# Analysis of changes, risk and possibilities for cross border market opening between Austria, Italy and Slovenia

# Deliverable report

# Document Information

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| **PU** | Public |
| **RP** | Restricted to other programme participants (including the Commission Services) |
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# Table of Acronyms

| Acronym | Meaning |
|---|---|
| **ACER** | Agency for the Cooperation of Energy Regulators |
| **AEEG** | Regulatory Authority for Electricity and Gas in Italy |
| **aFRR** | automatic Frequency Restoration Reserve |
| **APCS** | Austrian Power Clearing and Settlement AG |
| **AS** | Ancillary Services |
| **BRP** | Balance Responsible Party |
| **BSP** | Balance Service Provider |
| **CET** | Central European Time |
| **CHP** | Combined Heat and Power (Power Plant) |
| **DSO** | Distribution System Operator |
| **DR** | Demand Response |
| **EEX** | European Energy Exchange |
| **EFET** | European Federation of Energy Traders |
| **ENTSO-E** | European Network of Transmission System Operators for Electricity |
| **EPEX** | European Power Exchange |
| **ETSO** | Predecessor association of European Network of Transmission System Operators for Electricity |
| **EXAA** | Energy Exchange Austria |
| **FCR** | Frequency Containment Reserve |
| **FG EB** | Framework Guidelines on Electricity Balancing |
| **FRR** | Frequency Restoration Reserve |
| **GCT** | Gate Closure Time |
| **HV** | High Voltage |
| **ICT** | Information and Communications Technology |
| **IEC** | International Electrotechnical Commission |
| **LFC** | Load Frequency Control |
| **LV** | Low Voltage |
| **mFRR** | manual Frequency Restoration Reserve |
| **MGP** | Mercato del Giorno Prima (Italian Day-Ahead Market) |
| **MI** | Intraday Market (Italy) |
| **MPE** | Spot Electricity Market (Italy) |
| **MSD** | Ancillary Services Market in Italy |
| **MV** | Medium Voltage |
| **NC CACM** | Network Code on Capacity Allocation and Congestion Management |
| **NC EB** | Network Code on Electricity Balancing |
| **NC LFCR** | Network Code on Load Frequency Control and Reserves |
| **OTC** | Over-the-Counter market |
| **PTR** | Physical Transmission Right |
| **(f)RES** | (fluctuating) Renewable Energy Resources |
| **TSO** | Transmission System Operator |
| **UCTE** | Predecessor association of European Network of Transmission System Operators for Electricity |
| **VPP** | Virtual Power Plant |
| **XB / XBB** | Cross-border / Cross-border balancing |

# Glossary

| Term | Meaning |
|---|---|
| **AIS (*Region AIS*)** | Selected countries within the project eBADGE i.e. Austria (A), Italy (I) and Slovenia (S). |
| **Already Allocated Capacity (AAC)** | The total amount of allocated transmission rights, whether they are capacity or exchange programs depending on the allocation method. |
| **Available Transmission Capacity (ATC)** | That part of Net Transfer Capacity (NTC), which remains available after each phase of the transmission capacity allocation procedure for further commercial activity. Calculated as *ATC = NTC – AAC* (see definition from NTC below). |
| **Balance Subgroup (BSG) (Slovenia)** | A group of Balance Scheme Members. Its peak is represented by a Balance Responsible Party which is followed by any number of hierarchically inferior Balance Group Members. A Balance Subgroup is formed on the basis of a Compensation Agreement for the purpose of delivering balancing energy and the settlement of unmatched balances. |
| **Balance Scheme (Slovenia)** | The hierarchical arrangement of the organised electricity market where the relationships among Balance Scheme Members and management of revenue and expenditure accounts of Balance Scheme Members are uniformly defined with Balance Scheme Membership Contracts. |
| **Balance Group (BG) (Slovenia)** | A group of Balance Scheme Members. Its peak is represented by a Balance Responsible Party which is followed by any number of hierarchically inferior Balance Group Members. A Balance Group is formed in accordance with the Balancing Agreement for the purpose of delivering balancing energy, the operation of the Balance Responsible Party on the organised market with regulation of balance responsibility, risk management and control of imbalances of the Responsible Party and of the hierarchically inferior members of the Balance Group. |
| **Balancing Energy [MWh]** | The energy activated by Transmission System Operators to perform Balancing. |
| **Balancing Time Unit** | Time period for which the price for Balancing Capacity is established. |
| **Balancing** | Means all actions and processes, on all timescales, through which Transmission System Operators ensure, in a continuous way, to maintain the system frequency within a predefined stability range as set forth in the Network Code on Load- Frequency Control and Reserves, and to comply to the amount of reserves needed per Frequency Containment Process, Frequency Restoration Process and Reserve Replacement Process with respect to the required quality, as set forth in the Network Code on Load-Frequency Control and Reserves. |
| **BSP-TSO Model** | A model for exchange of Balancing Energy where the requesting Transmission System Operator has an agreement with a Balancing Service Provider in another Relevant Area. |
| **Coordinated Balancing Area** | Means any cooperation with respect to the Exchange of Balancing Services between two or more Transmission System Operators, each operating a Relevant Area. |
| **Control Area** | A part of the interconnected electricity transmission system controlled by a single TSO. |
| **ENTSO-E** | The European Network of Transmission System Operators for Electricity (ENTSO-E) represents all electric TSOs in the EU and others connected to their networks, for all regions, and for all their technical and market issues. The ENTSO-E got the assignment to develop the network codes |

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| | by Agency for the Cooperation of Energy Regulators (ACER). |
| **Explicit Auction** | In explicit auctions the grid user purchases the right to use a specific amount of transmission capacity of a congested line for a specific period of time. The auctioning of capacities is independent of energy trading transactions. |
| **Flow-Based Transmission Capacity (FB)** | The FBA method builds on technical power flow optimization models that take into account the relationships between all interconnectors of a network, following the physical laws of electricity flow and maximizing the capacity utilization of assets. |
| **Forward market** | Long time framed market (month, year…). Transmission Capacity (ATC) is determined before final energy flows are known. |
| **Frequency Containment Reserves (FCR)** | The Operational Reserves activated to contain System Frequency after the occurrence of an imbalance. |
| **Frequency Restoration Reserves (FRR)** | 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. |
| **Gate Closure Time** | It is a set point when contracts are fixed; there are Gate Closure Times for each of the market timeframes. |
| **Imbalance Pricing** | Financial settlement mechanism aiming at charging or paying Balance Responsible Parties for their Imbalances. |
| **Imbalance Settlement** | Refers to the imbalance settlement period, the definition of imbalance, imbalance calculation and imbalance pricing. |
| **Implicit Auction** | Implicit auctions are a mechanism whereby available cross border transmission capacity is sold as part of energy trade. In this mechanism, buying energy already includes the transmission capacity. |
| **International Trade Responsible (ITR)** | Balance Responsible Party which is known by the Nomination Validator as the entity entitled to use the PTR. |
| **LFC Area** | A part of a Synchronous Area or an entire Synchronous Area, physically demarcated by points of measurement of Interconnectors to other LFC Areas, operated by one or more TSOs fulfilling the obligations of a LFC Area. |
| **LFC Block** | A part of a Synchronous Area or an entire Synchronous Area, physically demarcated by points of measurement of Interconnectors to other LFC Blocks, consisting of one or more LFC Areas, operated by one or more TSOs fulfilling the obligations of a LFC Block. |
| **Marginal Price** | The change in price associated with a unit change in quantity supplied or produced. |
| **Market Coupling** | Market coupling is a mechanism for enabling trade between two or more power exchanges using implicit auctioning of cross-border transmission capacity. |
| **Market Splitting** | Market splitting is a congestion management mechanism that splits a power exchange into geographical bid areas of different electricity prices and limited capacities of exchange, when congestion occurs. |
| **Merit Order** | A way of ranking available sources of energy, especially electrical generation, in ascending order of their short-run marginal costs of production, so that those with the lowest marginal costs are the first ones to be brought online to meet demand, and the plants with the highest marginal costs are the last to be brought on line. |
| **Monitoring Area** | A part of the Synchronous Area or the entire Synchronous Area; physically demarcated by points of measurement of Tie-Lines to other Monitoring Areas, operated by one or more TSOs fulfilling the obligations |

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| | of a Monitoring Area. |
| **Net Transfer Capacity (NTC)** | The Net transfer capacity is the maximum total exchange program between two adjacent control areas compatible with security standards applicable in all control areas of the synchronous area, and taking into account the technical uncertainties on future network conditions. Calculated as *NTC = TTC – TRM* (see definition from TTC and TRM below). |
| **Nomination Agent** | A recognized Programme Party that carries out Intraday Capacity**.** |
| **Nomination** | The prior reporting by the network user to the TSO to which extent the network user wishes to use its capacity at cross border points. |
| **Pay-as-bid** | Contracted parties who provide a service are paid based on their offer price. |
| **Production Unit (PU) (Italy)** | One or more generators available to a User of Dispatching, regrouped according to the methods defined in Chapter 4 of the Grid code, and such that the injections or withdrawals of electrical energy regarding such group can be measured autonomously. |
| **Physical Transmission Right (PTR)** | Right to use Interconnection capacity for electricity transfers expressed in MW. |
| **Real-time balancing** | With real-time balancing, after gate closure, when all trading ceases among participants, the TSO takes full control of the power system and corrects any imbalance created by the difference between supply and demand in real-time. As the latter is not currently controllable, the TSO requires production reserves in the system to inject or withdraw energy as necessary. |
| **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. |
| **Reserve capacity (MW)** | Contractually agreed power capacity available for balancing load fluctuations in the transmission grid. |
| **Spot Energy Market** | The spot energy market allows producers of surplus energy to instantly locate available buyers for this energy negotiate prices within milliseconds and deliver actual energy to the customer just a few minutes later. |
| **Spot Price** | The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates. |
| **Synchronous Area** | Is an interconnected electric power system, characterised by a common operating frequency and implemented as a set of synchronously interconnected transmission networks (control areas). |
| **Target Model (TM)** | Provides a goal for pan-European harmonisation of electricity markets. The Target model covers forward, day-ahead, intra-day and Balancing Markets, as well as the calculation of cross border capacity (In this work mainly the Target Model for Balancing Market is addressed). |
| **Tendering Period** | The period in which the control power (primary/secondary/tertiary) should be provided. |
| **Transmission service** | The actions undertaken by the system operator to relief internal grid congestion by using bids and offers available in the Balancing Market. |
| **Total Transfer Capacity (TTC)** | The maximum exchange between two areas compatible with operational security standards applicable at each system if future network conditions, generation and load patterns were perfectly known in advance. |

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| **Transmission Reliability Margin (TRM)** | A security margin that copes with uncertainties on the computed TTC values arising from: a) Unintended deviations of physical flows during operation due to the physical functioning of load-frequency regulation; b) Emergency exchanges between TSOs to cope with unexpected unbalanced situations in real time; c) Inaccuracies, e. g. in data collection and measurements. |
| **TSO-TSO Model** | In a TSO-TSO model the BSPs offer balancing services to the TSO. For details see the deliverable of WP2.1. |
| **Unshared Bids** | An energy bid of a Standard Product or a Specific Product sent by a Balancing Service Provider to its Transmission System Operator which is not available for activation by other Transmission System Operators. |
| **Virtual Power Plant** | A cluster of dispersed generator units, controllable loads and storages systems, aggregated in order to operate as a unique power plant. |

# eBADGE Project

The 3rd Energy Package clearly boosts the development of an Integrated European balancing mechanism. In this context, ACER has in 2011 started the development of the Framework Guidelines on Electricity Balancing. It is expected from the ACER statements that Demand Response will play significant role in the future integrated Balancing Market allowing Virtual Power Plants, comprising Demand Response and Distributed Generation resources to compete on equal ground.

The overall objective of the eBadge project is to propose an optimal pan-European Intelligent Balancing mechanism also able to integrate Virtual Power Plant Systems by means of an integrated communication infrastructure that can assist in the management of the electricity Transmission and Distribution grids in an optimized, controlled and secure manner.

In order to achieve the above overall objective the eBadge project will have four objectives focusing on:

1. Developping the components: simulation and modelling tool; message bus; VPP data analysis, optimisation and control strategies; home energy cloud; and business models between Energy, ICT and Residential Consumers sector;
2. Integrating the above components into a single system;
3. Validating these in lab and field trials;
4. Evaluating its impact.

**Project Partners**

Telekom Slovenije d.d. - Slovenia
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Ricerca sul sistema energetico – RSE Spa - Italy
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**Project webpage**

http://www.ebadge-fp7.eu/

# Executive Summary

The Project eBADGE proposes an optimal pan-European intelligent Balancing mechanism, piloted on the borders of Austria, Italy and Slovenia, able to integrate VPP systems by means of an integrated communication infrastructure that can assist in the management of the electricity Transmission and Distribution grids in an optimized, controlled and secure manner. This is in line with the strong support shown by the European Commission towards the integration of Virtual Power Plants (VPPs) in the Electricity Markets and the development of an integrated European balancing mechanism.

This deliverable performs a comparison between the technical and regulatory frameworks of the Balancing Markets of Austria, Italy and Slovenia, based on well-defined market design variables. Besides, an overview of possible changes, possibilities and risks arising from the integration of these markets according to the European Target Model and considering the participation of VPPs is presented. This study is correlated to the aspects analysed in Deliverable 2.1, where the market arrangements for the integration of Balancing Markets are analysed and serves as input for the Deliverable 2.3, where a prototypal simulator for the analysis of a future trans-national reserve/Balancing Market between the analysed countries is to be defined.

Results show that the Balancing Markets in Austria, Slovenia and Italy are very different. These differences include fundamental aspects like the Balancing Market design and the Gate Closure Times of their Electricity Markets, but also bidded products, procurement mechanisms and imbalance settlement procedures. At least some of these differences have to be harmonized for the market opening of cross-border Balancing Energy; otherwise the cross-border provision of Balancing Energy between the countries will not be possible or will be open to important distortions. Besides that, the limited available transmission capacity between Austria, Italy and Slovenia is a main obstacle for an increased exchange of Balancing Energy and, therefore, for the achievement of the Target Model (TSO-TSO model with common merit order) within the ENTSO-E Network Code on Electricity Balancing

Regarding the integration of VPPs in the Balancing Markets, we show that it is highly recommended that the rules of the coordinated balancing area, are conceived such that the participation of VPPs, Demand Response (DR) and fluctuating Renewable Energy Resources (fRES) are facilitated: actually, some product specifications (as a lack of verification methodology – baseline), or the lack of rules for aggregation of small units currently hinder the participation of these units in the national Balancing Markets. A wider participation of VPPs in the Balancing Market would not only have a positive effect on increasing security of supply and decreasing balancing costs, but would also give end users the opportunity to directly benefit from Smart Grids by making their participation, through aggregation, less complicated and for providing a higher standard of service reliability and lower electricity prices. On the other side, the total investment costs for the pooling of units and implementation of communication interfaces have to be also taken into account.

# 1. Introduction

## 1.1. Scope

The third Energy Package clearly boosts the development of an integrated European balancing mechanism. In this context, ACER (Agency for the Cooperation of Energy Regulators) has started the development of the Framework Guidelines on Electricity Balancing (FG EB) in 2011 and has published the final version on 18 September 2012 [1]. Within the FG EB, ACER states, among others, that Demand Response will play a significant role in the future integrated Balancing Market allowing Virtual Power Plants (VPPs), comprising Demand Response and Distributed Generation resources to compete on equal ground with conventional generators [2].

In response to the FG EB a Network Code on Electricity Balancing (NC EB) is being developed by ENTSO-E (European Network of Transmission System Operators for Electricity) (last version: [3]). The goal of this Network Code is to establish common rules for Electricity Balancing. This will involve the establishment of common principles for procurement and common methodology for the activation and settlement of ancillary services, where also VPPs could participate. The requirements described in the NC EB have been formulated in line with the FG EB, with the aim of developing a regional and step-wise basis after the transitory period for the necessary levels of integration and harmonisation of Balancing Markets [3]. Furthermore, the NC EB takes into consideration other relevant ENTSO-E network codes. Especially the links with the Network Code on Load-Frequency Control and Reserves (NC LFCR) [4] are important as the technical requirements for the balancing are defined there.

Widely integrated cross-border day-ahead, intraday and Balancing Markets contribute to higher market liquidity and to ensuring security of supply [2]. The main European electricity stakeholdrs proposed a target model for the whole electricity market. One part of this target model foresees integration of the Balancing Markets to reduce total costs, increase social welfare and to safeguarding operational security. By including VPPs in the Balancing Markets competition on these markets can be further increased.

Based on the above, the overall objective of the eBADGE project is to propose an optimal pan-European intelligent balancing mechanism, piloted on the borders of Austria, Italy and Slovenia. This mechanism should also consider the existence of VPPs that can assist, through well-defined ICT requirements, in the management of the electricity Transmission and Distribution grids in an optimized, controlled and secure manner. Even if the cross-border mechanism proposed by eBADGE will be tested with reference to a trilateral case (Austria, Italy, Slovenia), the approach and the modelling methodology is meant to allow a gradual extension to other countries in Europe [2]. This objective is supposed to be concretized in a run pilot experiment between the three considered states. However, in order to implement this pan-European mechanism of energy exchange, there is a necessity to clearly standardize the products to be exchanged on a cross-border basis and to create a harmonized regulatory basis to prevent market distortions.

Thus, the present deliverable (D2.2), which is the result document of the research carried out within Task 2.2 of Work Package 2 of the Project eBADGE, aims at a wide comparison of the technical and regulatory frameworks between the Balancing Markets of the three involved countries, based on well-defined market design variables. Besides, an overview of possible changes, possibilities and risks of the integration of these markets according to the European Target Model and considering the participation of VPPs is presented. This study is strongly correlated to the Task 2.1 of WP2, where the market arrangements for the integration of Balancing Markets are analysed and serves as input for the Task 2.3, where a prototypal simulator for the analysis of a future trans-national reserve/Balancing Market between Austria, Italy and Slovenia is to be defined.

## 1.2. Document Structure

Further in this chapter (Section 1.3) a background analysis of the main topics studied in this document is presented. This background analysis establishes the basic interaction of the Balancing Markets with other Electricity Markets (e.g. Intraday and Day-Ahead Markets). It also explains the main requirements of the Target Model defined by the NC EB and the first considerations regarding the participation and the value of VPPs in Balancing Markets.

The methodology is layed out in Chapter 2 and the most important design variables for the harmonization of Balancing Markets are identified in. Furthermore, the related challenges for the integration of Balancing Markets are described in Chapter 3.

In Chapter 4 the national regulatory frameworks and the technical requirements for the participation on the national Balancing Markets are described. The constraints for VPPs to provide ancillary services are also discussed. Furthermore, the national Balancing Markets are compared with the national target model (refer to Model nr.1 of Deliverable 2.1).

A cross-border Balancing Market can only exist, if balancing energy can be transported from one area to another. Therefore, Chapter 5 focuses on the criticalities concerning the management of the transmission capacities between the three countries, possible congestions and the implications for cross-border balancing, especially in the case of VPPs.

In Chapter 6 the three Balancing Markets are compared to each other and to the TSO-TSO target model (refer to Model nr.4 of Deliverable 2.1). The risks, changes and possibilities of this integration are highlighted. Chapter 6 includes a comparison of the regulatory frameworks for VPPs in the analysed countries.

Chapter 7 concludes this work.

## 1.3. Background

### 1.3.1. Balancing Markets and interaction with other markets

In this section the balancing mechanism & energy markets and transmission capacity allocation are briefly outlined; the details are explained later in this study. An overview on the general course of action in these markets can be seen in Figure 1.

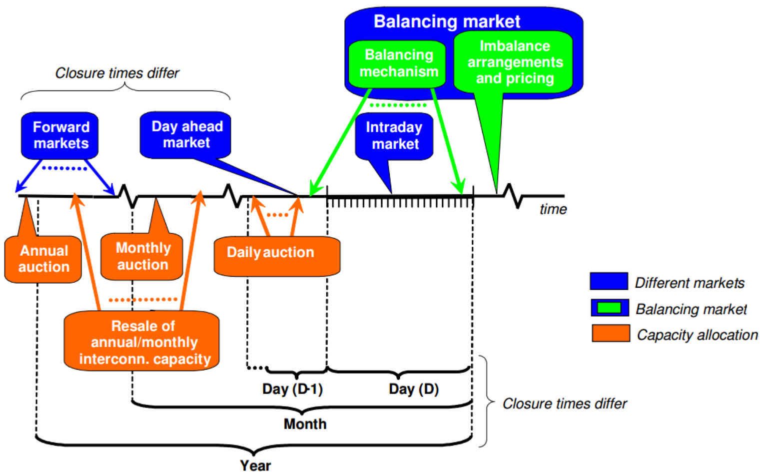


**Figure 1: Integration between balancing and other markets and relation to capacity allocation [5]**

For cross-border balancing the integration of energy markets and moreover, the chronology of Balancing Markets in relation to the energy markets and the auctions of cross-border transmission capacity are of high relevance, for instance regarding the correspondent Gate Closure Times.

**Energy markets**

Energy markets can be classified according to their timing [6]. In the long term electricity can be traded on non-standardized forward and standardized future electricity markets. In the shorter term electricity can be traded on the day-ahead and on the intraday markets. The electricity can be traded on power exchanges or bilaterally - over-the-counter (OTC). The electricity markets are not harmonized across Europe (e.g. their gate closure times), but the basic principles are very similar. The trend in Europe is towards further integrated electricity markets. For example the European Electricity Index (ELIX) shows the fictional price level for an integrated electricity market without congestions including the countries Germany, Austria, Switzerland and France.

**Balancing Markets**

The Transmission System Operator (TSO) has access to balancing services to ensure the instantaneous equilibrium between consumption and production. To put it in another way, balancing provides flexibility to react to sudden changes on the supply or on the demand side. When discussing balancing services two main components have to be distinguished:

i. **Balancing capacity** is procured to ensure the availability of resources to provide balancing energy. This is done either by bilaterally pre-contracting the availability of reserve capacity that can be used in real time or by setting up a reserve market that is cleared in advance to the real time. Another option, presently implemented in many member states in Europe is that all suitable capacity that is not allocated in the day-ahead market is forcefully offered in the market for the ancillary services without any associated payment.

ii. **Balancing energy** is used by the TSO in real-time to secure the balance between consumption and production. In general the available balancing capacity can be used and the selection mechanisms can foresee specific Balancing Markets or, sometimes obey only to technical requirements. According to the NC EB balancing energy means energy that is used by TSOs to perform Balancing.

Furthermore, there are several balancing processes with different full activation times as shown in Table 1.

**Table 1: Different balancing processes with characteristic activation and activation times**

| | **Activation** | **Full activation Time**<br>max. time for full activation |
|---|---|---|
| Primary control -<br>Frequency Containment Reserve (FCR) | Automatic | < 30 sec |
| Secondary control -<br>Frequency Restoration Reserve (aFRR) | Automatic | < 5 min |
| Tertiary control -<br>Manual Frequency Restoration Reserve (mFRR) | Manual | < 15 min |
| Replacement Reserves (RR) | Manual | < 1 h |

The different activation and deactivation times of the respective process can be seen in Figure 2. The FCR stabilizes the frequency after the disturbance at a steady-state value within the permissible Maximum Steady-State Frequency Deviation by a joint action of FCR within the whole Synchronous Area. The Frequency Restoration Process controls the frequency towards its set point value by activation of FRR and replaces the activated FCR. The Frequency Restoration Process is triggered by the disturbed Load-Frequency Control (LFC) Area; whereas, FRR can be segmented in an automatically activated (aFRR) and a manually activated (mFRR) component. The RR replaces the activated FRR and/or supports the FRR activation by activation of RR.

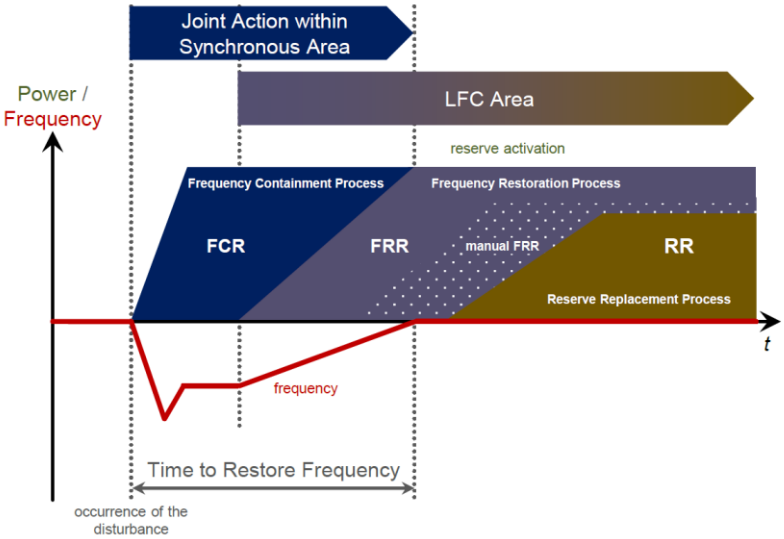


**Figure 2: Dynamic hierarchy of LFC processes (assumption that FCR is fully replaced by FRR) [8]**

The Balancing Market highly depends on the technical requirements (described in the NC LFCR). This is why the NC EB that describes the market concept is developed in close cooperation with the NC LFCR. The relation of the two network codes can be seen in Figure 3.

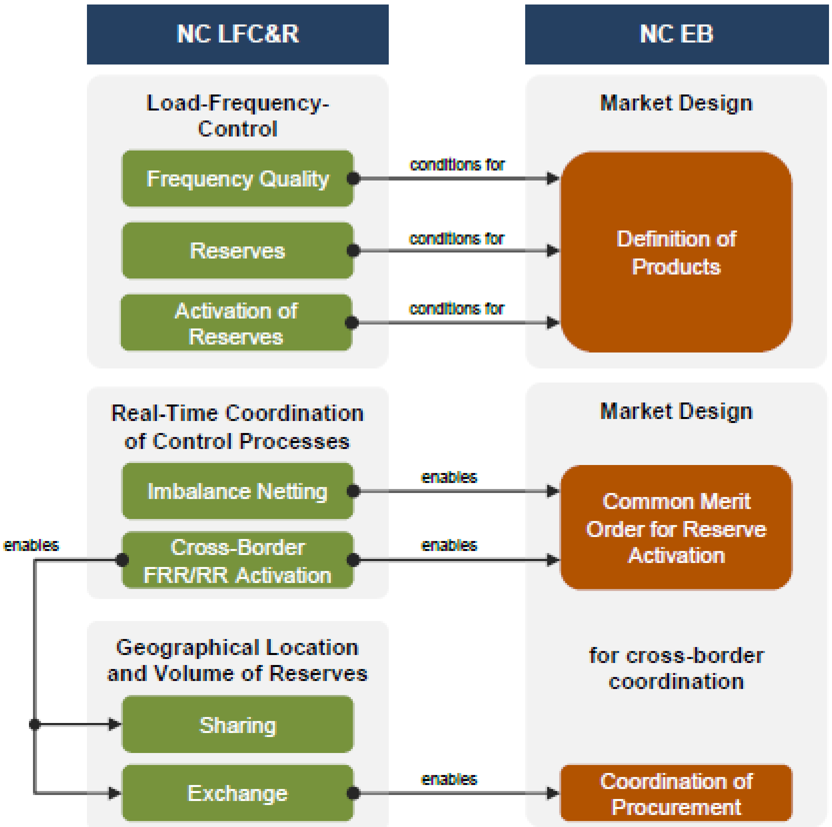


**Figure 3: Relation of the NC LFCR and the NC Electricity Balancing [8]**

Various cross-border Balancing Market models are proposed, according to the degree of harmonisation between markets and TSO cooperation required. In this study initially the national target model (refer to Model nr.1 of Deliverable 2.1) is considered and compared to the national schemes of Austria, Italy and Slovenia. Later the multilateral cross-border extension of this model, the TSO-TSO target model (refer to Model nr.4 of Deliverable 2.1) is considered. The latter requiring the highest level of harmonisation and cooperation. The market designs for both balancing capacity and balancing energy vary a lot across Europe

[9]. For example, the procurement of balancing capacity is not harmonized, e.g. mFFR is procured day-ahead in Germany and one year or even more ahead in Slovenia. In chapter 2 these harmonization issues are discussed in detail.

**Allocation of Transmission Capacity**
A cross-border Balancing Market can only exist if balancing energy can be transported from one area to another. Depending on the available transmission capacity and on the trade volume congestions on the transmission lines can occur. Therefore, electricity under the consideration of available transmission capacity can be traded. Analogous to the futures and energy markets with the physical energy delivery (day-ahead, intraday); there are normally annual, monthly, daily and intraday auctions for transmission capacity.

These auctions can be either explicit, where capacity and energy are independently auctioned or implicit, where transmission capacity is included (implicitly) in the auctions of energy in the market. In the explicit auctions, since the two commodities (capacity and energy) are traded separately, there is a lack of information about process of the other commodity [10]. In implicit auctions, the transmission capacity between bidding areas (price areas/control areas) is made available to the spot price mechanism in addition to bid/offers per area, thus the resulting prices per area reflect both the cost of energy in each internal bidding area (price area) and the cost of congestion. Implicit auctions normally ensure that electrical energy flows from the surplus areas (low price areas) towards the deficit areas (high price areas) thus also leading to price convergence. Implicit auctions signifies the concept used for both 'market coupling' and 'market splitting [10].

How capacity for balancing can be allocated for cross-border balancing services is still being discussed, as cross-border balancing shall not lead to a lower welfare by withdrawal of interconnection capacity from market players nor shall it limit opportunities for cross-border trade [5]. In the section 3.1.4 and in chapter 5 of this study the allocation of transmission capacity is further discussed. Furthermore, the implications of the distributed installation of the generation/load of virtual power plants (VPPs) are discussed.

### 1.3.2. Value and participation requirements of VPPs in Balancing Markets

**Value of VPP-participation in Balancing Markets**
An increasing amount of variable renewable generation[2] is expected to decrease the availability of traditional balancing resources (which would be more and more used as "cold-reserve") and, by raising the fluctuating characteristic of the generation, raise the short-term balancing costs. However, effective cross-border Balancing Markets, a central point in the project eBADGE, in addition to day ahead and intraday energy markets provide the tools to facilitate the cost effective procurement of short-term balancing services. This can potentially reduce the system balancing costs and facilitate the integration of the VPPs [11].

Besides that, by aggregating several VPPs the reliability of services provided individually by end-users can be improved; helping utilities, DSOs and TSOs to shave peak power demands, balance intermittent power generation, and increase security of supply. Even when a particular unit is not able to deliver the agreed capacity, the aggregator can still provide the service, by using other units of its portifolio.

Another advantage of the aggregation of VPPs is that registration, communication and settlement are performed at the level of the aggregator, facilitating and incentivating the participation of small units (like residential ones). It does not only offer end consumers the opportunity to benefit directy from the smart grids [12], but also have a positive effect on the security of supply and decrease the balancing prices, as more participants take part in the market.

**Technical and regulatory requirements for participation of VPPs**
The participation of VPPs in the Balancing Market demands the observation of specific technical and regulatory issues. In many countries there is no relevant provision regarding the treatment of fluctuating Renewable Energy Resources (fRES) or Demand Response (DR); however, in many cases they are indirectly excluded, since the ancillary service requirements cannot be fulfilled by them.

One fundamental aspect for the participation of VPPs (especially of small size, like resindential costumers) in any electricity market is the possibility of aggregation of their services in a pool; which means that the units

[2] Due to legislation (feed-in tariffs and priority of dispacth for those energy sources)

are treated as a single virtual unit and the so called aggregator and/or Balancing Group is allowed to stand in the place of the VPP, by fulfilling registration, prequalification, measurement and communication requirements. Aggregation is however still either not allowed or not facilitated in most European countries [12].

Even though the NC EB does not refer to any technology type and therefore provides opportunities for all potential sources of Balancing, it recommends that the participation of demand response and renewable sources of energy should be facilitated [3]. In this matter new solutions need to be created (e.g. the introduction of flexible products) to integrate the VPPs [11]. Specifically regarding DR a verification methodology (baseline) is necessary [13][14]. This baseline is an estimate of the electricity that would have been consumed by a customer in the absence of a demand response event. The baseline is then compared to the actual metered electricity consumption during the DR event to determine the quantitative demand reduction. The NC EB does not refer to any specific measurement for baseline. However, it is clear that both accurate monitoring and financial incentive schemes should be available to promote the participation of DR in the Balancing Market.

Depending on the composition of the VPPs the response time (full activation time) is influenced. In case the full activation time of the VPPs meets the technical requirements for the different Balancing Markets, then the VPPs can take part in these markets FCR, aFRR, mFRR. In eBADGE the VPP shall be designed according to the time requirements of the national mFRR Balancing Markets in AIS. This is why the focus of this report is on the integration of VPPs in the mFRR Balancing Market.

# 2. Methodology

When developing cross-border balancing schemes and for the integration of VPPs it is important to acknowledge the diversity of procurement schemes for Ancillary Services across Europe [15]. Indeed, common principles tend to exist on the technical side, but there is little or no consistency regarding market design. However, for the integration of Balancing Markets a certain degree of harmonization of the regulatory framework is needed as well as of technical aspects and the IT systems. The costs for the implementation of integrated markets have to be outweighed by efficiency gains [16]. ETSO wrote in 2007 that the full socio-economic benefit can only be reached with harmonization on some basic aspects, like gate closure, settlement period, procurement including product definitions and, finally, imbalance pricing principles, but a first technical prerequisite for integration of Balancing Markets is sufficient interconnection capacity [16]. In the “Revised ERGEG Guidelines of Good Practice for Electricity Balancing Markets Integration” (2009) it is stated that full harmonization of Balancing Markets is not a prerequisite for cross-border balancing [5]. Thus, in a step-wise process, cross-border balancing implementation should precede definition and implementation of a standard market design. When analysing the need for harmonization it is considered that it is not a target in itself, but it should be targeted in case it enhances social welfare.

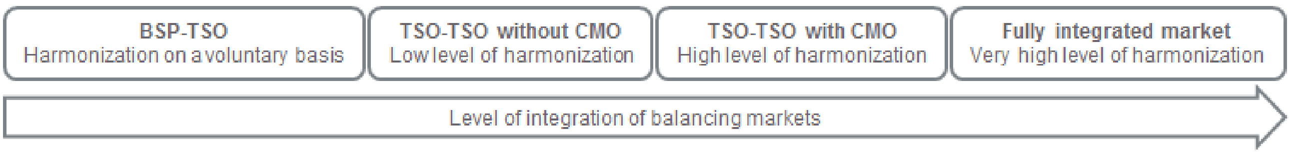


**Figure 4: Harmonization level for cross-border balancing models [17]**

In Figure 4 different models for cross-border balancing and their need for harmonization are shown. The different models for the interconnection of Balancing Markets are described in detail in Deliverable 2.1 of eBADGE [18]. As can be seen in Figure 4 the need for harmonization is increasing with further integrated Balancing Market. The question now is how much harmonization is needed to allow cross-border balancing arrangements without allowing large market distortions, how this harmonization can be achieved and how many balancing design parameters should be defined by the ENTSO-E and which parameters should be left open to national regulation. The more parameters are harmonized EU-wide the less is the probability that conflicts would occur in national law and the easier would be the further integration of coordinated balancing areas. Furthermore, the participation of smaller participants from different countries would be easier if the laws were highly harmonized as fewer resources are needed to comprehend different national laws. In the NC EB the current approach is to harmonize general aspects, but the harmonization of many design parameters are left to the responsibility of the TSOs. Balancing Markets should not be harmonized as a goal in itself, but to increase global welfare. Balancing Market harmonization and market integration are closely linked. A degree of harmonization is needed to make integration possible and higher integration is a driver for more harmonisation [19].

There are various design parameters that define the Balancing Markets as can be seen in Figure 5. On the one hand there are national Balancing Market design parameters that need to be harmonized for successful implementation of cross border balancing. On the other hand new design parameters have to be defined to make cross-border balancing possible. National as well as multinational design variables need to be defined and harmonised in a way to ensure secure balancing and to enhance the global welfare. The challenge of defining these parameters and of defining the degree of harmonisation is to specify them in an intelligible way, but to let room for national technical requirements and specifications. For instance in Austria a need for a shorter mFRR activation time exists due to technical restrictions (see chapter 4).

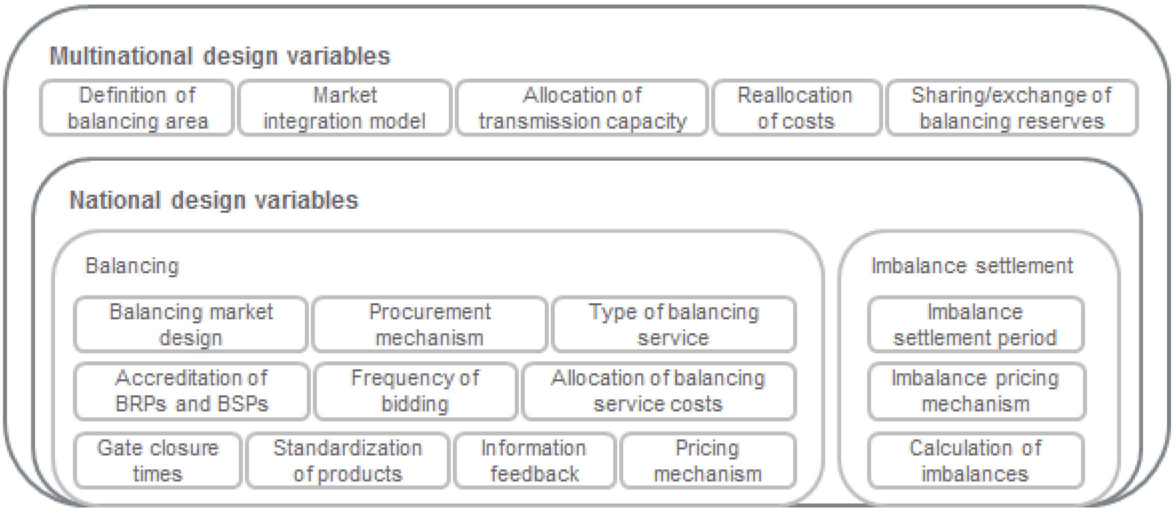


**Figure 5: Selected design variables for cross-border Balancing Markets**

In the following sections important design variables for an implementation of cross-border Balancing Markets are analysed regarding their harmonization needs. Therefore, on the one hand the harmonization of national balancing design parameters and on the other hand multinational parameters are relevant. The harmonisation of relevant national balancing is essential to avoid for instance market distortions or the creation of additional imbalances caused by arbitrage opportunities [20].

The national design variables are used for the comparison of the Balancing Markets in Austria, Slovenia and Italy to each other and to the national target model (Model nr.1 of Deliverable 2.1), while multinational design variables need to be defined for the cross-border integration of Balancing Markets. The evaluation of this market opening between the three countries in comparison with the TSO-TSO model with a common merit order list (Model nr.4 of Deliverable 2.1) was performed; considering for that risks, possibilities and changes that might rise during the process.

# 3. Harmonization issues for cross-border Balancing Markets

## 3.1. Impact analysis of selected multinational design variables for cross-border balancing

The possible market arrangements of balancing energy - as for instance imbalance netting, BSP-TSO and TSO-TSO models - are explained in another deliverable of the eBADGE project D2.1 [18]. The impact of market integration differs depending on the size, on the generation portfolio and on the price levels of these markets [19]. The smaller the market the higher is the impact of market integration on this market. The generation portfolio usually determines the volume and the price level of the balancing services. The difference of the price levels implies the direction of exchange of the balancing services.

The types of exchanged balancing energy (e.g. mFRR) are mandatory prescribed by NC LFCR [4], whereas main differences are among others the product characteristics and the degree of automation.

### 3.1.1. Effects of the coordinated balancing area

**Size of the coordinated balancing area**

The definition of the coordinated balancing area is a significant design variable especially regarding the harmonization requirements. First, the higher the original similarity of the national balancing parameters in the countries of a coordinated balancing area the easier is it to match these countries into a coordinated balancing area. Second, the more countries are going to be in a coordinated balancing area the higher is the probability that the design parameters differ in the countries and that it takes effort to harmonise and to integrate these regions. On the other hand is an enhanced integration a driver towards more harmonization and more benefits of cross-border balancing can be exploited by extending the coordinated balancing area.
The balancing costs depend on the balancing need and on the balancing prices of the entire coordinated balancing area and the balancing costs have to be distributed “fair” between the TSOs. Therefore, it has to be considered that the balancing energy prices will change when Balancing Markets are integrated and therefore the national costs for the TSOs will change, too. The geographical size and the portfolio of generation capacity of the countries that are combined to a coordinated balancing area have a main influence how the prices will change.

**Change of balancing energy prices**

Due to the common procurement of balancing energy the prices depend on the balancing energy needed for the entire coordinated balancing area. Because of the need for balancing in one country the costs for balancing can increase in another country as can be seen in Figure 6; the same principle applies in case of electricity market coupling. Thus, the balancing energy prices will change depending on the market sizes of the countries that are combined in a coordinated balancing area and on the available generation capacity in each country.

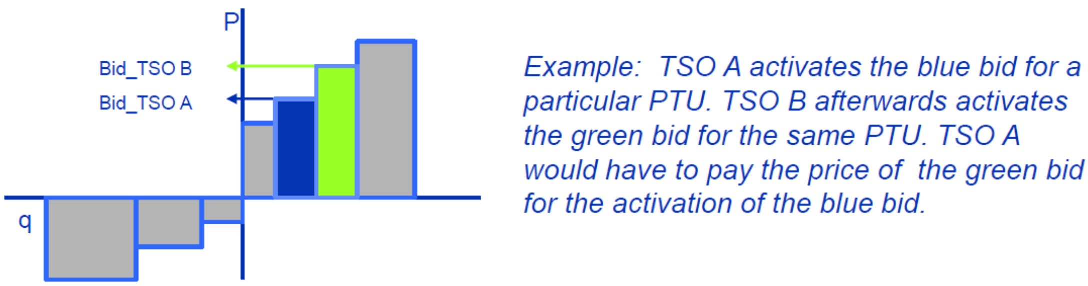


**Figure 6: Dependency of the costs for balancing from another country – Example [21]**

**Reallocation of balancing energy costs**

In case of marginal pricing one single price can be used for the reallocation of the costs between the TSOs. If congestions occur different prices have to be applied in different regions. When pay-as-bid pricing is applied the redistribution of costs is based on average pricing and more complicated [19]. Therefore, the NC EB supports marginal pricing until a cost-benefit analysis will show the advantage of pay-as-bid pricing.

### 3.1.2. Availability of information

Asymmetric available of information provides those market players with more information an advantage (see also section 3.2.9). Therefore, in a coordinated balancing area the information feedback should be at least partly harmonised.

### 3.1.3. Cross-border sharing/exchange of balancing capacity

Another important multinational balancing parameter is the implementation decision of cross-border sharing or exchange of balancing capacity. Sharing means the use of the same resources for balancing purposes, exchange means the provision of resources in another country. Exchange of balancing capacity changes the geographical distribution and sharing of balancing capacity additionally changes the volume of the balancing capacity that is procured [8].

According to the NC EB the sharing/exchange of balancing capacity can be implemented in a coordinated balancing area depending on the technical parameters, as for example available transmission capacity, defined in the NC LFCR.

### 3.1.4. Allocation of transmission capacities for balancing capacity

For cross-border Balancing Markets the availability of transmission capacity is a necessary condition. However, the more transmission capacity is used for balancing mechanism the less is available for electricity trade. The optimal level for the allocation of transmission capacity can be determined depending on the descending marginal value of capacity for trading and the increasing marginal value of capacity for cross-border balancing (see Figure 7). The problem is that this value is not known beforehand, but could be analysed on a ex-post basis.

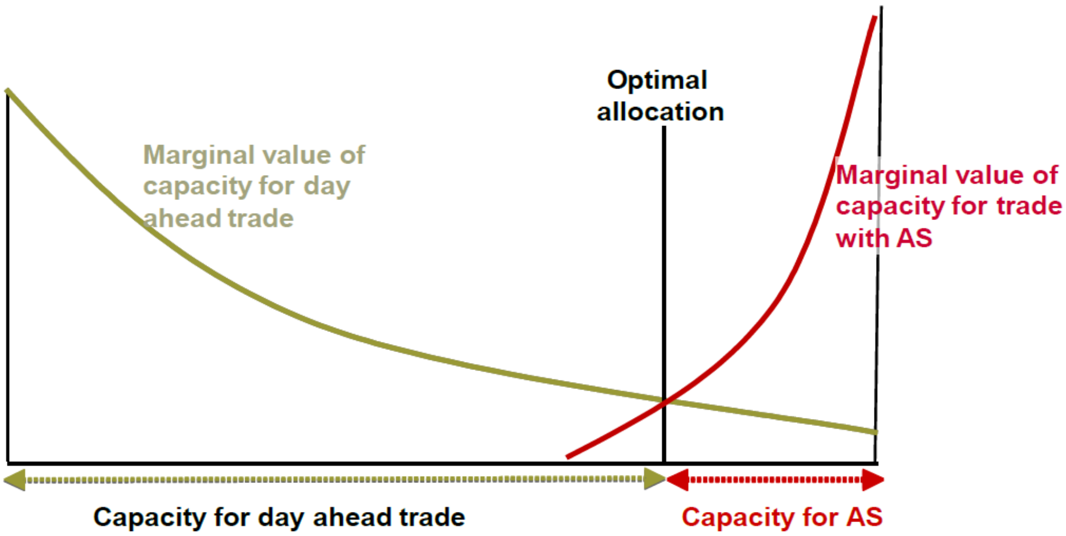


**Figure 7: Optimal allocation of transmission capacity for day ahead trading and balancing [22]**

According to the NC EB the TSO can decide how it allocates the existing transmission capacity for sharing or the exchange of balancing capacity as can be seen in Figure 8. The TSOs can either use the available transmission capacity after the intraday gate closure (without prior procurement) or the capacity can be procured based on the methodologies of the NC EB. Any cross border capacity that is available after intraday gate closure can be used for balancing purposes. The TSO can decide if it uses an additional provision methodology to make capacity available in earlier timeframes by a probabilistic approach or the reservation of transmission capacity. The reservation can take place through a co-optimization process, a market-based reservation process or a reservation based on economic efficiency analysis. When choosing the methodology the TSOs have to consider that the probabilistic approach is not an option for highly congested interconnection lines and that the reservation methodology has to be used if no weekly auction of cross zonal capacity is in place. In all other cases the TSO can choose between all the methodologies. [23]

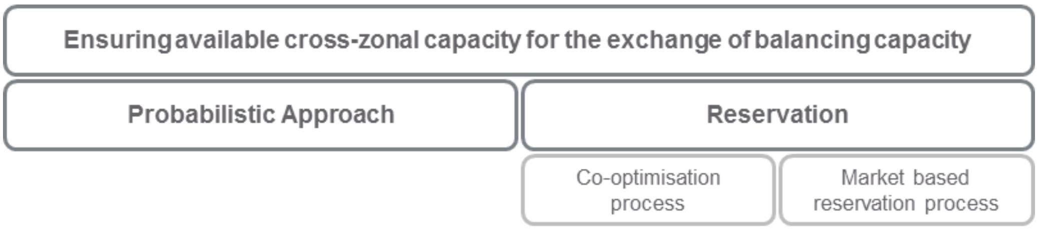


**Figure 8: Methods for the allocation of cross zonal capacity for balancing capacity[3] [24]**

The TSOs have to develop a pricing mechanism at least until one year before the implementation of sharing or exchange of balancing capacity [3].

For the exchange of balancing energy either the cross-zonal capacity that is available after the intraday gate closure or the reserved capacity can be used (see Figure 9).

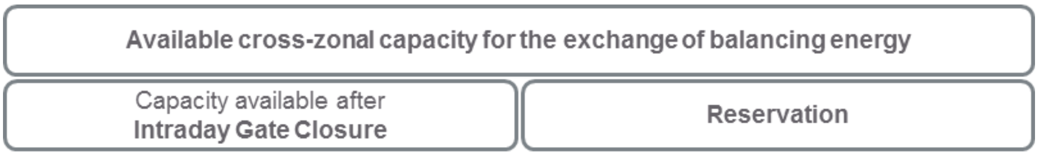


**Figure 9: Methods for the allocation of cross zonal capacity for balancing energy [24]**

## 3.2. Impact analysis of selected national design variables for cross-border balancing

### 3.2.1. Balancing Market design

Balancing of electricity is carried out in Europe in several different ways. Basically they can be grouped into self-dispatch model and central-dispatch model, whereas the main difference can be summarized in one question according to [25]: *Is the principle least cost dispatch or market position maintenance?*

**Central-dispatch balancing model**
In a dispatch arrangement the TSO determines the dispatch values and issues instructions directly to generators (or demand). The TSO determines the dispatch instructions based on prices and technical parameters provided by the participating parties in order to minimize the system production cost while meeting security requirements. [25] In a centrally scheduled market the charged TSO is free to make system analyses and modify the dispatching of the single units in order to increase the available reserve margin and solve congestion, and the participants are given their position based on a central decision. Central-dispatch models typically occur in electrical systems where the impact of local market imbalances is a material threat to the security of the system. In such systems, a central-dispatch model can be considered a necessity [26].
In a centrally dispatched market the TSO dispatches all plants, based on market Commercial Offer Data, to provide generation and demand balance, external transfers, reserve provision and transmission constraint management. This involves dispatch instructions being issued normally day-ahead to connect off line plant (in particular plant with long start up times) to real time instructions for connected plant. In a central dispatch market there is no inherent balancing link between generators and demand (suppliers). Generators bid into the market and become part of the market schedule if economic; suppliers buy at the resulting market price for their demand. The Grid Code stipulates the requirements for generators for following dispatch instructions. Differences between the market schedule and actual generation running as directed by the TSO to balance with reserve and constraint provision become a constraint cost to the end customers. [25]

**Self-dispatch balancing model**
A self-dispatching balancing model is a dispatch arrangement where generators determine a desired dispatch position for themselves based on their own economic criteria to provide commercial independence within a market [25] and the TSO is a market operator that chooses on the basis of an activation mechanism - mainly merit order - how to satisfy imbalance needs for his area. In the self-dispatch model, Balance Service Providers (BSPs) - single units or a portfolio of units - follow an aggregated schedule of actions to

[3] This was changed in new draft of NC EB V1.30

start/stop/increase output or decrease output in real time, including aggregated incremental instructions by the TSO [9]. The self-dispatching balancing model can be sub-divided in two further market design configurations:

(i) Self-Dispatch - Portfolio Based Balancing
(ii) Self-Dispatch - Unit Based Balancing

The difference between the two self-dispatch models is that the balancing is scheduled for either a portfolio of generators (i) or for a single unit (ii) [9].

**Comparison with respect of cross-border balancing**
In some countries the Balancing Market design is fundamentally different from the model assumed in the Framework Guidelines itself, thus, so far the different market designs are not fully considered in the guidelines by ACER or by the ENTSO-E. Even though the Framework Guideline on Electricity Balancing (FG EB) and, hence the Network Code on Electricity Balancing (NC EB) is predominantly designed from a self-dispatch model point of view, in the FG EB it is determined that ENTSO-E shall take into account the parallel existence of central dispatch (e.g. in Italy and Ireland) and self-dispatch (e.g. in Austria and Slovenia) arrangements of European electricity markets when drafting the Network Code on Electricity Balancing, but does not clarify this further [1][3]. Since the self-dispatch is not a requirement of the target model and central dispatch can operate efficiently in compliance with the target model, a co-existence of both models is demanded by the centrally dispatched Ireland [25] and it is currently considered by the actual NC EB. In their comments regarding the amendment of the NC EB stakeholders have commented that the central dispatch is not compatible with a harmonised Balancing Market [27].

In the present draft of the Network Code on Electricity Balancing the Transmission System Operators operating in Central Dispatch Systems can choose bids submitted by Balancing Service Providers for the Exchange of Balancing Services considering their technical availability and, if necessary, the TSOs convert these bids into standard products [3]. Complications can occur as participants in dispatching systems do have more information than participants in self-dispatching systems. The procurement of the balancing energy and the rules for updating balancing energy bids are regulated in Article 22 of the Network Code on Electricity Balancing.

The schematic sequence of cross border balancing in central dispatch systems is depicted in Figure 1. The BSPs - more correct the technical units - submit their bids to the TSO. Then, in an integrated dispatch process, the TSO examines the balancing need depending on the demand forecast and on the grid model. With the help of the grid model the internal congestions can be considered in the balancing need. The preliminary results are sent to the BSPs by the TSO and the BSPs adapt their schedules according to these preliminary results. In the meantime in the cross-border (xb) balancing mechanism the TSO submits the balancing demand and the balancing offers. The results of the activation optimization mechanism are sent to the TSO and to the BSPs that realize the balancing instructions. This activation optimisation mechanism considers the available cross-border capacity.

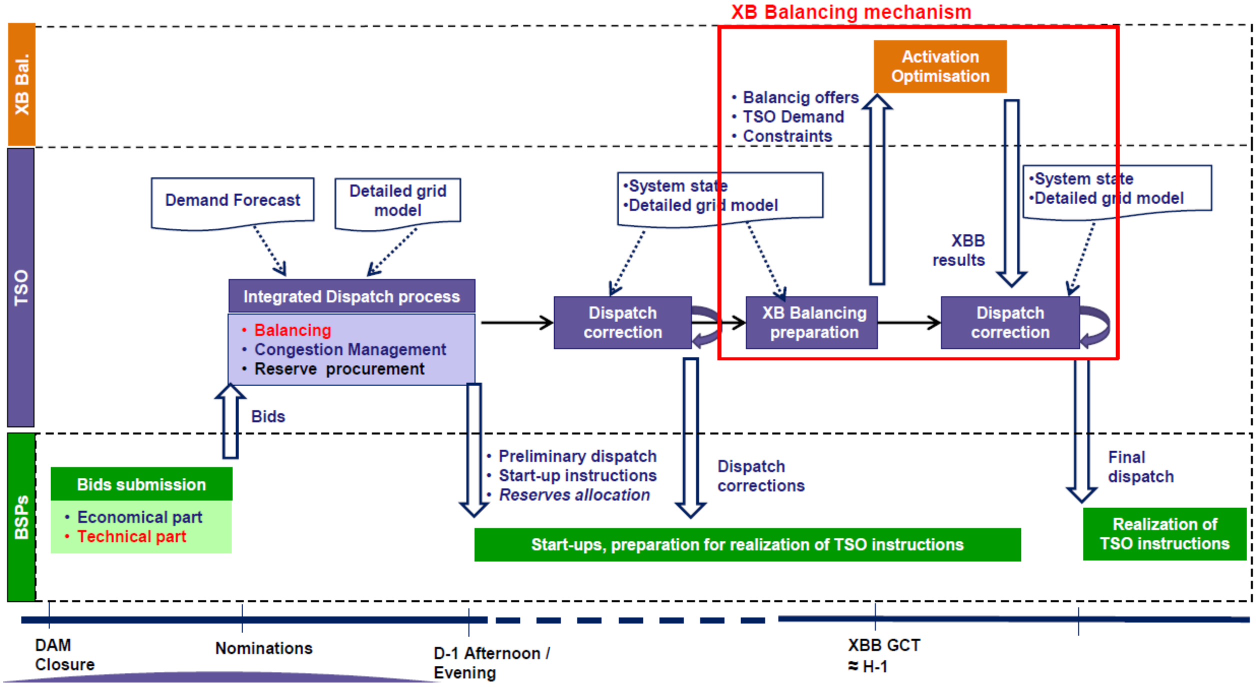


**Figure 10: Schematic sequence of cross border balancing in central dispatch systems [28]**

Each TSO of a Central Dispatch System can propose modifications for this updating process [3]. In cross border balancing a TSO operating in a central dispatch model acts as a BSP towards other TSOs [28].

### 3.2.2. Timing of Balancing Markets

The general sequence of the Balancing Market can be seen in Figure 11. At first the balancing capacity is procured and then the balancing energy is procured. The standard product defines the period during that activation is possible. After this, the activated balancing energy is evaluated in the technical monitoring and the final issue is the imbalance settlement. For simplicity only the timing of the Balancing Markets is considered in Figure 11 although the timing of the energy markets do currently influence the Balancing Markets.

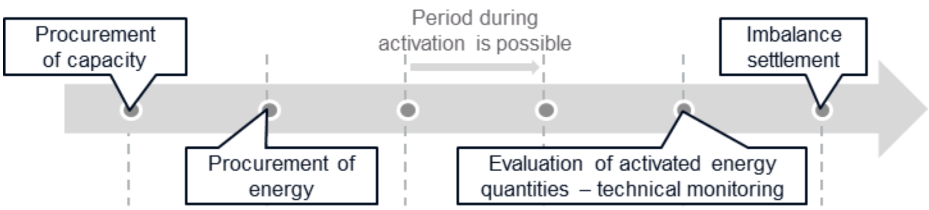


**Figure 11: General overview about the timeframes of balancing [29]**

The timing of markets contains the gate closure times of the different markets (see section 3.2.3), the procurement of the balancing capacity, of the balancing energy and the period during that activation is possible (see section 3.2.4) and the imbalance settlement period and the imbalance settlement (see section 3.2.10). The procurement of the balancing capacity and of balancing energy is currently in some countries at the same time (e.g. mFRR Slovenia), in other countries at different times (e.g. mFRR Austria). The period during that activation is possible will be defined by the TSOs of the coordinated balancing area.

### 3.2.3. Gate closure times

Relevant gate closure times are gate closure times of (i) Balancing Markets, of (ii) day-ahead and intraday markets, of (iii) communication - and therefore non-binding BRP’s energy schedules - and (iv) finalized and binding of BRP’s energy schedules.

For the fulfilment of the requirements of the Cross-border Balancing Target Model a proper harmonization of Gate Closure Times (GCT) of different Balancing Markets is very important. If they are not harmonized arbitrage and gaming possibilities exist.

Besides, the correlation between the GCT of Balancing Markets and other GCTs (e.g. Day-Ahead, Intraday) is of relevance. The NC CACM states that the GCT of Intraday Market shall be at a maximum of one hour prior to the start of the relevant Market Time Period [8]. According to [31] the BRPs should be given maximum opportunity to balance their own position, therefore, the GCT of the Intraday Market should be as close as possible to real time, including cross border intraday trading.

The preliminary energy schedules of BRPs have to be reported before the non-binding gate closure time (normally day-ahead after day-ahead gate closure time) and are finalized after the binding gate closure time (normally 24 hours to 30 minutes [32]). In [33] description of the correlation of all GCTs with the activities performed by both BRPs and BSPs is presented: During the Day-ahead market BSPs offer Balancing Capacity to TSO. After the GCT of Day-ahead Market the BRPs can no longer adjust their positions until opening of the intraday market. During the intraday market the BRPs can readjust their positions to balance their portfolios in light of the latest information and changes. By GCT of Intraday Market the positions of BRPs are final. During the Balancing Energy Market the BSPs can offer balancing energy bids to the TSO. All prequalified BSPs can participate, not only the pre-contracted reserves. Finally, by the GCT of the Balancing Energy Market the bids of BSPs for Balancing Energy are considered firm.

### 3.2.4. Products for balancing capacity and balancing energy

According to the NC EB there should be two separate tenders: one for the Procurement of Balancing Capacity and the other for the Procurement of Balancing Energy. Both of them should be split in upward and downward regulation (with separate Merit Order Lists). The bids for balancing energy can either have been placed together with the corresponding balancing capacity or have been selected during the Procurement of Balancing Energy.

**Timeframe of Balancing capacity**

The Procurement of Balancing capacity can be resolved by a single auction, where bids are placed and are, if accepted, valid for a pre-defined timeframe (year, month, week, …) or within a market, where the bids are placed in blocks (on a periodic basis) – the second method being closer to the FG EB [34]. The longer the difference between delivery period and period of bidding, the higher is the uncertainty for the BRP and the higher are the prices of balancing capacity [35][19]. The shorter the length of the balancing capacity product, the better it reflects the prices the actual values of the reserves and the lower is the hurdle for smaller participants as well as for VPPs. If the market for balancing capacity is cleared day-ahead and if the balancing gate closure time is after the gate closure time of the day-ahead market, the prices are generally lower without a huge additional risk surcharge, but a day-ahead balancing capacity clearing after the day-ahead market clearing implies a lower availability of balancing resources [35].

The timeframe of the balancing capacity will be limited to one month in the NC EB, although the national regulatory agency can approve a longer timeframe [30].

The frequency of bidding has not to be absolutely harmonized for cross border balancing, but the larger the differences the higher the possibility of gaming [36].

**Standardization of products**

The products of the Procurement of Balancing capacity are defined by a number of parameters such as quantity, minimum/maximum bid size and number and duration of activations. So far the rules of the Operation Handbook are applied by all countries [7], but still some important parameters vary significantly in the three countries Austria, Italy and Slovenia (see chapter 4) partly due to the different generation mix. The products of the three countries Austria, Slovenia and Italy differ in many parameters as can be seen in section 6.2.3.

According to [34] the FG EB has made it clear that in order to promote liquidity in regional markets for Balancing Services, and hence reduce costs to end consumers, and that they expect the Network Codes to define Standardised Products for Balancing Services that take account of available balancing resources and that in particular reflect the technical capabilities of demand and renewable generation. Therefore, in the NC EB it is defined that, when balancing products are diverse in different the LFC Areas in a coordinated balancing area, standard products between the LFC Areas are necessary to make trade possible. In the following the standard product is explained.

The timing of the standard products according to the NC LFCR can be seen in Figure 12. The *full activation time* is regulated in NC LFC-R and it contains the *preparation period* (2) and the *ramping period* (3). The *full delivery period* contains the *ramping period* (3), the *delivery period* (5) - the time during which the BSP delivers the full requested power to the system and the *deactivation period* (6). The *full activation period* and the *deactivation period* are relevant for the technical prequalification of market participants. For mFRR the *full activation period* and the *deactivation period* is maximal 15 minutes, but it can be lower according to technical requirements of the TSO.[3] The size of the *delivery period* is also of relevance; if it is long it will hinder some producers or consumers (especially small) to participate in the market, since they will not be able to delivery control service during all the time.  Also the *maximum* and especially the *minimum* quantity of single bids (4) can, for the same reason, hinder the participation of some entities. Possible increments between the minimum and the maximum quantity are not defined as part of the standard product.

Since the standard products have to be defined in a way that renewable sources, small-scale generation, intermittent resources and DR can participate in the balancing services market, the *divisibility* – the minimum divisible unit of Balancing Energy expressed in MW for the divisibility of volume and expressed in seconds for the divisibility of Delivery Period – can be seen as a key parameter. If it is adequately defined, it will give the opportunity to small fRES and small consumers to present bids that can be, if necessary, quantitatively and timely partitioned. The standard product should also permit that a baseline approach (refer to section 1.3.2) could be used for DR.

The full activation time is one main minimum requirement that has to be ensured by the VPPs to take part in providing different ancilliary services; the minimal time requirement can be seen in section 1.3.1 for the region of Central Europe. Depending on the composition of the VPPs the full activation time is influenced. The shorter the full activation time of the VPPs the more ancillary service they can provide (e.g. take part in FCR, aFRR, mFRR).

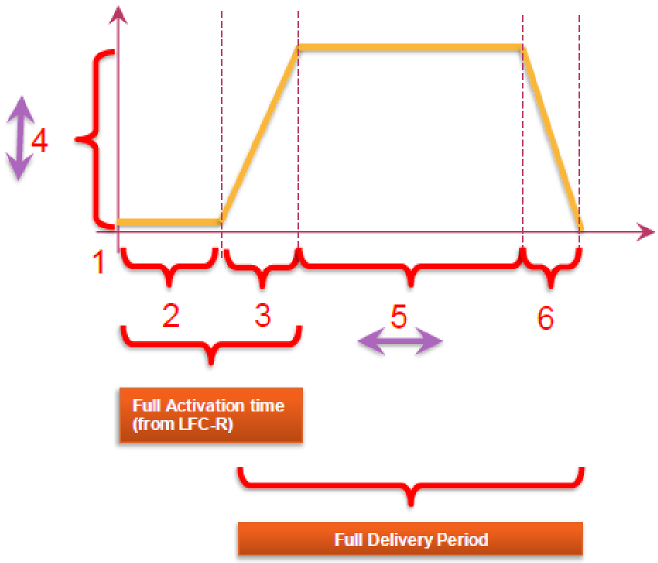


**Figure 12: Description of a standard product [8]**

Specific, non-standardized products will be further allowed, but the TSOs have to to get official approval by the relevant national regulatory authority (e.g. E-Control in Austria). The specific products of a central dispatch market can be converted by the TSO into standard products as mentioned in chapter 3.2.1.

It is also possible that an ancillary service (e.g. FRR) can be separated in different products, which can vary by one or more of the above mentioned parameters (e.g. full activation time). This separation can facilitate the participation of both conventional generators, but also of demand and intermittent generators such as RES [34]. The co-existence of these different products can be achieved by the application of sophisticated algorithms, which need to enable their usage in the same merit order list, in a transparent, fair and adequate way. If these algorithms are robust and powerful enough, they can even provide a possibility of coupling different Balancing Markets whose products are not 100% harmonised.

### 3.2.5. Accreditation of BRPs and BSPs

If the accreditation procedure and legal, economic and technical requirements of BRPs and BSPs vary significant the cross-border trading of balancing energy is possible in principle, but (foreign) market participants can be excluded [36]. The requirements should only be strict enough to ensure that BRPs can submit schedules and pay their imbalance costs - but not stricter than that - to keep the entry barriers as low as possible [19].

The Balancing Markets should allow the participation of conventional generators as well as renewable generators, storage and load [31]. Thereby, more participants are able to take part in the Balancing Markets and the competition increases. It is therefore strongly recommended to harmonize the accreditation of BSPs in coordinated balancing areas in a way to enhance the participation of VPPs.

If the TSO is allowed to possess own balancing capacity on a regular basis, this leads to market distortions in a Balancing Market. Hence, the use of own balancing capacity should be harmonized between countries and strictly regimented by the ENTSO-E. In the current draft of the NC EB the TSO is only allowed to offer balancing services, if there are insufficient bids or if it is foreseen in national law. The market distortions decrease with a small use of TSO own balancing services, therefore the first point will not induce large market distortions. But the exception for single countries should be deleted to ensure a “fair” market.

### 3.2.6. Procurement mechanism

The procurement mechanism can be an obligation (e.g. in Italy), self-procurement and bilateral contracts (e.g. in Slovenia), a tendering process (e.g. in Austria) and a spot market (see Chapter 4). Moreover, the TSO could own balancing resources itself. Depending on the procurement mechanism it is expected that the offered quantities, the submitted bid prices and the quality of the services varies [19].

Table 2 summarizes, for each procurement method, some of the advantages (+) and disadvantages (−) as in [37]. This grading is subjective and thus may change from one market participant to another. Moreover, advantages and disadvantages will be affected by the duration of the contracts and depend on the specific situation (e.g. threat of an abuse of market power, availability of resources, etc.). Furthermore, the importance of each parameter varies across jurisdictions (e.g., a market designer may give more importance to a procurement method that facilitates entrance of new participants, whereas another designer may prioritize market transparency).

**Table 2: Parameters Influencing the Choice of AS Procurement Method [37]**

| | Compulsory Provision | Self-Procurement | Bilateral Contracts | Tendering Process | Spot Market |
|---|---|---|---|---|---|
| Mitigate the influence of dominant players | +++ | +++ | + | −− | −−− |
| Facilitate entrance of new AS providers | + | −−− | −/+ | ++ | +++ |
| Hedge against risk | ++ | ++ | +++ | + | −−− |
| Lower transaction costs | ++ | + | − | − | − |
| Secure enough AS | +++ | +++ | +++ | +++ | + |
| Increase global welfare | −−− | −− | + | ++ | +++ |
| Increase market transparency | +++ | −− | −− | + | +++ |
| Recognize the externality of AS | −−− | − | +++ | +++ | +++ |
| Integrate demand response as an AS | −− | +++ | +++ | ++ | + |

The compulsory provisions lead to a higher availability of resources, but the quality of the services may suffer. A serious shortcoming of an obligation is that the global welfare is low in comparison to other mechanisms. According to [31] no need for mandatory balancing schemes exists, when Balancing Markets are attractive. A compulsory provision should be favoured only in case that system security is endangered or that the potential of market abuse is extremely high.

If the TSO owns resources on its own, the danger exists that the TSO favours its resources, which leads to unintended market distortions. Bilateral contracting diminishes competition when compared to tendering, but in case of market power of single participants it may help to avoid the abuse of market power [19]. In general it can be concluded that the most favourable procurement mechanism is tendering, because BSPs compete with each other to “offer cheap and high-quality” resources [19].

The NC requires that for the procurement of Balancing capacity there should be a separate tender. According to the NC the tender should be split in upward and downward regulation. The NC states that fall back procedures should be available in case the procurement of Balancing capacity fails. In this case TSOs may have an additional procurement process (e.g. second auction round) to achieve market based contracting to the greatest extent. To ensure transparency, market participants should be informed before TSOs use such fall-back procedures.

### 3.2.7. Activation mechanism

There are basically two methods for the activation of balancing energy: pro-rata and the merit order activation mechanism. In the pro-rata approach all bids are activated simultaneously and in proportion to the actual balancing need. In case of a merit order activation mechanism the available sources of energy are ranked in ascending order of their submitted bids, so that those with the lowest bids are activated at first. Figure 13 shows an example of the difference between a pro-rata and merit order activation mechanism of 60% of aFRR, where TSO A activates with a pro-rata and TSO B with a merit order mechanism. TSO A activates all the bids pro-rata, in this case the actual balancing need is 60%, and therefore every bid is activated with 60%. TSO B activates the bids one by one until the 60% total balancing need is reached. The merit order activation mechanism is the only one that is supported by the NC EB.

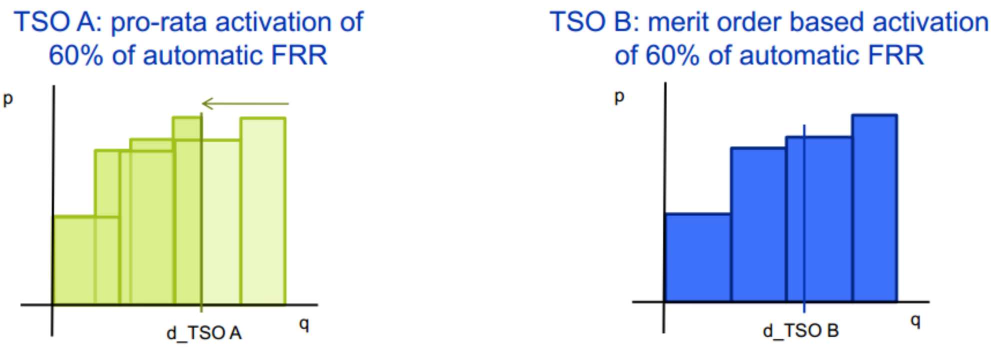


**Figure 13: Pro-Rata and Merit Order activation mechanism - example aFRR activation of 60% [21]**

### 3.2.8. Pricing mechanism

In markets, where participants have perfect knowledge, both auctions - marginal and pay-as-bid - would lead to similar results [20]. But in real markets, participants of pay-as-bid auctions try to guess the marginal price and to bid as close as possible to the marginal price. This can lead to pricing and dispatching inefficiencies [38]. Therefore, marginal pricing has some advantages as higher transparency, definite clearing price and no relative benefits (especially for big market participants) through information advantage or the use/abuse of market power. Furthermore, marginal pricing provides a fair and market-based incentive for BRPs to balance their portfolio. This is why institutions as for example EFET and EURELECTRIC (both 2012) support marginal pricing to be implemented by the NC EB [39][40]. In the current version of the NC EB marginal pricing is the favoured method until TSOs prove existing benefits by pay-as-bid pricing.

The pricing mechanism has also an impact on imbalance pricing. In case pay-as-bid is implemented imbalance prices are based on average prices, in case of marginal pricing the imbalance price is based as well on marginal prices [41].

If pricing mechanisms are not harmonized in a coordinated balancing area, this can lead to considerable inequality between countries [36].

### 3.2.9. Information feedback and penalty payment

To reach Balancing Market efficiency the design of the feedback - what to publish and when - is important [19]. Information is needed to allow the participants to estimate the marginal price and to bid more effectively and therefore to induce more competition. But if too much information is published, BRPs can use this information to bid strategically and to abuse market power [42]. The publication of marginal prices close to real-time allows BSPs to optimize their short term bidding strategy [19].

The publication of real-time information as the area control error and of the imbalance prices allows BRPs to control their imbalances depending area control error. The closer to real-time this information is published the more the BRP can actively take part in balancing the control area (as a sort of competition to balancing [19]).

### 3.2.10. Imbalance settlement

The imbalance settlement is a financial settlement mechanism aiming at charging or paying BRPs for their Imbalances. Therefore, a well-designed imbalance settlement gives an incentive to BRPs to balance their positions over commercial trading (day-head and intraday) and not wait until the real-time. Hence, the area control error and the costs for balancing services are reduced.

The imbalance settlement does not balance the system; it is an ex-post mechanism for defraying the costs of balancing and at the same time incentivising good contracting and short term planning behaviour on the part of BRPs [34]. The outcome of the Imbalance Settlement should be financial neutral for the TSO, enable fair and equal distribution of energy cost/benefit and avoid perverse incentives, like BSP non-delivery, BRP gaming, TSO free riding [23]. If the frequency of imbalance settlement is different in a coordinated balancing area this may result in uncertainty about final positions [36]. This is not the most important design variable to be harmonized. But in general it is better to have a higher harmonization level.

For the imbalance settlement all market participants should be treated equally; there should be no exception for fRES or demand as for example in Italy. The balancing need is associated with the responsible party (e.g. the wind energy plant is held responsible for forecasting errors). Due to this investments in more precise forecasts and in flexibility options as for instance storage applications are encouraged.

Based on imbalance settlement prices and on the difference between the notified positions of BRPs and their actual profile, the imbalance costs are calculated. Therefore each BRP should have information about accurate estimation of its imbalance from the TSO [43], besides the area control error and the imbalance prices should be published close to real-time. This publication rules for the imbalance should be harmonized to avoid different treatment of market participants [36]. To avoid instability caused by overreaction - triggered by publication short before real-time - there could be an option implemented to switch to dual prices in case it is necessary as dual prices give an incentive to the BRP not to act to balance its imbalance [20].

Regarding specifically to DR, there should be means available to compute the baseline (refer to [14][13]) in the imbalance settlement, which is an estimation of the electricity that would have been consumed by a customer in the absence of DR event, since customers should receive credit for the curtailment they actually provided.

**Imbalance settlement period**

One key aspect in this subject is the Imbalance Settlement Period; which according to the FG EB should not exceed 30 minutes (the NC EB though does not restrict it). There are several different imbalance settlement periods (e.g. 15 minutes, 30 minutes, 60 minutes…). A longer imbalance settlement period does not incentivize the BRPs to follow the notified positions, since only the average imbalance amount will be used as input for the calculation of the financial imbalance price. In this matter the measurement resolution interval plays an important role as the actual profile from BRPs is necessarily shorter than the imbalance settlement period, which means that, shortening the imbalance settlement period requires also a shortening of the measurement resolution. Some smart meters for example use 15min measuring interval (others one hour). Consequently the duration is a compromise between the metering possibilities and the necessity of the Balancing Markets. Currently a settlement period of 15 minutes seems to be the suitable solution [20].

The Monitoring of the imbalances is done by the TSOs. According to [34] TSOs need to submit information regarding the imbalance price per imbalance settlement period; the imbalance costs faced by each market participant per imbalance settlement period; imbalance volumes per market participant and imbalance settlement period; RES imbalances volumes and corresponding costs; Surplus/deficit in imbalances settlement account and deviations from the merit order list to alleviate congestions internal to a control area.

**Imbalance calculation and balancing responsibility**

The calculation of the imbalances consists on calculation of the difference between the notified positions of BRPs and their actual profile. When calculating the imbalances the scheduled positions, the metered data and the activated balancing energy shall be considered according to the NC EB. Differences in the calculation of imbalances may result in a migration of imbalances from the country with the more stringent imbalance calculation to another one [20].

Furthermore, the consideration of the geographical diversification of balancing responsibility - if it is a zonal or nodal (e.g. in Italy) system - is important; specific rules are needed between countries with different systems. Nodal responsibility gives a more specific incentive for a BRP to be balanced, and thereby leads to “unnecessarily high imbalance costs” [19].

The possibility of ex-post trading of imbalance energy after real-time reduces the imbalance volumes as well as the costs for BRPs and the incentive to be balanced [19]. Therefore, if this possibility is implemented it should be harmonised in a coordinated balancing area.

**Imbalance prices**

The final part of the imbalance settlement is the calculation of the imbalance prices, which should provide a clear price indication for the market participants, motivating them to better coverage their daily consumption diagram [ENTSO-E]. Different imbalance pricing in a coordinated balancing area can result in inequality and distortions [36]. The imbalance price can be composed of a basic price and of additional components. The basic price can be either related to the average or marginal costs of balancing or to the respective wholesale market price. In [20] it is recommended that no non-market based components as penalties (e.g. variable components of the imbalance prices) or power exchange prices should be used. This is in favour for fRES as (i) the imbalance prices are lower without penalties, (ii) especially the costs for fRES can be reduced - given that high imbalances of fRES are correlated with the a higher control area error and that the imbalance prices are lower without penalties, and (iii) conventional, adjustable generators can easier avoid short-term penalties [20].

Two possibilities exist for defining the imbalance prices: either single pricing or dual pricing. If the imbalance price is the same for each direction - negative and positive - of the imbalance of the BRP it is a single pricing approach. In case dual pricing is applied different prices are used for the BRPs depending on the sign of their imbalance. The price in the dual pricing approach is often linked to the price of the power exchange. While dual imbalance pricing provides better incentives for good forecasts, it is disadvantageous for unpredictable fRES (like wind power); on the other hand single imbalance pricing seems to be a fairer option in a Balancing Market as it rewards balanced BRPs. Furthermore, single pricing allows a growing participation of fRES and demand. As can be seen in [39] and [34] there is a tendency to favour single imbalance pricing. In [19] an agent-based analysis was performed that also supports single pricing as the leading pricing regime. Besides that, single imbalance prices avoid that BRPs perform “gaming” by applying planned deviations from the schedule or by minimizing the imbalance instead of eliminating it, which is not beneficial for the system stability. It is also important that the same imbalance prices are applied to both load and generation [39]. In cross-border balancing different pricing mechanisms as single/dual can be the reason for gaming possibilities and inequality [36].

Furthermore, the imbalance prices are influenced by the allocation of balancing service costs (capacity as well as energy).

Four options exist how **balancing capacity** costs can be allocated according to [19], whereas the first option can be seen as the option with the least negative effects:

- Adaptation of system service tariff - could be discriminatory if only paid by costumers and it does not affect the behaviour of the BRPs
- Assignment to BRPs by separate tariff - proportional to BRP (size, fixed, or proportional to imbalances)
- Assignment to BRPs by reserve obligation of BRPs (proportional to their size) - no incentive for the BRPs to acquire high-quality resources; lower utilization and price efficiency; high costs in case of large number of small BRPs
- Assignment to BRPs by adaptation of imbalance prices - influences the incentive of BRPs to be balanced; incentive to BRPs to keep own balancing resources; it will lead to higher balancing

accuracy, but to lower cost allocation efficiency and to lower utilization efficiency and therefore to higher balancing costs

The allocation of balancing capacity costs can influence the imbalance prices; therefore, if different rules exist in the coordinated balancing area the incentives to BRPs would differ. Harmonization is not necessary, but valuable.

**Balancing energy** can be used on the one hand to balance the system and on the other hand to relieve grid constraints. To give correct incentives to BRPs it is important to make this differentiation in the distribution of the costs to either individual users (BRPs) by the imbalance settlement or to remunerate it by grid tariffs [31]. For instance in Austria the costs of mFRR are remunerated by individual users, but the costs of aFRR are split between grid tariffs and BRPs.

The costs of the internal congestion management could be paid through a system service tariff to reflect real BRP imbalances in the imbalance price. When calculating the imbalance prices the internal congestion management has to be subtracted out otherwise the imbalance price gives the wrong incentive to BRPs [20]. For the implementing of cross-border balancing it would be beneficial that the allocation of internal congestions to either imbalance costs and with this to BRPs or to grid tariffs is harmonized. Otherwise the imbalance price would be different in the coordinated balancing area and this would give deviating incentives to BRPs.

### 3.2.11. Linkages with wholesale markets

A liquid intraday market can reduce the impact of distortions in the Balancing Markets [20]. Therefore, a well-developed intraday market is a helpful condition for Balancing Markets as on the intraday markets BRPs can balance themselves. But balancing services should be more expensive than those on the wholesale markets to make Balancing Markets more attractive than the power exchanges [20].

On the energy markets negative prices have positive effects for the integration of renewable energies as they send price signals to flexibility providers and they encourage renewable energy providers to react to system conditions.

# 4. Selected national Balancing Markets

In this chapter the relevant aspects from the Austrian, Slovenian and Italian Electricity Systems for the Project eBADGE are analysed. These include the regulatory framework of their Balancing Markets (with emphasis on the mFRR) and the prequalification requirements for the market participants; especially in what regards the participation of Virtual Power Plants. Table 3 shows a comparison of the terminology used in the three considered countries.

**Table 3: Comparison of terminology for Product Names**

| | | Austria | Slovenia | Italy |
|---|---|---|---|---|
| **Balancing** | Time Unit | Accounting Period | Contractual Period | Significant Period |
| **FCR** | Product | Primary Control | Primary Frequency Control | Primary Power Reserve |
| **aFRR** | Product | Secondary Control | Secondary Power Reserve | Secondary Power Reserve |
| **mFRR** | Product | Tertiary Control | Tertiary Power Reserve | Tertiary Power Reserve |
| **RR** | Product | - | | |

For the analysed markets a comparison between it and the national market-based TSO Balancing Model (Model 1 as of Deliverable 2.1) is performed in section 4.4.

## 4.1. Balancing Markets in Austria

### 4.1.1. Regulatory framework of Balancing Markets

Relevant institutions in Austria are the energy regulator “E-Control”, the APCS Austrian Power Clearing and Settlement AG, the Transmission System Operator APG Austrian Power Grid, and the power exchanges EXAA (Vienna, Austria) and EPEX (Paris, France). In Austria electricity can be traded on the electricity exchanges or on the over-the-counter (OTC) market bilaterally. In Figure 14 an overview of the gate closure times of the energy markets in Austria is given. In the following the day-ahead and the intraday market are briefly explained, whereas the Balancing Market are analysed in more detail.

Figure 14 depicts an overview of the most important market timeframes in Austria, including the different gate closure times for different activities. This overview includes the energy exchange for day-ahead and intraday, the procurement of balancingcapacity and balancing energy for mFRR, the imbalance settlement as well as the day-ahead and intraday cross-border capacities from Austria to Slovenia (AT > SI) and to Italy (AT > IT).

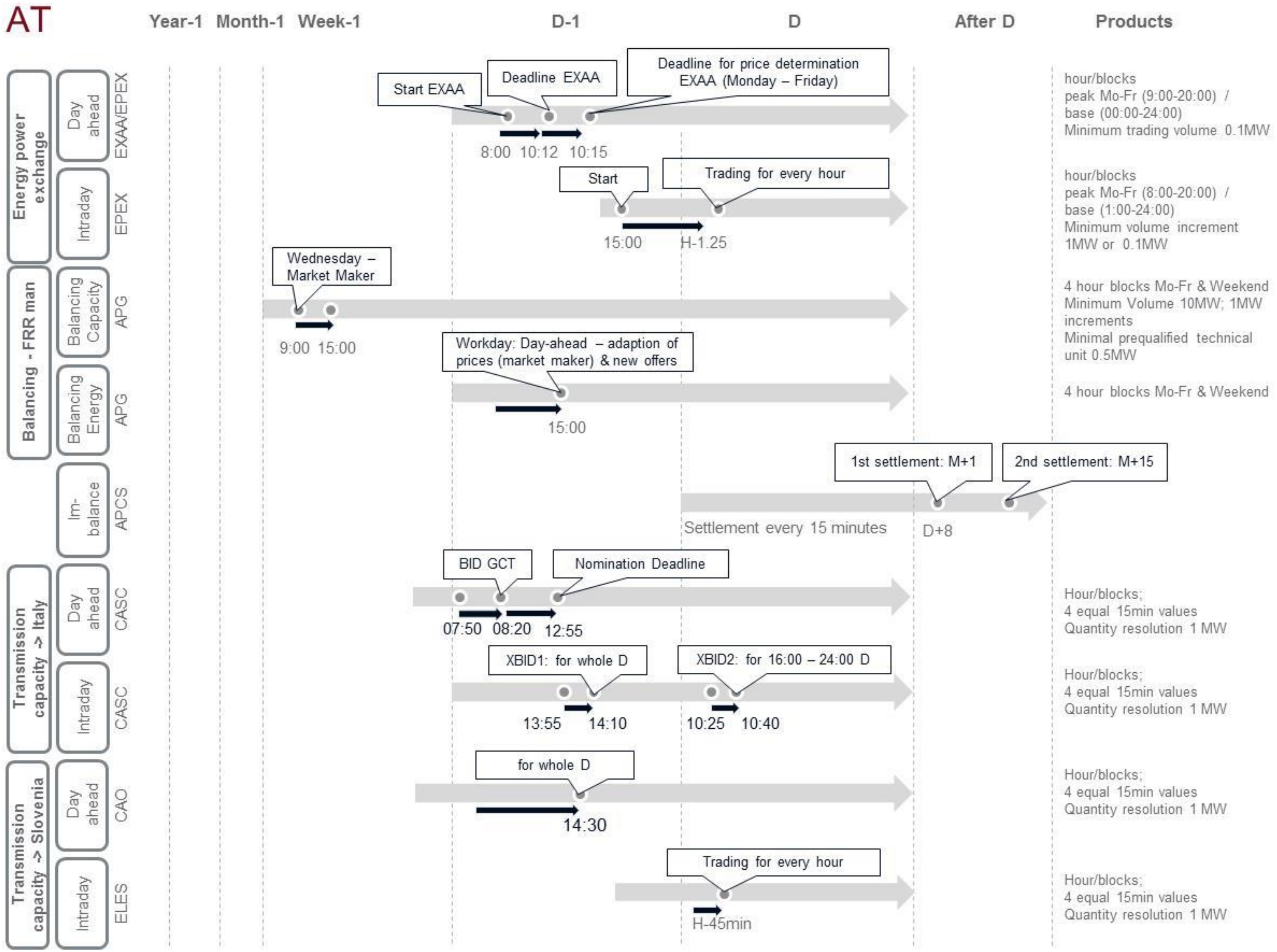


**Figure 14: Overview about the gate closure times of the energy markets in Austria**

**Day-ahead and intraday market**
Two power exchanges are relevant for the Austrian market players: the EPEX based in Paris, France, and the EXAA based in Vienna, Austria. At the EPEX a day-ahead and intraday spot market and at the EXAA a day-ahead spot market is situated.

No congestions limit the trade of electricity between Austria and Germany and thus, no auction of the capacity is needed [44]. Electricity for Austria can be traded on the **EPEX Spot** as well for the day-ahead and the intraday timeframe. The details for the relevant markets of the EPEX Spot are shown in Table 4 and in Figure 14.

On the power exchange **EXAA** the day ahead spot market is situated and electricity can be traded for the countries Austria and Germany. The details of the market are shown in Table 4. The relevant intraday market place for Austria is the EPEX Spot. The details of the intraday market are listed in Table 4 and in Figure 14.

**Table 4: Overview about the power exchanges EXAA and EPEX Spot – day ahead and intraday [45][46]**

| | EXAA Day-ahead | EPEX Spot Day-ahead | EPEX Spot Intraday |
|---|---|---|---|
| **Gate-closure time** | 10:12 | 12:00 | H-75 |
| **Minimum volume [MW]** | 0.1 | 0.1 | 0.1 or 1 |
| **Increments [MW]** | 0.1 | 0.1 | 0.1 or 1 |
| **Price range [€/MWh]** | 0[4] – 3000 | -3.000 – 3.000 | -9 999.99 – 9 999.99 |
| **Max volume block bid [MWh]** | 1000 | 400 | - |

On this power exchange EXAA no negative prices are allowed, but negative prices can have positive effects[5]. They are an important indicator for the supply-demand equilibrium and they send a price signal to flexibility providers. Until September 2013 it will be analysed if negative prices should be implemented for the Swiss day-ahead market [47].

**Balancing Markets**
Since 2012 the Balancing Markets in Austria are coordinated in one control area and the tendering is done in a harmonized approach for all Balancing Markets by the TSO APG (from 2010 for primary control and from 2012 for both secondary and tertiary control).

**Table 5: Overview about primary, secondary and tertiary control in Austria [48][49][50][51]**

| | Primary Control (FCR) | Secondary Control (FRR auto) | Tertiary Control (FRR auto) |
|---|---|---|---|
| **Explanation** | Control of frequency deviations in the ENTSO-E grid | Control of frequency deviations and xb-exchange in the control area; supersedes the primary control | Control of frequency deviations and xb-exchange in the control area; supersedes the secondary control |
| **Time to full activation/ deactivation** | <30 sec | <5 min | <10 min |
| **Tendered quantity** | The primary control amounts to +/- 66 MW in Austria for the year 2013 | For the year 2013 +/-200 MW are required for secondary control | The tertiary control is +280/-125 MW for the year 2013 |
| **Minimum offer** | The minimum offer is a band of +- 2 MW; after this steps of +/- 1 MW are possible | The minimum offer is +/-5 MW; then steps of +/-5 MW | The minimum offer is +/-10 MW[6], for the second offer it is 25 MW; then steps of 1 MW |
| **Minimal prequalified technical unit** | +-2 MW | >2 MW | >0.5 MW |
| **Period** | 1 week | 1 week / 4 weeks | 1 week |
| **Products** | | Monday-Friday peak (8 | Monday-Friday & |

[4] Was changed recently
[5] Was changed recently
[6] The minimum offer will be reduced to 5 MW as soon as the MOL-server is implemented [52].

| | | | |
|---|---|---|---|
| | | am -8 pm) & off-peak & weekend | weekend 4h blocks Distinction between Marketmaker (with procurement of balancing capacity) and Day-ahead (without procurement of balancing capacity) |
| **Start/end of tendering period** | Wednesday 09 am to 2 pm | Tuesday 09 am to 2 pm | Marketmaker Wendesday 09 am to 2 pm |

**Imbalance Settlement**

The Austrian imbalance settlement is regulated in detail in [53]. The settlement is performed by the APCS Power Clearing and Settlement AG. The relevant time-series have to be delivered by the responsible party to the APCS for the calculation of the imbalance:

- system operator: external time schedules & called primary, secondary and tertiary balancing energy
- coordinator of the BRP: internal time schedules
- grid operator: values of the metered load profiles & values of synthetic profiles of loads and generators & metered values of grid coupling points

These time-series have a resolution of the **imbalance settlement period** of 15 minutes [54].
In Austria two imbalance settlements are performed. In the **first settlement - calculation of the imbalances -** the imbalance of all Balancing Responsible Parties (BRP) is calculated eight days after the end of the relevant month on a monthly basis. The imbalance volume for the first settlement is calculated according to Eq. 1 [55].

$$IMt = (ECt - EPt) + (PSt - SSt) \qquad \text{Eq. 1}$$

$IMt$: $Imbalance\ volume\ of\ BRP\ in\ t\ [MWh]$
$ECt$: $Energy\ consumption\ of\ BRP\ in\ t\ [MWh]$
$aggregated\ meter\ readings + aggregated\ synthetic\ load\ profiles$
$EPt$: $Energy\ production\ of\ BRP\ in\ t\ [MWh]$
$aggregated\ meter\ readings + aggregated\ synthetic\ load\ profiles$
$PSt$: $Purchase\ schedule\ of\ BRP\ in\ t\ [MWh]$
$internal + external\ schedules$
$SSt$: $Sale\ schedule\ of\ BRP\ in\ t\ [MWh]$
$internal + external\ schedules$

The **imbalance price for the first settlement** is a single price[7] comprising two components and it is calculated dependent on the imbalance level of the control area ($V_t$) for each settlement time unit of 15 minutes. The principle of the calculation of the imbalance price can be seen in Figure 15.

The first component is the *basic price* (orange line). It is calculated depending on the sign of $V_t$. In case of a positive/(negative) $V_t$ not enough/(too much) energy is in place in the control area. If $V_t$ is positive/(negative), the basic price is the maximum/(minimum) value of either the price of the day ahead power exchange EXAA or the market price of balancing of the respective 15 minutes. Hence, the calculation of the imbalance settlement price is Austria rewards the BRP in case it supports the control area.

The second part of the imbalance price is a *variable component* that is influenced by the deviation of the control area. Thus, the larger the imbalance of the control area the higher the imbalance settlement price gets.

The *clearing price* is the sum of the basic price and the variable component. The detailed formulas can be found in [53].

[7] The same price applies for all BRPs and the price does not change if the BRP is supporting the control area or not.

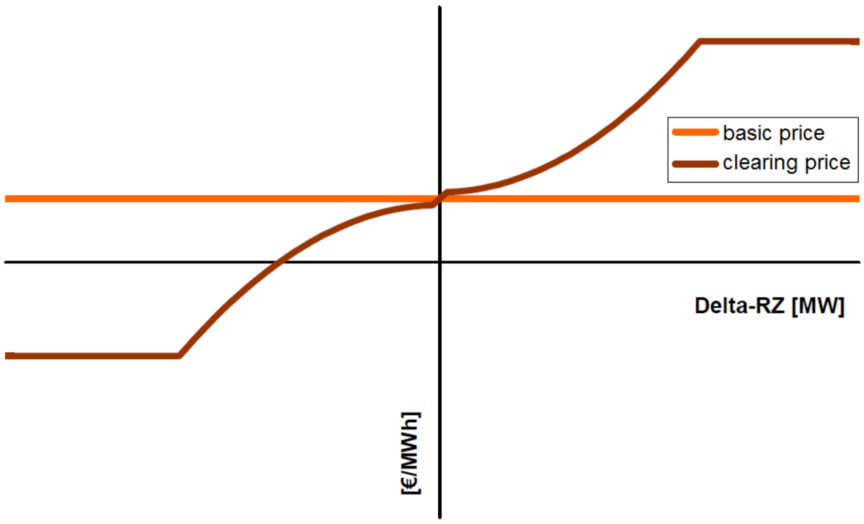


**Figure 15: Calculation of the imbalance price [55][53]**

Since the imbalance clearing is done and the deviation of the control area is published 15 minutes ex-post, the BRP cannot be sure if it supports the control area. Therefore, the BRP has an incentive not to deviate from its schedule.

In the **second settlement** a correction for the real consumption/production of smaller consumers/producers is conducted. For smaller customers/producers with a lower power rating than 50 kW and a lower yearly consumption/production of 100.000 kWh synthetic load/production profiles are calculated by the TSO to save costs (§ 17 (2) ElWOG 2010). The calculation of these different synthetic load and production profiles is regulated in [56]. Furthermore, in the second settlement other changes are taken into account - for example customers who were switching to another supplier - and, thus, these deviations are corrected ex post. The **imbalance price** for the second settlement is therefore a monthly value.

**Excursus: Implication of balancing request on imbalance settlement**
In the following it is shown what happens in case of a request for positive tertiary energy. The ramping period influences the imbalance volume of the BRP. During the delivery period the balancing request has no impact on the imbalance volume.

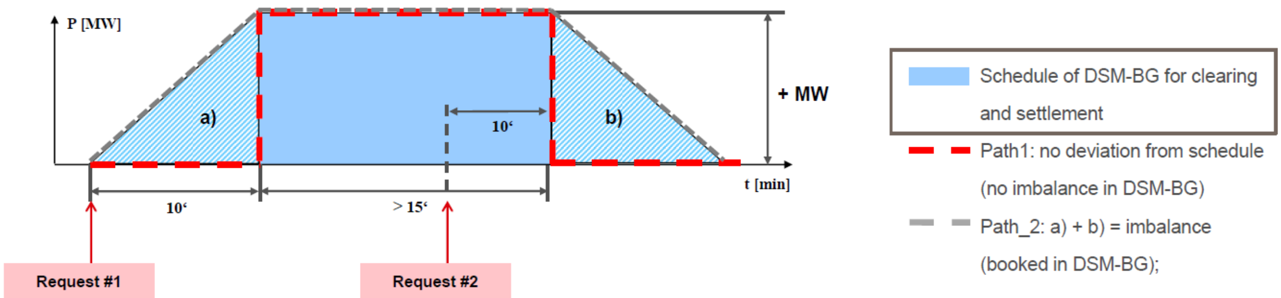


**Figure 16: Example of a tertiary balancing energy processing request and the implication for imbalance calculation [57]**

### 4.1.2. Prequalification

Each supplier can take part in the Balancing Market if it fulfils the technical as well as the organizational requirements [58]. The prequalification has to be done separately for primary, secondary and tertiary control.

**Technical Requirements**
An overview about the technical requirements is given in Table 6.

**Table 6: Overview about the technical prequalification of primary, secondary and tertiary control in Austria [48][49][50][51]**

| | Primary Control (FCR) | Secondary Control (aFRR) | Tertiary Control (mFRR) |
|---|---|---|---|
| **Explanation** | Control of frequency deviations in the ENTSO-E grid | Control of frequency deviations and xb-exchange in the control area; supersedes the primary control | Control of frequency deviations and xb-exchange in the control area; supersedes the secondary control |
| **Time to full activation/ deactivation** | <30 sec | <5 min | <10 min[8] |
| **Start/end of tendering period** | Wednesday 09 am to 2 pm | Tuesday 09 am to 2 pm | Marketmaker Wendesday 09 am to 2 pm |
| **Minimum gradient** | +/- 200 mHz evenly distributed within 30 sec | +/- aFRR in 5 min & 2% of nominal power | +/- mFRR in 10 min |
| **IT protocol** | IEC 60870-5-104/101 | IEC 60870-5-104/101 | IEC 60870-5-104/101 |
| **Monitoring** | Ex-post | Real-time (15 min) / ex-post | Ex-post |
| **Participation of DR** | Not defined | Not defined | Not defined |
| **Participation of fRES** | Not defined | Not defined | Net defined |

The prequalification has to be done for every unit and it is not sufficient to prequalify a pool (e.g. VPP; see chapter 4.1.3). A unit has to show in the prequalification process that it is possible to react in the defined time to several requests of the TSO, in this case to two processing requests of 20 MW negative mFRR. This prequalification is valid for a period of three years; afterwards it has to be renewed [51].

**Organizational Requirements**
After successful technical prequalification a framework agreement has to be concluded between the BSP and the control area manager APG. Hereafter the BSP is accredited and has access to the tendering process.

### 4.1.3. Considerations for VPPs

The **minimum size** for the participation in tertiary control is currently 10 MW [51]. In the beginning of 2014 an automated activation of the tertiary control (MOL-Server) will be implemented in Austria and therefore the minimum unit size will be reduced to 5 MW [52]. The smaller the minimum size the easier VPPs can participate in the market, therefore the reduction is very valuable for an implementation of VPPs.

**Pooling** is allowed for technical units with a size of at least 0.5 MW (minimal prequalified technical unit) [51]. There are no specific regulations for the prequalification of DR, yet. Pooling of facilities from different BRPs will be possible at the latest by 2014 [52].

The **requested capacity** has to be fully available after a period of 10 minutes after receipt of request. Time-delays resulting from longer communication lines/ways in a VPP have to be included in this period.

But the **prequalification** has to be done separately for each technical unit [51]. This is time-consuming and costly if done for smaller technical units. In Germany the prequalification can be done for a pool and has not to be completed for the single unit [59]. It is planned by APG to implement this pool approach as well. The prequalification is valid for a period of three years; thereafter the prequalification has to be repeated [51].

[8] This time-period is shorter than usually in Europe.

**DR and fRES** are not excluded from the tertiary control, but they are neither particularly included; for instance no special prequalification criteria is defined. This would be very beneficial for the implementation of VPPs. The balancing capacity has to be delivered with n-1 security. A discussion about reliability margins and an implementation would be beneficial for the participation of fRES in Balancing Markets.

The **metrological connection** for mFRR has not to be redundant and can be done via the IEC 60870-5-101 or IEC 60870-5-104 protocol. For aFRR it has to be redundant.

The **monitoring and verification** is done via online values of the pool with a resolution of at least one minute (e.g. current power, activated power for tertiary energy). These data and the values of the technical unit (current power, current Q-point of the pool) have to be archived for 6 months in a resolution of 15 minutes. For the implementation of the VPP it is an advantage that the online data have to be available just for the pool and for the technical unit. This point influences the costs of the connection. Specifically regarding DR no baselines are defined yet for real time and/or ex-post verification of activation.

The tertiary control **products** consist of 4 hour blocks. This short timeframe is beneficial for the implementation of VPPs. The products have to be available for a timeframe of five or two days (either from Monday to Friday or from Saturday to Sunday). The gate-closure for tertiary capacity is on Wednesday in W-1 (market maker tender). Day-ahead energy prices of the bids that have been accepted in the market maker tender can be adapted in favour of the TSO. New tertiary energy offers can be submitted, but new offers get no remuneration for the provision of tertiary reserve. For the VPP a gate-closure for the procurement of balancing capacity near to real-time is positive since at that time more information and a better forecast are available. Participating only in the Day-ahead tertiary Balancing Market is an option but a less interesting one since no remuneration for the balancing capacity is paid. For VPPs it would be an opportunity if gate-closure time and the tertiary reserve product timeframe would be closer to real-time. For instance in Germany the tendering is done day-ahead for a timeframe of one day. According to APG this is currently not possible in AT as mFRR is used to cover the outage of the biggest unit.[9]

Excursus: Harmonized and smaller increments (ticks) of **power exchange products** enhance the participation of smaller participants and it allows a better adjustment of the BRP-schedules to reduce balancing needs.

## 4.2. Balancing Markets in Slovenia

### 4.2.1. Regulatory framework of Balancing Markets

The electricity market in Slovenia is hierarchically arranged into a Balance Scheme. The Balance Scheme is maintained by the Power Market Operator (Borzen), with whom Balance Responsible Parties (BRPs) conclude Balancing Agreements in order to be included in the Balancing Scheme. Any legal or natural person that wishes to actively operate on the electricity market must become a member of the Balance Scheme, as a Balance Group (BG) or Balance Subgroup (BSG). Balance Subgroups conclude a Compensation Agreement with a Market Participant who is already included in the Balance Scheme. Balance Scheme Members can buy or sell energy according to volumes contracted in advance [60].

Borzen is responsible for preparing the legal framework and for the market operation. The Transmission System Operator (ELES) is responsible for the balancing by buying and selling electricity for the settlement of imbalances in the electricity system. In implementing the Balancing Market, Borzen co-operates with the BSP SouthPool energy exchange, which offers a trading platform for the implementation of the Balancing Market with all necessary functionalities [60].

[9] Comparison of the mFRR Balancing Market to Germany: In Germany the procurement of the balancing capacity is in favor for VPPs as it is done day-ahead. According to the Austrian TSO the procurement cannot be changed easily [29]: Per definition of the ENTSO-E (former UCTE) Operation Handbook the biggest generation unit has to be replaced by secondary control [31]. The Austrian secondary reserve volume put out to tender is 200 MW, but the largest power plant unit has a capacity of more than 200 MW. The missing capacity is tendered as “Ausfallsreserve” together with the tertiary power reserve. Hence, the secondary and the tertiary power reserve cannot be separated the same way than in Germany. The secondary power reserve is highly relevant to system security, this is why the TSO has to guarantee the volume of at least the largest power plant and it is critical to have parts of it ensured just before real-time e.g. day-ahead.

The participants can freely decide which BG or BSG they will affiliate with on the market and this decision has, normally, the objective to lower the costs resulting from the imbalance settlement [61].

Figure 17 depicts an overview of the most important market timeframes in Slovenia, including the different GCT for different activities. This overview includes the energy exchange for day-ahead and intraday, the energy and capacity balancing mFRR, the imbalance settlement and the day-ahead and intraday cross-border capacities from Slovenia to Austria (SI > AT) and Slovenia to Italy (SI > IT).

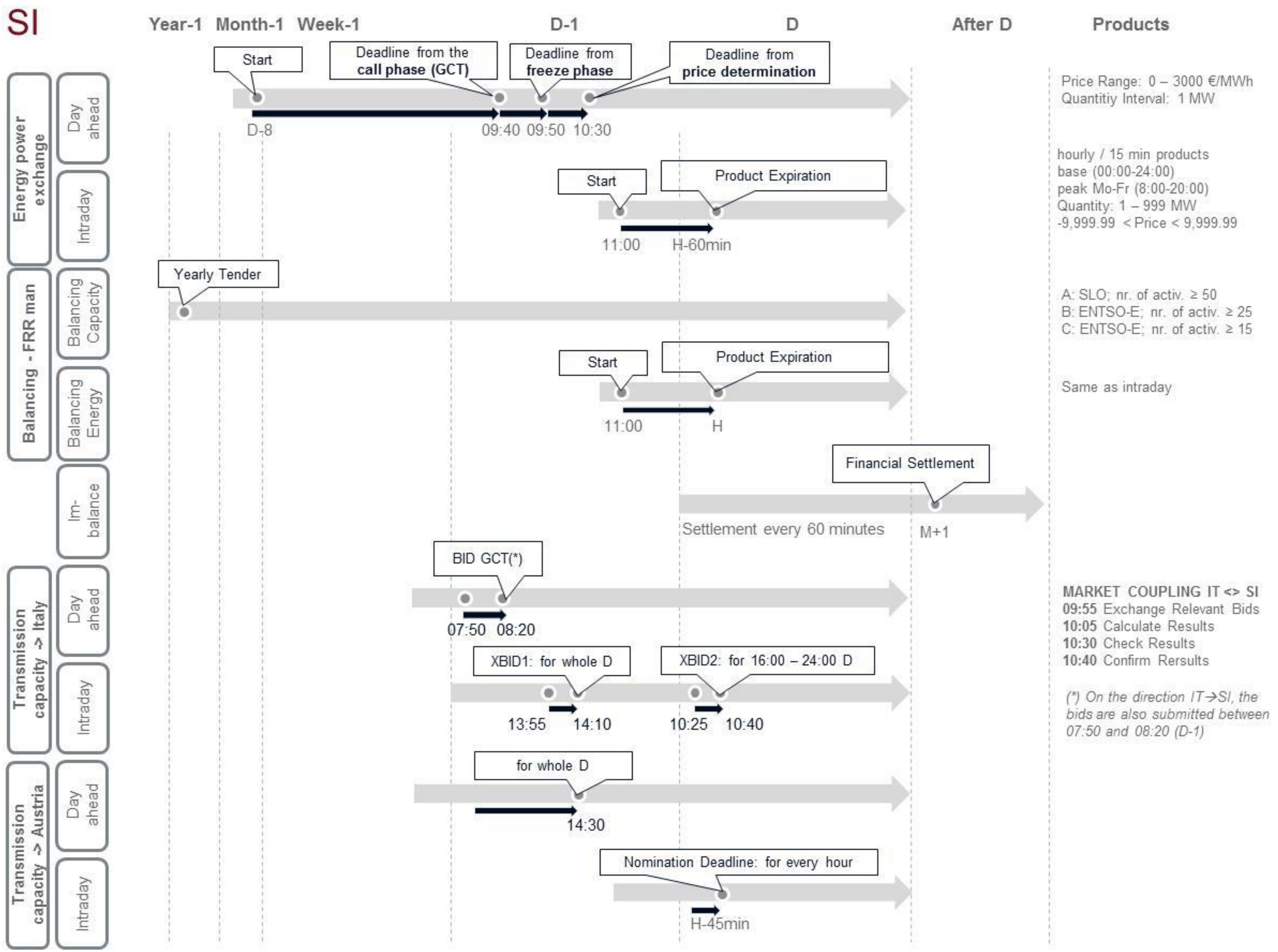


**Figure 17: Overview about the gate closure times of the energy markets in Slovenia**

**Day-ahead and intraday market**

The Slovenian Day-ahead market is conducted in a manner of auction trading in which market participants in the trading phase submit anonymous standardized hourly products on the EuroMarket[10] trading platform. Products are limited by price range from 0 €/MWh to 3000 €/MWh and with a quantitative interval of 1 MW. The calculation of the marginal price is based on a trading platform algorithm and is described in the Trading Rules [62].

Auction trading is divided into the following phases:

- The call phase runs to 09:40 a.m., however, it is possible to enter bids 8 days prior to the trading day. In this phase, orders can be entered, changed or deleted, and the participants can see only their own orders;
- The freeze phase runs from 09:40 a.m. to 09:50 a.m. at the latest. During the freeze phase, the Market Supervision can examine the orders and react in case of any irregularities;
- Price determination is made between 09:50 a.m. and 10:30 a.m. Marginal prices calculated at auction are shown to the trading members;
- After the price determination phase, the trading members have an overview of the marginal prices and their own deals.

Registration of schedules is performed in line with valid rules set by the Borzen (Market Operator).

It is important to stress that the trading on the Slovenian Day-ahead market is performed under the framework of SI-IT (Slovenian-Italian) Market Coupling. Trading results of SI-IT Market Coupling are part of Day-ahead market results [62].

The Intraday market is conducted in a manner of continuous trading in which market participants in the trading phase submit anonymous standardized and user-defined products in the ComTrader[11] trading platform. Transactions are concluded on the basis of the price/time priority criterion.

Traders involved in the intraday market can submit orders with a quantity from 1 to 999 MW, rounded to 1 MWh and a price between -9999,99 € and 9999,99 €.

There are predefined products, like base (00:00 – 24:00), peak (08:00 – 20:00), hourly and 15min products, as well as user-defined products (Buy or sell order defined by the user and constituting of at least two consecutive predefined products of the same delivery day).

The trading phase takes place one day before the delivery day from 11:00 till 60 minutes prior to product expiration on the delivery day. The registration of schedules is performed in line with valid rules set by Borzen. Table 7 summarizes the information about the day-ahead and intraday markets in Slovenia.

**Table 7: Overview about the power exchanges EuroMarket and ComTrader – day ahead and intraday**

| | **EuroMarket Day-ahead** | **ComTrader intraday** |
|---|---|---|
| **Gate-closure time** | 09:40 | H-1 |
| **Minimum volume [MW]** | 1 | 1 |
| **Increments [MW]** | 1 | 1 |
| **Price range [€/MWh]** | 0 – 3000 | -9 999.99 – 9 999.99 |
| **Max volume block bid [MWh]** | 1000 | 999 |

**Balancing Markets**

The Balancing Market is, since October 2012, embedded in the intraday market through the BSP South Pool platform. For trading on the Balancing Market the same rules as for the intraday market are applied. The only difference between these markets is a prolonged trading phase on the Balancing Market (with regard to the intraday market) for one hour [62]. It means the trading phase takes place one day before the delivery day from 11:00 until the product expiration.

[10] Trading platform where market participants can conclude transactions on the Slovenian and Serbian Day-ahead markets. This platform also enables implicit market coupling with neighbouring power markets. Market participants access the trading platform without any prior software installation, using a valid username and password

[11] On the ComTrader trading platform market participants can conclude transactions on the Slovenian Intraday market, Balancing Market and register bilaterally concluded contracts to OTC clearing. The trading platform enables implicit market coupling with neighbouring power exchanges. It is used also on the French, German and Austrian markets. Market participants access the trading platform using a valid username and password, and Java software.

The ancillary services in Slovenia are fully unbundled – there are dedicated yearly contracts between the TSO and the respective reserve providers for the provision of ancillary services. The capacity reservation costs incurred by the TSO are covered by the network tariff and the reserve usage costs are financed through the imbalance settlement procedure [63]. This is valid for secondary (aFRR) and tertiary (mFRR + RR). Power reserve for tertiary frequency control in Slovenia is provided mainly by gas turbines [64].

Primary control is not contracted neither refunded. It is an obligation for all generators connected to the high voltage grid [64] or units larger than 10 MW [63].

For the secondary frequency control (FRR automatic), for example, there was an auction in 2010 for the purchase of ±80 MW (positive and negative control) of active power reserve. For the same year also active power reserve for tertiary frequency control in the total amount of 348 MW (only positive control) was offered. The purchase for tertiary frequency control was divided in three products (different auctions): A (134 MW), B (66 MW) and C (148 MW). The same auctions for tertiary frequency control were repeated in 2011, for the purchase of the same products (same amount) for the years of 2012 and 2013.

For product A only potential providers with balancing sources inside Slovenia can compete, while for the other two both Slovenian and foreign providers can compete[12]. The final provider is selected by an auction for the period of one year and there are separate auctions for all three products. The three tertiary reserve products – apart from the location of source in the case of the first product – deviate as regards the number of activations and the duration of each activation.

The total capacity of all three products equals to the capacity of the largest generation unit in the Slovenian power system, which is half of the installed capacity of the Krško Nuclear Power Plant (The second half of this power plant belongs to Croatia). This is in line with the requirements of ENTSO-E Operation Handbook [63]. Table 8 shows the most important characteristics of the tertiary reserve products.

**Table 8: Overview of the different products for tertiary frequency control in Slovenia**

| | Product A | Product B | Product C |
|---|---|---|---|
| **Source of Reserve** | CASI (control area of Slovenia) | ENTSO-E | ENTSO-E |
| **Activation time** | ≤ 15 min | ≤ 15 min | ≤ 15 min |
| **Time to announce change of activation** | ≤ 15 min | ≤ 60 min | ≤ 120 min |
| **Number of activations** | ≥ 50 | ≥ 25 | ≥ 15 |
| **Time between two activations** | = 0 h | ≤ 12 h | ≤ 24 h |
| **Duration of one activation** | ≥ 16 h | ≥ 16 h | ≥ 16 h |

A bidder may offer an individual control unit or group of control units in the same way as any other product, if it is capable of meeting the technical requirements of a particular product. The bidder shall identify the control units where it offers tertiary active power reserve and the control area in which a unit is located.

The auction is considered successful only of the total amount (e.g. 348 MW) is accepted – the most advantageous bids are selected. The result of the auction includes, for each product, the accepted quantity (MW), the reservation price (€/MW) and the energy price (€/MWh).

In addition to the ancillary services that are contracted on a yearly basis, the TSO is balancing the system also with buying or selling energy on Balancing Market established by the Market Operator Borzen (BSP South Pool), where any BRP can offer Balancing Energy. Costs for the balancing energy are covered through the imbalance settlement procedure, similarly to the ancillary service reserve usage costs.

**Imbalance Settlement**

The imbalance settlement is a clearing of balance groups within which the amount of imbalances is determined and calculated by comparing the entire realization of balance groups and their market plan. The

[12] According to [Plan of Required Ancillary Services for 2010] 50% of the required secondary and tertiary reserve power is purchased within the control area of Slovenia ½ (80 + 348) = 214. Therefore the whole secondary reserve power 80 MW and 134 MW of the tertiary reserve power (product A) are contracted in Slovenia.

market plan is prepared by the Market Operator (Borzen) for each accounting interval (1 hour) for each Balance Scheme Member. In each accounting interval, the market plan of the Balance Scheme Member, who acts as a supplier on the market, is equal to its total consumption or generation of electricity [60].

The imbalance settlement is comprised of two parts: The first is the so-called quantitative settlement in which data on realisation and market plan are acquired, on the basis of which the imbalances of balance groups are calculated. The Market Operator receives data on realised values of production and consumption of all delivery points (units) from DSOs and TSO. For the second part, the Market Operator produces a final monthly imbalance settlement for an individual Balance Group on the basis of confirmed quantitative settlement. [60].

The measurements of realisation are forwarded to the market operator from the TSO and all the DSOs. The TSO forwards the hourly data on consumption and supply realisation (schedules) within the transmission network, and the DSOs forward the data on consumption and supply for each BG and BSG within the distribution network separately [61].

The deviations from the schedules are calculated and penalized on hourly basis since the schedules are also given on hourly basis. For the delivery points that do not execute measurements in an adequate time resolution (or do not have meters), the consumption in the Balance Scheme is estimated on the basis of an analytical procedure during the year. Differences that occur between actual (invoiced) quantities and quantities from the analytical procedure are calculated within annual recalculation [60].

Depending on the deviations from the operation schedules the amount to be paid or reimbursed is calculated. For this purpose each BG has a Tolerance Band, which is calculated within a BG and is based solely on the consumption in this BG. This tolerance band is defined in [65] as 5% of consumption and at least 1MWh. That means that if the consumption is lower than 20MWh in the settlement period, the tolerance band will be 1MWh.

The methodology for the calculation of the penalisation is based on a dual pricing principle, where C+ is the price BRP pays for positive imbalance and C- is the price reimbursed for negative imbalance. Besides that, the penalties rise by a quadratic function, which means, that for small deviations, penalties are small, for higher deviations, penalties are higher [65]. According to Borzen for the last two years, penalties are small in comparison to the balancing prices.

### 4.2.2. Prequalification

**Technical Requirements**
As seen before primary control is not contracted neither refunded. It is an obligation for all generators connected to the high voltage grid [64] or units larger than 10MW [63]. Since it is no part of the Balance Market, there are no specific prequalification criteria for it.

Active power reserve for secondary frequency control (aFRR) can be offered by bidders with available control units which are remotely controlled, i.e. a generating unit or a group of generating units capable of accepting telemetrically supported regulation command by which ELES can control their output power at any value within a secondary control range and within this control range the same time response of a control unit has to be exhibited [66].

The active power reserve for tertiary frequency control may be supplied by any bidder which disposes with control units that are adequately equipped for the performance of such services in accordance with the System Operating Instructions for Electricity Transmission Network: "*A regulation unit providing tertiary active power reserve may either be a **generating unit** capable of increasing power, or a **consumption unit** capable of reducing power in a range from 0 to 100% of the contractual power not later than 15 minutes after a phone call is placed by ELES' National Control Centre to the contact number of the on-duty dispatch centre (coordinating the activation of reserve on behalf of the bidder). All Balancing Market members must provide 24-hour stand-by.*"

The monitoring is based on the Ex-Post principle. Measurement data obtained from the main measuring points. Such data is regularly verified during operation by means of comparison with data from substitute measuring points. In case of any discrepancies, the source of reliable measurement data is established on the basis of data from jointly controlled measuring points (either main or substitute measuring points), and that source shall then remain in use from the moment of detecting a discrepancy until the elimination of a defect. No further changes in data are possible after the system operator of the transmission network has completed the final verification of settlement data and transferred such data to the market organizer. For operating purposes, the measurement data from the main, substitute and control measuring points are recorded in 1-minute measuring periods. The effectiveness of the provision of tertiary active power reserve is controlled by determining whether an individual activation was successful or unsuccessful.

**Organizational Requirements**

Engaging tertiary reserves of active power can be carried out through the Balancing Market. The System operator engages tertiary reserves with regard to procedures set out in agreements concluded with suppliers of this type of service. The procurement scheme represents a bilateral market, where the “buyer” (always ELES) and the “seller” or “bidder” (a BRP) sign a contract on the provision of active power reserve for tertiary frequency control. The procedure consists in a technical prequalification and the selection of the most advantageous bids.

ELES concludes with the most favourable bidders a contract for purchase of active power reserve for tertiary frequency control in the period of one year (starting from 1st January at 00:00 and ending on 31th December at 24:00h) or more.

A bidder may offer an individual control unit or group of control units in the same way as any other product; if it is capable of meeting the technical requirements of a particular product (see Table 8). The bidder shall identify the control units where it offers tertiary active power reserve and the control area in which a unit is located. A bidder wishing to create a bid in which the price depends on the accepted volume may submit several bids for the same control unit or group of control units, specifying the mutual exclusiveness of its bids. **A single bid cannot include a combination of control units from both Slovenia and a foreign country**. Selection of the winning bidders is by a merit order based on prospective total annual cost.

### 4.2.3. Considerations for VPPs

Theoretically there are no restrictions for the participation of producers as VPPs in the tertiary control market, as long as they can increase production or reduce consumption from 0 to 100% within 15min, respectively. Demand is however not explicitly included [34] – bidders were expected to be generators in the last (2010 to 2013 tertiary frequency control auctions. But they can still participate as members of a BG or BSG.

**Participation of RES** is not explicitly defined; being the only relevant provision regarding the treatment of renewables in the Energy Act the fact that the TSO has to give priority to energy produced from renewable energy sources and high efficient CHP facilities in dispatching – this may also include balancing [39].

Theoretically there is no minimum bid quantity of an individual participant, but the bid is rounded to 1 MW (products are evaluated according to the duration of the bid). Bid step is 1 MW. The maximum bid quantity is 999.0 MW. A single bid can contain a combination of control units in the control area [67]; therefore the possibility of **pooling** is not excluded.

The **validity of the tender** (one year or more) is too long; especially considering that the whole amount of reserves needs to be auctioned. It not only limits strongly the number and type of bidders but also leaves no resources available to the new entrants in the market. A shorter validity of the tender would permit that seasonal variations are taken into account (e.g. less reserve is required in the summer when demand is lower than during the winter) and, therefore, facilitate the participation of RES.

For tertiary control, the duration of a **single activation** (≥ 16 hours) is too long. Virtually VPPs could not guarantee such a long delivery time without a tolerance margin.

According to the actual scheme consumers can take part of the **Balancing Market** through the BSP South Pool platform, which runs in parallel to the intraday market. Consumers can bid through their BRP (from their BG or BSG) and offer any product in the intraday market. VPPs (both generation and demand) have, therefore, the possibility to participate in the Balancing Market. However for DR no baselines are defined yet for real time and/or ex-post verification of activation.

As seen in 4.2.1 the calculation of the **tolerance band** is based only on the consumption within a BG and is at least a minimum of 1MWh. In a BG with many VPPs, the tolerance band would not change with the size of installed capacity of generators; however, if the VPPs are represented by demand response, then the size of the realised consumption in the particular hour would define the tolerance band. Many small VPPs in one BG would therefore benefit mainly from the ability of offering energy more frequent and with lower resulting deviations.

# 4.3. Balancing Markets in Italy

## 4.3.1. Regulatory framework of Balancing Markets

**Relevant institutions, legislation and market framework**
The most relevant institutions for the electricity management are the electricity power exchange, the transmission system operator and the Italian Energy Regulator AEEG. The Italian Electricity market respectively the Italian Power Exchange "Mercati dell'Energia" is managed by the Italian Energy Market operator, Gestore dei Mercati Energetici SpA (GME). GME is a subsidiary company of Gestore dei Servizi Energetici SpA (GSE). GSE is assigned to and financed by the Italian Ministry of Economic and Finance. The Regulatory Authority for Electricity and Gas (AEEG) is obligated to "guaranteeing the promotion of competition and efficiency" while "ensuring adequate service quality standards" by the Law 481/95. [68] The transmission system operator Terna S.p.A. ensures the secure transmission of energy, is responsible for managing the over 63,500 km of HV lines [69] and procures the ancillary services. Besides, the largest power supply company Enel has an important role in the electricity market. In 2009 Enel had a contribution to gross national electricity production of 30.4% [70].

The most relevant Legislation and Manuals are:

- Integrated Text of Electricity Market Rules
- Technical Rules
- Grid Code and Appendixes
- Electricity Market Guide
- Market Participant's User Guide
- Market Participant's User Guide for the Me-Settlement Electronic Platform

The structure of the Electricity Market is pictured in Figure 18. There are two distinct markets, the Forward Electricity Market and the Spot Electricity Market. The Italian MPE consists of three submarkets:

- the Day-ahead market (MGP),
- the Intra-day Market (MI)
- Ancillary service market
  - Scheduling stage (ex-ante MSD)
  - Balancing Market (MB)

The price in the electricity market (MPE) shall not be less than zero. Hence, there are no negative electricity prices possible as for instance in the German electricity market. The maximum price is 3000 €/MWh. The Balancing Market is integrated in the Ancillary Market that is part of the Spot Electricity Market (MPE).

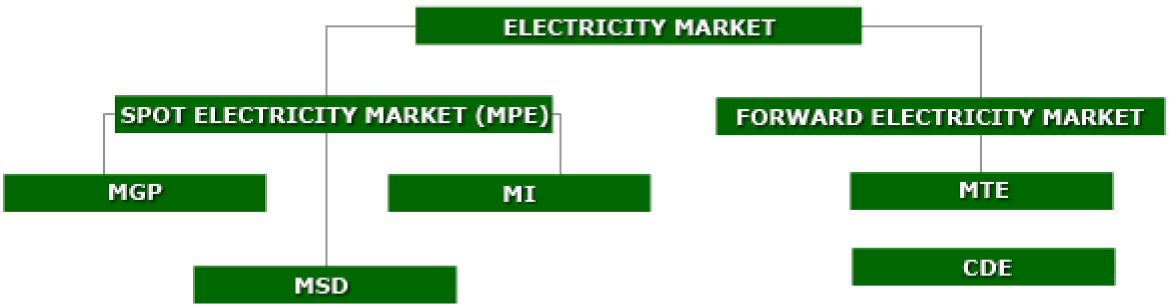


**Figure 18: Structure of the Electricity Market in Italy [71]**

Market participants can trade standardized products in the Electricity Market. Furthermore, market participants have the possibility to use the OTC-Registration Platform to trade non-standard products. An overview about the sequence of the Spot Electricity Market (MPE) is shown in Figure 19.

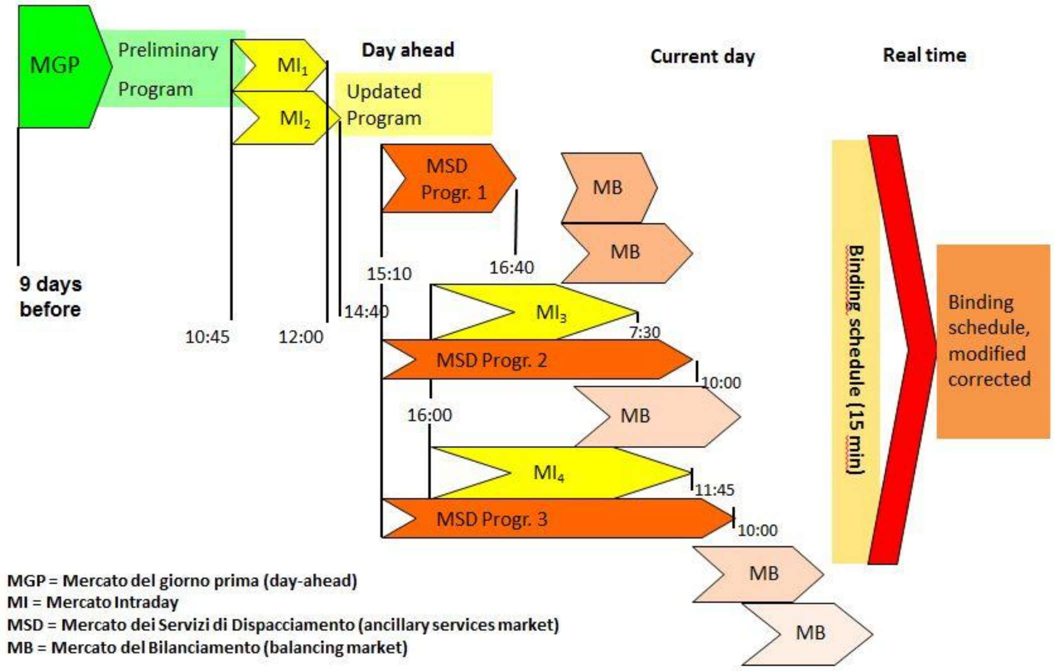


**Figure 19: Sequence of the Spot Electricity Market [internal document - Gestore dei Servizi Energetici SpA]**

The times are shown in Table 9. In the following a short overview about the day-ahead and the intraday market is given and the Balancing Markets are explained in detail.

**Table 9: Sequence of the Spot Electricity Market [72]**

| | MGP | MI1 | MI2 | MSD1 | MB1 | MB2 | MI3 | MSD2 | MB3 | MI4 | MSD3 | MB4 | MB5 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference day** | D-1 | | | | D | | | | | | | | |
| **Preliminary information** | 08:45 | 12:30 | 14:40 | n.a. | n.a. | n.a. | 07:30 | n.a. | n.a. | 11:45 | n.a. | n.a. | n.a. |
| **Opening of sitting** | 08:00 D-9 | 10:45 | 10:45 | 15:10 | Result MSD1 | 22:30 D-1 | 16:00 D-1 | Result MSD1 | 22:30 D-1 | 16:00 D-1 | Result MSD1 | 22:30 D-1 | 22:30 D-1 |
| **Closing of sitting** | 09:15 | 12:30 | 14:40 | 16:40 | Result MSD1 | 05:00 | 07:30 | Result MSD1 | 11:00 | 11:45 | Result MSD1 | 15:00 | 21:00 |
| **General results** | 10:30 | 12:55 | 15:05 | 20:30 | H+1 | H+1 | 07:55 | 09:50 | H+1 | 12:10 | 14:05 | H+1 | H+1 |
| **Individual results** | 10:45 | 13:00 | 15:10 | 20:40 | 15th M+2 | 15th M+2 | 08:00 | 10:00 | 15th M+2 | 12:15 | 14:15 | 15th M+2 | 15th M+2 |

**Day-ahead Market and Intraday Market**
In the Day-ahead Market (MGP) electricity is traded in a non-discriminatory implicit auction for each hour of the next day. The MGP opens nine calendar days before the day to which the bids/offers refer at 08.00 and closes one day before that day at 09.15 o'clock. 30 Minutes before this closing the hourly transmission capacity limits between geographical zones and with neighbouring countries and, furthermore, the hourly electricity demand estimation has to be published by GME.

The transmission capacity within Italy is not sufficient to avoid congestions. That is why Italy is divided into different market zones - six geographical and four national virtual zones. Furthermore Italy is connected with eight virtual zones in the neighbouring countries AT, FR, SI and GR. [68]

In the MGP sitting bids/offers can be submitted. These bids/offers can be of a simple, multiple or predefined type. After the closing the market resolution process determines the optimal bids for each hour under implicit consideration of the transmission limits. By this the clearing price and clearing volume are identified for each zone. Suppliers of electricity get marginal prices for each zone. Consumers pay the same, national purchasing price and not the zonal price.

In the Intra-day Market participants can update their bids submitted in the MGP. The MI consists of four sittings (MI1-MI4) according to the Technical Rule 3. The times of the opening and the closing hours of the sitting can be seen in Table 9. Before the closure of each sitting the residual transmission limits have to be published by Terna. The pricing is nearly the same for the intra-day market than for the day-ahead market. The only exception is that in the MI no national consumption price is calculated, but the intra-zonal compensation for the consumption is achieved by a non-arbitrage fee.

**Ancillary Services Market**

In the Ancillary Services Market (MSD) the Italian TSO has the possibility to procure resources for the relief of intra-zonal congestions, for real-time balancing and to create energy reserves. For this bids/offers are accepted by Terna to provide the needed secondary and ascending/descending tertiary control. The tertiary control is divided in the spinning reserve and the replacement reserve. The spinning reserve has a response time of 15 minutes and is comparable with the aFRR. The replacement reserve aims at re-establishing the tertiary spinning reserve and is comparable with the RR. The primary control reserve is not subject of the Ancillary Service Market as it is a mandatory service for every significant unit – see section 4.3.2 – that is not procured by the TSO.

In Ancillary Market offers/bids are sorted in a merit order and are paid after the pay-as-bid methodology. The participation in the ancillary service market is mandatory for every generation unit with more than 10 MW. Fluctuating renewable energies and generators that are in their trial period (first six months after initial operation) are excluded. The Ancillary service market consists of two markets the ex-ante MSD and the Balancing Market.

In the ex-ante MSD, Terna accepts energy bids and offers to make sure that reserve margins are available and to relief congestions. For this secondary and tertiary control reserve offers and bids are selected in the ex-ante MSD market supply offers and demand bids are accepted from 15:10 to 16:40. The individual results are communicated before 20:40.

The Balancing Market consists of five sessions (BM1-BM5). In every session 6 hours are covered for real-time balancing, e.g. in BM1 the hours from 0:00-6:00. In BM1 the relevant bids/offers of the ex-ante MSD are taken into account. The general results are published on hourly basis; the individual results are announced on the fifteenth day of month M+2. The prices and quantities of the balancing offers have to be non-negative, according to chapter 4.8.4 of the Grid Code [73].

In Italy the Market Operator GME operates a number of markets for energy products including a day ahead and intraday spot market for market participants. The TSO TERNA procures the resources that it requires for managing, operating, monitoring and controlling the power system on three day ahead Dispatching Services Markets (MSD) and five day Balancing Markets (MB1-MB5). Bidders may only participate in the Balancing Markets if they have previously submitted bids to the MSD. Successful bidding in the MSD effectively creates reserve and the resulting call off in the MB delivers the Balancing Energy. One key provision for MB rebidding is that those bidders may adjust prices and available volumes. Prices may only be adjusted to a more advantageous one for the TSO i.e. Offer prices may only decrease and Bid prices may only increase. Note however that participation in the market is mandatory. [34]

**Table 10: Overview about the technical prequalification of primary, secondary and tertiary control in Italy**

| | Primary Power Reserve (FCR) | Secondary Power Reserve (aFRR) | Tertiary Power Reserve (mFRR) |
|---|---|---|---|
| **Explanation** | Control of frequency deviations in the ENTSO-E grid | Control of frequency deviations and xb-exchange in the control area; supersedes the primary control | Control of frequency deviations and xb-exchange in the control area; supersedes the secondary control |
| **Time to activation/ deactivation** | <30 sec | <5 min | <15 min |
| **Minimum offer** | - | Depending on power plant, but min. ±10 MW (e.g. ±10MW and ±6% of | Min. +10 or -10 MW |

| | | | |
|---|---|---|---|
| | | the maximum power for thermoelectric units) | |
| **Period** | - | One day | One day |
| **Timeframe of product** | - | 6 hour Blocks, MB1-MB5 | 6 hour blocks, MB1-MB5 |
| **Start/end of tendering period** | | MSD1-MSD3 | MSD1-MSD3 |

**Imbalance Settlement**
The imbalance settlement is regulated in the resolution 111/06 – "Resolution on the dispatch of electricity on the national level" und it is further set out in the Grid Code Chapter 4, 6 and 7.

The significant period is one hour for non-enabled and 15 minutes for enabled units (Grid Code 4.3.2.5). The imbalance is calculated for each dispatching point per production/consumption unit by Terna. The metering data of all distribution companies are aggregated separately for each production and for each consumption unit per relevant period and per market area. The imbalance settlement time unit is one hour for consumption units and for not-enabled production units with a generation capacity of less than 10 MVA. For enabled production units it is 15 minutes.

The imbalance charges diverge for different generation types (enabled/not-enabled/RES) and they depend on whether the unit supports or opposes the aggregated zonal imbalance (regulated in chapter 7 Grid Code). The imbalance charges can be seen in Table 11.

**Table 11: Imbalance Charges in Italy [[74] adapted]**

| | Enabled | Non-enabled / consumption | fRES |
|---|---|---|---|
| **Aggravating & negative CA** | MAX of max price of MSD or Day ahead zonal price | MAX of weighted average MSD prices or Day ahead zonal price | Day ahead zonal price |
| **Aggravating & positive CA** | MIN of min price of MSD or Day ahead zonal price | MIN of weighted average MSD prices or Day ahead zonal price | Day ahead zonal price |
| **Supporting & negative CA** | Day ahead zonal price | see negative CA | Day ahead zonal price |
| **Supporting & positive CA** | Day ahead zonal price | see positive CA | Day ahead zonal price |
| **Significant Period** | 15 minutes | 1 hour | 1 hour |

### 4.3.2. Prequalification

**Technical Prequalification**
Significant units, units with more than 10 MVA, and enabled units are obliged/allowed to provide ancillary services. Enabled units are allowed to submit Minimum and Shutdown offers. According to Grid Code 4.3.2.7d) the secondary half-band of a significant production is dependent on the maximal power and on the operation range of the unit. An essential production plant is a plant that is necessary for dispatching services and if there is no alternative to its use. An essential production plant cluster is one that is necessary to satisfy a given requirement (4.3.5.1/2).

**Primary Power reserve**
The primary reserve is used to correct sudden imbalances in the ENTSO-E electricity grid. Every Italian production unit has an obligation to participate in the primary power reserve unless it has an explicit exception. A band of electricity production has to be made available by every eligible production unit (PU) [73]:

- ±10% of the efficient power in Sardinia and Sicily (the range depends on the opening hours of the interconnection of Sicily with the mainland)
- ±1.5% of the efficient power in the rest of Italy

This band can be used to automatically regulate the power output of the unit either decreasing or increasing by an automatic regulation device.
In case of unavailability for reasons mentioned in Appendix A.60 of the Grid Code Terna needs to be informed by the owner of the PU. The owner has to prove the unavailability reason by technical evidence (at the latest 15 days after the notification) and he has to pay a replacement contribution (Appendix A.37 Grid Code).

**Frequency Restoration Reserve automatic - Secondary Control Reserve**
The secondary power reserve is used to correct imbalances in the national electricity grid, to restore the power exchanges at the border to their planned values and to contribute to retaining the European frequency. The secondary power reserve for Italy is managed by one central regulator except for Sicily and Sardinia as they are managed locally. The power units are obliged to make the secondary power reserve control available except for conditions listed in 4.8.3 (Grid Code 4.4.3.4.a)).

Power units are enabled to take part in the secondary control if they can provide at least a minimum secondary reserve band of more than (Grid Code 4.4.3.2d)):

- ±15% of the maximum power for hydroelectric power units
- ±10MW and ±6% of the maximum power for thermoelectric units

The technical requirements for an PU are the same than for the tertiary power reserve, if [73]:

- one generator group fulfils the specification to participate in the frequency and frequency/load control (Appendix A.15 of the Grid Code)
- the generator unit can process the level signal submitted by Terna
- the unit shows Terna the remote indication of the secondary regulation
- one infrastructural element has a broader secondary reserve band than the minimum

The secondary and the tertiary power reserve are acquired in the Market for Dispatching. If production units take part in this market, the service has to be available exclusively for Terna.
To take part in the market for secondary power reserve the enabled generators have to:

- the secondary-half band has to be made available in case that
    - the generator is selected for the significant period of the day
    - it is needed by Terna (according to terms of Appendix A.23 of the Grid Code)
- notify Terna in case of unavailability or unplanned changes

**Frequency Restoration Reserve manual & Replacement Reserve - Tertiary Control Reserve**
The tertiary power reserve is activated manually and it can be either ascending (increase of injection /reduction of withdrawal) or descending. The tertiary control reserve is divided in the spinning reserve and in the replacement reserve. The spinning reserve has to be available within 15 minutes. The replacement reserve relieves the spinning reserve in case of unpredictable injection of renewable sources or demand shifts.
Enabled Production Units for tertiary reserve are generators that

- are connected to the transmission grid with third party access
- are not powered by renewable energies or are not in the period of first running
- have a reaction time to increase or decrease their injection of less than 5 minutes
- can vary their injection by +10 or -10 MW within 15 minutes
- for hydropower plants: the defined relationship of energy supplied in one day and maximum power is 4 hours
- is able to execute dispatching orders 24/7

Productions Units that want to take part in spinning reserve have to be additionally

- able to get available within 15 minutes
- able to vary their injection with a gradient of at least 50 MW/min
- characterized by decreasing or increasing structure time change of less than an hour

To take part in the market for **tertiary power reserve** the single generators have to:

- install a physical control point for receiving dispatching orders at the physical control point

- install a telephone communication system at the physical control point
- make the residual margins exclusively available for Terna S.p.A.
- notify Terna S.p.A. in case of unplanned unavailability of the plant
- submit their offers in the Ancillary Services Market (MSD)

The requirements for generators are defined in the Chapter 4 of the Grid Code. The primary and the secondary control are activated automatically. If needed, the tertiary control is started manually by the TSO.

**Balancing (special balancing capacity for Italy)**
A special form is the "balancing". It takes care of maintain the balance of injections and withdrawals, to solve grid congestions and to restore the secondary power reserve margin, restoring the secondary reserve margins. Productions Units that want to take part in balancing are able to vary their injection by ±3 MW within 15 minutes (instead of ±10 MW in the tertiary reserve power reserve). The other regulations for balancing are comparable to the ones for tertiary control.

**Organizational Requirements**
The users of the dispatching service need purchase and sale contract with the TSO.

### 4.3.3. Considerations for VPPs

In the grid code fluctuating **renewable energies** are explicitly excluded in the prequalification criteria for tertiary power reserve. In the secondary power reserve fRES are not excluded, but not included either.

Interruptible **load** is used by Terna just as a last backup in case that the MSD is not sufficient. In this case the counter part of Terna has to be an end consumer; therefore, it is not possible that an aggregator coordinates the interruptible load.

Virtual units are **defined** in the Grid Code (4.3.2.3) as (i) aggregation of non-significant units that belong to the same zone and are of same type (plannable/non-plannable) under the ownership of one dispatching user, and (ii) import and export units. This definition could be adapted to comprise virtual power plant including generators of different primary resources, types as well as demand response. These virtual units have to be registered in the registry of production units (Grid Code 2.4.3.2.7b)).

The **minimum volume** for the participation in the tertiary power reserve (aFRR) is currently an injection/withdrawal of at least ±10 MW. It would be easier for the participation of a VPP in power reserve, if the limits are lower than ±10 MW.

**Pooling** (respectively clustering) is allowed according to the Chapter 4.3.2.1 of the Grid Code, but just for generators that are connected to a single point of injection[13]. Generators that are in different locations or demand/load cannot be pooled. Furthermore, pooling of renewable generators is only possible for generators of one power generation plan, with uniform energy sources and the same type (plannable/non-plannable). To allow pooling of different resources and demand would be very beneficial for the implementation of VPPs. Regarding DR, also in Italy no baselines are defined for real time and/or ex-post verification of activation.

The limited transmission capacity within Italy reduces the possibility of a bigger possible area for pooling (more generators) and that in a bigger area fluctuating renewable energy can more easily smooth each other.

Significant units, units with no less than 10 MVA, have to get the needed infrastructure for the integration of Terna's control system.

It can be concluded that the regulatory framework and the prequalification criteria have to be adapted to make the realisation of VPPs possible in Italy.

[13] If market participants want to bid in the electricity market, the quantities of the demand/supply offers have to refer to dispatching points. This means the quantities have to come from the same type of demand/production and have to be sited in the same area.

## 4.4. Comparison of AIS mFRR Balancing Markets with National Target Model

The Austrian, Slovenian and Italian mFRR Balancing Markets are compared with the national target model. The three markets differ from the target model and moreover, from each other in several design parameters as can be seen in Table 12. A further comparision of the three markets and with the cross-border target model is performed in chapter 6.

**Table 12: Comparison of AIS mFRR Balancing Markets with National Target Model**

| | Target Model | Austria | Slovenia | Italy |
|---|---|---|---|---|
| **Dispatch System** | Original design: Self-dispatch Allowed: Both Self- and Central-dispatch | Self-dispatch on portfolio basis | Self-dispatch on portfolio basis | Central-dispatch |
| **Prequalification of RES and DR** | Enhanced participation of RES and DR | RES: not allowed<br>DR: not defined | RES: not defined<br>DR: not directly included | RES: excluded<br>DR: excluded |
| **Standard Products** | Minimum set of features has to be defined | Not yet | Not yet | Not yet |
| **Procurement of Balancing capacity** | Separate tender for reserves and energy; | mFRR procurement is separated with the market maker tender and the day-ahead tender | Common procurement through auction | Markets for reserves (MSD) and for balancing (MB) are separated |
| | Fall back procedure | Two additional tenders of balancing capacity | If first auction is not successful, direct negotiations are carried out | Several MSD/MB markets |
| | Split in upward and downward regulation | Yes | Not implemented as only positive mFRR is procured | Upward and downward regulation are listet in seperate Merit Orders |
| **Procurement of Balancing Energy** | Separated upwards and downwards merit order lists | Yes | Not implemented as only positive mFRR is procured | Implemented |
| | Marginal pricing approach | Pay-as-bid | Pay-as-bid | Pay-as-bid |
| | Gate Closure Time of Balancing Energy Market after Gate closure Time of Intraday Market | GCT for balancing energy is day-ahead, bids accepted in marketmaker tender can be changed only in the direction in favour of TSO | Balancing Market is embedded in the intraday market. After GCT of Intraday Market Balancing Bids can be changed for additional 60 min | After intraday market GCT generators can change balancing bids in MSD and in BM markets. Thus, in BM the prices can be changed only in the direction in favour of TSO. |
| **Activation of Balancing Energy** | Merit order | Merit order | Pro-rata | Merit order |
| **Monitoring** | Real-time monitoring of performance and quality of | Real-time & ex post | 15 minutes monitoring | Real-time |

| | | | | |
|---|---|---|---|---|
| | balancing | | | |
| **Imbalance Settlement** | Imbalance Settlement Period not defined yet (currently 30min or less); cost benefit analysis has to be performed by TSOs | 15 minutes | 15 minutes | 15 minutes for enabled units participating in balancing. Otherwise 1 hour for e.g. consumption & non-enabled units (e.g. fRES) |
| | Calculation of imbalances for BRPs considering scheduled position, metered data and an adjustment for the activated balancing energy | Calculation is similar to Target model. Adjustment for activated balancing energy is not directly included in the calculation of imbalances, but indirectly. | Similar to Target Model. Settlerment occurs in the level of the Balance Group (BG) and is negotiated between TSO (provide schedules) and DSO (provides positions from BG/BSG). | The calculation of the imbalances is done per user of dispatching (same type of production) per significant time unit and per market zone according to measured data (chapter 6.2 and 7.3 Grid Code). The NC EB refers to the use of BRP that are not implemented in Italy. |
| | Single pricing | Single pricing | Dual price for positive (C+) and negative (C-) imbalances are set separately; tolerance band (see 3.2.1) leads to variable, not fair incentives for BRPs; but Slovenia has limited available reserve capacity and system is relatively small, therefore tolerance band is still used in order to incentivise BRPs to be balanced | Dual pricing |
| | No variable components | Variable component included | Variable component: tolerance band | No variable components |
| | No exemptions | None, only for owner of RES, when RES is included in feed-in tariff; in that case RES are pooled in one BRP “OeMAG” | | fRES are considered differently |

# 5. Implications of transmission capacity and congestions on cross-border balancing in AIS

In this chapter a relation between the integration of the Balancing Markets in the Region AIS and the cross-border capacities is established. Also the congestion and congestion management actions on these borders are discussed. Finally the expected impact of VPPs on the cross-border balancing scheme and internal congestions is analysed.

The Network Code on Capacity Allocation and Congestion Management (NC CACM) [75] defines two methodologies for transmission capacity calculations: **Flow Based (FB)** and **Net Transfer Capacity (NTC)** [23]. The NTC method is known and still used in all European countries. The flow based approach is defined in this Network Code as *a capacity calculation method limiting the exchanges between Bidding Zones directly with the maximum flows on the Critical Network Elements and Power Transfer Distribution Factors*. This approach, in contrast to the NTC, takes into account parallel flows in the system. The flow based approach is preferred over the coordinated net transmission capacity approach for day ahead and intraday capacity calculation where interdependencies of cross zonal capacity between bidding zones are high [75].

## 5.1. Available intraday capacity[14] in the AIS Region

Based on both NC EB and on the NC CACM, the Transmission Reliability Margin **TRM** (see glossary) should not be used to reserve transmission capacities for exchanging balancing capacity or Balancing Energy between area except for FCR [23]. Therefore cross-border RR and FRR (automatic and manual) can only be exchanged if cross-zonal capacity is reserved for balancing or remains after intraday. In the next section the rules for the intraday cross-border capacity allocation in the Region AIS is depicted.

As seen in the section 3.1.4 , the TSOs can use for balancing services either the available transmission capacity after the intraday GCT or the reserved of capacity by e.g. a probabilistic approach (see Figure 8). Since there is still no established cross-border Balancing Market in AIS, only the first approach will be referred.

An **interim solution** (XBID) based on explicit allocation of the intraday capacity is available for Italy-Slovenia (since 2012) and Italy-Austria (since May 2013). This interim solution is, however, not compliant with the Target Model proposed by ACER [78].

This solution is performed by CASC.EU, regulated by [79] and defined as two additional auctions [80]:

- XBID1 (on D-1 13:55 - 14:10 p.m.) which covers energy delivery from 00:00 – 24:00 of the day D (deadline for nomination: D-1 15:30 p.m.)
- XBID2 (on D 10:25 - 10:40 a.m.) which covers energy delivery from 16:00 – 24:00 of the day D (deadline for nomination: D-1 12:35 p.m.)

On the Slovenia-Italy border, the allocation of capacities is done by Bilateral Market Coupling an implicit auction that simultaneously allocates capacity and settles energy bids. In case Bilateral Market Coupling cannot take place, explicit Daily Auctions are organized in accordance with the present Auction Rules where applicable [81]. This market coupling takes places, however, not in the intraday, but in the day-ahead timeframe – more information can be found in [62].

The allocation of intraday capacities on the Austrian-Slovenia border is the responsibility of ELES alone since 5 July 2011 and is described in [82]. This intraday allocation starts at 18:00 CET on D-1 and is running for every hour until H-1 in the order of receipt of bids according to the “first come first serve” principle.

[14] A 10-Year Network Development Plan 2012 [76] from ENTSO-E lists several planned and ongoing projects in Europe, also in the AIS Region – some of them have impacts on the NTC and, therefore could change the transmission capacity in all timeframes – also intraday. A further analysis of this projects is out of scope of this deliverable, but can be consulted at [76] and [77].

**Table 13: Rules for nomination of cross-border schedules for intraday capacity [44][83]**

| | AT-SI | AT-IT | SI-IT |
|---|---|---|---|
| **Responsible Entity** | ELES | CASC.EU | |
| **Auction Start** | D-1 18:00 | 1st Auction: D - 1 13:55,<br>2nd Auction: D 10:25 | |
| **Auction Deadline** | H -1 | 1st Auction: D - 1 14:10,<br>2nd Auction: D 10:40 | |
| **Nomination Start** | D-1 18:00 | After the auction | |
| **Nomination Deadline** | H-45min | 1st Auction: D-1 15:30,<br>2nd Auction: D 12:35 | |
| **Nomination Procedure** | m:n | A:A | |
| **Time Resolution** | 60 min (4 equal quarter-hourly parts) | | |
| **Quantity Resolution** | 1 MW (with 3 zeros as decimal places) | | |

Another aspect of the rules of nomination is the nomination procedure (see [44]). Between Austria and Slovenia direct cross-border business transactions can be carried out with any required trading partner. On the other hand, for the nomination procedure for intraday between both Italy–Slovenia and Italy–Austria, the capacity right owner must personally nominate the schedule on both sides of the border to utilise his capacity right. Even though [84] states that M:N nomination principle reduces transaction costs and increases the number of exchanges, the TSO APG Austrian Power Grid recommends the usage of A:A [44], which can minimise errors during schedule nomination thus guaranteeing very secure business transactions. Despite the method chosen, it should be the same, for the sake of harmonization, between the three borders.

Considering that the capacity available for balancing is that available after the intraday, Figure 20 and Figure 21 show, respectively, the intraday **ATC** values for one year (August 2012 to July 2013) on the border Austria-Slovenia and Slovenia-Italy. Such information is not available for the border Austria-Italy since the intraday allocation on this border started a couple of months ago.

On Figure 20 the period with available information was 363 days. The data resolution is one hour. During 100% of the time there was available transmission capacity in at least one direction; from which 60% (SI>AT) and 40% (AT>SI). The highest value in the period was 1902 MW and occurred in both directions.

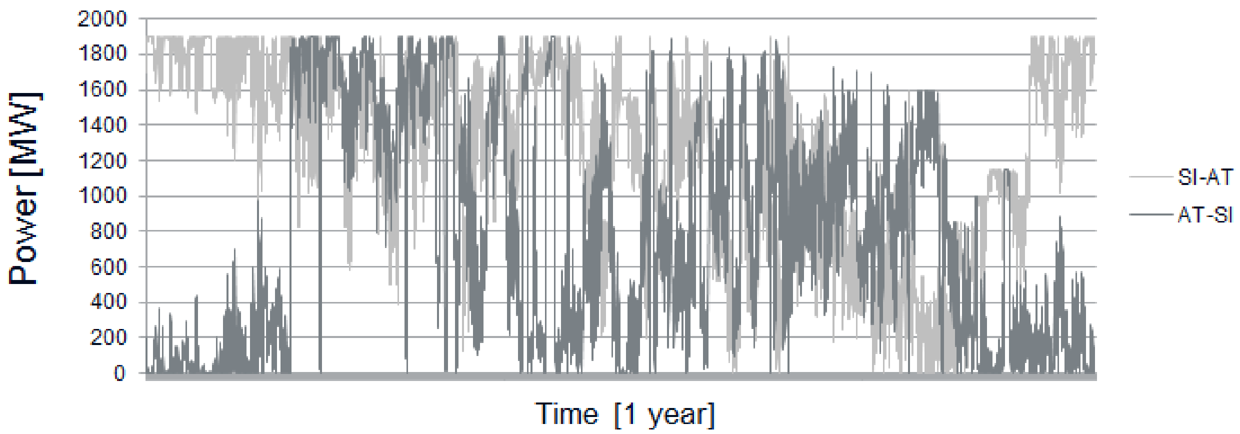


**Figure 20: Intraday ATC in the border Austria-Slovenia between August 2012 and July 2013**

On Figure 21 the period with available information was 345 days. The data resolution is one hour. During 81% of the time there was available transmission capacity in at least one direction; from which 77% (IT>SI) and 4% (SI>IT). The highest value in the period was 575 MW (SI>IT) and 790 (IT>SI).

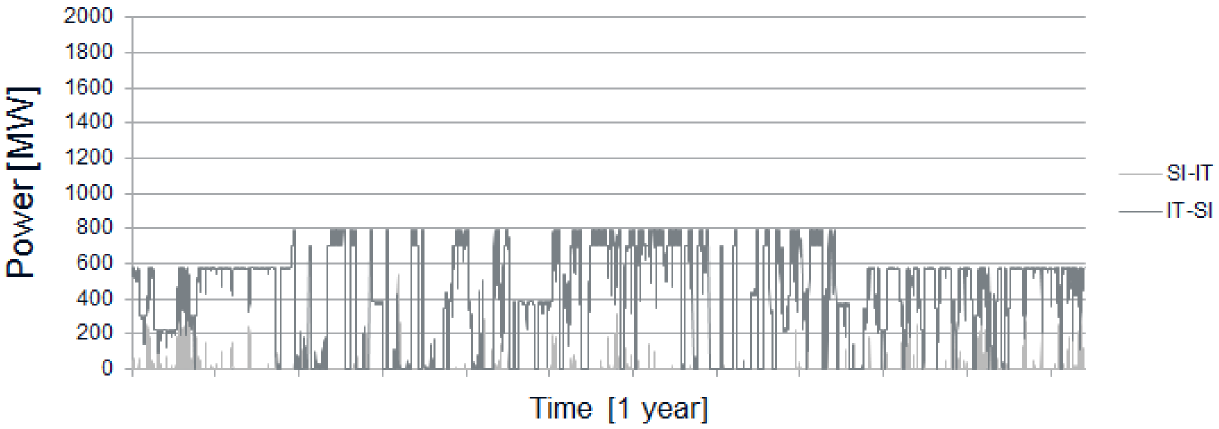


**Figure 21: Intraday ATC in the border Slovenia-Italy between August 2012 and July 2013**

Even though Figure 20 shows some pattern during the summer months, with more ATC in the direction SI>AT, there is not much that can be said by observing Figure 20 and Figure 21 regarding estimates for intraday ATC. Therefore, the capacity left after intraday, which could be used for mFRR, needs to be resolved in real-time and also consider the effects of congestions in the Region AIS.

After each successful reservation ATC values of other timeframes are automatically reduced. The figures show the last published (by ELES) intraday values for ATC. The part of these values which is not allocated could theoretically be used for balancing purposes - these quantities vary however a lot and don't show a specific trend.

## 5.2. The effects of congestion

Congestion is a situation where the demand for transmission capacity exceeds the transmission network capabilities, which might lead to a violation of network security limits, being thermal, voltage stability limits or a (N-1) condition. Congestion, being a result of power flows, may occur at any location in the interconnected network [85]. It can be, therefore, distinguished between internal (intra-zonal) and cross-border (inter-zonal) congestions.

### 5.2.1. Cross-border congestions

Cross-border congestion occurs between TSO's control areas, as in AIS. The biggest issue is that market organization, regulation and investment framework on both sides of the interconnection can be different, making the allocation of cross-border capacity and settlements of congestion costs more difficult [85].

A first step towards the alleviation of possible cross-border congestions in AIS would be the harmonization of the auction and nomination periods shown in Table 13 and the nomination procedure.

Grid expansions, as explained in [76] and [77], can enhance the transmission capacities in the cross-border connections and therefore alleviate possible congestions – this effect will depend, however, if the generation and consumption will also grow in the same proportion – Grid expansion is a long-term solution.

For real-time congestions, as those derived from cross-border balancing activities, other congestion management solutions are widely applied, as re-dispatching and curtailment of cross-border capacities [83]. To ensure transparent and cost-reflective prices for balancing and re-dispatching, costs due to congestions should be isolated and allocated separately from those from imbalance [41].

### 5.2.2. Internal congestions and the influence of VPPs

In order to find the TTC (see Glossary) the power exchange between the areas is increased until there is a breach of security constraints, being it internal or cross-border congestion. This is done by increasing generation in one area, and lowering it in the other. Using load flow calculations and detailed topology data, feasibility of such border exchanges is tested. The highest exchange without violating the security limits yields the TTC. The same procedure holds in both directions [85].

However, many DSOs do not possess access to measurement data from some distribution grids, especially low voltage (LV). Since most of the VPPs – demand and a high share of the distributed generators – are located in the distribution networks (MV and LV), this issue needs to be handled properly, as the participation of VPPs should not create local problems in the grids. However, today the majority if not all electricity meters (smart and non-smart) are providing pulse output, which can be used to establish dedicated real-time communication channel for the VPP purpose.

The participation of VPPs connected to the distribution network on the positive mFRR will require them to increase their generation (in case of producers) or decrease their consumption (in case of loads); this will increase the voltage level of the grid node this VPP is connected to and, as a result, also have an influence on the neighbour nodes (since VPPs are normally comprised by highly distributed loads and DGs, many single aggregated VPPs on neighbour nodes can raise the complexity of the voltage impact's problem). On the other hand, the participation of VPPs on the negative mFRR will lead to an opposite effect, as for decreasing the generation or increasing the consumption on generators and loads, respectively, a lower voltage level on the connection point will occur. This voltage needs to be kept between accepted levels [86].

One possible way to permit the participation of VPPs as BSPs for mFRR is, given the adequate ICT, to gather measurements enough in order to keep both the voltage levels of the grid nodes as the power flows of cables (loading - %) within tolerated limits by applying proper algorithms. Such algorithms relying on both on-load-tap-changer transformers as well as reactive and active power curtailment of the VPPs generators/loads themselves were extensively treated in [87][88][89]. This issue should be tacked by DSOs, as shifting this responsibility to new market players, just complicates the Balancing Market rules and increases the participation barriers.

By using this approach also the lower voltage levels could have their contribution to a more accurate calculation of TTC. However, this solution could be only feasible if the proposed active congestion control could be real-time or close to real-time, otherwise short term congestions could not be completely avoided and a re-dispatch/curtailment solution would be necessary. In this case a nodal approach is recommended [85][90].

# 6. Changes, risks and possibilities for cross-border balancing between AIS considering VPPs

There are general risks, possibilities and changes when cross-border Balancing Markets are introduced. These will be examined in the section 6.1 whilst listing the general points when introducing the target model (see D2.1 [18], model nr. 4). For the integration of markets a certain harmonization is necessary. Thus, the differences between the AIS markets in regard to the selected design variables (chapter 2) are depicted and analysed in section 6.2. The considerations regarding VPPs of the three Balancing Markets of AIS are shown in section 6.3.

## 6.1. General risks, possibilities and changes of the target model for mFRR

### 6.1.1. General Risks

The energy markets in Europe are becoming increasingly transnational, therefore, a centralized monitoring would be recommended to provide an overview of the markets and distortions. For this purpose, there should be a harmonisation of data collection, data analysis and data reporting. Furthermore, one challenge will be the handling of high amount of data.

Asymmetric available Information favours market players with more information and the published data influences the bidding behaviour of the BSPs. Therefore, the data should be published on a common platform and should be accessible to all BPSs. Furthermore, in a central dispatch balancing system the market participants have more information than in a self-dispatch system.

IT-security issues play a central role in a TSO-TSO model especially for aFRR, but restricted for mFRR, too. The more countries are interconnected the more dependent is the system on functioning of the IT-systems. A system error in one country – like in May 2013 in Austria [91] – cannot be smoothed in another country as the control systems are linked.

In smaller countries aggregation is limited to less possible participants and a smaller area, making participants more sensitive to geographical issues (e.g. lack of wind in one area); this being, therefore, a disadvantage for BSPs - especially BSPs with fRES and DR - in these countries.

Moreover, higher competition by for instance VPPs could reduce the revenues of some BSPs. In the following these BSPs could discourage the development of either a coordinated balancing area or the integration of VPPs.

In a cross-border Balancing Market the costs of the balancing energy are not directly linked to the area control error. It has to be ensured via the configuration of the imbalance price mechanism and the calculation of the imbalances that the TSOs as well as the BRPs have an incentive to be balanced. Therefore, harmonization is necessary to determine the correct imbalance prices, and furthermore, the incentives need to be consistent with the balancing responsibilities of the TSO [20].

For market integration the available transmission reserve is crucial, but between Italy and Austria and Italy and Slovenia interconnection is highly congested – for a sufficient Balancing Market a higher transmission reserve is required (could be tested in the simulator of WP2.3); but it is assumed that congestion will be a constraint just in one direction [21].

In case that in a coordinated balancing area balancing capacity are procured with diverging market mechanisms - with a difference how and if the balancing capacity are remunerated - market distortions can occur.

### 6.1.2. General Possibilities

Currently the Balancing Markets are markets with a small amount of participants. The cross-border Balancing Markets contain the possibility that more participants take part in the markets. Hence, the likelihood that participants can abuse their market power decreases. And due to future framework regulations, there could be an increased participation of RES/DR/VPPs in Balancing Markets. This would further increase the market participants. The participation of DR and fRES should be stimulated by ENTSO-

E by concrete standards. Even the NC EB is vague regarding many VPP important aspects as for example detailed definition of pooling/aggregation or the implementation of a reliability margin as proposed in the project REserviceS [92][93].

The volatility of area control error volume can be reduced with an implementation of cross-border balancing [21].

Reserve sharing leads to a lower need for procured resources and with this to lower costs, but it can only be employed under consideration of the system security (see NC LFCR [4]).

The implementation of the possibility for the exchange of balancing capacity lowers the combined expenditures for mFRR. This depends, though, on the price for the reserved cross-zonal capacity (in case of probabilistic dimensioning lower costs [21]) and on the provider based in the different countries.

### 6.1.3. Changes

The balancing costs will change depending on the market sizes of the countries that are combined and on the available generation capacity in each country.

Furthermore, the balancing prices are going to even up between relevant areas in a coordinated balancing area. Therefore, the prices could rise in some relevant areas.

The costs for balancing and, thus, for imbalance will align between countries. The costs will increase in some and decrease in others.

There will be a redistribution of the income situation for different BSPs as the sales volumes for cheap BSPs will increase, but the volumes for expensive BSPs will decrease.

## 6.2. Comparison of the target model and the AIS Balancing Markets for mFRR

### 6.2.1. Balancing Market design

Comparison: The dispatching system is the same in Austria and Slovenia (self-dispatch system on portfolio basis) but different in Italy (central dispatch system).
Target model: All three dispatch systems are accepted.
Risks: If products are converted by a TSO it is necessary to ensure transparency that the underlying calculation principles (selection and conversion) and reasons for withholding bids are made public.

### 6.2.2. Gate closure times

Comparison: The balancing gate closures are different in the three countries considered.

**Table 14: Gate Closure Times in AIS**

| | Austria | Slovenia | Italy |
|---|---|---|---|
| **Day-ahead** | 10:15 (D-1) EXAA<br>12:00 (D-1) EPEX | 9:40 (D-1) | 09:15 |
| **Intraday** | H-1.25 EPEX (D) | H-1 (D) | MI1 12:30 (D-1)<br>MI2 14:40 (D-1)<br>MI3 07:30 (D)<br>MI4 11:45 (D) |
| **Balancing Energy** | latest 15:00 (D-1) | Until real-time (D) | MSD1 = MB1 16:40 (D-1)<br>MB2 05:00 (D)<br>MB3 11:00 (D)<br>MB4 15:00 (D)<br>MB5 21:00 (D) |

Target model: Gate closure times have to be harmonized for each Balancing Energy Standard Product per Coordinated Balancing Area. All Transmission System Operators of a Coordinated Balancing Area shall commonly define and agree on balancing energy gate closure times. The GCTs of Balancing Services have

to be aligned with the GCTs of day ahead and intraday allocation of cross-border capacity and of GCTs of day-ahead and intraday energy markets.
Risks:

- The gate closure times of all the three markets are different.
- In a coordinated balancing area BSPs and BRPs in countries with a later Gate Closure Times have an advantage as they can adjust their positions for a longer time period. Furthermore, these participants have eventually the knowledge of the previous results and can use this knowledge for strategic bidding.
- The GCTs of the Balancing capacity Markets are very different in the three markets and should be harmonised. Besides the GCTs should be close to real-time taking into account on the one hand security of supply and on the other hand the increased participation of VPPs that would benefit from close to real-time GCTs (see next section 6.2.3; Validity period).

Possibilities:

- AIS day-ahead gate closure times happen all during a similar time of the day.
- The GCT of the Balancing Energy Market should be as close as possible to real time, giving the possibility to more BSPs, especially VPPs, to offer their bids in this market. Being close to real time these bids would incorporate more precise information (e.g. better wind forecasts).

### 6.2.3. Products for balancing capacity and energy

**Timeframe of Balancing capacity**
Comparison: In Slovenia the reserves are valid for one year or more. In Austria they are valid for weekdays or weekends in 4 hour blocks. In Italy there is an obligation for the generators to offer during all time (except the generators have an exception); they are selected for 6 hour blocks, but can even be activated when not selected.
Target model: The timeframe shall be no longer than one month. In case the timeframe is longer than that period permission from the NRA is necessary.
Risks:

- A BSP has to secure that the prices reflect its cost structure, but for a long timeframe of the product with fixed prices the risk is higher. This risk is priced into the balancing services bids (risk surcharge).
- In Slovenia a minimum number of activations are guaranteed to the BSP. The BSP can calculate with this minimum revenue.
- In countries where balancing capacity are pre-contracted for a long term some market participants such as demand response or fRES are limited or even excluded to take part in this market. Even one month is most certainly too long for fRES and DR to take part in balancing services.
- The higher the amount of pre-contracted reserves the higher the fees for this reservation. However, it is not necessary to pre-contract mFRR at all [5].

**Standard products**
Comparison: Table 15 shows the product characteristics in the considered countries.

**Table 15: Comparison of the product characteristics in AIS**

| | | Austria | Slovenia | Italy |
|---|---|---|---|---|
| **mFRR** | Full activation time | ≤ 10 min | ≤ 15 min | ≤ 5 min / ≤ 15 min |
| | Min/Max quantity | 10 MW[15] | 1 MW / 999 MW | 10 MW / - |
| | Increments | 1 MW | | - |
| | Deactivation period | ≤ 10 min | ≤ 15 min | ≤ 15 min |
| | Price of the bid | No limits | Max: 9,999.99 EUR/MWh Min: -9,999.99 EUR/MWh | Max: 3000 EUR/MWh Min: 0 EUR/MWh |
| | Divisibility | 1 MW increments | 1 MW increments | Yes |

15 Soon 5 MW

| | | | | |
|---|---|---|---|---|
| | Delivery period | ≤ 4 hours | ≥ 16 hours | Obligation, one block 6 hours |
| | Location | BSP | BSP | included |
| | Validity period | Days | One year or more | Obligation |
| | Mode of activation | Manual[16] | Manual (phone) | Automatic & Manual |
| | Schedule-/ Directly-activated | Directly-activated | Directly-activated | Directly-activated |
| | Activation rule | Merit order (energy-only) | Pro-rata & parallel | Merit order |
| | Definition of baseline | No | No | No |

Target model: There has to be at least one standard product in a coordinated balancing area.
Risks:

- The three markets do not have a compatible product for mFRR.
- Bid caps, if not active in all countries of a coordinated balancing area, can be overridden by cross-border marginal pricing, if this price is higher than the bid cap [21]. Thus, a bid cap just makes sense if implemented in all countries of a coordinated balancing area.
- Too long delivery periods (like in Slovenia) should be avoided in order to facilitate VPPs.

Possibilities:

- In the three countries the products are at least partly specified.
- An alternative to the harmonization of these products is the usage of robust and reliable algorithms that can deal with these differences in a transparent and fair way to all participants. In this case the harmonization would be emulated by the way in which the products are bid and presented to the TSOs [12]. This solution may, however, add a high degree of complexity to the system.

Changes: There has to be at least one uniform (standard) product in all considered countries.

### 6.2.4. Accreditation of BRPs and BSPs

**Authorized vendors of balancing services**
Comparison: In Italy only generators are allowed to provide mFRR. In Austria demand does not yet participate actively, but they are encouraged to do so if their consumption is higher than 0.5 MW. In Slovenia, even though theoretically both generators and consumers can participate, in the last years (2010-2013) only active power from conventional generation was auctioned for tertiary reserve control. Fluctuating renewable energies are explicitly excluded from providing mFRR in Italy. In Slovenia and Austria fRES are not explicitly excluded, but their participation is not yet stimulated either.
Target model: The participation of demand response and renewable generation has to be facilitated.
Risks: More experiences in integration of fRES in Balancing Markets outside of research projects (e.g. REserviceS, Regelenergie durch Windkraftanlagen) needed:

- The verification and billing of the power curtailment (negative balancing energy) is dependent on the definition and the measurement of the generation schedule.
- Possibility of adaptions such as for the usage of a reliability margin for fRES[17]
- Regarding DR there needs to be a baseline approach that permit customers to receive credit for no more and no less than the curtailment they actually provide [14].

### 6.2.5. Procurement Mechanism

Comparison: Three different balancing procurement mechanisms are in place. In Italy the enabled generators have an obligation to offer balancing services. In Slovenia an auction is implemented and, as a result, bilateral contracts are concluded. In Austria a weekly tendering process secures the balancing capacity.
Target model: Market based mechanism
Risks:

[16] Soon automated MOL-server
[17] Balancing capacity has to be available with 97.5% reliability in most countries [93], but for fRES it is not possible to guarantee 100 % reliability with no back-up capacity.

- Competitive distortion if in one Balancing Market has a market for the procurement of capacity implemented and in another one none (e.g. due to mandatory offers of balancing energy such as in Italy).
- Lower social welfare in a market with mandatory offers.

### 6.2.6. Pricing mechanism

Comparison: Balancing energy is priced pay-as-bid in all three countries.
Target model: The marginal pricing (pay-as-cleared) is recommended until a detailed analysis demonstrates that a different pricing method is more efficient. NE EB prescribes a harmonised pricing method per coordinated balancing area.
Risks:

- The costs for balancing depend on the balancing need in all countries of a coordinated balancing area. A high need for balancing in one country can increase the balancing costs in another country [19].
- The trading of balancing energy would not be impossible if the price mechanisms were different but the settlement would be more complex.

### 6.2.7. Activation mechanism

Comparison: In Italy and Austria the activation is done by merit order activation rule. In Slovenia the activation is performed with a pro-rata and parallel method (for explanation see section 3.2.7).
Target model: The activation rule is merit order.
Risks:

- In case of pro-rata and parallel activation inelastic prices can occur [21].
- Slovenia is not consistent with the other two markets and the target model, therefore in Slovenia the activation mechanism should be changed.

### 6.2.8. Imbalance settlement

**Imbalance Settlement Period**
Comparison: The imbalance settlement period in the three countries is different. In Austria it is 15 minutes, in Slovenia it is one hour and in Italy it is 15 minutes for enabled generators and one hour for non-enabled and consumption units.
Target Model: A cost-benefit-analysis will be performed if the imbalance settlement periods have to be harmonized.
Risks: Smaller imbalance settlement periods give better incentives to BRPs as power fluctuations during the period do not level out [19].
Possibilities: With an increase in the number of BRPs in the market a single BRP will have less influence on the imbalance settlement prices; therefore it will have a higher incentive that its position is as close as possible to its schedule in order to avoid possible penalties.

**Calculation of the imbalance**
Comparison: The imbalance is done differently in the three countries. In Italy the imbalance is done separately for the withdrawal and injection for every market zone. In Slovenia the calculation is done based on the market plan and the data of the realisation. Austria is comparable with the target model, except that the activation time of the mFRR is not adjusted.
Target Model: The calculation of the imbalance contains three parts: the notified positions, the metered values and the adjusted volumes reflecting the activation of energy bids.
Risks: The volume of the imbalance is part of the incentive to be balanced. A calculation that does not depict the real imbalances leads to wrong incentives.

**Imbalance settlement pricing mechanisms**
Comparison: In Austria a single pricing is implemented with a basic price and a variable component. In Italy the pricing is a dual pricing system and has exceptions for fRES and for consumption/non-enabled units. In Slovenia a dual price is used.
Target Model: The imbalance Price should be calculated for each direction. Besides, these prices should be the same since single price is also recommended by the TM. No exceptions for e.g. RES should be allowed.
Risks:

- The imbalance pricing is different in the three countries. A cross-border balancing is possible without full harmonisation, but it leads to market distortions.
- No exceptions for single participants - as for instance fRES - should be allowed to give incentives for the development of better forecasts. This is still the case in Italy and partly in countries with feed-in tariffs, too (e.g. in Austria). In the last case no particular exception is to be taken for the imbalance prices but the fRES owners are not faced by the risk of imbalances as they get fixed prices for each kilowatt hour produced.
- Dual prices can provide incentives to BRPs to minimize the imbalance instead of eliminating it leading to a strategic behaviour of the BRPs, which is not beneficial for the system stability.
- Even if the volatility of imbalance volume can be reduced by cross-border balancing, price spikes could occur [20].

Possibilities:

- Dual pricing could provide to minimize system imbalances though higher incentives.
- When no exceptions are allowed for fRES incentives are given to fRES to invest in more accurate forecasts.

### 6.2.9. Linkages with wholesale markets

**Existence of Intraday markets**
Comparison: An intraday market exists in all three countries.
ENTSO-E proposition: No obligation/recommendation is given in the NC Forward Capacity Allocation.
Possibility: The existence of intraday markets in all three countries supports the coupling of the Balancing Markets. Italy and Slovenia already operate in the day-ahead timeframe a market coupling that makes use of an implicit auctioning system.

**Day-ahead and intraday markets: Negative prices**
Comparison:

- Day-ahead: The day-ahead markets in AT, SI and in IT have a floor at 0 €/MWh.
- Intraday: The Italian intraday market has a floor at 0 €/MWh, the Austrian and Slovenian allow negative prices until - 9999.99 €/MWh.

ENTSO-E proposition: Without a floor no market distortion is induced and more accurate signals are sent to RES as well as flexibility providers [11].
Risks:

- Uncommon rules in coordinated balancing areas can lead to market distortions related to negative prices.
- In case that fRES are compensated with feed-in tariffs even negative prices do not send correct signals as fRES do not offer directly on the power exchanges and get fixed prices.

Possibilities: When negative prices are implemented, investments in flexibility equipment (e.g. storage, DR) are triggered.

### 6.2.10. Transmission capacity and congestions on cross-border balancing in AIS

**Available Transmission Capacity**
Comparison: In AIS the methodology for the calculation of transmission capacity is NTC. In all three borders there is an intraday auction (between Italy and Slovenia since 2013). Chapter 5 shows that intraday ATC varies a lot within one year.
Target Model: The TM proposed two options: Either to use the available capacity after the intraday auction or to reserve cross-zonal capacity for balancing.
Risks: To rely on the available transmission capacity after intraday does not guarantee that enough capacity will be available for balancing purposes.
Changes: Grid expansions in the HV network will have an effect in the cross-border congestions; however even a higher NTC does not guarantee that there are no congestions (especially in the distribution grid) due to for instance an increasing trade volume.

**Effects of internal congestions**
Comparison: There are internal trading limitations as well as cross-border congestions in as well as between the countries.
Target Model: Internal overloads are not considered yet, but this has to be included by the TSOs.
Risks: Especially the internal congestions in distribution networks are critical when considering VPPs, which are, in many cases, located in the LV grid. If the network operator has no information on the power quality in the lower voltage levels, the participation of these VPPs in technical and financial level is endangered.
Possibilities: A better knowledge about the distribution network with an adequate and broad measurement and communication system can mitigate the effects of internal congestion in lower voltage levels.

## 6.3. Considerations for the participation of VPPs in mFRR

In all three countries the regulatory frameworks - either market or technical criteria - do not allow the active participation of VPPs in the Balancing Markets, yet. Barriers are among others the requirements of a too big minimum size of one unit, missing possibility of aggregation by pooling the units, costs for pre-qualification of the minimal pre-qualified technical unit, too long activation times, lack of verification methodology (baselines), etc. Some relevant parameters for an implementation of VPPs can be seen in Table 16.

**Table 16: Relevant parameters for participation of VPPs in AIS**

| | | Austria | Slovenia | Italy |
|---|---|---|---|---|
| **mFRR** | Participation of DR | Not defined | Not directly included | Excluded |
| | Participation of fRES | Not defined | Not defined | Excluded |
| | Possibility for pooling of units | Yes | Yes | No |
| | Minimal prequalified technical unit | >0.5 MW | ≥1 MW | >10 MW |
| | Timeframe of Balancing capacity | Week ahead | Year ahead | Day ahead/Intraday |
| | Balancing products | 4 h block for five weekdays or two weekend days) | ≥16 hours | 6 hour blocks |

Moreover, the costs of the IT-connection, the data storage & transfer and the pre-qualification of the technical unit have an influence on VPPs. As VPPs consist of a large number of decentralized generation and demand units these costs accumulate if incurred for every single unit. By now, these costs for a VPP can be assumed to be quite high in every country of the AIS region. In Slovenia the 16 hours for the supplying of balancing products needs to be mandatorily reduced, as it excludes the participation of virtually all VPP technologies. These issues should be considered by the TSOs, when implementing the NC EB in national rules to allow the active participation of VPPs in the Balancing Markets and with this the participation of fluctuating renewable energies and smaller consumers.

To encourage the integration of VPPs in Europe it would be necessary to enable the aggregation of units and transfer registration, pre-qualification, measurement and communication to the aggregator level, facilitating the participation of even small residential consumers. Also standard products would be necessary, that support both fRES and DR. This could be achieved by the application of one product, which would be flexible enough to make the participation of different units - DR, fRES and conventional plants - in the

Balancing Market possible. This could be achieved by taking the characteristics of VPPs - among others the small size of the distributed units, and the dependency on weather conditions, and therefore on short-term forecasts - into account. The timing of the procurement of balancing capacity (e.g. day-ahead) and energy (e.g. intraday, after the gate closure of the intraday energy market) should be close to real-time and the period during that balancing energy can be activated should be short (e.g. best one to two hours). Moreover, the size of the minimum quantity of single bid (e.g. 1MW) and of the technical unit (e.g. 0.5 MW as in Austria or even smaller) that can be prequalified should be small. Furthermore, the introduction of a reliability margin as proposed by the project REserviceS could be positive for VPPs. An alternative option would be to rely on sophisticated algorithms (as mentioned in section 3.2.4) for the coupling of different Balancing Markets whose products are not 100% harmonised.

# 7. Conclusion

In this report two main questions were analysed. The first question regards the market opening of balancing energy between the three considered markets Austria, Italy and Slovenia. The second question aims at the national regulatory frameworks and the implications of Balancing Market integration for the participation of Virtual Power Plants. To answer these issues national and multinational parameters were analysed theoretically. The regulatory frameworks and technical pre-qualification requirements of the national Balancing Markets of Austria, Slovenia and Italy were analysed and compared with the national target model (D2.1; model nr. 1) and with the target model TSO-TSO model with a common merit order of ENTSO-E and ACER (D2.1; model nr. 4). Only in case of available transmission capacity a market opening is possible, therefore, implications of congestions in the transmission grid were discussed. The generation and demand units of Virtual Power Plants are situated mainly in the distribution grid, therefore congestions in the distribution grid can interfere with the overall need of balancing energy, and thus, this effect is depicted.

The Balancing Markets in Austria, Slovenia and Italy can be seen to be very different. The first main dissimilarity is the Balancing Market design. In Austria in Slovenia a self-dispatch model with portfolio-based balancing, a self-dispatch with portfolio-basis balancing and in Italy a central dispatch Balancing Market design is implemented. Many details in the Network Code on Electricity Balancing implicitly assume a self-dispatch Balancing Market design. For central dispatch markets an exceptional regulation is in place. The optimization algorithm in the central-dispatch model takes simultaneously the balancing requirement as well as the internal congestions into account. The balancing resources have to be mandatory offered in Italy, whereas in Slovenia the balancing capacity is procured via bilateral contracts. In Austria the market-based mechanism of a tendering process is used. The mFRR balancing service of the three countries is indeed according to the operation handbook of the ENTSO-E (former UCTE), but mFRR differs in some parameters as for instance regarding the time to full activation (10 minutes in Austria, 15 minutes in Slovenia and Italy). At least some of these differences have to be harmonized for the cross-border market opening of balancing energy. A start of these harmonisations would be an assimilation of the gate closure times – day-ahead, intraday, balancing energy, capacity allocation and favourable the (imbalance) settlement time unit - as different gate closure times make the cross-border provision of balancing energy nearly impossible. The detailed analysis of the risks, possibilities and changes regarding the implementation of the target model within Austria, Slovenia and Italy can be found in chapter 6. The limited available transmission capacity between Austria, Italy and Slovenia is a main obstacle for an increased exchange of Balancing Energy and, therefore, for the achievement of the TSO-TSO model with common merit order. With the extension of cross-zonal capacity the Balancing Markets could be integrated further.

The second question focuses on the integration of VPPs in the Balancing Markets. When defining the national rules respectively the rules of the coordinated balancing area it is highly recommended to explicitly consider VPPs, demand response and fRES as also stated in the NC EB. Some product specifications (as a lack of verification methodology – baseline) currently hinder the participation of VPPs, fRES and DR in the national Balancing Markets as for instance the maximal duration of the delivery period and the timing of the balancing capacity procurement. In the project REserviceS the introduction of a confidence level is suggested [92]. Additionally, the approach in case of congestions in the distribution grid has to be handled by the local DSOs, in order to solve local grid problems caused by the participation of generators or loads in the balancing scheme. Finally, as ENTSO-E stresses, the participation of VPPs should not only be considered, but especially facilitated in order to avoid the rise of short-term balancing costs in the current scenario of increasing penetration of fRES and DR. A huge step in this direction would be the possibility of aggregation of small units (pooling), which would transfer most of the technical and bureaucratical aspects to the aggregator’s level, giving to a large amount of small units the chance to participate in the Balancing Market.

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# Appendix

**Table 17: Important design variables of Balancing Markets in AIS ([9] adapted)**

| | | Design Variables[18] | Austria | Slovenia | Italy |
|---|---|---|---|---|---|
| **Balancing** | | Process | Portfolio Dispatch | Self-Dispatch | Central Dispatch |
| | | Nature of Obligation | Legal + Financial | Financial | Financial |
| | | Exemptions | None | RES | RES |
| | | Number of Portfolios | 1 | 1 | > 2 |
| | | Settlement | BRP | BRP | - |
| | | Settlement Time Unit | 15 min | 1 hour | 15 min/1 hour[19] |
| | | Pricing | Single | Dual | Dual |
| | | Main Component of Imbalance Prices (aggravating/reducing) | Day-ahead market price or Other | Average Control Energy Price/Day-ahead market price | Other/Day-ahead Market Price[20] |
| | | Additional Components | Variable | Other | - |
| | | Start/Stop costs | Implicitly | Not included | Not included |
| | | Publication | > 1 week after | > 1 week after | > 1 week after |
| | | Compliant Period | > 1 Month | - | - |
| | | Zonal/nodal responsibility | | | |
| **FCR** | | | | | |
| | | Energy Prices used | No | No | - |
| | Reserve | Procurement Scheme | Organised Market | Mandatory Offers | - |
| | Reserve | Minimum Bid Size | >5MW | No minimum | - |
| | Reserve | Timeframe of Product | Week | - | - |
| | Reserve | Timing of Offers | Week | - | - |
| | Reserve & Energy | Provider | Generators | Generators | Generators |
| | Reserve | Settlement Rule | Pay-as-bid | - | - |
| | Reserve | Cost Recovery Scheme | 100% Grid Users | - | - |
| | Reserve & Energy | Monitoring | Ex-post | - | Real-time |
| | Reserve | Secondary Market for Reserve Obligations | No | - | No |
| | Energy | Procurement Scheme | - | Mandatory Offers | - |
| | Energy | Minimum Bid Size | - | No minimum | - |
| | Energy | Timeframe of Product | - | - | - |
| | Energy | Gate Closure | - | - | - |
| | Energy | Settlement Rule | - | - | - |
| | Energy | Cost Recovery Scheme | - | - | - |
| **aFRR** | | | | | |
| | | Energy-prices used | Yes | Yes | No |
| | Reserve | Procurement Scheme | Organised Market | Mandatory Provision without Reservation | - |
| | Reserve | Minimum Bid Size | >5MW | No minimum | - |

[18] For description see Glossary and chapter 2
[19] generation listed for AS market: 15 min, consumption and not licensed generation: 1 hour
[20] Main component of Imbalance price for reducing consumption: other

| | | | | | |
|---|---|---|---|---|---|
| | Reserve | Timeframe of Product | 1Week/4Weeks | Year or more | - |
| | Reserve | Timing of Offers | 1Week/4Weeks | Year or more | - |
| | Reserve & Energy | Provider | Generators | Generators | Generators |
| | Reserve | Settlement Rule | Pay-as-bid | Pay-as-bid | - |
| | Reserve | Cost Recovery Scheme | Mix of Grid Users (78%) & BRP (22%) | 100% Grid Users | - |
| | Reserve & Energy | Monitoring | Real-time & ex-post | Hybrid | Real-time |
| | Energy | Procurement Scheme | Market | - | Mandatory Offers |
| | Energy | Activation Rule | Merit Order | In Proportion & Parallel | Merit Order |
| | Energy | Minimum Bid Size | >5MW | No minimum | 10MW |
| | Energy | Timeframe of Product | Blocks | Hour/Blocks | Hour/Blocks |
| | Energy | Gate Closure | D-1 | - | >H-1 |
| | Energy | Settlement Rule | Pay-as-bid | Pay-as-bid | Pay-as-bid |
| | Energy | Cost Recovery Scheme | Mix of Grid Users & BRP | 100% BRP | 100% Grid Users |
| **mFRR** | | | | | |
| | | Energy-prices used | Yes | Yes | Yes |
| | | Explicit bids / implicit bids | | | |
| | Reserve | Procurement Scheme | Organised Market | Bilateral Market | - |
| | Reserve | Minimum Bid Size | >10MW | No minimum | - |
| | Reserve | Timeframe of Product | Week(s) | Year or more | - |
| | Reserve | Timing of Offers | Week(s) | Year or more | - |
| | Reserve & Energy | Provider | Generators | Generators + Load | Generators |
| | Reserve | Settlement Rule | Pay-as-bid | Pay-as-bid | - |
| | Reserve | Cost Recovery Scheme | 100%BRP | 100% Grid Users | - |
| | Reserve & Energy | Monitoring | Ex-post | Ex-post | Real-Time |
| | Reserve | Secondary Market for Reserve Obligations | No | Yes | No |
| | Energy | Procurement Scheme | Market | Pre-Contracted Offers | Mandatory Offers |
| | Energy | Activation Rule | Merit Order | In Proportion & Parallel | Merit Order |
| | Energy | Minimum Bid Size | >10MW | No minimum | >1MW |
| | Energy | Timeframe of Product | Blocks | Hour/Blocks | Hour/Blocks |
| | Energy | Gate Closure | D-1 | - | >H-1 |
| | Energy | Settlement Rule | Pay-as-bid | Pay-as-bid | Pay-as-bid |
| | Energy | Cost Recovery Scheme | 100% BRP | 100% BRP | 100% Grid Users |
| **RR** | | | | | |
| | | Energy-prices used | - | Yes | Yes |
| | Reserve | Procurement Scheme | - | - | - |
| | Reserve | Minimum Bid Size | - | No minimum | - |
| | Reserve | Timeframe of Product | - | - | - |
| | Reserve | Timing of Offers | - | - | - |
| | Reserve & Energy | Provider | - | Generators + Load | Generators |
| | Reserve | Settlement Rule | - | - | - |
| | Reserve | Cost Recovery Scheme | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| | Reserve & Energy | Monitoring | - | - | Real-Time |
| | Reserve | Secondary Market Reserve Obligations | - | - | No |
| | Energy | Procurement Scheme | - | Market | Mandatory Offers |
| | Energy | Activation Rule | - | In Proportion & Parallel | Merit Order |
| | Energy | Minimum Bid Size | - | No minimum | >1MW |
| | Energy | Timeframe of Product | - | Hour/Blocks | Hour/Blocks |
| | Energy | Gate Closure | - | >H-1 | >H-1 |
| | Energy | Settlement Rule | - | Pay-as-bid | Pay-as-bid |
| | Energy | Cost Recovery Scheme | - | 100% BRP | 100% Grid Users |