are suitable also in a context with high penetration of decentralised generation. The focus is on the removal of constraints related to the technology and the size of resources that limit the participation of DER.

In the consultation document 255/2015/R/EEL of the Italian Authority (AEEGS) a list of possible innovative functionalities is listed, as reported in the Table 3.6:

Innovative functionality	Main role	Applicable also without network information communication
Observability of power flows and distributed generation	Distributor	Yes
Voltage regulation at medium voltage level	Distributor and enabled active users	Yes
Network users' active power regulation	Distributor and enabled active users	No
Remote tripping for avoiding the phenomenon "island" at medium voltage level	Distributor and enabled active users	No
Advanced exercise of medium voltage level network	Distributor and enabled active users	Yes (but a communication with network elements is necessary)
Use of storage system for network needs	Distributor	Yes

Table 3.6 List of possible innovative functionalities

4 Evaluation of the future needs for reserves

In order to guarantee the correct performance of the future European power system, an estimation of the reserves needs in 2030+ is required. For that purpose, the reserves forecasts for the different products existing today at a European level can be taken as a basis, together with the methods used by the responsible agents for such estimations.

In this chapter, this knowledge of current reserves mechanisms will be used as groundwork for projecting the reserves needs in the SmartNet horizon in Denmark, Italy and Spain through a Reserves Dimensioning Tool that could be easily extended to any other European country.

4.1 Approaches to reserves sizing

4.1.1 Frequency reserves

The ultimate cause of frequency changes is the difference between active power production and demand. These frequency deviations can occur as a result of different causes:

- Small and fast variations produced in generation and consumption.
- Stochastic errors coming from the forecasts of plants relying on fluctuating energy sources (wind, solar…) or from the forecasts for the electricity demand.
- Imbalances between the actual production and consumption curves and the stepwise results of the market based balancing schedule.
- Large disturbances caused by the sudden disconnection of a generator, a major component of the transmission network or a big load.
- Network splitting and reconfiguration.

The purpose of frequency control reserves is to maintain the system frequency within its boundary conditions. In order to determine which the reserves needs are in a power system, three different approaches can be used:

1. **<u>Deterministic:</u>** The most straightforward methods for dimensioning of reserves are the deterministic methods. A deterministic method calculates the reserves starting from a fixed assumption. This assumption can be the consideration of the event with the largest balancing impact or the definition of a reference incident to be used for dimensioning.

   The reference incident is the worst event occurring on the network that the available reserves need to be able to handle. This constitutes a simplified (but conservative) version of the deterministic approach where only the event with the largest impact is considered. In order to calculate the reserves needs in the deterministic approaches the sum of the contributions from the different

deviations can be taken. The application of this methodology tends to over-dimension the reserves. Some ways to work around it are to:

- Consider only a part of the forecast errors for generation and consumption by combining them with larger events.
- Include some weighting factors over the deviations instead of directly summing them up.

In general the contribution of variable sources of the same types is pooled. Wind power forecast error for example can be used as a single parameter, along with solar power production or consumption forecast errors.

2. **Probabilistic:** Probabilistic approaches consider the various possible incidents as well as the stochastic and deterministic factors together with their potential impact and likeliness to occur. The probability functions for the different stochastic and deterministic deviations vary depending on the system, preventing us from developing an easy method to compute the results. The main factors influencing them are:

- The nature of the generation mix.
- The size of the system.
- The types of loads connected.

For instance, the Probability Density Distributions (PDD) of typical deviations due to thermal plant generator failures, load and wind power forecasting errors are shown in Figure 21, along with an example of their combination by recursive convolution algorithms. In the x-axis, the MW for power is represented while the y-axis shows the probability of the deviation (%). The LOLP is the loss of load probability, showing how to dimension the reserves with a 1/400 risk of load shedding.

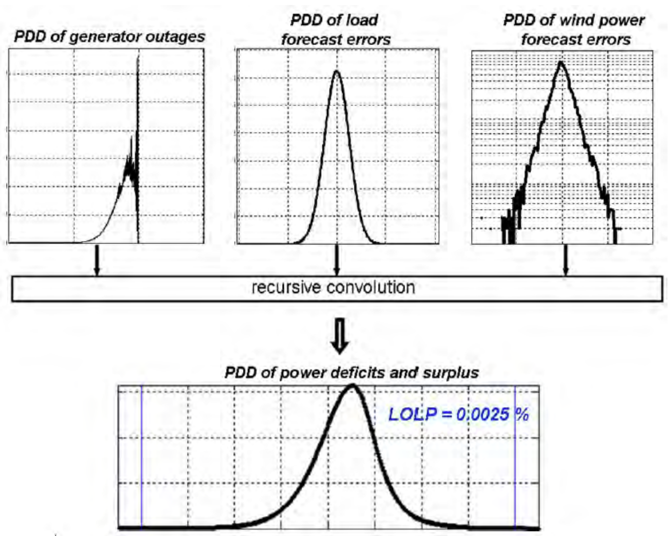

Figure 21 Calculation of reserve requirements based on power station outages, and load and wind power forecast errors [58]

According to ENTSO-E recommendations, the probability density functions representing the stochastic and deterministic variations to have to be assessed on the basis of the measurements spanning over at least one year. The use of a convolution product to combine the effects of different distributions can be made only if the factors are not correlated. For example, PV generation and forecasting error related to air conditioning loads are correlated. However, ignoring this effect does not leads to a underestimation of the reserve needs and the approach can be still considered conservative.

A typical method to handle a convolution product is to calculate them using the fast Fourier transform of the probability functions.

3. **Dynamic**: The deterministic and probabilistic methods already described compute the reserves needs for a long period of time, such as a year. They provide good results when the major or the only component for sizing is the reference incident. Other sources of deviations, such as errors in RES generation or load forecasts, can vary quite fast and have very different values throughout a day. For that reason, it can be more efficient to recalculate the needed amount of reserves at shorter intervals.

   The level of dynamicity can be different from case to case. For example, the FCR reserves are adjusted on a day-ahead basis in Finland, while studies on high levels of wind integration [59] point out that adjustment to reserve levels may be required up to every 10 minutes. The dynamic approach can be applied to any of the other approaches presented earlier.

   The use of a dynamic approach can help to reduce the costs of acquiring reserves. A longer term method is still needed to assess the amount of reserves that should be possible to activate at any given time. The dynamic approach optimises the costs but it works only if the resources are available.

4.1.2 Voltage control reserves

The objective of voltage control is the maintenance of the voltage value within the limits permitted by voltage quality standards and the restriction of the voltage drop in the event of a short circuit. In section 10 (Appendix D), five different future ancillary services for voltage control are defined: fault ride-through capability, congestion management, primary voltage control, secondary voltage control and tertiary voltage control. The categorisation adopted in this section is different from the one used in Appendix D because this is based on grid phenomena, where a distinction is made between static and dynamic voltage stability:

- Static voltage stability primarily involves maintenance of local reactive power balance.
- Dynamic voltage stability largely depends on the provision of short circuit power during a disturbance.

The TSOs have the commitment to ensure the availability of sufficient resources providing fast response to ensure normal operation in stationary conditions and to be able to push back the voltage levels in case of any contingency [11]. This is made by a combination of deterministic and dynamic approaches (according to the definitions given in subsection 4.1.1 for frequency reserve estimation methodologies).). For the dynamic adjustment of the voltage reserves, the worst condition that can be experienced in the real world (according to the actual generation capacity) it is periodically simulated, periodically, the worst condition that could take place in real-time, according to the actual generation capacity. In Tthis way, the reserve estimation of the reserves made in advance is corrected on the basis based onof the forecasted voltage profile. Current practices in estimating the reserves needs in Europe.

4.2 Current practises in estimating the reserves needs in Europe

4.2.1 Frequency reserves

There are three main types of frequency reserves:

1. **Frequency containment reserves (FCR)**: The establishment of the required FCR needs is determined by ENTSO-E for every synchronous area at a global level, but the responsibility to provide the FCR reserves is shared among the different TSOs. The FCR are used to keep the system balance and correct minor deviations in the synchronous area, as well as to stabilise the system in case of a severe disturbance (that should be later corrected by the FRR and RR). The FCR needs in every synchronous area are determined by means of a reference incident.

   In the Northern Europe Area (NE) the reference incident is the N-1 criterion and the reserve is dimensioned on the basis of the worst event that can occur. That disturbance can be the disconnection of a generating unit, a big load, a high-voltage direct current (HVDC) link or the tripping of an AC-line. The reference incident is volatile and it is calculated regularly [6]. In NE, the reference incident has been selected using a deterministic method, considering the maximum expected instantaneous power deviation between generation and demand in the synchronous area. The particularisation of the contribution of every country to the FCR reserves is done by introducing a coefficient affecting the total FCR. This coefficient is the ratio between the energy produced in the affected country the year before (considering importing/exporting power flows) over the energy produced (also the year before) in the whole synchronous area. Therefore, this coefficient is dynamic and has to be updated annually.

   In the Continental Europe area (CE), with more generating units, lines and loads, it is more likely that a second disturbance would occur before the first one has been completely recovered. In that case the N-1 criterion has a higher probability of not being sufficient and the N-2 criterion has shown to be the best practice by applying probabilistic techniques. In this case, two disturbances as described above

can occur simultaneously. In the CE synchronous area, the reference incident is currently considered to be 3000 MW (two nuclear power units of 1500 MW each) [6]. The share between countries follows the same rule as in the NE area, which is the application of a yearly updated coefficient over the total to make the distribution of FCR obligations among partners.

In both reference incidents, the reserve exhaustion possibility is checked by using probabilistic methods that combine the effectively used FCR reserves together with the existing Frequency Restoration Control Error.

2. **Frequency restoration reserves (FRR)**: The frequency restoration reserves have to be determined for every control area belonging to the synchronous region. The FRR rules, for example, the aFRR/mFRR ratio, have to be agreed between the TSOs in the same control block. In Spain, REE is the responsible for determining these needs for FRR reserves (jointly with REN, the Portuguese TSO, since they share the control block), whereas Terna must determine the requirements for the Italian case. In the Nordic countries, the situation is a bit different because several TSOs have responsibility on the NE, which is a single control block/control area. As a result, all the involved TSOs have to agree to fulfil the common goal of FRR reserves.

   The ENTSO-E recommendations to settle the minimum values of reserves in the CE and in NE given by ENTSO-E are based on the combination of both deterministic and probabilistic methods. The deterministic method uses the reference incident, which has to be combined with the historical records of the TSO (for at least one year). From this approach, the minimum requirement of FRR reserves established for the UCTE area [11] is shown in equation (2):

$$R = \sqrt{aL_{max} + b^2} - b \quad (2)$$

   Where a and b are known coefficients (10MW and 150MW respectively) and L_{max} is the anticipated consumer load in the control block. Considering the recommendations of the Network Code on LFCR [40], the minimum upward reserve in the whole Control Block should not be less than the positive value of the reference incident and the negative downward reserve should not be smaller than the negative reference incident. However, by common agreements between neighbouring blocks and considering probabilistic indexes, these minimum requirements for reserves can be reduced.

3. **Replacement Reserves (RR)**: As for the FRR, an agreement in the rules between the TSOs belonging to the same control block has to be reached. The RR must be sufficient to, at least, replace the operation of the FCR and FRR, both upwards and downwards.

4.2.2 Voltage control reserves

According to the ENTSO-E operational handbook, the recommended procedure to estimate the voltage control reserves is to apply the N-1 criterion to several facilities. Each generator is obliged, by the TSO in

its control area, to fulfil with the needed voltage control requirements, and to provide automatic response to voltage deviations. This way, the grid operators are aware of the voltage control resources in their own grid. In addition, suitable coordination of voltage control methods throughout the whole electricity grid is needed and neighbouring TSOs must agree about the voltage limits in the common borders.

4.3 Overview in current reserves needs in Europe

4.3.1 FCR

The FCR dimensioning is based on the reference incident established by ENTSO-E and each country's share is proportional to the share of net generation and consumption in the country with regards to the net generation and consumption in its synchronous area. The total value established in the CE is 3000 MW, while the total in the NE is 600 MW. The share of this responsibility among the pilot countries is shown in Table 4.1 .

	FCR (MW)	
Italy	1096	
Denmark	23 (DK1)	59 (DK2)
Spain	251	

Table 4.1 FCR obligations (2014)

In Italy, the FCR is procured in a competitive market, and the value to be traded is 1.5% of the reference incident. For Spain, the FCR is compulsory and the total value in MW has been estimated by considering the data provided by the TSO in its annual report [60]. In Denmark, the total requirements of FCR are shared between the two regions, since they belong to two different synchronous areas (DK1 to CE and DK2 to NE).

4.3.2 Automatic FRR (aFRR)

The data provided in this subsection has been gathered from the information directly received by the TSOs via questionnaires sent for the elaboration of the report "Impact of merit order activation of frequency restoration reserves and harmonised full activation times" [61]. The study shows the aFRR average reserves in 2015 by country, both upward and downward, that were contracted by the European TSOs (in average) in February and June of 2015. The results are shown in the following pie charts, Figure 22 and Figure 23.

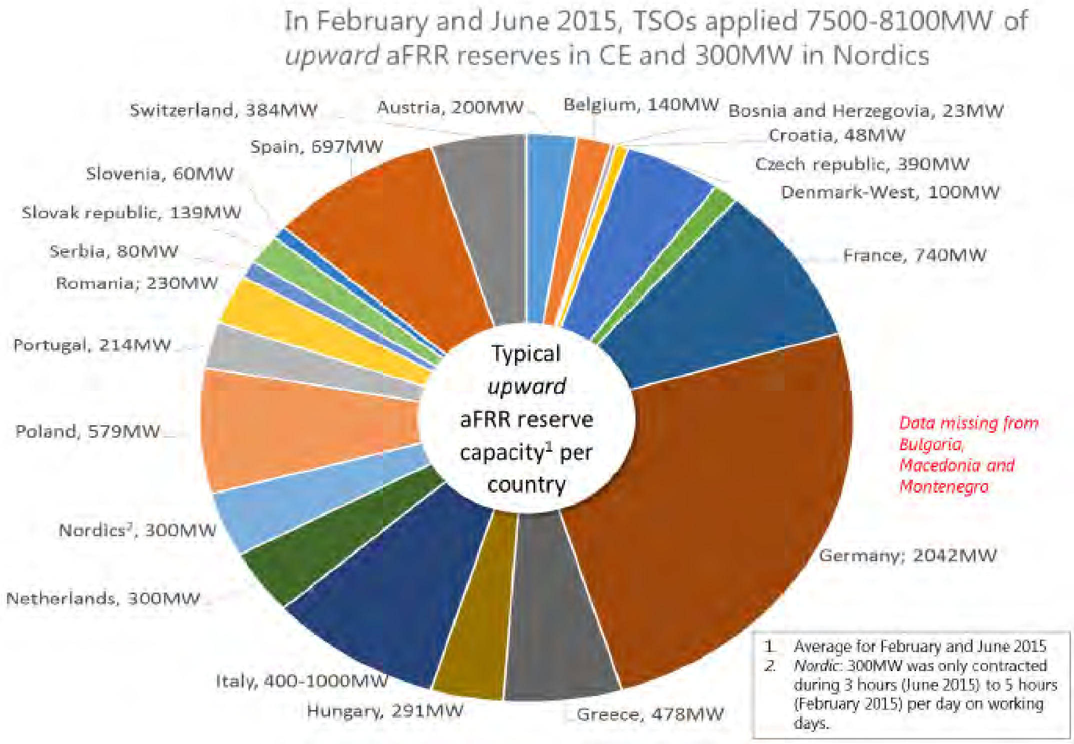

Figure 22 aFRR upward reserve capacity in Europe in February and June 2015 [61]

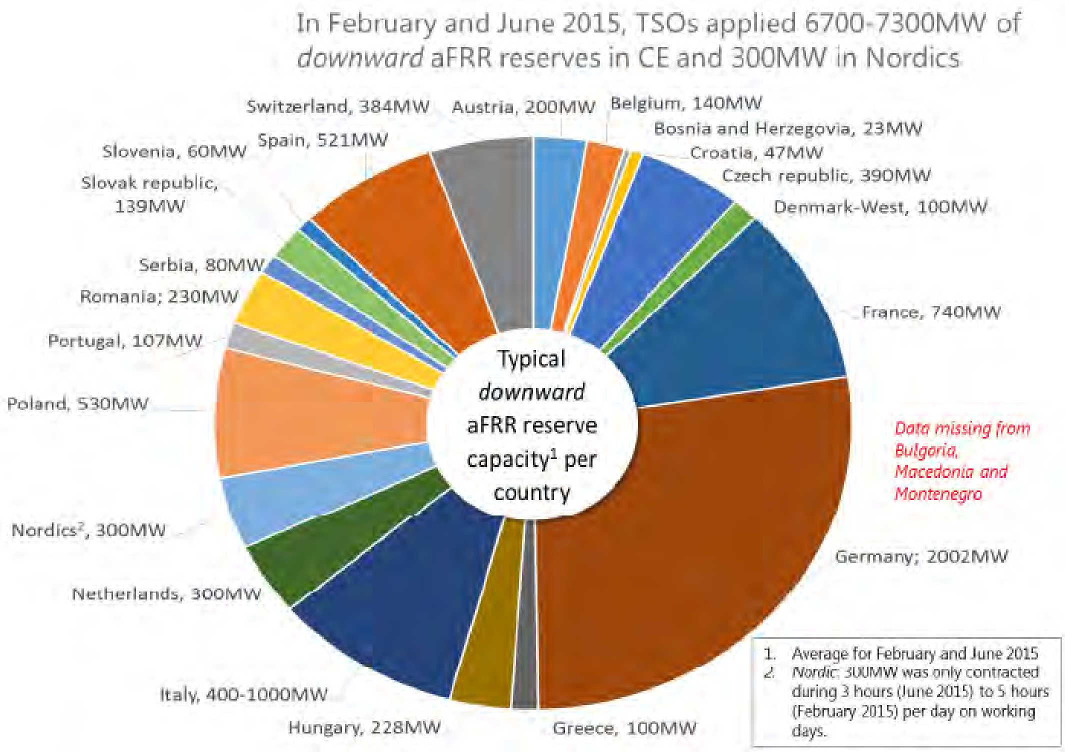

Figure 23 aFRR downward reserve capacity in Europe in February and June 2015 [61]

For dimensioning the aFRR reserves, the usual starting point used by the TSOs is the formula established by ENTSO-E (see equation (2)). However, due to the different characteristics of the control blocks and the agreements between them, the real contracted aFRR capacity is usually far away from the theoretically needed one resulting from the formula. In Figure 24, the typical aFRR capacity contracted is represented as a percentage over the formula.

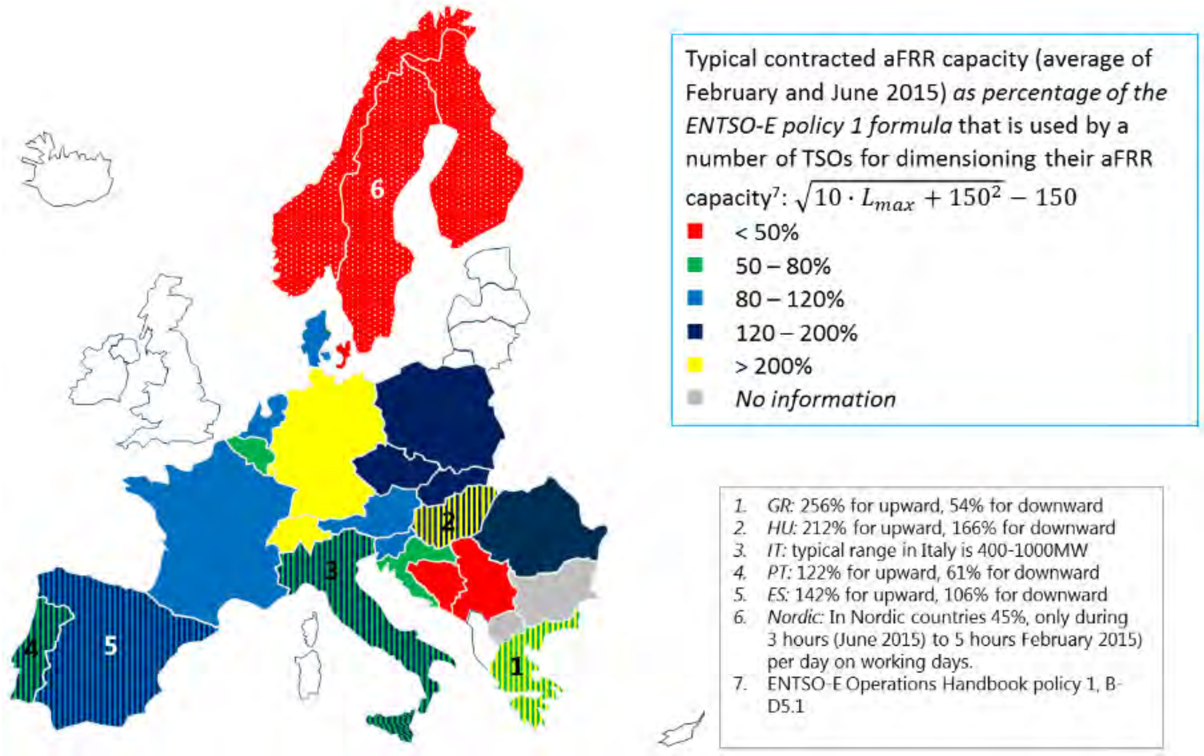

Figure 24 *Typical aFRR capability as percentage of the ENTSO-E formula used by a number of European TSO [61]*

4.3.3 Manual FRR (mFRR) + RR

Obtaining a graphical view of the mFRR and RR for the whole Europe is rather difficult because some TSOs balance their power system by trusting majorly in aFRR, while others trade a lot of manual reserves, but some of them as mFRR and others like RR (see section 2.1.1). However the ratio between manual reserves with regards to the total for every European country can be drafted as a percentage of the total reserves. This estimation is shown in Figure 25.

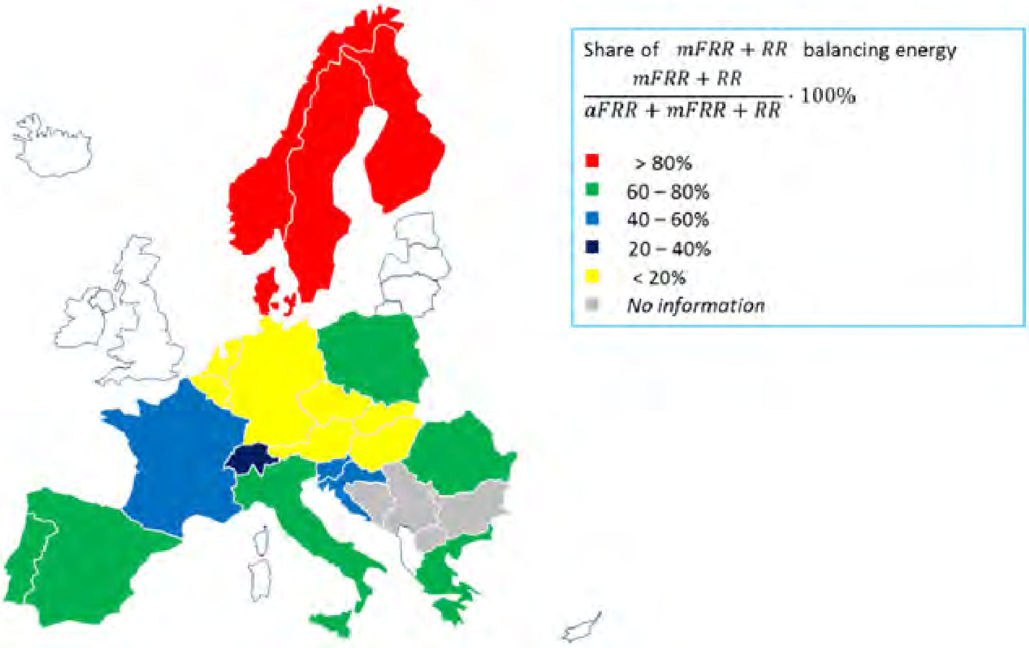

Figure 25 Percentage of mFRR+RR in total balancing energy (own figure with data from [61])

Considering the three pilot countries, where the information is publicly available, the average contracted mFRR and RR volumes in 2015 per country is summarised in Table 4.2.

		mFRR (MW)	RR (MW)
Denmark	**DK1 & DK2**	868	N/A
Spain		N/A	355
			319
Italy		568	4 327

Table 4.2 MFRR + RR in Denmark, Spain and Italy (2015)

4.4 Assessment of reserves needs in 2030

In this section, the evaluation of the reserves needs in the 2030 horizon is developed. Two different aspects are expected. On the one hand, an increase in the reserve needs due to the massive implementation of wind and PV generation, as well as the expected system imbalances, can be envisaged. On the other, the displacement of resources location will also change the ratio of the reserves that will come from distribution with regards to those located in transmission. However, the quantification of reserves by voltage level has to be done on the basis of the concrete scenarios that will be simulated in WP4.

4.4.1 Frequency control reserves

As discussed in section 4.2, there are three (four if both mFRR and RR are implemented) main types of frequency control reserves. Each country normally uses three types of reserves for different purposes. In all of them, FCR perform a similar role, but they are calculated in a centralised way and they are not able to contain frequency fluctuations for a long time. On the other hand, slower reserves can provide a more significant balancing capability and these can be traded in market environments. Therefore, the Reserve Dimensioning Tool has been designed to obtaining the reserve needs for aFRR, mFRR and RR. As described in section 4.3.3, RR is not considered separately but as part of mFRR.

The methodology used in SmartNet is based on the heuristics approach applied by the Belgian TSO, Elia [62], which is based on ENTSO-E recommendations. It roots on the combination of deterministic and probabilistic techniques. This approach was selected for three key reasons:

- It simplifies data needs compared to probabilistic methods.
- It is aligned with the current approaches applied by TSOs.
- It provides a rough but conservative estimation on balancing needs.

The total reserve is calculated taking into consideration the main sources of uncertainties in the power systems, both in the demand (load) side and in the side of non-dispatchable energy production (mainly wind and PV generation). The equation (4) represents the total reserve needs in a power system, in MW:

$$\text{TR} = GL^{max} + D^{err} + W^{err} + PV^{err} + AR \quad (3)$$

- GL^{max}: Maximum generation loss (in MW). E.g. largest nuclear power plant. This amount depends on the system's Reference Incident.
- D^{err}: Demand deviation error. Taken into account by increasing reserve needs by a percentage of the forecasted demand. E.g. x = 2% (in Spain).
- W^{err}: Wind power deviation error. Taken into account by increasing reserve needs to cover a certain percentile of wind forecast error (e.g. 99th percentile).
- PV^{err}: PV power deviation error. Taken into account by increasing reserve needs to cover a certain percentile of PV forecast error (e.g. 99th percentile).
- *AR:* Additional reserve needed to cope with further deviations of forecasts and market schedules as well as to manage international connections.

In order to have a simpler formulation, some of the equation terms are grouped and equation $\text{TR} = SI + W^{err} + PV^{err}$ (4) is obtained:

$$\text{TR} = SI + W^{err} + PV^{err} \quad (4)$$

Where SI represents the system imbalance, which includes demand error, unforeseen events and the reference incident, but not the errors of wind and PV. It is calculated by subtracting calculated PV and wind errors from the total imbalances in the system[13].

The total reserves should cover the imbalances 99% of the time, so this factor is taken as the percentile.

Then, this total amount of reserves must be split up by product type. The amount of aFRR is based on the variability of the residual quarter-hourly imbalances in the system in the following quarter hours. Instead of considering the total deviation errors, as it is done to calculate the total reserves, the differences of sequential deviation errors in each quarter of an hour are used, as illustrated in Figure 26. This gives an indication on the speed of the changes of the imbalances.

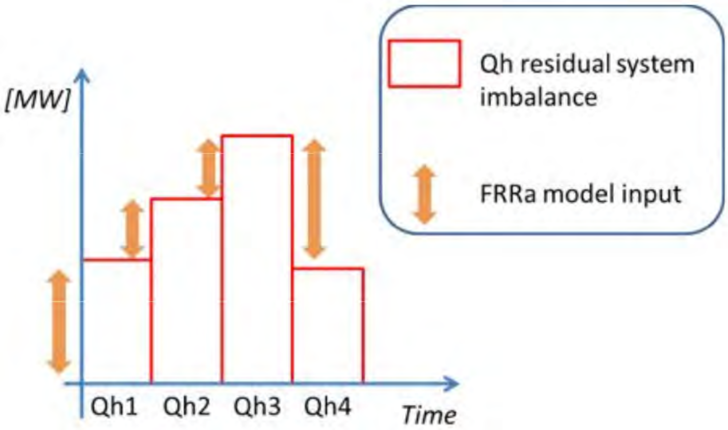

Figure 26 aFRR assumption [62]

These deviations are processed by means of equation TR = $SI + W^{err} + PV^{err}$ (4) which returns the total reserve of aFRR. It is important to highlight that selecting a percentile lower than 99% (default value in the ELIA methodology) is a common practice. In fact, according to the exemplificative cumulative curve reported in Figure 27 the amount of reserve needs increases exponentially with respect to the probability coverage. A more reasonable (but still safe) dimensioning of the reserve is obtained for the 90th percentile, which requires much less power than the one corresponding to the 99th coverage. With both total FRR and aFRR calculated, the mFRR is then obtained as the difference between total FRR and aFRR.

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[13] Other renewables will also generate forecasting errors but due to the small amount present in the system, they are omitted in this calculation and are assumed to be present in the general system imbalance term.

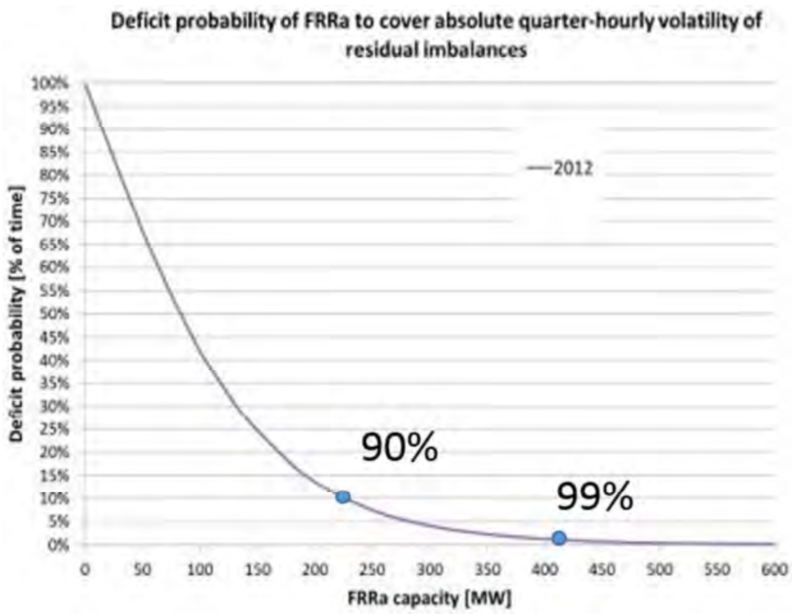

Figure 27 Comparison of probabilities for aFRR [62]

The proposed methodology has been tested by estimating the currently required reserves and considering the consistency with the data published by the corresponding TSOs. However, these needs have to be extrapolated to 2030. In order to accomplish this, two main assumptions have been made:

- The ratio of reserves needed compared to the total capacity of the system will remain constant up to 2030 (MW of reserve for each MW of wind/PV generation).[14]
- The system imbalances will also be constant.

The current total reserves for both PV and wind to compensate their forecasting errors are divided by their installed capacity. Then, these quantities are multiplied by the expected installed capacity in 2030 to get a forecast for the reserves needed in the future. The ratio of reserves needed for each technology compared to the total capacity of the system will remain constant up to 2030. The system imbalances excluding wind and PV come from unforeseen events and are difficult to predict.

Putting together the calculation of the total reserves as stated in equation $\text{TR} = SI + W^{err} + PV^{err}$ (4) and the extrapolation of these reserves to 2030, there are three categories of inputs needed for the total calculation of reserves in 2030:

[14] In 2030, we can reasonably assume that forecasting techniques will have improved and thus forecasting deviations will be lower. However, the approach considered here is a conservative evaluation as this presents the worst-case scenario.

- Both for wind and PV, the historical generation and the historical forecast for that generation is required so that the forecast errors can be calculated.
- For the system imbalance, the general imbalance of the system is needed. Together with the wind and PV errors, a new term can be calculated by subtracting wind and PV from the total system imbalance. This gives a new term called "SI-RES" that considers the additional imbalances in the system.
- For the 2030 forecast, both the currently installed capacity and the forecasted capacity in 2030 are needed, as well as both wind and PV capacities. For Italy and Spain, data from the PRIMES model is used. For Denmark, data from PRIMES is only used for the forecast [19]. However, as Denmark has two synchronous areas and only DK1 (West Denmark) is considered here, the data is adjusted by taking 75% of the total for wind and 70% for PV. These ratios are calculated from data provided by Energinet.dk, the Danish TSO.

Most data was with quarter-hourly granularity and for one whole year, i.e. 2015. The data with a different granularity was adapted in order to fit into the methodology.

As some data was only available with hourly granularity, the impact on aFRR had to be adjusted. For this purpose, data from Germany was analysed for 2015 and 2016. The average deviation for aFRR when using hourly data instead of quarter-hourly data was around 40%, meaning that hourly data gives 40% less reserves than quarter-hourly data. However, results are still limited as these differences will not be the same for each country.

As some data was only available with hourly granularity, the impact on aFRR had to be adjusted. For this purpose, the following method was used:

1. aFRR calculations are done for Germany[15], both for 15-minute and hourly data sets.
2. The average deviation between both data sets was calculated.
3. There is a reduction of 40% when using hourly data compared to 15-minute data

Therefore, the aFRR reserve calculations for countries with hourly data are reduced by 40%.

The application of the methodology and the calculation of the reserves for the pilot countries in SmartNet (Denmark, Italy and Spain) are shown below.

The total reserves calculated by the tool for Denmark by 2030 are shown in Table 4.3:

[15] German data is used for this as both 15-minute data and hourly data was available and the data is more reliable due to the experience with RES and forecasting

	aFRR (MW)	mFRR (MW)	Total FRR (MW)
Upwards	262	426	688
Downwards	257	334	591

Table 4.3 Calculated reserves – DK1

It is important to note that Denmark is considered here as DK1 (Denmark West) because this is part of the synchronous region with Western Europe and where Pilot B will be executed. Therefore, some adjustments that are reflected in the results were made. First of all, only wind and PV from West Denmark were entered into the tool. Secondly, the installed generation and forecasted installed generation were also adjusted as explained above. As there was no quarter-hourly data available, the data was adapted as explained above.

For Spain, the total reserves calculated by the tool are shown in Table 4.4 :

	aFRR (MW)	mFRR (MW)	Total FRR (MW)
Upwards	783	1 523	2 306
Downwards	669	1 028	1 697

Table 4.4 Calculated reserves – Spain

It can be highlighted that reserves were calculated on a MW basis, while for Spain only energy is used as a reserve. However, to generalise this tool for other countries, the results were also expressed in MW for Spain. Spain currently does not have mFRR (RR is used instead) but only aFRR, with a minimum requirement of 400 MW downwards and 500 MW upwards [62]. This is consistent with the reserves figures that have been calculated with this method.

In the Italian case, the total reserves calculated by the tool are shown in Table 4.5:

	aFRR (MW)	mFRR (MW)	Total FRR (MW)
Upwards	1 470.56	3 191.36	4 661.92
Downwards	1 413.66	5 472.60	6 886.26

Table 4.5 Calculated reserves – Italy

Due to data limitations for PV and system imbalances, the results in this case were not as accurate as for the other countries:

- For PV, data of realised generation was only available for 5% of the total installations. Therefore, we took this 5% as representative for the whole country but deviations are likely to occur as this is a large/strong assumption.
- For imbalances, no raw data was available. Instead, data of calculated imbalances based on bids in the balancing market was used. However, this data was not available for a full year (only 2 months), which may cause results to deviate from reality and also makes them not comparable with the other countries.

4.4.2 Voltage control reserves

The voltage control reserves have a local character and they are largely dependent on the grid topologies. As a result, it is complicated to have the required data to evaluate the voltage control needs in the different pilot countries in 2030+. Moreover, the WP4 simulations exclude the use of voltage control reserves and, hence, the lack of data for calculation of voltage reserve needs is not determining for the SmartNet purpose. In future scenarios, we can have an increased need for localised reserves. In the same way as FRR reserves are currently separated between control areas in order to better control the power flows, some new reserves could be beneficial to help alleviate congestion and to provide voltage control at the distribution level.

However, in order to review how the future development of voltage control needs could be, the situation of two countries where this problem has already been considered by local organisations are analysed: Germany, as an example of a strong and meshed grid with a high degree of variable distributed sources installed, and Ireland, as a representative mock-up of a weak grid.

4.4.2.1 Reactive power provision

As an example of voltage reserves calculation according to future grid developments, a study prepared by the German Energy Agency [64] is presented. The reactive power demand at each grid node was calculated for 8760 use cases (one per hour in a year) utilising the optimal power flow. The calculation was first carried out without a consideration of reactive power sources and the results represented the demand. In a second step, all available controllable resources were considered, and the additional demand to be covered by alternative sources was identified. Both the Rhine-Ruhr region and Greater Bremen were found to be the areas with the highest additional capacitive and inductive demand, respectively. The additional capacitive demand required in Rhine-Ruhr region was 2753 MVAr and the additional inductive demand for Greater Bremen was 562 MVAr. The range of reactive power demand at the grid nodes was found to be higher overall.

In sum, the demand for reactive power in the transmission and distribution grids will increase in Germany for 2030, as well as the demand for reactive power control in distribution grids. Although reactive power demand calculation was carried out in the study, the study does not highlight quantitative results of the changes in reactive power demand, but rather emphasised the trends and factors affecting the needs as well as potential situations and locations where lack of reactive power may occur in future. It is also important to notice that results from individual reactive power demand calculations cannot be extrapolated to indicate the additional reactive power demand in other cases. The additional reactive power demand in individual cases needs to be calculated separately taking into account the grid topology and the available reactive power capacity. In the context of SmartNet this will also be an outcome of the simulations in WP4.

For other countries, like Ireland, the future reserves needs for voltage control are more difficult to estimate based on national studies and other literature. The current performance of the Irish system is not causing significant problems at present, although the system is becoming more stretched. An Irish study [65] states that given the nature of the changes to the types, connection methods and location of the future generation portfolio, together with the development and evolution of the transmission and distribution networks, it is difficult to predict exactly how much reactive power will be required and where. However, the study estimates that it is reasonable to expect that secure system operation will require a reactive power range that is broadly similar to the one at present.

In Ireland, existing generation has slightly better capabilities in terms of lagging reactive power and poorer capabilities in terms of leading reactive power than required by the new grid codes. It is assumed that new generation will replace the existing one to fulfil the new grid codes. Thus, the system capability for lagging reactive power is expected to fall while the level of leading reactive power is expected to rise, as shown in Table 4.6 for different 2020 capabilities (wind power not providing reactive power, transmission grid connected wind power providing reactive power 0.95 lag/lead, and all wind power providing reactive power 0.95 lag/lead) [65].

	Lagging MVar	**Leading MVar**
2010	3 510	1 570
2020 (only conventional)	2 650 (-24 %)	1 310 (-16 %)
2020 (wind in transmission)	3 240 (-8 %)	2 000 (+21 %)
2020 (all wind)	3 830 (+9 %)	2 480 (+58 %)

Table 4.6 Average available reactive power in Irish system

The fundamental shift from bulk power generation and transmission system into a system with high levels of embedded variable generation may increase the range of reactive power control that is required to maintain system voltages within limits. The demand for reactive power may become higher than

expected due to additional capacitances in the transmission network and the distributed nature of wind generation.

4.4.2.2 Short-circuit power provision

According to the study of the German Energy Agency abovementioned, the volume of available short circuit power in Germany still mostly depends on the number and the apparent power of the grid-connected synchronous generators, as well as their electrical distance to the fault location.

One trend stated in the German study is that construction of new generation units in distribution grids will be associated with an increase in transfer capacity demand at the interfaces between the transmission and the distribution grid. This will require the construction of additional transformers or new grid interconnections, which will increase the coupling between the respective grid levels. This is expected to increase the short circuit current contributions from the transmission grid in case of faults in the distribution grid.

In the study, the short circuit power development trend in the German electricity grid was calculated based on an aggregated European transmission grid model and a showcase 110 kV distribution grid. Based on them, the short circuit power in Germany will increase by 20% on average by 2033. Minimum and maximum short circuit capacity levels will not be exceeded. The short circuit power of industrial regions will continue to be far higher than that of rural areas.

The largest share of renewable energy systems in Germany will continue to be installed in the 110 kV distribution grid, and not the 380 kV transmission grid. According to existing standard grid codes, wind turbines and PV systems disconnect from the grid in times when there is no active power supply. This is expected to lead to a certain level of weather and daytime-dependent fluctuations in the available short circuit power. However, Decentralised Energy Conversion Units with converters would be technically able to supply reactive current without primary energy provision and, consequently, stay connected to the grid at any time to provide short circuit power.

In sum, the bandwidth of the short circuit power available will hardly change in Germany by 2030. However, major time-dependent fluctuation at all grid levels is expected, due to the boost of decentralised energy units.

In Ireland, it is expected that at high non-synchronous penetration levels, the transient stability of the system will be significantly compromised, due to the reduction in synchronising torque - the forces that keep generators operating in unison. According to the Irish study [65], the percentage of contingencies with critical clearance time of less than 200 milliseconds will increase, meaning that the system will become less transiently stable at high shares of wind power.

The provision of dynamic reactive power from network devices (e.g., synchronous compensators or wind power plants) during voltage disturbances could be used to improve the transient stability of the system, by increasing the critical clearance time of the most onerous faults. In the Irish study, these strategies to improve the transient stability relied on wind power plants which are able to provide significant reactive current during voltage disturbances. However, the grid codes may not be that demanding for wind power plants - particularly not for distribution grid connected wind power plants.

The main cause for the reserve needs in distribution would be the congestion created by high or low levels of production by DER units, combined with variable levels of local consumption. Depending on the local regulations and the market prices, there could be situations where contracting local reserves could be used instead of the curtailment of DER for solving the congestion issues. These reserves could be voltage-controlled or activated by tripping signals in case the power flows in the transformers reach specific limits.

It should be noted that resources providing simultaneous reserves services on a local level could lead to voltage problems if, for instance, the activation of reserves for the larger area needs would create a local congestion. In this case, the dimensioning of the reserves in that area must include some restrictions and the amount of global reserves should be adjusted in accordance. Clear rules regarding priority of activation signals, as well as for measurement and settlement of actions, should be agreed upon between the different actors. Otherwise a resource could receive, for example, upward and downward activation signals from different controllers.

5 Summary and conclusions

This deliverable carries out a thorough analysis of the current status of ancillary services provision as well as an overview in the existing market structures in Europe by regions (North/Central/South). In order to identify the ancillary services needs that could exist in the SmartNet horizon (2030), the main trends concerning the generation/consumption mix changes, the boost of DER devices and DSM, the reduction of inertia or the improvement of the cross-border interconnections have also been analysed.

From the comparative study on current status of ancillary services markets together with the expected changes in the power networks by 2030, it has been possible to foresee, on the one hand, which novel ancillary services or products could be provided in the future by DER/DSM from distribution to transmission and, on the other hand, how could the future regulations evolve concerning to the ancillary services markets.

A method to create some high-level scenarios for being used as a framework for mapping the different countries with pilots in SmartNet has been developed and it is shown in this document. These scenarios have been derived as a function of their generation mix and the interconnection degree with the neighbouring countries, both considered the key impact factors. Eventually, a methodology to make a quantitative evaluation of the reserves needs has been deployed. The results of the application of the tool to the pilot countries (Denmark, Italy, Spain) are also presented.

As a summary, the main conclusions that can be drawn from work done in this document are:

- Regardless the fulfilment of several minimum requirements established by ENTSO-E, the ancillary services mechanism is freely stated by each country, which leads to great heterogeneity. Thus, while the main issues related to the frequency control and voltage control services definition maintain certain similarity between countries, the acceptance criteria for other ancillary services is determined individually by each country.
- The Directive 2009/72/EC intends to increase the convergence across Member States towards a unified market, ensuring non-discriminatory access for all market players (new providers, final customers and aggregators of final customers), while facilitating their participation in reserve and balancing markets. The day-ahead provision mechanisms are rather similar over the countries and there are a few differences in intraday markets (i.e. remuneration schema), but these differences are more pronounced in the ancillary services markets (minimum bid size, mandatory vs. non-mandatory, marginal price vs. pay as bid, etc.).
- The current regulatory frameworks still encourage the traditional network investments, dissuading of the use of ancillary services from DER. As a consequence, the national criteria for the provision of ancillary services usually promotes the use of large centralised power

plants for it; e. g. minimum bid size of at least 1 MW, symmetrical bids, aggregation of small prosumers not allowed, etc.

- Based on current and expected future development, the pilot countries were mapped to the SmartNet scenarios and it can be outlined that: in all the cases, 2030-emissions targets seem to be feasible at the whole EU level. Both Denmark and Italy are expected to fulfil these targets with an important contribution of RES. However, for Spain, emissions trading mechanisms among the European countries will be required. Even though RES contribution to the energy mix is already very high, it seems not to be enough to meet the target and national 2030 framework does not encourage further investment. With respect to cross-border interconnections, almost all European countries (with the exception of Spain) are in a good position to fulfil the 10% interconnection capacity goal[16] by 2020. The border links between Spain and France are the most congested in Europe and, although some projects aim to improve them, they will be insufficient to allow the 10% achievement, as the current ratio is still far from the target.
- The results of the most common methods to estimate the reserves needs by TSOs (probabilistic, deterministic, dynamic) highly depend on the country where they are applied, due to the network topology, the grid status, the historical data, the capacity installed, the energy mix, etc. This poses noticeable differences between the theoretical results derived from the application of the ENTSO-E recommendations and the real reserves nowadays contracted by the TSOs. The information about the methods used by the DSOs in distribution grids is even scarcer. Moreover, not all the countries use the same type of reserves (some mainly trust on aFRR, while some others use mFRR and/or RR), which makes it really challenging to foresee the evolution of the reserves needs in the SmartNet horizon.
- Based on the information concerning to those current methods of reserves sizing and considering some feasible assumptions, a tool was designed to estimate the reserves needs in the future for Denmark, Italy and Spain. Nevertheless, this tool is designed to be country-independent, so that it can easily be applied to other countries. However, calculation methods strongly depend on the grid topology, historical data, the generation mix, etc. and, thus, each TSO and DSO must use some coefficients to adjust the theoretical values to their real implementation. Therefore, the general results obtained from the tool may differ from those that could be more realistic according to the data publicly available up to date (e.g. in Italy).

[16] The 10% interconnection capacity goal is in comparison to the installed generation capacity.

The final goal of this document is to serve as a general framework for the project. Consequently, the current mechanisms of ancillary services provision have been analysed and the expected changes and the needed increase in the reserves resulting from the increased contribution by DER and DSM have been assessed. The results here are expected to deliver an input to the analysis on how the DER and DSM resources (which technologies) will be able to provide those ancillary services by 2030. Moreover, the information in this deliverable is also expected to be used for information purposes when identifying new coordination schemes between TSOs/DSOs, in order to settle the market structures for the provision of the services which are not in potential conflict with existing practices. Eventually, the amount of estimated data needs, the scenarios and the mapping to the countries under study will be of key importance for the simulation of the national cases which will lead to the identification of the most suitable coordination schemes and their cost-benefit analysis.

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7 Appendix A: Current status of ancillary services provision in some European countries

7.1 Austria

- **Frequency Containment Reserve – Primary reserve**

Procurement schema: Optional. Organised market. Tenders by the control area manager and TSO Austrian Power Grid (APG). At the end of the bidding period the bids are ranked according to prices, starting with the cheapest bids, until the total volume of control power required is reached. These bids are accepted, whereby acceptance of the last bid, the most expensive, may be restricted to ensure that the tender quantity is not exceeded.

Remuneration schema: Charges for the provision of control reserve (€/MW) only. Suppliers whose offers are accepted receive the power price they quoted, pay as bid approach is adopted. The energy is not remunerated.

Service provider: Power plant operators.

Cost recovery: Generators with a capacity of over 5 MW. The costs are allocated in proportion to annual output.

Minimum rated power: ± 1 MW (the bids must be equal in both directions: positive and negative).

Activation time/Duration: Activation time: 0 - 30 s. Service duration: Maximum 15 min until Frequency Restoration Reserve re-establishes the initial values of Frequency Containment Reserve.

Requirements: The access to tenders is organised in two steps:

i. Technical prequalification (according to [11])
ii. Framework Agreement concerning legal relationship between the supplier and the control area manager.

Penalty clause: A supplier who cannot meet the obligation to provide primary control power due to technical problems must inform Austrian Power Grid AG immediately by telephone and also by e-mail. If the failure can be attributed to gross negligence or intent, Austrian Power Grid AG can obligate the supplier to pay a contractual penalty and compensation. In the event that the contractual obligations are breached repeatedly, Austrian Power Grid AG has the right to terminate the framework agreement with the supplier.

Scheduling horizon: The tendering period (the period in which the primary control power should be provided) always extends from Monday 00:00 to Sunday 24:00 (a product over 7 days). The total volume of primary control power must be available in this period without interruption. This means that it must also be continuously reserved by the suppliers in their power plants. The product contains equal amounts of negative and positive primary control reserve. Separate offers for positive or negative primary control

power are therefore not possible. The bidding period for the provision of primary control power in the following week is normally from Friday, 12:00 to Tuesday, 15:00. In the event that a deviating bidding period needs to be defined due to special circumstances, the suppliers will be informed of the deviation at least one week prior to the commencement of the deviating bidding period.

- **Automatic Frequency Restoration Reserve – Secondary reserve**

Procurement schema: Optional. Organised market. Tenders managed by the control area manager and TSO Austrian Power Grid (APG). At the end of the bidding period the bids are ranked according to the following criteria and the contracts are awarded:

i. Lowest power price.
ii. If there are several bids with the same power price, the energy price will be used as a basis: lowest energy price for positive secondary control, highest energy price for negative secondary control.
iii. If the power and energy prices are identical, the bid that was placed first wins (time stamp).

Remuneration schema: Charges both, for the provision of control reserve (€/MW) and for the supply of control power (€/kWh). Service suppliers receive the power price they quoted (pay as bid approach is adopted). Once the bid has been accepted, the suppliers are obliged to reserve the corresponding volume of secondary control power.

Service provider: *P*ower plant operators, aggregators (virtual power plants).

Cost recovery: The costs of secondary control (capacity provision and energy) are allocated in the following manner:

i. 78% are charged to the electricity producers with an installed capacity of over 5 MW in accordance with the system utilisation tariff. This tariff component is referred to as a system service.
ii. The remaining 22% are forwarded to the balance responsible party as a partial component for the entire balancing energy.

Minimum rated power: ± 5 MW. The bids must be equal in both directions, positive and negative.

Activation time/Duration: Activation time: 30 s to 15 min. Secondary control power is activated when the system is affected for longer than 30 seconds or it is assumed that the system will be affected for a period longer than 30 seconds. Restoration of the secondary control range can take up to 15 minutes, whereas tertiary control may continue after this period.

Requirements: The access to tenders is organised in two steps:

i. Technical prequalification (according to [11])
ii. Framework Agreement concerning legal relationship between the supplier and the control area manager.

Penalty clause: A supplier who cannot meet the obligation to provide secondary control power due to technical problems must inform Austrian Power Grid AG immediately by telephone and also by e-mail. If the failure can be attributed to gross negligence or intent, Austrian Power Grid AG can obligate the supplier to pay a contractual penalty and compensation. In the event that the contractual obligations are breached repeatedly, Austrian Power Grid AG has the right to terminate the framework agreement with the supplier.

Scheduling horizon: The bidding period for four-week products is normally on Tuesday from 9:00 to 14:00. All other products can normally be tendered Tuesdays from 9:00 to 15:00. Suppliers who have been accepted can adjust their energy prices for the following day on each working day (except Saturday) up to 15:00. The original energy price may, however, not be exceeded in the case of positive secondary control power or undercut in the case of negative secondary control power. Corresponding rules can be found in the Framework Agreement for Secondary Control. The suppliers will be informed in due time should it be necessary to postpone or change the bidding period in the presence of exceptional circumstances.

- **Manual Frequency Restoration Reserve – Tertiary reserve**

Procurement schema: Optional. Organised market. Tenders managed by the control area manager and TSO Austrian Power Grid (APG). In the market maker tender, the bids with the lowest power price are accepted. If the prices of two bids are identical, preference is given to the bid that was placed first.

Remuneration schema: Charges for the supply of control power (€/kWh) only. Service suppliers receive the power price they quoted (pay as bid approach is adopted). Once the bid has been accepted, the suppliers are obliged to reserve the corresponding volume of tertiary control power.

Service provider: Power plant operators, aggregators (virtual power plants).

Minimum rated power: 5 to 50 MW per supplier and time interval. The bids can be positive or negative. This will be changed to 1 MW for the first bid. For the second bid of the same bidder: 5 to 50 MW.

Cost recovery: The power used for tertiary control is billed to the balancing group representatives via imbalance settlement.

Activation time/Duration: Activation time: 15 min after the frequency deviation. Duration: minimum 15 min. Tertiary control energy is activated when the deviation in the control area lasts for longer than 15 minutes.

Requirements: The access to tenders is organised in two steps:

i. Technical prequalification (according to [11])
ii. Framework Agreement concerning legal relationship between the supplier and the control area manager.

The available tertiary control reserve must be, at least, as large as the capacity of the largest power station unit in the control area.

Penalty clause: A supplier who cannot meet the obligation to provide tertiary control power due to technical problems must inform Austrian Power Grid AG immediately by telephone and also by e-mail. If the failure can be attributed to gross negligence or intent, Austrian Power Grid AG can obligate the supplier to pay a contractual penalty and compensation. In the event that the contractual obligations are breached repeatedly, Austrian Power Grid AG has the right to terminate the framework agreement with the supplier.

Scheduling horizon: The bidding period for the market maker tender is normally on Wednesday from 9:00 to 15:00. Suppliers who have been accepted can adjust their energy prices up to the end of the day-ahead tender. The bidding period for the day-ahead tender normally begins directly after the market maker tender and extends up to 15:00 on the previous working day (except Saturday) of the tendering period. The suppliers will be informed in due time should it be necessary to postpone or change the bidding period in the presence of exceptional circumstances.

- **Voltage control**

Procurement schema: Mandatory.

Remuneration schema: No remuneration.

Service provider:

Generation units. Each generation unit connected to the distribution grid must be able to operate within a certain area, depending on its size and location.

MV and LV:

i. Installations with Sn <3.68 kVA. A symmetric power factor is established at 0.90 (Qmax=43.6%Sr). If the real apparent power is at least 20% lower than the nominal apparent power, the fulfilment is not mandatory anymore.
ii. Installations with Sn >=3.68 KVa. In case the installation is connected on the LV network, the same rule applies as before. For the MV, the generators must be able to operate within the area delimited by a power factor of 0.925 (both for capacitive and inductive). The DSO might also require two other settings in some special cases: in this case the generator might be able to operate within an unsymmetrical area delimited by a capacitive cosφ of 0.90 / inductive cosφ of 0.95 and vice versa. Independently from the size and location of the installation, the installation must be able to provide a certain amount of reactive power for a given voltage level.

HV: The units connected to the HV grid must be able to provide a certain amount of reactive power depending on the voltage variation. The range is the same for each unit connected to the same voltage level (110 kV, 220 kV and 380 kV).

Penalty clause: No penalty (the network operators considers that the producer will fulfil the requirements because it has validated the grid connection).

- **Other services - Redispatch**

Procurement schema: The control area manager plans and controls the redispatch.

Remuneration schema: Remuneration fees for losses of profit.

i. Thermal power plant. Forced generation: variable operational costs minus proceeds. Restriction of generation: lost proceeds minus saved variable operational costs.
ii. Pumped storage plant (turbine operation). Forced generation: value of lost water reservoir minus proceeds. Restriction of generation: lost proceeds minus value of saved water reservoir.
iii. Pumped storage plant (pumping operation). Lost proceeds minus market value of planned purchase taking into consideration a pumping efficiency of 70%.
iv. Pondage power plant. Forced generation: market value of planned generation minus market value of forced generation. Restriction of generation: analogous.
v. Eco-electricity plants. Restricted power multiplied by the time and the feed-in tariff.
vi. Own production power plant (industry). Analogous to power plants above but plus additional costs due to limitation of production.

Service provider: Power plants.

Minimum rated power: Only power plants with power >50 MW.

- **Other services – Grid losses compensation**

Procurement schema: A procurement strategy already exists in Austria to procure electricity to cover grid losses in the Austrian transmission grid. Austria Power Grid (APG) handles the market procurement of grid losses by conducting a common tender in the form of tradable products (annual, quarterly and monthly base and peak products). APG acts as a major buyer of electricity and procures around 85% of electricty needed to cover grid losses.

Remuneration schema: Pay as bid approach is adopted.

Minimum rated power: The minimum bid is 1 MW.

Requirements:

i. Grid operators notify APG of grid loss forecasts up to 3 years in advance.
ii. APG cumulates the quantities and allocates them to several tenders of standard products.
iii. Any remaining quantites are covered on the daily spot market (short term process, no tenders)

Scheduling horizon: Yearly, quarterly and monthly products for base and peak times respectively up to 2 years in advance.

7.2 Belgium

- **Frequency containment reserve – Primary control (R1)**

Procurement schema: Mandatory. Organised market.

The global reaction of primary reserves set forth by the ENTSO-E regulations must be a symmetrical and linear activation with a total activation at a frequency deviation of +-200mHz. However in order to allow different types of flexibility (generation, load, generation in France...) to participate in primary reserves, Elia sources different types of products who react at different frequency deviations. Type of services:

i. FCR – R1 upwards - Load: This product is activated between [-200mHz, -100mHz], whereas the total contracted volume must be activated at -200mHz.
ii. FCR – R1 downwards: This product is activated between [100mHz, 200mHz], whereas the total contracted volume must be activated at 200mHz.
iii. FCR – R1 Symmetrical 100 mHz: This product is activated between -100mHz and +100mHz, whereas the total contracted volume must be activated at the most extreme bands of the frequency interval indicated. This maximum contracted volume must however also remain activated for frequency deviations between [-200mHz,-100mHz] and [100mHz, 200mHz].
iv. FCR – R1 Symmetrical 200 mHz: This product is activated between -200mHz and + 200mHz, whereas the total contracted volume must be activated at the most extreme bands of the frequency interval indicated.
v. FCR – R1 RTE (French TSO): Agreement with RTE that Elia may procure FCR from French BSP (TSO-BSP model).

Remuneration schema: The primary reserve is subject to a payment that covers the provision and activation of the service. No specific payment is made for the actual supply of energy.

Service provider:

i. FCR – R1 upwards - Load: Large industrial clients. TSO grid users (via aggregator).
ii. FCR – R1 Downwards: This product is only supplied by base-load Elia-connected generation (mainly nuclear power plants).
iii. FCR – R1 Symmetrical 100 mHz: Base-load flexible units (Gas, Steam and Gas power stations (STEG)).
iv. FCR – R1 Symmetrical 200 mHz: Base-load flexible units (Gas, Steam and Gas power stations (STEG)).
v. FCR – R1 RTE (French TSO): French generators.

Cost recovery: BRP via the procedure of the imbalance settlement + grid users.

Requirements: For FCR – R1 upwards, FCR – R1 downwards, FCR – R1 Sym 100 mHz and FCR – R1 Sym 200 mHz: local frequency measurement and continuous activation.

For FCR – R1 RTE: Requirements defined by RTE.

Activation time/Duration: Activation time: 0 - 30 sec. FCR must be able to be activated minimum 15 min.
Scheduling horizon: Monthly tendering.

- **Frequency restoration reserve – Secondary control (R2)**

Procurement schema: Optional. Organised market.
Remuneration schema: Two types of payment, a set contractual payment for provision of the reserve and a payment for activation of the reserve.

i. Maximum price for incremental activation: Elia pays the grid user on the basis of the latter's bid. The maximum price for a bid for upward activation is expressed in € per MWh and is based on the fuel price and on the market reference price. Price cap for upward regulation = Fuel cost of Combined Cycle Gas Turbine (CCGT) with 50% efficiency + 40€/MWh.
ii. Minimum price for decremental activation: The grid user pays Elia, because the user can reduce its generation output or use for other purposes the power normally deployed for the secondary reserve. The prices given in the bids submitted by grid users must be no lower than a certain stipulated minimum. Price cap for downward regulation = 0€/MWh.

Cost recovery: BRP via the procedure of the imbalance settlement + grid users.
Service provider: Base-load flexible units (Gas, Steam and Gas power stations (STEG)).
Minimum rated power: 5 MW.
Product resolution: Total volume of 140 MW maximally.
Activation time/Duration: Maximum reaction time from 0MW to maximum up or down: 7.5 min (or 15 min from max up to down). Maximum duration, no limit.
Requirements:

i. Setpoint sent by dispatching Elia over dedicated SCADA connection.
ii. Continuous activation

Scheduling horizon: FRR upward: Monthly tendering. FRR downward: Free bids day-ahead.

- **Tertiary control (R3) – R3 Production**

Procurement schema: Optional. Organised market.
Remuneration schema:

i. Payment for provision of the tertiary reserve: Elia has to make a payment to the grid user providing the tertiary reserve (expressed in €/MW/hour of availability).
ii. Payment for the energy supplied to Elia: Free prices nominated day ahead.
iii. Payment to cover start-up costs: The amount of the payment is calculated using the same formula found in the CIPU contract (Coordination of Injection by the Production Units). This formula

takes account of the specifications of the production unit, the cost of the fuel used and the management costs incurred.

Service provider: Turbo-jets, non-spinning units.

Cost recovery: BRP via the procedure of the imbalance settlement + grid users.

Minimum rated power: Total volume min, 300 MW.

Activation time/Duration: To be activated within 15 min and there is no duration limit.

Requirements: Interface (B2B). There is neither max activation/year nor minimum time between activations.

Penalty clause: Elia will apply a penalty if the supplier has failed, for any particular quarter-hour, to make the quantity of his tertiary control obligation to Elia. Said penalty is valued by means of the Belpex (Belgium energy market) day-ahead price and applies to any missing MW.

Scheduling horizon: Yearly tendering + monthly tendering.

- **Tertiary control (R3) – R3 Dynamic Profile**

The R3 DP is a new type of tertiary reserves that allows distributed energy resources to participate in the ancillary services.

Procurement schema: Optional. Organised market.

Remuneration schema: Elia has to remunerate (expressed in €/MW/hour of availability) the dynamic profile provider providing the tertiary reserve. This payment, the size of which is specified in the contract, covers the entire contractual term. The fee is determined by the offer from the dynamic profile provider in the tendering process. There is no remuneration for activation.

Service provider: DSO connected loads / emergency generators.

Cost recovery: BRP via the procedure of the imbalance settlement + grid users.

Activation time/Duration: Maximum duration of 2h.

Requirements: Interface (B2B). Maximum 40 activations/year. Minimum time between activations: 12h. R3-DP requires 100% availability of the contracted power.

Penalty clause: Elia will apply a penalty if the supplier has failed, for any particular quarter-hour, to make the quantity of his tertiary control power - dynamic profile obligations available to Elia. Said penalty applies to any missing MW.

Scheduling horizon: Yearly tendering + monthly tendering.

- **Tertiary control (R3) – R3 ICH: Tertiary control by interrupting grid users**

Procurement schema: Optional. Organised market.

Remuneration schema: Elia pays for both the provision of reserve and the activation of the interruptibility service.

i. Payment for providing the reserve: Payment according to tariff period. Elia has defined distinct tariff periods. Remuneration will be greater during peak hours than during off peak or weekend hours. Payment for provision of reserve is made via a system of monthly advances.
ii. Payment for activation of the service: The energy term price is set at 108% of the highest incremental bid selected in Belpex market and a minimum payment of 75 €/MWh is also stipulated.

Service provider: Large industrial TSO grid users (via aggregator).

Cost recovery: BRP via the procedure of the imbalance settlement + grid users.

Minimum rated power: 5 MW.

Activation time/Duration: It must be connected within 3 min. Depending on the product, maximum duration: 2 h – 4 h – 8 h. Maximum activations/year: 12 – 4 – 4.

Requirements: Dedicated SCADA connection. Minimum time between activations: 24h.

Scheduling horizon: Yearly tendering.

- **Voltage control (MVAr)**

Procurement schema: There are two types of voltage control:

i. Primary control: Controlling production units. Reactive energy is activated automatically, within the bounds of the band that is provided by the producer.
ii. Centralised control. Controlling and non-controlling production units. Elia asks the producer to activate reactive energy upwards or downwards, depending on the band specified in the contract.

Elia chooses suppliers of the voltage control service based on price and also on the location of the production units within the high-voltage grid. The reactive energy may be activated by the production units automatically (primary control) or at Elia's request (centralised control). Producers with units that have a capacity of over 25 MW have to take part in primary control.

Remuneration schema: Payment for the reserved control bands based on: a unit price, the volume contracted in MVAr and the length of use. In the event that absorptions or injections either by the centralised control or by the primary control go outside the contractual limits of the band (Qband-; Qband+), Elia pays the producer for the actual volumes absorbed or generated an amount in €/MVArh.

Service provider: Producers.

Requirements: The production units must have certain technical features that vary depending on whether the unit is a controlling production unit or a non-controlling production unit.

Scheduling horizon: Voltage control services are governed by contracts of at least one year signed by Elia and the producer.

- **Other services – Strategic Reserves (SGR & SDR)**

Elia has been given the task of organising a strategic reserve mechanism to cover the structural shortages in generation in the winter period. This mechanism differs from the balancing resources that offset the sum of residual imbalances of ARPs (also known as balance responsible party) in real time. The strategic reserve makes use of load shedding and off-market generation units.

Procurement schema: Optional. Organised market. The strategic reserve takes two forms, whose activation produces similar results:

i. Strategic Generation Reserve (SGR): Delivered by production units.
ii. Strategic Demand Response (SDR): Delivered by a reduction in the offtake on the demand side.

Remuneration schema:

i. SGR: It covers the expenses in generating the energy. This remuneration takes account of the cost of the fuels and overheads, and the period of activation and the volume injected.
ii. SDR: Suppliers are remunerated for the availability of the contracted capacity and for the activation of the SDR.

Service provider:

i. SGR: The SGR is supplied by generation units in the Belgian control area that have already been shut down. Production: EDF Luminus (Serain), Eon (Vilvoorde).
ii. SDR: The SDR is supplied by demand-side management offers. A temporary reduction, individual or aggregated, has the same impact on the balance of the control area as an increase in generation.

Cost recovery: BRP via the procedure of the imbalance settlement + grid users.

Activation time/Duration: To be activated within 1,5h . Maximum duration between 4 and 12 hours, depending on the product.

Other characteristics: Maximum number of activations/year between 20 and 40 depending on the product. The minimum time between activations, 4 – 12 h.

Scheduling horizon: Yearly tendering.

- **Other services – Black start service**

Procurement schema: Bilateral contracts. Selection criteria: location, start-up speed and availability of trained personnel.

Remuneration schema: Fixed payment (capacity). Investment costs incurred to meet technical requirements are covered by the fixed retribution (contractually stipulated).

Service provider: Power plants > 100 MW.

Cost recovery: Grid users.

Requirements:

i. be capable of starting up without using an auxiliary source of power derived from high-, medium- or low-voltage network;
ii. be capable of responding swiftly and dynamically to load fluctuations up to 10 M;
iii. be capable to absorb a minimum of 30 MVAr at the connection point;
iv. be equipped with a regulator enabling rotation speed to be geared to the frequency required by Elia's dispatching department;
v. have synchronisation equipment enabling voltage to be restored to a substation without power;
vi. be capable of feeding power into the grid:
vii. within 1.5 hours after the blackout for units in service at the time of the blackout;
viii. 3 hours after the blackout for units in shot-down;
ix. for a period of at least 24 hours.

Activation time/Duration: Activation time; 1.5h (units in service) and 3h (units in shot-down). Duration: 24h.

Penalty clause: There are penalties if contracted units do not pass the start-up tests under Black Start conditions. However, the specifics are unknown.

Scheduling horizon: From one to several years.

- **Other services – Compensation for grid losses**

Procurement schema: Candidates for supplying are selected and then a tender is sent out to these candidates. These tenders are submitted in online reverse auctions.

Remuneration schema: Energy term is remunerated according to the price agreed in the auction.

Service provider: All European suppliers with an ARP contract.

Cost recovery: Grid users.

Product resolution: Around 500 GWh.

Requirements: Candidates are selected on the basis of the following criteria:

i. Economic criteria (main business activity in recent years, experience of supplying similar services, main contracts, supplied volumes, etc.);
ii. Financial criteria (balance sheets, liquidity ratios, solvency, profitability, etc.);
iii. Technical criteria (quality system, suitably qualified staff, knowledge of languages, etc.).

Scheduling horizon: One year.

7.3 Denmark

Requirements to be met by suppliers of ancillary services vary slightly depending on whether the services are to be supplied in Eastern Denmark (called DK2) or in Western Denmark (called DK1). In general, ancillary services to be delivered are:

- DK1: i) FCR Primary reserves, ii) aFRR Secondary reserves - LFC (Load Frequency Control), iii) mFRR Manual reserves, iv) Short-circuit power, reactive reserves and voltage control.
- DK2: i) FCR-D Frequency-controlled disturbance reserve, ii) FCR-N Frequency-controlled normal operation reserve, iii) mFRR Manual reserves, iv) Short-circuit power, reactive reserves and voltage control.

- **FCR Frequency Containment Reserve - Primary reserve DK1: upward and downward regulation**

Procurement schema: Daily reserve auction of blocks of 4 hours.

Remuneration schema: Fixed price per MW per hour. Marginal price. All accepted bids for up-and down-regulation receive an availability payment corresponding to the auction's marginal cost. Running the primary reserve is paid as ordinary imbalances.

Service provider: Production or consumption units which, by means of control equipment, respond to grid frequency deviations.

Ramp size/Speed drop: The reserve must at least be delivered linearly with frequency deviations between 20 and 200 mHz deviation. The first half of the activated reserve must be delivered within 15 seconds, while the last part must be delivered within 30 seconds at a frequency deviation +/- 200 mHz. The regulation must continuously be active and contain features that ensure the maintenance of 100% power for a minimum of 15 minutes.

Minimum rated power: 0.3 MW.

Activation time/Duration: Automatically activated within 30 seconds. Maximum duration 15 minutes.

Requirements: Primary regulation must be delivered at a frequency deviation of +/- 200 mHz compared to reference frequency of 50 Hz. This will usually mean in the range 49.8 to 50.2 Hz. It is allowed a dead band of +/- 20 mHz.

Penalty clause: When it turns out that the capacity is not available, for example because of a breakdown, the availability payment is canceled and the player must cover any additional costs for replacement. In case of accidents, which implies that a plant cannot supply reserve, the reserve must be re-established at one or more plants that can supply the reserve as soon as possible but within 30 minutes after the incident. If the supplier cannot re-establish the reserve, contact Energinet.dk within 15 minutes to announce where and when the reserve can be restored.

Scheduling horizon: Daily auction.

- **aFRR Automatic Frequency Restoration Reserve - Secondary/Load frequency reserve DK1**

Procurement schema: Long term contract with Norway for delivery of aFRR over Skagerrak 4. There is only ad hoc procurement in DK1.

Remuneration schema:

i. Capacity is remunerated through a fixed price (stipulated on a bilateral contract with energinet.dk)
ii. Energy is remunerated marginally (DK1 spot price plus/less DKK 100/MWh, or at least, the price for upward/downward regulation at DK1)

Service provider: Secondary reserve regulation is automatic and provided by production or consumption units which, by means of control equipment, respond to signals received from Energinet.dk.

Cost recovery: This service is free of charge to users.

Minimum rated power: Minimum bid 1 MW, maximum bid 50 MW.

Penalty clause: When it turns out that the capacity is not available, for example because of a breakdown, the availability payment is canceled and the player must cover any additional costs for replacement. In case of accidents, which implies that a plant cannot supply reserve, the reserve must be re-established at one or more plants that can supply the reserve as soon as possible but within 30 minutes after the incident. If the supplier cannot re-establish the reserve, contact Energinet.dk within 15 minutes to announce where and when the reserve can be restored.

Activation time/Duration: Automatically activated within 15 minutes.

Scheduling horizon: Ad hoc.

- **mFRR Manual Frequency Restoration Reserve – Tertiary/Manual reserve DK1 and DK2**

Procurement schema: Auction, economic merit order. Energinet.dk buys manual reserve in DK1as upward regulation power. An auction is held once a day for each of the hours of the coming day of operation. In DK2 there is a long term contract, and ad hoc procurement in DK1.

Remuneration schema: Capacity and energy are marginally remunerated. Prices are settled marginally hour by hour.

Service provider: Typically gas turbines, thermal power, hydropower, CHP and load shedding.

Cost recovery: Reserve providers pay capacity fees and energy is paid by the imbalance parties through the imbalance settlement.

Minimum rated power: Minimum bid 10 MW. Maximum bid 50 MW.

Activation time/Duration: Manually activated within 15 min.

Penalty clause: When it turns out that the capacity is not available, for example because of a breakdown, the availability payment is canceled and the player must cover any additional costs for replacement. In case of accidents, which implies that a plant cannot supply reserve, the reserve must be re-established at one or more plants that can supply the reserve as soon as possible but within 30 minutes after the incident. If the supplier cannot re-establish the reserve, contact Energinet.dk within 15 minutes to announce where and when the reserve can be restored.
Scheduling horizon: Daily market.

- **FCR-D Frequency-controlled disturbance reserve DK2**

In the event of major system disturbances, the frequency-controlled disturbance reserve is a fast reserve used for regulating the frequency following substantial frequency drops resulting from the outage of major generation plants or lines.
Procurement schema: The reserve is activated automatically in the event of sudden frequency drops to under 49.9 Hz and remains active until balance has been restored or until regulation by means of the manual reserve takes over. Activation of reserves is based on the supplier's own frequency measurements.
Remuneration schema: Availability (capacity) payment equal to the price that the actor has bid (pay-as-bid). Energy is paid as a regular imbalance.
Service provider: Production or consumption units which, by means of control equipment, respond to grid frequency deviations.
Ramp size/Speed drop: 50% of the response must be delivered within 5 seconds and the remaining 50% within the next 25 seconds.
Minimum rated power: 0.3 MW.
Activation time/Duration: Supply 50% of the response within 5 seconds. The remaining 50% of the response must be supplied within the next 25 seconds.
Requirements: Power must be provided inversely linearly with frequency between 49.9 and 49.5 Hz. Completely activated at 49.5 Hz.
Penalty clause: When it turns out that the capacity is not available, for example because of a breakdown, the availability payment is canceled and the player must cover any additional costs for replacement. In case of accidents, which implies that a plant cannot supply frequency controlled normal operation reserve, the reserve must be re-established at one or more plants that can supply the reserve as soon as possible but within 30 minutes after the incident. If the supplier cannot re-establish the reserve, contact Energinet.dk within 15 minutes to announce where and when the reserve can be restored.
Scheduling horizon: Daily market. Energinet.dk buys frequency-controlled disturbance reserve in collaboration with Svenska Kraftnät (Swedish TSO) through daily auctions. Energinet.dk's and Svenska

Kraftnät's total requirement is purchased at daily auctions where part of the requirement is purchased two days before the day of operation (D-2), and the remaining part is purchased the day before the day of operation (D-1).

Other characteristics: The supplier can bid on an hourly basis or a block bid. Block bids that are submitted at the auction two days before the day of operation (D-2), may have a duration of up to six hours. Block bids that are submitted at the auction the day before the day of operation (D-1), may last up to three hours. The actor will state what hour block bid starts, however, the block bid must be completed within the day of operation.

- **FCR-N Frequency-controlled normal operation reserve DK2**

Procurement schema: Optional. Remunerated. Frequency controlled normal operation reserve is purchased as a symmetric product: the supplier simultaneously must provide both upward and downward regulation available.

Remuneration schema: Availability (capacity) payment equal to the price that the actor has bid (pay-as-bid). Energy is paid at the upward/downward regulation price.

Service provider: Production or consumption units. A delivery can be made up of supplies from several production units with different properties which collectively can provide the required response within the required response time. A delivery can also be made up of supplies from several consumption units with different properties which collectively can provide the required response within the required response time. Automatic regulation provided by production or consumption units which, by means of control equipment, respond to grid frequency deviations.

Ramp size/Speed drop: The reserve must at least be delivered linearly with frequency deviations between 0 and 100 mHz deviation. The activated reserve must be supplied within 150 seconds, regardless of the size of the deviation.

Minimum rated power: 0.3 MW.

Activation time/Duration: The activated reserve must be supplied within 150 seconds. It must be possible to maintain regulation continuously.

Requirements: The normal operation reserve must be supplied at a frequency deviation of up to +/-100 mHz relative to the reference frequency of 50 Hz. This means in the 49.9-50.1 Hz range. Deliveries must be made without deadband. The reserve must as a minimum be supplied linearly at frequency deviations of between 0 and 100 mHz.

Penalty clause: When it turns out that the capacity is not available, for example because of a breakdown, the availability payment is canceled and the player must cover any additional costs for replacement. In case of accidents, which implies that a plant cannot supply frequency controlled normal operation reserve, the reserve must be re-established at one or more plants that can supply the reserve as soon as

possible but within 30 minutes after the incident. If the supplier cannot re-establish the reserve, contact Energinet.dk within 15 minutes to announce where and when the reserve can be restored.

Scheduling horizon: Daily market. Energinet.dk buys the frequency-controlled normal operation reserve in collaboration with Svenska Kraftnät through daily auctions. Energinet.dk's and Svenska Kraftnät's total requirement is purchased at daily auctions where part of the requirement is purchased two days before the day of operation (D-2), and the remaining part is purchased the day before the day of operation (D-1). The supplier can submit bids hourly or as block bids. Block bids submitted to the auction two days before the day of operation (D-2) can have a duration of up to six hours. Block bids submitted to the auction the day before the day of operation (D-1) can have a duration of up to three hours. The player determines the hour at which the block bid commences. However, the block bid must end within the day of operation.

- **Voltage control**

Procurement schema: Mandatory
Remuneration schema: Not remunerated.
Service provider: Generators.
Requirements:

- Generators larger than 1.5 MW: In the point of common coupling, a power station unit connected to a point of common coupling with nominal voltage up to 100 kV must be able to use/produce reactive power with tanφ within the -0.20 to 0.40 range at nominal maximum power and at voltages in the point of common coupling within the full-load voltage range. In the point of common coupling, a power station unit connected to a point of common coupling with nominal voltage up to 100 kV must be able to use/produce reactive power as indicated by the hatched area in Figure X at nominal maximum power and at voltages in the point of common coupling within the full-load voltage range. At voltages in the point of common coupling lying outside the full-load voltage range, the potential reactive power production of a power station unit connected to a point of common coupling with a nominal voltage above 100 kV must only be reduced to an extent determined by the fact that the generator's and the step-up transformer's thermal limits are not exceeded and that the generator remains at a stable operating point.

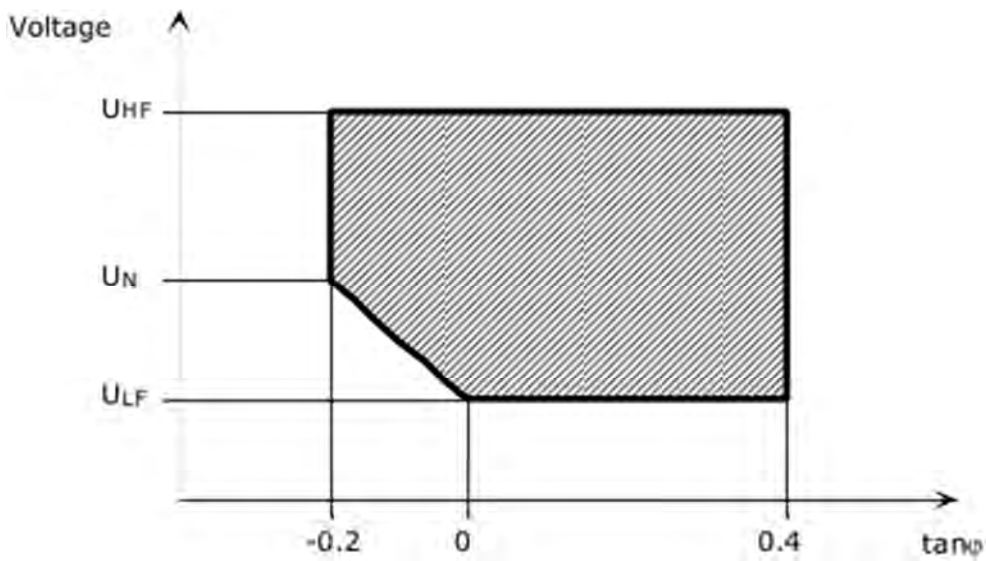

Figure 28 *Tanφ as a function of the voltage in the point of common coupling (voltage above 100 kV)*

- Generators larger than 11 kW and smaller than 1.5 MW: Measured in the point of common coupling, a power station unit must be able to use/produce reactive power with tan φ within the range of -0.20 and 0.40 at nominal maximum power and at voltages in the point of common coupling lying within the full-load voltage range.
- Generators of 11 kW or lower: Unless a special agreement to the contrary is made with the distribution network operator, the power factor (cos φ) for the electricity-generation plant must lie in the interval -0.95 ≤ cos φ ≤ +0.95 when generation constitutes more than 20% of the rated power.

7.4 Finland

- **Frequency containment reserve – Primary control**

Procurement schema: Optional. Organised market. In the Nordic power system, two types of frequency containment reserves are used; Frequency Containment Reserve for Normal operation (FCR-N) and Frequency Containment Reserve for Disturbances (FCR-D).

i. Annual markets organised by TSO. Separated markets (FCR-N) and for (FCR-D).
ii. Day-ahead market for each hour of the day organised by TSO. FCR for both normal (FCR-N) and disturbance reserve (FCR-D).
iii. Neighbour countries (Nordic countries, Russia and Estonia). Jointly maintained FCR reserves are divided between the Nordic TSOs in relation to the total consumption in each country.

Remuneration schema: Marginal price. The price is set based on the most expensive bid approved. For yearly market the same price for the whole year, for the hourly market separate price for each hour.

Service provider: Generators. Consumers.

Cost recovery: Via consumer (mostly) and producer tariffs. Payments collected in balancing services (from market imbalance payments).

Minimum rated power: 0.1 MW for FCR-N and for 1 MW FCR-D. Maximum single unit size 70 MW.

Activation time/Duration: Active all the time during contracted period when system fundamental frequency deviates from the nominal. For FCR-N the deadband is from 49.95 to 50.05 Hz and the operating range 49.9 to 50.1 Hz. FCR-D activates at 49.50 or 49.90 Hz.

Ramp size/Speed drop: For FCR-N the power must be fully activated in 3 minutes. For FCR-D fully within 30s but with additional requirements that depend on the type of resource.

Requirements: Automatic activation based on local measurement of the system fundamental frequency.

Penalty clause: Financial penalty.

Scheduling horizon:

i. Y-1: For the early markets the bidding competition is organised once a year in autumn.
ii. D-1: The bids for the hours in the following 24-hour period must be submitted by 6.30 pm.

- **Automatic Frequency Restoration Reserve – Secondary control**

FRR-A is a centralised automatically activated reserve. Its activation is based on a power change signal calculated on the base of the frequency deviation in the Nordic synchronised area and sent by the TSO.

Procurement schema: Optional. Organised market (hourly market). Operators can submit bids to the hourly market separately for upward and downward capacities

Remuneration schema: In addition to the capacity payment, the operator receives a separate energy compensation based on regulation carried out.

Service provider: Generators. Rules designed for generators, consumption allowed but is not participating.

Minimum rated power: 5 MW (aggregation allowed).

Activation time/Duration: 15 minutes.

Ramp size/Speed drop: Fully activated within 2 minutes. Responses must start within 30 seconds from the request when filtered control signal is applied. For slower responding units unfiltered control signal can be applied and then the response must start within 60 seconds and activate faster than 1(1+sT)^4 where the time constant T =35 s

Requirements: Automatic activation based on a power change signal sent by the TSO. This signal is calculated by StatNett (Norwegian TSO) based on measured frequency deviation and power flows between transmission network areas. The adequate response performance of the unit will be tested. Fingrid and the FRR-A units communicate with a maximum interval of 10 seconds.

Penalty clause: Financial penalty.

Scheduling horizon: D-1.

- **Manual Frequency Restoration Reserve – Secondary control**

FRR-M is used to control power balancing in normal and disturbance situations. FRR-M consists of market-based regulating bids in the Regulating Power Market (RPM) and capacity that TSO reserves for disturbances. Activation is done manually from Fingrid's Main Grid Control Centre..

Procurement schema: Fingrid maintains a balancing power market together with the other Nordic transmission system operators. In the balancing power market, production and load owners can give balancing power bids for their adjustable capacity. Mainly from power plants owned or leased by the TSO (Fingrid). Each Nordic TSO maintains FRR-M to cover the dimensioning fault of its own area.

Remuneration schema: Capacity and energy are remunerated; Capacity (pay as bid). Energy (marginal price). Activation payments (energy payments) reduce the capacity payments

Service provider: Generators. Consumption (disconnectable loads).

Cost recovery: Via consumer (mostly) and producer tariffs. Payments collected in balancing services (from market imbalance payments).

Minimum rated power: 10 MW. Aggregation allowed.

Activation time/Duration: Manual activation in 15 min.

Penalty clause: Financial penalty.

- **Voltage control**

Procurement schema: Mandatory.

Remuneration schema: Units are obliged to provide a non-remunerated minimal service for voltage control but fixed yearly remuneration based on unit real power for generators connected to 400 kV, 220 kV and 110 kV.

Service providers: Generators, DSOs.

Requirements: The requirements apply to generators connected to the transmission network as well as distribution network levels. In general, the monitoring rate is hourly values for reactive power tariffs and real-time monitoring for voltage control in generators. These units are obliged to provide a non-remunerated minimal service for voltage control. Requirements are defined according to generator unit's nominal power. Additionally, wind power units are defined separately.

i) Mandatory service

- Generators and wind units with power < 10 MW: No requirements.
- Generators with power > 10 MW: Voltage control at generator connection point. Constant voltage control. Power factor 0.95 reactive ≤ cos φ ≤ 0.9 inductive. Required during voltages 0.85 p.u. < V < 1.1 p.u. Generators with power > 100 MW require additional power system stabilisers (PSS).

- Wind units with 10 MW < Power < 25 MW: Voltage control at generator connection point. Type of service; constant reactive power, constant power factor or constant voltage control. 0995 reactive ≤ cos φ ≤ 0.995 inductive. Required during voltages 0.9 p.u. < V < 1.05 p.u.
- Wind units with Power > 25 MW: Voltage control at generator connection point. Type of service; constant reactive power, constant power factor or constant voltage control. 095 reactive ≤ cos φ ≤ 0.95 inductive. Required during voltages 0.9 p.u. < V < 1.05 p.u. Wind installations with power > 100 MW require additional PSS or power oscillation damping.
- DSOs: Defined constraints for free reactive power transfer at TSO/DSO interface. Penalties applied for exceeding these constraints. DSO sets own tariffs for its customers based on these reactive power constraints.

ii) Additional service

Generators connected to 110 kV, 220 kV and 400 kV can offer this optional service with a remuneration based on unit real power.

New principles for voltage control and reactive power management will be issued soon. First drafts indicate three connection types; consumption, generation and combined consumption/generation. Reactive power for voltage control would be measured for each connection. Related payments would be according to agreements. This would help to create a market for reactive power for voltage control purposes. However, this market structure is not defined yet.

- **Other services – Peak load capacity reserves**

Procurement schema: The Finnish energy authority arranges competitive bidding for two years period. In addition, consumption must go via the balancing power market and generation via the Elspot day-ahead market and the balancing market. The bid is activated if market-based bids are not sufficient to reach balance of supply and demand.

Remuneration schema: Marginal price at the balancing power market, but, at least, Elspot (day-ahead market) price.

Service provider: Generators. Consumption.

Cost recovery: Via consumer (mostly) and producer tariffs. Payments collected in balancing services (from market imbalance payments).

Minimum rated power: 10 MW. Aggregation allowed.

Activation time/Duration:

For consumption: Activation within 10 minutes and minimum duration 2 h.

For generation: 12 hours in winter time (December- February). In other seasons, 1 month.

Scheduling horizon: Y-2.

7.5 Italy

- **Primary Frequency Control**

Procurement schema: Mandatory provision.

Remuneration schema: There is an optional remuneration scheme for the provision of the service. The price of the service is related to the weighted average price of activation in real time balancing market.

Service provider: All units with rated power greater than 10 MVA must contribute to primary frequency regulation except of those without, by their nature, of regulating capacity, such as, hydro with reversible Francis turbine and the geothermal units.

Cost recovery: Partially recovered through imbalance settlement and cost charges applied to end users.

Minimum rated power: 10 MVA.

Activation time/Duration: half of the variation of the generated power requested to the unit must be supplied within 15 seconds and the full variation within 30 seconds; then, the new generation level must be kept for at least 15 minutes (in case there are no new frequency variations).

Product resolution: all the qualified generating units shall provide the primary control reserve responding to frequency variations with variations of the generated power within upward and downward bands equal to 1.5% of nominal power.

i. in Sardinia, the synchronous generation units must make available a regulation band of not less than ± 10% of the efficient power of each eligible generation group;
ii. in other areas, the synchronous generators must make available a regulation band of not less than ± 1.5% of the efficient power;
iii. in areas belonging to the region of Sicily, a control band should be made available not less than ± 10% of the efficient power of each of the appropriate generation unit, in time periods in which is not in service the interconnection with the mainland.

- **Secondary Frequency/Power Control**

Procurement schema: Optional. Market based schema.

Remuneration schema: Pay as bid. Only the energy term is remunerated (€/MWh).

Service provider: Only power generation units, but intermittent resources.

Cost recovery: Partially recovered through imbalance settlement and cost charges applied to end users.

Activation time/Duration: 15 min. Secondary reserve shall be guaranteed for 120 min.

Product resolution: Power generation units (but intermittent renewables) with rated power greater than 10 MVA with a minimum gradient of 10 MW in 15 min. They have to be able to provide a reserve margins equal to: a) ± 15% of the maximum power for hydro; b) the greater between ± 10 MW and ± 6% of the maximum power for thermal units.

Other characteristics: This automatic function is performed by a central controller in the control system of Terna (Italian TSO). The Sardinia (normally) and Sicily (when not in synchronism with the Continent), perform locally the secondary power reserve function.

The procurement of secondary reserve is made by the TSO in the ancillary services market in which the scheduling resulting from the energy market is modified in order to be compliant with system constraints (minimum reserve margins, network constraints). Secondary reserve margins are reserved upon generating units qualified for the provision of the service.

- **Tertiary Power Control**

Procurement schema: Optional. Market based schema.
Remuneration schema: Pay as bid.
Service provider: Only power generation units, but intermittent resources.
Cost recovery: Partially recovered through imbalance settlement and cost charges applied to end users.
Activation time/Duration: 15 min. Tertiary reserve shall be guaranteed for an indefinite time period.
Other characteristics: The procurement of tertiary reserve is made by the TSO in the ancillary services market. All the qualified units shall make available to the TSO all the residual margins after the energy market, up to the maximum power and down to the minimum power and they have to be ready to accept a variation in the generation scheduling to make available such margin.

- **Voltage control – Reactive reserve for the primary voltage control**

Procurement schema: Mandatory.
Remuneration schema: Not remunerated.
Service provider: Generators.
Product resolution: An enabled dispatching unit will make available the maximum reactive power (in delivery or absorption) compatible with the technical characteristics of each generation group.
Other characteristics: The supply of resources for the reactive reserve service for primary voltage regulation consists in the provision of the reactive power production; this provision is given through an automatic adjusting device able to modulate the reactive power supplied by the generation group on the basis of the voltage deviation of the same generation group of terminals with respect to a reference value. For the suitability of reactive reserve service for primary voltage regulation each unit must be equipped with an Autonomous System for the Regulation of reactive power and voltage in conformity with the specifications described in the network code.

- **Voltage control – Reactive reserve for the secondary voltage control**

Procurement schema: Mandatory. The eligible dispatching units have an obligation to provide the maximum reactive power available.

Remuneration schema: Not remunerated.

Service provider: Participation in the service from eligible generation units is determined depending on the location of the generation unit on the network and maintaining appropriate voltage profiles on the national network.

Other characteristics: Each unit will be equipped with an autonomous system for the regulation of reactive power and voltage and with telecommunications equipment able to exchange all the necessary information. The supply of resources for the reactive reserve service for secondary voltage regulation consists in the provision of the reactive power production; this provision is given through an automatic adjusting device able to modulate the reactive power supplied by the generation group on the basis of the voltage deviation of the same generation group of terminals with respect to a reference value defined for some network points.

- **Other services – Real time balancing**

Procurement schema: In the real time balancing service the TSO accepts secondary and tertiary reserve bids/offers procured ex-ante. Secondary reserve is activated according to a pro quota mechanism. Tertiary reserve is activated according to a merit order list.

Remuneration schema: Pay as bid.

Service provider: Only power generation units, but intermittent resources

Cost recovery: For the qualified generating units, energy imbalances are priced according to a dual price mechanism, depending on the sign of the control area imbalance. On the other hand, imbalances of consumers and of all the generating units not qualified for providing ancillary services are priced with a single price mechanism, depending on the sign of the control area imbalance. For non-dispatchable renewable energy sources the current regulation fixes an imbalance threshold for each energy sources (wind, PV, RoR hydro), within which the cost of imbalances is aggregated and equally divided among all generating units of a specific source. The net imbalance of a unit exceeding the threshold is then priced according to the non-qualified unit regulation.

Activation time/Duration: For qualified units the relevant time frame is 15 minutes, for non-qualified units it is 1 hour.

Other characteristics: The TSO uses the resources for the real-time balance for: a) maintaining the balance between injections and withdrawals of electricity; b) the resolution of network congestion; c) the restoration of the correct secondary power reserve margins.

- **Other services – Interruptible load service (Interruptibility)**

Procurement schema: Optional.

Remuneration schema: The amount of interruptible loads to be supplied in the 3-year-period (2015-2017) is 3300 MW, that the TSO Terna shall buy by means of a Dutch auction mechanism (auctioneer begins with a high asking price which is lowered until some participant is willing to accept the auctioneer's price, or a predetermined reserve price is reached), starting from a price of 105000 €/MW/year for Instantaneous switch-off and 60000 €/MW/year for Emergency switch-off. In addition to the capacity compensation, during the annual operation, interruptible loads receive an additional compensation of 3000 €/MW for each interruption ordered by the TSO.

Service provider: *A*ll the entities which are able to:

i. ensure the interruptible service: a) in real time, characterised by an actuation time less than 200 ms, on the basis of a remote signaling sent by Terna; b) in deferred time in an emergency, characterised by an actuation time of less than 5 s, on the basis of a remote signaling sent by Terna.
ii. be an end customer, so that the assumption of responsibility resulting from the load shedding is directly between Terna and each counterparty;
iii. certify that this gap does not lead, in any case, the risk to workers, the environment and production facilities;
iv. certify that they have a installed power according to specifications set by Terna. The requirements for a consumer for participating to the auction include the minimum size of the load equal to 1 MW, the capability to switch-off the consumption according to the required timing and the presence in the site of an automatic device for processing the control signal issued by the TSO.

Minimum rated power: 1 MW.

Product resolution: The standard products traded in this auction include:

i. A 3-year-period product (¾ of the total amount to be provided should be covered by this product);
ii. Annual product, that accounts for the residual capacity after the 3-year-period allocation;
iii. Monthly product, that accounts for the residual capacity after the previous long term allocations

Other characteristics: It is necessary an automatic device for processing the control signal issued by the TSO.

7.6 Norway

- **Frequency containment reserve – Primary control**

Procurement schema: Mandatory reservation for machines over 10 MVA (via droop set point).

i. Weekly markets organised by TSO. FCR for normal operation (FCR-N): on Thursdays for weekends and on Fridays for working days.

ii. Daily market organised by TSO. FCR for both normal (FCR-N) and disturbance reserve (FCR-D).

Remuneration schema: Marginal price. In special cases pay-as-bid can be applied.

Service provider: Generators. Consumption.

Cost recovery: Via consumer (mostly) and producer tariffs.

Minimum rated power: 1 MW.

Ramp size/Speed drop: The transmission system operator (TSO) requires that generators above 10 MVA can have a maximum of 12 % droop if they are not active in the market. During summer this requirement is lowered to a maximum of 6 %.

Activation time/Duration:

i. For FCR-N: Activation within 5 s and full activation 30 s. Duration: 4 hour block 20:00-24:00, 8 hour block 00:00-08:00, 12 hour block 08:00-20:00.

ii. For FCR-D: Activation, 2-3 minutes. Minimum duration, 1 hour.

Requirements: Automatic activation. The generators have to meet the general functional requirements.

Penalty clause: Financial penalty.

Scheduling horizon: W-1 for FCR-N. D-1 for FCR-D.

- **Automatic Frequency Restoration Reserve – Secondary control**

Procurement schema: Weekly market organised by TSO. Reserves from the other Nordic countries can be used.

Remuneration schema: Marginal price. In special cases pay-as-bid can be applied.

Service provider: Generators.

Cost recovery: Via consumer (mostly) and producer tariffs.

Minimum rated power: Minimum 5 MW. Maximum 35 MW.

Product resolution: The volume should be dividable by 5.

Activation time/Duration: Activation time, 120-210 s.

Requirements: Automatic activation.

Penalty clause: Financial penalty.

Scheduling horizon: W-1.

- **Manual Frequency Restoration Reserve – Tertiary control**

Procurement schema: Common Nordic Market arrangements (merit list order) for FRR-M:

- FRR Option market (season) week 45-15

- FRR Option market (week) as needed
- FRR Organised Market
- Bilateral Agreements

The Option Market is an additional arrangement, which secures liquidity on the regular RR market.

Remuneration schema: Marginal price.

Service provider: Generators. Consumption.

Cost recovery: Via consumer (mostly) and producer tariffs.

Minimum rated power: 10 MW.

Activation time/Duration: Activation time, 15 minutes. Minimum duration, 1 hour.

Penalty clause: Financial penalty.

Scheduling horizon: D-1 (bids are submitted the day before at 20:00).

- **Voltage Control**

Procurement schema: Mandatory

Remuneration schema: Not remunerated.

Service provider: Generators.

Requirements:

For hydro- and thermal power plants the requirements are applied to the production unit ≥ 1 MVA (not where the sum of production units exceed this size). In addition, the unit ≥ 0.5 MVA have to be synchronous machine with automatic voltage regulation. For wind turbines the requirements are applied where the overall production, i.e. wind energy park ≥ 1 MVA.

Hydropower (selection): The System Operator can define the voltage levels and limits for the exchange of reactive power in the regional and central grid, as well as adopting reactive regulation. Synchronous Generators ≥ 1 MVA shall at full load operate by the power factor cos φ ≤0.86 capacitively and cos φ ≤ 0.95 inductively. Asynchronous Generators should at least be compensated for the idle reactive power consumption, but this must be considered from the voltage of the place.

Generator (not asynchronous) ≥ 0.5 MVA should have voltage regulator / equipment for continuous voltage regulation.

Generator ≥ 25 MVA shall have PSS. Voltage setpoint (voltage reference) should be set locally and from the control room. Voltage Regulator has to operate freely and without undue restriction within operational limits for generator. Unless special circumstances require it, MVAr- or cos-regulation should not be used unless this is agreed and approved by the system operator.

Windpower (selection): The system operator can oblige the generator to provide regulation reactive power within production units' technical limitations. Windpower parks ≥ 1 MVA shall at full load operate by the power factor cos φ ≤ 0.95 capacitively and cos φ ≤ 0.95 inductively.

Directly connected asynchronous machines shall have equipment for compensating for the reactive power consumption. This equipment shall be designed with regard to reactive power needs in the connected networks, and if necessary provide dynamic voltage regulation.

7.7 Spain

This section is based on Spanish system operator's operating procedures [66].

- **Frequency Containment Reserve – Primary Reserve**

Procurement schema: Mandatory.
Remuneration schema: Not remunerated.
Service provider: Generators only.
Product resolution: ± 1.5% of maximum power output.
Activation time/Duration: The service is activated before 15s or 30s, depending on the imbalance, and the maximum duration is 15 min until Frequency Restoration Reserve re-establishes the initial values of Frequency Containment Reserve. The service must be activated before 15s for imbalances generation-demand lower than 1500 MW. For imbalances generation-demand higher than 1500 MW, 50% of the reserve before 15s and on a straight-line basis up to 100% before 30s.
Other characteristics: When any technical problem makes impossible the provision of the service, the duty-bearers must contract directly the service from other available providers.

- **Frequency Restoration Reserve – Secondary Reserve**

Procurement schema: Optional.
Remuneration schema: Market based schema. It is remunerated under two concepts: capacity (regulation band) and usage (energy):

i. Reserve assignation price: Marginal price of the regulation band assignation. The provision of more regulation than the previously assigned implies a collection right at a price equal to 1.5 marginal price. On the contrary, the no provision of the service implies a payment obligation equal to 1.5 marginal price.
ii. Effective net energy: The energy usage price is the marginal price of the tertiary energy price (replacement reserve) which has been necessary to assign for the replacement of the restoration reserve.

Service provider: Generation units included in a Regulation Area, which is a grouping of production units that can regulate under the management of an Automatic Generation Control system. The responsible entity of a regulatory area submits bids for power band in €/MW for each scheduling period of the next day. The bids for each scheduling period are made up of several blocks. Only one of these blocks can include an indivisibility clause.

Cost recovery:

i. The regulation band cost is defrayed through the acquisition units, depending on their consumption raised to power station busbars.
ii. The effective energy usage cost is allocated between the energy market participants who have committed any deviation with respect to their scheduled operation.

Minimum rated power: The minimum bid size is 10 MW.

Product resolution: The recommended minimum requirement of upward secondary regulation reserve is:

$$R = \sqrt{aLmax + b2} - b$$

Where, Lmax=Expected load in the control area, a = 10 MW and b = 150 MW.

In general, the downward band is between 40%-100% of the upward band. The minimum regulatory band, especially during off-peak periods, is 500 MW for the upward band and 400 MW for the downward band.

Activation time/Duration: The activation time is before 30 s and the service duration 15 min.

Penalty clause: Payment penalisation.

Other characteristics: The total amount of assigned power bands must be +/- 10% of the total required regulatory band.

Required by the System Operator:

- Upward reserve requirement (RSSUBh (MW)).
- Downward reserve requirement (RSBAJh (MW)).
- Minimum and maximum value of the regulation band (sum of the upward and downward reserve of the individual bids), RSBANmax (MW) and RSBANmin (MW).

Bids:

- Upward reserve offered, RNSsubirh (MW).
- Downward reserve offered, RNSbajarh (MW).
- Regulation band price, PSbandah (€/MW).
- Energy variation with respect to the planned in provisional daily viable schedule.

The sum of the upward and downward reserve within a bid (RNSsubirh + RNSbajarh) must be between the limits established by the System Operator (RSBANmax and RSBANmin).

Each regulatory area must comply with the established ratio between upward and downward reserve, RSBh (RSBh = RSSUBh/RSBAJh (p.u.)).

Scheduling horizon: Day-ahead market. The day before dispatching, D-1.

- **Replacement Reserve – Tertiary Reserve**

Procurement schema: Mandatory bidding for the available capacity.

Remuneration schema: Market based schema. Marginal price (€/MWh):

i. Upward energy assignation: Collection right at marginal upward energy price.

ii. Downward energy assignation: Payment obligation at marginal downward energy price.

Service provider: Generation installations and pumped hydro units (consumption) which have been pre-qualified by the TSO. Since February 2016, RES and other DER can also ask to be pre-qualified as service providers.

Cost recovery: The service cost is defrayed by the energy market participants who have committed any deviation with respect to their scheduled operation.

Minimum rated power: 10 MW.

Product resolution: Minimum upward reserve is equal to the maximum loss of generation caused by a simple failure of an electric system element, plus the 2% of the expected demand in each scheduling period. In general, the downward reserve is between 40%-100% of the upward reserve. Indivisible blocks of bids are not allowed.

Activation time/Duration: Activation time: 15 min. Service duration: 2 hours.

Penalty clause: Breach of:

i. Upward energy assignation: Payment obligation for breach of the assigned energy at an average price calculated considering several issues as; technical restrictions, deviation management, tertiary reserve, etc. and multiplied by 0.2.

ii. Downward energy assignation: Payment obligation for breach of the assigned energy at day-ahead market price.

Other characteristics: The bids must include the available reserve in MW, both upward and downward, and the related energy price in €/MWh. When several installations offer the same price, those using renewable resources have priority. Then, the high efficiency cogeneration installation, and at last, the remaining bids.

Scheduling horizon: Day-ahead market. The day before dispatching, D-1.

- **Voltage control – Transmission network**

Procurement schema: Mandatory (not remunerated) and Optional (remunerated)

Remuneration schema: Only the optional assignation is remunerated.

Generators: Four concepts are included:

i. Reactive power generation additional band availability (assigned by the Annual voltage control Plan).
ii. Reactive power absorption additional band availability (assigned by the Annual voltage control Plan).
iii. Reactive energy generated at power plant busbar, for the effective voltage control at transmission network, excluding the coming energy from the mandatory band.
iv. Reactive energy absorbed at power plant busbar, for the effective voltage control at transmission network, excluding the coming energy from the mandatory band.
v. The operation as synchronous compensator is remunerated for the power band availability and for the effective energy generated/absorbed for the voltage control.

Consumers (service providers) and distribution grid managers:

i. Additional band availability (assigned by the Annual voltage control Plan), equal to a reactive power generation.
ii. Additional band availability (assigned by the Annual voltage control Plan), equal to a reactive power absorption.
iii. Reactive energy delivered/no consumed, for the effective voltage control of the transmission network, within the additional band assigned in the day-ahead scheduling.
iv. Reactive energy consumed, for the effective voltage control of the transmission network, within the additional band assigned in the day-ahead scheduling.

Service provider:

i. Generation units with net power > 30 MW (ordinary regime) or renewable/cogeneration/wastes installations connected to the transmission network.
ii. Transmission Operators.
iii. Qualified consumers connected to transmission network and with a contracted power ≥ 15 MW.
iv. Distribution network managers.

Cost recovery: The service cost is defrayed through the holders of acquisition units and physical bilateral contracts, depending on their consumption raised to power station busbars.

Requirements:

Mandatory requirements:

i. Generators: They must have a minimum mandatory margin of reactive power, both in generation and in absorption, for the service provision. The aim is to maintain the voltage at power plant busbars within the established margins (for the whole variation range of active power between the technical minimum and the maximum net power). These margins are:

- Capacitive Cos φ = 0.989 (reactive power generation equal to 15% of the maximum net active power).

- Inductive Cos φ = 0.989 (reactive power absorption equal to 15% of the maximum net active power).

ii. Transmission System Operators: They must provide the service with the available equipment in their networks; reactances, capacitors, regulating transformers, etc.

iii. Consumers (service providers) and Distribution System Operators: For each hourly period (peak, off-peak, super off-peak):

   - Peak period: Reactive power consumption cannot exceed the 33% of active power consumption (Cosφ ≥0.95 inductive).
   - Off-peak period: Reactive power consumption cannot exceed the 33% of active power consumption and it cannot exist reactive power delivery to the transmission network (0.95 inductive < Cosφ < 1.00 inductive).
   - Super off-peak period: It cannot exist reactive power delivery to the transmission network (Cosφ ≥ 1 inductive).

Optional requirements (remaining resources): The bids for additional resources do not include any price, since this is regulated and established by the Government.

i. Generators: They can submit bids for the availability of a surplus band of reactive power generation/consumption exceeding the mandatory requirements. Additionally, bids for the operation of generators as synchronous compensators can be submitted.

ii. Consumers (service providers) and Distribution System Operators: They can submit bids for their additional available resources exceeding the minimum requirements.

Penalty clause: Breach of mandatory requirements: A payment obligation for the reactive power no delivered/consumed. Breach of additional resources assigned: A negative term and a coefficient to discourage these breaches are included in the payment formula.

Scheduling horizon: Annual assignation: Additional resource assignation for the next year, before 15 December.

The day before dispatching, D-1, the System Operator advertises:

i. The voltage set points to be maintained at control nodes (power plant busbars and nodes controlled by transformers with on load tap changer).

ii. Power factors to be maintained by consumers and the distribution system operators, related to assigned bids of additional resources.

When necessary, the System Operator can require some actions for the voltage control during system operation in real time.

- **Voltage control – Distribution network**

Procurement schema: Mandatory.

Remuneration schema: Not remunerated.

Service provider:

i. Consumers connected at distribution level
ii. RES installations connected at distribution network

Requirements:

Consumers: All consumers, apart from consumers type 2.0A, must have installed a reactive energy meter. The reactive energy term is applied over every tariff periods, except that one from 0:00 to 8:00 (super off-peak period for tariffs Type 3 and Type 6), when the reactive energy consumption is higher than the 33% of active energy consumption during the billing period (cos $\varphi < 0.95$) and only is applied over the excess. This excess price is defined in euro/kVArh.

The distribution operators must show the investments performed each year (by elements and by zones) to the competent authority in order to fulfil the voltage control requirements.

The conditions and obligation for this term application are:

i. Mandatory power factor correction: When the reactive energy consumption is 1.5 times higher than the active energy consumption in three or more measurements, the distribution operator, supplier of this consumer, must inform the competent authority. This entity can establish a period for the power factor improvement and, if this schedule is not fulfilled, may deny the access to the energy network. The consumers with simple tariff (2.0A) must have the suitable equipment for the correction of the reactive energy consumption to get an average consumption lower than the 50% of the active energy consumption.
ii. Capacitive effects correction: When the installation of a supply causes capacitive effects and disturbances in the distribution or transmission networks, anyone affected by these disturbances can inform the competent authority. This entity can establish a period for the disturbance correction and, if this is not achieved, may deny the access to the distribution network.
iii. Management of reactive energy correction equipment: The distributors can agree with their clients the total or partial disconnection of their reactive energy correction equipment and the reactive energy meters during the off-peak period, and the reactive energy term fixation to be applied in these cases. These agreements must be approved by the competent authority.

RES installations: The mandatory power factor range is established between 0.98 inductive and 0.98 capacitive. The special regime installations with power higher than 5 MW, or those ones with powers lower than 5 MW that are part of a group (of the same subgroup type) whose total power is > 5 MW, must be assigned to a generation control centre. This will be the interlocutor with the System Operator, sending the installations' information in real time and executing the convenient instructions in order to guarantee the electrical system reliability. The installations with installed power higher than 1 MW, or lower than 1 MW but being part of an installations aggrupation whose total power is higher than 1 MW,

must send tele-measurements in real time to the System Operator. These telemeasurements can be sent by the installation owner, its legal representative or through the distribution company control centre. The distribution system operators will have access to the real time telemeasurements of the installations connected to their networks. The installations with power > 5 MW must follow the indications launched by the System Operator for the modification of the power factor range, depending on the system necessities. Until the development of the procedure for RES participation in voltage control service the RES installations must maintain their power factor within the established range. The installations with power < 100 kW connected to networks < 1 kV must maintain the power factor as close to 1 as possible or, at least, higher than 0.98 when the installation is working at power higher than 25% of its nominal power. RES installations connected to transmission network can participate in the voltage control service in the same manner as the ordinary regime installations do.

Penalty clause:

Consumers: Payment obligation depending on cosφ and, ultimately, the prohibition of access to the distribution network.

RES installations: The mandatory power factor range is currently established between 0.98 inductive and 0.98 capacitive. This range can be modified annually. The penalty for breach is 0.261 c€/kWh and it is applied on an hourly basis.

- **Other services – Interruptible load service (Interruptibility)**

Procurement schema: Optional. Reverse auction managed by System Operator.

Remuneration schema: Two terms:

i. Fixed term linked to power availability

   Rmmax = (1/12)*Psub* Price

   Psub: Power assigned (auction). Price: Clearing price (auction)

ii. Variable term linked to the effective execution of power reduction

   Reoi = Psub * teoi * Preoi

   teoi: Operation duration (hours). Preoi: Reference price in €/MWh. Index-linked value to the estimated and weighted average tertiary reserve price.

Service provider: Electricity consumers connected to high voltage network.

Cost recovery: The service cost is borne by:

i. The owners of the power plants defray a part of the monthly fixed cost according to their contributions to the coverage of the system peak demand.
ii. The demand assumes the remaining monthly fixed cost proportionally to its consumption at the power plant busbars.
iii. The hourly variable cost and the energy reduced will be integrated with the balance energy according to the procedure of the imbalance settlement.

Minimum rated power: Demand reduction blocks of 5MW or 90 MW.

Activation time/Duration: Three options (to be determined by System Operator):

i. Immediate execution: Without prior notice.
ii. Fast execution: Minimum prior notice of 15 min.
iii. Hourly execution: Minimum prior notice of 2 hours.

Maximum duration of each execution = 1 hour. No more than 2 consecutive executions. Maximum per year:

i. 5 MW product: 40 hours/week and 240 hours/year.
ii. 90 MW product: 60 hours/week and 360 hours/year

Requirements: Some of the most relevant requirements to provide the service:

i. To fulfil the requirements to be considered as an electricity supply point or installation.
ii. To be high voltage consumers who buy electricity in the production market, directly or throughout a supplier, and which have a grid-access contract with the corresponding DSO.
iii. To have installed the measurement and control equipment for service management and a load shedding relay by subfrequency in the supply point.
iv. Financial guarantee for possible breach of service provision obligation.
v. To prove that, at least, 50% and 55% of monthly consumption is made in pricing period 6 (from 0:00 to 8:00 every day, and the whole day in Saturday, Sundays, bank holidays and August) for the 90 MW and the 5 MW products, respectively.
vi. For the 5 MW product: To prove that the average hourly consumption during the whole scheduling horizon is not below 5 MW over a reference residual power (Pmax) stated by the consumer during the qualification process.
vii. For the 90 MW product: To prove an effective and verifiable consumption higher than 90 MW over a reference residual power (Pmax) stated by the consumer during the qualification process during, at least, the 91% of the hours of the month.

Penalty clause: Payment obligation or exclusion and loss of retribution. It depends on several factors such as frequency and kind of breach; resource availability, load shedding relay, monthly consumption, etc.

Scheduling horizon: Annual market (assignation for the next year, 1 January - 31 December).

- **Other services – Deviation management**

Procurement schema: Optional. Market based schema.

Remuneration schema: Marginal price (€/MWh). Upward energy assignation: Collection right at marginal upward energy price. Downward energy assignation: Payment obligation at marginal downward energy price.

Service provider: Generation installations. Pumped hydro units (consumption).

Cost recovery: The service cost is defrayed by the energy market participants who have committed any deviation with respect to their scheduled operation.

Minimum rated power: 10 MW.

Activation time/Duration: Resolution of deviations arisen between generation-consumption after the end of an intraday market session till the beginning of the scheduling horizon of the next session.

Product resolution: The value of the extra active power reserve is calculated as:

i. Upward reserve: Sum of deficits caused by; a) Differences between the expected hourly demand by the System Operator and the resulting hourly demand in the Functioning Base Programme (PBF) and the successive intra-day sessions. b) Differences between the sum of the wind production in the Functioning Base Programme (PBF) and the hourly wind production foreseen by the System Operator. c) The foreseen loss of generation caused by successive failures and/or delays on the couplings or increase of the thermal set load, with a probability of 5% or more, is higher than the maximum loss of production caused by a simple failure of an electric system element.

ii. Downward reserve: Sum of excesses caused by the same concepts as in the upward reserve case.

Requirements: The System Operator, only when the foreseen average deviation is ≥ 300 MW, organises the deviation management market. The assigned bids must cover the +/- 10% of the advertised total requirement. When several installations offer the same price, the priority to organise the bids: a) Divisible blocks against indivisible blocks. b) For the same type of blocks, priority for those offering lower amount of energy. c) Those using renewable resources. d) The remaining bids. The upward or downward energy within an indivisible bid cannot be higher than 300 MWh.

Penalty clause: Breach of upward energy assignation: Payment obligation for breach of the assigned energy at an average price calculated considering several issues as; technical restrictions, deviation management, tertiary reserve, etc. and multiplied by 0.2. Breach of downward energy assignation: Payment obligation for breach of the assigned energy at day-ahead market price.

Scheduling horizon: Quasi real time. Dispatching day, D.

- **Other services – Black start service**

Procurement schema: Agreement of collaboration.

Remuneration schema: Not remunerated.

Service provider: Utilities operating in the Spanish power system. The hydro plants are the first to be restarted in case a blackout takes place.

Requirements: Every year a national blackout rehearsal coordinated by the system operator is performed using the system operator network model. All the generation utilities participate in this

simulation, taking about 4-5 hours to restore the 70% of the system. The renewable resources are not taking into account for this service provision due to the instability and unpredictability of its generation.

The steps of the procedure for the service restoration are:

i. Six different electric zones has been defined (zone division is related to hydro plants location).
ii. In case a national blackout occurs, the autonomous hydro plants are simultaneously started forming electrical islands.
iii. The zone which extends from the river Duero to the French border is considered as key zone. After connecting this zone to the European transmission network through the French border, the European frequency is achieved.
iv. This key zone acts as reference to which the rest of the electric areas will be then successively synchronised.

Scheduling horizon: Emergency plans are yearly reviewed.

- **Other services – Technical restrictions resolution (after day-ahead market)**

Procurement schema: Technical restrictions of the daily base operating schedule (PDBF). Two phases:

Phase I: Modifications of the PDBF scheduling for security reasons.

i. Technical restrictions identification. This includes several steps such as; i) analysis of available information related to production and demand forecasts, international exchanges included in the PDBF, unavailable units, etc. ii) identification of any circumstance which can affect the security, quality and reliability of the system, iii) resolution of restrictions affecting the interconnections and, at least, resolution of restrictions in the Spanish system.
ii. Means for technical restrictions resolution. The production units will have assigned a value no lower than the minimum technical limit and no higher than the net active power.

    - Increase of energy scheduled in the PDBF. By means of energy sale bids submitted during the technical restriction process by production installations. When several solutions are technically feasible the system operator carries out an economic assessment.
    - Decrease of energy scheduled in the PDBF: These reductions will be carried out by means of withdrawals in the PDBF schedule (submitted bids for technical restrictions resolution are not used).
    - Technical restrictions solution due to an insufficient upward power reserve. When after the incorporation of redispatchings and security limitations the upward reserve is not sufficient, the system operator establishes a schedule considering a value equal to the technical minimum over the thermal groups scheduled in the PDBF and also applies maximum limitations over the pumping consumption. When these actions are not enough the system operator schedules the start and coupling of additional thermal groups.

- Technical restrictions solution due to an insufficient downward power reserve. When after the incorporation of redispatchings and security limitations the downward reserve is insufficient, the system operator will apply limitations over the acquisition units up to the values established in the PDBF.

Phase II: Generation-demand rebalancing. Once the technical restrictions identified in the PDBF are solved, the System Operator modifies the schedule in order to obtain a balance generation-demand taking into account the limitations from phase I. The System Operator defines the modifications to be included in the PDBF. Firstly, these modifications are assigned to those units which are bound to submit energy bids but that have not met that requirement. When this is not enough, the System Operator makes use of the upward/downward technical restrictions bids. Pay as bid schema. After all these considerations the daily viable schedule (PDVP) is launched by the System Operator.

Remuneration schema:

Phase I: PDBF modifications for security reasons.

i. Phase I - Upward assignation:

   - Production units: The upward energy assignation is remunerated at the submitted price depending on whether the bids are simple or complex. When there are no bids, or not enough, and the exceptional mechanism of resolution is used, the price of remuneration will be 1.15xday-ahead market price.
   - Pumping consumption and exportation acquisition units: The upward energy assignation for acquisition units within the day-ahead market are considered as a rectification in the production market and imply a collection right at day-ahead market price. Transaction linked to a bilateral agreement: There will be no financial settlement.

ii. Phase I - Downward assignation, production units. The downward energy assignation for production units within the day-ahead market are considered as a rectification in the production market and imply a payment obligation at day-ahead market price. Transaction linked to a bilateral agreement (for sale units whose production is for national consumption): Payment obligation at day-ahead market price. Transaction linked to a bilateral agreement (for sale units whose production is for pumping consumption or exportation): There is no financial settlement.

The breach of assignations can cause penalties application.

When the energy is removed from bilateral contracts by congestion at international borders, there is no financial settlement.

Phase II: Generation-demand rebalancing. The downward energy assigned to bilateral contracts of production units whose demand has been reduced in the phase I, will not result in any financial settlement. The upward energy assigned to bilateral contracts of acquisition units (pumping or exportation) whose generation has been reduced in the phase I, will not result in any financial settlement.

i. Phase II - Upward assignation:

- With simple bid submitted: Collection right at upward price submitted for technical restrictions resolution.
- Without simple bids submitted:
  - Acquisition units which have not submitted upward bids: Collection right at 0.85xday-ahead market price.
  - Production units which have not submitted upward bids: Collection right at 0.85xday-ahead market price.
  - After all submitted bids have been assigned, if the exceptional mechanism of resolution is necessary: Collection right at 1.15xday-ahead market price.

ii. Phase II - Downward assignation:

- With simple bids submitted: Payment obligation at downward price submitted for technical restrictions resolution.
- Without simple bids submitted:
  - Acquisition units which have not submitted downward bids: Payment obligation at 0.85xday-ahead market price.
  - Production units which have not submitted downward bids: Payment obligation at 1.15xday-ahead market price.

Cost recovery: The extra charge due to technical restrictions is calculated as the addition of payment obligations and collection rights generated during the process. The technical restrictions resolution of the daily base operating schedule (PDBF) is defrayed through the acquisition units, depending on their consumption raised to power station busbars. Pumping consumption units, supply for ancillary services of production units and acquisition units for supply out of the Spanish electrical system are excluded of this assignation.

Requirements: Once the daily base operating schedule (PDBF) is issued the System Operator opens the bids process for 30 min. Different types of bids can be submitted:

i. Bids from energy sale units

- Energy sale bids. The submission of these bids is mandatory for no renewable thermal groups, reversible pumping station and renewable energy installations. The power to be offered is the maximum power available after the definition of the PDBF. In the case of bilateral contracts for the energy exportation through interconnections without coordinated system of exchange capacity management, the bids must include the whole maximum power available without considering the energy already scheduled in the PDBF. The submission will be optional for the energy units related to importations from external electrical systems where a coordinated system of exchange capacity management does not exist.

- Energy purchase bids. They are mandatory and must include the whole energy sale scheduled in the PDBF for each sale unit.

ii. Bids from energy acquisition units (for pumping consumption)

- Energy sale bids. They are mandatory and must include the whole pumping energy consumption included in the PDBF.
- Energy purchase bids. They are optional. Increase with respect to the consumption scheduled in the PDBF.

In general, the bids will be simple bids (only thermal groups are allowed to submit complex bids) and they must include the following information:

i. Type (production, importation or pumping consumption).

ii. For each scheduling period and with respect to the energy scheduled in the PDBF:

- Upward energy: Block number (Dividable blocks with increasing prices. From 1 up to maximum 10 blocks). Energy (MWh). Energy price.
- Downward energy: Block number (Dividable blocks with decreasing prices. From 1 up to maximum 10 blocks). Energy (MWh). Energy price.

iii. Code for the order of redispatching assignation when the same unit takes part in a market transaction and in one or more bilateral contracts.

Scheduling horizon: D-1.

- **Other services – Technical restrictions resolution (after each intraday market session)**

Procurement schema: Daily, the System Operator launches the security limitations jointly with the PDVP. These security considerations can be modified throughout the day. This information is available for the Market Operator before each intra-day session, so the security limitation can be taken into account before matching the intra-day bids. After each intraday session, the System Operator reviews the fulfilment of the previously established security limits and the interconnection capacities. After that, if any technical restriction is identified, the System Operator removes the bids which solve the identified restrictions, as long as these matched bids can be compensated with the removal of other bids matched in the same session and located in the Spanish system. After that, the rebalancing generation-demand is established by means of the withdrawal of bids submitted to that intra-day market session. The Final Hourly Schedule is launched after each intra-day market session, once the detected technical restrictions are solved.

Remuneration schema: A sale bid withdrawal previously matched in the intra-day market session implies a rectification in the production schedule and leads to a payment obligation for the sale unit at the marginal price of the corresponding session. An acquisition bid withdrawal previously matched in the

intra-day market session implies a rectification in the production schedule and leads to a collection right at the marginal price of the corresponding session.

Scheduling horizon: D.

- **Other services – Technical restrictions resolution (in real time)**

Procurement schema:

i. Modifications by security reasons: The minimum and maximum limits are continuously assessed by the System Operator. When the production schedule needs to be modified the following steps are followed:

   - Minimum cost by using tertiary regulation bids.
   - When the tertiary regulation is not enough the bids submitted for the PDBF technical restriction resolution will be used. After the assignation of the secondary reserve, the market participants can update the bids submitted for technical restrictions resolution of the PDBF.

ii. Capacity reductions/withdrawals caused by unavailability of transmission or distribution assets. The system operator will solve the congestion by an energy redispatching over the foreseen schedule of the unit.

iii. Insufficient downward reserve: Several solutions:

   - To increase the energy schedule of pumping consumption units.
   - To decrease the scheduled production of thermal groups to their technical minimum power.
   - To schedule the pause of thermal groups.
   - When the previous actions are not enough, the procedure will be the same as the detailed one for the technical restrictions resolution of the daily base operating schedule (PDBF).
   - Actions on the demand: When the technical restriction resolution implies an increase over the production units and this is not feasible, the following steps can be followed:
     - Reduction/withdrawal of pumping consumption: According to the upward tertiary reserve submitted bids.
     - Reduction/withdrawal of exportation capacity.
     - Interruptibility service application: According to its specific procedure.

iv. Rebalancing generation-demand after technical restrictions resolution in real time. There is no specific procedure for this rebalancing. Any deviation caused by the technical restriction resolution will be managed in the same manner as the rest of deviations, by means of the secondary and tertiary regulation and, when possible, through the deviation management mechanism.

Remuneration schema:

i. Upward technical restrictions in real time.

- With tertiary reserve bids: The assignation of upward energy using tertiary bids implies a collection right for each energy block at submitted upward tertiary price (and an additional term if a complex bid needs to be used).
- With bids submitted for the technical restrictions resolution of the daily base operating schedule (PDBF):
  - Simple bid: Collection right at the submitted price for technical restriction resolution.
  - Complex bid: Collection right (or payment obligation if the result of the formula is negative). The cost is calculated according to different terms such as; upward scheduled energy, limited energy by technical restrictions, energy of the last Final Hourly Schedule, average price of the energy assigned for the participation in the intra-day session and a price calculated for the complex bids price calculation.
- Without bids: Collection right at 1.15xday-ahead market price.

ii. Downward technical restrictions in real time.

- With tertiary reserve bids: The assignation of downward energy using tertiary bids implies a payment obligation for each energy block at submitted downward tertiary price (and an additional term if a complex bid needs to be used).
- With bids submitted for the technical restrictions resolution of the daily base operating schedule (PDBF): Payment obligation right at the submitted price for technical restriction resolution.
- Without bids: Payment obligation at 0.85xday-ahead market price.
- for pumping acquisition units: An additional payment obligation at 0.7xday-ahead market price for the energy reserve generated in the upper vessel of the pumping unit.

Cost recovery: The extra charge due to technical restriction in real time is calculated as the difference between the sum of payment obligations and collection rights and the cost of the assigned energy valued at day-ahead market price. The technical restrictions resolution in real time is defrayed through the acquisition units, depending on their consumption raised to power station busbars. Pumping consumption units, supply for ancillary services of production units and acquisition units for supply out of the Spanish electrical system are excluded of this assignation.

Scheduling horizon: D.

8 Appendix B: Market rules – Other countries

The market mechanisms established in the three selected national cases (Italy, Denmark, Spain) for the physical pilots within SmartNet were already described in section 2.2. In this appendix, the markets for other countries are described.

8.1 Electricity market - Belgium

In Belgium, the TSO (Elia) procures power reserves via an organised market.

Power reserves provided by grid users fall into three categories: Primary (R1)[18], Secondary (R2)[19] and Tertiary (R3)[20]. Elia uses these reserves to maintain frequency and voltage and reduce imbalances or solve congestions (Product sheet S in [67]).

To fulfill the requirement for primary reserve (R1), Elia may contract capacity from Belgian and French generators [68] and large industrial grid users at Elia's control area. In addition, Elia participates to the common FCR tendering (between Germany, The Netherlands, Austria, Switzerland and Denmark). By joining this international cross-border cooperation, the total Belgian FCR obligation (73 MW in 2016) will be auctioned on a weekly basis via both a national and a cross-border common auction [69]. Contrary to several other countries, Elia allows also non-symmetric offers for the primary reserve. In addition, recent changes in regulation make it possible that aggregated load (R1 Load) participates to the primary reserve as well. Nevertheless, participation to the market of primary reserves is still limited to resources connected at the transmission grid.

With respect to secondary reserve (R2), Elia contracts upward and downward reserve from baseload flexible units via monthly tenders. For R2, volumes are symmetrical, meaning that R2-upward volumes and R2-downward volumes have the same value. In 2016, Elia set 140 MW as the volume to be purchased via short-term auctions for secondary reserve [70].

Tertiary reserve (R3) may be contracted from generation units (R3-Production), loads connected at transmission level (R3-ICH) and DSO connected loads (R3-DP). The procurement of these reserves is done yearly and monthly.[21] In 2016, Elia set the required total volume to 770 MW. From the yearly total, a minimum of 300 MW must come from R3-Production while the amount for R3-ICH was capped at 300

[18] Reserves in this category refer to "Frequency Containment Reserves" (FCR).
[19] Reserves in this category refer to " Automatic Frequency Restauration Reserves" (aFRR).
[20] Reserves in this category refer to "Manual Frequency Restauration Reserves" (mFRR).
[21] R3-ICH is only procured on a yearly basis.

MW. Monthly, Elia procures 70 MW of R3-Production and R3-DP via short-term auctions [71][22]. The introduction of R3DP is one of the first examples in Europe of standardised ancillary service products that are structured to stimulate the participation of resources connected at the distribution grid to the market of ancillary services (Product sheet S8 in [67]).

In addition to these reserves, Elia procures voltage control and black start services. For voltage control, Elia organises tenders and choose the suppliers based on price and location (Product sheet S6 in [67]). The black start service is paid for via a contract that may cover several years. The selection of suitable generators is done based on performance, location and price offer (Product sheet S7 in [67]).

To ensure Belgium's electricity supply Elia organised a strategic reserve mechanism (Product sheet E9 in [67])[23]. This reserve is contracted with generation units (SGR) not participating to the organised markets and with consumption (SDR) located in various access points.[24]

New reserve products that allow provision of ancillary services from distribution connected generation and load may be introduced by Elia in 2017.

Additional to the services listed above, Elia coordinates the injections of electricity by means of a contract (commonly known as CIPU contract).[25] The CIPU contract allows Elia to use power available to manage grid balance (and frequency), voltage and congestion (Product sheet S5 in [67]). Within the framework of this contract Elia collects producers' forecasts that cover long- (a year) and short-term (day of delivery) and prices for energy increments and decrements (incl. start-up price). Bids provided allow for certain level of freedom, hence they are commonly known as free bids, to the producer (to offer his available capacity) and to Elia (to exploit available capacity close to real-time).

In 2013, Elia made a study that assessed reserve requirements for 2018 [62]. The study sheds light on the availability of appropriate ancillary services in Belgium. Based on the assumptions adopted in the study it could be expected that by 2018 reserves needs and according costs for society highly increase if, efforts and investments fall short. Elia concludes that "reserves needs of the system heavily depend on the BRP behavior". Therefore, to avoid steep costs to society, Elia continues, BRPs and network operators should behave proactively. In addition, Elia emphasises the crucial role of providing adequate incentives via the imbalance mechanism.

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[22] The volume represents the sum of both reserve types.

[23] The objective of the mechanism is to cover structural shortages in generation in the winter period.

[24] Access points connected to Elia's grid, to the distribution grid, or another point within the electrical facilities of a grid user downstream of an access point connected to Elia's grid.

[25] BRPs responsible for electricity injections (output of production units) that take place at Elia's grid are legally bound to conclude a CIPU contract with Elia.

Via the balancing mechanism Elia manages the instantaneous imbalances BRPs are not able to control. To recover the costs from balancing the system, Elia applies a charge to any BRP imbalance. This imbalance tariffs provides incentives to BRPs to maintain their balancing perimeter in balance. More information on the balancing mechanism and the imbalance tariff can be found in (Product sheet E1 in [67]) and (Product sheet E2 in [67]), respectively.

In the international arena, on October 1, 2012 the Belgian control block was added to the international grid control cooperation (IGCC). The IGCC is based on an optimisation system for the activation of secondary reserve. Austria (April, 2012) and Denmark (October, 2011) also belongs to this cooperation group. More information on the IGCC can be found in [72].

Current developments in network codes are expected to impact the Belgian market for ancillary services. Some of the expected impacts are:

- Dimensioned volumes needed to be available instead of procured.
- Stricter dimensioning with respect to downward mFRR.
- Short term procurement of reserve capacity (monthly instead of yearly).
- Evolution towards less contracted reserves upfront.
- Increased cross border cooperation (netting of balancing volumes, procurement of ancillary services cross border).

8.2 Electricity market - Finland

Nord Pool, Europe's leading (bulk) power market, delivers both day-ahead and intraday trading, clearing and settlement to its customers, regardless their size or location. Nord Pool delivers day-ahead trading within the Nordic, Baltic and UK markets, and intraday trading within the Nordic, Baltic, UK and German markets.

The Elspot market of Nord Pool Spot determines the next day's wholesale prices for electricity. Based on these bids and offers, Nord Pool Spot will calculate the spot price for electricity for every hour of the following day. 12:00 CET is the deadline for submitting bids for power which will be delivered the following day. Hourly prices are typically announced to the market at 12:42 CET or later. Finally, once the market prices have been calculated, trades are settled.

The intraday market supplements the day-ahead market and helps secure the necessary balance between supply and demand in the power market for Northern Europe. At 14:00 CET, capacities available for Nord Pool intraday trading are published. This is a continuous market, and trading takes place every day around the clock until one hour before delivery. The prices are set based on a first-come, first-served principle, where best prices come first, highest buy price and lowest sell price.

According to Directive [1] one of the tasks for TSOs is to ensure the availability of all necessary ancillary services and with that aim, TSOs must manage the corresponding balancing power markets. Holders of production units and loads can submit capacity bids to the balancing power market. The balance service agreement gives balance responsible parties a right to participate in the balancing power market. Other holders of flexible capacity can participate in the balancing power market through their balance responsible party or by signing a separate balancing power market agreement with the TSO. Fingrid uses the purchased products of balancing power markets also for congestion management purposes.

In the joint Nordic system (Finland, Sweden, Norway and East Denmark), the obligations for maintaining reserves have been agreed in System Operation Agreement between the Nordic Transmission System Operators (TSOs). The total amount of Frequency Containment Reserve for Normal operation (FCR-N) is 600 MW which is constantly maintained. This jointly maintained reserve is divided annually between the Nordic TSOs in relation to the total consumption in each country. Obligation for Finland is about 140MW. In 2013 the total consumption in Sweden was 137.5 TWh, in Norway it was 128.1 TWh, in Finland 81.4 TWh and in Eastern Denmark 34.0 TWh.

Frequency Containment Reserve for Disturbances (FCR-D) is maintained to the extent that the power system can withstand, for example, disconnection of a large production unit without the steady state frequency deviation exceeding 0.5 Hz. The dimension of this reserve is set weekly to correspond to the greatest individual fault in the system, reduced by self-regulation of load in the system (200 MW). In a normal situation, the dimension of the Frequency Containment Reserve for Disturbances is about 1 200 MW which is jointly maintained by the Nordic system. Obligation for Finland is 220-265 MW.

It has been agreed that up to 300 MW of Automatic Frequency Restoration Reserve (aFRR) is maintained in predefined morning and evening hours in the Nordic countries. Country-specific obligations have been divided between the Nordic TSOs in relation to the annual consumption. Obligation for Finland is 70 MW. Furthermore, each TSO maintains Manual Frequency Restoration Reserve (FRR-M) to cover the dimensioning fault in its own area. Obligation for Finland is 880-1100 MW. Fingrid meets its FRR-M obligation with the reserve power plants it owns and with the leasing of other power plants. These plants are not used for commercial electricity production since the unbundling of energy supply and generation from the operation of transmission networks is already established.

The TSO of each country procures its share of reserves as it considers best. In order to meet reserve obligations, trade can be done between countries. Part of reserves must be maintained nationally, so that the frequency can also be maintained in situations of island operation. In normal situation, a maximum of 1/3 of the obligations for frequency containment reserves can be purchased from other Nordic countries. Fingrid covers the maintenance costs of reserves with a grid network tariff and payments collected in balance services. The costs of the balancing power market are covered by imbalance power.

In the Nordic countries, loads from large-scale industry have, for a long time, acted as reserves used for maintaining the power balance; however, these loads are mainly focused on industry such as forestry and the metal and chemical industries. Demand-side management is a natural opportunity to increase supply on both regulating power and reserve markets.

In the electricity market there are so-called aggregators, i.e. companies that combine small-scale consumption, production and flexibility to larger entities, which can participate in different markets. Thus, they provide the link that connects the retail electricity market actors with the whole sale markets. This link is often complex due to the fractionalisation of the whole sale reserve markets. From the aggregation point of view the small-scale production of a consumer can be considered similar to demand-side management, if it reacts to the market situation and decreases the amount of electricity the party takes from the grid; these include the back-up power generators of buildings and commercial premises. The only differences are that loads typically (but not always) respond faster and the generation slower.

Participating in demand-side management can, at first, require investments from companies, but in the long term, it can offer a cost-efficient solution for both the company and the national economy.

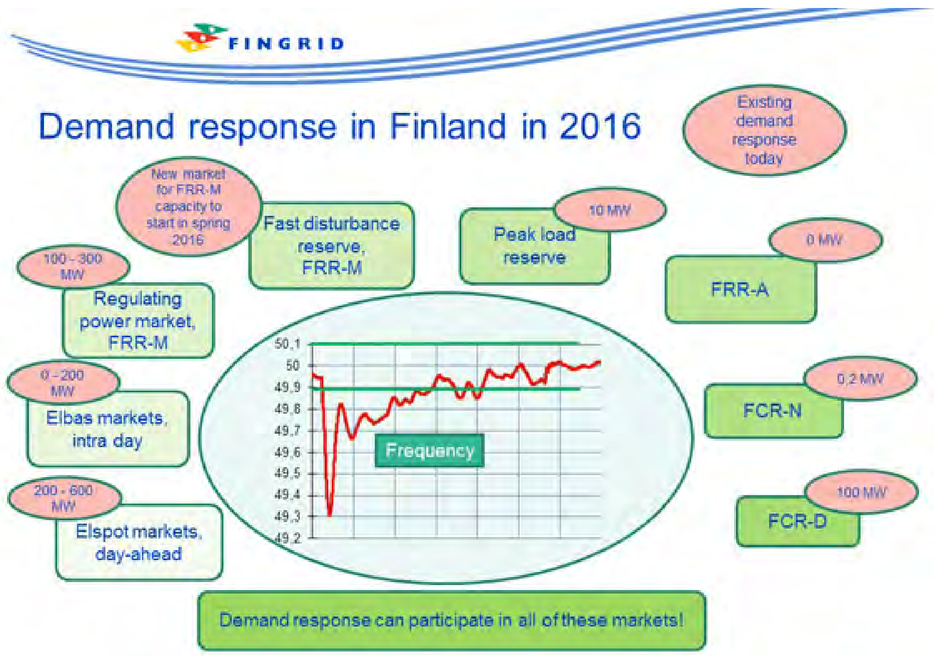

Figure 29 The amount of demand-side management on the Finnish market in 2016 [73]

Except for Denmark, the Nordic DSOs have prepared a harmonised Nordic Balance Settlement (NBS) model. In all the Nordic countries the DSOs are now responsible for the metering for settlement. In each of the Nordic countries there are plans to create a logically centralised datahub for the settlement measurements. The intention is that the centralised information exchange solution, or datahub, will not only make it easier to process measurement data, but will also simplify and speed up customer contract

events. The purpose also is that it will help the service to run more smoothly with fewer disruptions. The standardised interface to electricity consumption data promotes the full utilisation of smart networks and meters, as well as new business opportunities. However centralisation of settlement may create some new technical and business risks.

9 Appendix C: Literature review/Methodology approaches to high-level scenario design

9.1 Overview

In this framework, several approaches have been described in bibliography to undertake the scenario building process.

Next sub-chapters provide a summary of the methodologies found in some of the references examined. In particular:

- Subsection 9.2 analyses the approach from ENTSO-E
- Subsection 9.3 summarises one of the methodologies proposed in the Foresight Guide presented in the website of JRC IPTS
- Subsection 9.4 shows the point of view of Paul J. H. Schoemaker, published in MIT Sloan Management Review Magazine
- Subsection 9.5 presents the approach developed under the EvolvDSO project
- Subsection 9.6 summarises the methodology followed in e-Highway 2050 project
- Subsection 9.7 summarises the approach developed in the Gridtech project.

9.2 Scenario Outlook and Adequacy Forecast 2014-2030" (ENTSO-E)

The objective of the "Scenario Outlook and Adequacy Forecast 2014-2030 (SO&AF 2014)" [46] published by ENTSO-E (according to Article 8(3)b of Regulation (EC) No 714/2009) was to provide stakeholders in the European electricity market with a pan-European overview of generation, demand and their adequacy using different scenarios for the future power system.

Even though different approaches (deductive and inductive) were used in the selection of scenarios, the same criteria and methodology were used for their assessment. These scenarios include:

- The "EU2020" scenario: deductive (top-down) scenario based on the achievement of the energy policy targets established in the EU for 2020 translated into national level in the National Renewable Energy Action Plans (NREAPs) or the equivalent governmental plans.
- Two inductive (bottom-up) scenarios until 2025:
    - Scenario A or "Conservative": is based on the expectations of TSOs for the potential future developments, taking into account only the implementation of generation capacity already decided and considered secure.

- Scenario B or "Best Estimate": is based on the expectations of TSOs for the potential future developments, assuming the availability of suitable incentives for investments. In this case, not only secure generation capacity (scenario A) is taken into account but also future power plants that can be considered as likely and needed by the TSO with the available information.

- The "2030 Visions" that offer a "bridge" between the European energy targets for 2020 and 2050 and try to encompass all possible cornerstones of development until 2030.
    - Vision 1 "Slow progress"
    - Vision 2 "Money Rules"
    - Vision 3 "Green transition"
    - Vision 4 "Green revolution"

These four visions were based on different suppositions aiming to estimate the extreme values where future evolution of the parameters is expected to lie in-between with a high level of certainty. ENTSO-E defined these visions considering previous market studies (both regional and from the ENTSO-E), public economic analyses and existing European documents.

In general, Visions 1 and 3 assume lower levels of integration of the European energy market than Visions 2 and 4, which are based on a strongly integrated market at a European level. For this reason, Visions 1 and 3 were built based on national data (botton-up approaches) and Visions 2 and 4 were defined following a deductive (top-down) approach. With regard to the fulfilment of 2050 energy roadmap goals, Visions 1 and 2 assume a delay in their completion while Visions 3 and 4 are considered to be "on track" towards these goals.

9.3 FOR-LEARN Online Foresight Guide for "Scenario building" (JRC-IPTS)

The Joint Research Centre (JRC-IPTS) of the EC offers in its website a Foresight Guide [74] where knowledge on scenario building is provided. This online guide was developed within FOR-LEARN project (in the 6th Framework Programme of the EC) for introducing the users to the design steps, the implementation and the follow-up of foresight projects. It also shows the main methods used in their development, highlighting the fact that not every method suits to every study. For this reason, the method should be chosen having in mind the objective, context and resources. For example, some methods offer graphs as output, others narrative descriptions of scenarios.

Among others, the methodology for "Scenario Building" is presented as a method that helps the decision‑maker to enunciate a range of plausible visions of the future, gaining knowledge in this process. This methodology is also accompanied by a step-by-step guide for the development of scenarios. In short, the process could be summarised as follows:

- It starts with the definition of the time horizon and the identification of the focal issue based on the detected uncertainties.
- Then, the key drivers or parameters that have an influence on the case studied are identified, including Social, Technological, Economic, Environmental/Ecological, Political and Value-based issues (STEEPV thematic groups).
- These driving forces are then sorted out by importance and uncertainty level, aiming to obtain the two or three most important and most uncertain factors. This defines the number of scenarios.
- Scenario logics are then selected to structure the scenarios and reduce their number to the minimum that contain all the defined uncertainties. Once the final ones have been selected, they have to be elaborated, detailing the behaviour of each key driver in each scenario.
- Finally, an analysis is carried out to evaluate opportunities and threads and turn the scenarios into strategy.

9.4 "Scenario Planning: A Tool for Strategic Thinking"

In 1995, MIT Sloan Management Review Magazine published an article of Paul J. H. Schoemaker showing a systematic methodology for scenario planning [43].

This article defines the scenario planning as a way to capture the range of possibilities for future development, organises them into narratives and makes the use of great volumes of data easier. The possible futures selected should challenge present beliefs but avoiding "underprediction" and "overprediction" of changes.

The process for scenario planning can be collected in 10 steps:

1. *Definition* of the scope and time horizon.
2. Identification of the major stakeholders interested and affected by the subject of the study and those who have influence on it.
3. Identification of basic trends (in the political, economic, societal, technological, legal, and industry fields) that affect the case study and characterisation of their impact (positive, negative, or uncertain).
4. Specification of key uncertainties that significantly affect the defined trends and their possible outcomes. The relationships between these uncertainties should be checked to identify incompatibilities.
5. Construction of Initial Scenario Themes. This can be done by identifying, for instance, "extreme worlds" (one characterised by positive outcomes in all the uncertainties and the other by the negative ones) or by selecting the two most important uncertainties and the analysis of the plausibility and compatibility of all their possible outcomes by crossing them.

6. Refining of scenarios, eliminating similarities and inconsistencies on trends, on outcome combinations or based on the reactions of major stakeholders.
7. Development of "Learning Scenarios" by the identification of themes that are strategically relevant, the organisation of the possible outcomes and trends around them and the naming of the scenarios using a title easy to follow and remember.
8. Identification of further research needs from the learning scenarios.
9. Development of quantitative models to be used in the detection of implausible scenarios and to allow the quantification of the behaviour of certain selected parameters under various scenarios.
10. Definition of final scenarios, checking their relevance and internal consistency and making sure they describe different futures (instead of variations on one theme) that are expected to exist for some length of time.

9.5 "Definition of a Limited but Representative Number of Future Scenarios" (EvolvDSO project)

Deliverable 1.1. of EvolvDSO project [75] dealt also with scenario building. The objective of this publication was the definition of representative future scenarios for the evolution of distribution systems in some of countries involved on the project (Belgium, France, Germany, Ireland, Italy, Portugal and the UK).

The defined scenarios took into account the potential evolution of the electricity system in terms of generation mix, demand and degrees of technological freedom to determine the requirements that may be needed in the future. No regulatory or market aspects were included in this definition.

In this framework, each country defined three future scenarios in three time horizons (short-term, mid-term and long-term) where uncertainties were outlined by their upper and lower limits (extreme scenarios where the most likely scenario lies).

Scenario definition followed a methodology similar to the ones presented in subsections 9.3 and 9.4:

- Definition of the scope and time horizon.
- Definition of present and future scenarios, considering three types of futures: under-expected, most-likely and over-expected scenarios.
- Definition of the main parameter used to characterise these scenarios and its evolution in each case.
- Identification of relevant parameters and allocation of their values in each scenario.
- Analysis and comparison of the different options and identification of the main drivers and the uncertainties expected for the future evolution.

9.6 “Structuring of uncertainties, options and boundary conditions for the implementation of Electricity Highways System” (e-Highway 2050 project)

Within the WP1, the European project e-Highway2050 established the boundary conditions for the implementation of a scenario building methodology. Its main purpose was establishing the framework required for the transition from current solutions to the infrastructure needed to support an integrated power system in 2050, with expected electricity generation mainly driven by RES.

Deliverable 1.2 [76] presented the scenarios selected in the project for the implementation of an Electricity Highways System. They were built following a methodology that can be summarised in six steps:

- Specification of Uncertainties and Options and their boundary conditions (upper/lower limits) taking into account several fields (technical, economical/financial, political/social/environmental, R&D). Uncertainties are defined as variables that are not controllable by the decision maker. Options, however, are the ones chosen by the decision maker.
- Selection of the key Uncertainties and Options among all the identified in Step 1.
- Definition of possible Futures and Strategies. Futures are defined as a combination of Uncertainties and Strategies come from the combination of Options (see Figure 30).
- Definition of possible scenarios by the combination of Futures and Strategies.
- Optimisation of the number of scenarios. Inconsistencies and similarities are analysed for their refining.
- Selection of the most representative scenarios to enable subsequent detailed numerical analyses of each one.

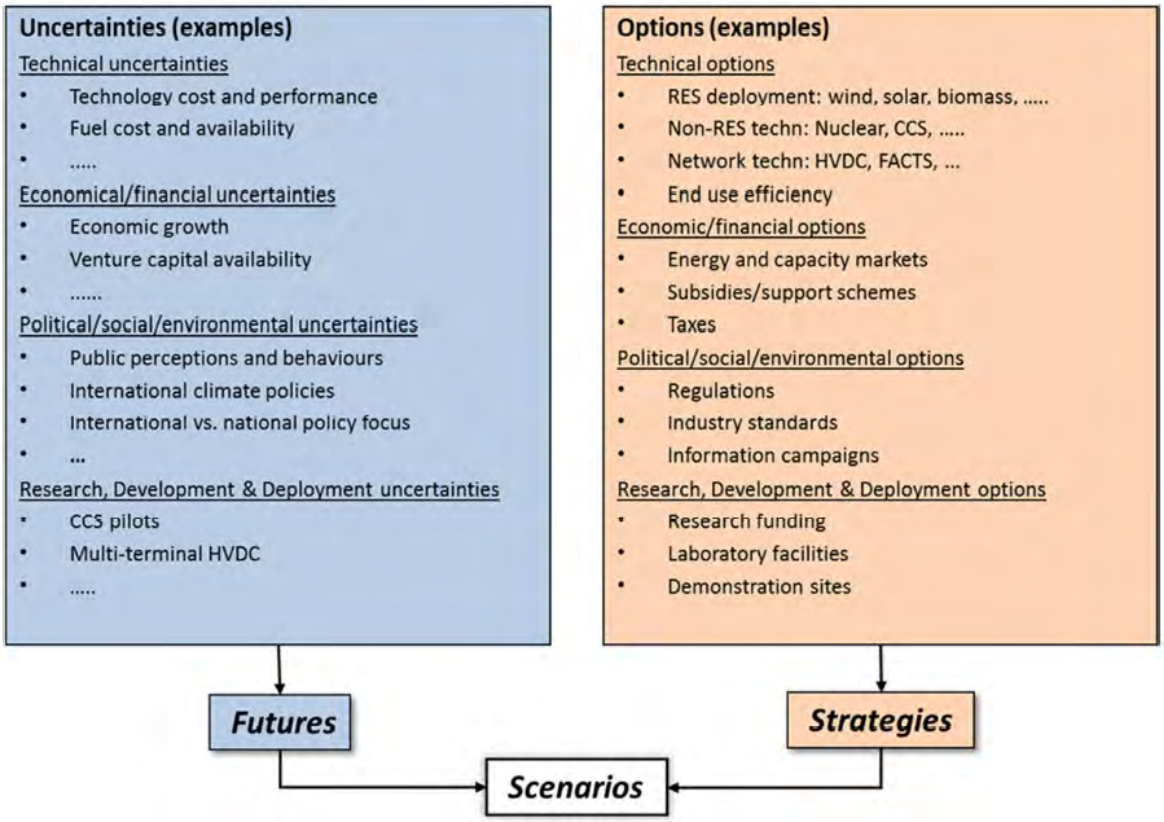

Figure 30 Construction of Scenarios from Uncertainties and Options in e-Highway 2050 project [76]

As a result of this methodology, five scenarios were finally selected in this project:

1. Large scale RES and no emissions: European agreement for climate mitigation is achieved and fossil fuel consumption is generally low worldwide. It is focused on the usage of large-scale RES technologies and centralised storage solutions.
2. 100% RES: Europe is fully committed to its greenhouse gases (GHG) reduction target by 2050. It is entirely based on RES technologies. Nuclear and fossil fuels with Carbon Capture and Storage (CCS) are not used, using storage (centralised and de-centralised) in case of imbalances.
3. Big and market: Europe is fully committed to meet its GHG reduction orientation by 2050 but it relies mainly on a market-based strategy. There is a special interest on large scale centralised solutions.
4. Large fossil fuel with CCS and nuclear: Europe is fully committed to meet its GHG reduction orientation by 2050 following a non-RES strategy. Nuclear and fossil fuel plants with CSS play pivotal roles. Electricity exchanges with outside Europe are low. No further flexibility is needed.
5. Small and local: Europe is fully committed to meet its GHG reduction orientation by 2050 by means of small-scale/local solutions (de-centralised generation, RES and storage and smartgrids,

mainly at distribution level). However, there are no common agreements/rules for transnational initiatives for internal EU market operation and no agreement has been reached on this matter in the global community. Nuclear and fossil fuels with CCS are not used.

9.7 The Gridtech project

For the achievement of the European Union (EU)'s ambitious renewable energy targets for 2020, 2030 and beyond, extensive electricity system planning and investments are necessary. This covers electricity generation capacity, transmission networks, and supporting technologies and measures that will ensure clean, secure and efficient energy supply. In particular, the development of adequate transmission infrastructures and grid-impacting technologies plays more and more a crucial role to foster the integration of Renewable Energy Sources (RES) and to realise the European Energy Union, set as strategic target by the European Commission. Within this framework, the European project **GridTech** (*Innovative grid-impacting technologies enabling a clean, efficient and secure electricity system in Europe*, http://www.gridtech.eu), run over 2012-2015, has conducted an integrated assessment of new grid-impacting technologies and their implementation into the European electricity system. This has allowed comparing different technological options towards the exploitation of the full potential of future electricity production from RES, with the lowest possible total electricity system cost.

Within the 2020, 2030 and 2050 time horizons, the goal of GridTech project has been to assess, among innovative grid-impacting technologies, which ones, where, when, and to what extent could effectively contribute to the further development of the European system, fostering the integration of an ever-increasing penetration of RES generation and boosting the creation of a pan-European electricity market, while maintaining secure, competitive and sustainable electricity supply. This has been carried out within GridTech by combining a pan-European analysis (top-down approach) and seven regional case studies (bottom-up approach) related to the seven project target countries (Austria, Bulgaria, Germany, Ireland, Italy, Netherlands, Spain) in order to get robust results.

Among the innovative technologies that indirectly impact on the transmission grid, the ones related to optimal Demand Response (DR) appear to be very promising and have been screened within GridTech for their global effects in terms of load shifting, upon opportune modeling.

In the pan-European study, the modelled (so-called EU30+)[26] system takes fully into account as endogenous 37 European countries such as the today's 28 Member States of the EU (EU28), the EU

[26] EFTA: European Free Trade Association. The EU30+ system includes as endogenous countries: AL (Albania), AT (Austria), BA (Bosnia-Herzegovina), BE (Belgium), BG (Bulgaria), CH (Switzerland), CY (Cyprus), CZ (Czech Republic), DE (Germany), DK (Denmark), EE (Estonia), ES (Spain), FI (Finland), FR (France), GR (Greece), HR (Croatia), HU (Hungary), IE (Ireland), IS (Iceland), IT

current and potential candidates (Albania, Bosnia-Herzegovina, FYR Macedonia, Iceland, Montenegro, Serbia, Turkey), and EFTA countries (like Switzerland and Norway) (see Figure 31). The choice of analysing such a quite extensive and large European system has been taken in order to duly keep into account the effects of RES and new grid-impacting technologies in all current and future EU Member States and their interconnected countries, explicitly (see the ones in light blue in Figure 31) and implicitly (see the ones in dark blue in Figure 31) treated in the model, depending on the scenario and time horizon.

Figure 31 The EU30+ geographical perimeter of the pan-European study

As the framework of GridTech has to be seen towards the exploitation of RES in Europe, the scenarios considered in the GridTech studies at 2020, 2030, 2050 are rather optimistic (yet not unrealistic) in terms of RES penetration in the different EU30+ countries, while also taking into account local specificities and national energy mix evolutions. For 2020, GridTech scenarios are then based on the general fulfillment of 2020 RES (EU or national, where present) targets in the European countries, taking into due account elements from different sources, including NREAPs and ENTSO-E SO&AF (Scenario Outlook and Adequacy Forecast) 2013 (EU2020 scenario). Following the trend, the scenario for 2030 considers a higher RES penetration, also to achieve the overall 2030 RES targets: the main reference data are based on multiple sources, including ENTSO-E SO&AF 2014 (Vision V3).

For a comprehensive description of the Gridtech project and its scenarios see [77].

(Italy), LT (Lithuania), LU (Luxembourg), LV (Latvia), ME (Montenegro), MK (FYR Macedonia), MT (Malta), NL (Netherlands), NO (Norway), PL (Poland), PT (Portugal), RO (Romania), RS (Serbia), SE (Sweden), SI (Slovenia), SK (Slovakia), TR (Turkey), UK (United Kingdom). The system of Kosovo is included in the one of Serbia. Depending on the time horizon, the exogenous countries (external regions) for the EU30+ system may include: AM (Armenia), AZ (Azerbaijan), BY (Belarus), DZ (Algeria), GE (Georgia), IL (Israel), IR (Iran), IQ (Iraq), MA (Morocco), MD (Moldova), RU (Russia) and RU-KA (Russian Kaliningrad enclave), SY (Syria), TN (Tunisia), UA (Ukraine).

10 Appendix D: Future ancillary services

This appendix is aimed at further developing the information included in section 3.4. Sections 10.1 to 10.4 present the services identified in section 3.4.1 more in detail, while the final section (10.5) presents the expected evolution of the characteristics of the ancillary services in Norway and the requirements to provide them, as an extension of the example provided for Italy in section 3.4.2.

In the tables below[27], one for each selected ancillary service, several issues are shown:

- Definition: This section includes the definition of an already existing service or, in the cases in which the proposed service does not exist yet, some ideas about how this may be developed.
- Status: This part tries to identify how the deployment of the service is nowadays, mainly focused on the distributed generation participation.
- Motivation: Some appealing factors for the procurement of each service have been identified.

10.1 Ancillary services for frequency control

Fast frequency reserves (FFR): Inertia emulation	
Definition	System inertia is an important part of the power system response to frequency events, being its magnitude proportional to the system's resilience to sudden change. It depends on the physical characteristics of the power system, namely the types of generators in operation and their own rotating masses that provide energy during the momentary frequency dips. The more inertia a system can exhibit, the more resilient to events is its frequency. With an increasing penetration of non-synchronous generation in the system, there will be an increasing need for capabilities from generators to supply very fast frequency response.
Status	Inertial response has not traditionally been considered as ancillary service, but rather a natural and uncontrollable characteristic of the power system. Introduction of technologies that make inertial response controllable is a substantial change. Some grid codes have already been modified to include some type of inertial response requirement. Inertia emulation is commercially available today. Renewable energy sources (especially wind turbines and solar plants), as well as battery storage capacities, can already be technically equipped to contribute to this inertia emulation. For example, for wind generators, a control scheme that is already being implemented in order to mitigate this problem is the addition of an inertia emulator. This emulator uses the accumulated kinetic energy in the wind turbine shaft to provide a temporary increase of the active power injected to the grid, proportional to the system frequency rate of drop. Other technologies require a long-term loss of active power and additional investments, so they are less

[27] The information in this Annex is based on references: [64], [78], [79], [80], [81], [82], [83], [84], [85], [86], [87], [88], [89], [90], [91], [92].

	efficient alternatives.
Motivation	The levels of inertia in power systems may decrease in the future, due to increased levels of energy being provided from renewable sources, which typically have little or no inertia. Suitable alternative technological solutions are required to provide this service in future in parallel to the further expansion of renewable generation. To implement this, the regulatory framework conditions must be adapted such that decentralised energy units can contribute to the provision of this service.

Ramp margin (RM): Ramp control	
Definition	Ramping is a significant change of generation power output over time frames ranging from a few seconds to a few minutes. Of particular interest are: a) wind generation ramping that is caused by rapid wind-speed variations and b) solar generation ramping which occurs as large clouds pass over the generator. Indeed, ramping may increase as variable resources are added to the grid. If ramping does become significant, then system operators will have to respond, or the grid could become unstable. The ramping ancillary service involves resources that offset output ramping, so, resources used for the ramping service provide output variability that is the reverse of other generations' output variability. Storage is a suitable technology for this service. The storage used for ramping service provides ramping up by increasing output and/or by decreasing charging. On the contrary, storage provides ramping down by decreasing output and/or increasing charging. In general, most conventional generation is not very suitable for ramping because it must be capable of relatively rapid output changes.
Status	Potential providers of these services include conventional generators that are not dispatched to their maximum output, storage devices, demand side providers, solar PV and wind power plants that have been dispatched down. The ramping margin service essentially needs capabilities comparable to frequency control services (FCR, FRR and RR).
Motivation	At present, imbalances between generation and demand in both directions (upwards and downwards) are managed using frequency response services (e.g. operating reserves) over very short timeframes (seconds and minutes). Over longer timeframes, additional factors can cause an imbalance which, if not managed, would result in unacceptable frequency excursions. These factors include changes in demand, wind generation, interconnector flows and generator availability. All these factors are expected to change in a near future.

10.2 Ancillary services for voltage control

Fault-ride through (FRT) capability	
Definition	FRT is the capability of electric generators to stay connected in short periods of lower electric network voltage (voltage dip) until the faulted element has been cleared from the transmission system. The fault-ride through capability mostly depends on the reactive power control. All DG units have a grid coupling device which feeds electrical energy into the grid as the last element of a chain of energy converters of the unit. The FRT capability depends on the grid-coupling technology, which has to balance the power flow on the grid-side and the DC-side in case of voltage disturbances. Inverters which couple a DC source to the grid show very good FRT capabilities because the DC voltage can be changed promptly. Initially it was identified as an issue with wind generation employing power electronic converters but the concept equally applies to all generation types. The fault ride through specifications for distributed generators, defined by the grid codes, establish the requirements of power supply in the event of short circuits based on the prevailing voltage levels at the grid connection point as a function of time.
Status	In general, FRT is not remunerated but required as mandatory from generators when connecting to the grid in Grid Codes. The FRT capability is dependent on the grid-coupling converter. Inverter-based DG has an acceptable flexibility in terms of FRT because they decouple the power generation process and the grid. This flexibility comprises the phase, magnitude and even harmonic content of the currents injected. However, there is one drawback, the maximum fault current that the converter may be able to provide.
Motivation	It is needed at distribution level (wind parks, PV systems, distributed cogeneration, etc.) to avoid that a short circuit on high voltage level leads to a wide-spread loss of generation.

Primary voltage control	
Definition	Primary voltage control maintains the voltage at the point of coupling of the generator close to a voltage reference given by the TSO. It is performed by automatic and rapid voltage regulators which control reactive power output so that the output voltage magnitudes are kept at specified values. The system operator fixes the voltage setting points of the different generators in order to guarantee an adequate operating point, the maximal reactive power which is possible to generate by each generator, the voltage drop in the transmission lines and finally the voltage profile at the transmission buses. Primary voltage control is performed in the range of milliseconds since a deviation of the voltage respect to the set point is detected. The primary voltage control referrers to the local response of the generators. This control has only local scope targeting the control in the particular bus assigned to the controllable device. The operational value of being able to deliver reactive power is very location-specific It can be provided by spinning generators and synchronous compensators, reactors and capacitors, Static VAR Compensators, HVDC substations and other FACTS (Flexible Alternating Current Transmission System) devices, or other equipment capable of fast regulation. It is a service used during voltage dips and for post fault voltage control.
Status	Currently, some studies have focused on voltage control solutions using the flexibility in DER units. However, the challenges and difficulties when applying their control strategies in practice have not been studied in depth. Planners have long recognised the need for reactive power delivery and, in particular, fast VAR. The behavior is similar to traditional synchronous condensers. Services based upon

	this capability may be needed much more often in the future, when there will be more need for local voltage support from distributed generators. In the specific case of the wind turbine technology, the current design includes the capability for a controlled fast reactive current response and limitations depend on the wind turbine conversion technology and the grid requirements imposed. Technical challenges include the development of accurate voltage sensing, recognition of fault types and appropriate tuning of controllers. In many countries the conditions for the connection of DG and RES have been updated along with the availability of advanced inverters that have been built to allow the DG and RES generators to provide primary voltage control.
Motivation	Voltage control service is a critical ancillary service used by all system operators for secure and reliable operation of the power system. It must be continuously active. The most significant benefits of using distributed generators are for systems with substantial dynamic reactive power requirements (i.e. projects that are physically remote with electrical weak connections to the grid or areas with heavy and variable loads).

Secondary voltage control	
Definition	Secondary voltage control is a slower control that acts to bring the voltage in a region back to the normal profile and it consists on the measurements of the voltage magnitude in some critical buses of the system. These buses are known by the operator as the result of its experience in the control of the system. If the voltages at these buses are out of range, the operator is going to change the settings points of the voltage regulators (generators) in order to recover a voltage profile in the normalised interval. The time response of the voltage secondary control goes up to one minute and less than several minutes. The secondary control refers to voltage control at a zonal level. The coordination and the supervision of the primary control set point values within a given geographical zone are the tasks of the secondary voltage control. The main idea behind this secondary control is to coordinate the various regional reactive power resources in such a manner that they control the voltage at given pilot nodes. Pilot nodes are selected such that the voltage magnitude at the pilot node represents the voltage profile over the associated zone. Usually the pilot nodes are the ones with the highest short-circuit power in a given zone. The definition and the implementation of the secondary and tertiary voltage control vary from one TSO to another. Some TSOs consider secondary and tertiary voltage controls together. In this case, the voltage control is divided only into two classes: primary and centralised voltage controls. The secondary control is performed by automatic or manual on load tap changers, so that the voltage ratio and hence the secondary voltage may be varied as the load supplied by the transformer changes. The objective of this control is to restore the voltage profiles to the required values within a region, but minimising circulating reactive power flows and maximising reactive reserves.
Status	In general, from the perspective of providers of voltage control services, the production of reactive power can be divided into a basic and an enhanced reactive power service. The basic or compulsory service includes the generating units' requirements that must be fulfilled to be connected to the network. The enhanced reactive power service is a non-compulsory service that is provided as supplement to the basic requirements. Currently, some studies have focused on voltage control solutions using the flexibility in DER units. However, the challenges and difficulties when applying their control strategies in practice have not been studied in depth.
Motivation	Voltage control service is a critical ancillary service used by all system operators for secure

	and reliable operation of the power system. It must be continuously active.

Tertiary voltage control	
Definition	Tertiary voltage control is used by the operator to optimise the system voltage profile and to provide reference values of the secondary voltage control. Normally, the tertiary control operates in a 15 minutes cycle. The tertiary voltage control is on a global system level. The basic idea is to increase the operating security and efficiency of the system through a centralised coordination of the secondary control zonal structure. The tertiary control considers the counteract coupling between controls at the secondary control levels. In fact, the tertiary control defines the optimal voltage set-points for the secondary pilot nodes. Different objectives like minimising the grid losses or maximising the reactive reserve can be taken into account when selecting these set-points. Normally secondary and tertiary controls are implemented with a delay and they involve both automatic and manual actions. The definition and the implementation of the secondary and tertiary voltage control vary from one TSO to another. Some TSOs consider secondary and tertiary voltage controls together. In this case, the voltage control is divided only into two classes: primary and centralised voltage controls. Tertiary control coordinates the action of primary and secondary control devices according to secured operation and economic criteria based on load and generation forecast. Tertiary control acts in a time scale of about 10 to 30 minutes. The objective in this case is to optimise the operation of the network by minimising losses, maintaining the required voltage and the substitution of reactive reserves. The control variables used in this case are the setting values sent to the generation controllers and switch orders sent to shunt capacitors, reactors and tap changers. Tap changers in general have been used as devices for secondary control, but the introduction of static compensators for voltage control may require the need for coordination of both types of equipment. It is inefficient to transfer reactive power across large electrical distances, including across the transformation between voltage levels. The effectiveness of distribution reactive power resources to provide support at transmission level will thus not be possible in all instances. It is highly dependent on the network impedance, and on the generation resource and technology employed.
Status	In general, from the perspective of providers of voltage control services, the production of reactive power can be divided into a basic and an enhanced reactive power service. The basic or compulsory service includes the generating units' requirements that must be fulfilled to be connected to the network. The enhanced reactive power service is a non-compulsory service that is provided as supplement to the basic requirements. Currently, some studies have focused on voltage control solutions using the flexibility in DER units in order to evaluate the benefits of reactive power control by distributed generation. The main objective of these projects is to evaluate whether reactive power supply on distribution grid level can reduce the need for grid reinforcements and further increase the hosting capacity for further generators.
Motivation	Connecting DG units to the network affects the voltage profiles and influences the voltage control in distribution systems. Voltage control service is a critical ancillary service used by all system operators for secure and reliable operation of the power system. It must be continuously active.

10.3 Ancillary services for power quality improvement

Injection of negative sequence voltages	
Definition	Voltage unbalance is regarded as a power quality problem of significant concern at the electricity distribution level. Although the voltages are quite well balanced at the generator and transmission levels the voltages at the utilisation level can become unbalanced due to the unequal system impedances and the unequal distribution of single-phase loads. Under asymmetrical grid faults, the negative sequence voltage produces additional generator torque oscillations and reduces the lifetime of the installed equipment. A voltage unbalance, according to IEEE, can be defined as the largest difference between the average root mean square (RMS) voltage and the RMS value of any single voltage phase divided by the average RMS voltage, usually expressed as a percentage. A major cause of voltage unbalance is the connection of unbalanced loads (mainly single phase loads connection between two phases or between one phase and the neutral). Voltage unbalance has some negative impacts on equipment such as induction motors, power electronic converters, etc. Thus, the International Electrotechnical Commission recommends the limit of 2% for voltage unbalance in electrical systems. Compensation of voltage unbalance is usually done using series active power filter through injection of negative sequence voltage in series with the distribution line. Whenever there is a voltage dip, the induction generator may consume a large amount of reactive power which can result into progression of faults and voltage collapse. When unsymmetrical faults occur, positive and negative sequence voltages are generated. Positive sequence voltage causes voltage instability and negative sequence voltage causes heavy generator torque oscillation which leads to mechanical vibrations. StatCom (Static Compensator) is a FACTS device that can be used for eradicating positive and negative sequence voltages. It is a type of synchronous generator whose capacitive or inductive output current can be controlled irrespective of its ac voltage. Statcom can operate as either a source or sink of reactive AC power to an electricity network and the basis of this device is power electronics voltage source converter. The degree up to which the StatCom can compensate the voltage depends on the rating current of StatCom and the impedance of the power system. When designing and dimensioning machines and converters, negative sequence voltage and currents resulting from system faults have to be considered as they cause oscillating torques.
Status	Some approaches have been developed to use DG for voltage unbalance compensation. For example, using a two inverter structure, one to control active and reactive power flow, and the other in series with the grid to balance the line currents and the voltages at sensitive load terminals, in spite of unbalanced grid voltage. This is done by injecting negative sequence voltage. The requirement of two inverters can be considered as a negative point in terms of the cost and volume of the DG interface converter. Another assessed approach, line currents become balanced in spite of the unbalanced loads presence through injection of negative sequence current by DGs. However, under severely unbalanced conditions, a large amount of the interface converter capacity is used for compensation and it may interfere with the active and reactive power supply by the DG.
Motivation	Unbalanced voltages can result in adverse effects on equipment and power system. Under unbalanced conditions, the power system will incur more losses and be less stable.

Damping of low order harmonics	
Definition	Harmonics cause distortion of source voltage, additional losses due to unwanted current flowing and it may also lead to malfunctioning of protective relays and control units. Harmonic compensation is the use of online generation equipment to compensate for harmonics caused by non-continuous loads. Harmonics can cause poor power quality, voltage imbalances, and excessive zero-sequence currents. The active power filters minimise the harmonics producing harmonic current of equal magnitude and opposite polarity. DG could perform a harmonic-compensation function. However, this compensation needs fast-response capability, so only DG with power electronics interfaces can perform this function. For harmonics compensation service, the DG needs to provide only reactive power. Through harmonic compensation provided by DG, the source avoids the need to provide harmonic current to a load with harmonic components. Thus, there will be no harmonic current flowing through the rest of the utility. This improves system efficiency and stability by reducing losses in the rest of the system.
Status	There are many techniques to reduce the effect of harmonics. Conventionally, passive LC filters have been used to eliminate line current harmonics and to increase the load power factor. However, these filters present several disadvantages. At present, active power filters have been developed. DG with power electronic technology could act as an active power filter to minimise the harmonics.
Motivation	Harmonics are the most common distortion in power systems, existing in both voltage and current. The existence of harmonics reduces the energy efficiency of a power system at the generation, transmission, and consumption points of the system. Harmonics can cause extra heating of the cores of transformers and electrical machines. Furthermore, the harmonics may expedite the aging of the insulation of the components in the system and shorten their useful lifetimes.

Mitigation of flicker	
Definition	Flicker is caused by voltage fluctuations (for example, when clouds pass by photovoltaic cells, rapidly changing their power output). The effect of these fluctuations will depend on its amplitude and the rate of their occurrence. Generally, mitigation measures are focused on limiting the amplitude of the voltage fluctuations. According to IEEE recommended practices, the measurement of flicker is comprised of the amount of system voltage variation involved and the frequency at which the variation recurs. Sources of flicker in industrial power distribution systems can be, for instance, the somewhat random variations of load typified by an arc furnace melting scrap steel or an elevator motor's starts and stops. DG capable of providing constant, uninterrupted power can improve power quality by mitigating flicker and other voltage regulation problems. But, on the other hand, DG connected to the grid via power electronic inverters (solar PV, fuel cells and most wind turbines) are sources of voltage waveform distortion. However, if designed and implemented properly the power electronics could theoretically cancel grid distortions and help regulate voltage.
Status	Some methods used to flicker mitigation are; series capacitors, thyristor switching of inductors with shunt capacitors (static var control), saturating shunt inductors, and thyristor switched shunt capacitors may be used to maintain a relatively steady voltage at the tie point. Many inverters on the market today are capable of cancel this grid distortion, but such feature adds cost and today DG owners rarely have incentives to invest in this added

	functionality. Some approaches are being assessed, for example, the feasibility and effectiveness of flicker mitigation solutions in the planning phase of the installation. The standard IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems, includes several provisions to mitigate DG's potential negative impacts on power quality and it requires that DG not create objectionable flicker for other customers.
Motivation	Flicker causes deterioration in quality of supply from the utility, especially to other consumers served from the same coupling point. It is necessary to find ways to mitigate its effect.

Damping of power system oscillations	
Definition	With a reduced number of power plants, the oscillation and damping characteristics of the integrated European grid can change. Based on Wide Area Measurement Systems), wide area damping controllers for HVDC transmissions and FACTS (Flexible Alternating Current Transmission System) can be designed to attenuate large-scale oscillations between grid areas (so-called inter-area oscillations). Damping of power system oscillations is one of the main concerns in the power system operation. The interconnection between distant located power systems is a common practice, which increases the low frequency oscillations. These oscillations, when not well damped, may keep growing until loss of synchronism. Low-frequency oscillations in a power system affect the system stability, the operating efficiency of the power system and restrict the operating capability of power transmissions. The Power System stabiliser (PSS), by which a supplementary stabilising signal is added to the excitation system, appears as a simple and cost-effective solution. Generally machine parameters change with loading and the machine behavior is different at different operating conditions. Hence, PSSs should provide some degree of robustness to the variations in system parameters, loading conditions and configurations. In most cases, the PSS works well in damping oscillations, however, its control has less flexibility if the operating conditions change. Other controllers have been developed such as; high voltage dc (HVDC), thyristor-controlled series capacitors and flexible ac transmission system (FACTS). FACTS devices have the advantage of flexibility of being located at the most suitable places to achieve the best control results. In general, the PSS provides satisfactory damping over a wide range of system loading conditions, but, at the same time, this PSS can cause great variations in the voltage profile. The FACTS devices have the capability of enhancing the system damping. The static compensators (StatCom) maintain the bus voltage by supplying the required reactive power even at low bus voltages and improve the power oscillation damping.
Status	Utilities are installing FACT devices in their transmission networks. In addition to their primary function, FACTS have the capability of enhancing the system damping.
Motivation	The European energy supply system exhibits low-frequency oscillations that are damped by conventional power plants by means of power system stabilisers. Due to the loss of conventional power suppliers, it may be possible that these oscillations cannot be attenuated this way in the future.

10.4 Other ancillary services (for other purposes or for combined f/V control)

Black start capability	
Definition	The black start capability is a system restoration service required to return electrical power system to normal operation after a blackout. Black start is used in the power system restoration phase, defined as "a set of actions implemented after a disturbance with large-scale consequences to bring the system from emergency or blackout system state back to normal state. Actions of restoration are launched once the system is stabilised. Restoration of the system consists of a very complex sequence of coordinated actions whose framework is studied and, as far as possible, prepared in advance". The re-energisation process can be implemented using two strategies. I) Top-down re-energisation using external voltage sources when the grid is reenergised from a neighbouring TSO, starting from the tie-lines. II) Bottom-up re-energisation based on internal sources capabilities is done using units that provide the capability of controlling voltage and speed/frequency during supplied isolated operation and stable operation in an islanded network. Those units are referred to as having black start capabilities. It is the capability of a generating unit to start up without an external power supply, called on as a means of restoring supplies following a major failure on all or part of the network.
Status	At present, the only distributed generators that are likely to be used for black start are large units with capacities in the tens of megawatts that are already designed for blackout service. There are such units at hospitals, airports and other large installations. These installations may be good candidates for black-start service.
Motivation	At present, the penetration of DG units which are capable to provide this service is not big enough to energise the transmission network. However, they might be able to energise parts of distribution grids which can then be operated in islanded mode. With the increase of such island grids it will be possible to interconnect these islands and energise an increasing share of the distribution network.

Compensation of power losses	
Definition	The line losses are basically dependent on the resistance, length, active and reactive power flow over the line and the voltage level. While the losses due to resistance, the length and the voltage level can only be optimised during the network planning process, the losses due to active and reactive power flows can be optimised during the operation by power dispatch strategies. The main objective of the optimisation/minimisation of grid losses is to reduce the costs of the power transport and distribution. Grid loss compensation consists in compensating the transmission system losses between the generators and the loads. Currently, losses reduction initiatives in distribution systems have been activated. In general, these initiatives have been introduced by the utilities as incentives/penalties.
Status	Elia (Belgium) purchases electricity to compensate for part of the losses on its grid. Domestic and foreign suppliers can submit bids for such purchase. Also Austria Power Grid (Austria) has a market-based and non-discriminatory procurement for the required electricity to cover grid losses.
Motivation	Theoretically, with DGs, locating generation closer to demand, distribution losses could be reduced as the distance over which electricity is transported is shortened and the number of voltage transformation levels is reduced. However, this is only true when the energy generated is consumed locally. In reality, in liberalised environments, their dispatching can

	lead to increased network flows (and thus losses), often translated into reverse flows from distribution networks to transmission systems. To enable reduction of power losses, DG units should be operated efficiently with a losses minimisation objective which would help to save a lot of energy.

Power factor control	
Definition	The power factor indicates how efficiently the load current is being converted into useful work output. Additionally it is a good indicator of the effect of the load current on the efficiency of the supply system. The power factor can be corrected (reactive power component is reduced) by installing suitable capacitors in the distribution system in order to minimise the wasted energy. With this correction the value becomes nearer to 1 improving the efficiency of a plant and liberating more kW from the available supply. Wind and PV can provide reactive power compensation (for example by predefined power factor), and this has direct influence on voltage control and power transmission losses.
Status	In general, when the power factor falls below an established value, the utilities charge a penalty by adding a reactive power charge to the bill.
Motivation	Power factor correction favours efficiency of electrical distribution lines. Power factor correction can improve the efficiency of the entire transmission network and reduce the need of additional new generation plants.

10.5 Plans for further improvement of ancillary services in Norway (2016-2021)

This section summarises the present plans for further development of the ancillary services, which are planned by the Norwegian TSO Statnett within the next five years. The summary is based on Statnett's own action plan and complies with both Nordic and European initiatives. Figure 32 shows the planned time schedule for the given actions.

The following actions are planned for implementation within the next five years:

- Definition of common Nordic targets for frequency quality and dimensioning of the automatic reserves

There is an extensive Nordic activity for further development of methodology for assessment of operational security, defining a common Nordic level for operational security and dimensioning of the automatic reserves in order to maintain this level. Based on the results of this work it planned to develop an optimal combination the automatic reserves.

- Implementation of the new Nordic specification requirements for FCR

Common understanding of requirements for FCR is missing in the Nordic countries at the moment. Therefore, it has been initiated a Nordic activity for defining new common Nordic technical specification for FCR N/D. It is further planned to develop requirements for pre-qualification and a plan for

implementation of new specification at the existing installations. The project was initially started in order to reduce wear of the generation equipment and improve the quality of frequency.

- Develop a common Nordic approach for securing FCR and inertia

There is an ongoing Nordic activity related to assessment of how the changing production mix and new cable connections are influencing the stability of the system frequency. The important part of this activity is a study of frequency stability because of the system's available inertia. The present results indicate that during some periods and especially summer periods availability of the rotating generation can be limited. During some periods of time the level can be insufficient for securing of the system frequency in case of disturbances in the system.

Securing the sufficient inertia in the system will be considered with relation to FCR. As a part of this work, creation of a common Nordic market for FCR will be studied with time horizon 2020. Since the emerging needs for securing inertia cannot be resolved through the existing markets new arrangements will be considered.

	2016	2017	2018	2019	2020	2021
Definition of common Nordic targets for frequency quality and dimensioning of the	Evaluate	SOA				
Implementation of the new Nordic specification requirements for FCR	Evaluate Improve	Gradual implementation				
Develop a common Nordic approach for securing FCR and inertia	Evaluate and implement gradually					
Develop regional/European market for activation of FRR		Implement gradually				
Introduce standard products for FRR	Make proposal	Consult.		Implement		
Establish Nordic capacity market for aFRR	Evaluation and design	Implementation				
Establish Nordic activation market for aFRR	Evaluation and design	Implementation				
Introduce 15 min bidding at regulating power market	Implementation					
Establish solutions for securing of down regulation for mFRR	Evaluation and implementation					
Introduce prequalification for suppliers of balancing services	Development of terms and the process	Gradual implementation				
Implement procurement of reserve capacity closer to operation (D-2)		Gradual implement.	aFRR	mFRR		FCR
Introduce coordinated procurement of capacity reserves				Evaluation		
Support increasing participation of the consumption side through DR	Map potential / Gradual implementation	Evaluate alt.				

Figure 32 Time schedule for improvement of the ancillary services in Norway. Source: [95]

- Develop regional/European market for activation of FRR

Market for FRR reserves and trading agreements in the Nordic countries for automatic and manual FRR will be developed according to the new European requirements. Creation of the Coordinated Balancing Areas (CoBA) will create a formal framework for exchange of balancing services. The existing

cooperation will be further improved of will include more harmonised products, terms for participation in the capacity markets and methods for reservation of the transmission capacities.

- Introduce standard products for FRR

This activity is ongoing under ENTSO-E work for specification of standard products for FRR. The objective for the standard products with clearly defined properties is to make possible exchange of the balancing services between countries, both within and between regional markets. A single TSO can define specific products for its own use, but there is a clear intention that the most of the balancing services within ENTSO-E area will be based upon standard products.

There is an expectation that it will be more products (for example 2-3) for mFRR instead of one single product today. The change will require considerable ICT-development both at the actors and TSOs.

- Establish Nordic capacity and activation market for aFRR

Statnett cooperates with other Nordic TSOs in development and implementation of common markets for aFRR. Firstly for procurement of the reserves and later for activation of these. Through the common market it is expected to achieve a more efficient use of regulating resources, what it expected to improve the socio-economic feasibility and contribute to limiting of costs for the reserves at the Nordic level. aFRR was taken into operation in Nordic countries in 2012 and until 2015 have been procured at national markets with different configurations. There is an agreement about common view for shaping the future aFRR market.

- Introduce 15 min bidding at regulating power market

Statnett plans to introduce a requirement that actors, submitting production plans with volumes varying pr. 15 minutes within an hour, will also have to submit 15 minutes volume bids at the regulating power market (mFRR). The price for these bids will be still given pr. one hour.

Reason for this is to achieve better operator's overview og handling of the capacities at the regulating power market during hours with varying production throughout an hour.

- Establish solutions for securing of down regulation for mFRR

The system responsible operator should be able to regulate balance in the power system in both directions. The framework today specifies requirements to the resources available for up-regulation i.e. increase in generation or reduction of consumption in the system. The Norwegian TSO has experienced situation with scarce resources for manual down-regulation event though in limited scale. There are however expectations that this is going to be an increasing challenge in the future, and therefore it will be a specific need to secure that sufficient resources for down-regulation will be available for TSO in the operation time.

The lack of resources is partially caused by physical limitations for down-regulation in the generating installations, water channels or/and the power network and partially because of the available down-regulation resources are not submitted to the markets. It is assumed that

- Introduce prequalification for suppliers of balancing services

Statnett intends to introduce prequalification procedures for suppliers of FCR and FRR. This is necessary to meet the growing needs for securing the necessary functionality and availability as well as to meet prequalification requirements of the European guidelines for System Operation. The prequalification also presumes that all suppliers of FCR and FRR have to apply formally to the TSO in order to participate in the markets for the reserves. The applicants should demonstrate that their own installations meet technical requirements for delivery and availability of the resources.

- Implementation of procurement of capacity reserves closer to operation (D-2)

The capacity reserves today are procured today at different points in time and durations. Usually it happens one week ahead and for approximately for one duration. By committing their reserves the suppliers reduce their flexibility for participation in other markets e.g. day-ahead market. Statnett plans to schedule daily procurement of the reserves to evening before clearing the day-ahead market i.e. D-2.

- Introduce coordinated procurement of capacity reserves

In the theory, the optimal solution will be to clear all capacity reserves' markets simultaneously with the day-ahead market and let the bids to include detailed information about production costs. This however is not considered to be realistic within the given planning period i.e. 2025. However it can be realistic within this period to introduce solutions, where suppliers will submit offers for several types of capacity reserves at the same point in time. In order to achieve this several procurement times and bid sizes should be harmonised for FCR, aFRR and mFRR. Development of these procedures will be coordinated among all Nordic TSOs in order secure that the resources can be shared and exchanged across the synchronised area.

- Support increasing participation of the consumption side through DR

Statnett works on solutions allowing new and more actors to participate in the capacity reserves' markets. The work includes assessment of necessities for development of new solutions for getting access to the flexibility on the consumption side as well as legal conditions because of the European framework. Further on it is an ongoing dialogue with the distribution networks in order to understand their opinions and needs related to the DR.

11 Glossary

Ancillary services: According to the United States Federal Energy Regulatory Commission (FERC) ancillary services are services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. The list of the six types of ancillary services by FERC is not as such suitable for the European context. In the SmartNet project we include as ancillary services the following services

- scheduling, dispatch and load following to the extent it is not done by the electricity market
- balancing and frequency control.
- control of reactive power, voltage and voltage quality
- management of losses
- protection.

Back-up generation capacity: Households and businesses connected to the main power grid may also have some form of "back-up" power generation capacity that can, in the event of disruption, provide electricity. Back-up generators are typically fuelled with diesel or gasoline and capacity can be from as little as a few kilowatts. Such capacity is distinct from mini- and off-grid systems that are not connected to the main power grid.

Balancing a power system means that the power consumed is kept equal to the power produced. This is necessary because the grid does not include much electrical energy storage. In alternating current systems the system frequency decreases if less power is produced than consumed and vice versa. The AC power system and many connected equipment can safely and properly work only within a relatively narrow frequency range around the nominal frequency of the system. In the European Union (EU) the balancing is done initially by the electricity markets and finally by the ancillary services for balancing and frequency control.

Biofuels: Liquid fuels derived from biomass or waste feedstocks and include ethanol and biodiesel. They can be classified as conventional and advanced biofuels according to the technologies used to produce them and their respective maturity.

Contingency reserves are also known as replacement reserves. See the definition of replacement reserves.

Coordinated Balancing Area (CoBA) means a cooperation with respect to the Exchange of Balancing Services, Sharing of Reserves or operating the imbalance Netting Process between two or more TSOs.

Demand side flexibility means the capability of electricity consumers to respond to market prices, grid tariffs, control commands, etc. by controlling their embedded generation, energy storages and controllable loads accordingly.

Distribution System Operator (DSO), operates the distribution networks by managing its balance, transmission constraints, voltage quality, losses, faults and protection. It is almost a synonym to a Distribution Network Operator (DNO) but emphasises the increasing role of the DSO in supporting the TSO in balancing and other ancillary services.

Frequency containment, Frequency Containment Process (FCP) means a process that aims at stabilising the System Frequency by compensating imbalances by means of appropriate reserves.

Frequency restoration reserves, Frequency Restoration Reserves (FRR) means the Active Power Reserves activated to restore System Frequency to the Nominal Frequency and for Synchronous Area consisting of more than one LFC Area power balance to the scheduled value.

Hydropower: The energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) power plants.

Imbalance Netting Process means a process agreed between TSOs of two or more LFC Areas within one or more than one Synchronous Areas that allows for avoidance of simultaneous FRR activation in opposite directions by taking into account the respective FRCEs as well as activated FRR and correcting the input of the involved FRPs accordingly.

Off-grid systems: Stand-alone systems for individual households or groups of consumers.

Photovoltaic (PV) is a method of converting solar energy into direct current electricity using semiconducting materials that exhibit the photovoltaic effect.

Operating reserve means the flexible energy resources available to the system operator for the provision of ancillary services such as balancing.

Renewable Energy Sources (RES), Now RES mainly include intermittent solar PV and wind as well as hydropower, geothermal and biomass. New promising sources such as tidal, wave, solar CSP power may need to be considered for the future.

Renewables, Includes bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Replacement reserves (RR) means the reserves used to restore/support the required level of FRR to be prepared for additional system imbalances. This category includes operating reserves with activation time from Time to Restore Frequency up to hours.

System reserves, See operating reserve

Transmission System Operator (TSO). The European Commission defines TSO as an entity entrusted with transporting energy in the form of natural gas or electrical power on a national or regional level, using fixed infrastructure. Electricity TSO is an operator that transmits electrical power from power generation plants over the electrical grid to electricity DSOs and large energy consumers. In Europe electricity Transmission Network Operator is also a System Operator (SO). In Europe the system operators are independent from the power generation just like the ISO:s (Independent System Operators) in the US.

TSO-BSP Model means a model for the Exchange of Balancing Capacity or the Exchange of Balancing Energy where the Contracting TSO has an agreement with a Balancing Service Provider in another Responsibility Area or Scheduling Area when appropriate.

TSO-TSO Model means a model for the Exchange of Balancing Services exclusively by TSOs. The TSO-TSO Model is the standard model for the Exchange of Balancing Services.

Sources: [25], [40] and Annex C of [94]