Deliverable 2.1.A
Proposal of Common Rules about the provision of system services: Mediterranean Grid Code chapter

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"Med-TSO—Mediterranean Project II"
Activity 2.1 "Mediterranean common target regulatory framework (phase II) "

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1 Scope and purpose

The present report constitutes Deliverable 2.1.A, the first one within Task 2 of the so called Mediterranean Project II (MP II), an ongoing two year project performed by Med-TSO and supported by the European Commission. The main goal is to develop a proposal of common rules in the Mediterranean region in the framework of system services in order to complement the proposal already developed by Med-TSO between 2015 and 2018 during Mediterranean Project I. With this report a complete proposal of Mediterranean Grid Code has been developed covering 3 main technical areas:

- Connection of users to the grid (developed in Mediterranean Project I).
- Operation of the interconnected systems (partially developed in Mediterranean Project I and completed now with the load frequency control aspects).
- Sharing of system services.

The work has been developed by Med-TSO Technical Committee 2 on Regulation and Institutions (TC2) with the direct involvement of Med-TSO members.

2 Methodology

The methodology used has been a very collaborative approach between Med-TSO TC2 members through various surveys that were completed by each TSO in order to understand the current regulatory situation in each country and taking as a reference the outcomes of Mediterranean Project I in order to assure the coherency of the complete Mediterranean Grid Code. As shown in the following figure, this approach has enabled a major involvement of 14 TSOs through specific task forces for each of the specific areas that have been analysed in detail:

Med-TSO TC2 members have completed various surveys aimed on understanding what the current regulatory situation in each country is. In addition the outcomes of Mediterranean Project I have also been considered in order to assure the coherency of the complete Mediterranean Grid Code. Specific task forces (composed by 14 TSOs) for each technical area have been involved in the development of this document, as is shown below:

- Capacity calculation: REN, GECOL and TEIAS.
- Capacity allocation: ONEE, GECOL, OST and REE.
- Legal issues: HOPS, TERNA and ONEE.
- Load Frequency Control and definition of reserves: IPTO, SONELGAZ/OS, STEG, CYP TSO and OST.
- Activation of reserves: REE.

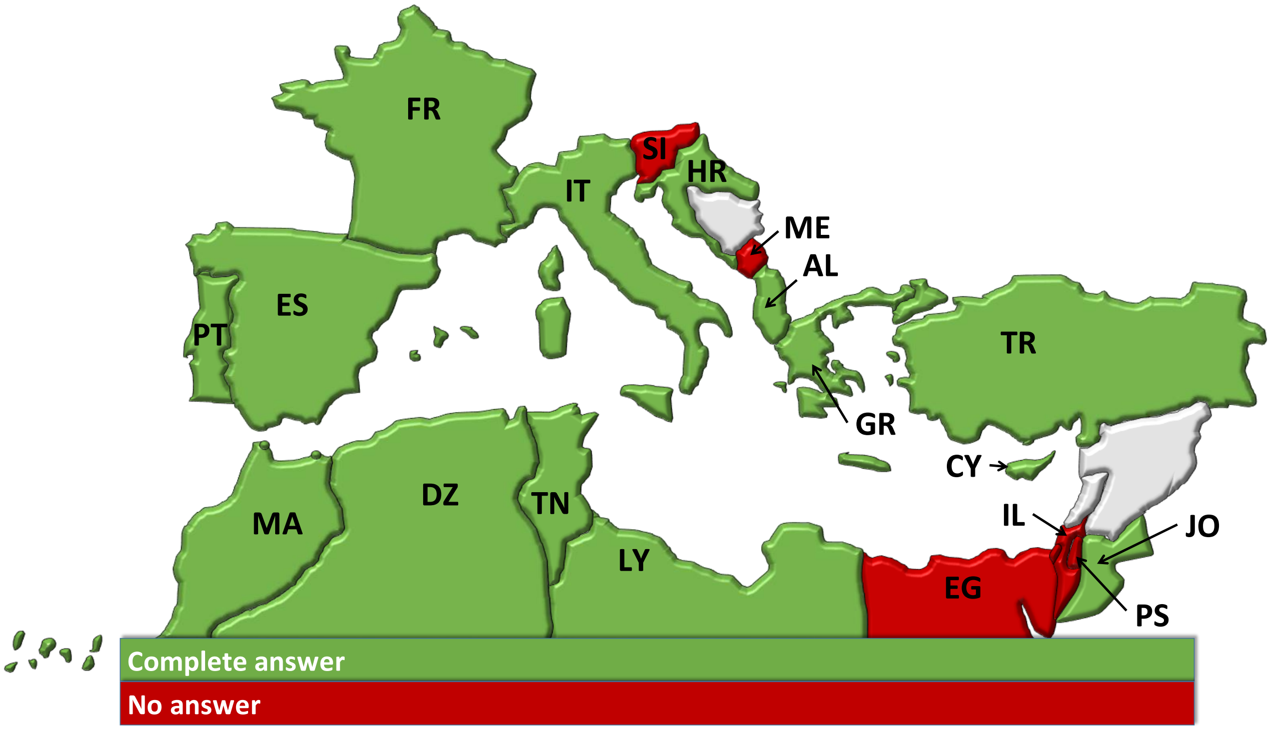


Figure 1. Map of the countries that have completed the Med-TSO surveys

3 Mediterranean Common Target Regulatory Framewok on System Services

3.1 Legal issues

3.1.1 Participant´s roles

Role of the Transmission System Operator

Transmission System Operator (TSO) is a natural or legal person responsible for power system operation (and power system planning where applicable), maintenance approval process or where applicable maintenance, cross-border congestion management and procurement of balancing services from balancing service providers in order to ensure operational security. TSO is also responsible for the planning of development of transmission system in given area, and, where applicable the construction of the development, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity.

Role of Market Participant

Market Participant is any person (producer, supplier, trader, DSO, TSO…), who enters into transactions, including the placing of orders to trade, in one or more wholesale energy markets.

Role of balance responsible parties

Each Market Participant, who signed the Contract for balancing responsibility with connecting TSO, is Balance Responsible Party (BRP).

Role of balancing service providers

Balancing service provider is a market participant qualified for providing balancing energy or balancing capacity, which are activated or procured by the connecting TSO or, in a TSO-BSP model, by the contracting TSO. This qualification process should follow rules in order to be compliant with the prequalification procedures established for providing the different types of reserves.

3.1.2 Registration

In order to establish cross-border exchange on the interconnections TSOs should conclude an Operational Agreement for coordination on energy exchanges on HVAC/HVDC lines which should define at least:

- cooperation in planning, maintenance and construction of interconnections;
- calculation of TTC, NTC, TRM values;
- allocation and use of cross border capacities on all time levels;
- exchange of balancing energy & capacities, emergency restoration reserve;
- accounting of intentional/unintentional cross border exchanges.

Rules on allocation and use of cross-border capacities

Depending on the way of allocation of cross-border capacities (unilateral/bilateral/coordinated), TSOs are obliged to define rules on allocation and use of cross-border capacities. Such rules should define at least following issues:

- process of calculation TTC/TRM/NTC/AAC/ATC values,
- process of market participant registration,
- process of allocation of ATC value,
- process of nomination of allocated physical transmission rights (PTR).

Terms and conditions related to balancing

On the basis of grid code and primary and secondary legislation of each country (LFC area), TSOs should develop:

a) Terms and conditions for balancing service providers;
b) License process Legal obligations to become balancing service providers (such as a license process)
c) Terms and conditions for balance responsible parties.

Where a LFC area consists of two or more TSOs, all TSOs of that LFC area may develop a common proposal subject to the approval by the relevant regulatory authorities.

These terms and conditions could include legal and financial requirements (as guarantees) or specific balancing contracts with each TSO.

3.1.3 Obligations

All balance responsible parties are obliged to operate according to rules mentioned in chapter 3.3.4.

3.1.4 Imbalance calculation

Imbalance is physical difference in schedule and realization of electrical energy trade. TSO activates balancing energy in order to cover imbalances.

Each BRP is financially responsible for the imbalances to be settled with the connecting TSO. In real time, each BRP is entitled to strive to be balanced or help the power system to be balanced.

Each TSO shall calculate within its scheduling area or scheduling areas when appropriate the final position, the allocated volume, the imbalance adjustment and the imbalance:
(a) for each balance responsible party;
(b) for each imbalance settlement period;
(c) in each imbalance area.

Each TSO if responsible for imbalance calculation, price and financial settlement.

3.1.5 Suspension or withdrawal

If market participant/BRP does not comply to any defined rules approved by national regulatory authority (NRA) TSO in cooperation with local NRA should be able to suspend or withdraw such party.

An Agreement between TSO, BSP, BRP or market participants (according to national legislation) should be established. The Agreement should detail also the termination, the suspension or withdrawal conditions.

If a market participant/BRP does not comply with any of the defined rules approved by relevant NRA, the suspension or withdrawal shall be carried out according to relevant Agreement.

3.2 Capacity calculation

The target is the coordination and harmonization of the capacity calculation methodology within the capacity calculation regions that could be established in the Mediterranean region. Coordinated capacity calculation means that when the capacity is calculated in the "coordinated" borders the interdependencies between them are considered to ensure that capacity calculation is reliable and that optimal capacity is made available to the market at regional level.

Capacity calculations regions should be established. Until the establishment of these regions the capacity calculation will be done bilaterally between bordering TSOs.

3.2.1 Timeframes

In general the time horizons used for capacity calculation should be yearly, monthly and daily.
Other timeframes could be agreed between the concerned TSOs.

Details should be included in internal agreements between the concerned TSOs.

3.2.2 Individual Grid Model

An individual grid model is defined in this context as a data set describing power system characteristics (generation, load and grid topology) and related rules to change these characteristics during capacity calculation, prepared by the responsible TSOs, to be merged with other individual grid model components in order to create the common grid model.

A scenario is defined as the forecasted status of the power system for a given time-frame.

All TSOs should develop scenarios for each market time unit and establish the Individual Grid Model (IGM). This scenarios should contain structural data, topology, and forecast of:

- Conventional generation
- Renewable Energy Source (RES) generation;
- Load;
- Flows on direct current lines (when applicable).

The process shall be done by a coordinator TSO (for each capacity calculation region) who carries out the coordination task within the TSOs in the same region. Each month a different TSO carries out this task. Calendar showing which TSO is the coordinator TSO is determined before each calendar year.

All the TSOs in the region constitute its own BCE (Base Case Exchange) table. These tables, which include import or export values for each border, are based on the third Wednesday of related month at 10:00 (CET). The coordinator TSO combines and harmonize these tables shared within the relevant group in a manner to create a balance within the relevant region. The harmonized BCEs table is shared within the group so that each TSO creates its own IGM (Individual Grid Model) according to this BCEs table. The created IGMs are shared within the group. The coordinator TSO combines the relevant IGMs to create the CGM (Common Grid Model).

A common format should be established or at least conversion into different formats should be considered.

3.2.3 Common Grid Model scenarios

A common grid model is defined in this context as a Mediterranean-wide data set agreed between various TSOs from the same capacity calculation region describing the main characteristics of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process.

The individual TSOs' IGMs are merged to obtain a Common Grid Model (CGM). The process of CGM creation is performed by the merging agent, which obligations are the following:

- Check the consistency of the IGMs (quality monitoring);
- Merge M-2[1] IGMs (for Monthly capacities) and create a CGM;
- Merge D-2[2] IGMs and create a CGM per market time unit;

[1] 'M-2' means two months before the day of delivery
[2] 'D-2' means two days before the day of delivery

- Merge D-1 IGMs and create a CGM (This model is usually used only to check the network security, not for capacity calculation except if intraday market exists).
- Make the resulting CGM available to all TSOs.

As a part of this process the merging agent checks the quality of the data and requests, if necessary, the triggering of backup (substitution) procedures (see below).

3.2.4 Methodology calculation

TSOs in the Mediterranean can use two approaches in order to perform the capacity calculation:

- Coordinated Net Transmission Capacity (NTC).
- Flow based (FB).

Coordinated net transmission capacity approach means the capacity calculation method based on the principle of assessing and defining ex ante a maximum energy exchange between adjacent bidding zones. It is the preferred option for those capacity calculation regions whose borders are very independent between them.

Flow-based approach means a capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on critical network elements. It is the preferred option for those capacity calculation regions whose borders are very dependent between them.

TSOs from the same capacity calculation region should agree on the methodology to be used in the borders within that capacity calculation region.

3.2.5 Operational security constraints and outages

3.2.5.1 Critical network elements and contingencies

A Critical Network Element (CNE) is a network element either within a bidding zone or between bidding zones monitored during the capacity calculation process. The CNEC (Critical Network Element and Contingencies) is a CNE limiting the amount of power that can be exchanged, potentially associated to a contingency (see below the definition). They are determined by TSOs for the same capacity calculation region for its own network according to agreed rules, described below.

The CNECs are defined by:

- A CNE: a line or a transformer whose flow is significantly impacted by cross-border exchanges; a node whose voltage is significantly impacted by cross-border exchanges; a line whose voltage phase angle difference is significantly impacted by cross-border exchanges after its trip.
- An “operational situation”: base case (N regime) or contingency cases (N-1, N-2).

A contingency is defined as the trip of one single or several network elements that cannot be predicted in advance as a result of a single event. A scheduled outage is not a contingency. The normal type of contingency comprises the loss of a single element, which can be:

- a line
- a tie-line
- a DC link
- a generation unit
- distributed generation of a relevant size like a clustered wind farm, cogeneration, etc.
- a transformer (including Phase Shifter Transformers)
- a large voltage compensation installations.

Contingencies situation could result from the combined loss of several elements.

3.2.5.2 Definition of operational security limits

Maximum permanent and temporary current on a Critical Branch

The maximum permanent admissible current/power means the maximum loading that can be sustained on a transmission line, cable or transformer for an unlimited duration without risk to the equipment.

The temporary current/power limit means the maximum loading that can be sustained for a limited duration without risk to the equipment (e.g. 115% of permanent physical limit can be accepted during 20 minutes). Each individual TSO is responsible for deciding which values (permanent or temporary limit and duration of each overload) should be used.

As thermal limits and protection settings can vary in function of weather conditions, different values are calculated and set for the different seasons within a year. These values can be also adapted by the concerned TSO if a specific weather condition is forecasted to highly deviate from the seasonal values.

Maximum/minimum voltage on a node of the network

If the voltage on a node is significantly impacted by cross-border exchanges, the voltage on this element shall be monitored in the capacity calculation.

Each TSO shall specify the voltage limits for each element of its transmission system. Usually voltages are considered as local issue except border nodes. TSOs make sure to keep the voltages on border SSs in the predefined limits, which is part of Operation Agreement, signed by respective TSOs. TSOs make sure to decrease the reactive flow on the interconnection as much as possible in order to use the NTC for active power exchange.

Voltage Phase Angles Differences

Following the opening or the outage of tie-lines a manual reclosure may be refused by Parallel Switching Devices (PSDs) in case of voltage phase angle difference exceeding the pre-set threshold of the device.

The setting of the threshold depends on operational conditions in this respective area of the grid and are often chosen around 30º.

3.2.6 Reliability margin calculation

The methodology for the capacity calculation is based on forecast models of the transmission system. The inputs are created in advance before the delivery day with the best available forecast for Day Ahead Market. Therefore the outcomes are subject to inaccuracies and uncertainties. To solve this situation reliability margins should be used when performing the capacity calculations.

For the Net Transmission Capacity methodology, the Transmission Reliability Margin is used. This value is used for the whole interconnection, not for each interconnector line.

Transmission Reliability Margins (TRMs) are used to cover these inaccuracies and uncertainties induced by those forecast errors. The TRM value is defined as a safety margin used to overcome the uncertainties (e.g. emergency exchanges between related TSOs in unexpected instability in real time, unintended physical flow deviations within the framework of load frequency control, some mistakes in data collection and measurement) on the calculated TTC (Total Transfer Capacity) values. TRM values are defined as a fixed number or a percentage of TTC. TSOs generally use one of the following two equations to determine the TRM values of different borders:

$$TRM = 100 * N \quad (1)$$

$$TRM = 100 * \sqrt{N} \quad (2)$$

N: Number of interconnection lines between two countries.

Results from formula 1 and formula 2 form a range for TRM.

In addition to the above procedure there is another procedure that can be performed by each TSO that will calculate its own TRM values according to the need of ensuring its network operation security. This TRM value is determined as follows:

$TRM_i = U_r + U_E$, or

$TRM_{ii} = \max(U_r, U_E)$

U_r = statistical estimate based on historic data.

U_E = margin for common reserve and emergency exchanges.

TRM_i value is the worst case combination, that takes into account both statistical estimate and common reserve and emergency exchanges margin. TRM_{ii} value assumes that both uncertainty margins cannot happen simultaneously.

For the Flow Based methodology a Flow Reliability Margin (FRB) is used. In this case, the margin is considered in advance before the calculations for each interconnector line.

3.3 Capacity allocation

3.3.1 Timeframes

The available cross-border capacity should be divided into different timeframes and allocated through different auctions for each time horizon.

In long-term auctions, cross-border capacity could be auctioned yearly and monthly. A successful bid for one MW of yearly capacity entails the right to use one MW of cross zonal capacity for energy trading in one direction for every hour for a whole year. The monthly auction functions in the same manner, but the cross-border capacity is only given out for one month at a time.

Cross border capacity should also be made via an auction the day ahead (D-1, the day prior to delivery). Finally in the intraday horizon at least one auctions could be established.

3.3.2 Mechanisms (auctions)

The aim of the capacity allocation procedures is to foster competition and market integration. This code shall set out how Transmission System Operators offer cross-border capacity on a regular basis for all firm energy transactions, by defining a number of regular points in time for the allocation of firm capacity

Auction design

All cross-border capacity with the possible exception of within-day (intraday) timeframe, should be allocated via auctions guaranteeing the principles of anonymous and transparent online-based auction procedures, which should avoid any abuse of a dominant market position.

The auction design should be harmonized and applicable at every interconnection point in particular for firm day-ahead capacity. This design does not aim to prevent Transmission System Operators from already implemented day-ahead implicit or explicit auctions. Anyway the same detailed auction design shall be coordinated at least between Transmission System Operators sharing the interconnection.

Congestion income

Congestion income shall be used for different aims subject to the approval by the National Regulatory Authority, such as PTR curtailment compensation to market participants, countertrading, lowering network tariffs, removing congestion by investments or providing incentives to the Transmission System Operators to offer maximum capacity.

Interim period

An interim period could be allowed before the implementation of auctions. Adjacent Transmission System Operators should apply harmonized allocation mechanisms at each interconnection.

3.3.3 Capacity splitting procedure

Bidding zones

TSOs from the same synchronous area must define the bidding zones in which the area is separated. A bidding zone is defined as the largest geographical area within which market participants are able to exchange energy without capacity allocation.

When defining zones, TSOs must be guided by the principle of overall market efficiency by integrating all relevant economic, technical and legal aspects, such as socio-economic welfare, liquidity, competition, network structure and topology, planned network reinforcement and redistribution costs.

The definition of bidding zones should also contribute to price correction and proper treatment of internal congestion. They concern all deadlines: long-term, day-ahead and intraday. In addition, zone boundaries must be coordinated with the balancing zones.

The principle of market efficiency mentioned above and aspects such as the security of the system should be reflected in the proposal and evaluated by providing a solid and complete justification for either the proposed new delimitation or the preservation of existing areas.

The assessment should be prepared in a coordinated regional manner, taking into account possible impacts on other areas of the region concerned and updated when the topology or the generation and load patterns of the network, or local energy situations (deficits or surpluses) undergo significant changes or when it is necessary to guarantee the security of the system.

The TSOs proposal of bidding zones should be approved by NRAs.

Rules for splitting capacity

Rules for splitting capacity between time frames should be established based on the level of long-term capacity calculated for a given allocation time frame, the portion of this capacity (expressed in absolute or relative terms) actually made available on the market for the time frame concerned (with the remainder of the NTC being either already allocated as part of previous allocations, or reserved for later time frames).

Several criteria may be taken into account when defining capacity-splitting rules. The criteria should be proposed by TSOs and approved by NRAs.

1. Sufficient available capacity for all allocations:
   - Splitting of capacities between long-term time frames and day-ahead and intraday time frames: The percentage allocated at long-term auctions, either physical or financial, shall be a trade-off between the minimum demanded by the market for their risks hedging needs and the maximum allowed by TSOs to not incurring in financial risks due to capacity calculation uncertainty.
   - Splitting of capacities between long-term time frames: splitting may be defined in advance to ensure that sufficient supply is available at each auction. In addition long-term time

frames should have enough capacity for market participants to be able to hedge risks on that timeframe.

2. Minimum volume of hedging products for market participants: Minimum floor levels may be set for each long-term time frame except for security situations, in order to ensure that the volumes offered for sale are adequate to meet the hedging requirements of market participants. These levels could, for example, be set based on the comparative volume of activity on the financial derivatives markets (long-term energy contracts). Additional auctions (seasonal, quarterly, etc.) could also be held, over and above the annual and monthly auctions required by the FCA Regulation, to allow for a more dynamic hedging strategy.
3. Consistency of capacity valuations with actual system status.
4. Independence from grid development. In addition to fluctuations in the NTC caused by variations in the anticipated status of the power system, interconnection capacity between zones can vary significantly when new installations come online. Consequently, it may be preferable to adopt splitting rules expressed in the form of a percentage of the NTC calculated (perhaps with a minimum floor value), rather than as absolute volumes, in order to ensure that such grid developments are automatically reflected.

3.3.4 Rules of the use and the nomination of the capacity

Capacity allocation methods for the forward market

The objective of long-term transmission rights (both yearly and monthly), whether physical or financial, is to provide market players with long-term coverage solutions against uncertainty in price differences.

Cross-border trading could be with Financial Transmission Rights (FTR) or the Physical Rights of Transfer (PTR) with Use-It-Or-Sell-It (UIOSI), except a cross-border financial hedging is offered on liquid financial markets on both sides of an interconnection. The PTR must be defined as options and subject to UIOSI. The nature of the FTR in terms of options or obligations should also be established.

Hybrid solutions mixing PTR and FTR on the same border are not allowed. A harmonized set of border rules where PTRs with UIOSI are applied and a harmonized set of rules for the boundaries where FTRs are applied should be established.

TSOs could provide a single platform for long-term transmission rights (PTR and FTR). As a transitional measure, regional platforms can work, provided that this does not hinder the improvement and harmonization of the attribution rules.

Capacity allocation methods for the day-ahead market:

TSOs should implement capacity allocation mechanism on the day-ahead based on explicit auctions.

Intraday Capacity Allocation

The essential characteristic of the intra-day market is to allow market participants to negotiate energy as close as possible to real time in order to (re) balance their situation. Intraday transactions are particularly important to support intermittent generation and unplanned events such as outages.

The capacity pricing and congestion pricing method is subject to the approval of the NRAs concerned. As a transitional measure, explicit direct access to capacity will also be permitted, subject to the approval of the relevant NRAs.

Firmness of allocated capacity

The codes shall provide that reduction of allocated capacity may only be used in emergencies and force majeure, and when all other means are exhausted, (reduction of allocated capacity shall be a last resort measure). The reduction of already allocated capacities will be compensated through congestion income.

3.3.5 Countertrading

The CACM Network Codes shall ensure that TSOs implement coordinated cross-border redispatching/countertrade at least at regional level, with a fair allocation of congestion costs between countries/zones. It shall be coordinated with control-area internal redispatching/countertrade.

The coordination of redispatching/countertrading measures shall be based on the use of a common grid model and the relevant data shared among all concerned TSOs.

Redispatching shall be conducted on the basis of its efficiency. The CACM Network Code(s) shall oblige each TSO to ensure that the pricing of generation capacity reservation does not distort the market and to coordinate capacity reservation conditions.

3.4 Load frequency control & definition of reserves.

The stability of the frequency, on an electrical network, reflects the equilibrium between production and consumption that is to say between the driving forces of the power plants and the resisting torque represented by the loads. If the demand (the consumption) exceeds the supply (the production), the system is out of balance, the speed of the machines, and consequently the frequency of the network decreases. On the other hand, if the supply is greater than the demand, the system sees the groups accelerate and the frequency increase.

Since consumption fluctuates by nature, it is necessary to constantly adjust the level of production to maintain the frequency at a stable reference value: 50 Hz in the Mediterranean region. The frequency must be kept within a certain tolerance range around this reference value, firstly because a constantly evolving frequency would make the electricity unusable for multiple uses, on the other hand, because most of the components of the System are optimized and specified to operate in a given frequency range. Outside this tolerance range, serious equipment malfunctions occur (especially on regulating devices) and, if the imbalance is too great, the groups are separated from the network inevitably causing the collapse of all or part of the electrical system.

The frequency setting meets two requirements:

- Satisfy users (the frequency is a common size and to monitor): In normal operation, we can consider that the frequency is uniform at a given moment on the entire network (alternators, being interconnected by the game of electromagnetic forces, all rotate at the same electrical speed). Maintaining the frequency close to its nominal value is necessary for the proper functioning of the electrical equipment and infrastructure of consumers and producers, designed for operation over a given frequency range. Too large frequency excursions are inadmissible for some equipment and may lead to malfunctions in user installations.

- Ensure the safe operation of the system: avoid frequency collapse.

The evolution of frequency is the direct sign of imbalance between production and consumption:

- Frequency increases when the production is in excess with respect to consumption;
- Frequency decreases when the production is in deficit with respect to consumption.

In the Mediterranean Area, the electrical system of Maghreb is fully interconnected to the European network by synchronous links between Morocco and Spain being part of a single system with the same frequency.

The production-consumption balance is ensured, in normal operation, by the coexistence of three actions, two complementary automatic actions which are the primary and secondary adjustment (frequency-power) and a third action which is the tertiary adjustment (in some cases, a fourth action is also in place through the activation of slow balancing reserve). The performance of the first two actions is essential for the safety of the system. More specifically, the primary adjustment is fundamental for the safety of the electrical system, during large amplitude variations, to provide very fast control of the frequency transient so as not to reach the first thresholds of frequency shedding. On an interconnected system, all TSOs contribute jointly to this primary setting, which in fact improves safety of the interconnected system.

To this end but also for the safety of each system, it is important that each TSO permanently maintains a sufficient upward and downward primary reserve on its system, by securing in advance a sufficient amount of reserves available in its production units, with the aim to hedge the uncertainty of facing a deficit or surplus of balancing energy to cope with real-time deviations due to imbalances. Imbalances in an interconnected system can have different reasons; the main cases to be considered are presented in **Errore. L'origine riferimento non è stata trovata.** and listed below:

1. Disturbance or full outage of a Power Generating Module, HVDC interconnector or load
2. Continuous variation of load and generation caused by fast variations of consumption and generation
3. Forecast errors – slow disturbances caused by forecast errors of load (e.g. due to untypical weather) and RES generation
4. Deterministic imbalances – a deterministic disturbance caused by the deviation between load and step-shaped schedules (induced by some fast dynamic power plants) which reaches its peak

at the time point with the highest change of schedules and causes deterministic Frequency Deviations.

5 Network splitting - these imbalances are generally out of the dimensioning of the Synchronous Area as they lead most likely to an emergency situation in a part or in all of the Synchronous Area.

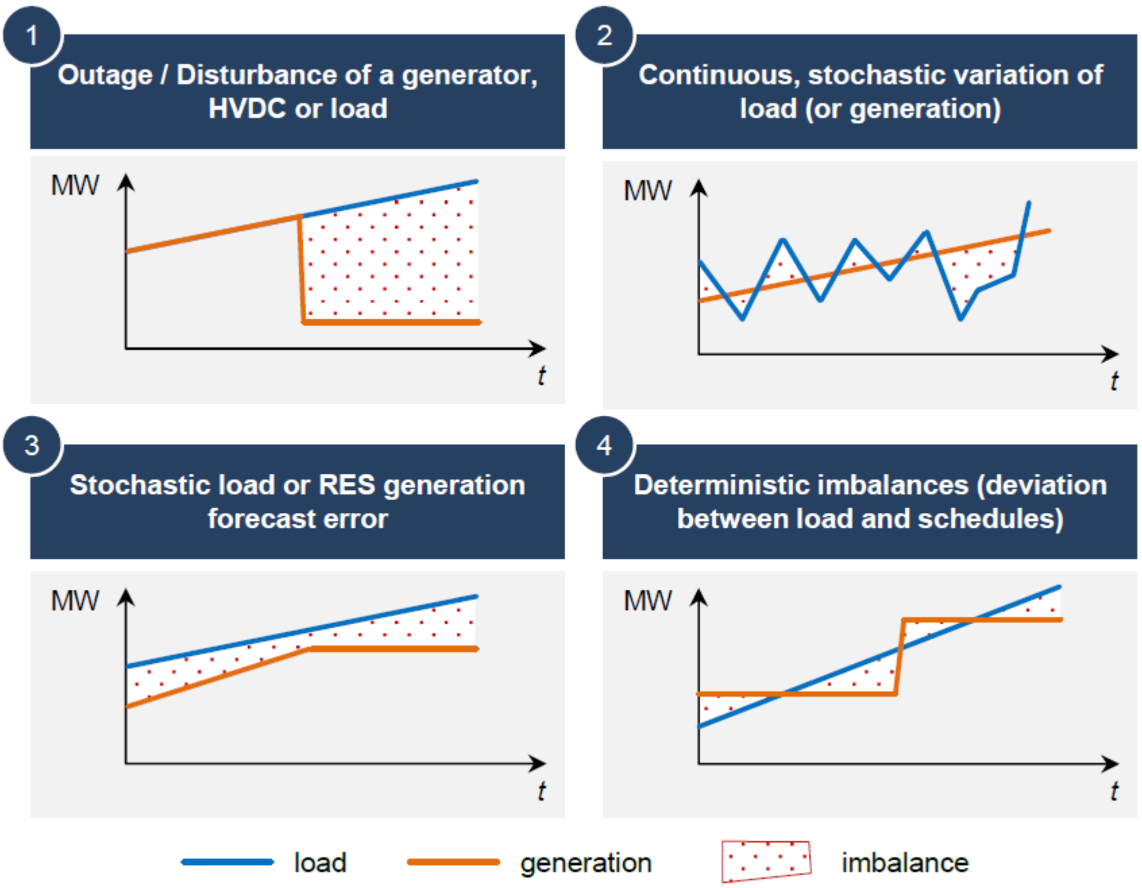


Figure 2. Simplified illustration of imbalance types

It is recommended for each TSO to secure a minimum upward and downward primary reserve (MW), with a minimum regulating energy (MW/Hz). In the same way, it is also important, that each TSO maintains a sufficient secondary reserve (MW) on its production units, in order to be able to compensate on its own for the production-consumption imbalance when the origin of the latter is in its adjustment zone, and thus to reconstitute the primary adjustment reserve.

3.4.1 Process activation structure

The Process Activation Structure defines:

- Mandatory control processes which have to be implemented and operated by the TSOs in each Synchronous Area
- Optional control processes which may be implemented and operated by the TSOs in each Synchronous Area

Accordingly the Process Responsibility Structure defines:

- different area types ;
- hierarchical relationship between different areas ;
- area process obligations,(control processes, quality targets, reserve dimensioning) which must be fulfilled by a TSO operating an area.

Synchronous Area: a synchronous area includes interconnected TSOs with a common System Frequency in a steady operational state. In the Mediterranean Region the following synchronous areas are defined:

- Continental Europe (including Turkey)
- Maghreb (Morocco, Algeria and Tunisia)[3]
- Mashreq (Libya, Egypt, Jordan, Palestine, Syria, Lebanon and Israel)

Control Area: **a** control area is a coherent entity (usually coinciding with the territory of a company (TSO), a country, or a geographical area, physically demarcated by the position of the delivery points for the measurement of the power and energy exchanged with the rest of the interconnected grid), operated by a single operator network, with loads and production units able to load monitoring at within the adjustment zone.

Monitoring Area: defines part or the entire Control Area, physically demarcated by points of measurement of Tie-Lines to other Monitoring Areas, operated by one or more TSOs fulfilling the obligations of a Monitoring Area.

Each Synchronous Area consists of one or more control Blocks (or each control Block is a sub-area of a Synchronous Area). A control Block consists of one or more Monitoring Areas (or a Monitoring Area is a sub-area of a control Block)

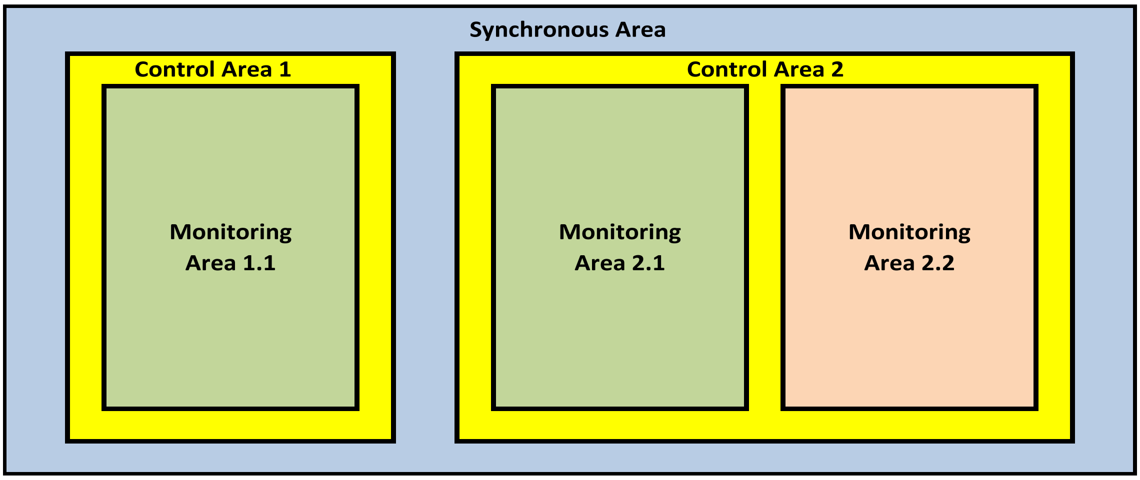


Figure 3. Areas Structure

[3] In the medium-long term Libya could be included in the Maghreb synchronous area depending on the studies performed about the desynchronization with Egypt and the potentail back to back solution in the interconnection between Egypt and Libya).

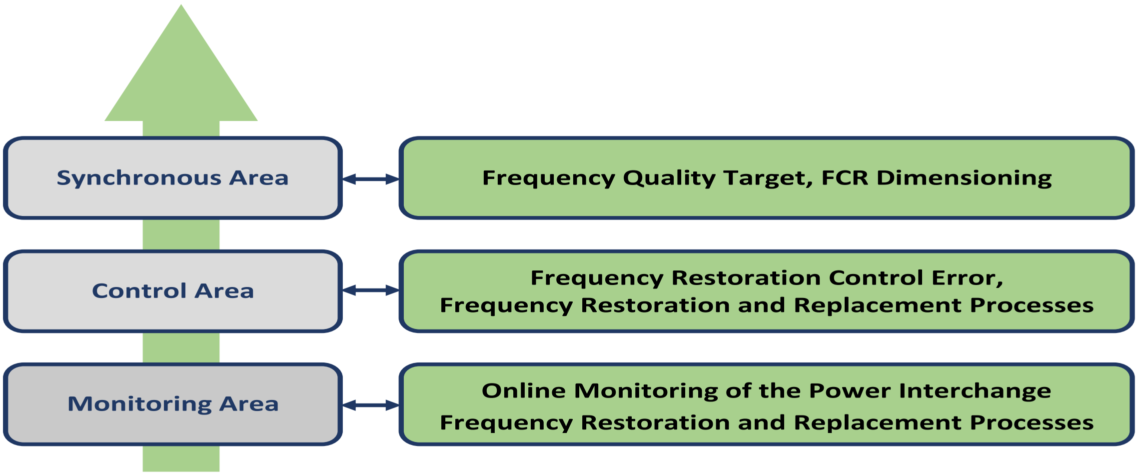


Figure 4. Process Responsibility Areas Structure

3.4.2 Definition of reserves

As mentioned in paragraph 3.4, with the aim to keep power system frequency within secure limits, TSOs shall maintain the balance between load and generation on a short term basis. An option which gives the TSOs the possibility to activate a certain amount of Balancing Energy within a certain timeframe is referred to as "Reserve Capacity", typically defined as the available generation or demand capacity which can be activated (upward or downward) either automatically or manually to balance the system in real time. "Balancing Capacity", refers to the contracted part of the Reserve Capacity. Thus, Balancing Energy in real time can be provided either by the balancing resources which were secured in advance as Balancing Capacity, or by other balancing resources that can offer Balancing Energy based on their availability in real time.

The framework of the Load-Frequency-Control processes is based on the current best practices in power system operation and in control engineering in general:

- The Frequency Containment Process stabilizes the frequency after the disturbance at a steady-state value within the permissible maximum steady-state frequency deviation by a joint action within the whole Synchronous Area.
- The Frequency Restoration Process within controls the frequency to its set-point value and replaces the activated FCR. The Frequency Restoration Process is triggered by the disturbed control Area.
- The Reserve Replacement Process (activation of the slowest balancing energy) replaces the activated FRR (composed of secondary aFRR and tertiary mFRR), and the FCR in some Synchronous Areas (this process can also support the FRR activation). The Reserve Replacement Process is triggered by the disturbed control Area

Errore. L'origine riferimento non è stata trovata. illustrates the interdependencies between the Frequency Containment Processes, Frequency Restoration Process and Reserve Replacement Process

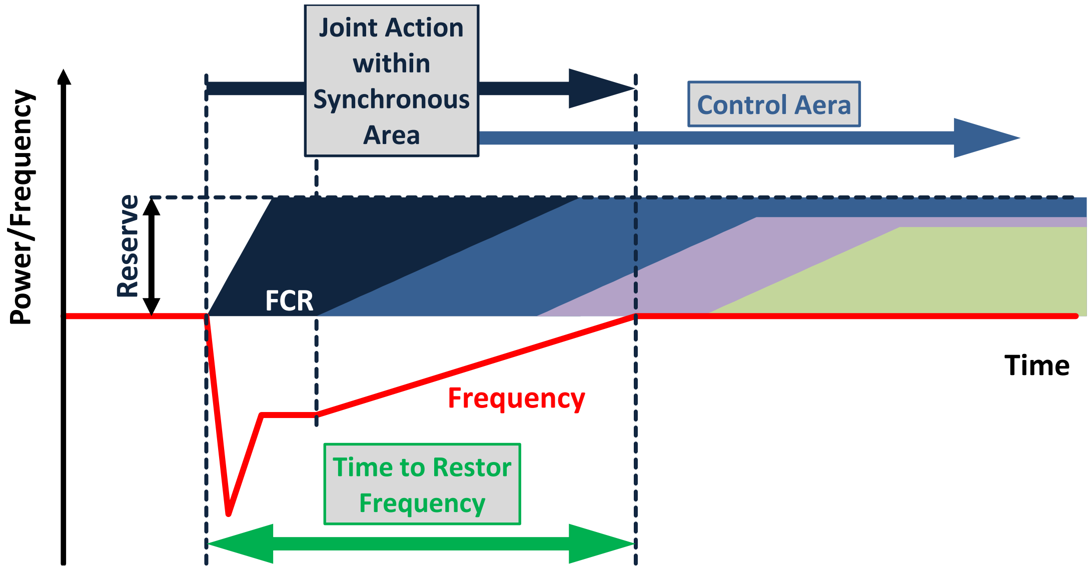


Figure 5. Load-Frequency-Control processes as successive “layers” of Reserve Capacity activation

Based on the above, the different types of Reserve Capacity that shall be secured by the TSO as Balancing Capacity are the following:

a) Frequency Containment Reserve (FCR)
b) Frequency Restoration Reserve with automatic activation (aFRR)
c) Frequency Restoration Reserve with manual activation (mFRR)
d) Replacement Reserve (RR)

In general, TSOs initially apply Frequency Containment Reserves (FCR). These reserves are activated fast (typically within 30s), stabilize the power system frequency and make sure that the frequency will not further deviate from 50Hz. Frequency Restoration Reserves (FRR) are intended to replace FCR and restore the frequency to the target frequency. Where applied, Replacement Reserves (RR) restore or support the required level of FRR to be prepared for additional system imbalances. As depicted in **Errore. L'origine riferimento non è stata trovata.**, the above types of Reserve Capacity essentially reflect the successive “layers” of control that are activated to ensure system security after a disturbance of the balance between generation and demand.

Reserve management is considered a key issue when it comes to enhancing the performance of power systems. From this perspective, it should be possible for TSOs to exchange the reserve whenever it is required and possible. TSOs should mutually agree on whether they can exchange the reserve. An external rule should include all types of reserves (FCR, FRR or RR) that could be exchanged differentiating between exchanges of reserves within the same synchronous area and between two different synchronous areas. In addition, the internal agreement between TSOs should detail the requirements and the process to share each type of reserve.

3.4.3 Frequency Containment Reserve (FCR or Primary Reserve)

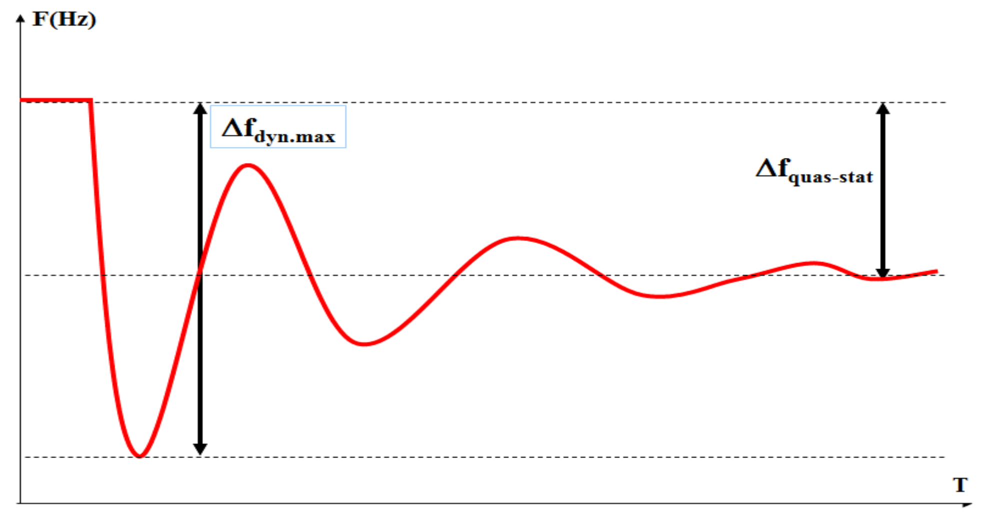
Frequency Containment Reserve or FCR or Primary Reserve refers to the active power reserves available to maintain system frequency after the occurrence of an imbalance and is essential for the safety of the electrical system. The purpose of FCR activation is the stabilization of the system frequency as quickly as possible in order to avoid the system imbalance deterioration.

Indeed, in the face of hazards and incidents such as rapid fluctuations in consumption (tariff interruptions, charge triggers, etc.) and triggering of production units, FCRs are the operating reserves that instantaneously restore the power balance in the whole synchronously interconnected system and maintain the constant containment of frequency deviations from nominal value. The common activation of Frequency Containment Reserve (FCR) in the whole synchronous area modifies the balance between generation and load at the scale of each TSO and hence consequently the power exchanges between the TSOs are varying from their set point. Activation time depends on level of frequency deviation (at the limits, to be activated up to 30 seconds).

The FCR contracted capacities are continually activated automatically by the FCR service providers through bilateral agreements or market based. FCR's technical unit shall be equipped with a frequency control system. It shall detect automatically frequency deviations in the grid and shall react to them by activating operation of FCR. Further detailed technical requirements are explicitly listed in the Minimum Requirements of potential FCR providers.

3.4.3.1 FCR product definition

Frequency containment depends on reserve providing units made available to the system in combination with the physical stabilizing effect from all connected rotating machines. As generation resource it is a fast-action, automatic and decentralized function. Frequency containment reserves are activated locally and automatically at the site of the reserve providing unit, independently from the activation of other types of reserves.



$\Delta f_{dyn\ max}$: Dynamic gap

$\Delta f_{quas\text{-}stat}$: Quasi-stationary gap

The primary setting restores the supply-demand balance but the final frequency is different from the reference frequency.

Figure 6. Quasi-stationary frequency difference after a disturbance

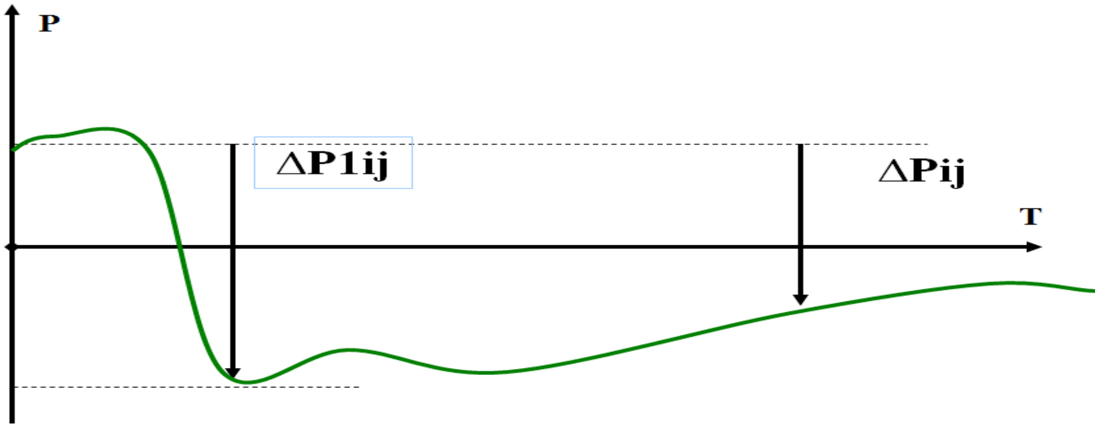


Figure 7. Transit Variation on Interconnections after a Disturbance

For each group **j** participating in the primary frequency setting, the static control law of the mechanical power variation resulting from the action of the speed regulator shall be of the form:

$$\mathbf{Pj - Pcj = - Kj\,.(\boldsymbol{f} - \boldsymbol{fo})}$$

Pj [MW] = Real power withdrawn by the entity "j" in quasi-stationary mode.
Pc j [MW] = Reference power of the withdrawal of the entity "j" at the reference frequency f0.
f [Hz] = frequency of the network to which the entity "j" is connected.
f0 [Hz] = setpoint frequency, usually equal to the reference frequency (50 Hz).
Kj [MW / Hz] = "Regulating energy" of the entity "j".

The compensation of a difference in the production-consumption balance is ensured by an action spread over all the entities of the synchronous interconnected system participating in the primary adjustment (production groups and consumption installations). The response time must be between 15 s and 30 s.

The frequency f1 reached at the end of the action of the primary adjustment is different from the reference frequency f0, and the difference between f1 and f0 is even lower than the total regulating energy of the interconnected synchronous system is large.

The compensation of a difference in the production-consumption balance ΔPbil by all the regulatory entities is equal to:

$$\mathbf{\Delta P_{bil} = -\sum K_j\,(P_j - P_{cj})}$$

The resulting frequency difference is then determined by the following equation:

$$\mathbf{f1 - f0 = \frac{\Delta Pbil}{\sum Kj}}$$

With:
ΣKj [MW / Hz] = Total control energy of the synchronous system.
And each regulating entity "j" produces:

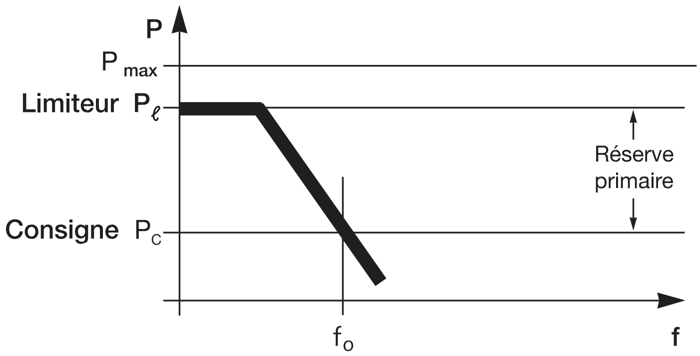
$$\mathbf{Pj} = \mathbf{Pcj} - \mathbf{Kj} \,.(f - fo)$$

The availability in sufficient quantity of the primary frequency reserve makes it possible to restore the production-consumption balance after disturbance quickly (in a few seconds).

However, this "production-consumption" equilibrium is restored only if the TSOs have a reserve of power - the primary reserve - sufficient. The available primary reserve is the sum of the primary reserves of the entities of the entire synchronous interconnected system.

- For a given group

The speed regulator acts on the intake members of the engine fluid to the turbine and seeks to impose, in equilibrium, a linear relationship between the speed (direct image of the frequency) and the power. Taking into account the limitations of the hardware, the static characteristic of this setting is that of the figure below.



Pmax: Maximum constructive power
Pl: Power displayed on the limit (maximum power allowed at the moment considered)
Pc: Displayed power setpoint
f0: Reference frequency (50 Hz)

Figure 8. Transit Variation on Interconnections after a Disturbance

This linear relation is written in the form:

$$\mathbf{P - P_0 = K\ (f - f0)}$$

- For all groups in the network

Compensating for a sudden change in the ΔPbil balance sheet requires an action spread over all the groups such that, at the end of the adjustment action:

$$\mathbf{\Delta P_{bil} = \sum K_j\ (f_1 - f_0)}$$

ΣKj: primary regulating energy of the network.
f1: Frequency reached at the end of the adjustment action. The primary setting restores the supply-demand balance if the primary reserve is sufficient, but the final frequency is different from the reference frequency.

ΔPbil = ΣΔP of the groups. The available primary reserve is the sum of the primary reserves of the participating groups.

It should be noted that the excursions of the frequency are even lower than the primary regulating energy (ΣKj) of the network is large.

Some orders of magnitude

For a given system, ΣKj ~ 20 000 MW / Hz of which more than a quarter for a particular zone.

As a result of the loss of a group of 1,300 MW in this zone (size of the largest units):

- if this zone were alone in a separate network (disconnected from the rest of the system) with K = 5,000 MW / Hz, the frequency drop would be 260 mHz and the contribution of each group to the primary setting should be 13% of its power nominal (that is, beyond the primary frequency setting constructive capabilities of most production facilities);

- if this zone is interconnected with the rest of the system (normal situation) with K = 20 000 MW / Hz, the frequency drop is 65 mHz and each regulating group contributes 3.2% of its rated power.

Interconnection allows all partners to pool participation in the primary frequency adjustment and each to reduce the size of its primary reserve both in terms of construction provisions of new production units in operation.

3.4.3.2 FCR Compliance scheme - Minimum Requirements of potential providers of FCR

The FCR should be fully available in the entire contracting time. For a maximum frequency deviation, the FCR providing units need to activate half of the contractual capacity within 15 seconds and the full capacity after 30 seconds. After reaching the full capacity, the FCR should stay activated for at least 15 consecutive minutes.

Measuring of frequency accuracy for the FCR must be better than or equal to 10 mHz. Insensitivity of generating unit’s regulator should not exceed ± 10 mHz. FCR activation of power generating units of the FCR Provider starts before the frequency deviation exceeds ± 20 mHz (which is the frequency measurement accuracy and the regulator dead band). The constant which will be set in regulators of each control area and contribution coefficients on FCR shall be determined and published annually for each control area / Control block by the relevant TSO.

The FCRs are contracted as capacity. The technical aspects of compliance schemes with minimum requirements are related to the availability commitment.

Availability committed capacity size requirement (minimum FCR capacity per unit, market or non-market based)	Dimensioning shall be determined in (± MW) by all TSOs of each defined synchronous area.
Availability committed capacity size requirement (maximum FCR capacity per unit, market or non-market based)	Dimensioning shall be determined in (± MW) by all TSOs of each defined synchronous area. The share of the FCR provided per FCR providing unit must be limited to 5 % of the reserve capacity of FCR required for each of the synchronous areas.
Inherent frequency response insensitivity	≤ ±10 mHz
Frequency dead band	max combined effect of inherent frequency response insensitivity and frequency dead band of 10 mHz
Full Activation Time	Full response within 30 seconds after frequency event also 50% of FCR capacity shall be activated after 15 seconds for a maximum frequency deviation event
Delivery duration	At least 15 minutes Specific duration may apply for units with energy limited reservoirs (e.g. batteries, fly-wheels, hydro pumped reservoirs)
Frequency deviation at which full response is required	± 200 mHz
Operational metering requirement	To be established at national level (MW)
Droop: Quotient of the relative quasi-stationary frequency deviation (Δf/fN) with the relative power change (ΔP/PN) depending on the type of unit.	Should be able to be adjusted when TSO requests (default recommended value: 5%) and making sure that the contracted capacity is fully activated for a 200 mHz frequency deviation.

Figure 9. FCR technical specifications for the FCR availability commitment

A potential FCR provider shall demonstrate to the reserve connecting TSO that he complies with the technical and any additional requirements (market or non-market based) set out by completing successfully the tests of providing the minimum technical requirements of potential FCR providing units or FCR providing groups.

FCR Compliancy monitoring must be in place to observe that the contracted FCR Provider is compliant with product *minimum* technical requirements and the *availability* commitment.

Each FCR Provider shall comply with the properties required for FCR in **Errore. L'origine riferimento non è stata trovata.** and with any additional properties or requirements specified in any relevant agreements and activate the agreed FCR by means of a proportional governor reacting to frequency deviations or alternatively based on a monotonic piecewise linear power-frequency characteristic in case of relay activated FCR. If lack of compliancy is detected, the TSO shall take all technical and legal measures needed to provide system security and FCR provision.

3.4.4 Frequency Restoration Reserve (FRR or Secondary Reserve)

Frequency Restoration Reserve or FRR or Secondary Reserve refers to the active power reserves activated automatically or manually (with activation time less than the Time To Restore Frequency (TTRF), established in the Grid Code) to restore system frequency to the nominal value and for the interconnected systems consisting on more than one Load Frequency Control (LFC) area to restore the power balance to the scheduled value.

The quick adaptation of the production to the consumption made by the primary adjustment leaves, at the end of the action, a frequency deviation with respect to the set frequency f0. It also causes transit differences between the countries of the synchronous interconnected system: indeed, all the machines of the different countries of the synchronous interconnected system participating in the primary adjustment react to the common frequency variation, even if the disturbance has occurred in a neighboring country. Frequency restoration depends on reserve providing units made available to the TSOs independently from FCR. Activation of Frequency Restoration Reserve (FRR) modifies the active power set points / adjustments of reserve providing units.

In each Control area, FRR are activated centrally at the TSO control centre, either automatically or manually, thus FRR is constituted by two parts:

- aFRR – Frequency Restoration Reserve automatically activated: corresponds to the former secondary reserve and includes all the active power reserves that can be activated within a delay less than 30sec
- mFRR – Frequency Restoration Reserve manually activated: corresponds to a part of the former tertiary reserve with activation time less than TTR

The Frequency Restoration Process is designed to control the Frequency Restoration Control Error towards zero by activation of manual and automated FRR within Time to Restore Frequency. In this way, the frequency is controlled to its setpoint value and the activated FCR are replaced. The Reserve Replacement Process replaces or supports the Frequency Restoration Process. Figure 8 shows the implementation of the Frequency Restoration and Reserve Replacement Process from perspective of a LFC Area as a general control scheme.

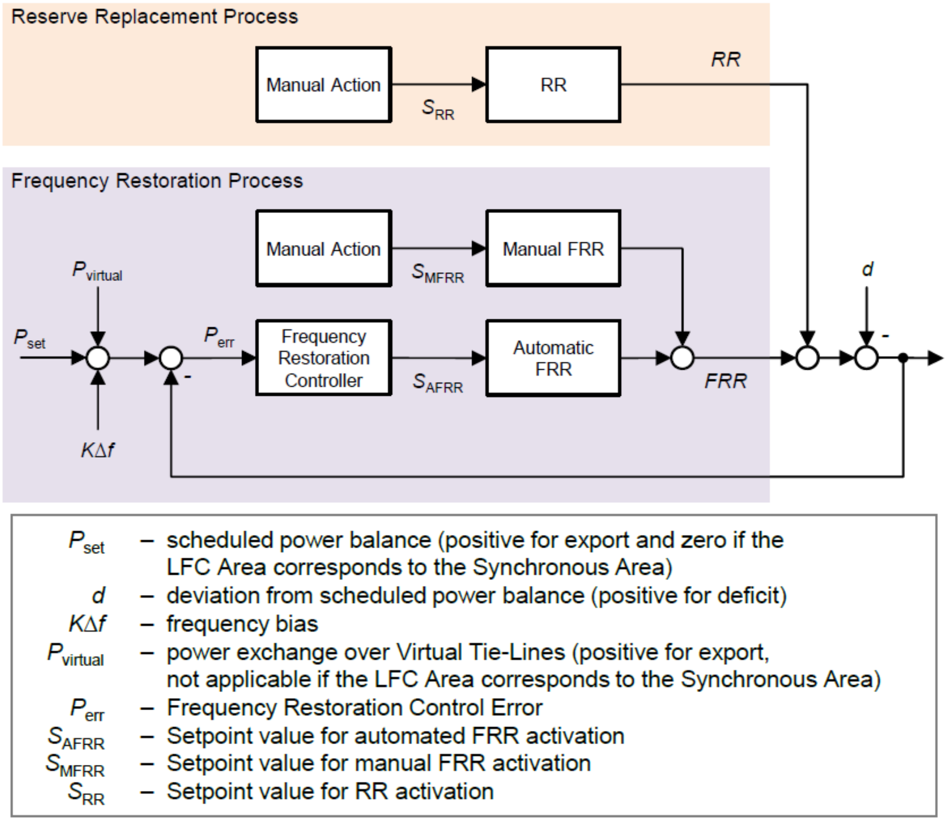


Figure 10. Frequency Restoration Process and Reserve Replacement Process

3.4.4.1 FRR Product definition

Purpose of secondary adjustment
The secondary adjustment of an adjustment zone (adjustment zone: composed of one or more coherent systems, each system being controlled by a single TSO, each adjustment zone has only one secondary frequency - power adjustment system) so for purpose:

- essentially soliciting the secondary reserve from the only control zone where this imbalance appeared;
- to find the exchange program initially agreed between the zone of origin of the disturbance and all the neighboring zones to which it is interconnected, and to reduce the frequency of the synchronous system to its reference value;
- and thus, restore the entire primary reserve committed by all members to offset any new imbalance production - consumption.

Let Δf be the residual frequency difference and ΔPi the difference between the P1 balance of the powers observed on the international interconnection lines of a given country and the Pio balance sheet of the contractual exchanges to be respected (ΔPio> O: export too important).

For an incident located in a given area, representing a production loss ΔPi, the reaction of all the interconnected groups results in:

$$\Delta Pi + K\,\Delta f = \Delta P$$

ΔPi = exchange gap. Represents the help provided by our partners.
K Δf = action of the primary adjustment of the zone considered.
By dividing by K, we obtain a homogeneous difference at a frequency:

$$\Delta E = \Delta f + \Delta Pi / K.$$

In fact, the secondary setting uses the parameter λ, called "secondary regulating energy" such as:

$$\Delta E = \Delta f + \frac{\Delta Pi}{\lambda}$$

Secondary regulation

A centralized unit located at the national dispatching station has the role of modifying the production program of the groups in order to cancel the power deviation ΔPi + λ Δf.
For this purpose, it develops, from the telemetry of the frequency and the transits on the interconnection lines, a signal N (t) called level of remote setting, between -1 and +1, and sends it to the production groups participating in the secondary setting to change their setpoint powers.
Expression of level N (t):

$$N = -\frac{\alpha}{Pr}.\int \Delta E.dt - \frac{\beta}{Pr}\Delta E$$

α [MW / revolution] = adjustment slope (integral gain),
β [MW / Hz] = proportional gain, taken equal to zero,
λ [MW / Hz] = secondary regulating energy,
Pr [MW] = half-band of adjustment, or total of participations, of entities belonging to the adjustment zone.

In addition to its basic production P0, a group will produce a power from -Pr to + Pr for a level N ranging from -1 to +1. Instant production of a group is:

$$P = P_0 + N\,Pr$$

The choice of the parameters of the regulators of each control zone i is decisive in order to allow only the regulator of the disturbed zone to react and implement the necessary secondary adjustment power. For this, a temporal decoupling between the action of the primary adjustment and that of the secondary adjustment is necessary (to define the time constant of the secondary adjustment of the order of 100 to 200 s).

Choice of secondary adjustment parameters

- Choice of parameters α and λ

Take the simple example of two countries, A and B, interconnected. We denote PA and PB their productions, CA and CB their internal consumptions, KA and KB their primary regulating energies, λA and λB their secondary regulating energies, Pio the transitory power from A to B (program).

Following a disturbance in A (for example a variation in consumption ΔCA), assuming that the secondary adjustment action is slow compared to that of the primary adjustment, which is true if a time constant of sufficiently large integrator (of the order of 100 s), we can consider that the primary setting establishes a first balance.

We can then write:

$$\Delta P_A = \Delta C_A + \Delta Pi = K_A\, \Delta f \;\;\&\;\; \Delta P_B = \Delta Pi = -\, K_B\, \Delta f.$$

The terms to integrate are:

$$\Delta E_A = (\Delta f + \Delta Pi / \lambda_A) = (1 + K_A / \lambda_A)\, \Delta f$$

$$\Delta E_B = (\Delta f - \Delta Pi / \lambda_B) = (1 - K_B / \lambda_B)\, \Delta f$$

If one makes sure to choose λA = KA and λB = KB one gets ΔEB = 0. Only the level of the country A will thus vary to restore f = f0 and Δ Pi = 0.

Automatic Frequency Reserve is used in case of frequency deviation from the nominal values and/or the deviation of balance of exchanged from the scheduled value. This reserve is deployed on the Power Generating Units or Groups /FRR providers. For the calculation of FRR, the following formula is indicatively used:

$R = \sqrt{aL_{\max} + b^2} - b$, where a = 10, b = 150, and L is the demanded load

Every Year the TSOs shall dimension the volume of mFRR capacity according to criteria established in chapter 3.4.6.

The **aFRR** is activated upwards or downwards automatically depending on the conditions of the imbalance (short or long respectively). In case of activation, a signal is transmitted by TSO's dispatching centers to the FCR's Provider dispatching center with a setpoint resulting in an increase or decrease in the power injected. The activation process must ensure that the full reserve can be delivered upon TSO's request within the minimum requirements set in **Errore. L'origine riferimento non è stata trovata.**.

The **aFRR** is operated in a closed-loop manner (generic overview of the process is presented in **Errore. L'origine riferimento non è stata trovata.**) taking the Frequency Restoration Control Error (FRCE)[4] as input and the setpoint for **aFRR** activation as output. The activation of **aFRR** aims to lead to reduction of the FRCE toward zero.

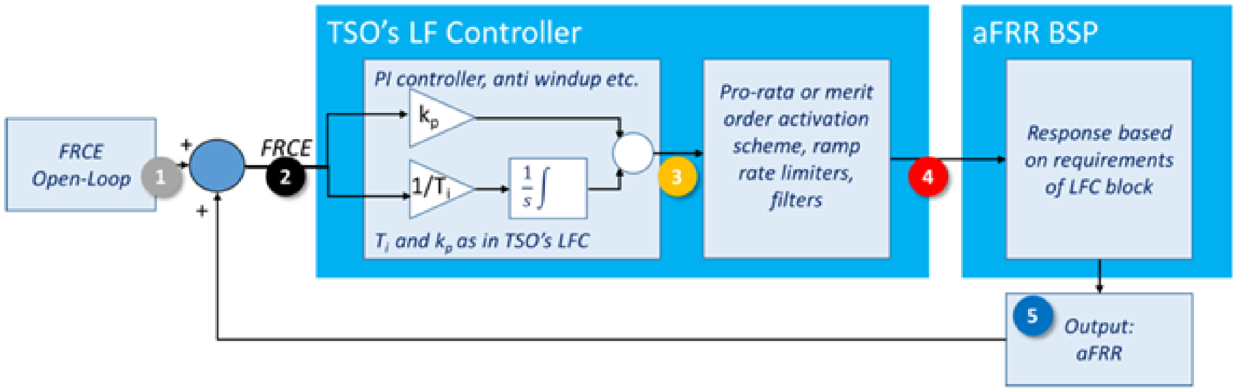


Figure 11. Generic overview of automatic frequency restoration process

The setpoint for **aFRR** activation shall be calculated by a single Frequency Restoration Controller operated by TSO within its Load Frequency Control (LFC) area. The Frequency Restoration Controller shall:

- be an automatic control device designed to reduce the FRCE to zero;
- have proportional-integral behavior;
- have a control algorithm which prevents the integral term of a proportional-integral controller from accumulating the control error and overshooting;
- have functionalities for extraordinary operational modes for the alert and emergency states.

3.4.4.2 FRR compliance scheme - Requirements of potential providers

FRR minimum technical requirements shall be the following:

a. each FRR Provider shall be connected to only one reserve connecting TSO;
b. a FRR Provider or shall activate FRR in accordance with the setpoint received from the reserve instructing TSO;
c. the reserve instructing TSO shall be the reserve connecting TSO or a TSO designated by the reserve connecting TSO in an FRR exchange agreement;
d. a FRR Provider for a aFRR shall have an automatic FRR activation delay not exceeding 30 seconds;
e. Real-time power measurements shall be available for monitoring purposes.
f. a FRR Provider of aFRR shall be capable to activate its complete automatic reserve capacity on FRR within the automatic FRR full activation time;
g. a FRR Provider of mFRR shall be capable to activate the complete manual reserve capacity on FRR within the mFRR full activation time;
h. a FRR provider shall fulfil the FRR availability requirements and the ramping rate requirements of the LFC block.

2. All TSOs of a LFC block shall specify FRR availability requirements and requirements on the control quality of FRR providing units and FRR providing groups for their LFC block in the LFC block operational agreement.
3. The reserve connecting TSO shall adopt the technical requirements for the connection of FRR Providers to ensure the safe and secure delivery of FRR.

4. Each FRR provider shall:
    - ensure that its FRR providing units fulfil the FRR technical minimum requirements, the FRR availability requirements and the ramping rate requirements;
    - inform its reserve instructing TSO about a reduction of the actual availability of its FRR capability as soon as possible.
5. Each reserve instructing TSO shall ensure the monitoring of the compliance with the FRR minimum technical requirements, the FRR availability requirements, the ramping rate requirements, and the connection requirements by its FRR Providers.

Availability committed capacity size requirement (minimum capacity)	FRR dimensioning to be determined by all TSOs of a LFC block (in ± MW)
Availability committed capacity size requirement (maximum capacity per unit)	
Activation duration	at least 15 consecutive minutes
First observable power change	At least within 10 seconds after a setpoint change
Full activation and deactivation time	To be determined by all TSOs of a LFC block
Maximal short-term overshoot	10% of aFRR volume, but not more than 1 MW
Accuracy	Deviation should be smaller than 7.5% only two deviations are allowed for each 10 seconds measurement window

Figure 12. The technical specifications for the aFRR availability commitment

Examples of aFRR compliance tests are presented below. The potential aFRR provider shall demonstrate that the technical unit is capable to follow at least the ramping requirements as presented in the figure below.

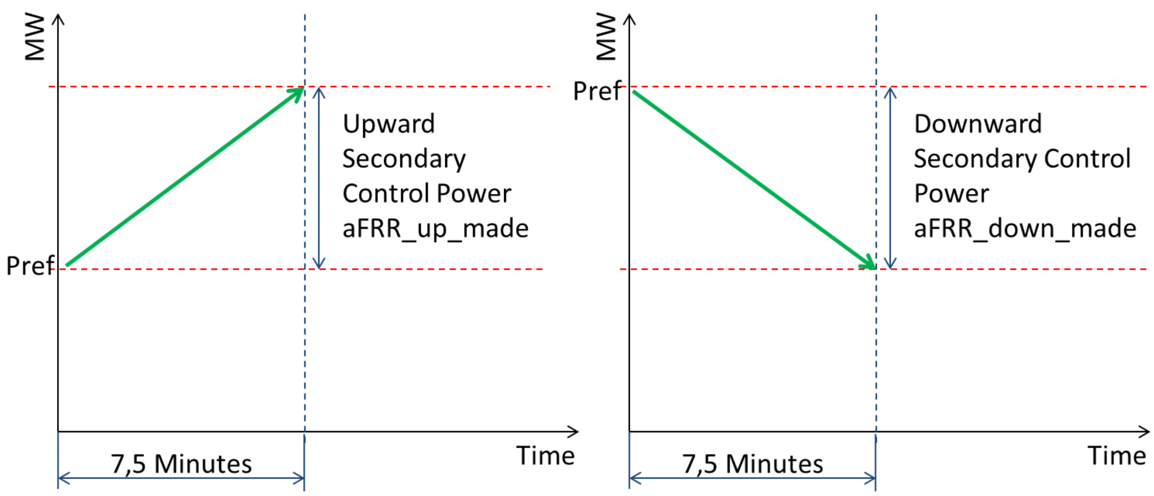


Figure 13. Ramping requirements of potential aFRR providers

For the simulation of aFRR, the aFRR Service Provider must simulate the activation signal presented in **Errore. L'origine riferimento non è stata trovata.**. With this signal TSO will test whether the aFRR Service Provider can activate aFRR of the Production Unit and if he is able to follow a variable signal with a deviation smaller than 7.5% of the maximum value (2 deviations of 10 seconds allowed). This test will take 100 minutes.

For this test a sample will be taken every 10 seconds (starting at 00:00:00, 00:00:10...). This signal must be between the upper and lower accuracy limit (band of 15%) as indicated in the figure below.

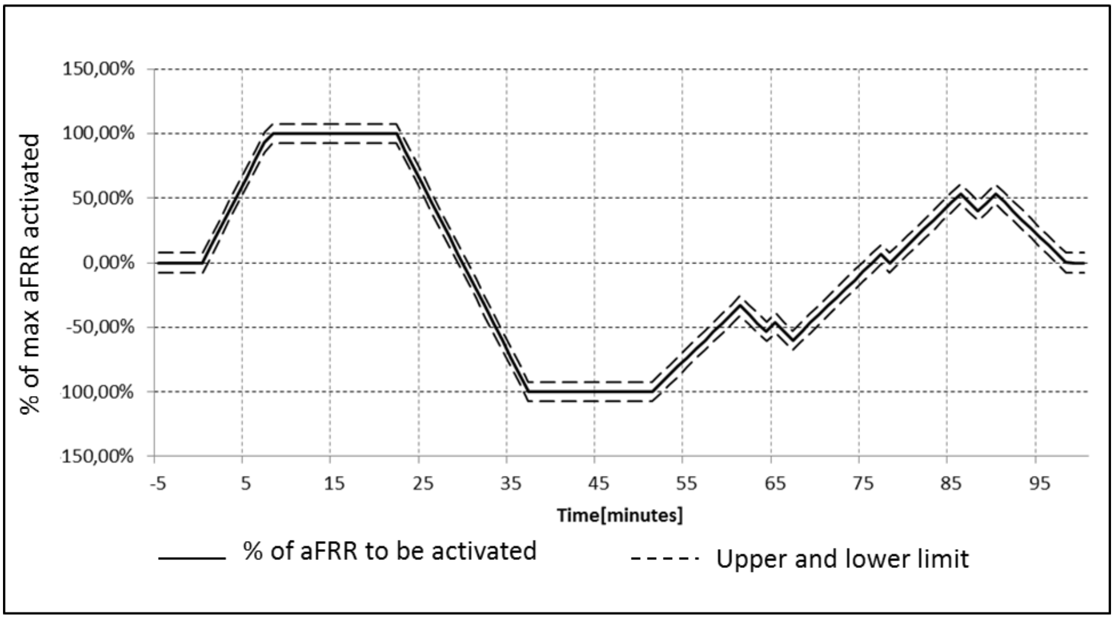


Figure 14. Activation signal for aFRR compliance test

Requirements for attestation:

- aFRR Provider shall supply and reach the maximum as indicated in max increment
- The deviation shall be smaller than 7.5% (2 deviations of 10 seconds allowed)

Availability committed capacity size requirement (minimum capacity per unit)	FRR dimensioning to be determined by all TSOs of a LFC block (in ± MW
Availability committed capacity size requirement (maximum capacity per unit)	
Full activation and deactivation time	within 15 minutes
Activation duration	Activation duration to be determined by all TSOs of a LFC block according to the agreement

Figure 15. Technical specifications for the aFRR availability commitment

3.4.5 Replacement Reserve (Tertiary adjustment - RR)

The effect of the secondary adjustment, following a disturbance, may not fully absorb the frequency and power transit variations on the interconnections, the level reaching its stop (N = ± 1). The primary reserve is then started and the secondary reserve exhausted. The arrival at the level stop (high or low) can also be the result of a slow drift between the consumption and the walking programs of the groups (image of the consumption forecast). It is necessary to rebuild depleted reserves to secure against new hazards.

The tertiary reserve serves not only to compensate for a possible secondary reserve deficit in the event of a rapid increase in the gap between production and consumption, but also to rebalance the system in the event of a slow increase in the gap between production and consumption.

In anticipation of circumstances of this type, it is envisaged, by daily contract in D-1, a reservation of power which is broken down into several products according to its mobilization time and its duration of use: rapid tertiary reserve 15 minutes, tertiary reserve complementary 30 minutes, reserves to maturity. This power is mobilized, according to the needs in real time and the deadlines, by call on the mechanism of adjustment, in order to recalibrate the programs of production on the realization and to rebuild the reserves primary and secondary (f = 50 Hz, N = 0).

The fast mobilizing power reserve is made up of groups that are not at maximum power or that can start up quickly (hydraulic units, combustion turbines). Note that a downward reserve is also planned, always by contracting.

The tertiary control, coordinated by the national dispatching, aims to mobilize throughout the day, as much as necessary, the tertiary reserve while seeking to reconstitute or adjust it according to the evolutions of the System.

The mobilization of these reserves is not automatic unlike the primary and secondary regulation: it is currently coordinated via telephone call from the control centers to the production facilities. The margin 15 min (secondary reserve + tertiary reserve 15 min) must compensate for the loss of the largest coupled group. It must be able to be reconstituted in less than half an hour. More generally, the sizing of reserves (tertiary + secondary) should allow to spend peaks of consumption in the morning and evening.

3.4.5.1 RR Product Definition

Replacement Reserves or RR or emergency reserves refer to the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including generation reserves, with activation time ≤ 30 minutes.

The Reserve Replacement Process replaces or supports the Frequency Restoration Process as illustrated in the general control scheme presented in **Errore. L'origine riferimento non è stata trovata.** above.

3.4.5.2 RR Compliance scheme - Minimum Requirements of potential RR providers

RR providing units and RR providing groups shall comply with the following minimum technical requirements[5]:

a. connection to only one reserve connecting TSO;
b. RR activation according to the setpoint received from the reserve instructing TSO;
c. the reserve instructing TSO shall be the reserve connecting TSO or a TSO that shall be designated by the reserve connecting TSO in the RR exchange agreement.
d. activation of complete reserve capacity on RR within the activation time defined by the instructing TSO;
e. de-activation of RR according to the setpoint received from the reserve instructing TSO;
f. a RR provider shall ensure that the RR activation of the RR providing units within a reserve providing group can be monitored. For that purpose, the RR provider shall be capable of supplying to the reserve connecting TSO and the reserve instructing TSO real-time measurements of the connection point or another point of interaction agreed with the reserve connecting TSO concerning:
    a. the time-stamped scheduled active power output, for each RR providing unit and group and for each power generating module or demand unit of a RR providing group with a maximum active power output larger than or equal to 1,5 MW;
    b. the time-stamped instantaneous active power, for each RR providing unit and group, and for each power generating module or demand unit of a RR providing group with a maximum active power output larger than or equal to 1,5 MW
    c. fulfilment of the RR availability requirements

3.4.6 Criteria for dimensioning national reserves

Dimensioning of Reserves in general has to take into account all of the corresponding effects and has to respect:

- expected magnitude of the imbalance
- expected duration of the imbalance
- possible mutual dependency of imbalances
- imbalance gradients

The present section treats the methodologies for dimensioning of FCR, FRR and RR which are activated in the framework of the Load-Frequency Control processes and necessary precondition to achieve the required System Frequency quality.

3.4.6.1 Dimensioning of FCR

Any imbalance between generation and demand in a synchronously connected grid immediately results in a Frequency Deviation which continuously increases as long as the respective imbalance exists. Without any countermeasure the System Frequency would reach a critical value resulting in the collapse of the synchronously connected grid.

[5] Minimum requirements according to Art. 161 of COMMISSION REGULATION (EU) 2017/1485 (SOGL).

We recall that, the objective of the Frequency Containment Process is to maintain a balance between generation and consumption within the Synchronous Area and to stabilise the electrical system by means of the joint action of respectively equipped FCR Providing Units and FCR Providing Groups. Appropriate activation of FCR results consequently in stabilisation of the System Frequency at a stationary value after an imbalance in the time frame of seconds.

Whereas the stochastic imbalances and deterministic Frequency Deviations are transient and vanish after some minutes an imbalance caused by a disturbance, outage or even network splitting is persistent and has to be covered for a comparably longer period of time by an appropriate amount of FCR followed by activation of other reserves FRR and RR.

With regards to persistent power imbalances, the disturbance/outage of generation or load or HVDC interconnector is considered. The basic dimensioning criterion of the FCR is to withstand the Reference Incident in the Synchronous Area by containing the System Frequency within the Maximum Frequency Deviation and stabilizing the System Frequency within the Maximum Steady-State Frequency Deviation

The Reference Incident has to take into account the maximum expected instantaneous power deviation between generation and demand in the Synchronous Area that may cause the biggest Active Power Imbalance with an N-1 failure and can be determined by taking into account at least

- ✓ The loss of the largest Power Generating Module;
- ✓ Loss of a line section;
- ✓ Loss of a bus bar;
- ✓ The loss of the largest load at one Connection Point
- ✓ a loss of a interconnector (either AC or DC)

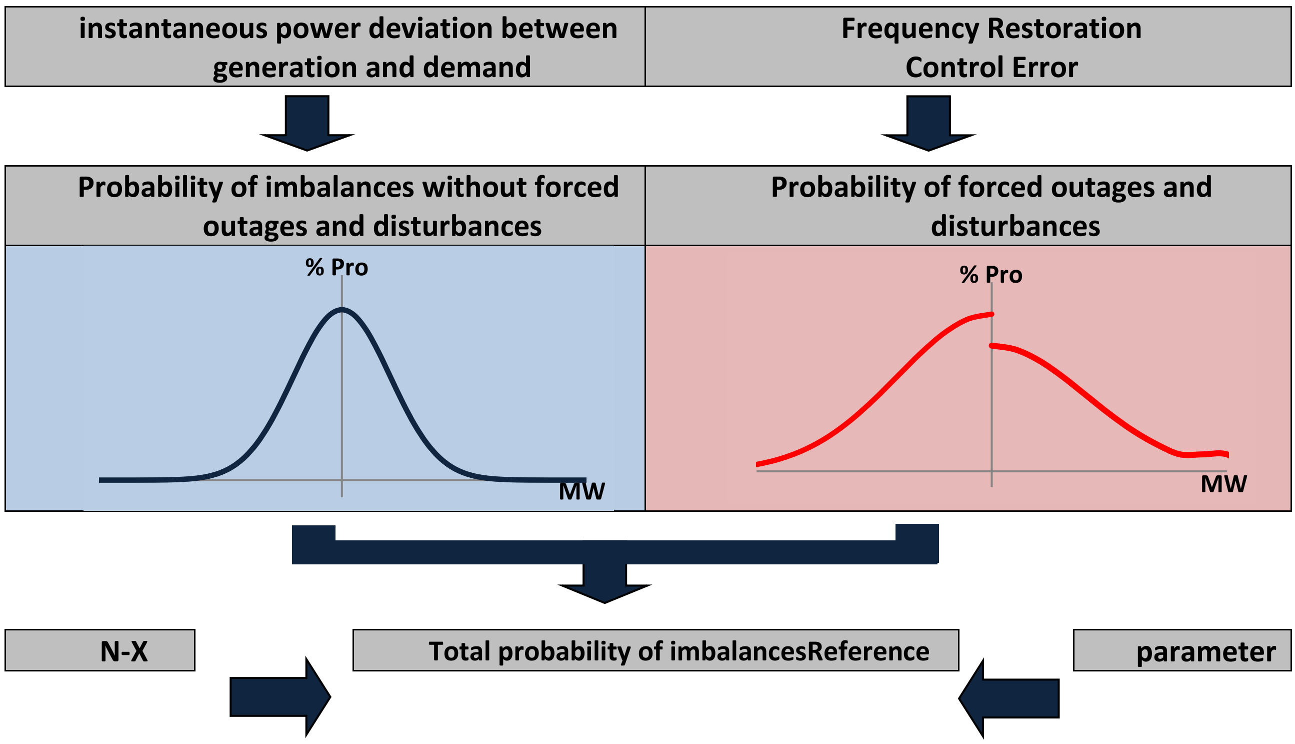
In developed systems such as CE, the amount of the generating capacity and demand leads to a larger probability of an additional loss of generation, consumption or in-feed before the system has recovered from a previous loss within the design window. Therefore, the dimensioning approach for CE requires a probabilistic assessment for the calculation of the Reference Incident. The performed probabilistic assessment of the Reference Incident calculation confirmed the best-practice approach implemented in CE for decades: An N-2 criterion shall be used to determine the size of the Reference Incident. Furthermore, the Reference Incident is symmetrical which means that the positive FCR Capacity is equal to the negative FCR Capacity.

In addition to the Reference Incident, the probability of FCR exhaustion can be calculated by combining the probability of forced instantaneous outages and disturbances with the probability of used FCR due to the existing Frequency Restoration Control Error. The FCR is then dimensioned based on a defined risk level of insufficient FCR. This approach is implemented due to increasing impact of the persisting imbalances, in particular the deterministic imbalances which occur due to optimisation of generation based on energy market rules result in lack of coordination between generation and load.

LOAD-FREQUENCY CONTROL STRUCTURE

FCR dimensioning

1- All TSOs of each synchronous area shall determine, at least annually, the reserve capacity for FCR required for the synchronous area and the initial FCR obligation of each TSO
2- All TSOs of each synchronous area shall specify dimensioning rules in the synchronous area operational agreement in accordance with the following criteria:
   a) The reserve capacity for FCR required for the synchronous area shall cover at least the reference incident and, for the Mediterranean synchronous areas, the results of the probabilistic dimensioning approach for FCR carried out pursuant to point.
   b) the size of the reference incident shall be determined in accordance with the reference incident which shall be at least the largest infeed of energy or the biggest generation unit (or combination of generation units) that could be lost by a single event in the system. in both directions;
   c) for the Mediterranean synchronous areas, all TSOs of the synchronous area shall have the right to define a probabilistic dimensioning approach for FCR taking into account the pattern of load, generation and inertia, including synthetic inertia as well as the available means to deploy minimum inertia in real-time in accordance with the methodology referred to Dynamic stability management, with the aim of reducing the probability of insufficient FCR to below or equal to once in 20 years; and
   d) the shares of the reserve capacity on FCR required for each TSO as initial FCR obligation shall be based on the sum of the net generation and consumption of its control area divided by the sum of net generation and consumption of the synchronous area over a period of 1 year.



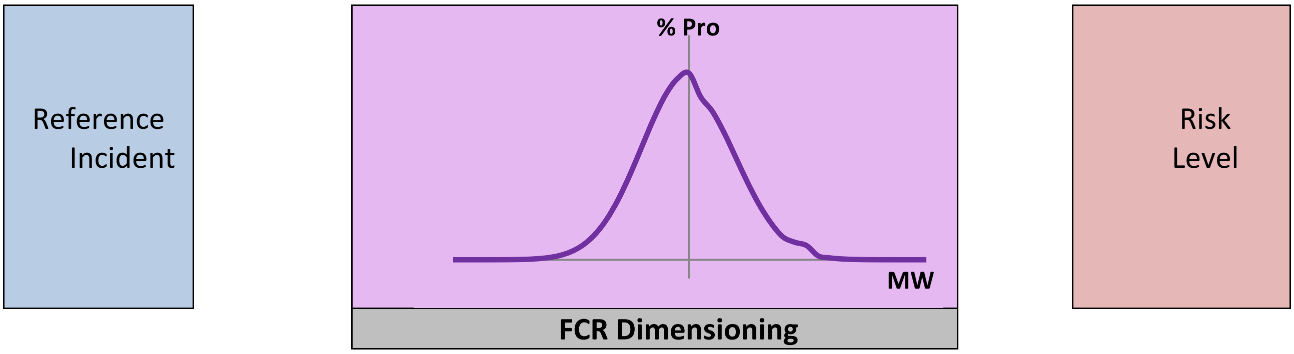


Figure 16. Probabilistic approach for FCR dimensioning

3.4.6.2 Dimensioning of FRR and RR

The present section describes the methodology of FRR and RR dimensioning in context of System Frequency quality.

Interdependencies with FCR and Frequency Quality

As explained any imbalance between Active Power generation and consumption leads to a persisting rise or fall of System Frequency and therefore to a Frequency Deviation which has to be countered by FCR activation.

Thus, there is a direct physical relationship between the amount of FCR, FRR and RR. Any imbalance amount which is not covered by FRR or RR leads to a Frequency Deviation followed by joint and automatic activation of FCR in the whole Synchronous Area.

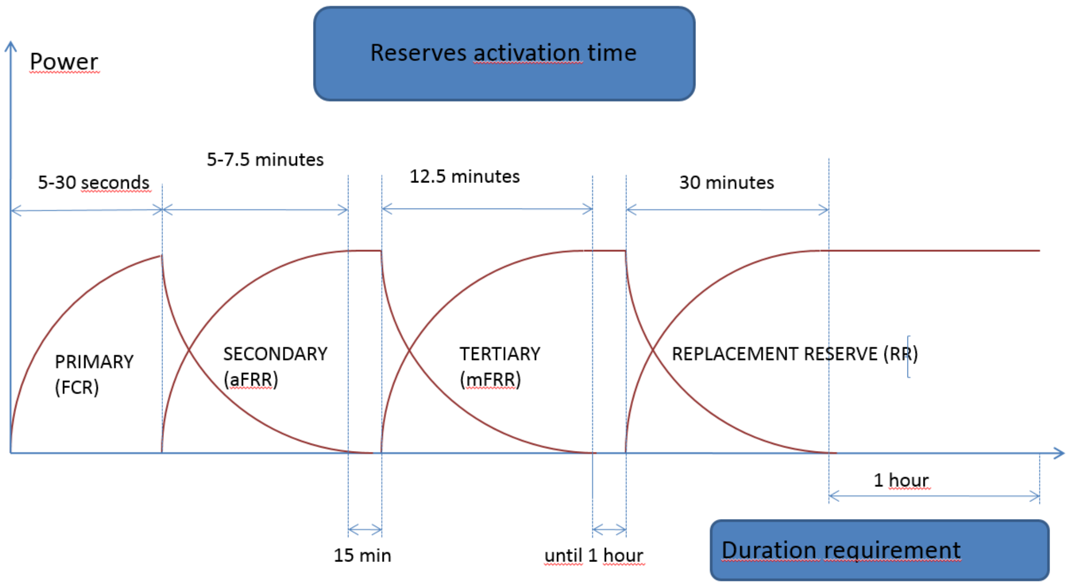


Figure 17. Interdependencies with FCR and Frequency Quality

Figure 17 shows this basic interdependency between FRR and RR activation and the impact on FCR and System Frequency quality.

It is obvious that, due to the relationship of FRR and RR with System Frequency, the total reserve amount and the shares of single reserve types will have an impact on the overall Operational Security. For this reason, we must define minimum requirements for FRR and RR dimensioning based on a combination of a deterministic and probabilistic approach and coherent with the quality requirements.

Dimensioning Methodology

This Grid Code obliges the TSOs to perform a dimensioning of FRR and RR on the level of Control Area. Although, the dimensioning of FRR and RR has to take into account the following requirements:

- The Frequency Quality Target Parameters and Frequency Restoration Control Error Target Parameters.
- The amounts of aFRR, mFRR and RR.

Cannot be expressed by a simple mathematical formula. The suitable dimensioning approach differs from Control Area to other Control Area due the physical sources and patterns of its imbalances. For this reason the Grid Code intentionally leaves the final choice to the TSOs of the Control Area. Nonetheless, it is possible to define obligations for TSOs as boundary conditions which enable the TSOs of each Control Area

- To ensure that the FRR and RR available to the TSOs of the Control Area are sufficient to guarantee a safe operation.
- To respect quality target of the Control Area.
- To contribute to the overall System Frequency quality.

The following Figure illustrates the components of the FRR Dimensioning Rules and RR Dimensioning Rules based on a simple fictional example. Similar to the dimensioning of FCR, the minimum values for FRR and RR required for Mediterranean Region shall be based on a combination of:

- A deterministic assessment based on the positive and negative Dimensioning Incident
- A probabilistic assessment of historical records for at least one full year
-

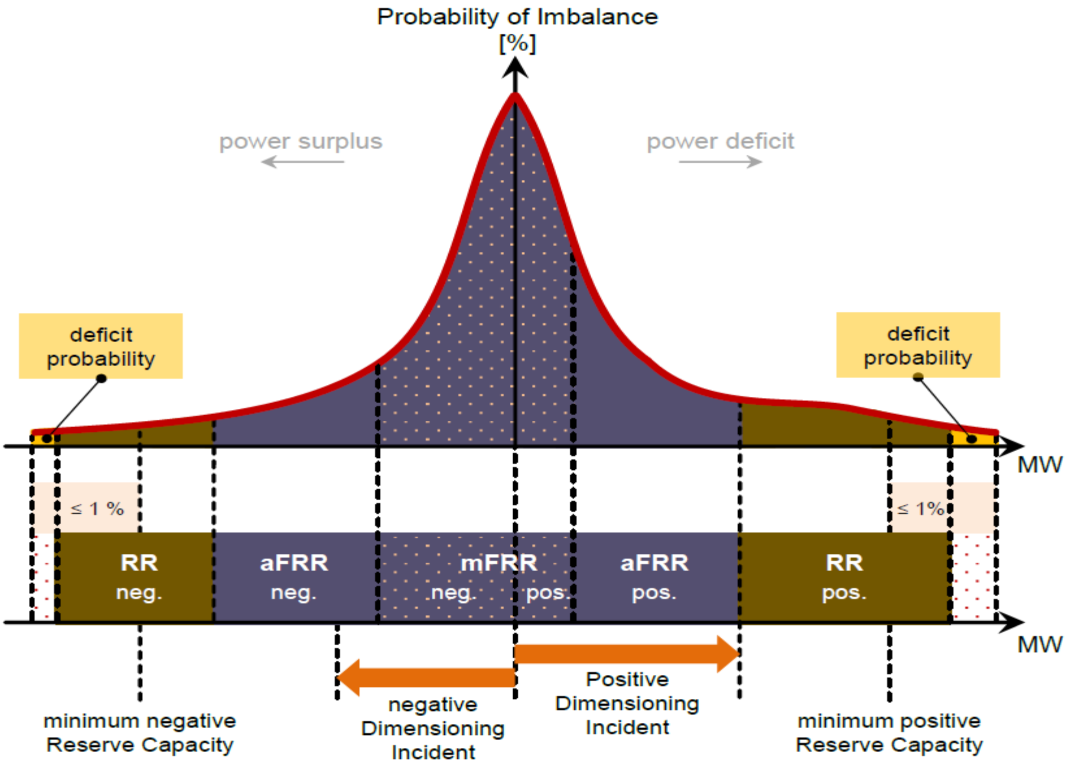


Figure 18. Probability of imbalance

The deterministic approach requires that the FRR Capacity shall not be smaller than the Dimensioning Incident (separate for positive and negative direction). In general, this is the tripping of the largest generation unit for the positive direction and the largest demand facility for the negative direction. In certain Control Area an HVDC interconnection might be the determining element for the Dimensioning Incident.

For the probabilistic assessment the Grid Code defines a minimum value for the sum of FRR Capacity and RR Capacity, which is defined by the 99 % quantile of the Control Area Imbalances (separate for positive and negative direction).

In the example provided by **Errore. L'origine riferimento non è stata trovata.** the 99 % quantiles are bigger than the respective Dimensioning Incidents and therefore determine the overall sum of FRR Capacity and RR Capacity. The 99 % quantile is a minimum value and thus can be harmonised for all Control Area. At the same time, the example shows that for a specific Control Area it is in general necessary to exceed the minimum values defined by the Grid Code.

- to comply with FRCE Target Parameters
- to respect network constraints within a Control Area
- to take all factors into account which may lead to unavailability of FRR or RR (for instance, in case of unavailability of Reserves provided from a different Control Area or Sharing).

Furthermore, the different response times of aFRR, mFRR and RR must be also considered in the dimensioning and lead to the respective shares (in the example, the share of aFRR and RR is bigger in positive direction). Based on the available transmission capacity a certain distribution and amount of FRR and RR within a Control Area may be required.

LOAD-FREQUENCY CONTROL STRUCTURE

FRR dimensioning

1- All TSOs of a Control Area shall define in the control Area Operational Agreement FRR Dimensioning Rules.

2- The FRR Dimensioning Rules shall comprise at least the following requirements

a) All TSOs of a control Area in the Synchronous Areas shall determine the required FRR Capacity of the control Area based on consecutive historical records at least comprising historical control Area Imbalance values.

b) All TSOs of a control Area in the Synchronous Areas shall determine the FRR Capacity of the control Area such that it is sufficient to respect the current Frequency Restoration Control Error FRCE Target Parameters for the considered historical period of time based at least on a probabilistic methodology.

c) All TSOs of a control Area shall determine the ratio of Automatic FRR Capacity, manual FRR Capacity, the Automatic FRR Full Activation Time and manual FRR Full Activation Time such that requirement (b) can be fulfilled. For this the Automatic FRR Full Activation Time of a Control Area and the Manual FRR Full Activation Time of the control Area shall at most be the Time to Restore Frequency.

d) The TSOs of a control Area shall determine the size of the Dimensioning Incident. The Dimensioning Incident shall be the largest imbalance that may result from an instantaneous change of active power of a single Power Generating Module, single Demand Facility, and single HVDC interconnector or from a tripping of an AC-Line within the Control Area.

e) All TSOs of a Control Area shall determine the positive FRR Capacity such that it is not smaller than the positive Dimensioning Incident of the Control Area;

f) All TSOs of a Control Area shall determine the negative FRR Capacity such that it is not smaller than the negative Dimensioning Incident of the Control Area;

g) All TSOs of a Control Area shall determine the FRR Capacity of a Control Area and possible geographical limitations for its distribution within the Control Area and possible geographical limitations for any Exchange of Reserves or Sharing of Reserves with other Control Areas to respect the Operational Security;

h) All TSOs of a Control Area shall ensure that the positive FRR Capacity or a combination of FRR and RR Capacity is sufficient to cover the positive Control Area Imbalances in at least 99 % of the time based on the historical record as defined in (a);

i) All TSOs of a Control Area shall ensure that the negative FRR Capacity or a combination of FRR and RR Capacity is sufficient to cover the negative Control Area Imbalances in at least 99 % of the time based on the historical record as defined in (a);

j) All TSOs of a Control Area are allowed to reduce the positive FRR Capacity of the Control Area, resulting from the FRR Dimensioning Process, by concluding a FRR Sharing Agreement with other Control Areas. The reduction of the positive FRR Capacity of a Control Area is limited to the difference, if positive, between the size of the positive Dimensioning Incident and the FRR Capacity required to cover the positive Control Area imbalances in 99 % of time based on historical records as defined in (a)

3- All TSOs of a Control Area shall have sufficient reserve capacity on FRR at any time in accordance with the FRR dimensioning rules. The TSOs of a Control Area shall specify in the Control Area operational agreement an escalation procedure for cases of severe risk of insufficient reserve capacity on FRR in the Control Area

LOAD-FREQUENCY CONTROL STRUCTURE

RR dimensioning

1- All TSOs of a Control Area shall have the right to implement a reserve replacement process.
2- To comply with the FRCE target parameters, all TSOs of a Control Area with a RRP, performing a combined dimensioning process of FRR and RR to fulfil the requirements established, shall define RR dimensioning rules in the Control Area operational agreement.
3- The RR dimensioning rules shall comprise at least the following requirements:
   a) for the Mediterranean synchronous areas there shall be sufficient positive reserve capacity on RR to restore the required amount of positive FRR.
   b) for the Mediterranean synchronous areas, there shall be sufficient negative reserve capacity on RR to restore the required amount of negative FRR.
   c) there shall be sufficient reserve capacity on RR, where this is taken into account to dimension the reserve capacity on FRR in order to respect the FRCE quality target for the period of time concerned;
   d) compliance with the operational security within a Control Area to determine the reserve capacity on RR
4- All TSOs of a Control Area may reduce the positive reserve capacity on RR of the Control Area, resulting from the RR dimensioning process, by developing a RR sharing agreement for that positive reserve capacity on RR with other Control Area. The control capability receiving TSO shall limit the reduction of its positive reserve capacity on RR in order to:
   a) guarantee that it can still meet its FRCE target parameters;
   b) ensure that operational security is not endangered; and
   c) ensure that the reduction of the positive reserve capacity on RR does not exceed the remaining positive reserve capacity on RR of the Control Area.
5- All TSOs of a Control Area may reduce the negative reserve capacity on RR of the Control Area, resulting from the RR dimensioning process, by developing a RR sharing agreement for that negative reserve capacity on RR with other Control Area. The control capability receiving TSO shall limit the reduction of its negative reserve capacity on RR in order to:
   a) guarantee that it can still meet its FRCE target parameters;
   b) ensure that operational security is not endangered; and
   c) ensure that the reduction of the negative reserve capacity on RR does not exceed the remaining negative reserve capacity on RR of the Control Area.
6- Where a Control Area is operated by more than one TSO and if the process is necessary for the Control Area, all TSOs of that Control Area shall specify in the Control Area operational agreement the allocation of responsibilities between the TSOs of different Control Area for the implementation of the dimensioning rules.
7- A TSO shall have sufficient reserve capacity on RR in accordance with the RR dimensioning rules at any time. The TSOs of a Control Area shall specify in the Control Area operational agreement an escalation procedure for cases of severe risk of insufficient reserve capacity on RR in the Control Area.

3.5 Activation of reserves and management of unintended deviations

This chapter will include guidelines for the activation of reserves and management of the unintended deviations. In addition general principles on the dimensioning and procurement of commons reserves between Mediterranean power systems will also be developed.

The current development of the different power systems in the Mediterranean region is rather different as it was described in previous reports. Concerning provision of system services, two main areas can be identified:

- ENTSO-E countries with full liberalized competitive markets.
- Non ENTSO-E countries without competitive market based structure where, in general, a “single buyer” scheme is in place.

Considering this situation as the starting point the proposal of harmonization is divided in 2 different time horizons:

- Medium-term: Development of a common platform to be used by countries in the same synchronous areas as defined in chapter 4.4 for activation of reserves through a system of netting needs (both upwards and downwards) in different time horizons:
  - Cross Border Replacement reserve RR activation (30’ dynamic time response): activation 30’ before real time H (so process of submitting TSO´s upward/downward RR balancing energy needs and matching process of netting those RR needs subject to transmission capacity constraints should occur at period [(H-1)+0’ , (H-1)+30’]). Considering that in principle there won´t be RR balancing bids activation (due to the fact that several countries in the project do not have energy/balancing markets as such yet), only netting of needs, this process would simply imply a Cross Border re-scheduling 30’ before real-time.
  - Cross Border Manual frequency restoration reserve mFRR activation (15’ dynamic time response, equivalent to tertiary energy): activation 15’ before real time H (so process of submitting TSO´s upward/downward mFRR balancing energy needs and matching process of netting those mFRR needs subject to transmission capacity constraints should occur at period [(H-1)+30’ , (H-1)+45’]). Considering that, as in the RR previous case, there won´t be mFRR balancing bids activation, only netting of needs, this process would simply imply a Cross Border re-scheduling 15’ before real-time.
  - Cross Border aFRR platform activation (secondary energy): seems not feasible to implement due to the absence of market conditions and implicit high complexity of the process.
  - Netting of aFRR needs in real time (participation at IGCC platform): could be feasible depending on transparency conditions about expost pricing of needs (unlike RR and mFRR process, no economic signals are currently used by IGCC algorithm).

  This common platforms (one per synchronous area) could take advantage of the existing IT infrastructure in Europe under development due to the Guideline on Electricity Balancing (EBGL).

The proposal should include the economic scheme that will complete the netting of needs. A possibility could be to fix ex-ante an upward/downward price in €/MWh by each TSO for each type of balancing energy activation that will be settled later, for instance on a monthly basis. The price could vary between hours or days.
Another possibility will be to follow the "IGCC rule", consisting on netting balancing energy needs without using economic information and to declare ex-post upward and downward opportunity prices by each TSO and to compute a common unique settlement price using a weighted average of opportunity prices (with a possible correction if the unique settlement price turns out to be not convenient for a given TSO, compared to its own opportunity price). More details could be established in a Multilateral Agreement between TSOs.
Common dimensioning of reserves will not be developed at this stage; keeping it under national umbrella.
Unintended deviations could be managed through a pay in kind mechanism or using the fixed ex-ante price at this stage.
At the end of this stage the platforms for each synchronous area will be merged into a single platform in order to be able to activate reserves between power systems from different synchronous areas.

- Long-term: Use of European Platforms (under development nowadays fulfilling current obligations of EBGL about reserves activation and potential future obligations from Winter Package about common reserves dimensioning) by non ENTSOE countries. This long-term objective cannot be completed at a shorter stage due to the technical and legal requirements to be fulfilled by the power systems using the platforms. In a summarized way these requirements are that it should already exists a balancing market in each system in order to each TSO to be able to submit to the platform not only balancing needs but also balancing upward/downward bids.
  Unintended deviations current compensation procedure based on a pay in kind approach, could be evolve towards an economic settlement procedure (in Europe, the current draft proposal uses weighted average day ahead prices with an additional economic penalty at settlement periods with large frequency deviations in the case of unintentional deviations in the direction of aggravating such frequency deviation).

Between the 2 horizons an intermediate step is needed in which the interconnections between ENTSO-E and non ENTSO-E countries are included in the platform. Two potential options:

- Integrate the management of the interconnections between ENTSO-E and non ENTSO-E countries in the European Platforms.
- Integrate the management of the interconnections between ENTSO-E and non ENTSO-E countries in the non ENTSO-E platform with less strict requirements to participate. Issues related with the activation structure (close to real time) of the European interconnections need to be addressed.

4 Annex A: Proposal of Mediterranean Grid Code on Connection and Operation

GRID CODE ON REQUIREMENTS FOR CONNECTION TO THE GRID

Article 1. Subject matter

This network/technical code aims at laying down the requirements for grid connection of generation facilities, to the interconnected system. It, therefore, helps to ensure system security and the integration of renewable electricity sources, and to facilitate Mediterranean-wide trade in electricity.

Article 2. Definitions

For the purposes of this Regulation, the following definitions shall apply:

(1) “*relevant system operator”* means the transmission system operator or distribution system operator to whose system a generation facility, demand facility or distribution system is or will be connected;

(2) “generation facility owner” means a natural or legal entity owning a power-generating facility;

(3) “synchronous generation facility” means an indivisible set of installations which can generate electrical energy such that the frequency of the generated voltage, the generator speed and the frequency of network voltage are in a constant ratio and thus in synchronism;

(4) “connection point” means the interface at which the generation facility is connected to a transmission system, distribution system, as identified in the connection agreement;

(5) “non-synchronous generation facility” means a unit or ensemble of units generating electricity, which is either non-synchronously connected to the network or connected through power electronics, and that also has a single connection point to a transmission system or to a distribution system;

(6) “fault-ride-through” means the capability of electrical devices to be able to remain connected to the network and operate through periods of low voltage at the connection point caused by secured faults;

Article 3. Scope of application

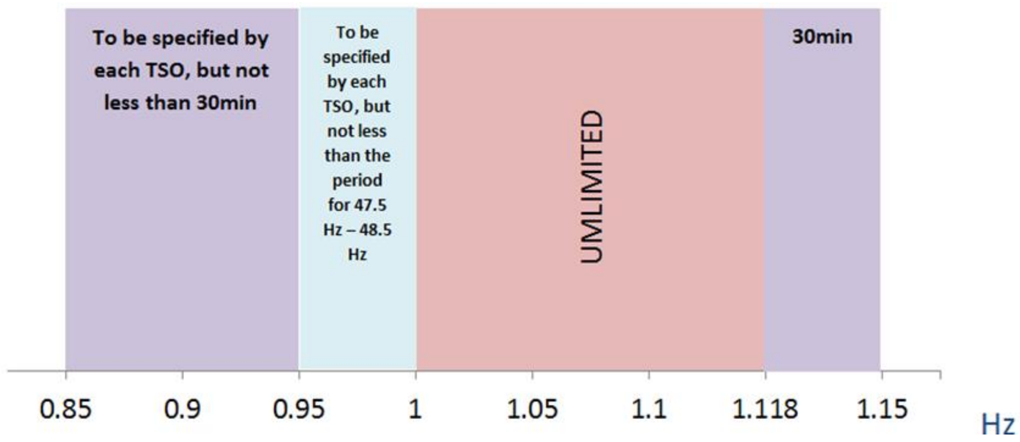
The connection requirements set out in this Regulation shall apply to new generation facilities, connected both to the transmission and the distribution grid.

The relevant system operator shall refuse to allow the connection of a generation facility which does not comply with the requirements set out in this Regulation. The relevant system operator shall communicate such refusal, by means of a reasoned statement in writing, to the generation facility owner and to the relevant regulatory authority or other responsible body of the Member State.

Article 4. Requirements related to frequency stability

a) With regard to frequency ranges:

i. a generation facility shall be capable of remaining connected to the network and operate within the frequency ranges and time periods specified in Figure 1;



The figure shows the requirement of the GC RC for all Med-TSO countries for the minimum time period during which a generation facility has to be capable of operation on different frequencies, deviating from a nominal value, without disconnecting from the network

Figure 1. GC requirement of frequency/time range limits for users to withstand without damage

ii. the relevant system operator, in coordination with the relevant TSO, and the generation facility owner may agree on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a generation facility, if it is required to preserve or to restore system security;

iii. the generation facility owner shall not unreasonably withhold consent to apply wider frequency ranges or longer minimum times for operation, taking account of their economic and technical feasibility.

b) With regard to the rate of change of frequency withstand capability, a generation facility shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection. Based on the results of the survey of TC2 in the Mediterranean area, it is required by the GC RC that the rate of change of frequency withstand capability is set between 1 and 2 Hz/sec.

Article 5. **Requirements related to limited frequency sensitive modes – over and under frequency schemes**

Each TSO should specify the actual frequency threshold and droop in order to provide the active power frequency response according to Figure 2 and Figure 3.

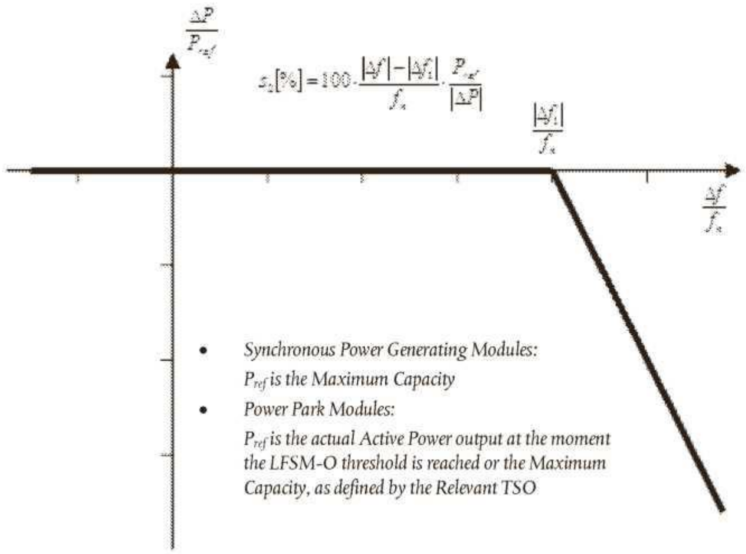


Figure 2. Active power frequency response capability of generation facilities in LFSM-O

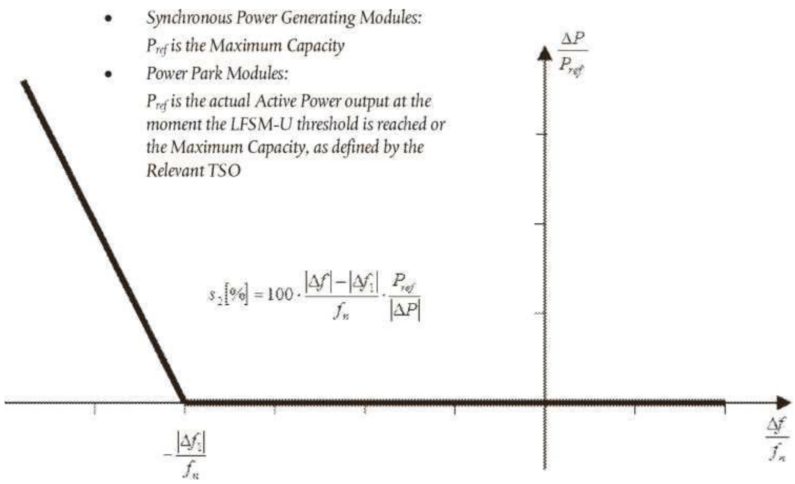


Figure 3. Active power frequency response capability of generation facilities modules in LFSM-U

Synchronous Power Generation Modules and Power Park Modules is the terminology used in the European Grid Codes, recently approved by European Commission. For the purpose of this Regulation we will use synchronous generation facilities and non-synchronous generation facilities respectively.

The generation facility shall be capable of activating active power frequency response as fast as technically feasible with an initial delay that shall be as short as possible and reasonably justified by the generation facility owner to the TSO. The generation facility shall be capable of either continuing operation at minimum regulating level when reaching it or alternatively further decreasing active power output, the choice to be defined by the TSO. This choice should be informed by system characteristics (including needs of the synchronous area / defence plan) and also the capability of the generating technology.

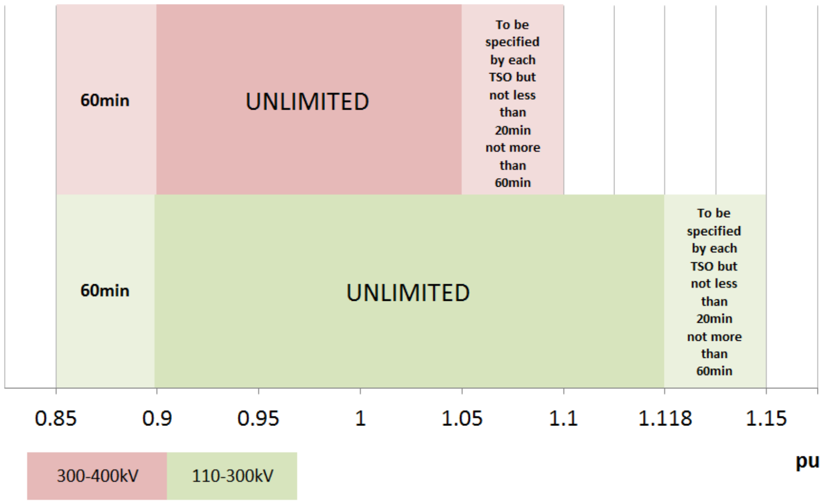
The actual delivery of active power frequency response in LFSM-U mode depends on the operating and ambient conditions of the generation facility when this response is triggered, in particular limitations on operation near maximum capacity at low frequencies and available primary energy sources.

In general, parameters such as droop, time and speed of active power activation can vary for different power generating units, depending also on the constraints of each technology, but it is important that the time of activation is as short as possible in order for this requirement to contribute to system stability.

TSO-TSO coordination to agree such parameters within one synchronous area is strongly recommended, with the aim to minimize unplanned power flow between the countries, after activation of LFSM. Furthermore, TSO – Grid User coordination is implicitly established (not on a case-by-case basis, but on generation technology level), because the selection of the full set of parameters to exhaustively define LFSM, should take into consideration technology-specific characteristics and constraints.

Article 6. Requirements related to voltage/time range limits for users to withstand without damage

Each TSO should establish the requirements so that the power generating modules shall be capable of staying connected to the network and operating within the ranges of the network voltage and for the time periods as specified in Figure 4.



The figure shows the requirement of this GC for all Med-TSO countries for the minimum time periods during which a power-generating module must be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network where the voltage base for pu values is from 110 kV to 400 kV

Figure 4. Voltage/time range limits requirement in the GC

Article 7. Requirements related to Fault-ride through capability

The fault-ride-through profile of synchronous and non-synchronous generation facilities is set within the limits specified in Figure 5 and Figure 6:

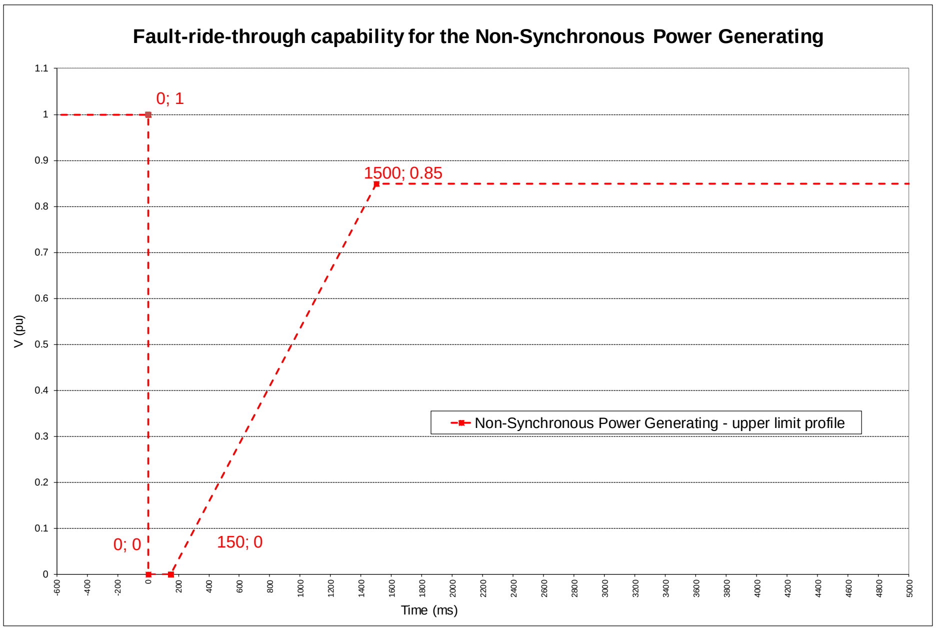


Figure 5. FRT capability for non-synchronous generation facilities

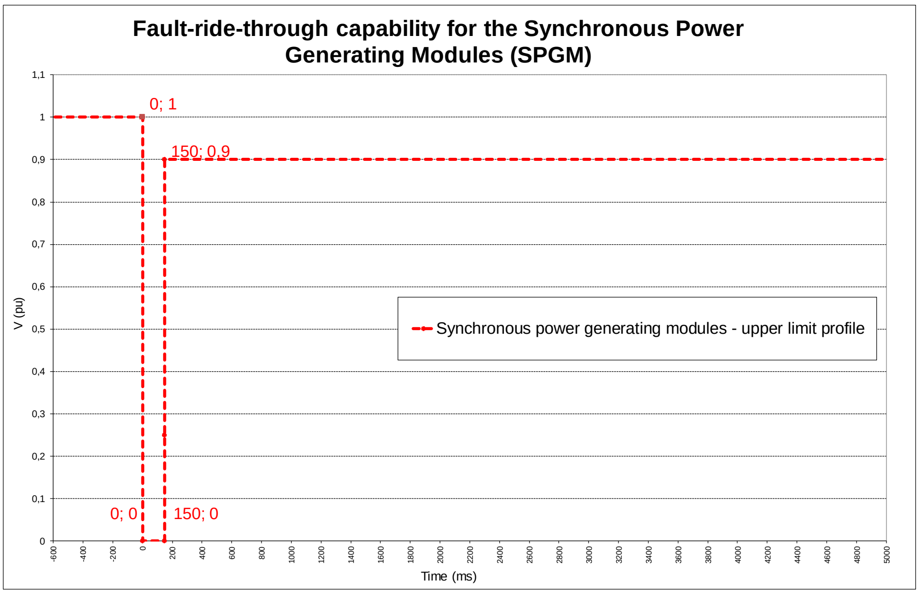


Figure 6. FRT capability proposal for synchronous generation facilities

Generation facilities shall be capable of remaining connected to the network and continue to operate in a stable manner, when the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault remains above the limit of fault-ride-through profile specified by Med-TSO countries according to the limits in the figures above, unless the protection scheme for internal electrical faults requires the disconnection of the power generating module from the network. The protection schemes and settings for internal electrical faults must not jeopardize fault-ride-through performance.

With regard to fault-ride-through capabilities in the case of asymmetric faults, they must be specified by each TSO, but it is strongly recommended to consider profiles similar or equivalent to those presented above.

***Article 8*. Reactive power requirements**

Each TSO should define the reactive power provision capability requirements in the context of varying voltage and active power. Especially related to the reactive power contribution for the different technologies, it should be set as an interval of adequate reactive requirement (the maximum range of Q /Pmax = between - % of P and + % of P), especially in situations where the possible impact of the generation can appear, like generation plants near the neighbouring countries. However, there should be a difference in limits of reactive power contribution, for synchronous and non-synchronous generation facilities.

Synchronous generation

In context of varying voltage, the TSO shall specify power provision capability requirement, which is defined by the U-Q/P_{max} profile within the boundaries of which the synchronous power-generating shall be capable of providing reactive power at its maximum capacity. Therefore, the U-Q/P_{max} profile considered at the connection point, and it has to be represented through a diagram (see below - **Errore. L'origine riferimento non è stata trovata.**), expressed by the voltage at the connection point (ratio of actual value and its nominal value, i.e. per unit) against the ratio of the reactive power (Q) and the maximum capacity of the synchronous power-generating (P_{max}).

Therefore, each TSO should specify U-Q/P_{max}-profile by the inner envelope in the **Errore. L'origine riferimento non è stata trovata.**. The dimensions of the U-Q/P_{max}-profile envelope (Q/P_{max} range and voltage range) shall be within the range specified for synchronous area:

- Maximum range of Q/P_{max}: **0,95**
- Maximum range of steady - state voltage level in PU: **0,225**

The position of the U-Q/P_{max}-profile envelope shall be within the limits of the fixed outer envelope in **Errore. L'origine riferimento non è stata trovata.**;

Non-Synchronous generation

In context of varying voltage, the TSO shall specify power provision capability requirement, which is defined by the U-Q/P_{max} profile within the boundaries of which the non-synchronous power-generating shall be capable of providing reactive power at its maximum capacity. Therefore, the U-Q/P_{max} profile considered at the connection point, and it has to be represented through a diagram (see below - **Errore. L'origine riferimento non è stata trovata.**), expressed by the voltage at the connection point (ratio of actual value and its nominal value, i.e. per unit) against the ratio of the reactive power (Q) and the maximum capacity of the non-synchronous power-generating (P_{max}).

Therefore, each TSO should specify U-Q/P_{max}-profile by the inner envelope in the **Errore. L'origine riferimento non è stata trovata.**. The dimensions of the U-Q/P_{max}-profile envelope (Q/P_{max} range and voltage range) shall be within the range specified for synchronous area:

- Maximum range of Q/P_{max}: **0,75**
- Maximum range of steady - state voltage level in PU: **0,225**

The position of the U-Q/P_{max}-profile envelope shall be within the limits of the fixed outer envelope in **Errore. L'origine riferimento non è stata trovata.**.

For the non-synchronous power-generating, the P-Q/P_{max}-profile shall be specified by each TSO too, in conformity with the following principles: **a)** the P-Q/P_{max}-profile shall not exceed the P-Q/P_{max}-profile envelope, represented by the inner envelope in **Errore. L'origine riferimento non è stata trovata.**; **b)** the Q/P_{max} range of the P-Q/P_{max}-profile envelope is specified for the synchronous area as mentioned above for the Non-Synchronous generation; **c)** the active power range of the P-Q/P_{max}-profile envelope at zero reactive power shall be 1 pu; **d)** the P-Q/P_{max}-profile can be of any shape and shall include conditions for reactive power capability at zero active power; and **e)** the position of the P-Q/P_{max}-profile envelope shall be within the limits of the fixed outer envelope set out in **Errore. L'origine riferimento non è stata trovata.**.

Therefore and as mentioned above, each TSO should specify within the following boundaries for U-Q/Pmax and P-Q/Pmax profiles for synchronous and non-synchronous generation facilities:

- A fixed outer envelope, exhaustively defined in the GC RC.
- An inner envelope for which maximum dimensions (Q/P_{max} range and Voltage range) are defined for each synchronous area in the GC RC.

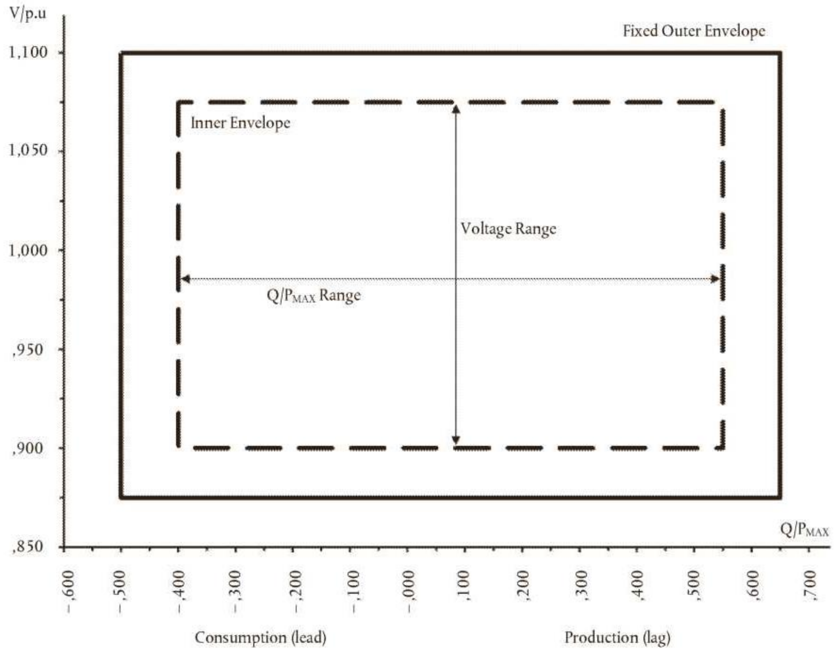


Figure 7. U-Q/P_{max}-profile of a synchronous generation facilities

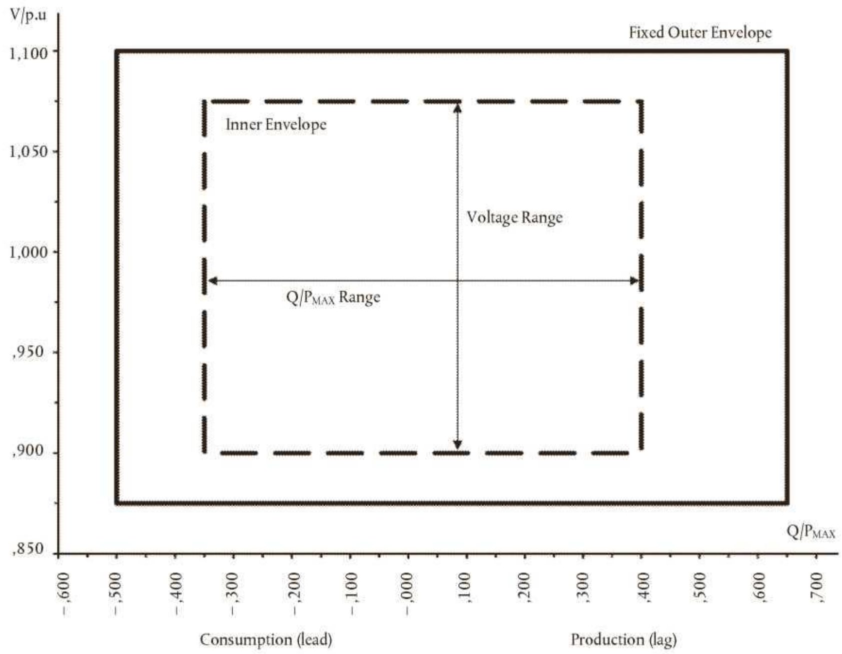


Figure 8. U-Q/P_{max}-profile of a non-synchronous generation facilities

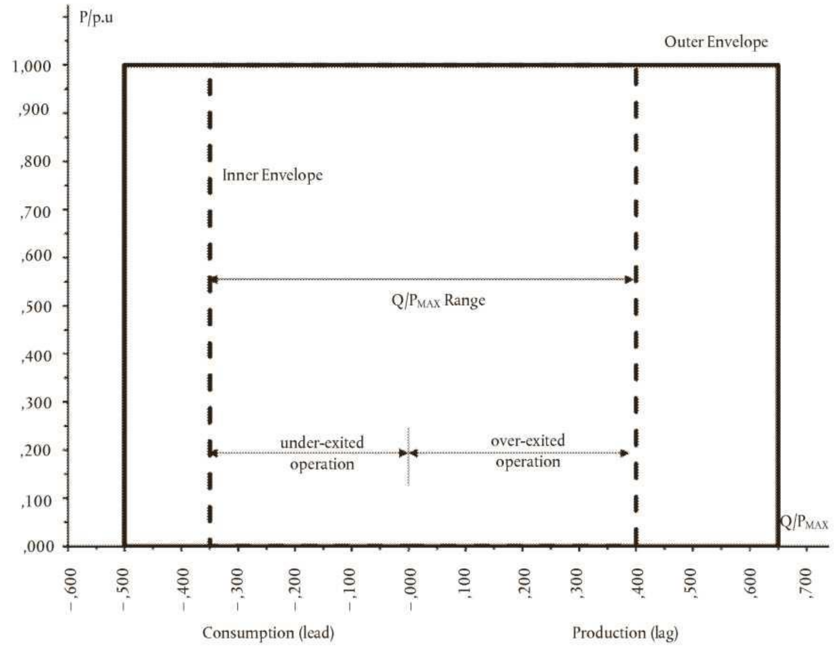


Figure 9. P-Q/P_{max}-profile of a non-synchronous generation facilities

It should be noted that the position, size and shape of the inner envelope in the diagrams above are indicative. The inner envelope shall be adequately located by each TSO within the fixed outer envelope and define its own U-Q/Pmax and P-Q/Pmax profile within the inner envelope. Regional needs regarding reactive power capability shall be taken into account and as a consequence more than one profile is appropriate when regional system characteristics vary significantly within the area of responsibility of a network operator. This U-Q/Pmax and P-Q/Pmax profile shall take any shape that does not need to be rectangular.

***Article 9*. Observability and controllability requirements**

Each TSO should define the observability and controllability requirements from the TSO Control Centres of generation facilities connected to the transmission grid or the distribution grid

Generation facilities shall be observable and/or controllable by TSO´s Control Centres, depending on their installed capacity:

a. Generation facilities with more than 1MW of installed capacity shall be observable from TSO Control Centres.
b. Generation facilities with more than 10MW of installed capacity shall be controllable by TSO Control Centres.

The communication between TSO and generation facilities shall comply with performance requirements (speed, reliability, etc.) and shall be directly between the user and the TSO or, alternatively, via an intermediate Control Centre designated by the generation facility.

The magnitudes of V, P, Q and the status (On/Off) of the circuit breakers shall be provided from non-transmission facilities to TSO Control Centres. In addition, other magnitudes like the current magnitude or other requirements and conditions may also be established at national level or for a specific interconnection.

GRID CODE ON SYSTEM OPERATION

Article 1. Subject matter

This Regulation/ grid code aims at establishing the main principles about frequency quality parameters, the requirements concerning operational security, the requirements on outage coordination and the data exchange rules between TSOs.

Article 2. Definitions

For the purposes of this Regulation, the following definitions shall apply, in addition to the ones included in the GC RC:

'operational security' means the transmission system's capability to retain a normal state or to return to a normal state as soon as possible, and which is characterised by operational security limits

´contingency list' means the list of contingencies to be simulated in order to test the compliance with the operational security limits;

'N-situation' means the situation where no transmission system element is unavailable due to occurrence of a contingency;

'(N-1) situation' means the situation in the transmission system in which one contingency from the contingency list occurred;

'internal contingency' means a contingency within the TSO's control area, including interconnectors;

'external contingency' means a contingency outside the TSO's control area and excluding interconnectors, with an influence factor higher than the contingency influence threshold;

'contingency analysis' means a computer based simulation of contingencies from the contingency list;

'system state' means the operational state of the transmission system in relation to the operational security limits which can be normal state, alert state, emergency state, blackout state and restoration state

'frequency deviation' means the difference between the actual and the nominal frequency of the synchronous area which can be negative or positive;

'observability area' means a TSO's own transmission system and the relevant parts of distribution systems and neighbouring TSOs' transmission systems, on which the TSO implements real-time monitoring and modelling to maintain operational security in its control area including interconnectors;

'neighbouring TSOs' means the TSOs directly connected via at least one AC or DC interconnector

´operational security analysis' means the entire scope of the computer based, manual and automatic activities performed in order to assess the operational security of the transmission system and to evaluate the remedial actions needed to maintain operational security;

Article 3. **Scope of application**

This Regulation shall apply to all transmission systems, distribution systems and interconnections between the countries in the Mediterranean region. In addition, the requirements included in this Regulation shall apply to existing and new generation and demand facilities connected to the transmission grid or any provider of ancillary services and/or of demand response services.

Article 4. **Classification of system states**

A transmission system can be in the following system sates:

- Normal state. The following conditions should be fulfilled:
    - No violation of operational security limits, even after the occurrence of a contingency from the contingency list.
    - Steady state system frequency deviation is within the standard frequency range or not larger (in absolute value) than the maximum steady state frequency deviation without entering in alert state.
    - Active and reactive power reserves are sufficient to withstand contingencies from the contingency list without violating operational security limits.

  In general a system is in normal state if is within operational security limits in the N-situation and after the occurrence of any contingency, taking into account the effect of the available remedial Actions.

- Alert state. No violation of operational security limits and at least one of the following conditions:
    - (i) At least 1 contingency from the contingency list leads to a violation of the operational security limits (even after activation of remedial actions);
    - (ii) Steady state system frequency deviation is not larger (in absolute value) than the maximum steady state frequency deviation and has continuously exceed 50% of the maximum steady state frequency deviation for period larger than the alert state trigger;
    - (iii) Reserve capacity is reduced more than 20% for more than 30 minutes with no possibility to compensate in real time operation.

  In general, a system is in alert state if is within operational security limits, but a contingency has been detected, for which in case of occurrence, the available remedial actions are not sufficient to keep the normal state.

- Emergency state: At least one of the following conditions should be fulfilled:
    - (i) At least one violation of operational security limits;
    - (ii) Frequency does not meet criteria of normal or alert states;
    - (iii) One measure of the defence plan is activated;
    - (iv) Unavailability of TSO tools for more than 30 minutes.

  In general, a system is in emergency state if operational security limits are violated and at least one of the operational parameters is outside of the respective limits.

- Blackout state. At least one of the following conditions should be fulfilled:

- (i) Unexpected loss of more of 50% of the total national demand at a particular point in time;
- (ii) Total absence of voltage for at least 3 minutes.

At a national level a "Partial Blackout state" could also be defined, if the blackout affects only a part of the system (not fulfilling the previous requirements).

- Restoration state: When any measure of the restoration plan is activated, partially of fully.

Article 5. **Frequency ranges in the different system states**

The frequency of the electrical system is the indicator of the balance between electricity generation and consumption. Generation facilities must fulfil the following requirements as established in GC RC:

- withstand frequency and voltage deviations under normal operating conditions;
- withstand frequency and voltage deviations under exceptional operating conditions;
- allow exceptional operation for limited times in the range of 47 to 53 Hz.

The GC SO establishes the frequency quality parameters taking into account the state of the system in each frequency range. These quality parameters are:

- Nominal frequency: 50 Hz.
- Standard frequency range: between 20 and 200 mHz, but in the future should be harmonized to at least 50 mHz.
- Maximum instantaneous frequency deviation: between 700 and 1500 mHz, but in the future should be harmonized to at least 800 mHz.
- Maximum steady state frequency deviation: between 200 and 500 mHz, but in the future should be harmonized to the lower value (200 mHz).
- Time to restore frequency: 10 to 20 minutes. In the future could be harmonized to the average value (15 minutes).

Article 6. **Voltage ranges for unlimited operation**

Each generation facility must have the constructive ability to contribute to voltage regulation by providing and absorbing reactive power fulfilling the following requirements as established in GC RC

- be designed to withstand voltage drops and spikes;
- supply or absorb reactive energy without disconnecting from the network;
- be designed to operate continuously in the voltage range around the rated voltage at the operating point

The GC SO establishes voltage ranges for unlimited operation in normal conditions depending on the voltage level:

- Between 110 kV and 300 kV the voltage should stay between 0.9 pu and 1.118 pu.
- Between 300 kV and 400 kV the voltage should stay between 0.9 pu and 1.05 pu.

Anyway, more exigent conditions could also be established at national level.

At national level voltage ranges for unlimited operation in extraordinary conditions (unexpected conditions not studied in real time by the TSO) should also be established, differentiating by voltage level.

Article 7. **Reactive power management measures**

The GC SO establishes the list of potential remedial actions to manage the reactive power that could be applied by TSOs when the voltage is outside the ranges defined for unlimited operation:

- switching of reactors and capacitors;
- on load tap change transformers;
- instruction to distribution companies;
- set points to generation facilities or HVDC installations.

Each TSO shall be entitled to use all available transmission-connected reactive power capabilities within its power system for effective reactive power management and maintaining the voltage ranges set in "Voltage ranges for unlimited operation" section.

Each TSO shall ensure reactive power reserve, with adequate volume and time response, in order to keep the voltages within its power system and on interconnectors within the ranges set out in "Voltage ranges for unlimited operation" section.

For each interconnector each TSO shall agree with the neighbouring TSO on common operational security limits. TSOs interconnected by AC interconnectors shall jointly specify the adequate voltage control regime in order to ensure that the common operational security limits established in accordance with the mutually agreed common operational security limits.

Article 8. **System protection coordination criteria**

Each TSO shall operate its transmission system with the protection and backup protection equipment in order to automatically prevent the propagation of disturbances that could endanger the operational security of its own transmission system and of the interconnected system.

Each TSO shall specify setpoints for the protection equipment of its transmission system that ensure reliable, fast and selective fault clearing, including backup protection for fault clearing in case of malfunction of the primary protection system.

Before protection and backup protection equipment entry into service or following any modifications, each TSO shall agree with the neighbouring TSOs on the definition of protection setpoints for the interconnectors and shall coordinate with those TSOs before changing the settings.

***Article 9*. List of structural data to exchange with other TSOs**

The GC SO establishes the list of structural data that TSOs shall be entitled to exchange with the neighbouring TSOs to perform Operational Security Analysis.

The list of structural data shall include at least the following data from the observability area that shall be agreed between neighbouring TSOs (in principle, at least border substations shall be included in the observability area):

- Normal topology of substations.
- Technical data on transmission lines.
- Technical data on transformers, including phase-shifting transformers.
- Technical data on HVDC systems.
- Technical data on reactors, capacitors and other.
- Reactive power limits from generation facilities.
- Operational security limits.
- Protection set points of transmission lines included as external contingencies.

***Article 10.* List of scheduled data to exchange with other TSOs**

The GC SO establishes the list of scheduled data to exchange to coordinate operational security analysis. TSOs from the same synchronous area shall exchange at least the following:

- Topology of the transmission grid above 220 kV (including 220 kV).
- Model of the transmission grid below 220 kV, which has a significant impact.
- Thermal limits of the transmission elements.
- Aggregated generation forecast in each node of the transmission grid.
- For dynamic stability studies, additional data should be exchanged.

***Article 11.* List of real time data to exchange with other TSOs**

The GC SO establishes the list of real time data to be exchanged between TSOs of the same synchronous area as follows:

- Frequency
- Frequency restoration control error
- Active power exchange between control areas
- Aggregated generation
- System state
- Set point of the load frequency control

In addition the list of real time data from the observability area to be exchanged between neighbouring TSOs shall include at least the following:

- Substation topology (including availability).
- Active and reactive power in line bay or transformer bay, including transmission and distribution
- Active and reactive power in generation bay
- Reactive power in reactor bay and capacitor bay
- Bus bar voltage
- Restrictions (if any) and outages.
- Positions of tap-changers transformers

Article 12. **Contingency analysis**

Each TSO shall perform contingency analysis in its observability area to identify contingencies which may endanger operational security limits, as established in article 13 and also identify the remedial actions that may be needed to solve the contingency, as established in article 14. Each TSO shall ensure that potential violations of the operational security limits which are identified by the contingency analysis do not endanger the operational security of its transmission system or of interconnected transmission systems.

Each TSO shall assess the risks associated with the contingencies after simulating each contingency from its contingency list and after assessing whether it can maintain its transmission system within the operational security limits in the (N-1) situation. When a TSO assesses that the risks associated with a contingency are so significant that it might not be able to prepare and activate remedial actions in a timely manner to prevent non-compliance with the (N-1) criterion or that there is a risk of propagation of a disturbance to the interconnected transmission system, the TSO shall prepare and activate remedial actions to achieve compliance with the (N-1) criterion as soon as possible. In case of an (N-1) situation caused by a disturbance,

Each TSO should inform neighbouring TSOs about the external contingencies and also about any topological change included in the external contingency list.

Each TSO shall establish a contingency list, including the internal and external contingencies of its observability area, by assessing whether any of those contingencies endangers the operational security of the TSO's control area. The contingency list shall include both ordinary contingencies and exceptional contingencies.

The external contingency list should be agreed by neighbouring TSOs in the bilateral corresponding internal TSO-TSO agreements.

Article 13. Operational security limits

Each TSO shall specify the operational security limits for each element of its transmission system, taking into account at least the following physical characteristics:

- Voltage limits in accordance with article 6.
- Short-circuit current limits
- Stability limits.
- Current limits in terms of thermal rating including the transitory admissible overloads

In case of changes of one of its transmission system elements, each TSO shall validate and where necessary update the operational security limits. For each interconnector each TSO shall agree with the neighbouring TSO on common operational security limits.

Article 14. **List of joint remedial actions**

The GC SO establishes the categories of remedial actions that TSOs could use in case of a contingency (either when need or not need to be managed in a coordinated way) as follows:

- Topological actions

- Reschedule of maintenance through the duration of outages
- Voltage control and reactive power management
- Re-dispatch of generation
- Countertrading
- Modification of active power flows through HVDC links

Article 15. Outage coordination

The outage coordination regions within which the TSOs shall proceed to outage coordination shall correspond with the two neighbouring TSO, unless the transmission system of another TSO is affected by an outage in the two neighbouring TSO. Due to the importance of quick access to information about outages, all TSOs should perform the two following steps:

- Definition of assets (network elements and generation and consumption units) with cross border (XB) relevance, to be included in the contingency list that should be agreed by neighbouring TSOs in the bilateral corresponding internal TSO-TSO agreement**.**
- On a year ahead timeframe, outage planning agents of XB relevant generation and consumption shall provide their proposals for outages (Availability Plans) to the connecting TSO.

In the bilateral corresponding internal TSO-TSO agreement the following requirements should be agreed:

- Perform individual assessment of XB relevant units (generation and consumption) outages, detecting possible incompatibilities (adequacy or network problems). If Outage Incompatibilities are detected, each TSO has to provide a solution, in coordination with the impacted Outage Planning Agents. In the event that no coordinated solution is reached, the lowest impact solution is proposed by the TSO. TSO informs the NRA of the not coordinated solution and of its technical and financial impacts for all parties. The conducted coordination processes are handled according to and in line with the current existing practices (regulations, law, contracts) as they are installed in the different Member States.
- Plan based on Availability Plans provided by Outage Planning Agents the Availability Statuses of its Relevant Grid Elements. The outages on the Relevant Grid Elements should minimize their impact on the market and preserve operational security. When a TSO detects outage incompatibilities, it should initiate coordination with the impacted parties in order to reach a solution taking into account if the work of the outage is relevant for maintaining the Operational Security.
- Share among them their individually assessed "preliminary Year-Ahead Availability Plans" (units and grid elements).
- Define the perimeter of the electrical interdependent (in terms of mutual affection of outages) region (Outage Coordination Region) in which has sense to jointly coordinate outages.
- Jointly assess, within the same Outage Coordination Region, the preliminary Y-A Availability Plans. If Outage Incompatibilities arise when combining the Availability Plans of all the Relevant Assets within the Outage Coordination Regions, a solution is found for each Outage Incompatibility in coordination with all concerned TSOs, each TSO being responsible for coordinating with its connected concerned Outage Planning Agents.
- Publish a final Y-A Availability Plan

Update Year-Ahead Availability Plan. After a change has been initiated, the impact on the overall Availability Plans is assessed and a coordination phase is set up between affected TSOs, which coordinate possible Outages Incompatibilities with their connected Outage Planning Agents as affected, according to the applicable legal framework.

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