MARI – First Consultation

Call For Input

Abstract

This document provides details on the options of the European mFRR platfrom design, which are consulted from 21 November 2017 – 20 December 2017

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CHAPTER 1 Introduction

The Guideline on Electricity Balancing (GLEB), approved by the Electricity Cross-Border Committee on March 16th 2017, defines tasks and a timeline for the implementation of a European platform for the exchange of balancing energy from frequency restoration reserves with manual activation (mFRR).

The GLEB defines a framework for common European technical, operational and market rules for a cross-border balancing market. This market serves the purpose to secure economically efficient purchase and in time activation of regulation energy by simultaneously ensuring the financial neutrality of the TSOs. Important means to achieve these goals are the harmonization of the balancing energy products and close cooperation of the TSOs at regional and European level.

Given the importance of an efficient balancing mechanism for an integrated electricity market, 19 European TSOs decided to work on the design of an mFRR platform in order to address pending issues and questions connected with the establishment of such a platform as soon as possible. These TSOs decided to work on a technical solution, which does not only reflect the views of the founding parties but could also be acceptable for potential new parties joining the initiative.

The 19 TSOs signed a Memorandum of Understanding on April 5th 2017, which outlines the major cornerstones of the cooperation. Shortly after, the project was officially named MARI (Manually Activated Reserves Initiative). Since then seven additional TSOs have joined the project as observers.

In September 2017 the MARI project was selected by the ENTSO-E as the implementation project for the European mFRR platform, which is to be developed according to GLEB.

1.1 Consultation Background

The framework of a European platform for the exchange of balancing energy from frequency restoration reserves with manual activation is set by Article 20 of the GLEB. It sets forth that a joint proposal from all TSOs for a European platform for the exchange of balancing energy shall be developed and submitted to the NRAs within one year of the entry into force of the GLEB.

This proposal shall contain most importantly the high-level design of such a platform. As the TSOs are aware that creation and agreement on the details of an mFRR European platform necessitates broad discussion about the details, the TSOs agreed to – as a first stage - identify options in several specific fields and as a second stage to select one or more options, which will then be implemented.

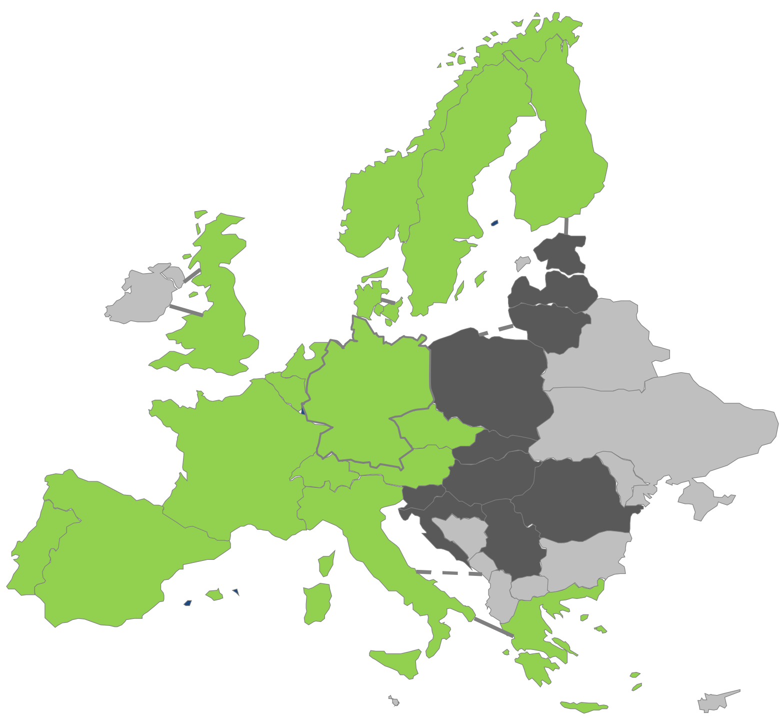
The MARI members (see below) are initiating this voluntary open online consultation for a period of 1 month (21 November 2017 – 20 December 2017).

MEMBERS	
Austria	APG
Belgium	elia
Czech Republic	čeps
Denmark	ENERGINET
Finland	FINGRID
France	Rte
Germany	50hertz amprion TenneT TRANSNET BW
Greece	
Great Britain	nationalgrid
Italy	Terna Rete Italia
Netherland	TenneT
Norway	Statnett
Portugal	REN
Spain	RED ELÉCTRICA DE ESPAÑA
Sweden	SVENSKA KRAFTNÄT
Switzerland	swissgrid

OBSERVERS	
Estonia	elering
Hungary	MAVIR
Latvia	AST
Lithuania	Litgrid
Serbia	EMC
Slovakia	
Slovenia	ELES
Croatia	HOPS
Poland	PSE
Romania	

MARI members

Observers



1.2 Document Structure

This document provides details on the possible design aspects of the future European mFRR platform and is divided into 5 sections:

1. Product and Process

Dealing with the questions on the product shape and the sequence of direct vs. scheduled activation.

2. Algorithm

Explaining the main inputs and outputs of the algorithm and identified constraints.

3. Settlement

Tackling the issue of how to settle the delivered energy in terms of volume as well as price.
We are providing a number of settlement options for the working assumptions that direct activation takes place before scheduled activations. We chose this example for illustration purposes only.

4. Congestion Management

Outlining the options, which the TSOs have at hand in case the security of the system would be endangered.

5. Harmonization

Providing a list of aspects, which are not an inherent part of the mFRR platform design, however could be considered for harmonization, in case it would have a crucial impact on the level-playing field for the platform users and the liquidity of the platform.

Each of the described sections provides a description of the respective issues and identifies several options for the possible future design. Questions for stakeholders are clearly marked at the end of the respective chapters.

CHAPTER 2 Product and Process

2.1 Product Properties

This chapter describes the different aspects of the process from the submission of a TSO need for a manual activated frequency restoration product (a need) until full activation of the product. First we address the actual shape of the product and product characteristics, which is followed by the description of the process of activation for both scheduled as well as directly activated products.

2.1.1 Key Characteristics of the Product

The key characteristics of standard products are listed in Article 25 of the GLEB:

- Preparation period – (Figure 1 – 1)

'preparation period' means the period between the request by the connecting TSO in case of the TSO-TSO model or by the contracting TSO in case of the TSO-BSP model and the start of the ramping period;

- Ramping period – (Figure 1 - 2)

'ramping period' means a period of time defined by a fixed starting point and a length of time during which the input and/or output of active power will be increased or decreased;

- Full activation time – (Figure 1 - 3);

'full activation time' means the period between the activation request by the connecting TSO in case of the TSO-TSO model or by the contracting TSO in case of the TSO-BSP model and the corresponding full delivery of the concerned product;

- Minimum and maximum quantity;

means the power (or change in power) which is offered in a bid by the BSP and which will be reached at the end of the full activation time. The minimum (maximum) quantity represents the minimum (maximum) amount of power for one bid.

- Deactivation period;

'deactivation period' means the period for ramping from full delivery to a set point, or from full withdrawal back to a set point;

- Minimum and maximum duration of the delivery period (Figure 1 - 4 and 5);

- Delivery period;

'delivery period' means the period of delivery during which the balancing service provider delivers the full requested change in power in-feed to, or the full requested change in withdrawals from the system;

- Validity period;

'validity period' means the period when the balancing energy bid offered by the balancing service provider can be activated, where all the characteristics of the product are respected. The validity period is defined by a start time and an end time

- Mode of activation (i. e. manual or automatic).

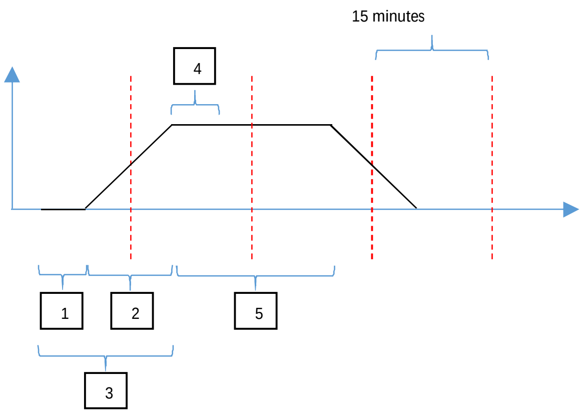


Figure 1: Elements of the Product Shape

2.1.2 Relation between the Shape of Product and the Shape of Cross-Border Exchange

The shape of the cross-border exchange refers to how the changes in physical flows resulting from activations of the platform are realized through virtual tie lines or set point generators. The shape of the cross-border exchange needs is to be agreed on in advance and will influence the shape of the product.

Currently, the TSOs co-operating in MARI foresee using a linear ramp of 10 minutes for the cross-border exchange. A 10-minute ramp equals the ramp which is used for scheduled programs of exchange across Continental Europe. An infinite ramp would not be possible, as there are limits to how quickly the flow can be changed between synchronous areas without risking reduced operational security and voltage problems. It is assumed to be more realistic to follow a 10-minute ramp for most BSPs and BSPs with fast units should be able to ramp slower, but not the other way around.

In the following we refer to the shape corresponding to the cross-border ramp as the "expected shape". If there are deviations between the actual delivery/withdrawal of certain units and the expected shape, this will lead to imbalances in the connected TSOs area. Whether there shall be a harmonized method to incentivize the BSPs to follow the expected shape, will be investigated in the second design phase of the project.

2.1.3 Options and analysis

Full Activation Time

At least two possible interpretations of Article 3 of the GLSO were identified by TSOs in order to enable them to respect the time to restore frequency (TTRF). TTRF is the maximum expected time after the occurrence of an instantaneous power imbalance of an LFC area within which the imbalance is managed. This time is set to 15 minutes in all synchronous areas. The two identified interpretations can be summarized as follows: according to the first interpretation, FAT of the mFRR product could be equal to 15 minutes whereas with the second interpretation, FAT of the mFRR product has to be strictly lower than 15 minutes.

Based on the guidance from ENTSO-E's System Operation Committee the assumption used in this document is a FAT of 12.5'. However, the impact on liquidity and possible alternative FAT durations will be considered for further analysis in the project.

Other Product Characteristics

At the moment, the following shapes are put forward for the mFRR standard product:

A) Scheduled activation (SA):

For the scheduled activation, the minimum and maximum duration of the delivery period are the same and assuming a ramp of 10 minutes around the shift of each quarter hour (QH) this equals 5 minutes.

B) Direct activation (DA):

For direct activations, the duration of the delivery period will be dependent on when the bid is activated and on the point of deactivation. Assuming a ramp of 10 minutes and deactivation at the end of the next QH, the duration cannot be longer than 20 minutes.

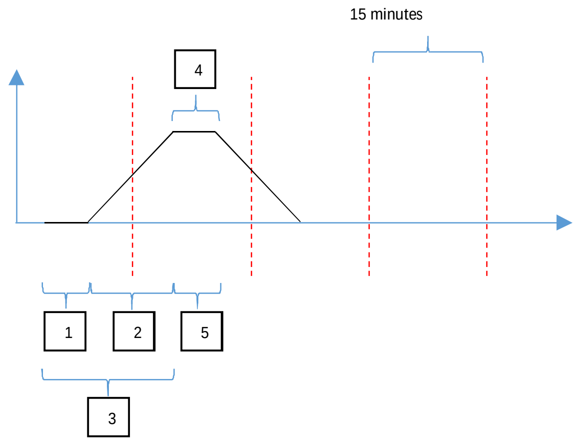


Figure 2: mFRR Product Physical Shape SA

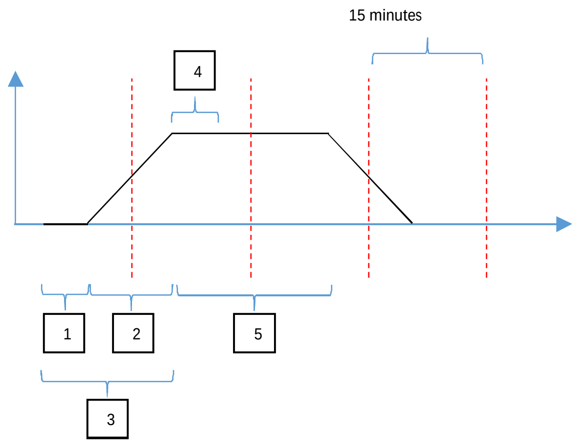


Figure 3: mFRR Product Physical Shape Longest DA

How to define the product is dependent on the shape of cross-border exchange and needs to be consistent with the timings of the elements in the overall process (described in 0). Moreover, the shape in the case of a scheduled activation equals the cross-border exchange of an energy product between LFC blocks. By this, there is a 10 min activation ramp starting 5 min before a QH and 10 min deactivation ramp starting 5 min before the end of a QH.

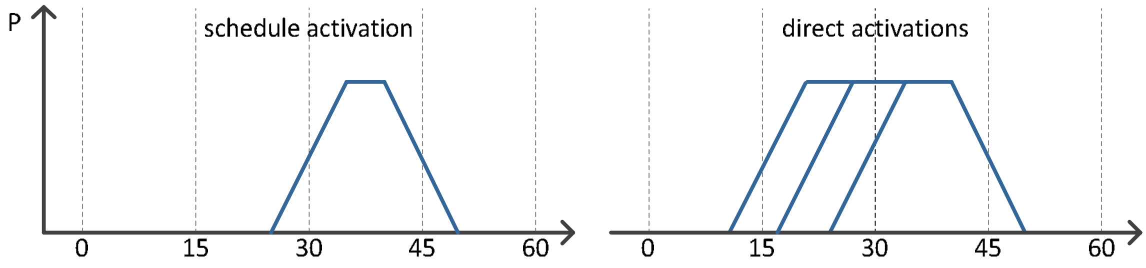


Figure 4: Illustration of the Shape of the Cross-Border Exchange for a Scheduled Activation (left part) and Various Direct Activations (right part)

The Table 1 below summarizes the currently foreseen product characteristics according to these shapes.

mFRR Standard Product		
Preparation period	Expected Shape	Accepted Shape
	2.5 minutes	0-12.5 minutes** The shapes of delivery from BSPs that will be accepted, may vary between TSOs
Ramping period	Expected Shape	Accepted Shape
	10 minutes	0-12.5 minutes** The shapes of delivery from BSPs that will be accepted may vary between TSOs
Full activation time	12.5 minutes*	0 - 12.5 minutes
Minimum quantity	1 MW*	
Maximum quantity	9999 MW*[1]	

[1] This maximum amount concerns the divisible bids quantity. The maximum on indivisible bids is tackled in subsequent chapters.

mFRR Standard Product		
Deactivation period	Expected Shape	Accepted Shape
	10 minutes	0-12.5 minutes
Minimum duration of delivery period	5 minutes SA and DA **	
Maximum duration of delivery period	20 minutes – longest DA 5 minutes – SA **	
Validity period	To be analysed in the next phase of the project	
Mode of activation	Manual	

*Table 1: mFRR Product Definition (the marking * means that the values follow current discussion at the ENTSO-E level; the marking ** meants that it is related to the FAT)*

Note 1: By default the mFRR bids can be both directly and scheduled activated. It is not mandatory for a bid to be directly activated, and the possibility to mark a bid as only scheduled corresponds to a variable characteristic of an mFRR bid.

Note 2: The accepted shape will be defined locally, but it has to be defined in such a way that full power must be reached at the latest at the end of the FAT. The accepted shape is dependent on the local requirements between the TSO and BSPs, and determines how much BSPs may deviate from the expected shape. This may relate to both prequalification and settlement. Whether the accepted shape will be the same for all TSOs of the cooperation will be analysed in the second phase in the TSO-BSP rules harmonisation.

Note 3: Minimum and maximum duration of the delivery period in the Table 1 are derived from the expected shape. However, the actual minimum and maximum duration may differ depending on the accepted shape.

2.1.4 Questions

Q1.	How would a FAT of 12.5’ impact the amount of MW you could offer for mFRR, as compared to the current FAT in the country you are operating in? Provide answer per each country you are operating in.
Q2.	What would be the lowest possible FAT that would not decrease the amount of MW you could offer for mFRR, as compared to the current FAT in the country you are operating in?
Q3.	What is your view on the consequences of a 5' duration (please refer to points 4 and 5 in the legend to Figure 1) period of the scheduled product?
Q4.	BSPs that have received a (capacity) payment for availability cannot withdraw their bids. Do you have a need for a maximum delivery time across several activations, in effect a limit on the number of reactivations?
Q5.	If allowed, do you intend to use a limitation on the maximum energy quantity within a certain period, e.g. to facilitate storage?
Q6.	Are there additional features that should be incorporated to enhance the flexibility of the standard product?
Q7.	Do you have any additional comments to the characteristics and shape of the product?

2.2 Process

2.2.1 Introduction

The time needed from the moment when a TSO submits a need to the platform until bids are fully activated is dependent on the following elements:

- Computation time of algorithm;
- Time to change flow on HVDC cables;
- Communication times between platform, TSOs and BSPs;
- Full activation time of the balancing product;
- Potential delay from the moment when a need is submitted to the platform until the algorithm starts to process it, i.e.:
    - waiting time until a scheduled process starts;
    - waiting time if algorithm already runs.

The time needed for all listed elements is uncertain. The drawing in Figure 5 illustrates the different elements for the scheduled process with some assumptions on their respective timings that yield 15 minutes total time from TSOs' GCT for submitting needs until full activation of balancing bids. Based on the knowledge we have today, both the assumption of 3 minutes for changing the flow on HVDC cables and 1 minute for the processing time of the algorithm may be challenging to realize.

From the chart, we can see that from the time the results of the platform are communicated to TSOs the process of (i) changing the flow on HVDC cables and (ii) the communication process TSO-BSP can start in parallel.

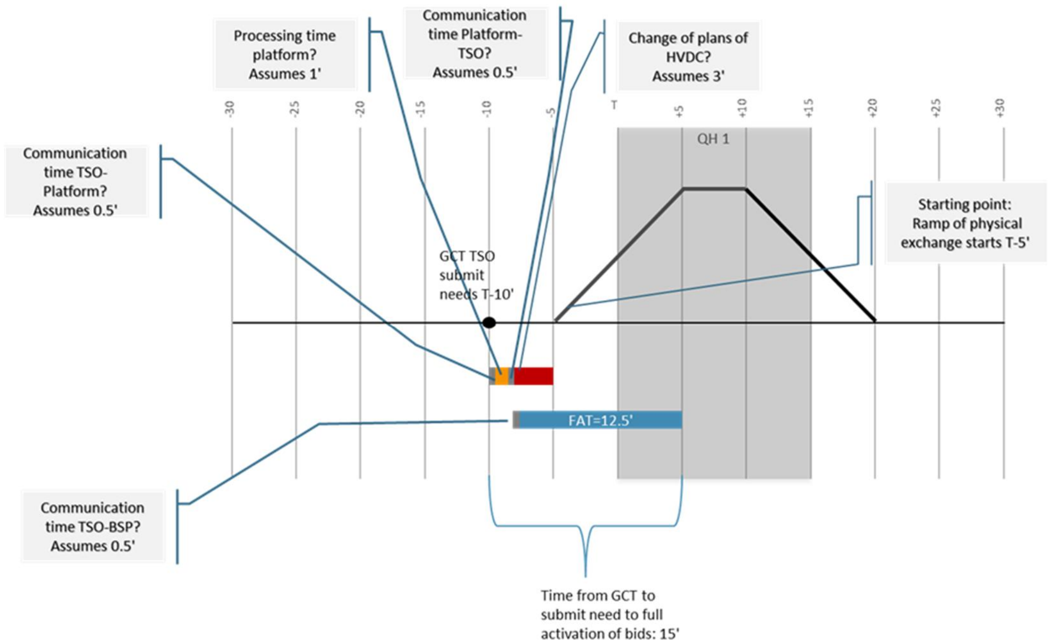


Figure 5: Timing of the Scheduled Process

Today, the total time needed for changing the physical flow of HVDC cables varies between cables and depends on several features:

- Electronic interfaces between market management systems, energy management systems/SCADA and controllers;
- Physical properties and functionalities of the conveter stations;
- Resolutions of HVDC plans (typically 1 or 5 minutes).

It is uncertain how much time can possibly be gained when this improvement can be realized. However, it is clear that improved IT systems, automation and development of more efficient procedures adapted to the platform will be necessary. Several critical elements are involved in the process of changing the flow on HVDC cables and currently we need to account for minimum 2-3 minutes.[2] Parts of this process

[2] Taking into account new investments in IT systems and processes, technical experts in Statnett and National Grid have assessed the time needed from the point where a TSO receives a request until the flow of a cable can start to change. The estimated time of 2-3 minutes is uncertain and the functionality of older HVDC cables may not allow this flexibility.

will have to be fully completed before the cable is ready for making new HVDC plans, which determines how frequently direct activations can impact the flow across HVDC interconnections.

2.2.2 Options

Direct Activations

1) Base case: Activation in continuous manner
2) Alternative Option: Direct Activation in cycles

An aim of the project is to have a continuous process. This minimizes the time from the moment of submission of a need until the bid is fully activated, and is a necessary feature for many TSOs to fulfil the TTRF. This may however be technically demanding to achieve and an alternative is to have the direct activations in cycles, where activations happen at fixed points in time similarly to the scheduled activation.

Scheduled Activations

The process for scheduled activations follows from the assumptions given in Figure 5.

Deactivation

As a base case for the analysis, it is assumed to introduce a scheduled deactivation. This deactivation would be implicit (for some TSOs), meaning that no explicit deactivation signal would be sent.The option of direct deactivation is, however, also considered below.

Sequence of Direct and Scheduled Activations

Two alternatives are analysed regarding the interaction between direct and scheduled activations.

1) Direct before scheduled activation
2) Scheduled before direct activation

2.2.3 Analysis

2.2.3.1 The Process of Direct Activations

2.2.3.1.1 Base Case: Direct Activation in a Continuous Manner

Direct activation in a continuous manner implies immediately running the algorithm and activating bids whenever a need is submitted to the platform i.e. at every possible second. This may however, prove difficult to achieve for three reasons:

Although direct activation in a continuous manner seems technically feasible for AC interconnections, the management of HVDC cables will require a delay from one activation until the next one.

As we assumed for the scheduled process, the process for direct activations will be influenced by the communication times. It will take some time for the TSOs to receive results from the platform and send activation requests to BSPs.

The computation time of the algorithm will also affect the frequency of direct activations as the cross-zonal capacities and selected bids must be updated before other needs can be served by the platform. At least for the quarterly scheduled auction, it is likely that the algorithm will require significant computation time, as a large number of needs, bids and cross- zonal capacities are taken into account in the optimization. Furthermore, if there are several needs submitted at the same time this may also require additional computation time. Therefore, there is a risk that direct activation in a continuous manner cannot be accomplished. There might be a waiting time from when the need is received by the platform (e.g. if the algorithm is processing another need) until the start of the algorithm and the computation time of the algorithm. This may also potentially cause the time from submission of a need until bids are fully activated to exceed the 15 minutes.

2.2.3.1.2 Alternative Option: Direct Activation in Cycles

An alternative for organizing the process of direct activations is to have it in cycles which allow bids and needs to be gathered and optimized with respect to network constraints and netting possibilities the same way as for the scheduled activation. In practice, we would have multiple scheduled auctions based on the same CMOL.

It is a question of how long the cycles of "direct activations" can and need to be. An example with five minutes cycles is illustrated in Figure 6. There is a scheduled auction every quarter with a ramp for the physical exchange starting 5 minutes prior to each QH, i.e. T+10, T+25, T+40 and T+55. BSPs can submit scheduled only bids, which can only be activated as a result of the scheduled auction. The activation takes place in five minutes cycles with ramps of the physical exchange starting at T+2.5', T+7.5', T+12.5', T+17.5' and so forth. In each quarter there are four potential activations from the platform platform including the scheduled auction..

The illustration is based on the assumption of a 5-minute minimum delivery period (expected shape) and scheduled deactivation starting five minutes before the end of a QH. The colored dot represents the moment of the submission of a TSO's need to the platform.

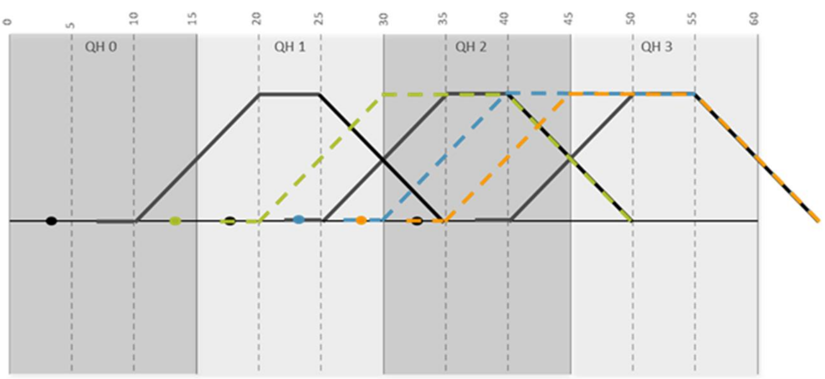


Figure 6: Example of Activation with 5-Minute Cycles for Direct Activation (the shape of the cross-border exchange is shown)

Gathering needs for a certain period, i.e. during one cycle for activation, allows benefiting from netting and more optimal usage of the available cross- zonal capacity. However, the time from the moment of submission of a need until bids are fully activated is prolonged.

The total time from the moment of the submission of a TSO's need to the platform until bids are fully activated with assumptions given in the illustration above and assuming 2.5 minutes for platform processing and communications in total, is:

- Min: 14 minutes;
- Max: 19 minutes;

We see that in this example with 5-minute cycles it cannot be guaranteed that a power imbalance can be resolved within 15'.

2.2.3.1.3 Minimum Distance between Cycles

The minimum distance between cycles depends on the duration for the algorithm. Under the assumption that the algorithm takes 1 minute to run, the minimum distance between individual cycles would be 1 minute as well. By this, an activation can be done every minute, irrespective of whether it is a direct activation or scheduled activation. Such a process is illustrated in Figure 7.

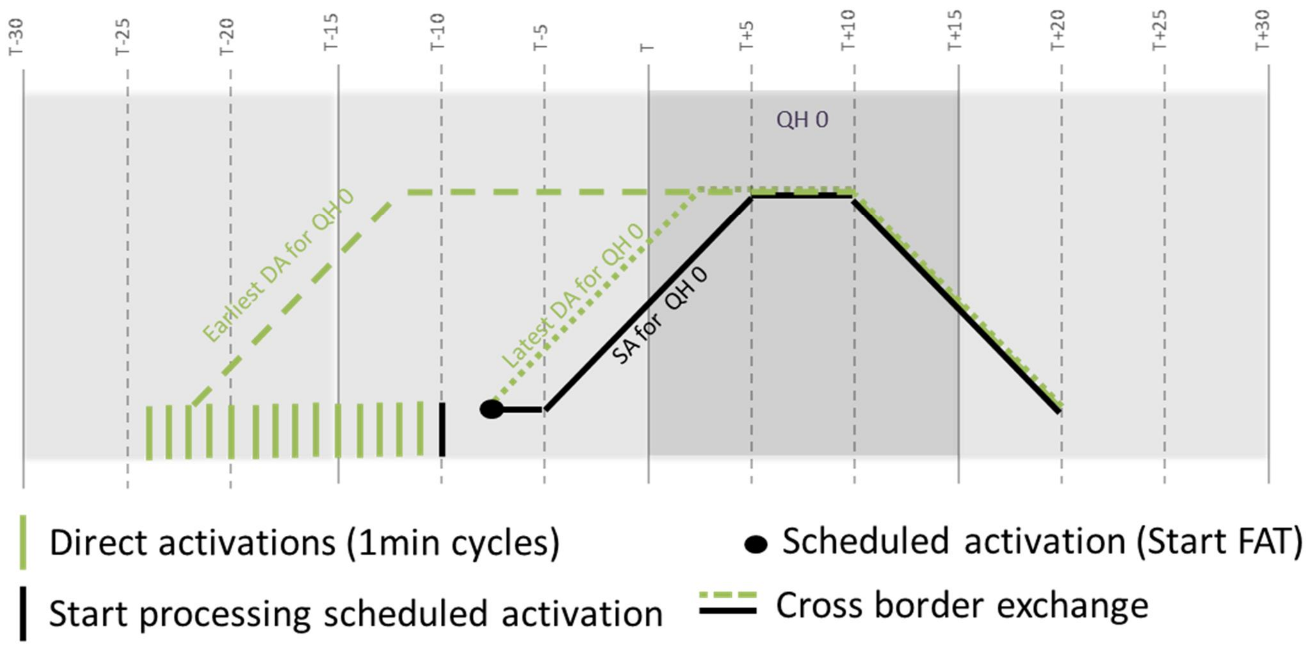


Figure 7: Example of Activation with 1 Minute Cycles for Direct Activation

This would have the advantage that new ATC values as a result of a previous run of the algorithm can be considered and unavailability of bids as well.

However it cannot be guaranteed that a power imbalance can be resolved within 15'. Dependent on the waiting time from when the need is received by the platform until the start of the algorithm, it can take up to 16 minutes (i.e. 1 min of algorithm waiting time, 1 min algorithm processing time, 1.5 min of total communication time and 12.5 min FAT) until full activation is reached.

Direct Deactivation

- Although scheduled deactivation is assumed above, direct deactivation is also a possibility.

PROs	CONs
► Balancing costs are reduced by avoiding counter activations during direct activation.	► The minimum duration of the delivery period cannot be ensured.
	► The process is more complex.

Table 2: Direct Deactivation

The first disadvantage (the minimum duration of the delivery period cannot be ensured) could be solved by allowing the direct deactivation only after the minimum duration of the delivery period, i.e. after 5 minutes of full activation.

The possibility of a direct deactivation different to the scheduled deactivation point in time is not investigated further. In case we find it as advantageous, this possibility will be rediscussed.

2.2.3.2 The Interaction between the Direct and the Scheduled Process

An important choice is whether direct activations of bids of a specific CMOL shall take place before or after the scheduled activation from the same CMOL. Below, two different alternatives are illustrated based on the same assumptions as depicted for the scheduled process in section 2.2.1. For the direct activation, a continuous process with close to zero computation time of the algorithm is assumed in these illustrations; as opposed to the assumption depicted in previous section.

We have assumed that the communication times between the platform, the TSOs and BSPs are the same as for the scheduled process. During the algorithm's computation time for clearing the scheduled auction (1 minute assumed), the algorithm for direct activations cannot run since e.g. ATC values cannot be used twice. Thus, if a TSO’s need is received by the platform at the moment the clearing of the scheduled auction starts, processing of this need has to wait for 1 minute before it can be processed. The process of direct activation itself takes 14 minutes, but as a result of what is stated above the total time for a direct activation can take up to 15 minutes maximally if the 1 minute waiting time applies.

Stakeholders should be aware in the options detailed below that it is possible for a bid for a specific QH to be activated outside of that QH. In some scenarios, the ramping can start 20 minutes before the start of the QH, while in other scenarios deactivation can end up to 20 minutes after the end of the QH (more details in the options discussed below). A probable consequence is that BSPs will have to carefully consider in which QHs they can safely bid.

Note: for the illustrations and explanations of the different alternatives for the interaction between DA and SA, the base case of a direct activation in a continuous manner is assumed (see section 2.2.3.1.1).

Alternative 1: DA Process before SA Process

For this alternative, TSOs can submit needs for direct activation just after TSO GCT for the previous QH until just before the GCT of the same specific QH. Referring to the specific QH starting at T, this is between T-25' and T-10'. Correspondingly, BSPs can receive the activation signal between T-22.5’ and T-8.5'. As the scheduled clearing of the previous QH ends at T-23.5', a DA need received by the platform directly after this clearing starts will await the clearing to be finished. Then there will be 1 minute in communication time (i.e. 0.5’s of platform to TSO plus 0.5’s of TSO to BSP communication time) before the BSP receives the activation signal. Hence, the earliest point of activation of a DA bid can be at T-22.5'. The last point in time when the algorithm can process a need is just before the scheduled clearing for the same specific QH which is starting T-9.5’. Taking into account the 1-minute communication time, the latest direct activation will be at T-8.5'. In order to allow the process to operate correctly, the platform needs at T-23.5' information about the remaining ATC and available bids after the SA process of the previous QH (i.e. QH-1).

The GCT for BSPs is set at T-30' in the illustration in order to give TSOs the necessary processing time for assessing and processing bids. This may, however, still leave too little time for certain TSOs' need for processing of the bids.

As the RR process is proposed to close at T-30‘, the BSPs participating both in the RR and the mFRR process may need time to update their offers for the mFRR process taking into account the RR process results.

These BSPs are invited to inform the TSOs about the time needed for their internal process in order to submit the mFRR offers. Depending on the BSPs' answers, the TSOs will potentially need to analyse possibilities to shorten the time between mFRR BSP GCT and TSO GCT in order to, for example, allow a BSP GCT after T-30.

This would in turn reduce the time window for the aFRR process which can make it unpractical from an operational perspective.

In general, the interactions between the timing of the different processes have to be seen in an holistic way. At this stage of investigation, there is no guarantee that a full absence of overlap between all the processes can be achieved. The views of the stakeholders will be used in the assessment of the possible trade-offs.

Also, from the BSPs' point of view, given that the results of the mFRR platform for QH 0 are published after the BSP GCT for QH 1, the BSPs participating in mFRR will not have an opportunity to update their bids for QH 1 after knowing the results for QH 0. Therefore, it is necessary to assess opportunities for giving the algorithm information about bids that are dependent on not being activated in the previous QH.

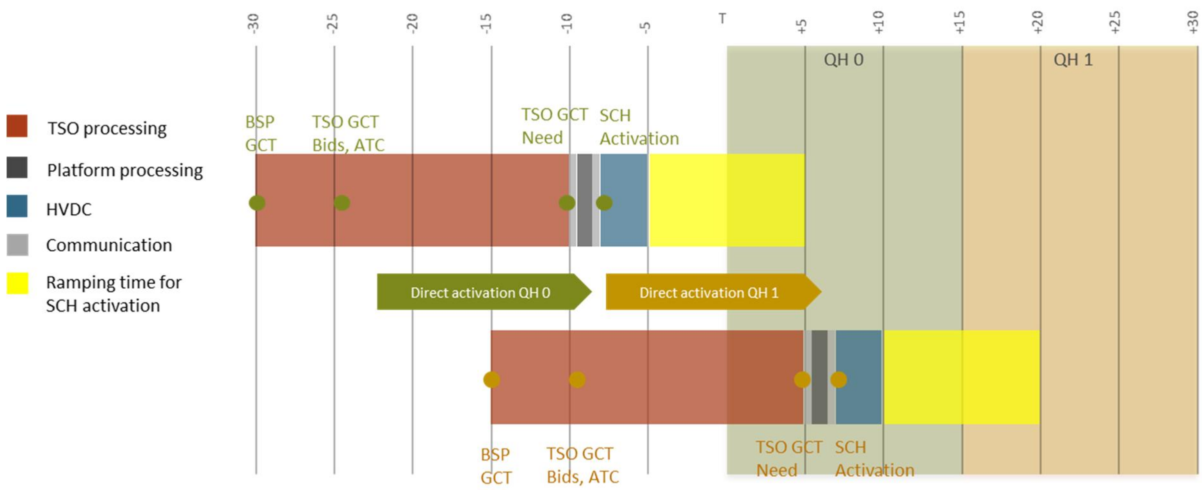


Figure 8: Alternative 1 - Direct Activation before Scheduled Activation for Two Consecutive QHs

The Figure 8 above illustrates to what extent energy will be delivered in different QHs depending on when a bid is activated. For all DA, most of the energy will be delivered in the target QH. Hence, delivery will only take place in QH-1 and QH 0.

This alternative allows all pricing options identified, since they were created based on the assumption that DA takes place before SA.

Alternative 2: SA Process before DA Process

For this alternative, the TSO can submit needs for direct activation just after the TSO GCT of the same specific QH until just before the TSO GCT of the next QH. This is between T-10' and T- +5', referring to the QH starting at T (QH 0). Correspondingly, BSPs can receive the activation signal between T-7.5' and T+6.5'.

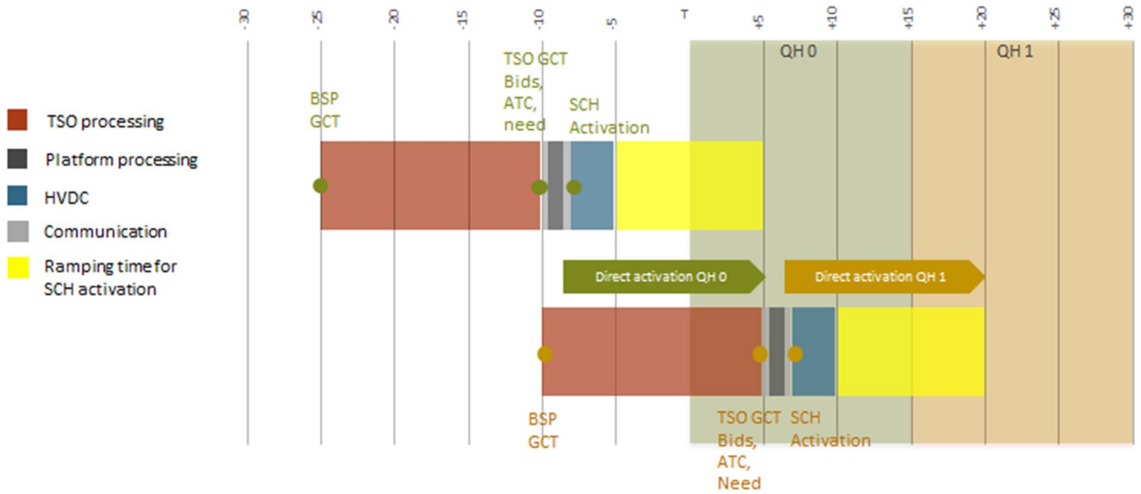


Figure 9: Alternative 2 - Scheduled before Direct Activation for Two Consecutive QHs

It is sufficient for TSOs to submit bids and ATCs at the same time as the SA needs and a GCT of T-25‘ for BSPs may be feasible, giving the BSPs opportunity to update their positions after results of the RR auction are published at T-30‘. However, as mentioned for Alternative 1, given that the results of the mFRR platform for QH 0 are published after the BSP GCT for QH 1, the BSPs participating in mFRR will not have the opportunity to update their bids for QH 1 after knowing the results for QH 0.

The requirements for minimum and maximum duration of the activation period lead to the following rules for deactivation: DA activations before T-5’ take place at the end of QH 0, and the DA activation after T-5’ takes place at the end of QH 1. The minimum delivery period is respected, i.e. the trapezoidal shape is met, and it avoids the case that most of the energy is delivered outside the target QH. For activations after T-5’, most of the energy will be delivered outside of the target QH as opposed to Alternative 1 where this is never the case (Figure 10).

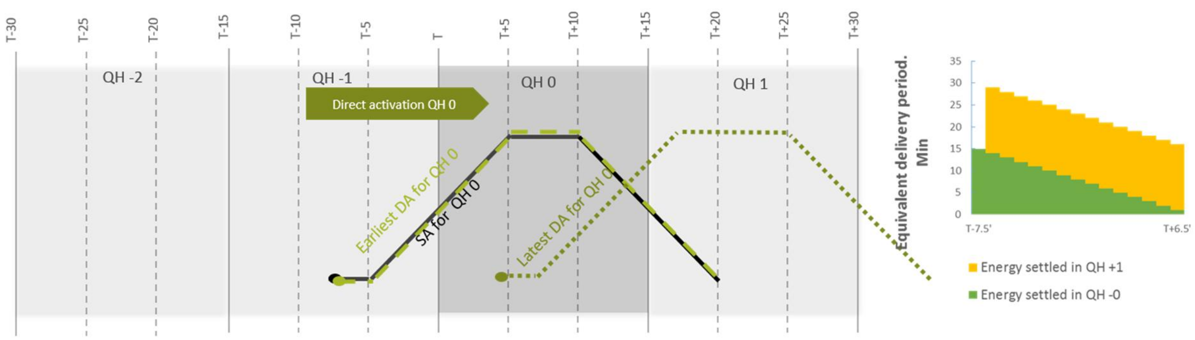


Figure 10: Scheduled Activation before Direct Activation with Deactivation in QH0 and QH1

An alternative option is that all deactivations take place at the end of QH 0 as illustrated in Figure *11*. Then no energy will be delivered outside the target QH which CMOL bids are submitted for. It will, however, not be possible to guarantee a minimum delivery period of at least 5'.

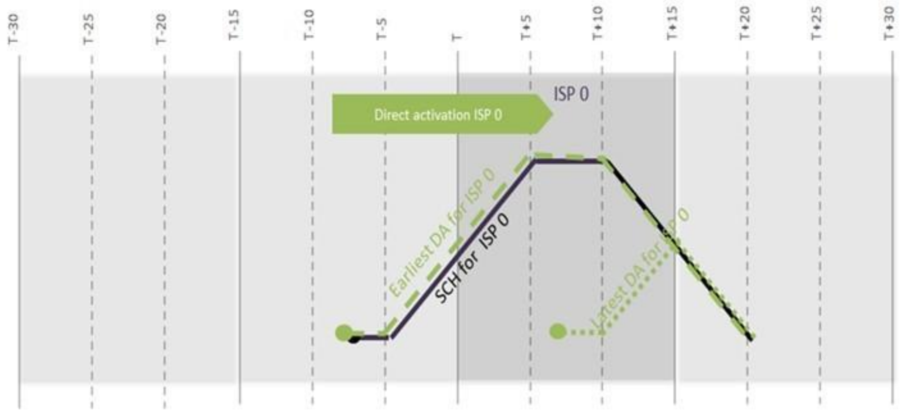


Figure 11: Scheduled Activation before Direct Activation with Deactivation in QH0

2.2.3.3 Evaluation of Alternatives for the mFRR Activation Process

The process options presented in this chapter show that the interaction with an mFRR platform will be demanding both for TSOs and BSPs, and will require development of new IT systems and routines compared to today. There is limited time for BSPs to prepare and submit bids and for TSOs to assess congestions, availability of bids and to submit needs to the platform.

The Table 3 below summarizes the different alternatives presented in this chapter. The purpose of the table is only to make it easier to compare the properties of the alternatives based on the analysis above. It should be stressed that each alternative can be modified in many ways and the properties indicated in the table are highly dependent on the assumptions about timings. For instance, many combinations of BSP GCTs and processing times for TSOs would be possible for each alternative for the sequence of DA and SA leaving either more time to BSPs or to TSOs. Therefore, the examples in the table below indicate tendencies of the different alternatives.

	1.DA >SA Deactivation only QH 0	2. SA>DA Deactivation QH 0 and QH 1	2. SA>DA Deactivation only QH 0
GCT for BSPs (possible range)	T-30' to T-24'	T-30' to T-10'	T-30' to T-10'
Processing time for TSOs (possible range)	6' to 0' As explained above, reducing the processing time for TSOs would allow a later BSP GCTs. The timings given here are indicative and need further analysis based on input received from stakeholders and other elements.	20' to 0'	20' to 0'
Maximal number of QHs with delivery	2 (QH-1, QH0)	2 (QH0, QH+1)	1 (QH0)
What is the delivery period of balancing energy?	5‘ for SA and 5' - 20‘ for DA,	5’ for SA and 5’-20’ for DA	5’ for SA and 0’-5’ for DA
Can direct activations yield a delivery period longer than 20' (maximum) or lower than 5' (minimum)?	No	No	Yes, zero duration of delivery is possible

Can direct activations lead to an activation where most of the energy delivery is outside the target QH?	No	Yes	No

Table 3 : Summary of Activation Alternatives

The choice between different options is to a large extent dependent on technical feasibilities, e.g. algorithm computation time, communication times and time to prepare flow changes on HVDC cables. These technical limitations determine, among others, how to design the process for direct activations, i.e. whether there should be activation in cycles and if so, the length of the cycles.

The sequence of direct and scheduled activations of bids of a particular QH is an important choice with different advantages and disadvantages from the BSP's and TSO's perspective and potential impact on the market performance.

The analysis of the options above shows that one advantage of SA before DA is that it may allow for more time for BSPs for their bidding process and more time for TSOs to determine ATCs and availability of bids. How much of a challenge this is will depend on the exact need of BSPs and TSOs and on how MARI will interact with other processes like the TERRE. How much of a challenge this is will depend on the exact need of BSPs and TSOs and on how MARI will interact with other processes like TERRE (RR) or PICASSO (aFRR).

Based on the analysis, we see that having DA before SA has the advantage that in the case of an direct activation on average more energy is delivered in the QH for which the bid has been placed in comparison with having DA after SA..

2.2.4	Questions
Q8.	What should be the gate opening time (how long in advance should BSPs be allowed to bid in for a given QH)?
Q9.	Which alternative for the sequence between the direct activation (DA) and scheduled activation (SA) process has your preference: DA before SA or DA after SA? In case DA is after SA, do you prefer the option deactivation in QH 0 and QH 1 or deactivation in QH 1 only?
Q10.	Do the countries with RR consider a BSP GCT of T-30' for the DA before SA option, or T-25' for the SA before DA option acceptable?
Q11.	Do you consider a direct activation in QH-2 (as of T-22.5') based on the CMOL of QH 0 acceptable?

2.3 Bid Properties

2.3.1 Smart Bids

2.3.1.1 Introduction

Linking bids together in terms of power (two or more bids offered for the QH) or in terms of time (two or more bids offered for different QHs) is understood as an important feature which could be beneficial for the BSPs and could help maximize the liquidity of the mFRR platform.

2.3.1.2 Options

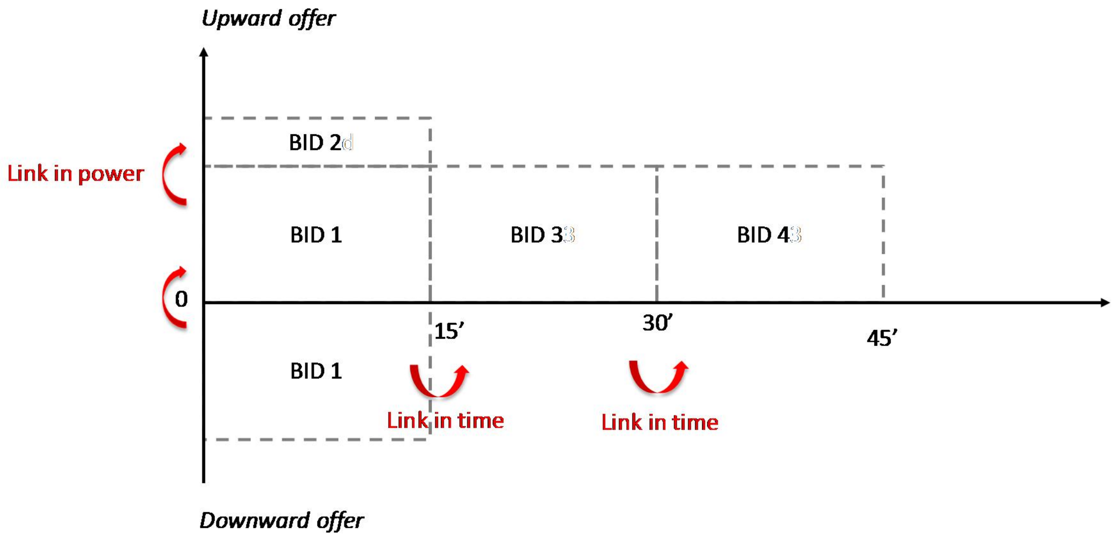


Figure 12: Possible Links between Bids

The following so-called ‘smart bids’ will be considered for inclusion in the MARI platform:

- Linked bid orders: the acceptance of a subsequent bid can be made dependent on the acceptance of the preceding bids.

  Example: BID 2 (child) can only be accepted if upward BID 1 (parent) is also accepted; i.e. the BID 2 (child) is linked to bid 1 (parent) and not vice-versa;

- Exclusive group orders: only one bid can be accepted from a list of mutually exclusive bids. Example: only one of the following bids can be accepted (they can differ in size, time, price and other properties): A_1, A_2, A_3...A_n.

  Example: An asset that is directly upward activated in one QH cannot necessarily be directly downward activated in the same QH in order to ensure that the minimum delivery period of their asset is respected. In the figure above, this is illustrated by Bid 1 that is offered both for upward and downward activation, but that can only be activated once.

Smart bids could allow BSPs to offer more flexibility, maximize the opportunity to be activated by fitting with TSO needs, reduce costs of balancing, reduce counter activations and contribute to an efficient and competitive balancing market. For example, by linking bids BSPs could reflect the start-up costs and power limits of their units more correctly. In the drawing shown above this can be shown as follows: the price of BID 1 is 70 €/MWh and includes a starting cost of 1000 € while the price of BID 2 is only 50 €/MWh. There is no starting cost, only energy related costs but the use of this bid is conditional to the preceding activation of BID 1.

However, smart bids generate complexity for the activation optimization function.

2.3.1.3 Analysis

Based on the draft ENTSO-E proposal for standard products and the analysis of sections 2.1 and 0, the following starting points are assumed:

- Linking of bids between different platforms (e.g. PICASSO, TERRE projects) is a particular challenge. The need for this and alternatives for such links have to be addressed at a later stage of development.
- Since the balancing needs of the TSOs are only known for the next QH, the clearing algorithm can only optimize the selection of bids for this QH and not the subsequent ones, thus no links between bids in the next QH and bids in QHs thereafter are possible. For the clearing of the next QH, the activation can only take into account the information of preceding QHs not of future QH.
- Other types of smart bids, next to linked bid orders and exclusive group orders, could be considered with respect to the impact they have on the time needed by the algorithm and the added value they generate (flexibility, lower costs,...).

2.3.1.3.1 Need for Technical Links between Bids in Different QHs

Due to the nature of the direct activation process and the timing of activations and gate closure times there is a need to ‘technically’ link bids between QHs. E.g. due to the fact that the results of the mFRR platform for QH 0 are known only after the BSP GCT for QH 1, a technical link between bids in QHs 0 and 1 permits to avoid that the underlying asset of a bid is activated twice, i.e. with overlapping delivery periods but activated in different QHs. Such technical links between bids will be especially needed for a BSP with small portfolios or for countries with unit bidding.).

Several situations exist which require a technical linking between bids over different QHs, often related to the interaction between DA and SA:

- In alternatives 1 (see section 2.2.3.2), an asset that has been scheduled activated on QH 0 for its maximum power output cannot be direct activated on QH 1. The corresponding asset will actually not be able to provide the additional power output required to satisfy the DA need. The two activations do actually overlap;
- In alternatives 1 and 2 (see section 2.2.3.2), an asset that has been direct activated on QH 0 for its maximum power output cannot be direct activated on QH 1. The corresponding asset will actually not be able to provide the additional power output required to satisfy the second DA need. The two activations do actually overlap;
- For activations where the delivery period is between 5 and 20 min, this linking between bids will even have to extend over more than one QH.
- Therefore the Activation optimization function (AOF) will need to be able to make the necessary links between bids in different consecutive QHs to avoid infeasible overlapping activations of the same bid. Hence, BSPs will be required to indicate if bids in consecutive QHs are linked, i.e. to indicate if the underlying assets of a bid are the same as a bid offered in previous QH(s). An analysis will be done in order to see if and how this feature will be implemented. This will make the whole process more complicated as inputs from all activations (DA or SA) need to be given to the next CMOL.

2.3.1.3.2 Possibility for Economical Optimisation based on Technical Links

Although technical links between bids arise from a technical need, they create new possibilities to optimize activations and costs. By linking bids over QHs, the issue of start-up costs and not to pay them more than once in several consecutive QHs can be tackled. A logic could be implemented to automatically adapt the bid price of the same bid for the next consecutive QH based on information given by the BSP when the bids were introduced. This means that the price of a bid for consecutive activations after the first activation could be lower, e.g. by the amount of the start-up cost. Consequently, it would increase the probability of the bid being selected again in the following activation period.

2.3.1.3.3 Conclusions

For the mFRR process, we propose allowing linking of bids, i.e. 'smart bids', by BSPs for economic reasons within the same QH, not between QHs. However, not all possible links should be allowed and there should be limits to the possibilities of linking (e.g. maximum number of linked bids). A methodology to link bids over different QHs in order to avoid overlapping activation of the same bid in different QHs (i.e. linking for technical reasons) is required.

2.3.1.4 Questions

Q12.	Should there be a possibility to introduce ‚smart bids‘ and if so, which options to link bids should be foreseen?
Q13.	Are technical links between bids in different QHs necessary? If yes which should be implemented and why?

2.3.2 Divisibility of Bids

2.3.2.1 Introduction

Divisibility refers to a parameter of the bid specifying whether the bid can be partially activated or not. This section examines alternatives for having a cap on the bid size for indivisible bids and alternative rules for accepting and rejecting indivisible bids in the algorithm including the possibility to have tolerance bands for TSOs' needs.

2.3.2.2 Indivisible Bids - Maximal Size

2.3.2.2.1 Options

To carefully consider where to set the maximal size of the indivisible bids is important for the liquidity of the platform.

A small investigation among the majority of TSO participating in the project shows that most TSOs allow indivisible bids at least implicitly. Therefore indivisible bids should be allowed.

There is a great variance concerning the preferred maximum bid size which varies from 25 MW to 310 MW.

2.3.2.2.2 Analysis

In the following Table 4, two options are compared. Option 1 is 25 MW which stands for a small maximum bid size and Option 2 is 310 MW which stands for a big maximum bid size. The concrete proposal for a maximum bid size can differ to these two options. Moreover, the comparison is based on the assumption that the maximum bid size should be the same in the whole cooperation.

Criteria	Explanation	25 MW	310 MW
Liquidity	The higher the maximum bid size, the higher the liquidity, because units which can only be switched on or off are not excluded from the market.	-1	1
Avoid market abuse	The higher the maximum bid size, the higher the possibility of market abuse especially in small countries with a high market concentration.	1	-1
Possible deviations from need	The higher the maximum bid size, the higher the possible deviations from the need.	1	-1
Changes to current market design	Both options require changes in the current market design in at least some countries of the MARI project.	1	1
Implementation effort	Both options will presumably have the same implementation effort.	1	1
Incentives for BSPs to be flexible	The smaller the maximum bid size, the higher the incentives for BSPs to become flexible.	1	-1
Distribution of activated balancing energy	In the case of an unexpected outage of power unit providing balancing energy, it is better to have activation distributed among more units with smaller activated volumes.	1	0

Table 4: Comparison of the Two Options for a Maximum Bid Size of Indivisible Bids Representing a Small (Option 1) and a Big (Option 2) Maximum Bid Size.

The comparison shows that the most important question is if promoting market liquidity is more important than avoiding market abuse, reducing deviations from need and incentivizing BSPs to be flexible.

In that sense, a compromise could be to have a rather limited maximum indivisible bid size and to create specific products to allow for a relatively low number of specific units with a higher size to still participate in the market.

2.3.2.2.3 Questions

Q14. If there should be a maximum size for indivisible bids, how large should the maximum be?

2.3.2.3 Divisible Bids – Minimum Activation and Granularity of Activation

The TSOs will investigate, together with the introduction of an indivisible bid, the possibility for BSPs to declare part of the divisible bid as minimum power, i.e. the minimum power that has to be activated, otherwise the bid can't be activated at all.

Example:

A divisible bid of 50 MW with a minimum quantity of 20 MW means that either at least 20 MW from this bid are activated (up to 50 MW in a divisible manner), or no activation from this bid takes place. Another important feature to be analysed is the increment amount of activation for divisible bids (granularity of activation) that the algorithm can result in, for example can activation of the divisible bid be :[20 MW, 20.01 MW, 20.02 MW] or [20 MW, 21 MW, 22 MW].

2.3.2.3.1 Implications of Existence of Divisible and Indivisible Bids

Two options concerning rejection of bids are to be thought of (see section 3.2.2.2 IV) as well as the feature of the tolerance band for a TSO need which can mitigate the occurrence of such rejections (see sections 3.1.2.2 and 3.2.2.2 IV). Using a tolerance band by TSOs means that for a TSO more or less power is activated compared to its actual need.

Certain criteria are listed which could be used to assess the two options described in CHAPTER 3 together with the option to not allow indivisible bids. These are listed in the relevant section 3.2.2.2 IV, due to the strong link to the algorithm.

2.3.2.3.2 Questions

Q15. Do you foresee using indivisible bids?

Q16. Do you need the possibility to declare minimum activation in divisible bids?

Q17. What should the granularity of activated volume be for divisible bids (e.g. 0.1 MW or 1 MW)?

2.3.3 Reliability of Bids

Reliability of bids can be understood in two possible ways:

A. Reliability of cross-border exchange: This describes the reliability of the cross-border exchange if a bid in LFC block A has been activated for LFC block B. The reliability of the cross-border exchange should be 100% irrespective of a possible outage of a power plant of the BSP in LFC block A or other disturbances. When such a situation presents itself, the non-compliancy of the BSP will lead to an additional aFRR-demand or even results in an ACE in LFC block A (i.e. connecting TSO);

B. Reliability of bids: This describes the reliability of a bid. This can vary from BSP to BSP and especially from country to country depending on the back-up requirements, unit bidding/portfolio bidding and the fact that real time change of schedules by market parties are allowed or forbidden. The requirements concerning reliability and the penalties in case of non-delivery shall be further discussed in the work stream harmonization of TSO-BSP rules.

Reliability of bids is not to be confused with the concept of firmness of bids. Firmness of bids refers to the fact that as of a given point in time, e.g. GCT, both the volume and price of a submitted bid cannot be changed anymore, i.e. the bid is firm. As of this point, the bid is expected to deliver once activated according to the reliability requirements discussed above. In the public consultation of the Explore study, some respondents argued in favour of having non-firm bids, i.e. having the firmness deadline only at the point of activation. Because this would lead to additional complexity for the algorithm, system security risks and a shift in responsibility from BSP to TSO regarding reliability, the idea of non-firm bids is considered as non-optimal.

We propose requiring a 100% reliability of the cross-border exchange, but how to deal with non-compliancy and whether there are special challenges related to the physical firmness of HVDC cables shall be further discussed in the work stream harmonization of TSO-BSP rules.

We propose that the deadline for bid firmness shall be the same as GCT for bid submission by BSPs.

2.3.4 Minimum Duration between the End of Deactivation Period and the Following Activation

Certain units may require some time in a rest state after the end of a deactivation period before they are able to be activated again. The GLEB foresees in Article 25.5 that BSPs shall, as one of the variable characteristics of a standard product, determine the minimum duration between the end of the deactivation period and the following activation.

The fact that the result of the clearing for QH 0 is known only after the BSP GCT for QH 1 necessitates a form of technical linking of bids between consecutive QHs to allow for this characteristic to be taken into account by the algorithm as discussed in section 2.3.1.2. This way it can be avoided that the same bid is activated again too shortly after a deactivation.

2.3.4.1 Questions

Q18. Do you foresee using a "resting time", i.e. a minimum time between activations?

Q19. The granularity of bid volumes (divisble with 5 MW, 1 MW or 0.1 MW etc.) has not been discussed in this document. What would be a relevant granularity for expressing your bid volume?

2.4 Rules for Balancing Need

2.4.1 Restrictions on Activation Volume

2.4.1.1 Introduction

The question of how much each TSO can activate through the platform relates to the operational security. According to the GLSO (article 119 and 157), each LFC block shall jointly develop dimensioning rules for FRR, taking into account historical imbalances and dimensioning incidents of the LFC block. The TSOs of a LFC block determine the geographical distributions for the FRR capacity and limitations on exchange and sharing within the LFC block. The TSOs of the LFC blocks that consist of the synchronous areas determine the geographical distributions for the FRR capacity and limitations on exchange and sharing within and between synchronous areas.

Furthermore, because of potential agreements for sharing and exchange of mFRR balancing capacity within an LFC block or between LFC blocks, a TSO may have a larger balancing need than the bids made available for the platform. This implies that the restriction on submitting balancing needs not exceeding the volume of bids depends on these agreements between TSOs or LFC blocks. The TSOs of the LFC block are responsible for the surveillance of whether TSOs' needs and bid volumes are in line with relevant agreements.

2.4.1.2 Options

In a non-emergency situation, it is proposed to have two restrictions on the volume of balancing needs requested from the platform by a TSO:

1) The total volume of needs (DA and SA) requested by TSO A from the platform for a certain direction (upward or downward regulation), as reported in GLEB Art. 29, must not exceed:

   a. The volume from bids (DA and SA) submitted by the TSO A;

   b. The volume from bids (DA and SA) submitted by another TSO B for the TSO A as a result of a balancing capacity exchange between the TSOs;

   c. The volume from bids (DA and SA) that corresponds to a sharing of reserves agreement between the TSO A and other TSOs, under the condition, that nobody from the other TSOs has requested them already (mutually exclusive relation between the TSOs of the sharing agreement).

2) The total volume of DA needs requested by TSO A from the platform for a certain direction (upward or downward regulation), must not exceed:

   a. The volume from DA bids submitted by the TSO A;

   b. The volume from DA bids submitted by another TSO B for the TSO A as a result of a balancing capacity exchange between the TSOs;

   c. The volume from DA bids that corresponds to a sharing of reserves agreement between the TSO A and other TSOs, under the condition that nobody from the other TSOs has requested them already (mutually exclusive relation between the TSOs of the sharing agreement).

With the second restriction, if a TSO submits only SA bids to the platform, it is forbidden for the TSO to use DA bids. On the other hand, if a TSO or the TSOs of an LFC block submit only DA bids to the platform, the TSO is allowed to use up to the same volume of SA bids for two reasons:

- to increase liquidity of DA bids;
- DA bids are the bids that are always also scheduled activatable.

Example:

Below, examples are given to clarify the implications of the restrictions.The examples applies to one specific activation direction. Either all bids are upward or downward.

For restrictions 1.a and 2.a:

► If a TSO A submits 200 MW of SA bids and 0 MW of DA bids, the TSO A is not allowed to use DA bids, but only SA bids up to 200 MW.

- ► If a TSO A submits 100 MW of SA bids and 100 MW of DA bids, the TSO A is allowed to use up to 100 MW of DA bids and 100 MW of SA bids or up to 200 MW of SA bids.

For restrictions considering the case of 1.b and 2.b:

- ► If a TSO A submits 200 MW of SA bids and 0 MW of DA bids, and another TSO B submits due to a Balancing Capacity exchange agreement 0 MW of SA bids and 150 MW of DA bids on behalf of TSO A:
  - the TSO A is allowed to use up to 150 MW DA bids, and 200 MW SA bids
  - or up to 350 MW only SA bids.

For restrictions considering the case of 1.c and 2.c:

- ► If a TSO A submits 200 MW of SA bids and 0 MW of DA bids, and it has an mFRR sharing of reserves agreement with another TSO B of 0 MW of SA bids and 150 MW of DA bids:
  - If TSO B has not yet requested the DA bids at all:
    - the TSO A is allowed to use up to 150 MW DA bids, and 200 MW SA bids
    - or up to 350 MW only SA bids.
  - If TSO B has requested e.g 50 MW from the shared DA bids:
    - the TSO A is allowed to use up to 100 MW DA bids, and 200 MW SA bids
    - or up to 300 MW only SA bids.

2.4.1.3 Analysis

Can the MARI platform be used to facilitate interconnector controllability?

In certain situations TSOs need the facility to manage the operational flow range of HVDC links. In the TERRE cooperation this is facilitated within the optimization algorithm by allowing the TSO to submit a minimum and/or maximum exchange.

Example:

- ► TSO 1 and TSO 2 both have mFRR needs of 0 MW. The planned HVDC flow from TSO 1 > TSO 2 is 30 MW for the target QH. TSO 1 requests a flow of <25MW for the target QH. This is considered by the optimization algorithm which issues instructions of -5MW in TSO 1 and +5MW in TSO 2 plus the new HVDC flow of 25MW. The energy balance in both TSO areas is unchanged but now the HVDC flow respects the limitation imposed by TSO 1.

In this example, we describe a simple scenario (no mFRR need) to illustrate the process. Settlement of these types of actions should adhere to the principle that the requesting TSO will be responsible for the costs relating to bids accepted for the above purposes (in the previous example TSO 1 will be responsible for the costs relating to bids accepted to facilitate flow change on HVDC).

To calculate the appropriate settlement responsibilities in more complex scenarios, the MARI platform can run two optimizations (either in parallel or sequentially):

- ► Constrained: As described above, HVDC limitations included;

- Unconstrained: Ignoring HVDC control limitations (only considering mFRR needs) for computation of the marginal price.

2.4.2 Allowing Price Dependent Needs

A TSO can balance its area(s) with several balancing products. When the TSO has alternative measures to manage an imbalance the ability to specify a limit on the price will remove uncertainties and allow the TSO to utilize available resources cost efficiently. It may also lead to more needs submitted to the platform, since it removes the incentive for the TSO not to submit needs due to the expectation of alternative measures being less costly.

Options for price dependency:

- Inelastic: not priced (the volume is absolutely required by the TSO);
- Elastic: One or more request levels with volume and max/min price they are willing to accept for up-/down activation.

In the MARI Project, we will take the possibility of elastic demands into account in the design. On the other hand, we also need to take into account the selected option of timing and settlement, because for some options the elastic demand may not be possible.

2.4.3 Questions

Q20. Do you have any comments on the Rules for Balancing need? If yes, elaborate.

CHAPTER 3 Specification of Activation Optimization Function

3.1 Inputs for the Merit Order List and Optimal Outputs

3.1.1 Introduction

The Activation Optimization Function (AOF) that will be used in MARI is based on the maximization of the social welfare.

A scheme of the optimization model is presented in Figure 13. As illustrated in this figure, the optimization model uses as input the TSO demands, the BSP bids, as well as network information, i.e., cross-zonal capacities (CZC) or any relevant network constraints and HVDC constraints. It creates a cost curve consisting of the TSO demands and the Common Merit Order List (CMOL) of all bids, and based on this curve as well as on all defined constraints, it provides the optimal social welfare, the satisfied demands, the accepted bids, the XB marginal prices and the XB commercial schedules.

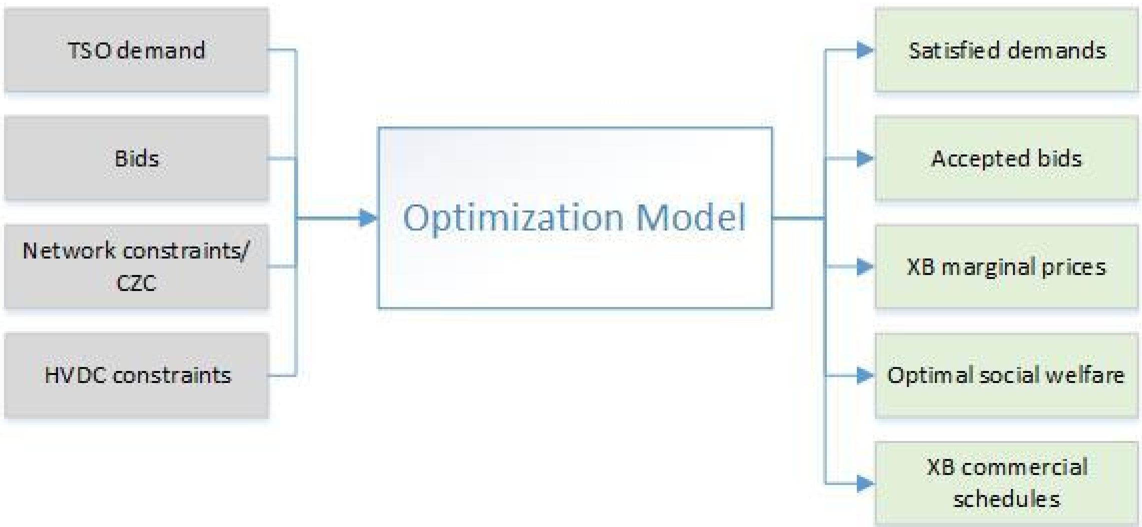


Figure 13: Scheme of Activation Optimization Function

The following subsection presents the structure of the inputs and outputs of the AOF.

3.1.2 Analysis

3.1.2.1 Structure of Bids

The submitted bids have the following features:

- Quantity [MW] (for the sake of the algorithm examples MWh is used in this chapter);
- Price of the bid (bid price)[3] [€/MWh];
- Method of activation (SA or DA+SA);
- Divisibility (divisible or indivisible);
- Location (e.g., the country, LFC area or LFC block);
- Minimum duration between the end of a deactivation period and the following activation [min];
- From the algorithm point of view, it is important that prices of divisible linked bid orders are non-decreasing (monotonic objective function);
- Regarding smart bids, apart from the features stated above, there must be an indication (a flag or ID) showing these bids belong to a set of linked bids.

Example:

Quantity [MW]: 10
Price of the bid [€/MWh]: 30
Divisibility (divisible or indivisible): divisible
Location: Country A

Minimum duration between the end of a deactivation period and the following activation [min]: 15

3.1.2.2 Structure of Demands

As described in section 2.4.2, TSO demands are assumed to be elastic (price dependent), as all principles considered for elastic demands hold also for inelastic (price independent) demands.

TSO demands have the following features:

- Quantity [MW or MWh] (for the sake of the algorithm examples MWh is used in this chapter);
- TSO demand price [€/MWh]: this will provide flexibility to the TSOs to determine if their need will be satisfied by MARI or by an alternative possibility, and will help them to deal with uncertainties. A TSO can also declare an inelastic need;
- Location of demand (e.g., the country, LFC area or LFC block);
- Purpose: balancing purposes or other purposes;

[3] Please note that there must always be a bid price, which shall not be confused with the marginal price.

- Tolerance band: it means that a TSO can declare a range in which additional or lower energy is activated compared to its demand submitted to the platform. Note that TSOs will analyse this feature further.
- Please note that all demands are considered to be divisible. An example of a demand is provided in Table 5.

Regarding the sign convention used in this Chapter, we note that:

- For positive needs (short TSOs), a positive price indicates that a TSO is willing to pay (maximum) this price in order for its need to be satisfied. On the other hand, a negative price indicates that the TSO is willing to be paid (at least) with the submitted price in order for its needs to be satisfied.
- For negative needs (long TSOs), a positive price indicates that the TSO is willing to be paid (at least) with the submitted price in order for its needs to be satisfied. On the other hand, a negative price indicates that the TSO is willing to pay (maximum) the submitted price in order for its need to be satisfied.
- For upward offers, a positive price indicates that the BSP wants to be paid (at least) with the submitted price in order to be activated. On the other hand, a negative price indicates that the BSP is willing to pay (maximum) the submitted price in order to be activated.
- For downward offers, a positive price indicates that the BSP is willing to pay (maximum) the submitted price in order to be activated. On the other hand, a negative price indicates that the BSP wants to be paid (at least) the submitted price in order to be activated.

TSO	Demand Name	Quantity (MWh)	TSO Demand Price (€/MWh)	Elastic/Inelastic	Location
TSO 1	Positive demand 1	100	10	Elastic	Country A
TSO 2	Positive demand 2	100	--	Inelastic	LFC area X
TSO 2	Negative demand 3	-50	-20	Elastic	LFC area XX

Table 5: Demand Structure

In Table 5, TSO 1 has an elastic positive demand of 100 MWh with a price of 10 €/MWh. This implies that this TSO is willing to pay a maximum of 10 €/MWh to satisfy its demand. TSO 2 has an inelastic positive demand of 100 MW which is located in the internal zone X and an elastic negative demand of 50 MWh located in the LFC area XX with a price of -20 €/MWh. That is, TSO 2 is willing that its demand of 100 MWh in the LFC area X will be met irrespective of (high or low) marginal prices, while he is willing to satisfy its demand of -50 MWh in the LFC area XX paying maximum 20 €/MWh.

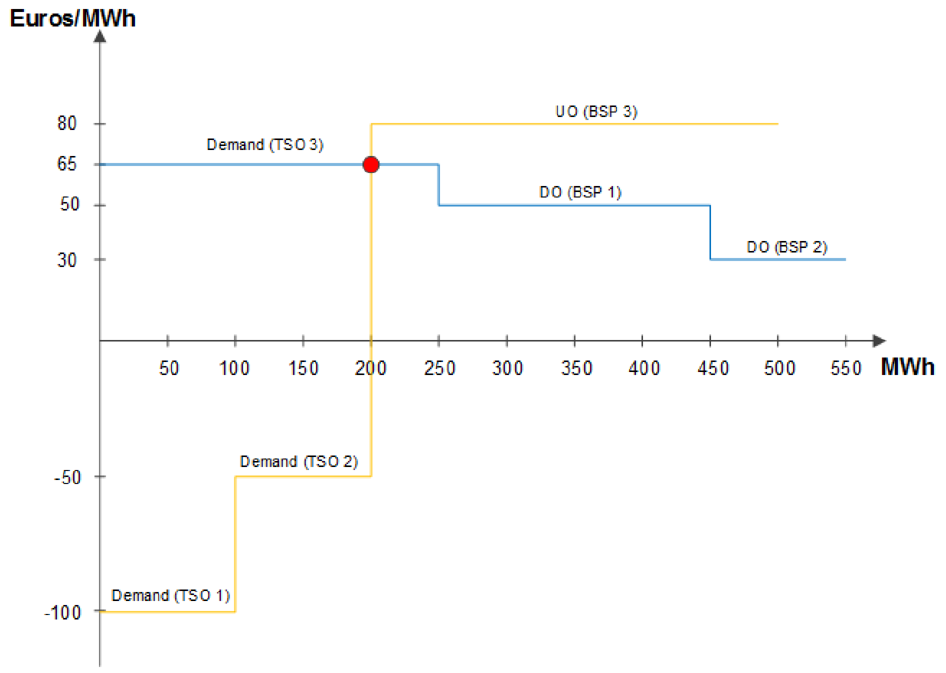


Figure 14: An Example of Cost Curve Formed by Bids and Elastic Demands

3.1.2.3 Example of the Cost Curve

A cost curve consists of a CMOL and the TSO demands. An example of such a curve is illustrated in Figure 14 based on the information of offers and demands provided in Table 6.

TYPE	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand
Negative demand (TSO 1)	-100	-100	Elastic
Negative demand (TSO 2)	-100	-50	Elastic
Positive demand (TSO 3)	250	65	Elastic
Downward Offer (DO BSP1)	200	50	--
Downward Offer (DO BSP2)	100	30	--
Upward Offer (UO BSP3)	300	80	--

Table 6: Example - Cost Curve Formed by Offers/Bids and Elastic Demands

3.1.2.4 Other Inputs

Other inputs of the AOF include ATC limits, power flow limits related to internal zones (i.e., mFRR bidding zones) and HVDC loss factors.

3.1.2.5 Optimal Output

The optimal clearing algorithm outputs are as follows:

- Accepted bids per each area [MW] (for the sake of the algorithm examples, MWh is used in this chapter);

- Satisfied demands per each TSO[MW] (for the sake of the algorithm examples, MWh is used in this chapter);
- XB Marginal Prices per each area [€/MWh];
- Optimal Social Welfare [€];
- Used CZ Capacity, including flows at each border. We note that further flows may be needed, and therefore be calculated by the algorithm, for example the flow between LFCI areas.

3.1.3 Questions

Q21. Are all relevant inputs being addressed in the clearing algorithm design? If not, could you please state the elements that you are missing?

Q22. Are all relevant outputs being addressed in the clearing algorithm design? If not, could you please state the elements that you are missing?

3.2 Criteria of the Clearing Algorithm

3.2.1 Introduction

In this section, we elaborate on the criteria to be considered in the clearing algorithm. These criteria define the objective function to be optimized and constraints to be respected. We assume that the optimization of scheduled bids and demands will be carried out within a single auction, and there will be one independent auction per 15-minute period.

This implies that the algorithm considers a single time interval (a single QH interval) without connection of this interval to other 15-min intervals. Therefore, it is concluded that bids as well as TSO demands cannot be linked over time intervals, as already explained in CHAPTER 2.

Example:

Bid 1 is 50 MW in time interval t1.

Bid 2 is 55 MW in time interval t2 and can be activated only if Bid 1 is activated in interval t1.

Such Bids are not considered in the algorithm.

3.2.2 Analysis

3.2.2.1 Objective Function: Maximizing Social Welfare

The objective of the clearing algorithm is to maximize the social welfare. In the context of balancing markets, the social welfare is the total surplus of all TSOs obtained from satisfying their demands and the total surplus of BSPs resulting from the activation of their associated offers, as illustrated in Figure

15. The curve consisting of positive TSO demands and downward BSP offers constitutes the consumer curve (based on economic theory), and therefore indicates what price consumers (TSOs and BSPs) are prepared to pay for consuming mFRR balancing energy, based on their expectations of private costs and benefits. On the other hand, the curve consisting of negative TSO demands and upward BSP offers constitutes the producer curve (based on economic theory), and therefore shows the price they are prepared to receive for supplying mFRR balancing energy. Social welfare, also known as economic welfare, is the total benefit available to society from an economic transaction, and therefore is made up of the red area in Figure 15 which is the consumer and the producer surplus.

For inelastic demand, the social welfare cannot be determined (in theory infinite value), as the demand must be satisfied at any cost. For implementation purposes, a price will always be assigned, but for inelastic demands, this price will be higher than any MARI offer and will represent the technical limit[4] of the MARI AOF.

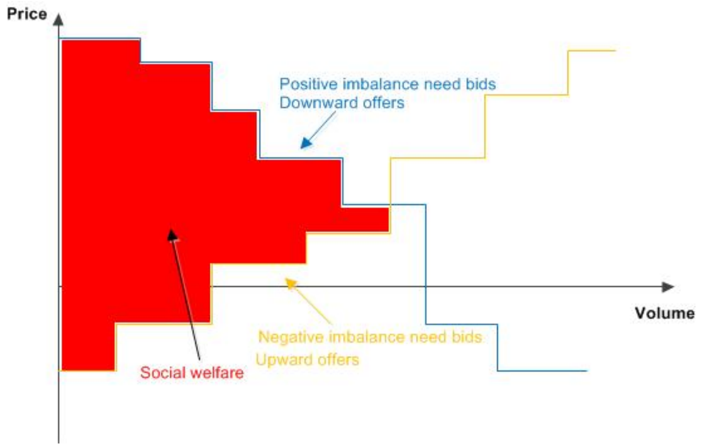


Figure 15: Social Welfare

The following example illustrates how the AOF maximizes the social welfare of a region consisting of two TSOs. The inputs of the example are presented in Table 7 and the outputs of the example are presented in Table 8.

TYPE	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Divisibility of Offers
Positive demand (TSO 1)	+100	1000	--
Positive demand (TSO 2)	+100	1000	--
Upward Offer (UO BSP1)	100	10	Divisible
Upward Offer (UO BSP2)	100	20	Indivisible
Upward Offer (UO BSP3)	200	5	Indivisible

Table 7: Inputs for Example - Activation of Bids with the Aim of Maximization of Social Welfare

Type	Activated Quantity/Satisfied Demand (MWh)
Positive demand (TSO 1)	+100
Positive demand (TSO 2)	+100
Upward Offer (UO BSP1)	0
Upward Offer (UO BSP2)	0
Upward Offer (UO BSP3)	200
Social Welfare (€)	Marginal Price (€/MWh)
100·1000 - 100·5 + 100·1000 - 100·5 + 200·5 - 200·5 = 199’000	5

Table 8: Output for Example

3.2.2.2 Constraints

Constraints are the criteria and conditions that must be respected by the algorithm.

I. Power Balance Constraints

<u>Principles:</u>

I.A : In of the special situation that no demands are submitted (i.e. zero total demand),, there is no activation (no simultaneous upward and downward activations).

I.B: Total activated bids satisfy the total demands of the TSOs.

I.C: In the power balance constraint, netting of the TSO demands inherently occurs. The netting of the TSO demands occurs as long as it results in a higher social welfare and it does respect other technical constraints, e.g. power flow constraints.

Power balance constraints enforce the total demand to be satisfied. In other words, the total activated upward bids and satisfied negative demands must be equal to the total activated downward bids and satisfied positive demands. This does not hold if a demand tolerance band will be used. In this case, the tolerance band has also to be included in these power balance constraints.

We illustrate the power balance constraints through an example in ANNEX 1 - Examples of Algorithm Constraints.

II. Power Flow Constraints

Principles:

II.A: Respecting ATC limits of the corresponding TSOs.

II.B: Respecting Internal Zones with Any Resolution

II.C: TSOs building a Cluster

The power flow constraints guarantee that the accepted offers respect the cross- zonal capacity limits communicated by the TSOs. Note that the algorithm does not specify what these limits shall be; rather the algorithm must respect these limits irrespective of what they are.

For the purpose of design phase 1, we consider ATC limits and internal zones, which could be the same as bidding zones or zones with a smaller or a higher resolution[5] (size) than bidding zones. The resolution of zones may vary depending on the need of a TSO for congestion management. Although the resolution of zones is not discussed here, the algorithm must respect any resolution required.

The TSOs requiring that their area is split up into internal zones must also provide offers and demands with corresponding location information. That is, if a TSO needs to specify 3 zones, this TSO must specify accordingly the location (zone) of its offers and demands.

The algorithm also foresees that some TSOs have a need for representing their network with a number of zones. The electrical model behind these zones (e.g., the number of interconnecting lines between the zones, the number of zones, the cross- zonal capacity (thermal limits of lines), etc.) are inputs from respective TSOs to the algorithm.

The only important feature is that the TSO, which gives its zones as inputs to the algorithm, must also provide correspondingly location information regarding its demands and its offers.

Another possible constraint is the need of some TSOs to represent their network model building a cluster together with other TSOs. If bids were to be activated within this cluster, bids from a certain TSO would be given priority over the other TSOs to a certain amount of MWs. System security/congestion management are stated as the reason for this arrangement. The inputs to the algorithm include the control zones involved, the priority TSO and the amount of MW to be activated from this TSO.

We illustrate the power flow constraints through example in an ANNEX 1 - Examples of Algorithm Constraints.

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[5] The topic will be further investigated with a focus on the compliance with GLEB

III. HVDC Constraints

Principles:

III.A: Max ramp between two mFRR clearing intervals express the maximum change of power exchange between two clearings intervals. Max ramp is defined per each border that includes HVDC interconnectors. These ramps will be considered by the TSOs before submitting the ATC values for the HVDC interconnectors to MARI.

III.B: Not allowed flow means the balancing power exchange interval that is not possible due to the technical minimum power of HVDC interconnectors. Also, in this constraint, the power flow of the HVDC line from the previous clearing is important.

HVDC constraints conceptually can be understood similar to ATC from the algorithm point of view. That is, there are limits on the power that could flow through HVDC lines. However, the losses in HVDC lines shall be considered.

In the following, we elaborate on HVDC losses as well as HVDC dynamic constraints.

HVDC Losses

As for any AC transmission line, the physical flow on an HVDC interconnector is subject to losses.The HVDC losses are explicitly modelled in the Day-Ahead Market Coupling and in TERRE. Therefore, in order to be consistent with the markets in other timeframes, HVDC losses will also be considered in a similar way by the MARI AOF. . Thus, assuming the running-time of the algorithm would not be heavily impacted by this feature, it is explained in ANNEX 1 - Examples of Algorithm Constraints how the algorithm can take into account the losses on HVDC cables.

Because of these losses, for each settlement period, the energy volume sent from an exporting area A may differ from the received energy in the importing area B. This will also have an impact on the prices, and hence there will be a price difference between these two areas.

HVDC-Dynamics Constraints

HVDC constraints will be considered by the TSOs before they submit their inputs to MARI, and hence the capacity of the HVDC cables that will be submitted to the optimization will integrate these constraints.

IV. Constraints on Prices: Unforeseeably Rejected Bids (URB)

In the presence of indivisible and divisible bids, bids with an offered price smaller than the marginal price can be rejected if this leads to a higher social welfare. If these bids are divisible (indivisible), they are called unforeseen rejected divisible (indivisible) bids (URBs). This is called paradoxically rejected divisible bids in the Market-Coupling Model.

We note that the possible application of the tolerance band can reduce the occurrence of URBs. However, it is not guaranteed that the issue will be solved and it has not been analysed what the impact of this application will be. TSOs will analyse the potential application of a tolerance band and the effect it has on the URBs.

The inclusion of URB constraints in the algorithm is still an open point. In the following, we explain the unforeseeably rejected divisible bids by using a simple example presented in Table 9. Note that in this example, the UO BSP2 is an unforeseeably rejected divisible bid. We consider that the demands are inelastic, and hence we assign them a very high price that represents the technical limit (10'000 in this case).

Type	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers
Positive demand (TSO 1)	+100	10000[6]	Inelastic	--
Positive demand (TSO 2)	+100	10000	Inelastic	--
Upward Offer (UO BSP1)	+190	10	--	Indivisible
Upward Offer (UO BSP2)	+8	20	--	Divisible
Upward Offer (UO BSP3)	+10	21	--	Indivisible
Upward Offer (UO BSP4)	+2	30	--	Indivisible

Table 9: Inputs for Example 10 - Unforeseen Rejected Divisible Bids

As shown in Table 10, the outcome of the algorithm, in terms of activated offers, balancing cost, and marginal prices, is totally different with and without this constraint about unforeseeably rejected divisible bids.

Under the solution of allowing URBs, UO BSP2 is rejected. However, its offer price is smaller than its marginal price (20 €/MWh < 21 €/MWh). With this solution a higher social welfare is obtained than that of avoiding URBs.

[6] For the shake of the example the technical limit assumed for the inelastic TSO demand is 10000 €/MWh

Type	Output of Balancing Cost Minimization (Allowing Unforeseen Rejected Divisible Bids) Activated Quantity/Satisfied Demand (MWh)	Output of Market-Coupling model (Avoiding Unforeseen Rejected Divisible Bids) Activated Quantity/Satisfied Demand (MWh)
Positive demand (TSO 1)	+100	+100
Positive demand (TSO 2)	+100	+100
Upward Offer (UO BSP1)	+190	+190
Upward Offer (UO BSP2)	0	+8
Upward Offer (UO BSP3)	+10	0
Upward Offer (UO BSP4)	0	+2
Marginal Price (€/MWh)	€21/MWh	€30/MWh
Social welfare (€)	100·10000 + 100·10000 - 100·21 - 100·21 + 190·21 + 10·21 - 190·10 - 10·21 = 1’997’890	100*10000 + 100*10000 – 100*30 – 100*30190·30 + 8·30 + 2·30 - 190·10 - 8·20 - 2·30 = 1’997’880

Table 10: Output for Example 10

Table 11 lists three criteria solely from the algorithm point of view and provides a qualitative evaluation. From a computation point of view, it needs to be investigated if the algorithm with the constraints of avoiding unforeseeably rejected divisible bids can find a solution within an acceptable time (around 1 min).

We should also note that the complexity problem is a relevant criterion: the more complex the algorithm is, the harder to find an optimal outcome it is and the more time the algorithm will require. This may have an impact on the gate closure time.

To have a quantitative estimate of the impact of this constraint (e.g. computation time, balancing costs, the frequency of occurrence etc.), a precise simulation with a strong computation engine is required.

Criteria	Allowing Unforeseeably Rejected Divisible Bids (Social-Welfare Maximization)	Avoiding Unforeseeably Rejected Divisible Bids (Market-Coupling Algorithm)
Optimal Social Welfare	Higher social welfare	Lower social welfare
Complexity Level of Algorithm	Low (Simple) (solving a primal clearing model)	High (Complex) (including a non-linear constraint and solving a primal-dual problem)
Computation Time	Lower computation time	Higher computation time
Bid structure	No particular incentive	Incentivize (a) divisible bids and (b) indivisible bids of lower volume

Table 11: Criteria for Qualitative Evaluation of Allowing/Avoiding Unforeseen Rejected Divisible Bids from the Algorithm Point of View

Further possible criteria are listed which could be used to assess the two options together with the option to not allow indivisible bids:

- Complexity algorithm: Not allowing indivisible bids would reduce complexity drastically. Allowing Unforeseeably Rejected Divisible Bids is considered to have the least complexity.
- Incentives to offer divisible bids: In the case of Allowing Unforeseeably Rejected Divisible Bids, the incentives to offer divisible bids are higher compared to not allowing at all indivisible bids, but slightly lower in comparison to Avoiding Unforeseeably Rejected Divisible Bids.
- Transparency The results of the optimization are easier to check if indivisible bids are not allowed.
- Social welfare: Not allowing indivisible bids will reduce social welfare since liquidity is reduced. Allowing Unforeseeably Rejected Divisible Bids will be slightly better concerning social welfare than Avoiding Unforeseeably Rejected Divisible Bids since a cheaper indivisible bid might be activated instead of a more expensive divisible bid;
- Consistency with other markets: For Day-Ahead market coupling, Avoiding Unforeseeably Rejected Divisible Bids is used and the recent results from the public consultation of the FCR cooperation also showed a preference for Avoiding Unforeseeably Rejected Divisible Bids, (however, the latter is a market for balancing capacity and not for balancing energy). In North American energy markets, the option of Allowing Unforeseeably Rejected Divisible Bids is used.

V. Constraints on Prices: Unforeseeably Accepted Bids

The existence of complex bids, e.g. indivisible bids, in the MARI AOF introduces non-convexities in the mathematical formulation of the optimization problem. Due to the non-convex nature of the problem, there may be cases where the resulting marginal price is lower (resp. higher) than the price of some upward (resp. downward) accepted bids. These bids incur financial losses for the BSPs and are called Unforeseeably Accepted Bids (UAB). In the Day-Ahead Market Coupling, the same bids are referred to as Paradoxically Accepted Bids.

An example where an indivisible bid is unforeseeably accepted is presented below. The input data are presented in Table 12.

Type	Area	Volume (MWh)	Price (€/MWh)
Positive demand (long TSO)	TSO 1	+100	Inelastic
Upward divisible bid 1	TSO 1	+50	10
Upward divisible bid 2	TSO 1	+40	20
Upward indivisible bid 3	TSO 1	+40	30
Upward divisible bid 4	TSO 1	+100	60

Table 12: UAB Example: Input Data

The merit order list is presented in Figure 16.

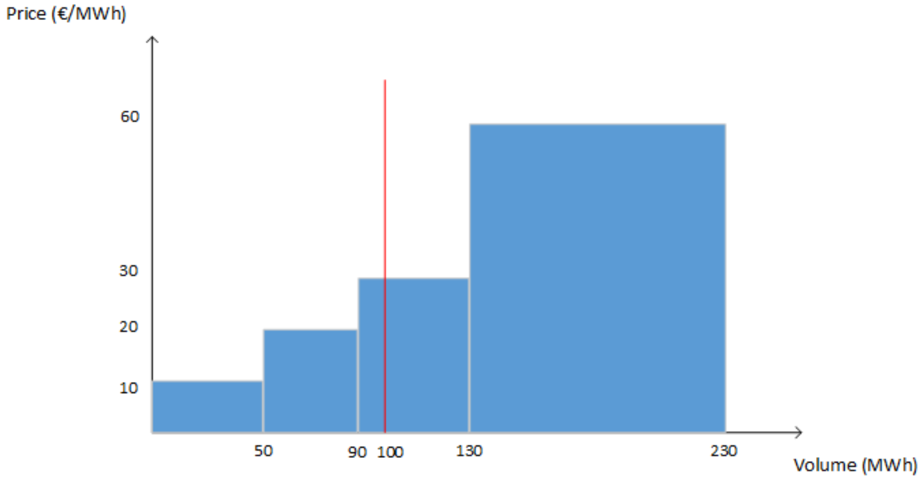

Figure 16: UAB Example: Merit Order List

If the algorithm maximizes purely the social welfare with no further constraints, then the upward divisible bid 1 and the upward block bid 3 is fully accepted and only 10 MWh of the divisible bid 2 is accepted. The resulting marginal price is set to 20 €/MWh. In this case, there are no unforeseeably rejected bids, but the upward indivisible bid 3 is unforeseeably accepted as the bid price is 30 €/MWh and the resulting marginal price 20 €/MWh.

This can be avoided either by setting the price to 30 €/MWh (in this case, part of the upward divisible bid 2 is unforeseeably rejected) or by rejecting the upward indivisible bid 3 and accepting the whole upward divisible bid 2 and 10 MWh of the upward divisible bid 4 (in this case, the upward block bid 3 is unforeseeably rejected).

The final solution given by the AOF will not contain any UABs, i.e. one of the aforementioned options will be chosen, as this would require an extra payment of uplifts to the market participants in order for them to recover their costs, and would hence deviate from the concept of marginal pricing. This will be achieved by a primal/dual formulation of the optimization – clearing and pricing in a single problem - with extra constraints to ensure that all BSPs recover their costs.

The unforeseeable acceptance and rejection rules are not relevant for elastic needs. As a consequence, the price in a given area may exceed for example the price of the elastic positive imbalance need in the area.

VI. Constraints on Activation Volumes: Scheduled Counter-Activations

With the term scheduled counter-activations, we refer to the simultaneous activation of a scheduled upward and a scheduled downward offer by the AOF in order to increase the social welfare. Due to the fact that all positive and negative demands, as well as all upward and downward bids are treated in a single common merit order list, scheduled counter-activations could occur if some downward offers had higher prices than some upward offers, i.e. if some BSPs would be willing to pay higher prices to reduce their production than the prices that some other BSPs would be willing to receive to increase their production.

Figure 17 presents a merit order list. If a downward offer had a higher price than an upward offer then these two offers would be simultaneously activated, as this would result in a higher social welfare.

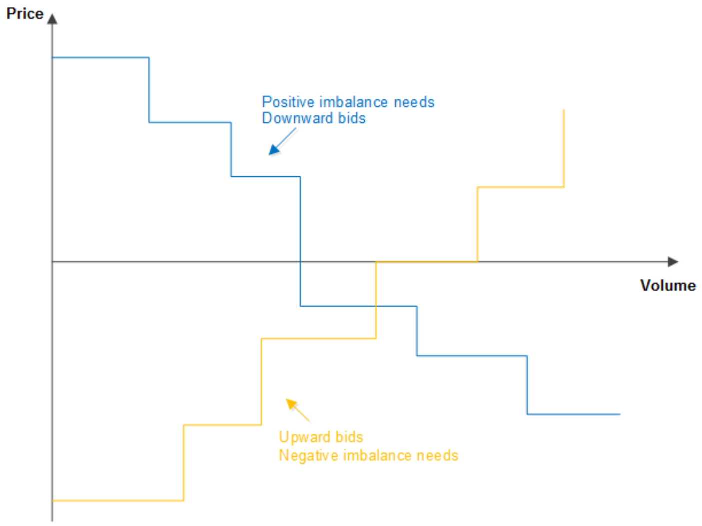

Figure 17: Merit Order List

An example is provided below. We consider a system of three TSOs. The volume of demands with limit prices and bid prices are presented in Table 13, and the ATC values are high enough not to affect the solution.

Type	Area	Volume (MWh)	Price (€/MWh)
Negative demand (long TSO)	TSO 1	100	-100
Negative demand (long TSO)	TSO 2	-100	-50
Positive demand (short TSO)	TSO 3	+150	100
Downward bid (BSP 1)	TSO 1	300	50
Downward bid (BSP 2)	TSO 2	100	30
Upward bid (BSP 3)	TSO 3	+300	40

Table 13: Example Input Data

Figure 18 presents the merit order created for this example, and Figure 19 depicts the final activations and flows.

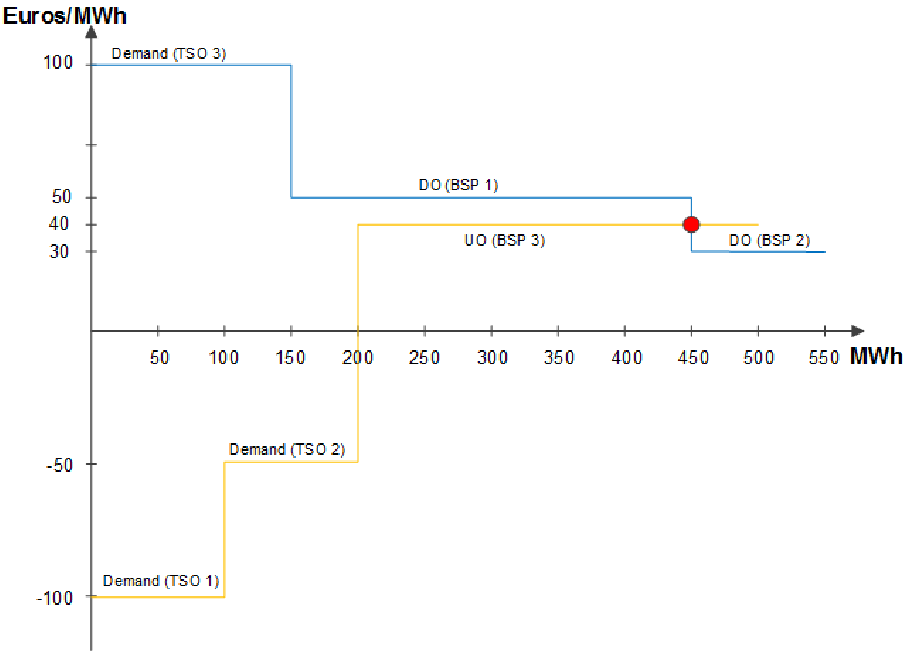

Figure 18: Example Merit Order List

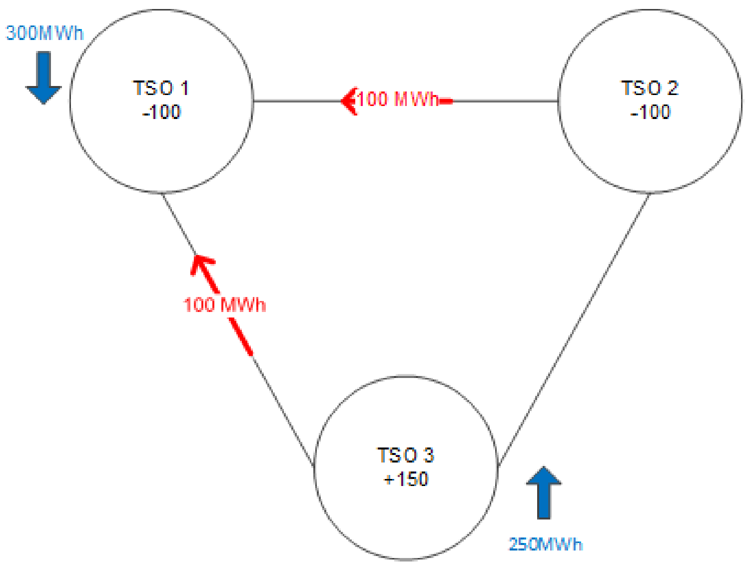

Figure 19: Example Activations

We observe that in this case upward and downward bids are simultaneously activated. More specifically, a 300 MWh downward bid is activated from BSP 1, 250 MWh from an upward bid is activated from BSP 3, and the demands are fully satisfied. It is activated 100 MWh downward and 100 MWh upward beyond the demands. The marginal price for this case is 40 €/MWh and the social welfare is 35 000 €.

Restricting the scheduled counter-activations would lead to the results presented in Figure 20 and Figure 21.

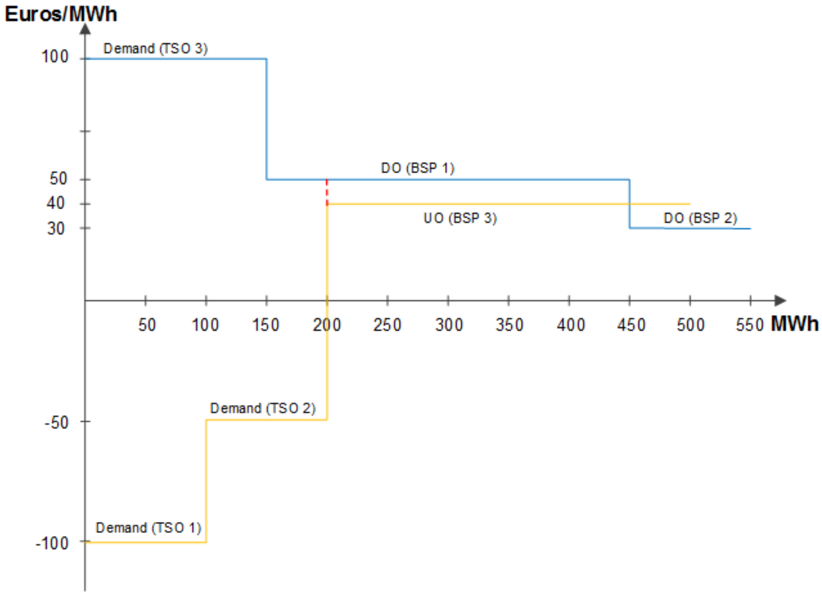

Figure 20: Scheduled Counter-Activations' Restriction: Impact on Merit Order List

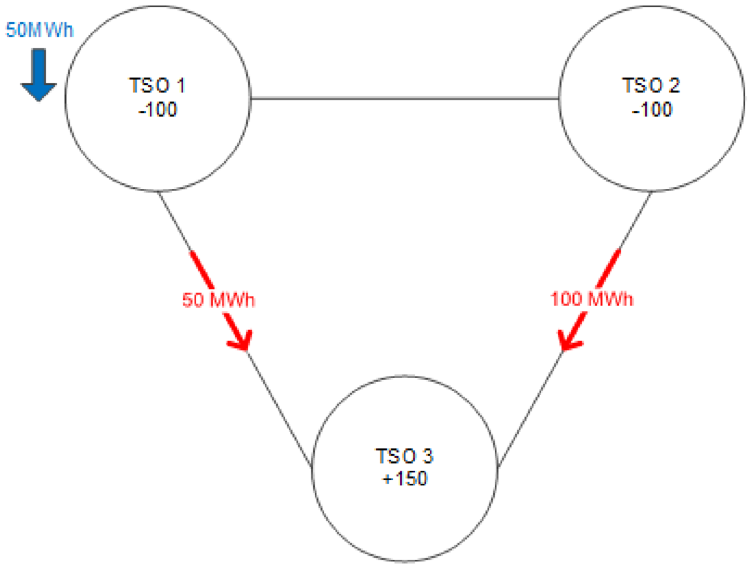

Figure 21: Scheduled Counter-Activations' Restriction: Impact on Activations

In this case, only a 50 MWh downward offer from BSP 1 is activated, whereas the demands are fully satisfied. Therefore, with this option we manage to limit the activation of offers. However, in this case there is price indeterminacy (see further 4.3.4.5). The social welfare in this case is 32 500 €, and is therefore decreased by 2 500 €.

Note that scheduled counter-activations could be restricted, as presented in the previous example, by using additional constraints in the AOF. This would, however, increase the complexity and could result in higher computation times.

In this particular example, the scheduled counter-activations could be avoided by introducing a pre-netting stage. After the pre-netting stage, only 50 MWh of the negative need of the TSO 2 would remain and the market clearing algorithm could run only with downward offers. However, when there is not enough ATC, a pre-netting stage is not sufficient to avoid scheduled counter-activations. We illustrate this by using the same example with the following ATC values, which are assumed to be symmetrical regarding the exchange direction:

Link	ATC (MWh)
TSO 1 – TSO 2	100
TSO 1 – TSO 3	50
TSO 2 – TSO 3	50

Table 14: Example Input ATC

With these ATC limitations, the 150 MWh upward need from TSO 3 can no longer be entirely netted with the other TSO needs. Since only 50 MWh can go through the ATC network between TSO 3 and each other TSO respective area, only 100 MWh from TSO 3's need can be satisfied through the pre-netting process. Afterwards, both TSO 1 and TSO 3 will face a remaining need that could not have been netted, as illustrated in Figure 22.

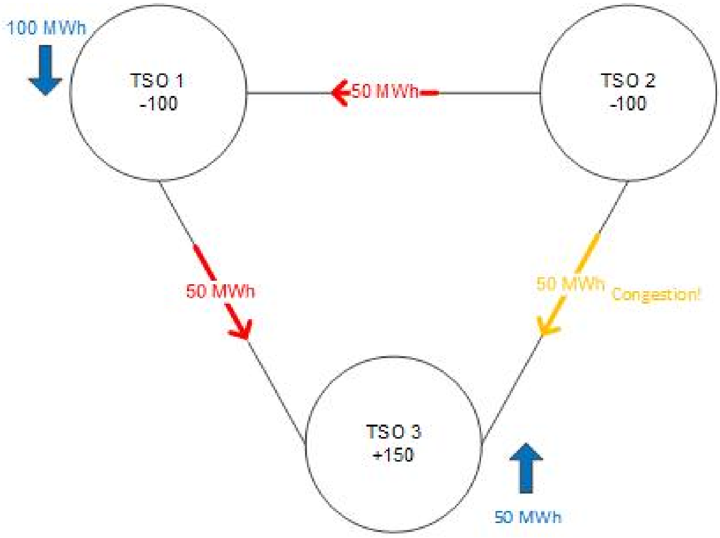

Figure 22: Impact of a Congestion on Counter-Activations

TSO 1 will have a remaining 100 MWh downward need, and TSO 3 will have a remaining 50 MWh upward need. For them to be satisfied, a counter-activation has to occur: since both the links TSO 1 – TSO 3 and TSO 2 – TSO 3 are congested, the only solution is to activate an upward offer from BSP 3 and some downward offer from BSP 1 or BSP 2. If we block this counter-activation, two needs could remain unsatisfied, even if they were submitted at any price (inelastic), which is not acceptable. This proves that a pre-netting process is not sufficient to address the problem of counter-activation prohibition.

It is also important to stress that a potential restriction of scheduled counter-activations could distort the price signals in unpredicted ways, as presented in Figure 23 and Figure 24.

Figure 23: A Restriction of Scheduled Counter-Activation Increases the Marginal Price

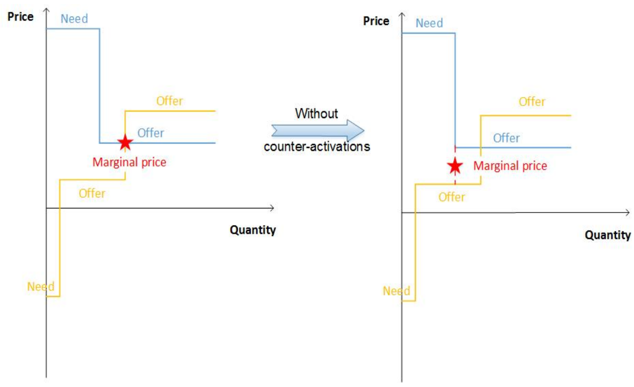

Figure 24: A Restriction of Scheduled Counter-Activation Decreases the Marginal Price

Table 15 provides the qualitative evaluation criteria for allowing or restricting the scheduled counter-activations.

Criteria	Allowing scheduled counter-activations	Restricting scheduled counter-activations
Optimal Social Welfare	Maximum social welfare	Reduced social welfare
Complexity Level of Algorithm	Low (Simple)	High (Complex)
Computation Time	Lower computation time	Higher computation time
Liquidity	Increased (more opportunities for BSPs to be activated)	No influence
Use of XB capacity	Potential use of more XB capacity (in one direction)	Limited use of XB capacity
Impact on other markets	No influence	No influence
Availability of resources	Reducing availability of resources	Increasing availability of resources
Activation serving balancing purpose	Partially	Yes

Table 15. Evaluation Criteria for Allowing or Restricting Counter-Activations

Regarding the criterion 'Impact on other markets', e.g. the Intraday (ID) Market, we consider that a potential allowance of scheduled counter-activations would not have any impact. More specifically, the GLEB includes several references aimed at guaranteeing that the balancing markets do not endanger the efficiency of the previous markets such as the ID. Examples of such rules are the GCT, rules for updating the positions from the BRPs, rules for the submission of balancing bids to the European platforms, as well as pricing and settlement principles. These references will be followed by MARI in order to contribute to the efficient functioning of the energy markets (DA/ID). Moreover, the bids submitted to MARI shall be prequalified to fit the characteristics of the mFRR balancing product; this clearly differentiates them from the authorized bids of the ID market. Therefore, due to the aforementioned features, the allowance, and also not allowance, of scheduled counter-activations in MARI shall not affect the liquidity of the energy markets.

A quantitative study would be necessary in order to identify the exact impact of scheduled counter-activations on the social welfare, computation times, marginal prices and use of XB capacity.

3.2.3 Questions

Q23. Do you agree with the maximization of social welfare as the main objective of the Activation Optimization Function?

Q24. Do you prefer to allow or to block the scheduled counter-activations?

Q25. What are your views regarding unforeseeably rejected and accepted bids?

Q26. Which of the two options would you prefer regarding the handling of HVDC constraints?

3.3 Further Issues Connected to the Algorithm

3.3.1 Computation Time

The computation time of the algorithm is important as it has an impact on the gate closure time of MARI. For quantitative statements, a precise simulation with a strong computation engine is required.

3.3.2 Multiple Optimal Solutions

This section describes the cases where multiple optimal solutions exist, and proposes possible solutions to choose a solution among these equally optimal solutions. We should remind that all these optimal solutions result in the same optimal social welfare (same minimum balancing cost) and meet all the constraints, described above.

3.3.2.1 Analysis

3.3.2.1.1 Case 1: A Set of Optimal Solutions with Different Marginal Prices

If a set of optimal solutions from the algorithm exists, but which lead to different marginal prices (optimal variables of the dual problem), two possible solutions are:

Solution case 1.A: The optimal solution leading to a smaller marginal price should be considered.

Solution case 2.B: The optimal solution respecting the increasing/decreasing order of offered prices should be considered.

Please note that since rejecting an unforeseen indivisible bid is allowed, both solutions result anyway to reject an unforeseen indivisible bid.

In the following example, the final solution is Solution A, as this solution results in a smaller marginal price than that of solution B.

Type	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Divisibility of Offers
Demand (TSO 1)	+100	1000	--
Demand (TSO 2)	+100	1000	--
Upward Offer (UO BSP1)	+190	10	Divisible
Upward Offer (UO BSP2)	+8	20	Indivisible
Upward Offer (UO BSP3)	+10	21	Indivisible
Upward Offer (UO BSP4)	+2	25	Indivisible

Table 16: Inputs for Example

Type	Solution A Activated Quantity/Satisfied Demand (MWh)	Solution B Activated Quantity/Satisfied Demand (MWh)
Demand (TSO 1)	+100	+100
Demand (TSO 2)	+100	+100
Upward Offer (UO BSP1)	+190	+190
Upward Offer (UO BSP2)	0	+8
Upward Offer (UO BSP3)	+10	0
Upward Offer (UO BSP4)	0	+2
Marginal Price (€/MWh)	€21/MWh	€25/MWh
Social welfare (€)	100·1000 + 100·1000 - 100·21 - 100·21 + 190·21 - 190·10 + 10·21 - 10·21 = 197’890	100·1000 + 100·1000 - 100·25 - 100·25 + 190·25 - 190·10 + 8·25 - 8·20 + 2·25 - 2·25= 197’890

Table 17: Output for Example

3.3.2.1.2 Case 2: A Set of Optimal Solutions with the Same Marginal Prices

If a set of optimal solutions with equal marginal prices (optimal variables of the dual problem of the dual algorithm) exists, the solution leading to a smaller energy exchange (power flow) between TSO connections is considered.

In the following example, the final solution is solution B, as this solution results in acceptance of UO BSP2 which is located in Area 2 as demand of TSO 2. However, solution A results in unnecessary flow from Area 3 to Area 2.

Type	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Divisibility of Offers	Area
Demand (TSO 1)	+100	1000	--	Area 1
Demand (TSO 2)	+100	1000	--	Area 2
Upward Offer (UO BSP1)	+190	10	Divisible	Area 1
Upward Offer (UO BSP2)	+8	20	Indivisible	Area 2
Upward Offer (UO BSP3)	+10	20	Indivisible	Area 3
Upward Offer (UO BSP4)	+2	20	Indivisible	Area 4

Table 18: Inputs for Example

Type	Solution A Activated Quantity/Satisfied Demand (MWh)	Solution B Activated Quantity/Satisfied Demand (MWh)
Demand (TSO 1)	+100	+100
Demand (TSO 2)	+100	+100
Upward Offer (UO BSP1)	+190	+190
Upward Offer (UO BSP2)	0	+8
Upward Offer (UO BSP3)	+10	0
Upward Offer (UO BSP4)	0	+2
Marginal Price (€/MWh)	€20/MWh	€20/MWh
Social welfare (€)	100·1000 + 100·1000 - 100·20 - 100·20 + 190·20 - 190·10 + 10·20 - 10·20 = 197’900	100·1000 + 100·1000 - 100·20 - 100·20 + 190·20 - 190·10 + 8·20 - 8·20+ 2·20 - 2·20 = 197’900

Table 19: Output for Example

3.3.3 Questions

Q27. If a set of optimal solutions exists, which lead however to different marginal prices, which of the two proposed approaches, Solution case 1.A or Solution case 2.B would you prefer?

Q28. Do you agree with the suggested approach when a set of optimal solutions with equal marginal prices exists?

CHAPTER 4 Settlement

4.1 Introduction

This chapter explains the idea of Cross-border Marginal Pricing and options for how to handle TSO-TSO settlement including the sharing of congestion rents. Since there is a link to TSO-BSP and TSO-BRP settlement, and since the GLEB requires a framework for harmonization of terms and conditions for BSPs and BRPs (acc. to GLEB Art. 20), these topics are touched on in CHAPTER 6; however, only ideas on how these topics could be approached are provided in this document.

4.2 Settlement Model and Fundamental Considerations

4.2.1 Cross-Border Marginal Pricing

Article 30 of EBGL provides guiding principles for the pricing of balancing energy. The pricing method shall notably:

- be based on marginal pricing (pay-as-cleared);
- give correct price signals and incentives to market participants;
- take into account the pricing method in the day-ahead and intraday timeframes.

The MARI project proposes to use a cross border marginal price for the TSO-TSO and TSO-BSP settlement. The cross border marginal price is the price of the last bid of the mFRR standard product which has been activated to cover the energy need for balancing purposes within an uncongested area. Therefore, it defines the value where the selling curve and the buying curve meet (e.g. 65 €/MWh in Figure 25).

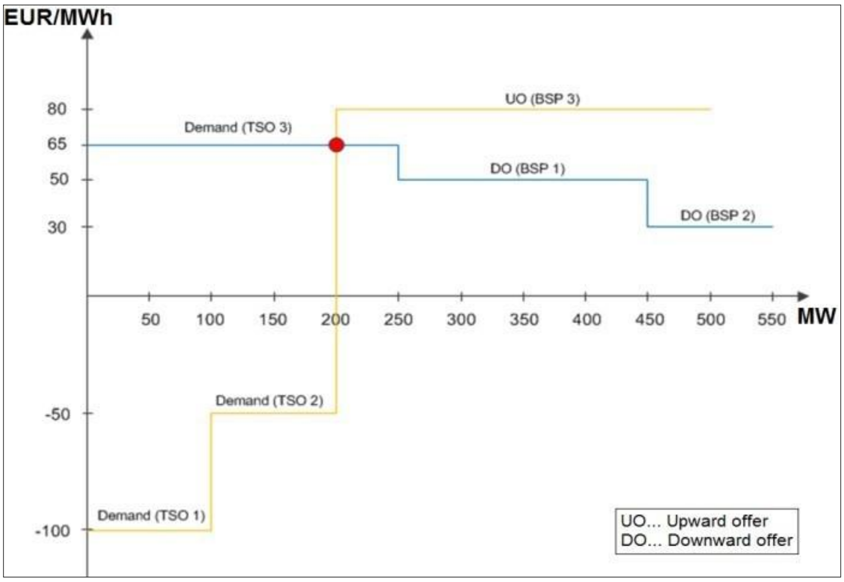

Figure 25: Cost Curve Formed by Offers and Elastic Demands

Differences in prices occur in congested situations which are described in the following chapters.

The cross-border marginal price has the following advantages:

- As it is a marginal price, it is compliant with the GLEB requirements;
- XBMP contributes to establish a level playing field within the cooperation. BSPs providing the same service in an uncongested area are remunerated with the same price;
- As it is a marginal price, it does not incentivize BSPs to add a premium to the bid price (which can then be cost-reflective);
- Cross-Border Marginal Pricing is currently used for market coupling and thus ensures consistency with the pricing method in the day-ahead and intraday timeframes;
- A congestion rent appears in cases of congestion.

4.2.2 Case without Congestion

If no congestion applies within the cooperation, the highest activated bid price defines the TSO-TSO price of the TSO-TSO-settlement as well as the TSO-BSP price of the TSO-BSP-settlement. Every BSP receives the same price for activated balancing energy from the connecting TSO and every TSO pays/receives the same marginal price for imported/exported balancing energy.[7]

The following Figure 26 shows a qualitative example with two TSOs, TSO A and TSO B. In this simple example, it is assumed that all bids have the same volume. The demand of A (d_A) and the demand of B (d_B) is commonly activated (d_{AB}) from a CMOL. In Figure 26 on the left side, the local demands and bid curves are shown as well as the local marginal price (MP_A and MP_B) which would occur without cooperation. On the right side, the CMOL and the resulting cross-border marginal price (MP_{AB}) is drawn.

[7] Due to the presence of indivisible bids, there may be special cases when this does not always hold.

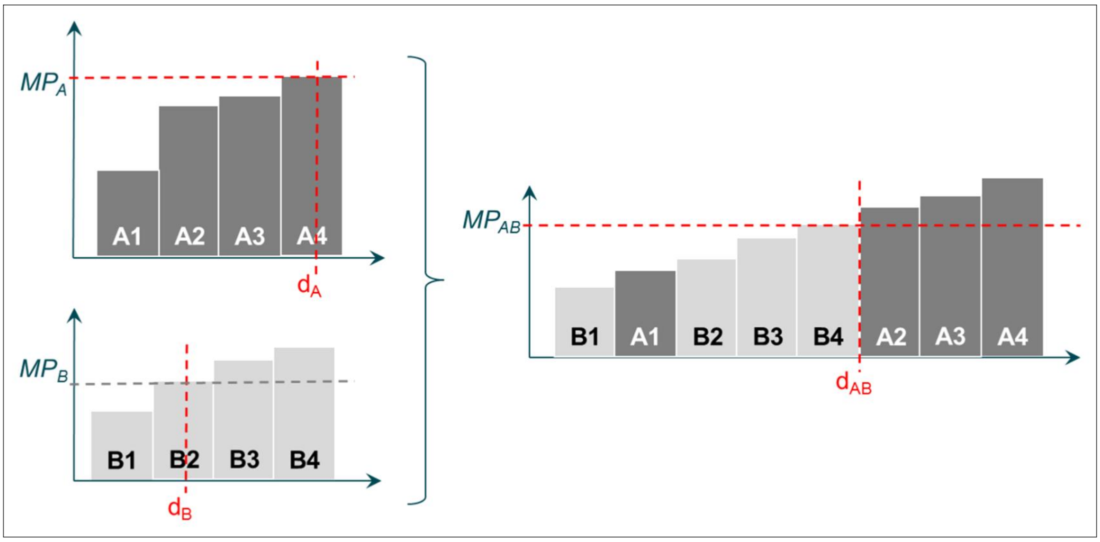

Figure 26: Local vs. Common Merit Order List, without Congestion

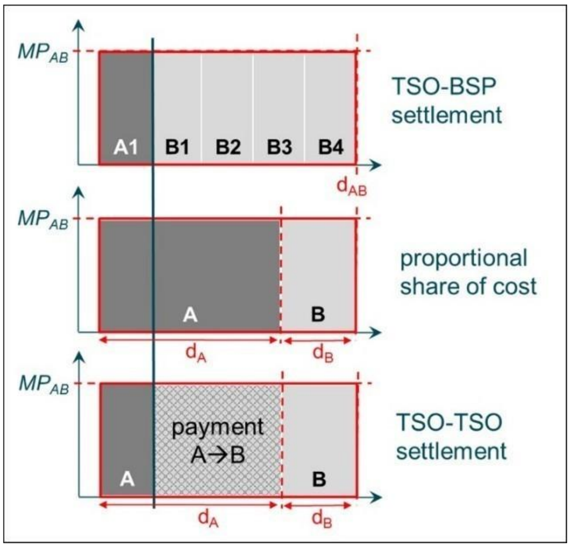

Figure 27: Settlement without Congestion

All BSPs receive the same (cross-border) marginal price (MP_{AB}) from the connecting TSO from the TSO-BSP settlement (see Figure 27).

In this example, the TSO with the higher demand (TSO A) pays to BSP for one bid (A1) and the exporting TSO B pays to BSPs for four bids at the same marginal price.

Because TSO B pays to BSPs for the volume requested by TSO A, a TSO-TSO-settlement is needed to compensate the exporting TSO B for the additional activation costs. If cross-border marginal pricing is applied for TSO-TSO settlement, all TSOs take a proportional cost share according to their respective demand.

The cost differences caused by import or export are paid through the TSO-TSO settlement with the cross-border marginal price (MP_{AB}).

For a better understanding, please find below a quantitative example:

Indicator	TSO A	TSO B
Requested activation (demand) in MWh	90	10
Activation in MWh	30	70
Balancing energy export in MWh	0	60
Balancing energy import in MWh	60	0
Highest activated bid price in €/MWh	50	25

Table 20: Theoretical Example without Congestion

Because there is no congestion, the cross-border marginal price is 50 €/MWh (max of all activated bids). TSO B exports 60 MWh (70 MWh-10 MWh) and TSO A imports 60 MWh (90 MWh-30 MWh). For TSO-TSO settlement TSO A pays 50 €/MWh for 60 MWh imported balancing energy. At the end each TSO has paid the costs for its requested activation (local demand x marginal price).

The following financial flows occur. For simplicity reasons, it is assumed that the imbalance price is based on the marginal price and mFRR is the only product activated and therefore BRPs pay the cross-border marginal price.

Step	Evaluation	TSO A	TSO B
1	Requested activation (demand) in MWh	90	10
2	Activation in MWh	30	70
3	Highest activated bid price in €/MWh	50	
4	Costs of local activation (TSO-BSP Settlement) (2)x(3) in €	1500	3500
5	Costs of local demand (TSO-BRP Settlement) (1)x(3) in €	4500	500
6	TSO-TSO settlement (Import (“+”); Export (“-“)) in € [(1)-(2)]x(3)=(5)-(4)	3000	-3000
7	Financial flows (4)+(6)-(5)	0	0

Table 21: Financial Flows without Congestion [8]

This settlement method guarantees the financial neutrality of TSOs (acc. to line 7 of Table 21) if the costs of local demand are recovered by the TSO-BRP settlement.

4.2.3 Case with Congestion

A congestion originates in the situation where cross- zonal capacity available between locations is not sufficient to accommodate all economically optimal cross-border exchanges, according to previously established criteria (i.e. optimization of social welfare).

The common platform for mFRR will facilitate the netting of TSO mFRR needs and optimize the allocation of cross zonal capacities. Thus, congestion situations are to be likely in the context of MARI activations.

After optimization, for economic reasons, the energy flows from the cheapest to the more expensive area. In cases of congestion, there is a price difference between the price that an area is “willing to pay” and the price that the other area is “willing to receive” at either side of the interconnector. Thus, a surplus from the congested interconnection will occur.

[8] The convention for costs (positive) and proceeds (negative) is consistent with Art. 46 of the GLEB.

Congestion rent for activation of mFRR energy can be stated as follows:

Congestion rent [€] = Imported volume [MWh] x (MP of the exporting TSO [€/MWh] – MP of the importing TSO [€/MWh])

Example:

In Figure 28 it is assumed that bid B4 is not available due to a congestion.

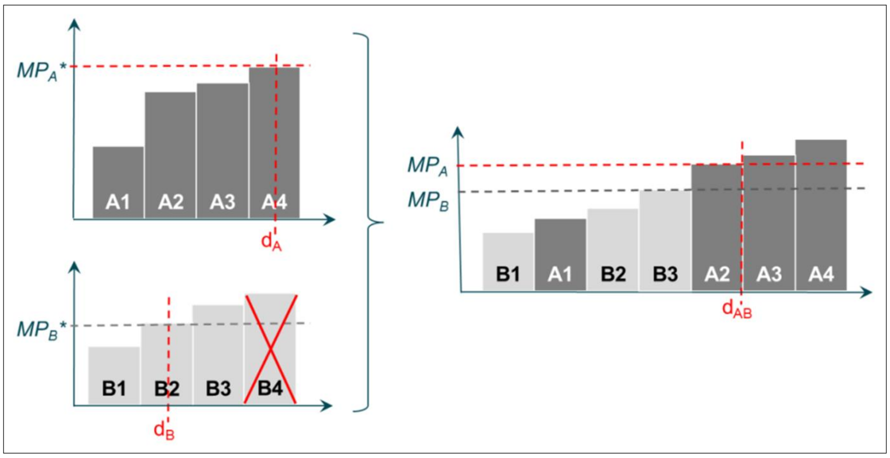

Figure 28: Local vs. Common Merit Order List, with Congestion

TSO A needs to activate a second local bid (A2) which is more expensive than the unavailable bid B4. As a result, there are two marginal prices at each side of the border (MP_A and MP_B).

The TSO-BSP price at control block A is MP_A and the TSO-BSP price at control block B is MP_B, BSPs are settled at different prices according to their connecting TSO.

In the example in Figure 29, the TSO with the higher demand (TSO A) pays to BSPs for 2 bids and the exporting TSO B pays to BSPs for 3 bids.

TSO A caused one and a half bids of the activation of TSO B. The price could be MP_A or MP_B.

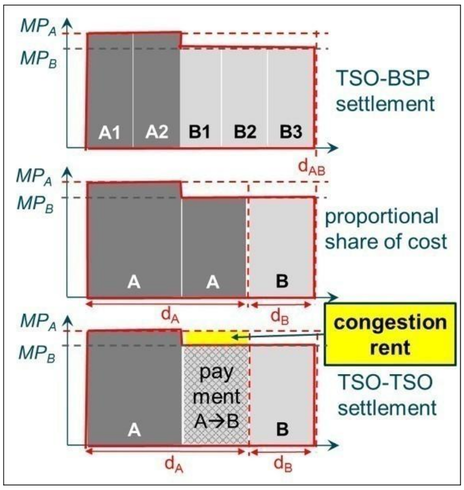

Figure 29: Settlement with Congestion

The importing TSO A pays the difference between the costs of local activation and the costs of local demand to the exporting TSO B. If the TSO-TSO settlement price is the marginal price of the importing TSO A (MP_A), the exporting TSO B would receive more money than the actual costs. This would violate the requirement of financial neutrality. If the importing TSO A pays the price of the exporting TSO B (MP_B), TSO B is financially neutral, but assuming an imbalance price of MP_A in control block A, TSO A is no more financially neutral.

The price difference due to the congestion causes a "Congestion Rent" which needs to be handled in a way that guarantees financial neutrality of TSOs.

For a better understanding, please find below a qualitative example:

Indicator	TSO A	TSO B
Requested activation (demand) in MWh	90	10
Balancing energy export in MWh	0	50
Balancing energy import in MWh	50	0
Activation in MWh	40	60
Highest activated bid price in €/MWh	60	20

Table 22: Reference Data for Example with Congestion

For instance, due to the congestion TSO B activates 1 bid less and TSO A activates one bid more compared to the example of the uncongested situation. Therefore, the price of TSO B decreases, e.g. from 25 to 20 and the price of TSO A increases from 50 to 60. The bid of 50 €/MWh is not available because of the congestion and TSO A has to activate the more expensive bid. The marginal price for TSO B is now 20 €/MWh and the marginal price for TSO A is now 60 €/MWh.

The following financial flows occur:

Step	Evaluation	TSO A	TSO B
1	Requested activation (demand) in MWh	90	10
2	Activation in MWh	40	60
3	Highest activated bid price in €/MWh	60	20
4	Costs of local activation (TSO-BSP Settlement) (2)x(3) in €	2400	1200
5	Costs of local demand (TSO-BRP Settlement) (1)x(3) in €	5400	200
6	TSO-TSO settlement (Import ("+"); Export ("-")) in € [(1)-(2)]x(3 (TSO B))*	1000	-1000
8	Financial flows (4)+(6)-(5) in €	-2000	0
9	Congestion rent (XB flow x delta price) in €	-2000	0

Table 23: Financial Flows with Congestion

*according to the working assumption

The exporting TSO B needs 1000 € to cover the activation costs caused by the export. The importing TSO A pays the 1000 € but receives 3000 € from its BRPs for the imported balancing energy (50 MWh @ 60 €/MWh) according to the local marginal price. The resulting congestion rent of 2000 will be shared between TSOs.

Before TSOs agree on how to share the congestion rent, the question on how this surplus is supposed to be used needs to be answered. The use of congestion rents is a regulatory issue which falls under the scope of the Member States and NRAs. The TSOs will cooperate with the NRAs in any related aspect that would be required regarding this issue.

In the context of the MARI project, it has been agreed as a working assumption at this stage that, the congestion rent resulting from mFRR activations will be considered a congestion income, assumed as the result of an implicit allocation of available capacity in the context of balancing services.

This interpretation would be the same as that used in other timeframes such as the day ahead market (Multi Regional Coupling) and the current approach of the project TERRE (RR). Taking the previous assumption into account, the aspects related to the use of congestion rents would fall under the existing regulations on this topic (Regulation 714/2009 article 16-6), and the possible future treatment under the proposal of Clean Energy for All Europeans:

"Any revenues resulting from the allocation of interconnection shall be used for [...] (b) Maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors.[...]"

NRAs will be consulted on whether this assumption, i.e the applicability of Regulation 714/2009 article 16-6 is valid or not.

4.2.4 Effects of XB-Marginal Pricing on Imbalance Pricing and Local Imbalance

This section illustrates some expected implications of the cross-border marginal price on the imbalance prices. The considerations here are not necessarily shared by all TSOs and are mainly put forward by TSOs allowing the BRPs to move in real time (applying a so-called reactive balancing philosophy).

4.2.4.1 Imbalance Price and Local Imbalance Stipulations of the GLEB

The imbalance price serves as a financial incentive for BRPs to be balanced or to support the system to be balanced. Therefore, the GLEB imposes several requirements that links balancing energy pricing with imbalance pricing and sets directions which should be ensured via the settlement:

- Whereas 14 – The pricing method for standard products for balancing energy should create positive incentives for market participants in keeping and/or helping to restore the system balance of their imbalance price area, reduce system imbalances and costs for society[...];
- Whereas 17 - The general objective of an imbalance settlement is to ensure that balance responsible parties support the system's balance in an efficient way and to incentivise market participants in keeping and/or helping to restore the system balance[...];
- Article 30[9](1)(d) - give correct price signals and incentives to market participants;
- Article 44[10](1)(a) - establish adequate economic signals which reflect the imbalance situation;

[9] Pricing for balancing energy and cross-zonal capacity used for exchange of balancing energy or for operating the imbalance netting process.

[10] General settlement principles

- Article 44(1)(b) - ensure that imbalances are settled at a price that reflects the real time value of energy;
- Article 44(1)(c) - provide incentives to balance responsible parties to be in balance or help the system to restore its balance;
- Article 44(1)(f) - avoid distorting incentives to balance responsible parties, balancing service providers and TSOs.
- The term “system” in GLEB “Whereas 17” and the term “local”, as used in this chapter, refer to LFC area, LFC block, or Imbalance Area[11], because, according to the GLSO, the balancing of this area lies within the responsibility of the respective local TSO. The imbalance price and its underlying balancing energy price reflects the imbalance of the respective imbalance area and are therefore means to provide the desired incentive to the BRPs of this area.

The GLEB attempts to ensure the fulfilment of the requirements described above by providing rules for an imbalance price calculation in Article 55:

- The imbalance price for negative/positive imbalance shall not be less/greater than alternatively the weighted *average price* for positive/negative activated balancing energy from frequency restoration reserves and replacement reserves.
- I.e. decoupling of the balancing energy price and imbalance price is not possible.

4.2.4.2 Imbalance Price and Local Imbalance Stipulations of the GLSO

GLSO is a technical regulation; therefore, it focuses on the matter from a technical point of view. It does not tackle imbalance pricing but builds a process control structure that defines imbalance as a local responsibility. This is to avoid an exchange of imbalances across synchronous areas. The main pillar for achieving it is the LFC area, which implements and operates a FRP to fulfil the FRCE target parameters of the LFC area (FRCE is an area control error for synchronous area continental Europe - the remaining part of unregulated imbalance). In other words – LFC area strives to solve the imbalance within the area (see GLSO Article 141), distributes and ensures local balancing responsibility in a synchronous area to avoid a lack of possible balancing actions due to congestions when large imbalances occur. Without this, TSOs would have to increase, for example, the margins in order to solve balancing issues.

It is of utmost importance to read GLSO’s requirements in conjunction with GLEB’s requirements. LFC area should strive to keep the balance local and GLEB reinforces such technical principles by requiring TSOs to set up the settlement mechanism (business principle) that provides an incentive to *"help the system to restore its balance"*. In the latter, word *system* refers to LFC area as this is the area where TSO reacts on the imbalance.

[11] The imbalance calculation is performed at the „Imbalance Area“ level (GL EB Art 54). The imbalance Area is defined as (Art 54): “2. The imbalance area shall be equal to the scheduling area, except in case of a central dispatching model where imbalance area may constitute a part of scheduling area.“

4.2.4.3 XBMP implications on TSO operation

► According to GLEB Art.55, decoupling of the balancing energy price and imbalance price is not possible in a cross-border context and the application of cross-border marginal pricing. Consequently, for a given imbalance in an imbalance area, the price will move within a range of values depending on the situation in other areas. This effect will become particularly obvious in areas with typically small deviations (e.g. thanks to their stable energy mix) and resulting small demands.

Example Scenario: Balancing energy exchange between two control blocks (CBs), without congestions.

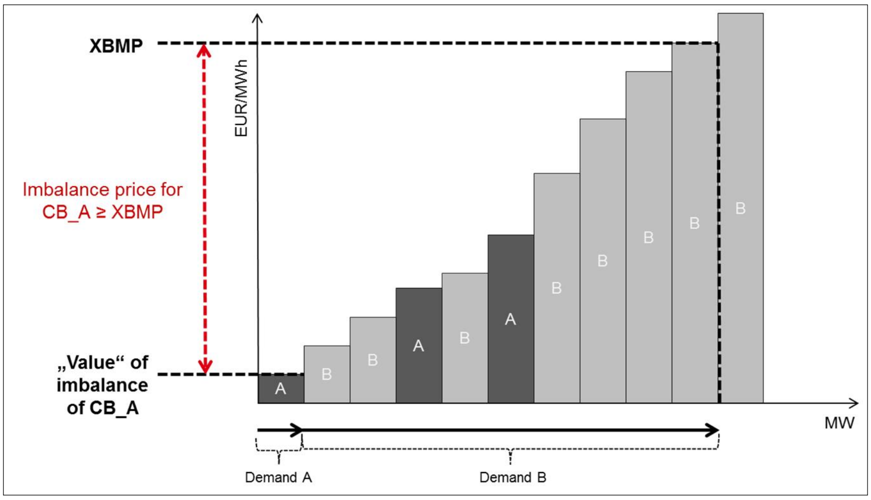

Figure 30: XBMP vs. Local Imbalance Pricing

Despite a relatively small imbalance, BRPs in CB_A are exposed to financial risk for their imbalances due to high demand in CB_B. On the other hand, CB_B benefits from lower balancing energy prices in CB_A without the CMOL. As a result, BRPs in both CBs will pay the same imbalance price[12] irrespectively of whether their area has a small or large imbalance. The regionalized price signal may lead to a focus on the balance of an uncongested region rather than the balance of the respective LFC area. In a single pricing environment and publication of prices close to real-time as foreseen by the GLEB, BRPs in CB_A, if this represents a system where BRPs are used in real time to react to such information, may be incentivised to deliberately create an imbalanced position (“long” /”short” i.e. respectively a positive/negative imbalance position) which helps the region but could worsen CB_A’s imbalance and be the one cause of CB’s imbalance. Local incentive mechanisms which rely on a direct relationship between the local imbalance volume and the imbalance price will become obsolete.

If MARI proposes to apply the XBMP – single (in cases without congestion) balancing energy price for all EU mFRR BSPs, influencing the imbalance price for all BRPs in the EU - the economic incentive for BRPs to minimize their local (LFC area) deviations might be lost but BRPs will have an incentive to minimize the deviations of the whole MARI region.

[12] Given the assumption that local market rules do not increase/decrease the imbalance price with additional components, and given the assumtion that assumption that the energy exchanged for RR and aFRR is zero.

The question arises of which balancing incentives (by price, publication, etc.) will be received by the local BRPs and if mitigation measures need to be defined in order to ensure the incentive for BRPs to be in balance or help the system to restore its balance.

On the other hand, the consequence of BRPs helping the region could be that the imbalance of their area moves in the opposite direction of the region and increases until inverse balancing energy needs to be activated, which would lead to an unfavorable imbalance price. It may be, that BRPs will be discouraged to over-react as soon as they are aware of this self-regulating effect, i.e. to learn to react to an imbalance volume in their area rather than to an imbalance price of the region.

Possibly, the described self-regulating effects will sufficiently avoid overreactions by BRPs and the balancing prices may still give an incentive for BRPs to be balanced as long as they are higher than the prices in preceding markets.

Based on the results of simulations, the TSOs will carry out a common analysis in order to assess the magnitude of the possible effects described. If negative consequences prove to be relevant in size, the TSOs will start to commonly identify, assess and select mitigation measures.

4.2.5 Questions

Q29. Do you agree with the approach of the congestion rent definition?

Q30. Which other attributes/impacts of Cross-Border Marginal Pricing do you see?

Q31. Would you mitigate any negative attributes/impacts of Cross-Border Marginal Pricing? If yes, how?

4.3 TSO-TSO Settlement

The following chapter provides an overview of options for determining volumes and prices of exchanged balancing energy among the TSOs.

4.3.1 Common Principles of the TSO-TSO Settlement

- The TSO-TSO physical exchanges will be based on trapezoid profiles with 10-minute ramps.
- Balancing energy products capable of being directly activated and balancing energy products that can only be schedule activated will both be allowed.
- Pre-contracted bids and voluntary bids will both be allowed as well, where applicable. Pre-contracted bids will be bids which can be either directly and/or schedule activated.
- There shall be no perverse financial incentives to request balancing energy before other TSOs or to make direct activations instead of scheduled activations. However if a TSO expresses its mFRR need for a direct activation there should not be a penalty for this.
- BSPs submit only one price per bid.

- The TSO-TSO cross-border exchange shape is standardized and firm.
- The exchanged product is settled in quarter hours (QH), independent from the imbalance settlement period.

4.3.2 Assumptions Applied for the Settlement Examples

As the sequence of DA and SA and the timing of processes are not yet certain, the following assumptions have been made, which apply only for the given examples and figures presented:

- TSOs can allow BSPs to mark their bids as only schedule activated, or activated in both ways;
- Deactivation of schedule activated and direct activated product occur at the same point in time, which is 5 minutes before the end of a QH;
- Most of the energy shall be delivered within the QH for which the bid is submitted. The equivalent delivery period (=delivered energy divided by requested power) is 15 minutes for SA and a maximum of 30 minutes for DA;
- Direct activation takes place ahead of scheduled activation. The following exchange profiles are taken as an underlying assumption for the examples. The assumption of the sequence DA before SA is only for illustrative reasons and does not imply a preference.

NOTE 1: The following descriptions, examples, illustrations, derived options, assessments and shortlists refer to the underlying assumptions given above only. Further options on product, process and timing should be considered in order to assess the impact on settlement when they are assessed and evaluated.

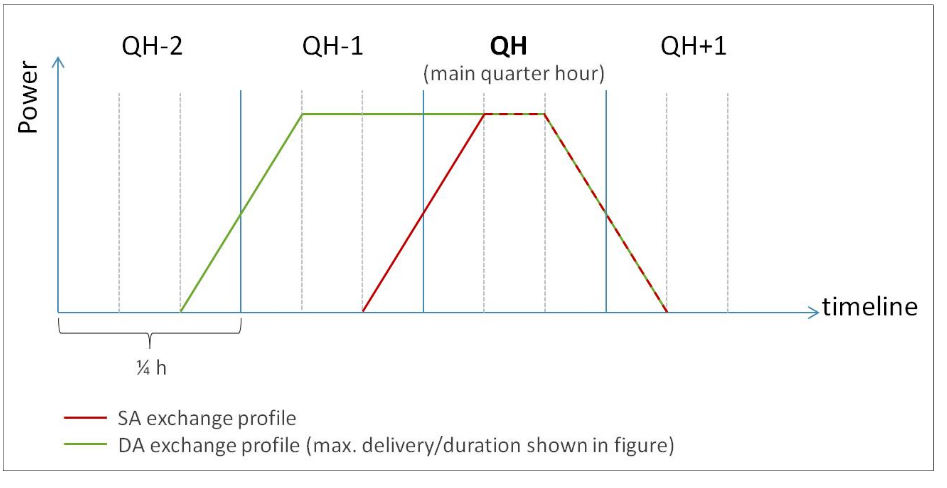

Figure 31: Assumed Exchange Profiles of Scheduled and Direct Activation[13]

[13] In this figure, the direct activation of the bid submitted for QH occurs shortly (1 sec) after the scheduled activation in QH-1. This direct activation would not be deactivated in QH-1, because the minimum delivery period (5 min) is not fulfilled by 1 second; therefore, it is deactivated in QH.

4.3.3 TSO-TSO Volume Settlement

In the following chapter the question of which volumes to be settled within which quarter hours is addressed.

4.3.3.1 Criteria for TSO-TSO Volume Settlement Options

In order to identify and evaluate possible options, the following criteria were identified.

Criterion	
a.	Consistency with algorithm: Volumes considered in the algorithm should be consistent with the volumes for TSO-TSO settlement.
b.	Limited number of QHs affected (Simplicity & transparency): The number of quarter hours affected by an activation should be limited (max. 2 in case of DA)
c.	Settled energy = XB exchange: The energy settled between TSOs should be equal to the total energy in the XB schedule.

Table 24: Criteria for Volume Options

4.3.3.2 TSO-TSO Volume Settlement Options

► Volume Option 1

In Option 1, the delivered energy of a scheduled activation, i.e. the integral of power over time, is settled within the main QH , as depicted by the red-shaded area Vi in. the Figure 32.

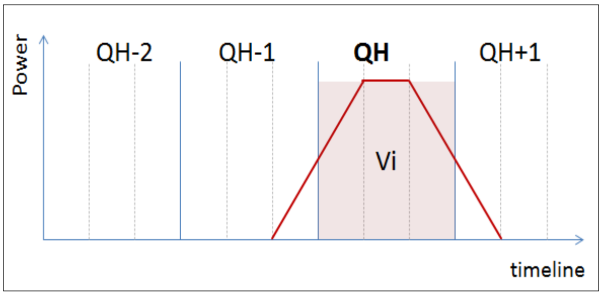

Figure 32: Volume Option1 for SA

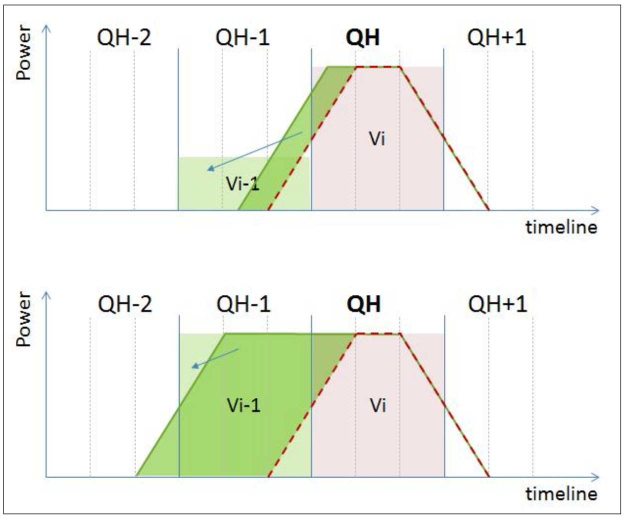

Figure 33: Volume Option 1 for DA

For DA the same principle applies, i.e. Area Vi is independent from the point in time the DA bid was activated. The additional volume, exceeding the equivalent volume of a scheduled activation, is settled in QH-1 as shown in Figure 33, represented by the light green shaded area. At the bottom of Figure 33, an example of a DA bid activated somewhere within the possible timeframe for direct activation is shown as well as an example of a DA bid activated at the earliest possible point in time of a direct activation (i.e. assumed maximum duration of a DA).

► Volume Option 2

In Option 2 the delivered energy of a SA is settled in each quarter hour affected. The principle is the same for SA and DA. In the case of SA three QHs are affected. In the case of DA, three or four QHs are affected as shown in Figure 34 represented by the red-shaded areas for SA and green-shaded areas for DA.

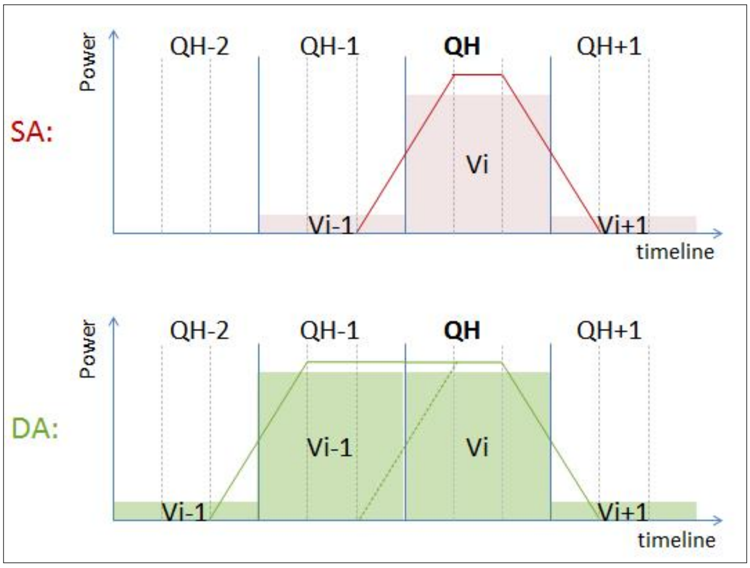

Figure 34: Volume Option 2 for SA and DA

4.3.3.3 Analysis of Volume Settlement Options

The evaluation of Option 1 shows that all criteria are met for SA. For DA all but one criteria are met, as a direct activation affects another quarter hour.

Criterion		Score (-1 to 1)	
		SA	DA
a.	Consistency with algorithm	1	-1
b.	Limited number of QHs affected (Simplicity & transparency)	1	1
c.	Settled energy = XB exchange	1	1

Table 25: Assessment of Volume Settlement Option 1

The evaluation of Option 2 for SA and DA concluded that this option would not be consistent with the Algorithm, i.e. it would not equal the volumes which the algorithm assigns to the quarter hour. Moreover, the number of QHs affected is at maximum.

Criterion		Score (-1 to 1)	
		SA	DA
a.	Consistency with algorithm	-1	-1
b.	Limited number of QHs affected (Simplicity & transparency)	-1	-1
c.	Settled energy = XB exchange	1	1

Table 26: Assessment of Volume Settlement Option 2

4.3.3.4 Questions

Q32. Which of the TSO-TSO volume settlement options do you prefer? Why?

4.3.4 TSO-TSO Pricing

The following chapter provides options for the determination of prices which can be used in the settlement of the exchanged energy.

4.3.4.1 Criteria for TSO-TSO Pricing Options

In order to identify and evaluate possible options, the following criteria were identified. Indicative weightings were used to reflect the importance of each criterion, however, some of the criteria were defined as “must-criteria” which have to be met in any case.

Even though the following criteria are to assess TSO-TSO settlement options, some criteria refer to BSP incentives. This is due to the direct link to TSO-BSP settlement. As a result of the requirement of the financial neutrality of the TSO, no more money can be paid to the BSP than BRPs pay. Hence it is assumed in this chapter that the TSO-TSO settlement is to be consistent with these payments. However, taking this assumption into account in the assessment of options for the settlement between TSOs, it does not touch TSO-BSP harmonization.

Criterion		Formula	Relevance	Weight
a.	Pay at least bid price for all energies	For all i $P_{SA\ bid}(QH_i) \geq P_{bid\ SA}$ $P_{DA\ bid}(QH_i) \geq P_{bid\ DA}$	Must	-
b.	Price formulas for DA should not include prices (bid prices or clearing prices) of quarter hours which are not affected by the DA.		Must	-
c.	No financial incentive for TSO to activate sooner (DA before SA). DA bids should at least get what they would have gotten if they were schedule activated.	$P_{DA\ bid}(QH_i) \geq P_{SA\ bid}(QH_i)$ Where QH_i is the main QH for a DA bid	Must	-
d.	No financial incentive for TSO to activate sooner (DA before DA)	The price paid for the first DA bid should not be lower that the price paid for the last DA bid within the same main QH	Must	-
e.	No incentive for TSO to use DA for the next QH instead of SA (DA after SA)	$P_{DA\ bid\ for\ CMOL\ i+1}(QH_i) \geq P_{SA\ bid\ from\ CMOL\ i}(QH_i)$	Must	-
f.	Incentives for BSP to submit direct activated bids = no incentive to submit only SA bids.		Important for some TSOs with need for DA to ensure TTRF criteria	2
g.	Pay all mFRR energy volumes exchanged within the same QH at the same MP (transparency & simplicity reasons)		Nice to have (There can be different prices within one QH as long as BSPs are incentivised to bid at their marginal cost)	1
h.	Incentives for BSPs to bid at their marginal cost		Important	2
i.	Limited number of settlement prices for a single bid (simplicity) = 1 price (the same price for volumes in QHi-1 and QHi)		Nice to have	1,5
j.	Do not create a « Rejection of Scheduled Bids » (i.e. SA bids with a price under the most expensive DA bid but over the price of SA need); transparency issue		Nice to have	1

Table 27: Criteria for Pricing Options

NOTE 2: Criterion h has so far not been taken into consideration in the assessment of different options, since real bidding behaviours are difficult to estimate, especially in the case of direct activations, which can be priced differently in different settlement periods.

$P_{SA\ bid}(QH_i)$	Settlement price of a Schedule Activated bid for the volume requested in QHi
$P_{DA\ bid}(QH_i)$	Settlement price of a Direct Activated bid for the volume requested in QHi
$P_{bid\ SA}$	Bid price of bid which can only be schedule activated
$P_{bid\ DA}$	Bid price of a bid which can be direct and schedule activated
$P_{DA\ bid\ for\ CMOL\ i+1}(QH_i)$	Settlement price of a Direct Activated bid from a CMOL with QHi+1 as main QH, for the volume requested in QHi
$P_{SA\ bid\ from\ CMOL\ i}(QH_i)$	Settlement price of a Schedule Activated bid from a CMOL with QHi as main QH, for the volume requested on QHi
$P_{clearing}(QH_i)$	Clearing price for schedule activation (Scheduled clearing price), calculated by the algorithm for QHi
i	Index indicating a respective quarter hour (i = main quarter hour for which the bid was offered; i-1 = previous quarter hour; i+1=subsequent quarter hour)

Table 28: Definitions for Table of Criteria for Pricing Options

4.3.4.2 TSO-TSO Pricing Options

As there is a possibility to take into account direct activated bids in the scheduled clearing[14], two option categories were defined:

- A: The clearing price applied for schedule activation is set by the most expensive activated SA- and DA-bid of the main QH.
- B: The clearing price applied for schedule activation does not take into account direct activations, i.e. the clearing price can be higher or lower or the same as the highest activated DA bid price.

The following pricing options are linked to the volume option 1 (acc.Table 28). In all pricing options SA is settled with the scheduled clearing price of the main QH, however, the distinction between category A and B has to be considered. For DA-bids activated from the CMOL of the main QH, the question arises, which price to apply for the volume of the main QH and which price to apply for the volume of QH-1. The following tables show how schedule activations and direct activations can be priced. The prices resulting from these formulas refer to an uncongested area. As a first step, all options were assessed against the defined criteria by application of scores between -1 and 1 without taking into account weighting factors.

In all of the following options, the bid is activated from the CMOL of the main QH (highlighted in gray). "Settlement price for DA" refers to the settlement price applied for DA-bids (submitted for QH_i) which were directly activated. The term "Scheduled clearing price" refers to schedule activations, i.e. the price

[14] Scheduled clearing is performed based on bids that can be schedule activated and directly activated, and on bids that can only be schedule activated.

applied for all bids which were schedule activated. For A options the Scheduled clearing price is defined according to the following formula:

$P_{clearing,A}$ (QH_i) = Max(prices of SA- and DA-bids activated for the main QH)

For B options, the Scheduled clearing price is defined according to the following formula:

$P_{clearing,B}$ (QH_i) = Max(prices of SA bids activated for the main QH)

Pricing of the options shows table:

Option A1	QH-1	QH
Scheduled clearing price	$P_{clearing,A}$ (QH_{i-1})	$P_{clearing,A}$ (QH_i)
Settlement price for DA	$P_{clearing,A}$ (QH_{i-1})	$P_{clearing,A}$ (QH_i)
Option A2	**QH-1**	**QH**
Scheduled clearing price	$P_{clearing,A}$ (QH_{i-1})	$P_{clearing,A}$ (QH_i)
Settlement price for DA	Max($P_{clearing,A}$ (QH_{i-1}); prices of DA bids activated for the main QH_i)	$P_{clearing,A}$ (QH_i)
Option A3	**QH-1**	**QH**
Scheduled clearing price	$P_{clearing,A}$ (QH_{i-1})	$P_{clearing,A}$ (QH_i)
Settlement price for DA	$P_{clearing,A}$ (QH_i)	$P_{clearing,A}$ (QH_i)
Option A4	**QH-1**	**QH**
Scheduled clearing price	$P_{clearing,A}$ (QH_{i-1})	$P_{clearing,A}$ (QH_i)
Settlement price for DA	Max(prices of DA bids activated for the main QH_i)	$P_{clearing,A}$ (QH_i)
Option A5	**QH-1**	**QH**
Scheduled clearing price	$P_{clearing,A}$ (QH_{i-1})	$P_{clearing,A}$ (QH_i)
Settlement price for DA	Max($P_{clearing,A}$ (QH_i), $P_{clearing,A}$ (QH_{i-1}))	Max($P_{clearing,A}$ (QH_i), $P_{clearing,A}$ (QH_{i-1}))
Option A6	**QH-1**	**QH**
Scheduled clearing price	$P_{clearing,A}$ (QH_{i-1})	$P_{clearing,A}$ (QH_i)
Settlement price for DA	Max($P_{clearing,A}$ (QH_i), $P_{clearing,A}$ (QH_{i-1}))	$P_{clearing,A}$ (QH_i)
Option B1	**QH-1**	**QH**
Scheduled clearing price	$P_{clearing,B}$ (QH_{i-1})	$P_{clearing,B}$ (QH_i)
Settlement price for DA	Max($P_{clearing,B}$ (QH_i); prices of DA bids activated for the main QH_i)	Max($P_{clearing,B}$ (QH_i); prices of DA bids activated for the main QH_i)
Option B2	**QH-1**	**QH**
Scheduled clearing price	$P_{clearing,B}$ (QH_{i-1})	$P_{clearing,B}$ (QH_i)
Settlement price for DA	Max($P_{clearing,B}$ (QH_i); $P_{clearing,B}$ (QH_{i-1}); prices of DA bids activated for the main QH_i)	Max($P_{clearing,B}$ (QH_i); $P_{clearing,B}$ (QH_{i-1}); prices of DA bids activated for the main QH_i)
Option B3	**QH-1**	**QH**
Scheduled clearing price	$P_{clearing,B}$ (QH_{i-1})	$P_{clearing,B}$ (QH_i)

Settlement price for DA	(max($P_{clearing,B}$ (QH_i); activated DA bids for main QHi) + max($P_{clearing,B}$ (QHi_{-1}); activated DA bids for QHi)) / 2	(max($P_{clearing,B}$ (QH_i); activated DA bids for main QHi) + max($P_{clearing,B}$ (QHi_{-1}); activated DA bids for QHi)) / 2

Table 29: Pricing Options

NOTE 3: As already pointed out, these options refer to the underlying assumtions defined in section 4.3.2, which include DA occuring before SA, thus they do not show any preference for the process options. We note that pricing options B could also be applied for the alternative sequence (DA after SA). DA would then be settled in QH and QH+1. However we note here that the applicability of the pricing options A needs to be further investigated for the process DA before SA (e.g.: in case of congestions, impact on the algorithm), as well as their applicability in the alternative process DA after SA (e.g. in case of an elastic/inelastic demand).

Assessment of the options (scores -1 to 1):

	Criterion	A1	A2	A3	A4	A5	A6	B1	B2	B3
a.	Pay at least bid price for all energies	-1	1	1	1	1	1	1	1	1
b.	Price formulas for DA should not include prices (bid prices or clearing prices) of quarter hours which are not affected by the DA.	1	1	1	1	1	1	1	1	1
c.	No incentive for TSO to activate sooner due to financial incentive to do so (DA before SA). DA bids should at least get what they would have gotten if they were schedule activated.	1	1	1	1	1	1	1	1	1
d.	No incentive for TSO to activate sooner due to financial incentive to do so ((DA before DA)	1	1	1	1	1	1	1	1	1
e.	No incentive for TSO to use DA for the next QH instead of SA need (DA after SA)	1	1	1	-1	1	1	-1	1	1
f.	Incentive for BSP to submit DA compatible bids = no incentive to submit only SA bids.	-1	1	1	1	1	1	1	1	0
g.	Pay all mFRR energies delivered within the same QH at the same MP (transparency & simplicity reasons)	1	-1	-1	-1	-1	-1	-1	-1	-1
h.	Incentive for BSPs to bid at their marginal cost	?	?	?	?	?	?	?	?	?
i.	Limited number of settlement prices for a single bid (simplicity) = 1 price (same price for volumes in QH_{i-1} and QH_i)	-1	-1	1	-1	1	-1	1	1	1
j.	Does not create a « Rejection of Scheduled Bids » (i.e. SA bids with a price under the most expensive DA bid but over the price of SA need); transparency issue	-1	-1	-1	-1	-1	-1	1	1	1

Table 30: Assessment of Pricing Options

NOTE 4:	Option B2 maximizes the price for DA. Possible excessive prices may incentivise TSOs to use specific products for DA instead of the standard product defined for the mFRR platform. Therefore Option B3 has been identified to eliminate this issue, however, it comes with different drawbacks.
NOTE 5:	In comparison to Option B2, Option B3 reduces the incentive for TSOs to use specific products for DA instead of the standard product, by applying an average price instead of maximizing it. However, this may affect the incentive for BSPs to submit DA bids. A score of Zero was assigned for criterion f., because, the settlement price for a Direct Activation can be either lower or higher than the clearing price for SA in QHi.

4.3.4.3 Analysis of Pricing Options

For the comparison of the options, the scores assigned in Table 30 were multiplied with the set weighting factors according to Table 31. Taking into account the weighting factors, only the Options A2, A3, A5, B2 and B3 can be taken into consideration, which only differ in regards to criteria f., i. and j. as follows:

Criterion		Weight	A2	A3	A5	A6	B2	B3
f.	Incentive for BSP to submit DA compatible bids = no incentive to submit only SA bids.	2	2	2	2	2	2	0
i.	Limited number of settlement prices for a single bid (simplicity) = 1 price (same price for volumes in QHi-1 and QHi)	1,5	-1,5	1,5	1,5	-1,5	1,5	1,5
j.	Does not create a « Rejection of Scheduled Bids » (i.e. SA bids with a price under the most expensive DA bid but over the price of SA need); transparency issue	1	-1	-1	-1	-1	1	1
		4,5	-0,5	2,5	2,5	-1,5	4,5	2,5

Table 31: Comparison of the Options which Meet All Must-Criteria

Since Options A1, A4 and B1 are not applicable, because they do not meet all of the defined must-criteria, and since A2 and A6 score negative in criteria i and j, it is proposed to consider option A3, A5, B2 and B3 for further comparison.

Options A3 and A5 show the same assessment results. Nevertheless, option A3 is the preferred option, since lower prices are expected according to the given formulas in Table 29. Therefore, option A3, B2 and B3 are recommended for a shortlist. The respective formulas are compared once more in Table 32

Opt.		QH-1	QH
A3	Scheduled clearing price	$P_{clearing,A}$ (QH_{i-1})	$P_{clearing,A}$ (QH_i)
	Settlement price for DA	$P_{clearing,A}$ (QH_i)	$P_{clearing,A}$ (QH_i)
B2	Scheduled clearing price	$P_{clearing,B}$ (QH_{i-1})	$P_{clearing,B}$ (QH_i)
	Settlement price for DA	Max($P_{clearing,B}$ (QH_i), $P_{clearing,B}$ (QH_{i-1}), activated DA bids for QH_i)	Max($P_{clearing,B}$ (QH_i), $P_{clearing,B}$ (QH_{i-1}), activated DA bids for QH_i)
B3	Scheduled clearing price	$P_{clearing,B}$ (QH_{i-1})	$P_{clearing,B}$ (QH_i)
	Settlement price for DA	(max($P_{clearing,B}$ (QH_i); activated DA bids for main QHi) + max($P_{clearing,B}$ (QHi_{-1}); activated DA bids for QHi)) / 2	(max($P_{clearing,B}$ (QHi); activated DA bids for main QHi) + max($P_{clearing,B}$ (QHi_{-1}); activated DA bids for QHi)) / 2

Table 32: Formulas of Shortlisted Options

The shortlisted options differ in the following respects:

- Price level;
- Incentive for BSPs to submit DA bids;
- Rejection of Scheduled Bids:
- Unlike the B-options, A-options could lead to a Rejection of scheduled bids, which is a situation in which some SA bids were not activated although the clearing price is higher than the prices of these SA bids. This case is illustrated in Figure 35. The SA bids concerned are SA bids with a price under the most expensive DA bid but over the price of SA need (e.g. SA7, SA8 and SA9 in Figure 35). This is due to the inclusion of DA bid in the scheduled clearing.

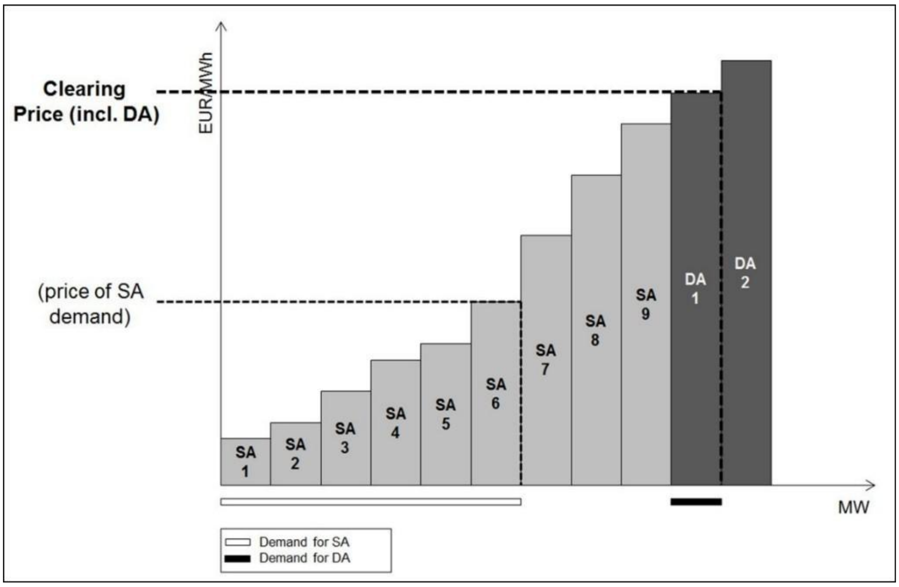

Figure 35: Rejection of Scheduled Bids

- The question arises as to whether this situation poses a problem. Basically, when the need does not occur at the same time, there is no way to guarantee the absence of rejection. It is certain, that TSOs which only need SA will have to pay a higher price compared to a pure SA CMOL, if others activate DA bids, however, this option provides a strong incentive to offer direct activatable bids.

► Rejected scheduled demand

- Another aspect to consider, is the possibility of social welfare loss for TSOs which only need SA and in case they place prices for their SA demands ("elastic demands"). This issue occurs, if DA bids are considered in the scheduled clearing (option category A). Figure 36 provides a simplified example. In the situation shown, SA1-SA8 would not be activated, since the clearing price, which was determined by the most expensive DA bid, exceeds the price limit set for elastic SA demand.

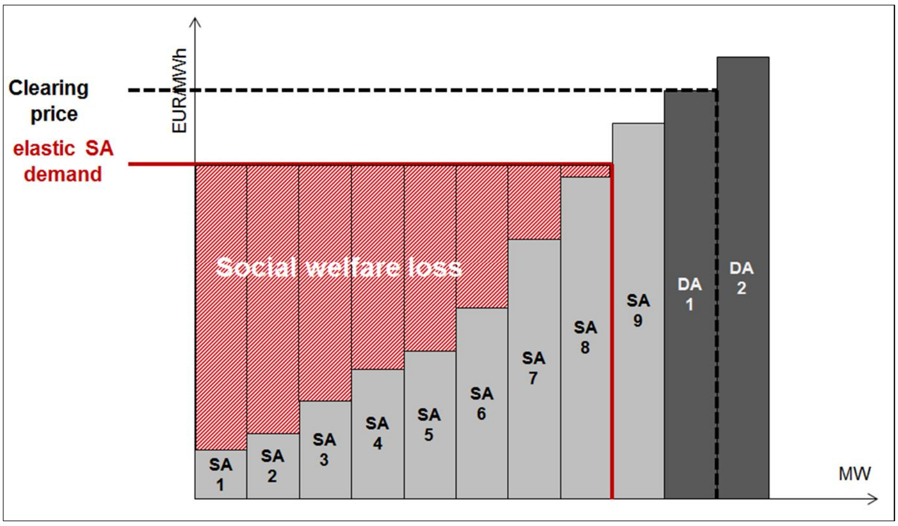

Figure 36: Social Welfare Loss in Case of TSOs Which Only Use SA, Elastic SA Needs and a Clearing Price Incl. DA

In this case, there would be a remaining balancing need to be covered by another balancing process, (e.g. aFRR and/or specific products, etc.). The costs of this subsequent process will affect the resulting total welfare loss. Accordingly the social welfare loss could be higher or lower as is illustrated in Figure 36. Moreover, this rejection leads to an activation of less balancing energy within the mFRR-platform, which could be avoided with B-options or without the application of elastic demands.

4.3.4.4 Counter-Activations

4.3.4.4.1 Definition and Examples

With the term counter-activations, we refer to the activation of offers of opposite direction for the same QH, which could be avoided, if the TSOs had netted their demands. "Scheduled counter-activations", i.e. the simultaneous activation of a scheduled upward and a scheduled downward offer (as described in chapter 3.2.2) is accepted, if it leads to a higher social welfare, otherwise these opposed demands would be netted. The term „Counter-Directactivation" refers to counter activations which can't be avoided are due to the nature of direct activations and occur in the case of a direct activation which is opposed to a scheduled activation or another direct activation.

The following example presents a Counter-Directactivation case due to absence of demands' netting. The assumption is that all demands and bids are directly activated, and their features are presented in Table 33. Note that there is enough ATC in order not to affect the results.

Type	Quantity (MW)	Price (€/MWh)	QH	Submission time	Activated/Satisfied quantity
Positive demand (TSO 1)	50	Inelastic	10:00-10:15	09:40	50
Negative demand (TSO 2)	50	Inelastic	10:00-10:15	09:42	50
Upward bid (BSP 1)	60	100	10:00-10:15	BSP GCT for QH	50
Downward bid (BSP 2)	60	5	10:00-10:15	BSP GCT for QH	50

Table 33: Example of Counter-Directactivation Due to Absence of Netting

TSO 1 submits a positive demand at 09:40 and the upward bid from BSP 1 is partially activated in order to cover the TSO 1 demand. After 2 minutes, TSO 2 submits a negative demand which is equal, in terms of volume, to the demand of TSO 1. However, the demand of TSO 1 has already been satisfied, therefore the downward bid of BSP 2 will be partially activated to cover the TSO 2 demand. In this case, we have a Counter-Directactivation of 50 MW (50 MW upwards and 50 MW downwards).

The following example presents a Counter-Directactivation involvingscheduled activated bids. The inputs and the results are presented in Table 34. Similarly to the previous examples, it is assumed that there is enough ATC in order not to affect the results.

Type	Quantity (MW)	Price (€/MWh)	QH	Submission time	Activated/Satisfied quantity
Positive demand (TSO 1)	100	Inelastic	10:00-10:15	09:43:30	100
Negative demand (TSO 2)	50	Inelastic	10:00-10:15	Scheduled	50
Negative demand (TSO 3)	50	Inelastic	10:00-10:15	Scheduled	50
Upward bid (BSP 1)	100	100	10:00-10:15	BSP GCT for QH	100
Downward bid (BSP 2)	60	20	10:00-10:15	BSP GCT for QH	40
Downward bid (BSP 3)	60	10	10:00-10:15	BSP GCT for QH	60

Table 34: Example of Counter-Directactivation involving SA bids

TSO 1 has a positive demand and asks for DA at 09:43:30, which is covered by the upward bid of BSP 1. Assuming that the SA follows the DA, TSO 2 and 3 submit negative demands for SA, which are covered by the activation of the downward bids from BSP 2 and BSP 3. We observe that the demand of TSO 1 would have been netted completely with the demands of TSO 2 and TSO 3 if it was submitted for SA. Therefore, in this case, we have a Counter-Direct activation of 100 MW (100 MW upwards and 100 MW downwards).

4.3.4.4.2 *Analysis of Pricing Options in Terms of Counter-Activations*

It is important to analyse the differences of the presented pricing options with respect to counter-activations. The assumption of the following analysis is that the SA is after the DA, however there are differences depending on the sequence of SA and DA.

The example presented in Table 34 will be used to explain the differences. For the sake of completeness, for QH-1, we assume that only scheduled activations occurred, the price of the schedule activation was equal to 110 €/MWh and the volume equal to 100 MWh. For the sake of simplicity, we also assume that the algorithm calculating the DA does not need any time. Figure 37 presents the activated volumes – energy and not power profiles are presented - at each QH. Due to the activation of the upward bid from BSP 1, 15 MWh were delivered in the period 09:45 – 10:00 (the ramping started at 09:46 and finished at 09:56) and 25 MWh were delivered in the period 10:00 – 10:15. In addition, due to the activation of the downward bids from the BSP 2 and BSP 3, 25 MWh downwards were delivered in the period 10:00 – 10:15.

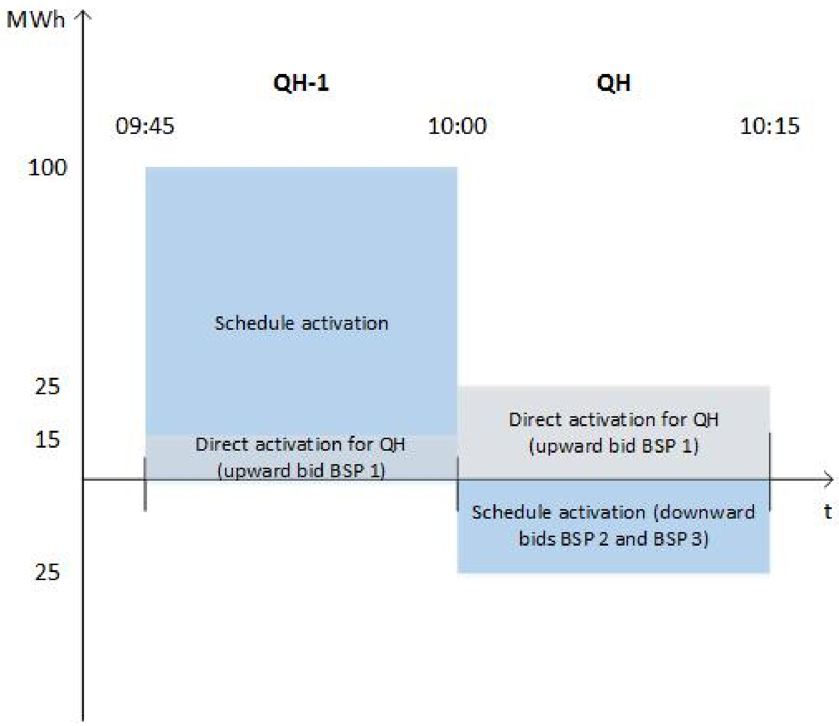

Figure 37: Counter-Activations, Example

For QH, the total delivered energy is equal to 0; however all activated bids have to be settled, resulting in a higher balancing cost compared to the situation that the TSO 1 would have submitted its demand for SA. Therefore, it is important to incentivize the TSOs, through the pricing option, to submit demands for SA, and to request DA only when this is necessary for the system security.

In the following, we will analyse the results of the different options, and the incentives they provide with regard to the counter-activations. As aforementioned, for the A options, the clearing price is defined as:

$$P_{clearing,A}(QH_i) = \text{Max(prices of SA- and DA-bids activated for the main } QH_i\text{)}$$

Therefore, for this example, the clearing price would be equal to 100 €/MWh for the period QH (10:00 – 10:15) and 110 €/MWh for the period QH-1 (09:45 – 10:00). The clearing price for B options is defined according to following formula:

$$P_{clearing,B}(QH_i) = Max(\text{prices of SA bids activated for the main } QH_i)$$

In this case, the clearing price is 20 for QH and 110 for QH-1. Note that the pricing option A1 will not be analysed and has already been excluded, as the DA bids could receive a price lower than the bid price, which would not be acceptable.

Pricing option		QH-1	QH
	Scheduled clearing price	110	100
A2	Settlement price for DA	110	100
	Scheduled clearing price	110	100
A3	Settlement price for DA	100	100
	Scheduled clearing price	110	100
A4	Settlement price for DA	100	100
	Scheduled clearing price	110	100
A5	Settlement price for DA	110	110
A6	Scheduled clearing price	110	100
	Settlement price for DA	110	100
B1	Scheduled clearing price	110	20
	Settlement price for DA	100	100
	Scheduled clearing price	110	20
B2	Settlement price for DA	110	110
B3	Scheduled clearing price	110	20
	Settlement price for DA	105	105

Table 35: Pricing Options

As aforementioned, the shortlisted pricing options are A3, B2 and B3. The option B2 results in the highest price for DA bids, as it considers the maximum price of the DA bids activated for QH, the scheduled activations for QH-1 and the scheduled activations for QH, and therefore provides the strongest incentives for the TSO to wait for the scheduled activation and not proceed with direct activation.

4.3.4.5 Price Indeterminacy

Price indeterminacy is a special situation when identical bid and demand selection lead to multiple optimal clearing price solutions, as depicted Figure 38. In this case, all solutions have an identical social welfare and is therefore necessary to define a rule to choose a single price between the set of optimal prices. This situation can occur either due to the presence of elastic demands or due to scheduled counter-activations.

Symbolic Illustration:

Any price between the Upper Boundary (UB) and the lower Boundary (LB) is a valid Marginal Price. A possible solution is to apply the mid-point as the Market Clearing Price (MCP).

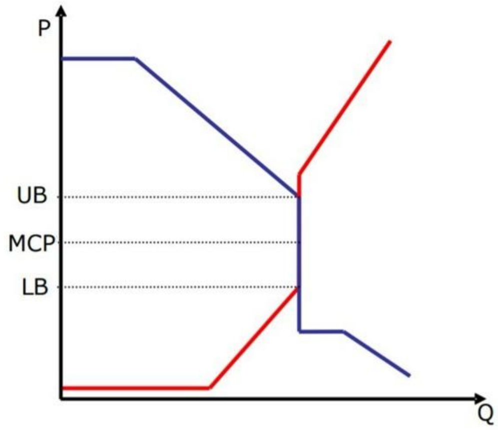

Figure 38: Price Indeterminacy: Multiple Optimal Clearing Prices

4.3.4.5.1 Options on Solutions for Price Indeterminacies

To deal with price indeterminacies, we suggest following one of these rules:

► Option A

The mid-point between the lowest and the highest possible price will apply. This approach would be consistent with the current practice in the day-ahead market coupling and TERRE.

► Option B

An alternative would be to have two marginal prices, one for upward bids and negative demands which corresponds to the lowest possible price, and one for downward bids and positive demands which corresponds to the highest possible price. This approach is allowed by the GLEB as in the Article 49 (2) of the GLEB, it is mentioned that *'the price, be it positive, zero or negative, of the activated volume of balancing energy for the frequency restoration process shall be defined for each direction.'*

► Option C

Another approach would be to determine the price in a way such that it maximizes the TSO surplus and hence decrease the balancing costs for the TSOs.

4.3.4.5.2 Analysis of Options on Solutions for Price Indeterminacies

The following example illustrates a case of price indeterminacy. We consider a system of two TSOs and enough ATC in order for the exchange not to be affected. Table 36 presents the bids and demands and Table 37 presents the results.

Type	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers
Demand (TSO 1)	+100	--	Inelastic	--
Demand (TSO 2)	-10	--	Inelastic	--
Upward Offer (UO BSP1)	100	5(TSO pays BSP)	--	Divisible
Downward Offer (DO BSP2)	-10	7 (BSP pays TSO)	--	Divisible

Table 36: Example Inputs

<table>
<tr><th>Type</th><th colspan="3">Activated Quantity/Satisfied Demand (MW)</th></tr>
<tr><td>Demand (TSO 1)</td><td colspan="3">+100</td></tr>
<tr><td>Demand (TSO 2)</td><td colspan="3">-10</td></tr>
<tr><td>Upward Offer (UO BSP1)</td><td colspan="3">+100</td></tr>
<tr><td>Downward Offer (UO BSP2)</td><td colspan="3">-10</td></tr>
<tr><th>Social Welfare (€)[15]</th><th colspan="3">Marginal Price (€/MWh)[15]</th></tr>
<tr><td rowspan="2">+200
(= -500+700)</td><td colspan="3">Output of algorithm: a value between 5 and 7</td></tr>
<tr><td>Option A:
6</td><td>Option B:
5 for upward and 7 for downward</td><td>Option C:
5</td></tr>
</table>

Table 37: Example Outputs

We observe that all bids are fully activated and all demands are satisfied. The optimal price can be anything between 5€/MWh and 7€/MWh. Following Option 1, the result would be 6€/MWh as the mid-point would be chosen. Considering Option 2, the result would be 5€/MWh for upward bids (UO BSP 1) and negative demands (TSO 2), and 7€/MWh for downward bids (DO BSP 2) and positive demands (TSO 1). Finally, Option 3 would result in a price of 5€/MWh, as in this way the total TSO surplus is maximized.

[15] Calculation concept of social welfare optimization and derivation of marginal prices explained in chapter 3.2.2.1.

4.3.5 Questions

Q33. Do you prefer pricing option category A or B? Why?

Q34. Do you agree with the proposed criteria, weights and scoring for the assessment of pricing options? Why?

Q35. Would you consider additional pricing options? Why?

Q36. Which of the pricing options do you prefer? Why?

Q37. Which of the pricing options would incentivize you the most to submit Direct Activatable bids? Why?

Q38. Do you consider the issue of "Rejected Scheduled bids/demand" to be problematic? Why?

Q39. Which of the three options regarding price indeterminacies would you prefer? Why?

4.3.6 Settlement of Netted Volumes

4.3.6.1 Definition of Netted Volumes

In order to avoid counter activation (simultaneous activation in opposite directions) of the balancing energy, the demands on upward and downward mFRR will be netted within the cooperation area by taking into account available cross-zonal capacities capacities. It means that an LFC area which is long supplies energy to an LFC area which is short. In that way, the netting process enables all participating TSOs to reduce mFRR activation as well as activation costs and leads thus to social welfare generation within the mFRR cooperation.

Table 38 illustrates the netting process between four LFC areas. LFC area A is short and would activate 700 MWh positive mFRR whereas LFC areas B, C and D are long and would activate in total 600 MWh negative mFRR. If there is no congestion, TSO A imports 600 MWh while TSO B exports 100 MWh, TSO C exports 200 MWh and TSO D exports 300 MWh. The residual mFRR demand of 100 MWh after netting is covered by activating the cheapest bids of the upward common MOL. Thus due to the netting, the mFRR demand can be reduced to 100 MWh and the netted energy results in avoided mFRR activation.

Indicator	TSO A	TSO B	TSO C	TSO D
mFRR demand in MWh	700	-100	-200	-300
Correction in MWh	-600	100	200	300
mFRR netting import in MWh	600	0	0	0
mFRR netting export in MWh	0	100	200	300
mFRR activation in MWh	100	0	0	0

Table 38: Netting of Opposed Activations

The netted volumes for each direction (separately for import and export) will be determined for each TSO and for each quarter-hour.

4.3.6.2 Settlement of Netted Volumes with the Cross-Border Marginal Price

The settlement of the netted mFRR energy should be based on a price which reflects the opportunity value (opportunity costs) of the avoided mFRR activation. This is an average price of mFRR activation from the common MOL within an uncongested area. This price is equivalent to the cross-border marginal price in this uncongested area. Thus, the mFRR opportunity price respectively for upward and downward direction is the cross-border marginal price for this direction resulting from mFRR activation and reflecting the value of the avoided mFRR activation within an uncongested area. In order to determine a monetary exchange between the TSOs, a settlement price will be calculated. It is based on the opportunity prices per direction and is equal for both import and export.

If a perfect netting occurs, i.e. if inelastic demands are netted without activation of other bids, the marginal price issued by the algorithm is zero. For that case, a different opportunity price will be calculated. The next chapter provides some options of the opportunity price calculation in case of perfect netting.

4.3.6.3 Settlement Options for the Case of Perfect Netting

For each of the hereinunder mentioned options it is assumed that netting avoided activation of 25MW.

- Option 1: The price of the least expensive bid in the common MOL

According to this option, the price of the least expensive bid (separately for each direction - upward and downward) in the common MOL will be used for the settlement in case of perfect netting.

CMOL		Avoided Activation	Opportunity Price
Energy [MWh]	Energy Price [€/MWh]	[MWh]	[€/MWh]
10	7	25	7
5	10		
10	50		
15	100		

Table 39: Example for Option 1

This method is very simple and pragmatic. Furthermore, it is successfully used by some TSOs within the IGCC and aFRR cooperation.

► Option 2: Marginal price of avoided mFRR activation

This price corresponds to the cross-border marginal price resulting from a fictitious mFRR activation if the volumes would not have been netted but fully activated. The opportunity price of this option is usually higher than the price in option 1 (see Table 40).

CMOL		Avoided Activation	Opportunity Price
Energy [MWh]	Energy Price [€/MWh]	[MWh]	[€/MWh]
10	7	25	50
5	10		
10	50		
15	100		

Table 40: Example for Option 2

► Option 3: Average price of avoided mFRR activation

This price results from a fictitious mFRR activation if the volumes would not have been netted but fully activated as in option 2. Table 41 shows an example for the average price with the following calculation:

Opportunity price = Average price = (10 * 7 + 5 * 10 + 10 * 50)/(10 + 5 + 10) = 620/25 = 24,8

CMOL		Avoided Activation	Opportunity Price
Energy [MWh]	Energy Price [€/MWh]	[MWh]	[€/MWh]
10	7	25	24,8
5	10		
10	50		
15	100		

Table 41: Example for Option 3

In contrast to option 2, this is an average price from mFRR activation based on the pay-as-bid-settlement. The settlement price of this option is usually higher than the price in option 1 but lower than in option 2.

► Option 4: Settlement based on avoided cost of mFRR activations in each area

The objective is to calculate the net welfare resulting from the perfect netting and to share equally this welfare. The welfare is calculated taking into account all the avoided costs in each control area. Following this, the welfare per TSO draws an opportunity price that is based on all the avoided costs in each control area. In order to calculate the avoided costs of each TSO, the mFRR marginal price is used that would result from a fictitious activation in case that all TSOs had been isolated (e.g. local demand and local mFRR bids, with ll ATC=0), see Table 42 and the following calculation:

Opportunity costs TSO A = (10 + 5) * 10 = 150

Opportunity costs TSO B = 5 * 50 = 250

Opportunity costs TSO C = 5 * 60 = 300

Opportunity price = (150 + 250 + 300)/ (15 + 5 + 5) = 28

Then, there is a settlement applied to each control area.

	MOL		Avoided Activation	Marginal Price	Opportunity Costs	Total welfare	Opportunity Price (welfare per MWh)
	Energy [MWh]	Energy Price [€/MWh]	[MWh]	[€/MWh]	[€]	[€]	[€/MWh]
A	10	7				700	28
	5	10	15	10	150		
B	5	50					
	15	65					
	3	70	5	50	250		
C	5	60					
	12	70	5	60	300		

Table 42: Example for Option 4

This solution warrants that no TSO has a deficit. This is currently proposed in TERRE project.

► Option 5: Weighted average of DA/ID market price

DA or ID market price of each balancing area is used as a reference for the calculation of the settlement price. Whereas this method is simple, it is not ensured that it will be positive for all the TSOs.

► Option 6: Predefined regulated price

This option implies application of a regulated price which should be approved by NRAs and reviewed if necessary. However, there are several questions that would have to be investigated for this option:

How to calculate this price? Will this be a fixed price for a whole period (e.g. month)?

How to ensure that it is GLEB compliant?

How to ensure that it will be positive for all the systems? And that benefits will be equally distributed?

CHAPTER 5 Congestion Management

5.1 Introduction

This chapter tackles the issues and questions concerning congestion management, building on the provisions of the GLEB on cross-zonal capacity calculation (Art. 37), i.e.:

1. *After the intraday-cross-zonal gate closure time, TSOs shall continuously update the availability of cross-zonal capacity for the exchange of balancing energy or for operating the imbalance netting process. Cross-zonal capacity shall be updated every time a portion of cross-zonal capacity has been used or when cross-zonal capacity has been recalculated.*
2. *Before the implementation of the capacity calculation methodology pursuant to paragraph 3, TSOs shall use the cross-zonal capacity remaining after the intraday cross-zonal gate closure time.*
3. *3. By five years after entry into force of this Regulation, all TSOs of a capacity calculation region shall develop a methodology for cross-zonal capacity calculation within the balancing timeframe for the exchange of balancing energy or for operating the imbalance netting process. Such methodology shall avoid market distortions and shall be consistent with the cross-zonal capacity calculation methodology applied in the intraday timeframe established under Commission Regulation (EU) 2015/1222.*

Since the second paragraph stipulates that TSOs shall use the cross-zonal capacity remaining after the intraday cross-zonal gate closure time, we took the working assumption that the cross- zonal capacity to be used in the algorithm is the remaining capacity after intraday and also after RR process. The validity of this assumption will be critically examined again in the second phase of MARI design, especially regarding the interactions with other balancing processes such as aFRR. The working assumptions will be reconsidered at the later stage according to the development of capacity calculation methodologies.

By dealing with congestion management, two main aspects are considered:

- The first purpose is that the TSOs shall make sure that bids that are activated for balancing purpose are not going to endanger the system security. The TSOs shall design an mFRR process and a platform which guarantee that the system constraints are fully respected;
- Then, the second purpose is that a TSO may have a congestion management need to do countertrading or re-dispatch. In such case, the GLEB leaves open the possibility for the TSOs to use the balancing platform to address TSO needs for countertrading or re-dispatch. In such case additional type of needs shall be considered in the mFRR process and platform.

In this report the focus is put on the congestion management constraints that shall be taken in account by the platform when balancing need are covered by mFRR activated bids (see section 5.2).

5.2 Options to Handle Bottlenecks

When using the same area definition for mFRR as intraday some TSOs need additional measures to handle congestions. The measures can be arranged before, within and/or after the algorithm calculation. The discussed measures are summarized and explained below.

1. TSOs limit ATC;
2. TSOs filter bids (mark them as unavailable);
3. Smaller internal mFRR zones in the mFRR algorithm;
4. Critical network elements in the mFRR algorithm;
5. Several TSOs form a cluster;
6. Re-dispatch the resulting flow after the mFRR algorithm.

According to the MARI Principles the Parties recognize that pragmatic congestion management handling should first be implemented in the mFRR Common Platform. Improved solutions should be jointly assessed and implemented in a second step. This assessment should happen as soon as first operational experiences have been gained.

This implies that the first implementation of congestion management in the mFRR common platform should open up for the TSOs to use their preferred measures to handle congestions, as long as the measures do not require an implementation within the algorithm. The option evaluation will be elaborated as part of the design phase 2.

5.3 Analysis

5.3.1 Measures before Algorithm

5.3.1.1 Limiting ATC

To keep the transmission system within agreed security limits in the operational phase the TSOs has an opportunity to limit ATC after the ID market.

The measure creates an opportunity for a TSO to limit ATC for cross zonal capacity in order to handle congestion management. This measure is common practice and currently used before intraday, RR process and in the IGCC cooperation. Each TSO update their ATC values and submit them to the platform before the TSO gate closure time.

The Figure 39 below shows how limiting ATC will affect the output from the clearing. A detailed description of this example can be found in Section 3.2.2.2/II.

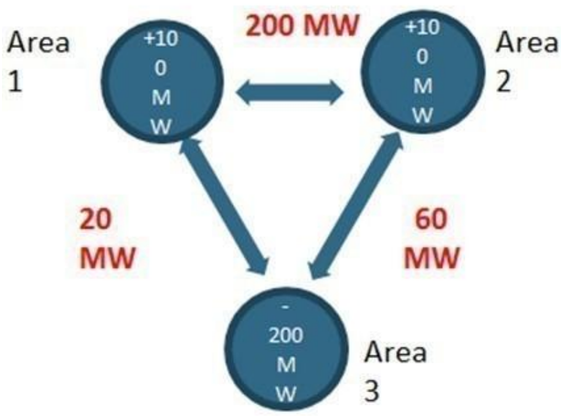

Figure 39: Limiting ATC

The pros are that the measure is well-known, simple and needs no additional mechanism in the algorithm when the measure is done in each TSO system. Furthermore this measure needs no direct harmonisation.

This measure shall always be possible but only used if other measures are not suitable (or while improved solution is implemented). Limitation of cross-zonal capacity for purposes of congestion management should be done in a coordinated and transparent way.

5.3.1.2 Filter Bids

The GLEB in its Article 29.14 states the following:

Each TSO may declare the balancing energy bids submitted to the activation optimisation function unavailable for the activation by other TSOs because they are restricted due to internal congestion or due to operational security constraints within the connecting TSO scheduling area.

This measure creates an opportunity for each TSO to filter bids that will create congestions by marking them as unavailable before submitting them to the platform.

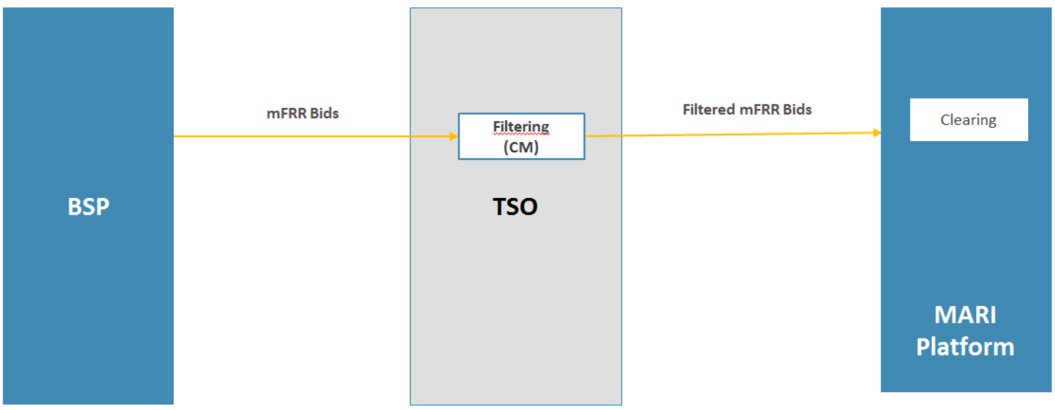

Figure 40: Bids Filtering

This is also a simple measure for which no additional mechanism in the algorithm and harmonisation is needed. The measure is also foreseen in GLEB and shall therefore be foreseen anyhow. There shall be sufficient time (to be assessed further) between BEGCT and TSO GCT, to let the TSO performing such filtering actions.

Information on unavailable bids has to be reported according to GLEB Art. 12(3)(b)(v).

5.3.2 Measures within Algorithm

5.3.2.1 Several Internal mFRR Zones within the Intraday Bidding Zone

In this measure the algorithm includes smaller areas than the intraday process, according to internal congestions. The Figure 41 below depicts a simple case with three TSOs using internal zones. A more detailed description can be found in Section 3.2.2.2./II.

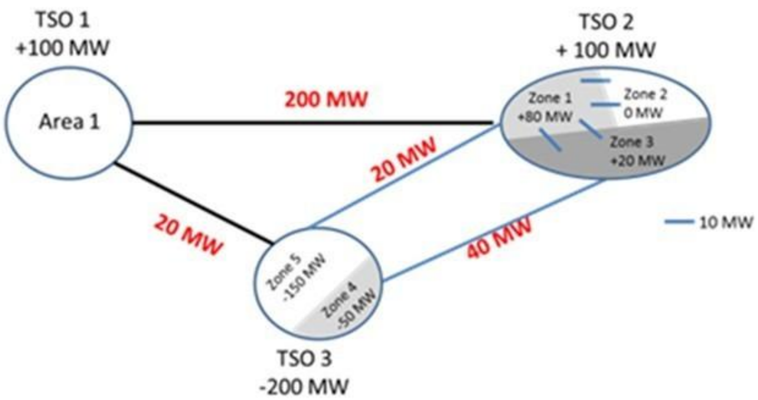

Figure 41: Several Internal mFRR Zones within the Intraday Bidding Zone

The advantage of this option is that the higher resolution grid model will be used to guarantee a more efficient method for dealing with external and/or internal congestion. This measure is more optimized than measures applying before the algorithm (cf. sections 5.3.1.1 and 5.3.1.2) but need to be investigated further in the following aspects: compliancy with GLEB, definition of ATC values, criteria and limitations for the additional (smaller zones) and feasibility in such a small timeframe.

Implications on TSO-TSO settlement methodology (e.g. definition of uncongested area, sharing of congestion rent, etc.) and TSO-BSP settlement need to be investigated.

5.3.2.2 Critical Network Elements

Similar to the flow based approach in day-ahead, this approach is based on critical network elements monitoring and setting limits on the calculated flows on these elements influenced by mFRR balancing energy exchanges. In this case a flow based congestion domain replaces ATCs, where flow based for Intraday and Balancing will be developed.

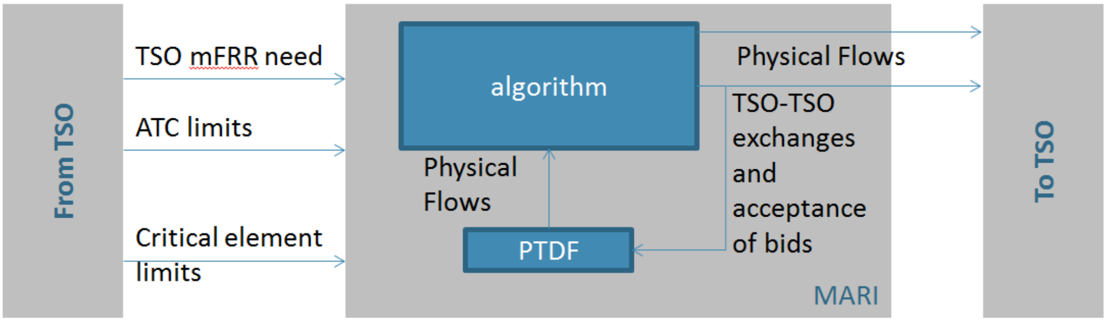

Figure 42: Critical Network Elements

The main principle of this approach is that a TSO has the possibility to monitor of the (approximated) change of the physical flow on predefined critical network elements and when necessary to set limits to the induced physical flows on these predefined critical network element.

Further, during activation, the activation optimization function could consider limits on the induced flows from MARI on these modeled critical network elements. Thus, a critical network element limitation shall be taken into account by the algorithm as an extra-constraint. The incorporation of these constraints and the monitoring would be performed via the usage of one PTDF matrix. The methodology to define the critical elements that would be monitored and the associated PTDF matrix would have to be further discussed..

The advantage of this option is that the higher resolution grid model will be used to guarantee a more efficient method for dealing with external and/or internal congestion

The main difficulty of this option is to define the methodology to define the PTDF matrix including a grid model. Further, compliancy with GLEB, implications on TSO-TSO settlement methodology and TSO-BSP settlement need to be investigated.

5.3.2.3 Several TSOs Form a Cluster[16]

Some TSOs have a need of representing their network model building a cluster together with other TSOs. If bids where to be activated within this cluster, bids from a certain TSO would be given priority over the other TSOs to a certain amount of MWs. The inputs to the algorithm include the control zones involved, the priority TSO and the amount of MW to be activated from this TSO are inputs from respective TSOs to the algorithm. The Figure 43 below illustrates this option and a detailed description can be found in Section 3.2.2.2/II.

[16] This option will be further analysed with particular emphasis on the compliance with GLEB.

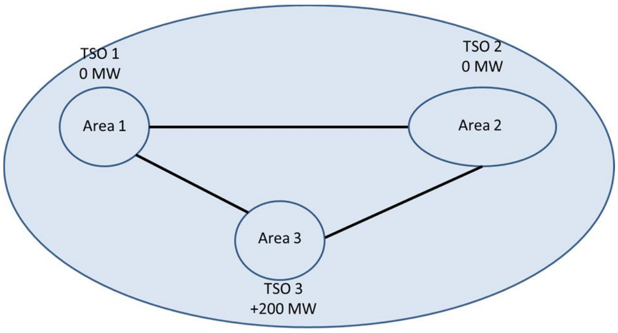

Figure 43: A Simple Example with Three TSOs Building a Cluster

This option could lead to social welfare reductions due to deviation from the merit order list. Additionally, the precedence of bids from a certain TSO over other TSOs could be seen as discriminatory. Further implications for settlement, level playing field and compliance with GLEB will be analysed at a later stage of the project.

5.3.3 Measures after Algorithm

5.3.4 Re-Dispatch

This measure creates an opportunity for the TSO to re-dispatch the resulting flow from the clearing. This measure can be handled by re-dispatch using generation, consumption, topological changes and phase shifting transformers. The TSO who block the activation of one bid selected by the platform shall provide the amount activated power in another way.

The Figure 44 below illustrates the option re-dispatch.

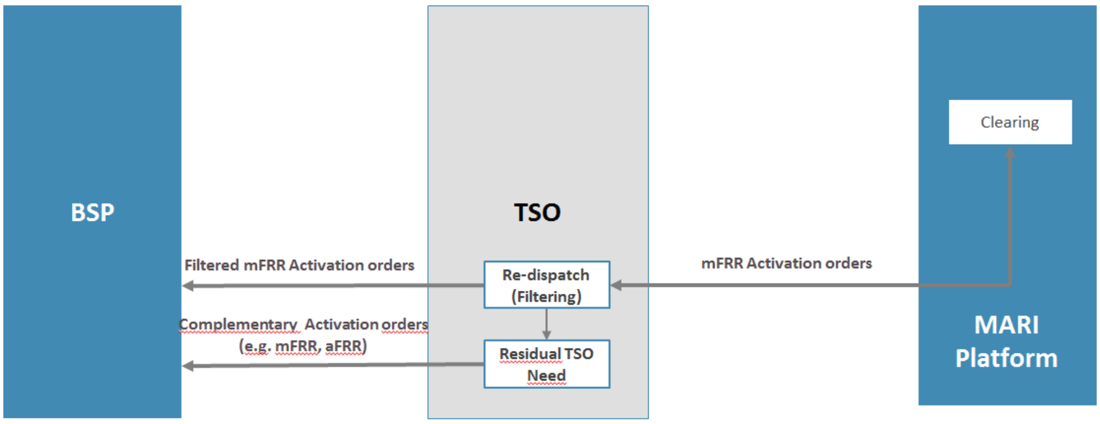

Figure 44: Re-Dispatch

This measure is simple and needs no additional mechanism in the algorithm when the measure is done by each TSO.

This measure might not be compliant with GLEB Art. 29(6): *Each connecting TSO shall ensure the activation of the balancing energy bids selected by the activation optimisation function*. On the other hand, a situation may occur where a TSO needs to perform re-dispatch and cannot guarantee activating the bids selected by the optimisation function.

Moreover, the measure can be seen as economically suboptimal because it might require some bids to be kept locally just as a back-up for bids that may or may not be activated on the platform.

5.4 Questions

Q40. Do you have specific comments regarding the congestion management options presented here?

Q41. Do you think that additional congestion management options are missing? If that is the case, could you please elaborate?

CHAPTER 6 Harmonization

6.1 Introduction

The GLEB aims at fostering an efficient, transparent and non-discriminatory pan European balancing market. To do so, it establishes certain rules and obligations for TSOs, BSPs, BRPs and other market actors.

In order to achieve the objectives, the GLEB requires certain level of cooperation in the mentioned rules so that the implementation of the balancing market provides an equal and fair treatment as well as a level playing field for all the parties involved, especially the BSPs and the BRPs.

Nowadays, the balancing markets (and in particular the mFRR market) are very different from each other, as they are strongly linked to the real operation of the system, which is, at the same time, conditioned by structural aspects such as, for example, the energy mix or the level of interconnections. Thus, all the systems will need to implement changes in order to achieve an integrated balancing market in Europe.

In order to ensure a stable and reliable development, and to comply with the deadlines imposed by the GLEB for the implementation of the European platforms such as MARI, there should be a prioritization among all the rules and aspects of the balancing market. The aim of this chapter is to list the potential aspects of harmonization under the scope of MARI project and to identify which of those would be most important from the stakeholders' point of view.

6.2 Harmonization Requirements in the GLEB

The GLEB establishes several harmonization requirements such as:

- Framework for harmonization of terms and conditions for BSPs;
- Framework for harmonization of terms and conditions for BRPs;
- Implementation frameworks for European platforms for exchange of balancing energy;
- Requirements for the exchange of balancing capacity;
- List of standard products;
- Gate Closure Times for submission of balancing bids;
- Principles for Integrated Scheduling Process (for central dispatch systems);
- Methodologies for activation of balancing energy bids;
- Settlement rules;
- Methodologies for the use of cross-zonal capacities (CZC);
- Transparency requirements etc.

6.3 List of Potential Topics for Harmonization in MARI

Based on all the requirements of the GLEB, the MARI project is working on the identification of the most important design features to be harmonized under the scope of MARI. In order to ease the understanding, the different items have been structured as follows:

Bid Characteristics	
Considered Aspect for Harmonization	Description
► Maximum bid size	The maximum size of a divisible or indivisible bid, which can be offered at one time.
► Price limits	Existence of maximum and/or minimum price for the bid.
► Requirements for Direct Activated products and for Scheduled activated products	Some TSOs perform mFRR process mainly based on scheduled products, while other would require more direct activated products
► Application of the “expected shape” of a trapezoid with 10 min ramps (up / down)	Although the algorithm optimizes the block of energy, the expected shape to be delivered by the BSP should be a trapeze with 10 min ramps up/down
► Definition of the “accepted shape” of the product	The local tolerance bands for bids for the delivered mFRR energy accepted by the national TSOs
Settlement of TSO-BSP	
Considered Aspect for Harmonization	Description
► Application of cross border marginal price to the BSP activated bid (= same as TSO-TSO price);	Settlement to the BSP at the XBMP
► Energy settled (energy corresponding to the block of energy offered by the BSP);	Volume of energy taken into account for the settlement to the BSP (energy corresponding to the activated bid)

▶ Incentives applied to the BSPs:	
▶ "Expected shape":	Incentive to follow the desired shape (through power profile or through energy schedules), and application of a tolerance band;
▶ Existence of penalties	Existence of financial consequences (penalty) in case of under/over delivery of the power profile or the energy schedule
▶ Penalties price principles	Principles/components of the price applied for the penalties.
Settlement TSO-TSO	
Considered Aspect for Harmonization	Description
▶ Application of cross border marginal price to the energy scheduled and exchanged (Block of energy)	Settlement between TSOs at the XBMP for the energy exchanged (scheduled) between them
▶ Energy settled (blocks of energy converted into the "desired shape" trapezes	Volume of energy scheduled and settled between the TSOs as resulting from mFRR algorithm
Other Topics for Harmonization	
Considered Aspect for Harmonization	Description
▶ Prequalification requirements	Technical, contractual, IT and/or regulatory conditions in order to perform the prequalification process
▶ IT requirements	The requirements concerning the IT connection between the BSP and the TSO and between the BSP and the units (Redundancy,...).
▶ Back-up requirements	The requirements concerning back-up units in a pool which shall deliver balancing energy if a unit in the pool has an outage e.g. in some countries at least one back-up unit is required.
▶ Transfer of balancing obligations	Existence and conditions for the transfer of balancing obligations related to mFRR, between BSPs
▶ Independent BSP:	Existence of entity of independent BSP
▶ Scheduling requirements	Balancing energy has to be delivered relative to a reference point which could be a schedule value which is valid for e.g. 15 min. Scheduling requirements can vary concerning the aspect how long in advance a schedule has to be sent and for how long this schedule is valid.
▶ Real time measurement requirements	This aspects describes how many data in which resolution have to be sent to the TSO in real time.
mFRR gate opening time	
▶ mFRR gate opening time (BSPs)	Moment from which the BSPs can start sending mFRR bids to the TSOs
▶ mFRR gate opening time (TSOs)	Moment from which the TSOs can start sending mFRR bids to the mFRR platform
mFRR gate closure time	
▶ mFRR gate closure time (BSPs):	Moment after which reception of bids from BSPs to the TSO are no more accepted
▶ mFRR gate closure time (TSOs)	Moment after which reception of bids from TSOs to the mFRR platform are no more accepted

► Nature of mFRR market:	Nature of the mFRR energy market: obligation to offer into the market or voluntary provision.
mFRR need:	
► Reasons for activating bids for other purposes than balancing	e. g. how to solve a congestion
► Transparency	Transparency requirements from Transparency Regulation and from GLEB (common publications and National publications).

Table 43. Potential Harmonization Topics

6.4 Questions

Q42. Following the list of elements provided in this Chapter, could you indicate your top three harmonization priorities?

Q43. In your opinion, which elements should be harmonized before the MARI project goes live?

Q44. In your opinion, which elements should foster harmonization, but not necessarily before the MARI project goes live?

Q45. Apart from the elements mentioned in this Chapter, do you think other elements should be harmonized? If yes which ones?

ANNEX 1 - Examples of Algorithm Constraints

In this examples we assume the same sign conventions as well as assumptions for the shake of the examples we took in Chapter 3 (i.e. the assumption for the technical price limit for the inelastic demand).

1) Power Balance Constraints

EXAMPLE 1:

In Example 1, there is a demand of +100 MWh. The accepted upward offers are 80 MWh of UO BSP1 and 20 MWh of UO BSP3. Although UO BSP2 is a cheaper offer, it is not activated as it is an indivisible bid (its activation of 21 MWh along with the activation of 80 MWh of UO BSP1 exceeds the demand of TSO1 of 100 MW).

TYPE	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers
Demand (TSO 1)	+100	--	Inelastic	--
Upward Offer (UO BSP1)	80	10	--	Indivisible
Upward Offer (UO BSP2)	21	20	--	Indivisible
Upward Offer (UO BSP3)	30	30	--	Divisible

Table 44: Inputs for Example 1 - Maximization of Social Welfare & Netting

Type	Activated Quantity/Satisfied Demand (MW)
Demand (TSO 1)	+100
Upward Offer (UO BSP1)	80
Upward Offer (UO BSP2)	0
Upward Offer (UO BSP3)	20
Social Welfare (€)	**Marginal Price (€/MWh)**
100·10000 - 80·10 - 20·30 - 100·30 + 80·30 + 20·30 = 998'600	30

Table 45: Output for Example 1

EXAMPLE 2, 3, 4,:

Examples 2, 3, and 4, below, focus on netting of TSO demands (principle I.C):

EXAMPLE 2	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers
Demand (TSO 1)	+100	+10000	Inelastic	--
Demand (TSO 2)	-100	-10000	Inelastic	--
Upward Offer (UO BSP1)	100	10	--	Divisible
EXAMPLE 3	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers
Demand (TSO 1)	+100	+10000	Inelastic	--
Demand (TSO 2)	-100	1	Elastic	--
Upward Offer (UO BSP1)	100	10	--	Divisible
EXAMPLE 4	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers
Demand (TSO 1)	+100	--	Inelastic	--
Demand (TSO 2)	-100	10	Elastic	--
Upward Offer (UO BSP1)	100	2	--	Divisible

Table 46: Inputs for Example 2, 3, 4 - Maximization of Social Welfare & Netting

	Activated Quantity/Satisfied Demand (MWh)		
Type	Example 2	Example 3	Example 4
Positive demand (TSO 1)	+100	+100	+100
Negative demand (TSO 2)	-100	-100	0
Upward Offer (UO BSP1)	0	0	100
Marginal Price (€/MWh)	0	1	2[17]
Social Welfare (€)	Indefinite[18]	100·10000 - 1·10000 +1·10000 - 1·10000 = 990'000	Cannot be calculated due to missing information (see footnote 17)

Table 47: Output for Example 2, 3, 4

In example 2, the demands of TSO 1 and TSO 2 are netted without the activation of other bids. The social welfare isindefinite, and the marginal price is also zero.

In example 3, the demands of TSO 1 and TSO 2 are netted without the activation of other bids, as TSO 2 is willing to receive a bid with a price of 1 €/MWh which is smaller than 10 €/MWh of UO BSP1. In other words, the social welfare (990 000€ by considering netting the demands

[17] Here we note that although not explanied, in this example the implicit assumption is that also a downward offer is activated to balance TSO 2

[18] If assumed the technical limit on the inelastic demand: 100·10000 + 100·10000 = 2'000'000

In example 4, the demands of TSO 1 and TSO 2 are not netted, as TSO 2 is willing to receive a price of 10 €/MWh which is higher than 2 €/MWh of UO BSP1. The social welfare in order to be determined would need to know the price of DO in order to satisfy the TSO 1 demand.*Power Flow Constraints*

EXAMPLE 5, 6

Through examples 5 and 6, described below, we illustrate the outcome of the algorithm for the case with only ATC values and the case with internal zones involved.

Figure 45 shows a scheme for a simple system where three areas representing by three TSOs are linked together through ATC values in red.[19] Considering offers and demands in Table 48, the outcomes are provided in Table 49.

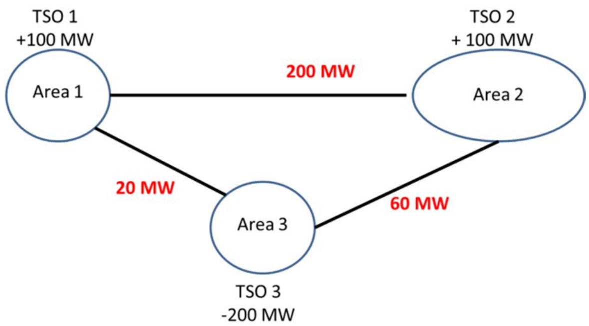

Figure 45: A Simple Example with Three TSOs Involved with ATC. Values in Red are ATC Limits.

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[19] We should note that all four German TSOs can represent one area of Germany with the corresponding ATC values with neighboring countries.

Type	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers	Area
Positive demand (TSO 1)	+100	+10000	Inelastic	--	Area 1
Positive demand (TSO 2)	+100	+10000	Inelastic	--	Area 2
Negative demand (TSO 3)	-200	-10000	Inelastic	--	Area 3
Upward Offer (UO BSP1)	100	10	--	Divisible	Area 1
Upward Offer (UO BSP2)	30	20	--	Divisible	Area 2
Downward Offer (UO BSP2)	-50	-20	--	Divisible	Area 2
Downward Offer (DO BSP3)	-200	-50	--	Divisible	Area 3

Table 48: Inputs for Example 5 – Respecting Power Flow Constraint in term of ATC

As shown in Figure 45, TSO 3 can have in total 80 MW exchange with TSO 1 and TSO 2.

To obtain the maximum social welfare (i.e., minimum balancing cost) while respecting the power balance constraint (total supply equals to total demands.) and power flow constraints, the optimal outcome includes the activation of upward offers UO BSP1 (full 100 MW) and UO BSP2 (20 MW of 30 MW), as well as downward offer DO BSP3 (-120 MW of -200MW).. These activated amounts along with 80 MW netted amount ensure the power balance equations while respecting ATC limits.

Due to ATC limits, a power exchange larger than 80 MW is not possible between area 3 and the rest of the system. This leads to two marginal prices: one in areas 1 and 2 (20 €/MWh) and the other one in area 3 (50 €/MWh).

Type	Activated Quantity/Satisfied Demand (MWh)	
Positive demand (TSO 1)	+100	
Positive demand (TSO 2)	+100	
Negative demand (TSO 3)	-200	
Upward Offer (UO BSP1)	100	
Upward Offer (UO BSP2)	20	
Downward Offer (UO BSP2)	0	
Downward Offer (DO BSP3)	-120	
Social Welfare (€)	**XB Marginal Price (€/MWh)**	
+100*10'000 +100*10'000 +200*10'000 -(10*100+20*20)+(-120*50) =3'992'600(	Area 1 & 2: 20 €/MWh	Area 3: 50 €/MWh

Table 49: Output for Example 5

As shown in Figure 46, example 6 illustrates a simple case where TSO 1 expresses its power flow limits through ATC whereas TSO 2 and TSO 3 express their power flow limits through a number of zones. If there is a cross- zonalcapacity between different zones illustrated with a blue line, the corresponding cross- zonal capacity limit is assumed to be 10 MW in this example. We should note that since there is no line between zone 4 and zone 5, there is no possibility of exchange between these two zones in this example.

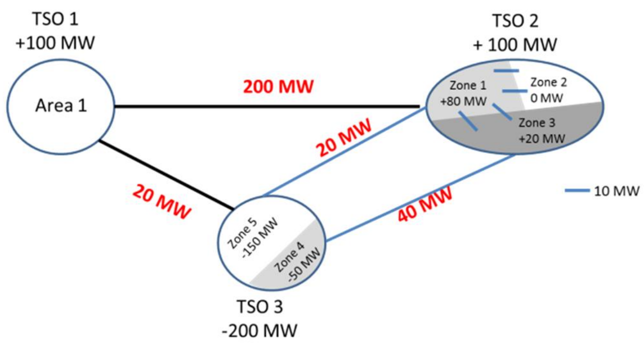

Figure 46: A Simple Example with Three TSOs Involved with ATC Values and Zones.

The inputs for Example 6 are provided in Table 50.

Type	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers	Area
Positive demand (TSO 1)	+100	+10000	Inelastic	--	Area 1
Positive demand (TSO 2)	+80	+10000	Inelastic	--	Zone 1
Positive demand (TSO 2)	+20	+10000	Inelastic	--	Zone 3
Negative demand (TSO 3)	-50	-10000	Inelastic	--	Zone 4
Negative demand (TSO 3)	-150	-10000	Inelastic	--	Zone 5
Upward Offer 1 (UO1 BSP1)	100	10	--	Divisible	Area 1
Upward Offer 2 (UO2 BSP2)	10	15	--	Divisible	Zone 1
Upward Offer 3 (UO3 BSP2)	50	20	--	Divisible	Zone 2
Upward Offer 4 (UO4 BSP2)	20	50	--	Divisible	Zone 3
Downward Offer 5 (DO5 BSP3)	-50	-40	--	Divisible	Zone 4
Downward Offer 6 (DO6 BSP3)	-150	-50	--	Divisible	Zone 5

Table 50: Inputs for Example 6, Respecting Power Flow Constraint in Term of ATC and Zones

<table>
<tr><th>Type</th><th colspan="6">Activated Quantity/Satisfied Demand (MWh)</th></tr>
<tr><td>Positive demand (TSO 1)</td><td colspan="6">+100</td></tr>
<tr><td>Positive demand (TSO 2)</td><td colspan="6">+80</td></tr>
<tr><td>Positive demand (TSO 2)</td><td colspan="6">+20</td></tr>
<tr><td>Negative demand (TSO 3)</td><td colspan="6">-50</td></tr>
<tr><td>Negative demand (TSO 3)</td><td colspan="6">-150</td></tr>
<tr><td>Upward Offer 1 (UO1 BSP1)</td><td colspan="6">100</td></tr>
<tr><td>Upward Offer 2 (UO2 BSP2)</td><td colspan="6">10</td></tr>
<tr><td>Upward Offer 3 (UO3 BSP2)</td><td colspan="6">10</td></tr>
<tr><td>Upward Offer 4 (UO4 BSP2)</td><td colspan="6">0</td></tr>
<tr><td>Downward Offer 5 (DO5 BSP3)</td><td colspan="6">-10</td></tr>
<tr><td>Downward Offer 6 (DO6 BSP3)</td><td colspan="6">-110</td></tr>
<tr><th>Social Welfare (€)</th><th colspan="6">XB Marginal Price (€/MWh)</th></tr>
<tr><td rowspan="2">(100+80+20+50+150)*10000-
(100*10+10*15+10*20+10*40+110*50)
= 4’000’000 – 7250 = 3’995’750</td><td>Area 1</td><td>Zone 1</td><td>Zone 2</td><td>Zone 3</td><td>Zone 4</td><td>Zone 5</td></tr>
<tr><td>20</td><td>20</td><td>20</td><td>0</td><td>40</td><td>50</td></tr>
</table>

Table 51: Output for Example 6.

The following demands are simultaneously netted and compensated by acceptance of offers in the algorithm:

- Area 1: +100-20 = +80 (netting of demands TSO 1 and TSO 3 Zone 5 with limit of 20 MWh)

Activation of UO1

- Zone 1:

+80-20 = +60 (netting of demands TSO 2 zone 1 and TSO 3 Zone 5 with limit of 20 MWh)

+60-20 = +40 (netting of demands TSO 3 Zone 4 through Zone 3 to Zone 1 = 20 MWh)

Activation of UO1 & UO2 & UO3

Therefore, Area 1 and Zones 1 and 2 have the same marginal price driven by activation of UO3 (no congestion appears between these areas).

- Zone 3: +20-20 = 0 (netting of demands TSO 2 zone 3 and TSO 3 zone 4)

No Activation of offers à marginal price of zero

- Zone 4: -50+40 = -10 (netting of demands TSO 2 zone 3, TSO 2 zone 1 and TSO 3 zone 4)

Activation of DO5 à marginal price of 40 €/MWh

- Zone 5: -150+20+20 = -110 (netting of demands TSO 1, TSO 2 zone 1 and TSO 3 Zone 5 with a total limit of 40 MWh)

Activation of DO6 à marginal price of 50 €/MWh

EXAMPLE 7 – TSO building a Cluster

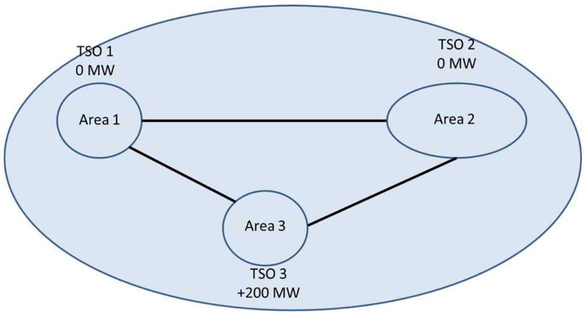

Figure 47: A Simple Example with Three TSOs Building a Cluster

The inputs for example 7 are provided in Table 52.

Type	Quantity (MWh)	TSO Demand Price/Offer Price (€/MWh)	Elasticity of Demand	Divisibility of Offers	Area	Priority volume
Demand (TSO 1)	0	--	Inelastic	--	Area 1	0
Demand (TSO 2)	0	--	Inelastic	--	Area 2	+120
Positive demand (TSO 3)	+200	--	Inelastic	--	Zone 3	0
Upward Offer 1 (UO1 BSP1)	+100	10	--	Divisible	Area 1	
Upward Offer 2 (UO2 BSP2)	+120	15	--	Divisible	Area 2	

Table 52: Inputs for Example 7 – TSOs Build a Cluster

Type	Activated Quantity/Satisfied Demand (MWh)
Demand (TSO 1)	+0
Demand (TSO 2)	+0
Demand (TSO 3)	+200
Upward Offer 2 (UO2 BSP2)	+120
Upward Offer 1 (UO1 BSP1)	+80
Social welfare (€)	**XB Marginal Price (€/MWh)**
200*10000-(120*15+80*10) = 2000000 – 2600 = 1’997’400	Same Marginal price for the Cluster = 15

Table 53: Output for Example 7

2) HVBC Constraints Example:

EXAMPLE 8:

In the following example, the losses on the HVDC link are characterized by a percentage (4 %) of the circulating flow inside the interconnector. This percentage entirely determines the line's losses, and should be applied in both directions, whether A or B is the exporting area. Thus, when A wants to export 1000 MWh, only 960 MWh actually reaches market area B.

Figure 48: Example of Power Flow Losses on an HVDC Link

To take into account these physical losses, the algorithm should provide two specific features: some specific power flow constraints, and a specific output price computation. These two features can be directly inspired from what has been done in the Euphemia algorithm for DA market coupling. They should of course be completed with an appropriate settlement process regarding the congestion rent management, as again in the current example of the Euphemia algorithm.

EXAMPLE 9:

- Power flow results from the algorithm in ISP1 = 600 MWh
- Max ramp (input to the algorithm) = 300 MW (ramp speed 30 MW/minute and 10 minute ramping time)
- Therefore, to respect the flow in this HVDC line in ISP2, the limit is calculated using a given input of a max ramp of 300 MW and considering the flow of this line from the previous clearing interval. That is, the power flow must be within limits from 600-300 = 300 MW to 600+300=900 MWh

EXAMPLE 10:

- Input data for TSO:
- CZC =±500 MWh
- Already allocated flow in previous clearing Area A -> Area B = 100 MWh
- Technical minimum power = ± 50 MWh
- Input data for AOF:
- CZCB Area A -> Area B 400 MW (500 MWh - 100 MWh)
- CZCB Area B -> Area A 600 MW (500 MWh + 100 MWh)
- Not allowed balancing power exchange flow from Area B to Area A at an interval of [100-50 100+50] MWh= [50 150] MWh.

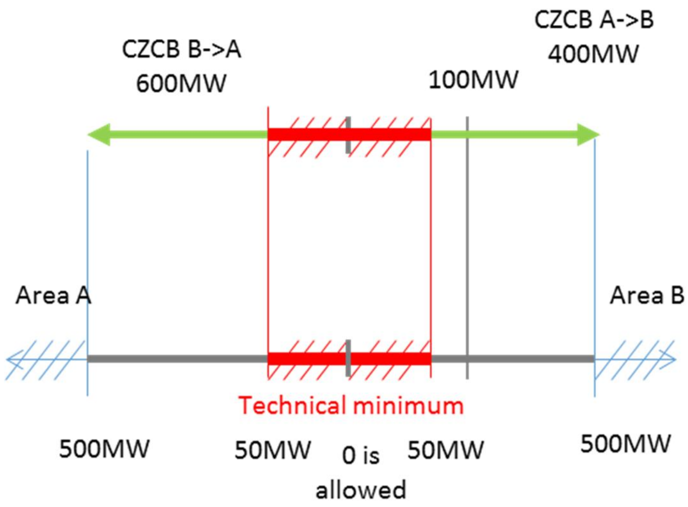

Figure 49: HVDC Dynamics Constraints

ANNEX 2 – List of Tables

ANNEX 3 – List of Figures

ANNEX 4 - List of Abbreviations

AC	Alternating Current
ACE	Area Control Error
aFRR	Automatic Frequency Restoration
AOF	Activation Optimization Function
ATC	Available Transmission Capacities
BEGCT	Balancing Energy Gate Closure Time
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CACM	Guideline on Capacity Allocation and Congestion Management
CB	Control Block
CCRs	Capacity Calculation Regions
CID	Congestion Income Distribution
CM	Congestion Management
CMOL	Common Merit Order List
CZC	Cross-Zonal Capacity
DA	Direct Activation, directly activated, directly activatable
DO	Downward Offer
EBGL	Electricity Balancing Guideline
EC	European Commission
EPDA	Earliest Point of Direct Activation
FAT	Full Activation Time
FB	Flow-based
FCR	Frequency Containment Reserves
FRCE	Frequency Restoration Control Error
FRP	Frequency Restoration Process
GCT	Gate Closure Time
GLSO	Guideline on Electricity Tranmission System Operation
GLEB	Guideline on Electricity Balancing
HVDC	High Voltage Direct Current
ID	Intraday (Market)

IGCC	International Grid Control Cooperation
ISP	Imbalance Settlement Period
LB	Lower Boundary
LFC	Load Frequency Control(ler)
LPDA	Latest Point of Direct Activation
MARI	Manually Activated Reserves Initiative
MC	Market Coupling
MCP	Market Clearing Price
MEAS	Mutual Emergency Assistance Service
mFRR	Manual Frequency Restoration Reserves
MOL	Merit Order List
MoU	Memorandum of Understanding
MP	Marginal Price
NRA	National Regulatory Authority
NTC	Net Transmission Capacity
PTDF	Power Transfer Distribution Factor
QH	Quarter Hour
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RR	Replacement Reserves
SA	Scheduled Activation, scheduled activated, scheduled activatable
SCADA	Supervisory Control and Data Acquisition
SOC	Systém Operation Committee
TERRE	Trans-European Replacement Reserves Exchange
TSO	Transmission System Operator
TTRF	Time to restore Frequency
UAB	Unforseeably Accepted Bids
UB	Upper Boundary
UO	Upward Offer
WG AS	Working Group Ancillary Services under ENTSO-E
XB	Cross-Border
XBMP	Cross-Border marginal pricing