NEW ENERGY FOR INDUSTRY

Industry4Redispatch (I4RD)

Deliverable 3.3

Definition of processes for the provision of redispatch

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GLOSSARY

System Operator

An entity operating an electric power system.

Transmission System Operator (TSO)

An entity operating an electric power system, that is mainly designed for the transmission of electric power between control areas and between distribution systems. Article 2 of Directive (EU) 2019/944 [1] includes a legal definition of a transmission system operator

Distribution System Operator (DSO)

An entity operating an electric power system, that is mainly designed for distribution of power from the transmission system to customers and electricity. Article 2 of Directive (EU) 2019/944 [1] includes a legal definition of a distribution system operator.

Redispatch

"'redispatching' means a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security;" Art. 2 Regulation (EU) 2019/943 [2]

Fequency Containment Reserves (FCR)

"'frequency containment reserves' or 'FCR' means the active power reserves available to contain system frequency after the occurrence of an imbalance" [3]

Automatic/Manual Frequency Restoration Reserves (aFRR/mFRR)

"'frequency restoration reserves' or 'FRR' means the active power reserves available to restore system frequency to the nominal frequency and, for a synchronous area consisting of more than one Load-Frequency Control area (LFC area), to restore power balance to the scheduled value" [3]

Prequalification

A prequalification process is a process designed to prove the ability of a service provider to provide a service in accordance with the technical requirements of a certain product or service. This includes an evaluation of the effects of this service at the connecting point to the transmission/distribution system. A successful prequalification is a prerequisite for the participation in a certain market.

Market Time Unit (MTU)

The specific timeframe that specifies the beginning and end of the energy delivery of a product.

Delivery Day (D)

The day for which the energy delivery of a bid is specified.

Day Ahead (DA/D-1)

Day Ahead describes the calendar day before the delivery day(D).

Two Days Ahead (D-2)

Two days ahead describes the calendar day two days before delivery day(D).

Asset

An asset describes any self-contained and clearly identifiable machine or device capable of generating or consuming electricity, independent of it's nominal power generation/consumption. It is required that the consumption or generation of an asset could theoretically be measured. Assets providing services to the TSO/DSO can range from the generators of power plants to distributed heat-pumps.

Smaller Assets

Within this text the term "smaller assets" may be used to describe assets that are rated below the typical nominal power consumption or generation capabilities of conventional power plants. This term is used when referring to assets at rated powers below approx. 25 MW or connected at voltage levels below 110kV.

Flexibility Service Provider (FSP)

The flexibility service provider is capable and legally allowed to change the generation or consumption of an asset according to the technical requirements of a service such as redispatch and offers such services to system operators.

Redispatch Platform

The Redispatch Platform is a platform used to exchange redispatch bids between flexibility service providers and transmission/distribution system operators. It also receives network capacities by the TSO/DSOs in order to prevent the activation of bids which are incompatible with secure system operation. Via the platform bids are activated by TSO and DSOs. The detailed configuration of the Redispatch Platform will be defined in WP5 and WP9.

Point of Common Coupling (PCC)

"Point of common coupling or "PCC" means the point where the generating facility's local electric power system connects to the utility's electric system, such as the electric power revenue meter or at the location of the equipment designated to interrupt, separate or disconnect the connection between the generating facility and the utility." [4]

Gate Opening Time (GOT)

The first point in time when flexibility service providers may submit bids for a service.

Gate Closing Time (GCT)

The last point in time when flexibility service providers may submit bids for a service.

Use Case 4a (UC4a)

The Use Case 4a is defined in the Deliverable 3.1 and encompasses the provision of redispatch by industry.

FAT

The full activation time (FAT) can be divided into preparation period (during which energy is delivered) and a ramping period. The requirements for the preparation period vary across Europe as it depends on the mode of activation in use and the local generation structure. The maximum allowed duration for the full activation or deactivation of a standard energy bid after the activation request is called full activation time (entsoe, 2018). FAT plays mainly a role in the balancing energy market.

SoMa/ Electricity Market Code

SoMa is the abbreviation of the “Sonstige Marktregeln” [5] (Engl. other market rules also known as Electricity Market Code) which are defend by the Austrian regulatory authority, E-Control, in accordance with Article 22 E-ControlG [6].

CACM

CACM is the abbreviation for the Commission Regulation (EU) 2015/1222 on capacity allocation and congestion management [7].

SOGL

SO GL is the abbreviation for the Commission Regulation (EU) 2017/1485 on transmission system operation [3].

EU-VO 2019/943

Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity [2].

Schedule

“‘schedule’ means a reference set of values representing the generation, consumption or exchange of electricity for a given time period;” Art. 2 SO Gl [3]

Generation/Load Shift Key (GSK)

Generation Shift Key means a set of nodes and multiplication factors that is used to describe the nodal distribution of power generation or consumption.

TSC = Transmission System Operator Security Cooperation

TSC is an association of currently 14 (TSCNET Services, n.d.) *“European transmission system operators. Its stated goal is to further increase the security of electricity transmission networks in Central Europe and thus secure the supply of electricity for 170 million Europeans over the long term. TSC enables the TSOs to coordinate their work more closely among each other.”* (APG, n.d.-a)

1 Preamble

These requirements for redispatch were created as a draft within the project Industry4Redispatch and are not final requirements for the participation in an existing or future redispatch process. Any future implementation of redispatch by APG and/or DSOs in Austria depends on the current and future legal framework, guidance by the NRA and details in technical implementation. Hence neither APG nor the contributing DSOs are bound by this document or liable for the validity of this document and any implementations of it.

2 Introduction and Methodology

Congestion management in transmission and distribution grids is achieved by different means such as capacity limitations between bidding zones, changes in grid topology and switching states and redispatch. Redispatch is defined as the purposeful change in the schedule of the active power infeed or consumption of a flexible generation or consumption unit. To relieve the congestion on a grid element with high loading active power infeed is increased on the downstream side of the congestion and active power infeed is decreased on the upstream side of the congestion. Achieving this change in power infeed or demand requires the flexibility of assets to change their intended infeed and consumption.

Redispatching assets requires that certain boundary conditions of the affected assets and the TSO/DSOs are considered. On the side of flexibility provision, quite some of the various generation and consumption units in the electrical power grid have the capability to deviate, to some extent, from their planned schedules, but they possess different technical characteristics such as lead times, lag times or minimum up-/downtimes. On the side of flexibility demand, it is necessary that the grid operator who requests flexibility services, not only changes the schedule of one asset but also finds a balanced set of changes for the schedule of different assets such that all grid congestions are relieved. Simultaneously all the technical constraints of the different assets have to be considered and the balance between generation and consumption must be maintained.

Redispatch in the APG control area ranges from smaller requests of about 50 MW to requests of up to 4000 MW. Current redispatch procedures require specific knowledge about unit parameters in order to observe each units' technical constraints when planning redispatch measures. While installed capacity of conventional power plants varies considerably, a lot of them exceed installed capacities of 300 MW. Therefore, current procedures require that the TSO has knowledge about the characteristics of all participating units. However, if single units providing redispatch become smaller, characteristics of hundreds, if not thousands, of units need to be considered. This poses a challenge not only for the data exchange between the TSO/DSO and single units but also for the interaction with aggregated assets such as a Virtual Power Plants (VPP). This raises the questions of how to design these interactions, and which engagement strategies are suitable to attract participation by these smaller units.

In order to limit the complexity in redispatch planning and to provide a clear picture of requirements for assets providing redispatch a standardisation, similar to the existing markets for other ancillary services is proposed. This means that data provision on redispatch potentials or bids is standardised to such an extent, that technical constraints are already considered in the provided redispatch bids by the flexibility service provider and not by the TSO/DSO. The deliverable at hand aims at defining the basic principles for the provision of redispatch services for TSOs/DSOs by smaller generation/consumption units. In the context of the project structure, it is the result of Task 3.2 - defining the redispatch requirements, Task 3.3 - engagement strategies for industry and Task 3.5 - examining the VPP context. This is also reflected in the structure of this deliverable.

Chapter 3 summarizes the results of Task 3.2. The goal was to describe a minimal set of parameters that considers the needs of TSO, DSOs, aggregators and industrial units alike. The initial set of parameters was provided by APG and based on the technical characteristics of current redispatch procedures and conventional generation units. The list was expanded in expert group sessions with participation by EN, NOÖ, NNÖ, NB, SIE, AIT and APG. Where necessary, literature research was conducted on the effect of parameters and their ideal value. Suggestions were then presented and decided on in expert group sessions.

Chapter 4 continues the work of Chapter 3 and examines the previously defined requirements from a VPP perspective. i.e., the control of smaller decentralized assets as well as their possibilities and limitations.

3 Requirements for Redispatch provision

Using industry assets for redispatch differs from the use of conventional power plants since the scheduling of assets is not only constrained by the technical parameters of generation or consumption units but also their business process. As the redispatch providing assets become smaller, more assets are needed to achieve the same change in power required to relieve grid congestions. While it is possible to model the constraints of a small set of large-scale generation and consumption units and their location in the power grid, this task becomes increasingly difficult as unit sizes become smaller and the number of constraints increases. In order to facilitate an effective use of such flexibility potentials a standardized definition of redispatch requirements is therefore proposed and suggest that the consideration of unit constraints is considered by the providers of redispatch when submitting their redispatch potential as bid to a common platform.

The following criteria describe which technical parameters need to be fulfilled, which information needs to be included in a flexibility offer as well as the range of possible values they may take, so that the flexibility can be used for redispatch. The criteria described are mandatory requirements to participate in the provision of redispatch. The different criteria were grouped into three categories, technical criteria, data exchange and organizational criteria/contractual obligations.

Technical criteria comprise all the technical information on the potential and constraints of changing a power generation/consumption schedule. This ranges from bid size to the consideration of catch-up effects and monitoring of redispatch provision. **Data exchange** covers an overview of data to be exchanged between the flexibility service provider and the common Redispatch Platform. The last category, **organizational criteria**, deals with the contractual obligations between the providers and the requesters of redispatch.

In addition to our list of requirements TSOs/DSOs and the providers of redispatch need to abide by the requirements set forth by the legal framework for redispatch such as but not limited to the SOGL and EU Regulation 2019/943.

3.1 Technical criteria

3.1.1 Redispatch bid and presuppositions

This section defines the basic presuppositions to be able to participate in redispatch and introduces a general description of a redispatch bid, expanding on the example use case UC4a described in the Deliverable D 3.1. In general, flexible units plan their day-ahead operation regardless of any redispatch provision and bids may be submitted once redispatch potential can be calculated by the flexible units. An indicative description of a simple use-case is shown in Figure 1.

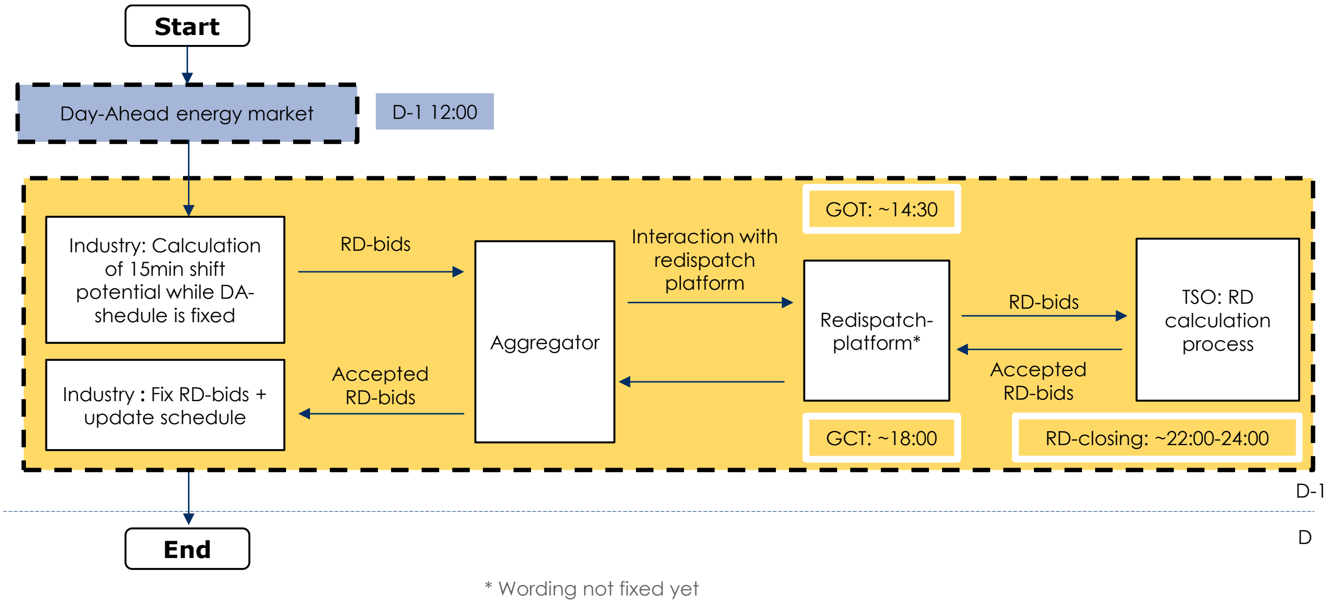

Figure 1: Flow-chart UC4a

3.1.1.1 Eligibility

Similar to balancing markets such as FCR, aFRR and mFRR it is necessary for the flexiblility service providers to complete a prequalification process to be eligible to participate in redispatch provision. The prequalification occurs during the registration on the common Redispatch Platform. During the prequalification the flexibility provider agrees that master data shared with the connecting TSO/DSO is also shared with and used by the common Redispatch Platform.

In general, eligible bidders of flexibility for redispatch are any market participants which are responsible for the scheduling and operation of a single unit able to offer the minimum bid size or able to aggregate assets above the minimum asset size in order to reach the minimum bid size, pursuant to chapter 3.1.2.

3.1.1.2 Scheduling information

System operators perform daily as well as hourly grid security analysis to keep the system within safe operational limits. These calculations require forecasts for renewable energy generation and schedules of assets connecting to the power grid. This is the bases for any redispatch planning. In order to allow grid operators to perform these calculations and to be able to evaluate the effects of flexibility use on congestions in the power grid, providers of redispatch need to provide information on their intended active power generation / consumption schedule before redispatch.

By participating on the Redispatch Platform providers of redispatch agree that their technical unit is necessary for considerations regarding grid security and is thus required to provide schedule information pursuant to SoMa 3 [8] and SOGI Datenaustausch-V [9]. The exchange of scheduling data is an independent daily process that takes place regardless of whether redispatch is offered/required on a specific day or not.

In addition to the provision of production schedules SoMa 3 [8]also includes the provision of availability schedules. Such schedules indicate the required lead time and theoretically available flexibility potentials. Thus allowing the TSO to distinguish unavailabilities, e.g. due to maintenance, from potentials not offered on the Redispatch Platform due to economic considerations of the flexibility service provider.

3.1.1.3 Submission of bids

As per definition in use-cases UC4a – UC6b defined in deliverable 3.1, providers of flexibility for redispatch (and other flexibility services) provide the information on their ability to change their schedule in the form of bids on a common Redispatch Platform.

3.1.1.4 Bid content

Object of a standard redispatch bid is the change in power generation / consumption offered for a quarter-hour as well as the corresponding pricing information pursuant to chapter 3.1.6 and the energy associated with the change in generation/consumption. To account for the different constraints due to unit characteristics and the nature of grid congestions a more complex connection between bids can be desirable and is described in section 3.1.5.

When a bid is accepted by a requester of redispatch, the energy transfer between the bidder and the requester is agreed. The resulting change is to be scheduled between the balancing group of the flexibility provider and the requester of redispatch. Thus, the provision of redispatch does not create an imbalance energy and the flexibility provider does not have to procure the balancing energy. If the provider of redispatch however fails to provide the agreed redispatch, it leads to imbalance energy. Any anticipatory- or catch-up effects in power generation/consumption required to achieve the offered redispatch bid are not part of the bid, I.e., this energy is not purchased by the requester of redispatch, but these effects need to respect the limitations pursuant to section 3.1.7.2 of these redispatch criteria. Table 1 gives an example of the direction of energy.

Positive Redispatch (+1 MW)	Generation units:	Increase in power generation by 1 MW
	Consumption/Demand:	Decrease in power consumption by 1 MW
Negative Redispatch (-1 MW)	Generation units:	Decrease in power generation by 1 MW
	Consumption/Demand	Increase in power consumption by 1 MW

Table 1: Possible redispatch bid directions

Example:

A redispatch bid of 1 MW for 15 min is submitted by the bidder. If the redispatch bid is accepted by the requester, e.g. APG, the requester purchases said energy. The flexibility providers informs its balance responsible party and a "Bilanzgruppen Fahrplan" from the flexibility service provider to the EPM balancing group is initiated.

3.1.1.5 Bid firmness

Only such redispatch bids may be submitted that can be activated at the grid connection point and all offered redispatch bids must be feasible for the asset(s). Redispatch bids are provided by the bidder after gate opening for redispatch on the Redispatch Platform. A cancellation of bids is only possible until a redispatch calculation processes at either TSO or DSO has started. After the time for the submission of bids is over (gate-closure), the redispatch calculations start. Any bids submitted are considered firm and locked until redispatch calculations are over and bids are either accepted or rejected. Flexibility providers will receive an information on whether their bids are selected for redispatch after the calculations have finished. Bids cannot be withdrawn during this time and accepted redispatch bids must be provided in full (compare chapter 3.1.8). Thus, before submitting a redispatch bid, the bidder must consider the actual deliverable redispatch capacity dependent on any influencing variables such as the forecasted ambient temperature and other constraints (e.g. lead time, time for a new activation, limited storage capacity). The concept of Gate-Opening and Gate-Closing works well for a limited number of discrete calculation processes, such as the description of use case UC4a in deliverable 3.1 as a starting point for day-ahead redispatch. As the number of processes which make use of redispatch bids increases and redispatch bids are also activated in the intraday timeframe, ensuring bid firmness and tracking bid participation for each individual step becomes increasingly difficult. Therefore, bids may include a bid validity period for which the bid may be considered as firm, as detailed within the timings of different events in chapter 3.1.4. Bids past their expiration date are not considered in redispatch calculations and must be resubmitted with a different validity period to be again considered in calculations.

3.1.2 Bid size and asset size

The redispatch bids must be combined into a meaningful set to achieve a solution to grid congestions. This means that the volume of upwards redispatch and downwards redispatch procured by the requester of redispatch is balanced (upwards redispatch == downwards redispatch) and sufficient. Yet only the amount necessary to resolve congestions should be procured in order to avoid unnecessary costs. This requires that the redispatch bids have standardised sizes. This allows the requester of redispatch to combine different bids to achieve the desired effect. The size of bids must be large enough to have a significant influence on the power flow over congested elements in the distribution and transmission grid. At the same time, bids must not be too large or else the minimum amount of redispatch which can be procured could be excessive compared to the congestion, or even become entirely infeasible due to other grid constraints.

3.1.2.1 Minimum bid size

The minimum size of a redispatch bid that can be submitted on the Redispatch Platform needs to be defined. The minimum bid size has to be reached either by a single flexibility providing asset or by several assets that are aggregated in a pool.

On the one hand, the minimum bid size should be small enough to enable individual assets and aggregated pools to participate in the provision of redispatch and allow all potential redispatch providers non-discriminatory market access. On the other hand, the aggregation of redispatch capacity should reach a size that is effective to solve grid congestions. This necessity arises from the large-scale of power systems and the vastly different sizes of assets involved and from the computational requirements by the requester of redispatch. Without a defined minimum bid size, redispatch bids could be arbitrarily small and an infinite number of redispatch bids would have to be activated/selected to solve a grid congestion. Depending on the specific problem, selecting the correct bids to solve a congestion is a combinatorial problem with 2^n complexity. From this perspective, a smaller number of large bids is preferable to a larger number of small bids and a minimum limit to account for the technical feasibility of automated processing should be considered.

The minimum bid size should meet the needs of the TSO as well as of the DSOs. As the rated voltage and transmission capacity decrease at the distribution level, DSOs may need smaller bids to solve their grid congestions than the TSO.

A minimum bid size of 1 MW is suggested for bids that solve grid congestions. These minimum bid sizes account for the reasons above but should be reviewed by the TSO/DSOs after an implementation.

3.1.2.2 Minimum bid increment

The minimum bid increment describes the steps in which the offered volume of a redispatch bid can be increased. A defined step size of possible increments is necessary to ensure that the sum of selected bids by the redispatch requester can add up to 0 without resorting to an additional slack (e.g. 1 MW upwards redispatch + 1 MW downwards redispatch = 0). While the minimum bid size is set at 1 MW, we propose to define the minimum bid increment at 0,5

MW. As long as an effect in the transmission grid is secured by the minimum bid size, a smaller increment might enable the participation of more assets.

3.1.2.3 Maximum bid size

The definition of a maximum bid size is necessary in order to avoid redispatch bids much larger than the minimum redispatch needed to solve the congestion and to avoid possible market distortion by flexibility providers. A maximum bid size at 400 MW is thus proposed. This size was chosen, based on a typical size of conventional assets in Austria and would allow even large-scale assets to provide flexibility via the Redispatch Platform.

3.1.2.4 Minimum size of single asset

When talking about the size of an asset, this text refers to the installed capacity of grid connection of a single facility at the grid connection point.

In order to allow also small-scale assets non-discriminatory market access, they can be aggregated in a pool and operated by an aggregator to bid on the Redispatch Platform in order to reach the minimum bid size. In an ideal environment even smaller assets at household level should be able to participate if they can reach the minimum bid size via aggregation. Currently, capacity management in the distribution grid is only in the development phase and redispatch could lead to congestions of grid elements due to higher simultaneity factors and detailed monitoring of participating assets is desirable. This requires that assets can be monitored by the DSOs.

Therefore, as a starting point, a minimum size of an asset participating in an aggregated pool of 500 kW is proposed, which usually ensures observability in grid level 5 or 6. Units located at lower voltage levels usually do not meet this criterion. As such, this requirement currently prohibits units located at lower voltage levels from participating and a smaller minimum asset size should be evaluated at a later stage.

3.1.2.5 Maximum size of single asset in a pool

Pooling can be used to achieve the minimum sizes required for redispatch bids, to allow smaller assets to participate in redispatch provision and to unlock flexibility potentials that cannot be accessed with single assets. Pools should however not be used to mask medium- and large-scale assets (piggybacking) and thereby create undesirable inefficiencies. This requirement results in a higher resolution of bids and thus allows for more efficient solutions to grid congestions. Therefore, a definition for the maximum size of a single asset that is allowed to participate in a pool is needed. A maximum size (installed capacity) of 50 MW for single assets within a pool is therefore suggested, as such assets are usually very well capable of participating in redispatch on their own. Feasibility of this limitation and a possible further reduction is to be evaluated during the course of this project.

3.1.3 Geographic information and aggregation

Redispatch is usually used to address the power flow on specific elements in the power grid. This means that the efficiency of redispatch measures depends highly on the location of the unit providing the redispatch. In order to determine the effect, the location (metering point) within the grid for any given asset must be defined and communicated. Communicating the location of an asset is performed as part of the registration for the Redispatch Platform, when submitting the master data.

Pooling

For bids composed of individual assets (pooling) the bid must contain the geographic information of the units involved. Pooling of different units to reach the minimum bid size is allowed. However, pooling assets increases the complexity of the redispatch problem as the geographic information of different assets must be considered and it must be ensured that the resulting bid still has a sufficient efficiency to solve specific grid congestions. To facilitate this, it was necessary to define certain regions within which aggregation is possible. Aggregation must allow efficient pooling of flexibility potentials and simultaneously provide enough granularity to ensure effective redispatch to relieve network congestions. For the different levels of granularity, the following aspects must be considered. In discussions with TSO and DSO representatives this results in the set of demands listed in Table 2 for both TSO and DSOs which must be considered.

When deciding on possible aggregation levels (compare Figure 2), there is a trade-off between granularity of locational information and the ease of aggregation resulting in higher flexibility potentials. This trade-off is showcased in Table 2.

High granularity (aggregation at low voltage level)	**Low granularity (separation of Austria into few zones)**
• Allows exact modelling and shaping of redispatch bids in the distribution grid and thus an effective congestion management at low grid levels • Low liquidity: small aggregation zones lead to few flexibility providers and to potential discrimination against potential flexibility providers, who cannot meet the minimum bid size • High risk of gaming due to low competition • Higher administrative overhead and complexity • High granularity might not always be justified by congestions in the distribution grid. Currently, the amount of grid congestions in the distribution grid is only minimal and thus high granularity is not always necessary.	• Redispatch on lower voltage levels is only possible with decreasing effectiveness • Complicated GSK modelling: A low granularity increases the complexity of accurately mapping the change in generation to grid nodes • High liquidity: low granularity facilitates more pooling options • Lower administrative overhead and complexity

Table 2: Advantages and disadvantages of high/low granularity

Currently most grid congestions are located in high voltage grid levels and redispatch is mainly requested by the TSO and the methodology for capacity calculation in the DSO grid is not yet implemented. For the scope of this project, it was decided that the advantages of higher liquidity and an easier methodology to aggregate units outweigh the disadvantages of a lower resolution.

Therefore, aggregation at the 110kV grid level is proposed during this project and for further evaluations in WP5. This means that units within the distribution grid of one DSO may be aggregated to a bid. However, bids might still be limited by available grid capacity. The methodology for evaluation of grid capacity will be developed in WP5 and described in the according deliverable.

While pooling within the entire region of one DSO has advantages regarding the liquidity of bids, the efficiency of bids regarding congestions within the DSO grid or highly localised congestions in the TSO grid may be limited. Bids may also be limited by capacity limits inside the pooling area. Should frequent congestions within the distribution grid be identified in the future, which either regularly limit the provision of redispatch or need redispatch themselves but lack locational resolution of bids to find a solution, it might be necessary to increase the geospatial resolution and define smaller pooling areas. The same holds true if the efficiency of redispatch measures for the TSO is regularly impeded by the rough locational resolution. Such findings are outside the scope of WP3 and should be further discussed after seeing results from WP5.

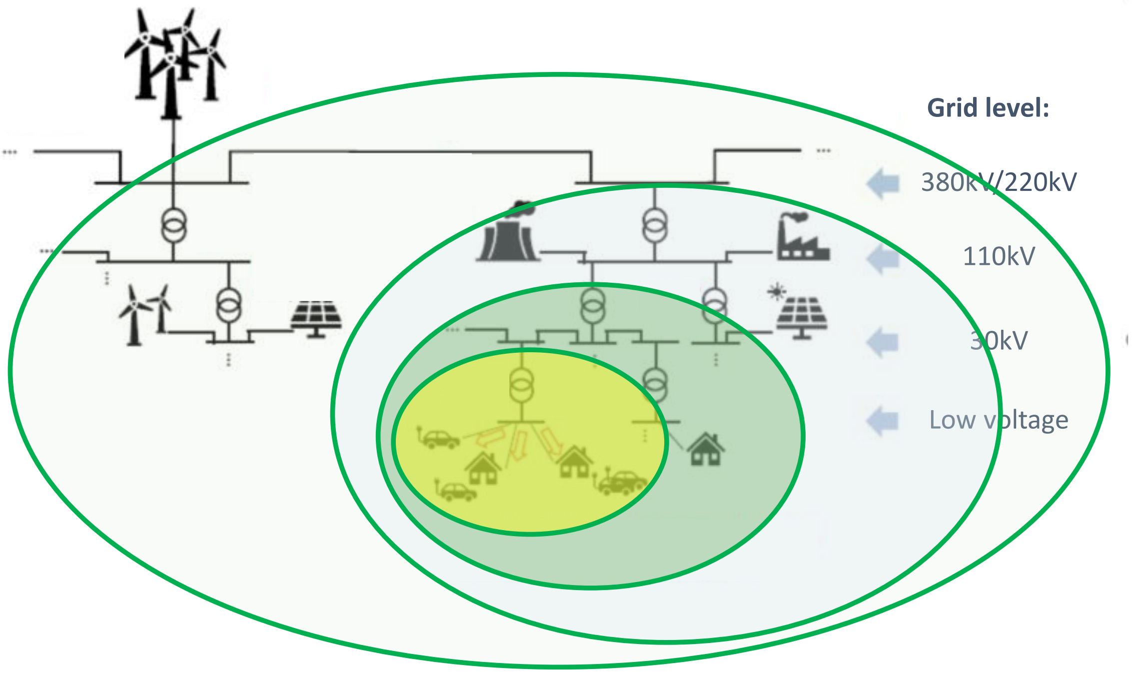

Figure 2: Possible levels of aggregation

3.1.4 Timings

While procedures for "conventional" redispatch are already in place, the timeline for the acquisition of new flexibilities as well as the cooperation between TSO and DSOs must be defined for the day-ahead and intraday timeframe.

3.1.4.1 Redispatch from D-1 security analysis:

The timings for the day-ahead redispatch process with smaller flexibilities must fit into the timeline of the already existing processes. This applies to market procedures as well as TSO and DSO grid security analysis. SoMa 3 [8] in Austria specifies that the schedule updates after the day-ahead gate closure are to be carried out until 14:30. Those schedule updates are needed for the grid security analysis; hence grid security analysis cannot start before 14:30. The grid security analysis on the TSO level requires the information about neighbouring transmission grids and is thus dependant on the regional security coordination, i.e., the merging of national IGMs to the international CGM as well as the joint security analysis at TSCNET. The latter starts no sooner than 18:30. Considering these processes as well as additional DSO grid security analysis and capacity calculation steps a sequence of events for TSO-DSO security calculations and redispatch calculation was conceived and is depicted in Figure 3. Requirements from the SO Regulation [3] and Core ROSC Methodology [10] require that redispatch calculation is coordinated among TSOs. An implementation is expected by 2025 and would currently require provision of redispatch potentials or bids shortly before 18:00 and it is expected that redispatch calculation results should be available at 22:00. While some adjustments will be necessary depending on ROSC implementation, the process timings below should be in line with the currently envisioned process. The figure shows the following key timings that need to be considered:

- Schedule update at 14:30 Day-Ahead: Day Ahead Schedules must be updated before 14:30 regardless of whether redispatch bids are placed or not. From 14:30 onwards bids containing flexibility potential and price can be sent to the Redispatch Platform.
- Optional: To account for the possibility of DSO redispatch bids available at the start of DSO grid security analysis can be considered for DSO redispatch (approx. 15:00, since the DSO forecasting process for security analysis and redispatch is not in place yet the future timings might differ).
- DSO Grid security Analysis: Once schedules are updated the DSOs grid security analysis (1st iteration) can be carried out. Outputs of these analyses are grid capacity restrictions (as input for the common Redispatch Platform). Capacity constraints are sent to the platform.

- Optional: Bid accept messages for DSO redispatch are sent by DSOs (approx. 16:00).
- TSO Grid Security Analysis: Compilation of TSO Data for grid security Analysis starts at 16:00. For the international grid security analysis, the TSO uses the schedule data as well as information from the DSOs to compile the national IGM which is then send to TSCNet.
- Gate-Closure for redispatch in the D-1 process. The GCT of the Redispatch Platform for redispatch at the D-1 level occurs at 18:00, because only bids that are available when the security analysis starts can be considered.
- The IGMs are merged to form the CGM, and the TSO security analysis starts at approx. 18:30.
- Calculating necessary redispatch: based on the CGM, congestions in the transmission grid are identified internationally and the activation of remedial action is optimized in a coordinated manner to relieve congestions.
- Confirmation of bid acceptance or rejection: The TSO sends redispatch bid accept information to the Redispatch Platform. The timing of those messages is dependent on the international process. The current calculation process finishes between 21:00 and 01:00 and confirmations should generally be expected by 22:00. Current plans for the ROSC implementation foresee calculations to be finished by 22:00. Providers of redispatch will receive confirmation or acceptance at approx. 22:00.

In order to consider interdependencies between DSOs and TSO at least two iterations are necessary. In general, DSOs send their redispatch requests before the TSO does.

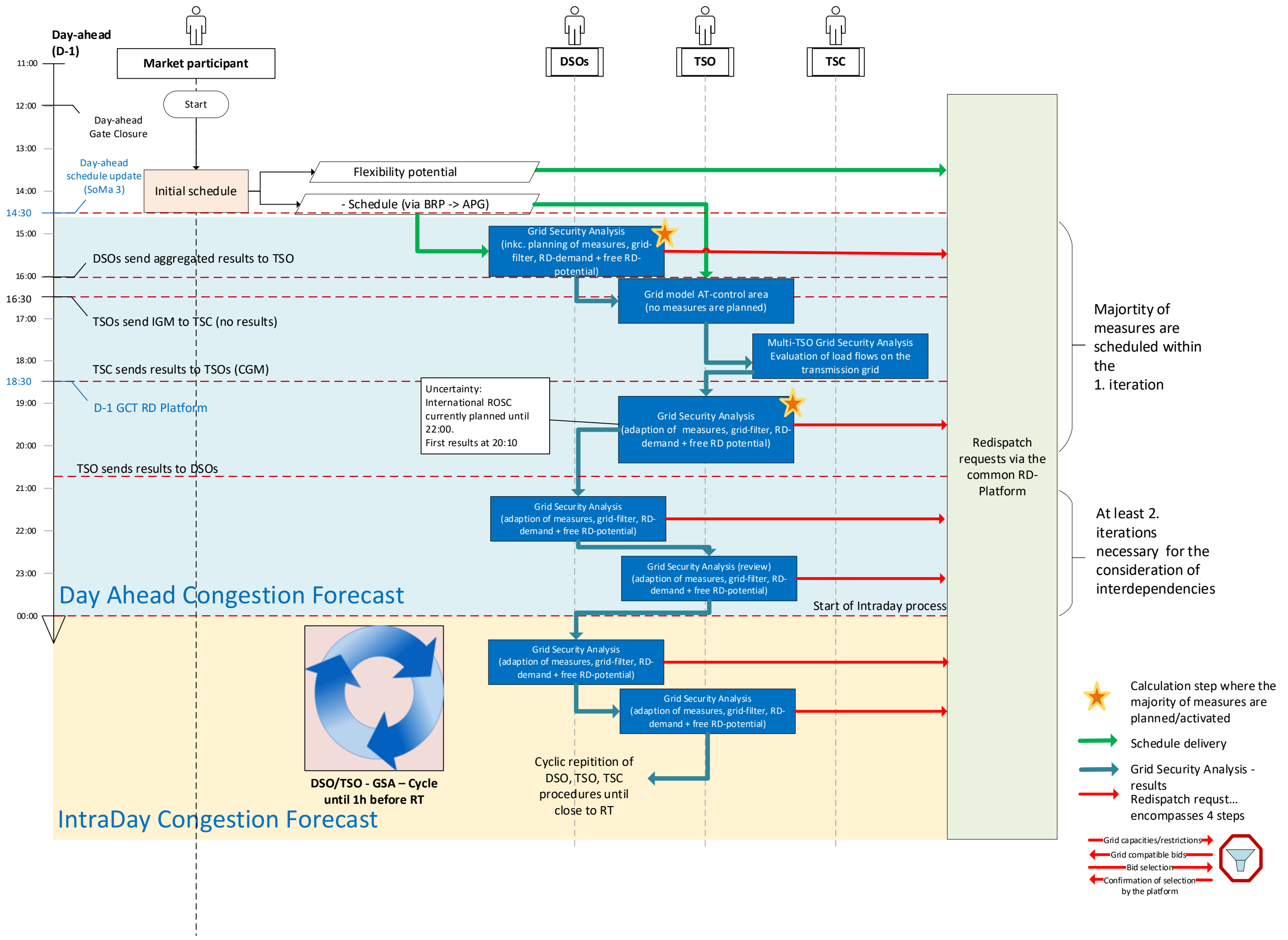

Figure 3: Timings of grid security analysis and redispatch

3.1.4.2 Redispatch resulting from Intraday Calculations and real time congestions:

Once the day ahead process is completed the subsequent intraday process follows. While the day ahead contingency calculation is a discrete process resulting in one main security analysis, intraday security analysis is a continuous process with a rolling time horizon. In every hour of the day intraday models are compiled for all remaining hours of the same day and a security analysis is performed. This may result in additional redispatch requests. This is not unlike the day ahead and intraday energy markets where day ahead energy trading happens mainly as a single auction whereas intraday trading happens as continuous trading. Therefore, the handling of redispatch requests from intraday process needs additional information. As gate-closure times are no longer the limiting factor for bid validity an additional parameter to limit bid validity must be submitted. The bid validity may be indicated by an expiry date (DD.MM.YYYY hh:mm). Any bids with an expiry date can remain on the common Redispatch Platform after the day ahead process is completed, offers without an expiry date will not be activated past the day ahead process. When a new intraday calculation starts, any bids with an expiry date past the time needed for redispatch calculation can be considered in subsequent security analysis and can also receive bid acceptance notifications until it has expired. This is illustrated in .

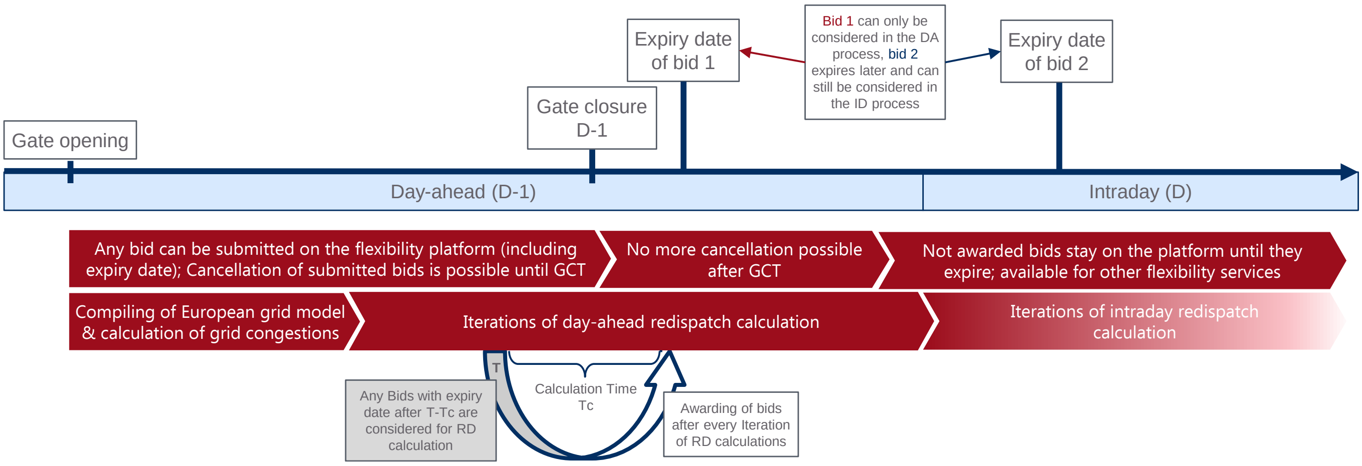

Figure 4: Timing of redispatch bids and calculation processes

3.1.5 Bid structure

The basic bid structure of a bid is an energy delivery for a quarter-hour. These quarter-hourly segments are also referred to as a market-time-unit (MTU). The most simple bid must provide information on the starting time, end time, power and the associated price. However, various constraints limit the application of such simple bids. This requires that additional information is included with a bid.

An introduction to bid linking can be found in the documentation of bid linking for mFRR in the MARI Project [11]. Bid linking is necessary whenever the availability of a bid in one MTU depends on the clearing of another bid. Such constraints may arise either due to current hourly resolution of grid security analysis, minimum-up time constraints of technical units, or the energy content of storage systems. This requires that those additional constraints are somehow mapped to a more complex bid structure.

Various complex bid structures have been devised and are currently in use for energy trading on the day ahead spot and balancing markets. A list of such structures is included in Annex A: Bid structure. Increased complexity also increases development efforts and pushes the limited scope of this project. Allowing various bid-shapes and links might also cause problems when matching upwards and downwards bids for redispatch if insufficient liquidity does not allow for balanced redispatch and might require a market-maker. Because of this, available bid complexity should be kept to a minimum. As a starting point the following bid structures besides the basic bid should be offered:

- **Exclusive Bids**: Accounting for energy/process limitations it should be possible to place multiple bids that cannot be executed simultaneously – i.e. logical XOR. Figure 5 illustrates three exclusive bids that cannot be realized simultaneously.

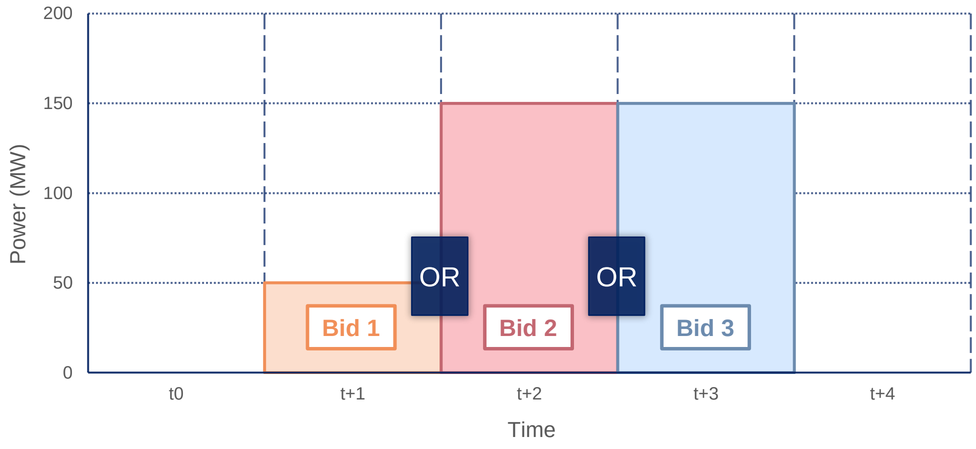

Figure 5: Exclusive bids

- **AND linked bids**: Accounting for minimum-up time or ramping constraints it should be possible to place bids that can only be realized jointly - i.e. logical AND. Figure 6 illustrates how linked bids are realized.

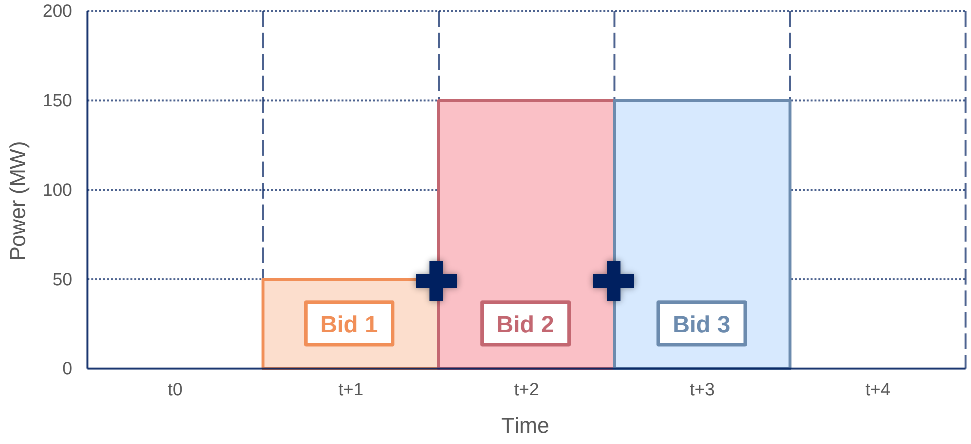

Figure 6: AND linked bids

- **Profile Blocks** provide the opportunity to place bids that are characterised by a unique profile matching the specific flexibilities an industrial process can offer. Figure 7 illustrates a unique profile, used to offer a specific flexibility potential.

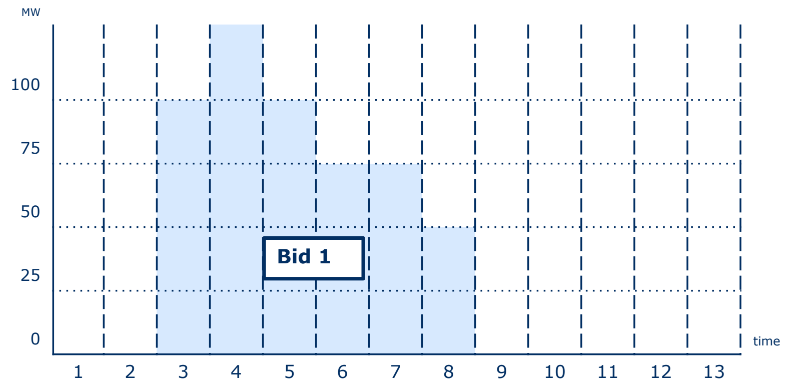

Figure 7: Profile block bids

These minimum requirements for bid complexity for redispatch share similarities with the bid complexity for balancing but deviate with respect to certain properties. While current bid linking in MARI [11] includes multi-part bids and mutually exclusive bids, the complexity requirements for redispatch bids would extend the list of necessary linking options by profile bids, logical ANDs and a considerably longer look-forward horizon of up to 35 hours. This results mainly from the longer lead-times for redispatch activation compared to balancing reserves and from possibly longer durations of redispatch activations.

3.1.6 Cost model

In theory the cost of a change in generation or consumption for a technical unit can be composed of fixed-costs such as start-up costs which arise as a result of the binary decision to change the schedule and marginal costs associated with the energy volume supplied. A list of possible price components, which serve as a lower bound for the redispatch bid price is included in **Fehler! Verweisquelle konnte nicht gefunden werden.**. The list and technical implementation how prices are transmitted shall not prejudice the decision on the remuneration model. The discussion of different remuneration models is addressed in the regulatory analysis and has to be evaluated as a socioeconomic optimum.

For the purpose of the definition of technical requirements for redispatch provision, this document shall specify how price information for redispatch bids shall be provided to the Redispatch Platform. As a starting point every bid should be associated with one price as a single scalar, naming the specific cost of the bid as €/MWh. This price includes the costs of the whole bid i.e., the total cost in euros divided by the total volume of energy included in the bid. E.g., a bid of 5 MW for one quarter hour, that costs 25 € shall give a price of 25/5*4 = 20 €/MWh.

However, this price model, together with the offered bid complexity does not allow for the modelling of start-up costs. Multipart-bids/parent-child bids used-to model a one-way dependency, which would allow a more detailed modelling of costs should be considered at a later stage but were not considered necessary for a starting solution.

3.1.7 Catch-up / Anticipatory effects

Industrial flexibility can provide redispatch by shifting their power demand to times with fewer or no grid congestions, by changing their production process, using options to store energy or resort to using their own generation capacities. Generally, the daily energy demand is determined by the industrial process and if industrial flexibilities are limited to shifting their demand/generation they might have to make up for a demand reduction at one point in time by increasing demand at some other time.

These effects are called catch-up (after the redispatch activation) or anticipatory (before activation) effects. The duration of congestions in the transmission grid varies and often exceeds one or two hours. If these effects coincide with times of congestion, they have an adverse effect and result in the need for additional redispatch. Any such adverse effects are to be avoided. Figure 8 illustrates a problematic catch-up effect. The blue curve represents the original load profile of a pool of industrial flexibility units. The red curve indicates the redispatch by the provider. In this case, the industrial flexibility units provide redispatch by reducing their power consumption. It is possible that the industrial flexibility units could try to catch-up on their required consumption indicated by the dotted red curve. Directly after the provision of redispatch, they could increase their energy consumption, which could aggravate a congestion in the following hour. Hence, such immediate and uncontrolled catch-up of consumption (or generation) should be avoided.

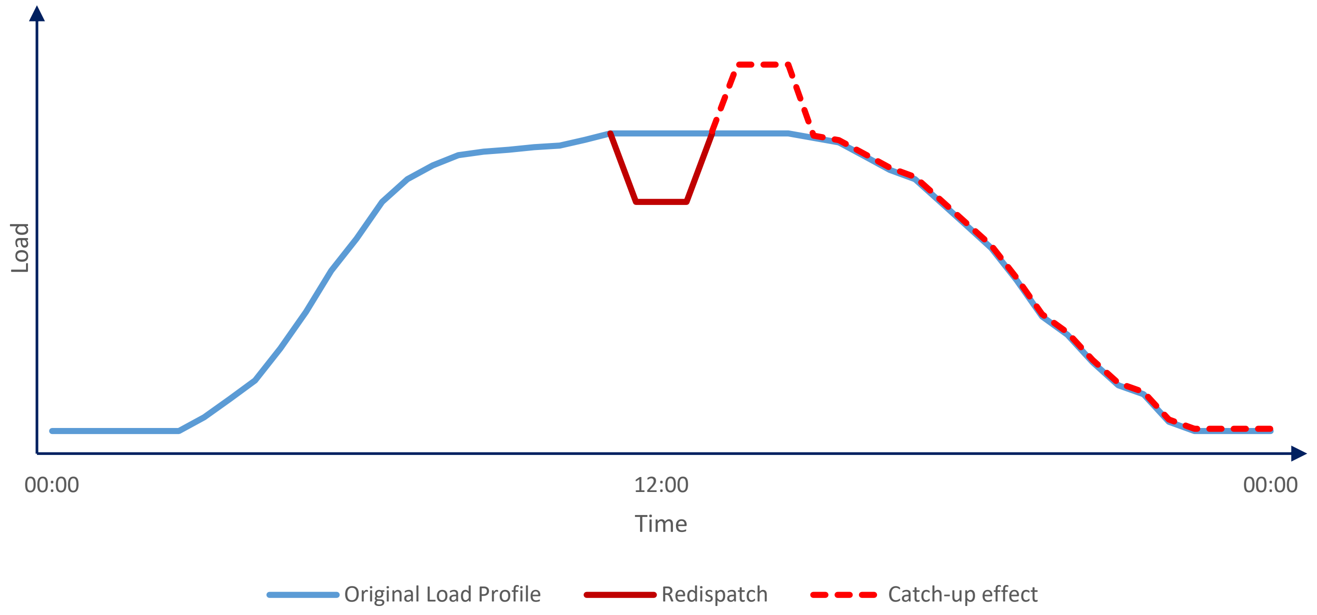

Figure 8: possibly problematic catch-up effect immediately after RD-devlivery

3.1.7.1 Possible solutions for catch-up / anticipatory effects

To manage these catch-up effects, three options were identified and discussed:

1. **Additional catch-up timeseries**: The offered bid includes a time series that indicates which hour the consumption / generation is shifted to. The optimizer then considers this information during the redispatch calculation process. In this way, redispatch bids with catch-up/anticipatory effects that increase a congestion won't be selected by the optimizer. This allows a lot of flexibility for all stakeholders. While this option would ensure that no harmful redispatch bids would be selected by the optimizer there are some drawbacks. Without knowledge when catch-up effects cause problems, it is impossible for the aggregator or flexibility service provider to find the most suitable pool composition and timing to recoup their consumptions which results in the least harmful catch-up effect, and therefore does not cause the exclusion of the bid. Moreover, this approach poses the question of how to inform providers of redispatch that their bid was rejected due to its catch-up effect and how to improve a bid. Therefore, it would be rather difficult for the bidders to optimize their bidding behavior, as the optimization goal is unclear.
2. **Publishing congestions in advance:** Before the submission of bids, time series of congestions are published. These time series include information when redispatch is possibly required and the times when catch-up effects are allowed. This option appears to provide a clear optimization goal for the provider of redispatch, but besides its high complexity it also entails two major drawbacks: As redispatch depends on the direction of bids and on the specific location of assets within the grid this option needs a high geographic resolution of the congestion information. This option also possesses an inherent risk of gaming behavior by publishing congestions, and it is not compatible with current process timings. Precise information on congestions could lead market participants to engage in behavior, which causes these congestions. TSOs are therefore reluctant to publish detailed congestion information. As outlined in chapter 3.1.4 such congestion information becomes available at approx. 18:30, when the redispatch calculation starts. Redispatch bids are already required at this time if they are to be selected during the calculation. Without additional processes to forecast congestions at an earlier time, the causality problem cannot be resolved.
3. **A general envelope curve for catch-up effects:** Another option would be to define an envelope curve for catch-up effects. Any bids submitted to the common redispatch Platform must observe that the catch-up effects associated with activating the bid do not exceed the pre-defined maximum shape for catch-up effects. This option is easily implemented but nevertheless, it is not as flexible as the other two options. It presupposes that grid congestions have recurring characteristics and might still aggravate congestions if they deviate from these

standard assumptions. This makes it difficult to develop an envelope curve that meets the characteristics of different congestions. Further simulations for this approach need to be performed in order to prove feasibility.

Table 3 gives an overview of the advantages and disadvantages of the different options how to deal with anticipatory/catch-up effects.

Table 3: Overview of the advantages and disadvantages of different options

	Bid incl. time series of anticipatory / catch-up effects	Publication of anonymized time series of grid congestions and allowed anticipatory / catch-up effects	General envelope curve
Advantages	- No harmful redispatch bids	- Clear optimization goal for industrial customers	- Easy implementation in optimization
Disadvantages	- Lack of transparency - No clear optimization goal for industrial customers	- Timing problem: bids already need to be submitted when grid congestions are calculated - High geographic resolution of congested regions and the direction of congestions needs to be communicated to flexibility service providers - Gaming problem	- General envelope curve for different types of grid congestions difficult to define - Generalization may lead to the neglect of exceptional situations

3.1.7.2 Project solution to catch-up and anticipatory effects

During the work package meetings, the pros and cons of the different approaches were weighed, and it was decided to use a combination of approaches 1 and 3 to tackle the problem of catch-up effects: A general envelope curve should define when and to what extend catch-up/anticipatory effects are permissible. This gives an orientation to the flexibility service provider how to optimize its planning schedule. Furthermore, the bid is submitted including the time series of anticipatory / catch-up effects. These time series indicate which hour the consumption / generation is shifted to. The optimizer for the redispatch calculation process then considers these in order to find the best solution for the redispatch problem. Redispatch bids with anticipatory / catch-up effects that result in the aggravation of a congestion won’t be selected by the optimizer.

Considering the envelope curve the industrial flexibility provider may catch-up the energy offered as redispatch as illustrated in Figure 10.

The effectiveness of the envelope curve needs to be evaluated during the course of the project and should be adjusted in case the characteristics of grid congestions change. In case a flexible unit does not require any catch-up or anticipatory effects bids may be submitted without a catch-up/anticipatory effect timeseries. Omitting the timeseries despite catch-up effects is not permitted.

Development of a general envelope curve for catch-up / anticipatory effects

Figure 9 illustrates the general envelope curve for catch-up and anticipatory effects. At time 0, the delivery of redispatch takes place. This represents the start and the end of a redispatch delivery. In the example shown (indicated by the green curve), the industrial flexibility unit must not catch up the lost/shifted consumption (or generation) for the 4 hours leading up to and following the delivery. In the subsequent hours the maximum possible catch-up effect is limited by a linear trajectory, between 0 and the maximum power delivered as redispatch, over the next 2 hours (4-6) until there are no more limitations 6 hours after the end of delivery. The limitation applies relative to the already submitted schedule, i.e., no changes to the hours without redispatch are required but changes in the burdening direction are restricted. As such an envelope curve is only an upper limit the provider of redispatch may choose to start catching up the consumption (or generation) later than indicated by the envelope curve or at a lower power. The same principle that applies for the catch-up effects also applies for anticipatory effects. This is illustrated by the blue curve.

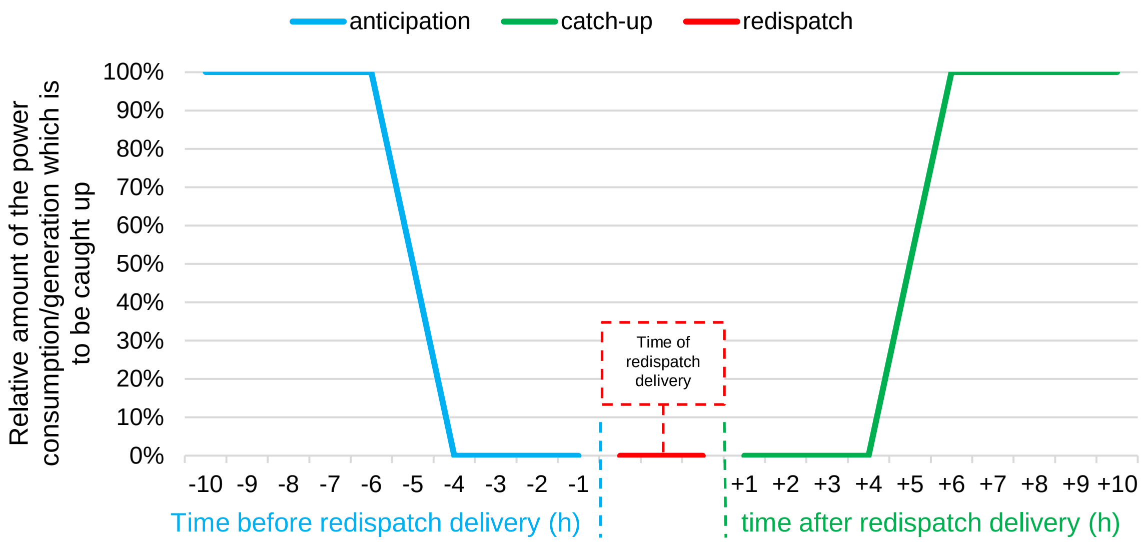

Figure 9: Envelope curve

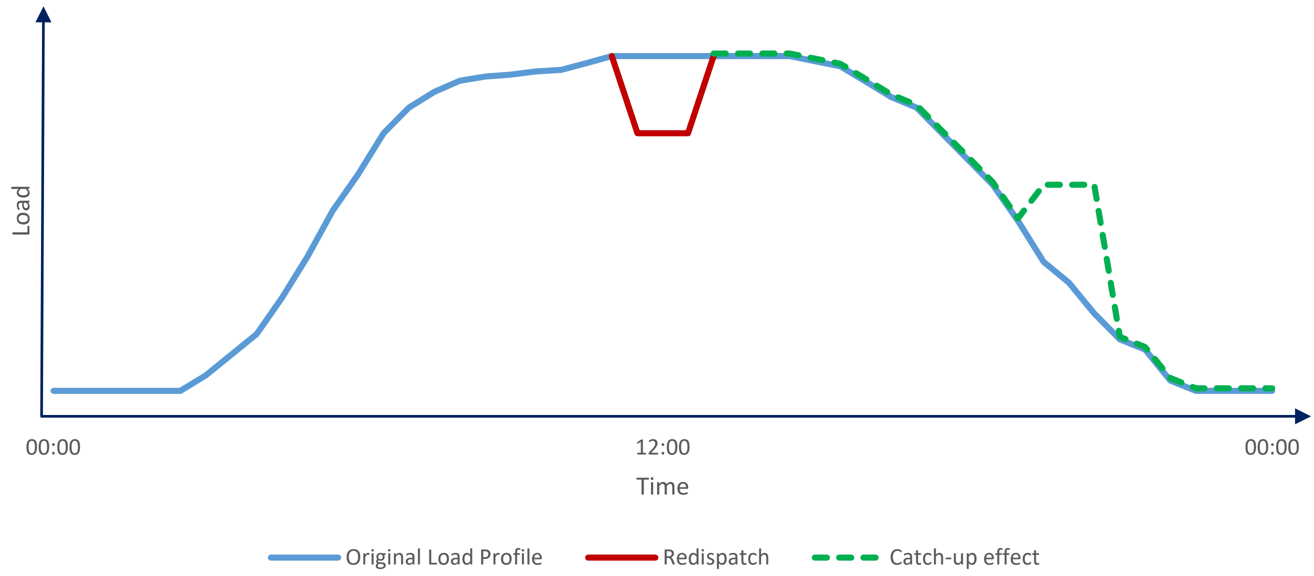

Figure 10: acceptable catch-up effect

3.1.8 Quality criteria

In order to ensure the quality of redispatch provision and to maintain grid security, the definition of quality criteria is essential. The aggregator/flexibility service provider has to ensure the fulfilment of these criteria. Quality criteria can be further grouped into three categories:

- Observability and schedule data; sufficient information on schedules and measured values
- Reliability/Dependability
- Shape/Quality of Energy Delivery

Quality criteria generally apply to a bid i.e., if a bid is offered by a single unit the criteria apply for this unit, if a bid is provided by a pool the quality criteria must be met by the pool as a whole. However, this does not exempt individual units from providing an initial schedule.

These criteria are detailed as follows.

3.1.8.1 Observability

For the planning capabilities of grid operators, it is essential to obtain reliable information about the schedules of consumption and generation units. This information is used to calculate the congestions in the grid and to take measures accordingly. If these schedules are not correct or not up to date the secure operation of the grid might be at risk. For monitoring purposes, it is also important to obtain reliable measurements of asset to compare them to the schedule.

Therefore, one quality criterion is the **reliability of the schedules**. Schedules need to be announced on time to ensure that they can be considered in grid security calculations.

These schedules must always be up-to-date (**up-to-date schedules**). If an asset/a pool of assets has to deviate from its announced schedule for the day-ahead timeframe due to any reason (e.g. intraday trading) they should be updated as soon as possible. Another important criterion is the **accuracy of schedules**: the actual measured load/generation profile must align with the final transmitted schedule (see also [8]).

The accuracy of the schedules should be monitored (**Monitoring**): Measurements are available to demonstrate whether the schedule was met at every time unit and monitoring of activation periods. Tools for monitoring the different aspects of the schedule (baseline, RD-Power...) are yet to be defined.

3.1.8.2 Reliability

An asset is only suitable for redispatch if it is reliable. Therefore, a critical quality criterion is the **reliability of redispatch bids**. Once a redispatch bid has been accepted, it must be delivered with the exact timing and amplitude as offered. This means that the actual measured load/consumption matches the sum of the initial schedule and the accepted redispatch bids (see also chapter 3.2.2). Furthermore, it is important that a redispatch offer can be **delivered without interruption** by third parties. This means that once a redispatch offer has been accepted, it is delivered, and no third party may interfere with the delivery (e.g., another grid operator disconnects the asset from the grid through a different contract). This means that flexibility providers cannot offer their flexibility to redispatch and to a third party at the same time.

Part of the reliability of an asset is also the guarantee, that an asset offered in a bid will deliver the offered energy when selected for redispatch (**availability**). Any delivery failures are to be avoided (e.g. asset or plant not available, because it can’t be controlled or is not ready for operation). In case of a delivery failure despite the redispatch providers best effort, there are three options available to mitigate the situation. The options to replace the lost generation/consumption are shown in Figure 11 and must be coordinated with the requester of redispatch (TSO/DSO) by phone.

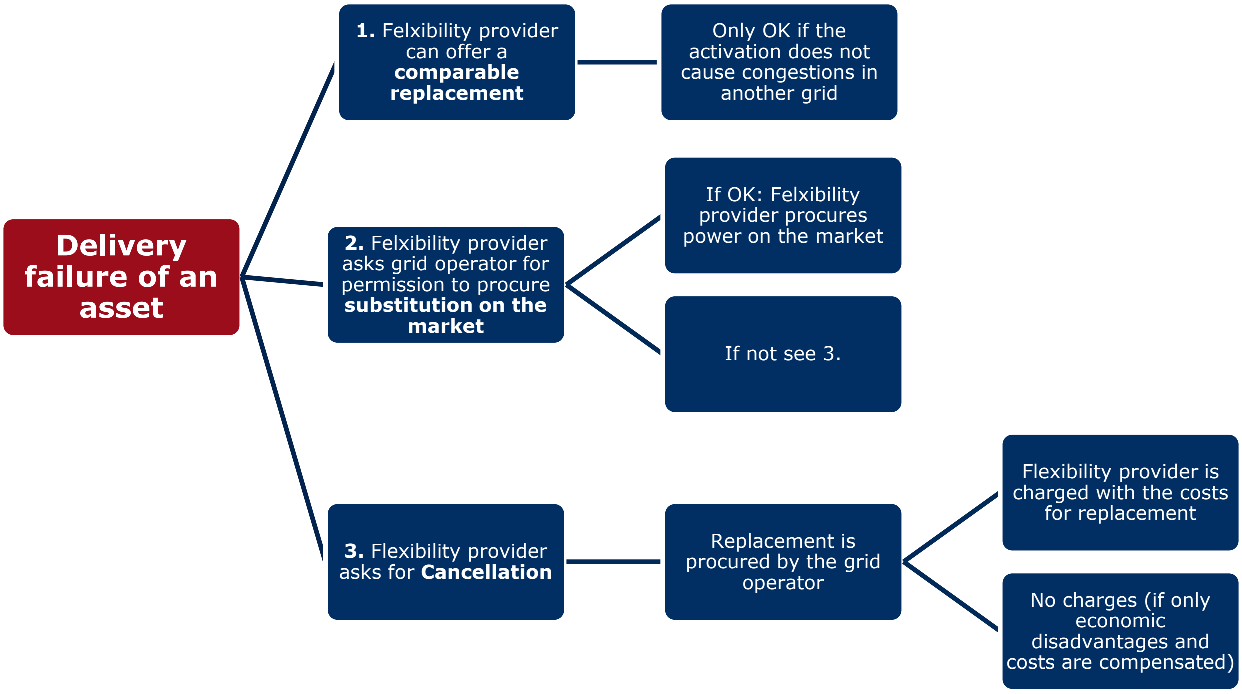

Figure 11: Options in case of failure

TSO/DSOs reserve the right to exclude flexibility providers from redispatch provision if failures occur regularly.

3.1.8.3 Shape of Energy Delivery

For system operation the shape of the energy delivery is relevant, since it ensures effectiveness of redispatch measures and has an impact on voltage and frequency stability, as well as the monitoring of delivery.

Quality of delivery considers the overall shape of the supplied energy/demand. Figure 12 The actual consumption/generation of the asset or pool must at least reach 95% of the offered and accepted power, and no more than 115%. Any energy bought/sold as redispatch but not supplied results in imbalance energy (see chapter 3.2.2).

The **ramp-up and ramp-down of power** is an important quality criterium as well. In order to be congruent with future balancing products that will be introduced with MARI and aim to have a ramp-up/down that reduces frequency deviations (dips and peaks) at the beginning and end of delivery time, it might be reasonable to introduce a corresponding ramp-up/down requirement for redispatch as well. However, the ramp up/down would have to be implemented internationally, since cross border redispatch needs to be uniform to be able to match and combine redispatch bids properly. Furthermore, a gradual ramp-up inherently discriminates bidders that have a pool of assets with a two-point controller, that only allows for a sudden in/decrease in power. Conversely, a block delivery, i.e. the sudden increase up to the delivery power at the begin of the delivery period with a steep edge, represents the status quo of redispatch deliveries and would be rather easy to implement. However, block deliveries might result in dips and peaks in frequency. Furthermore, not all bidders are flexible enough and need a certain time to ramp up to the delivered power.

Therefore, until a final form is defined internationally, no shape for the ramp-up is defined. The quality criterium to be met is defined as follows: At least 95% of the offered power, must be reached 5 minutes after the start of the delivery period. Redispatch will be offered in quarter-hourly time slices. Regardless of the exact shape of the delivery, the flexibility service provider offers a bid from T until T + 15 minutes with the corresponding amount of energy. This means that for a 1 MW bid of a quarter hour, 0,25 MWh are delivered. Additional energy due to ramping or other deviations are the concern of the flexibility service provider.

For monitoring purposes only (until a final form is (re)defined internationally), the delivery of the product has the shape as illustrated in Figure 12. The figure shows the product shape for one single quarter hour bid.

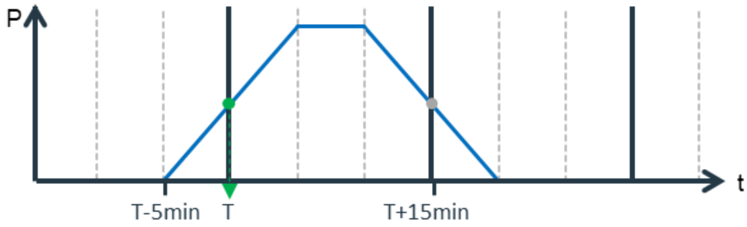

Figure 12: General ramp shape

3.2 Data exchange criteria

These criteria describe all data exchanges that are necessary for offering, processing, monitoring, and settlement of redispatch measures. At the beginning, an overview of necessary data exchanges between all parties is presented. This includes the necessary schedules for planning, baseline methodology for the evaluation and online metering data for the monitoring of activated redispatch measures. After the description of data exchanges, Section 3.2.2 illustrates the requirements for a baseline for redispatch provision. At the end of the Chapter the data provision for a fictitious flexible unit showcases what data needs to be provided.

3.2.1 Necessary data exchange

The utilisation of assets for redispatch requires the exchange of data for five different groups of datapoints.

1. General Asset Master Data (at Grid Connection): This data must be provided to the connecting distribution or transmission system operator during the initial connection to the grid.
2. Flexibility Service Provider/Aggregator Master Data at Registration: This data must be provided when a provider of redispatch first registers to provide redispatch and applies for prequalification.
3. Master Data at Registration/Prequalification for Redispatch: In case of pooled assets, pools and their individual assets may need prequalification and provide some additional data during this stage. This data is further separated into Pool/Group Master Data and Asset Master Data at Registration.
4. Bid Data: For the coordination of redispatch the information described in section 3.1.1 must be transmitted in form of a bid for each market time unit where redispatch is offered.
5. Miscellaneous Data for grid operation: Any regular data exchanges associated with local rules and regulations.

In general, the data exchange for assets connected to the power grid in Austria at the distribution or transmission grid level is governed by the Austrian ElWOG [12], the terms and conditions of the transmission/distribution system operator, the Electricity Market Code (SoMa) [5], SO Regulation [3] and data exchange regulation [9], which are covered in more detail in D3.2. For the purpose of technical requirements for redispatch, the master data as described in the SO Regulation [3] and “Datenaustausch-Verordnung” [9] allows the TSO/DSO to get an initial minimum set of data for the participating assets. This general data about the unit includes the size and location, as well as the operator. The Austrian regulatory framework “SO GL Datenaustausch-Verordnung" [9] determines the following data exchanges:

- Name and address of the plant operator
- Metering point and coordinates of the asset/technical unit
- Address of the grid connection point
- Voltage level
- Installed power in total
- Classification in accordance with RfG thresholds (Type B, C, D), in case of a generation unit
- Maximum load-reduction, in case of demand unit

This information is shared in TSO-DSO communication and used for grid security assessment. If an asset is later signed up for redispatch provision the information provided at its initial connection to the grid will be linked to the information on the Redispatch Platform (I.e., FSP ID etc.).

As laid out in 3.1.1.1 any actor capable and legally allowed to change the generation or consumption of an asset according to the requirements for redispatch, either by direct control or by directing the asset owner(s), may register as an aggregator/flexibility service provider (FSP). During this process additional prequalification data for the aggregator/FSP must be provided. This data serves to identify the aggregator/FSP and enable any administrative exchanges. This data includes contact information, bank details, contractual agreements, baseline methodologies the FSP is prequalified for, as well as documentation of the prequalification process. An extensive list of necessary data is included at the end of the chapter.

After prequalification of the aggregator/FSP, the aggregator/FSP may register assets, pools/groups and pooled assets. At this point additional prequalification data of the asset/technical units must be exchanged in order to complete the initial master data and allow the TSO/DSOs to correctly model the asset in grid security analysis. This data includes additional technical data relevant for the consideration of a flexibility in the redispatch process, prequalification information, baseline methodology as well as data exchange infrastructure. An extensive list of necessary data is included at the end of the chapter.

In case the FSP offers assets that are aggregated in a pool another set of data has to be provided specific to the pool. This includes the technologies included in the pool, the upper and lower power limits of the pool as well as the technical units participating and the reference to the corresponding FSP.

While the previous part of this section was concerned with different types of master data, which must be exchanged at different stages of the registration, or in case of updates, the next part is concerned with regular data exchanges in the daily redispatch process. Most of this information is transmitted as bid information via the Redispatch Platform and must include all information necessary to evaluate the bid in a remedial action optimisation process. This includes the market time unit, power and energy volume, price, duration and other characteristics described in this document as well as structural information of the bid such as relation to other bids and the assets included in the offer. An exemplary dataset can be found in section **Fehler! Verweisquelle konnte nicht gefunden werden.**.

The last data exchanges which are worth mentioning are any miscellaneous data for grid operation. This means schedule, measurement and metering data, which are already exchanged between assets, DSOs and TSO and are regularly used for other processes. Their exchange is governed by the electricity market code [5], ElWOG [12] and SO Regulation [3]. Besides, the fact that units for redispatch provision agree to send schedules via the established system for this data, no changes are foreseen.

It may be necessary that an additional data path for measurement data related to the monitoring of redispatch provision is required.

3.2.2 Schedules, baseline, online metering data

A reliable network security analysis and the resulting congestion forecast is the basis for any redispatch calculation. As mentioned in chapter 3.1.8, this requires a reliable schedule to be able to correctly consider assets during the network security analysis and an appropriate forecast of unscheduled demand and feed-in from renewable sources. After redispatch has been activated a methodology to monitor and verify this activation is required. The following section illustrates the requirements for a baseline methodology for redispatch. At first, it is necessary to mention that schedules are not necessarily submitted for metering points but are rather submitted for single assets, where required. This means that a link must be found between the schedule(s) of a redispatch providing asset and the metered values of its metering point, as well as possibly further asset related measurements in addition to the data collected at the metering point.

Energy feed-in/consumption at a metering point usually contains the different components as illustrated in Figure 13, which can be grouped into scheduled and unscheduled components. The scheduled components are the initial schedule that results from day-ahead trading, the schedule update resulting from RD and the scheduled changes from intraday trading. Unscheduled deviations from this schedule may be either intentional such as those caused by balancing (aFRR and mFRR) or result from forecasting errors or unplanned process changes and result in contributions to imbalance energy. Identification of these components is needed to evaluate which products have been delivered.

In case there is more than one asset behind the metering point the complexity level is further increased as these assets may themselves either be unscheduled or scheduled and also comprise these components.

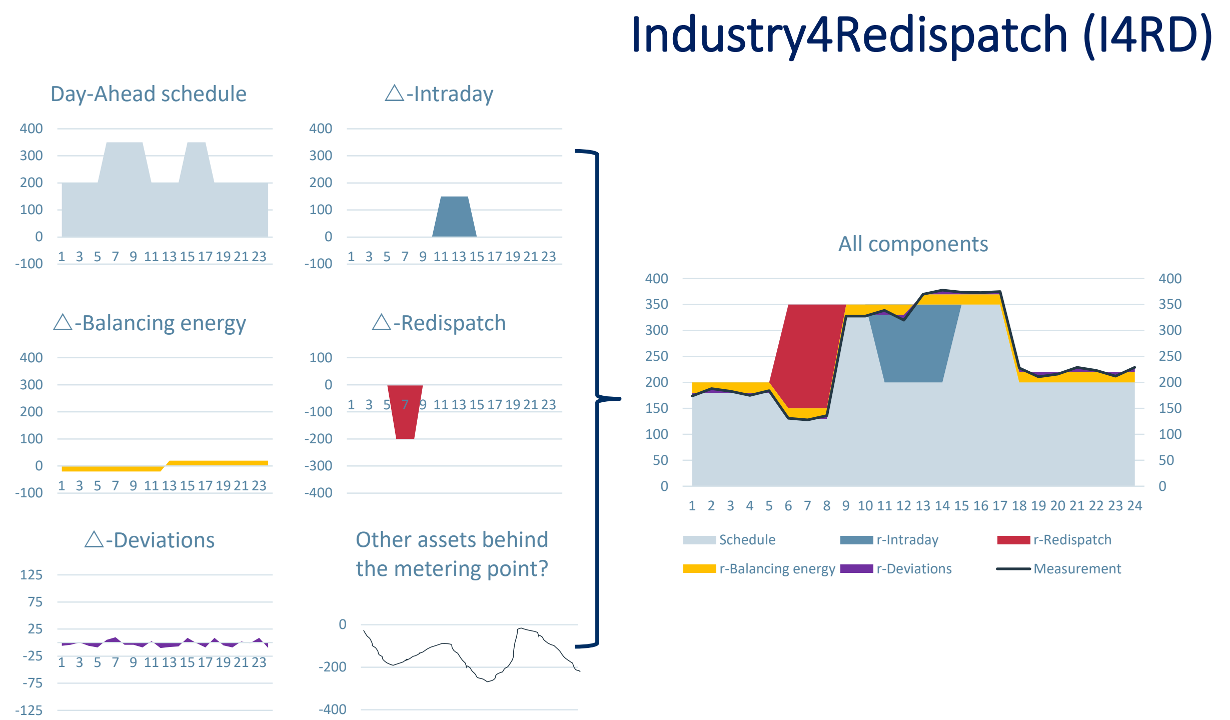

Figure 13: Components of a measurement

For an effective redispatch measure it is vital that the scheduled and measured change at the asset level is, also reflected as a change in infeed/consumption at the metering point. Therefore, the monitoring of deviations due to other plants/assets behind the metering point is necessary.

As also illustrated by Figure 13 the following information is essential for a successful redispatch process:

- Before the energy delivery: initial schedules and their verification
- Where applicable, (Online) measurement data of assets (in real time for the operational processes)
- Meter data at the grid connection point, as well as additional measurements
- Baseline methodology for ex-post analysis, that is used for settlement and monitoring purposes

The corresponding steps are elaborated in the following chapters.

3.2.2.1 Schedule data

For any evaluation of reliability as well as operational security analysis, the delivery of schedules is essential. Schedules must be delivered (as defined by the quality criteria) as soon as possible and must be accurate to allow a reliable forecast of the load flows on the grid. Schedule delivery has to be carried out to the extent necessary to allow appropriate modeling of the assets within the network security analysis of the TSO and/or the DSOs. In general, schedules have to be delivered per asset.

If there are multiple assets behind the metering point, the redispatch providing assets, considered as assets relevant to network security, must deliver a schedule pursuant to the electricity SoMa 3 [8]. This applies as well for any other assets behind the metering point covered by SoMa 3. For the assets behind the metering point that do not provide a schedule, because the assets or loads do not provide redispatch and are also not covered by chapter 3 of the electricity market code, a profile should be assigned. In order to validate the schedule, measurements are needed at the metering point as well as at the redispatch and schedule delivering assets as demonstrated in Figure 14. This facilitates the verification of the delivery according to the schedule. It furthermore demonstrates that changes in the schedule (redispatch) do not only change the output of the redispatch providing asset but are also reflected in the feed-in/consumption at the metering point, which is relevant to the system operator.

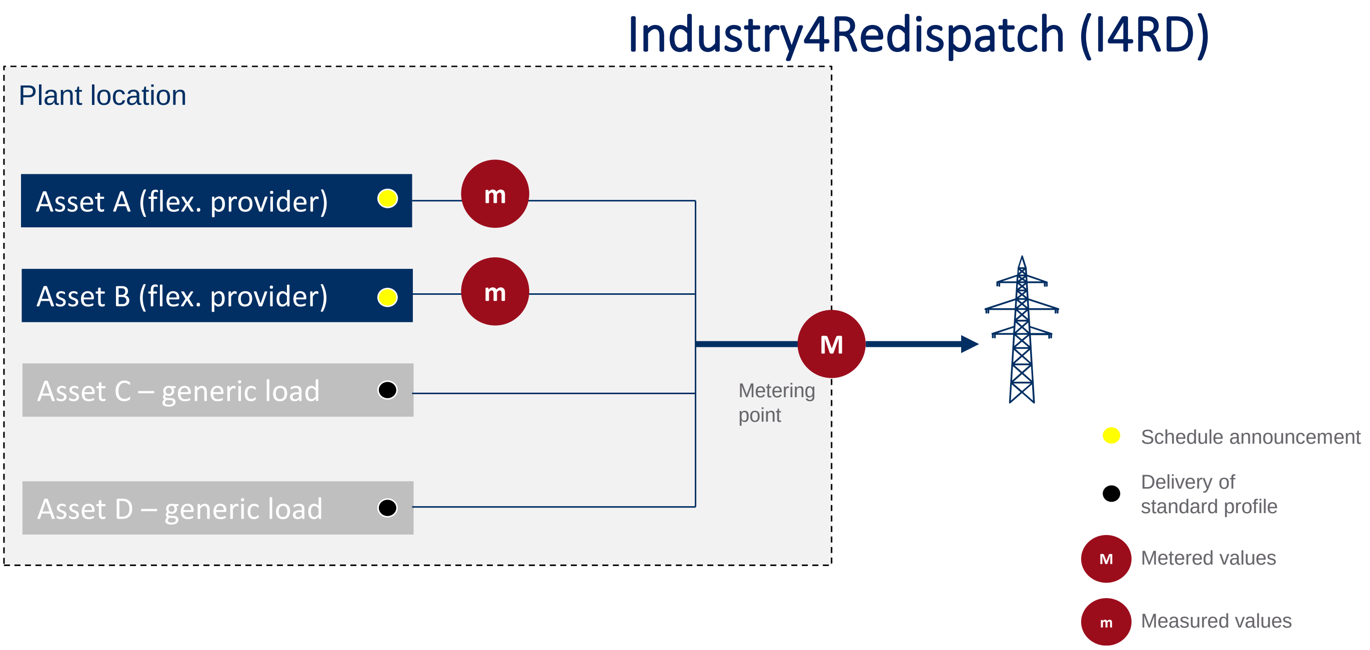

Figure 14: Schedules and metering/measurement points

In case multiple small assets are located behind a metering point, it shall be possible to send a schedule aggregated per metering point, if the TSO and the relevant DSO(s) allow it. This option to send aggregated schedules is also regulated for producers by the SoMa 3 [8]. In that case, the schedule is sent for the metering point and metering is only necessary at the metering point, because it is sufficient for the evaluation of the schedule and the redispatch delivery.

Furthermore, it is necessary to rule out the possibility of gaming, e.g. the announcement of a schedule that is intentionally lower than intended so the increase in power that was planned anyways can be sold as redispatch.

Therefore, the day-ahead schedule should be evaluated by checking two different properties, schedule quality and schedule plausibility. The first characteristic is the quality of previously sent schedules. This would be achieved by conducting an analysis and comparing historical schedules to the actual measurements. The deviation between measurements and schedules gives an indication of the quality and reliability of the schedule.

The second check regards the plausibility for new incoming schedules. To verify the new schedule, it is compared to previous schedules of comparable historical business days. This plausibility check can help to mitigate gaming by giving an indication if the initial schedule is viable before redispatch and was not artificially altered to participate in increase/decrease gaming.

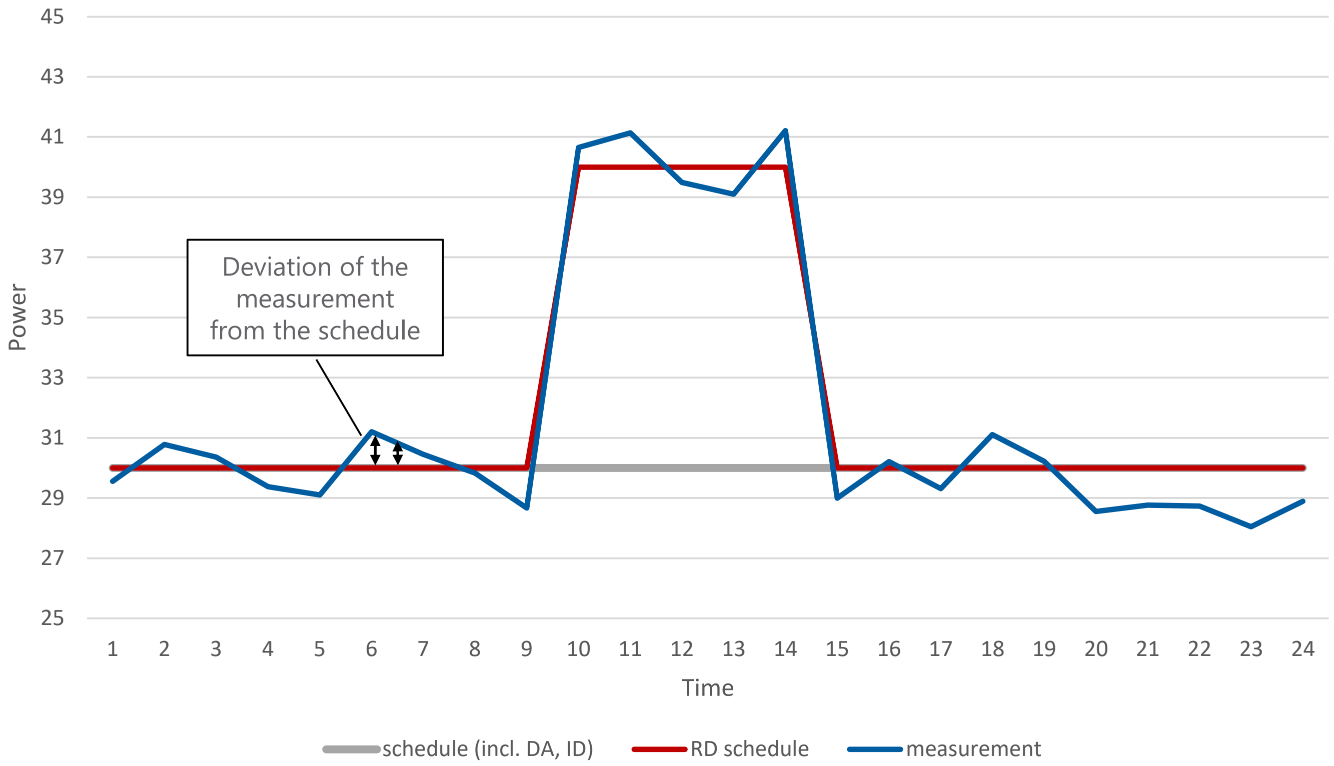

Figure 15: Schedule evaluation

The treatment of schedules and measured/metered values can be summarized by the following steps that would take place for all hours in a given day for any asset providing redispatch:

1. Announcement of the day-ahead schedule for an asset or a metering point at 14:30
2. Schedule plausibility is evaluated based on previously sent schedules for comparable business days (process not yet developed)
3. Optional schedule update due to intraday trading either before the RD bids are selected or after, considering that participation in other markets (intraday and balancing) shall not counteract redispatch measures
4. Acceptance of Redispatch bids followed by a corresponding schedule update by all assets included in the redispatch offer
5. Final schedule is known
6. If balancing services are provided: Shortly before real-time an indicative operating point for balancing is communicated
7. Schedules are evaluated based on historical data and measured values (process not yet developed)

3.2.2.2 (Online-) Measurement data

In order to observe the actual power generation/consumption of an asset compared to its schedule, derive its compliance with the schedule additional measurement data per-asset on a one-minute interval might be necessary. In addition to ex-post monitoring of redispatch provision real-time data might be necessary.

To allow grid operators observe redispatch provision and to determine whether additional remedial actions are necessary, online data might be requested by the TSO/DSO for larger assets (>25 MW as defined in SOGL Datenaustausch VO [9]). Online measurement data is delivered at a one-minute rate at the same aggregation level as the schedules.

3.2.2.3 Baseline Concept

For the ex-post identification of the different components mentioned in section 3.2.2, in particular the delivered redispatch, a suitable baseline methodology is needed. A baseline defines the profile an asset would have followed if it had not provided a certain service, in this case redispatch. As the term baseline is often used without clarification on which service is being monitored, the following section describes the general problem for the term baseline regarding redispatch and it's connection to the baseline for balancing services.

The baseline for the flexibility use-case redispatch is required for monitoring purposes, whereas for balancing it is used for monitoring and settlement. As described in the beginning of this chapter the complete task at hand would be the ex-post identification of all the different scheduled and unscheduled components, including all flexibility markets, of the measurements taken at the asset and metering point level.

This means that the baseline concept cannot be clearly separated into a baseline concept for balancing and a baseline concept for redispatch but must be conceived as a holistic approach. It is necessary that the delivery of balancing energy is evaluated according to the baseline methodology chosen for balancing by the provider of balancing energy.

Delivering an indicative point of operation for balancing (balancing baseline)

In case the FSP participates on the balancing market, the provision of an indicative operating-point according to the balancing baseline methodology provides a starting point for further calculations. This is what is usually referred to as "baseline" in the context of balancing. There is a multitude of baseline concepts deployed internationally as elaborated in the

Annex C: Baseline. Figure 16 illustrates schematically the evaluation of the delivered balancing energy based on an indicative operating point. The measurements of a balancing providing asset are compared to their indicative operating point. If the difference between the indicative operating point and the measurement is greater than or equal to the requested balancing energy, it is considered as fully delivered. If the difference is less than the requested balancing energy the difference between indicative operation point and measurement defines the delivered amount.

Subtracting delivered balancing energy

Once the amount of delivered balancing energy has been determined, based on the indicative operating point, it can be subtracted from the measurement values. This results in the sum of all schedules and any unintentional deviations. If there is no balancing provision, this step is not required, and the measurements can be directly compared to the final schedule.

Allocating deviations between scheduled components

As the final schedules are known, the unintended deviations can be calculated by subtracting the final schedule, which includes the DA-schedule, ID updates as well as the RD schedule from the measurements without balancing. If the difference is equal to zero, all schedules have been delivered accurately and in total. However, if it is not equal to zero at least one component has not been delivered completely. This makes it possible to determine the total deviation from the intended schedules. Furthermore, assessing the quality of redispatch provision requires a methodology to divide the total deviation fairly among the components of the day-ahead/intraday and redispatch schedule, which is yet to be defined.

Applying the allocation of deviations to the different components results in the fictitious redispatch delivery which can be compared to the agreed quantity and monitored as a quality criterion. Frequent deviations from the redispatch schedule, i.e. a non-fulfilment of the redispatch delivery, may be penalised.

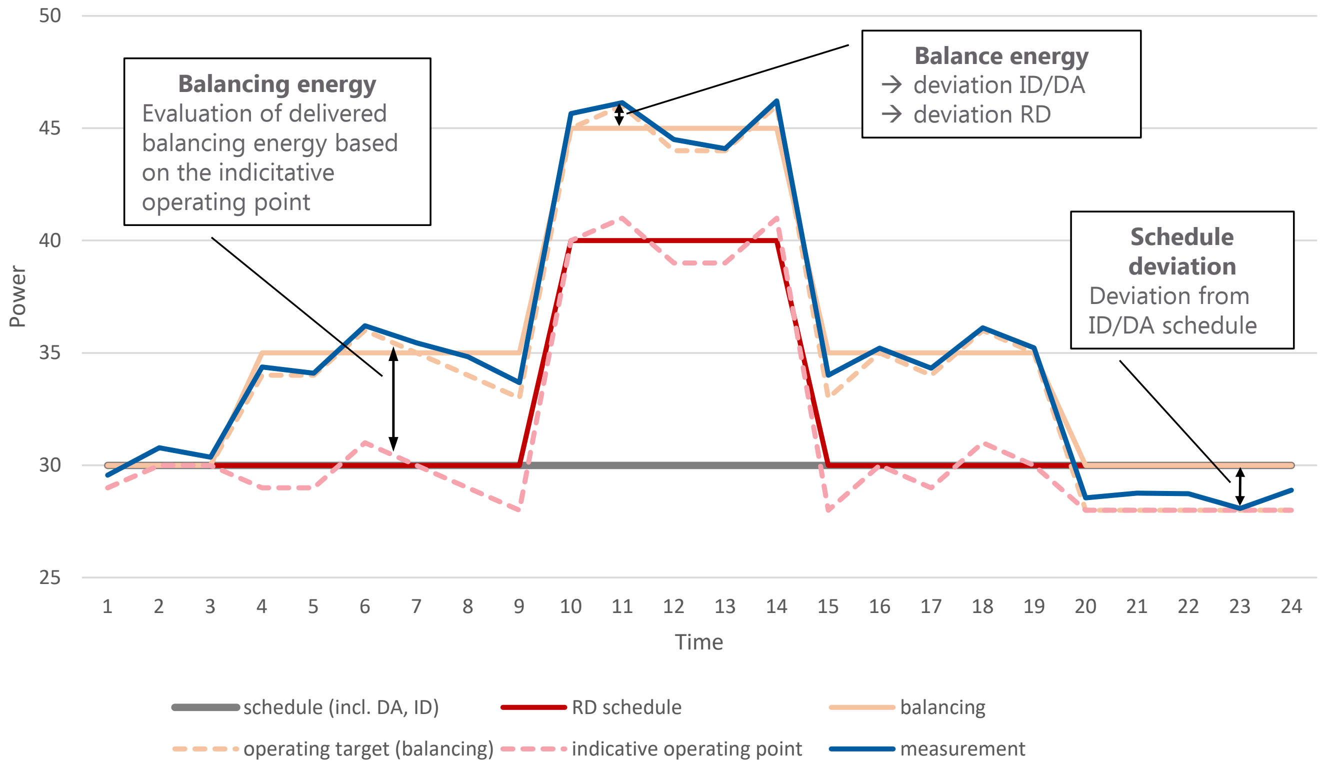

Figure 16: Interaction between the different components of an energy delivery

3.3 Organizational criteria

These criteria describe the conditions of participation of organizational nature. The contractual conditions encompass all terms and conditions associated with providing redispatch services. Next, the consideration of system charges within the remuneration of redispatch is discussed. Finally, existing options to secure sufficient flexibility potentials for redispatch services are elaborated.

3.3.1 Conditions of participation

The participation on the Redispatch Platform requires the acceptance of its terms and conditions, which regulate the rights and obligations of a redispatch provider and grid operators. By participating in the provision of redispatch FSPs agree to these terms and conditions.

These terms and conditions contain the following points:

1. **Prequalification**:
    a. Before the registration a prequalification process has to be completed successfully. The prequalification process ensures that a redispatch offer can be delivered in accordance with the redispatch requirements and will be defined outside of the project scope. Units greater above a certain threshold and individual non recurring units have to undergo prequalification as an individual asset, or in case of pooling each individual asset in the aggregate. For smaller recurring units a prequalification is expected on an asset type basis. Such assets below the threshold with the same asset type on't need to be prequalified individually once the FSP is prequalified for the asset type.
    b. APG and the DSOs reserve the right to adapt the prequalification requirements to ensure that redispatch deliveries comply with possibly changed national and international requirements with an appropriate lead time.
    c. A supplier can apply for the prequalification of additional assets at any time.
2. **Registration on the redispatch Platform as a Flex-Service Provider (FSP)**: During registration the FSP must provide the following information.
    a. Assets: For the consideration of bids of an asset/pool the master data of all assets is needed. Therefore, with registration an FSP accepts that the grid operators are allowed to use the data from the connecting system operator (the plants name, power, metering point, connection point, technical minimum power, …). The connecting system operator determines possible restrictions associated with the participation. Metering points as well as the relevant measured and metered values have to be delivered for all components that transmit a schedule for metering and monitoring purposes. In order to participate on the platform, it is necessary that the FSP is able to control/schedule the offered assets; evidence of this (e.g., contract between asset owner and FSP or a similar document) has to be provided.
    b. Balancing group: The balancing group which the FSP uses to schedule energy deliveries for redispatch must be named. Should the assignment of the balancing group change it has to be announced to the grid operators immediately. When a DSO/TSO accepts a redispatch offer the transfer of energy is scheduled with its respective "EPM" balancing group.
    c. Contact information: A single point of contact to the supplier needs to be provided. Thereof the following information is needed: Name(s), E-Mail address, telephone number and business hours as well as bank details.
    d. Recognition of the significance of redispatch providing assets for the network security: When an asset provides redispatch it is inherently relevant for network security. Thus, the Austrian SoMa Chapter 3 [8] applies, which demands the delivery of daily schedules of the planned feed-in or consumption. In order to comply with its responsibilities as a grid significant actor, it may not carry out any actions (e.g. balancing energy) in the hour(s) of the redispatch delivery that counteract the effectiveness of the redispatch (I.e., the opposite direction). The schedule delivery is independent of the submission of bids; this means that schedules have to be delivered every day even if no redispatch bid is submitted. Furthermore, regular feedback of the asset's availability is required. This is facilitated via a keepalive message, signaling that the bidder is still actively participating in redispatch.
3. **Operatorial process** follows the steps and timings as elaborated in chapter 3.1.4.
4. **Delivery obligation**: The FSP is obligated to deliver the offered bids that have been submitted in accordance with the quality requirements. During the time of redispatch delivery the offering asset(s) may not make any offers on the balancing market for the opposite direction, i.e. if an FSP offers a power increase on the Redispatch platform it may not simultaneously offer a reduction of power on the balancing market and vice versa. Placing offers for both products is possible if they are simultaneously feasible, and both result in either an increase or a decrease in power.

5. **Settlement and payment**:
    a. The direction of energy flows between the FSP and the requester of a flexibility service must be defined. For unambiguous settlement the definition of incoming party and outgoing party, describing the sink and source of energy, for each transaction and the associated cost is necessary.
    b. Settlement is carried out monthly by the grid operator based on the transactions carried out via the Redispatch Platform. The electronic invoice contains a list of all redispatch requests.
    c. Detailed cost breakdown for cost checks: If the final cost model should be cost based or have a cost-based component the detailed cost breakdown of selected redispatch requests has to be delivered to the grid operator and/or the regulator to allow the audit of cases that give reasonable doubts that the prices might not be justified or are questioned by “Energie-Control Austria”.
6. **Communication of additional data for the Baseline methodology**: The FSP delivers all measured and metered values required for the prequalified baseline methodology to the grid operators to enable them to verify the redispatch delivery. Aggregated ex post metered values always have to be delivered for each metering point, for special cases (especially plants with an installed power greater than a certain threshold) online measuring values have to be provided. The duration and power of each requested redispatch measurement has to be documented by the FSP and the requesting grid operator.
7. **Contract duration:**
    a. The contract enters into force as soon as the FSP registers on the Redispatch Platform and is valid for an unlimited duration. Its termination is possible for both parties at the end of each calendar month in writing.
    b. An extraordinary termination with immediate effect is possible:
        i. For grid operators, if the prequalification requirements are not met, if the contractual obligations are violated repeatedly, if the FSP violates the prohibition by competition law to abuse one's market-dominating position or violates another antitrust regulation to the detriment of the grid operator.
        ii. For the FSP in case of changed prequalification requirements, timeframes for bidding or minimum sizes.
8. **Failure of an asset, a bid or partial bid**:
    a. In the case of failure, the FSP has to notify the grid operator immediately and announce the extent as well as the expected duration via phone. In such a case the grid operators' obligation to remunerate depends on how the failure of an asset is handled (see below). Schedules are to be adapted accordingly as soon as any deviations resulting from the failure of an asset are known.
    b. In case of failure three options exist, which are elaborated in chapter 3.1.8.2:
        i. The FSP is able to offer a comparable replacement; in this case no financial consequences arise.
        ii. The FSP is able to procure a replacement on the market; in this case no financial consequences arise.
        iii. Cancellation, in the case that the FSP is not able to offer any kind of acceptable replacement and it is not acceptable to the TSO that the FSP procures a replacement on the market; In this case energy deliveries to/from the EPM balancing group need to be rescheduled in order to avoid balance energy. Replacements are procured by the TSO and the cost to the FSP depends on a future remuneration scheme for redispatch. In any case the cancelled redispatch counts as undelivered and will not receive compensation. If a cost-based model is used for reimbursement and FSP does not stand to profit from redispatch, the FSP will not receive compensation for its cancelled bid, but no additional costs are charged to the FSP. In case of market-based pricing whereby the FSP would stand to profit from redispatch, the FSP will be charged additionally for the replacement by the TSO.
    c. Any other deviations result in balance energy for the FSP
9. **Force Majeure**: Both parties are exempt from their rights and responsibilities during events of force majeure.
10. **Liability**: The FSP is liable for the direct damage caused by gross negligence or intent.
11. **Confidentiality**:
    a. Grid operators may publish redispatch measures to comply with their legal obligations, the FSP may not publish redispatch data.
    b. The TSO may use the bids in international redispatch processes, i.e., ROSC and other internationally coordinated and optimized processes.
    c. Metered values are strictly confidential.
    d. Measured values may only be used internally to verify redispatch measures and must not be shared with third parties.

e.

12. **Test redispatch requests**: The FSP agrees to be available for at least one test redispatch request, after their registration or, if they have not been activated via the Flexibility Platform within one year, in the following year. The grid operators are not obliged to exercise their right to do so.
    a. The day and time period of a test redispatch request are agreed upon in advance via phone, the FSP has to make an offer for the agreed time.
    b. Costs of the test redispatch are borne by the requester (by DSO/TSO). The FSP has the opportunity to sell the energy of the test request on the market; in this case the system operator only bears the costs for difference between market revenues and costs of the test activation.

3.3.2 System charges

For providers of redispatch it is essential that they are able to calculate the costs arising to them from providing redispatch to the TSO or DSO. Pursuant to Article 23 (2) ElWOG [12] the economic disadvantages and expenses caused by redispatch services must be compensated. Part of the expenses associated with redispatch are the corresponding system charges. Therefore, it is necessary to clarify which additional system charges could arise from the provision of redispatch services.

In general, the following system charges exist, which are explained in Part 2 of the ElWOG [12] in sections 51 to 58 and further elaborated in the SNE-VO [13]:

- **System utilization charge** designed to compensate the system operator for the cost of constructing, expanding, maintaining and operating the system. It consists of an energy part and a capacity part and is applicable for withdrawing parties.
- **Charge for system losses** designed to cover those costs that are incurred by the system operator in relation to the transparent and non-discriminatory procurement of adequate energy volumes to offset physical grid losses. These charges are relevant to withdrawing and injecting parties, thereof only powerplants with a connected capacity greater than 5 MW.
- **System admission charge** compensates the system operator for all reasonable cost, considering normal market prices, directly arising from connecting a facility to a system for the first time or altering a connection to account for a system user's increased connection capacity. It is a one-time payment borne by withdrawing and injecting parties.
- **System provision charge** covers the past and future system development measures necessary to enable the connection of withdrawing parties. It is a one-time payment at the time of first connection or upon exceedance of the agreed extent of system utilization.
- **System services charge** is designed to cover the costs incurred by the control area manager in relation to the requirement to offset load variations by means of secondary control. It includes an energy part only and is payable by injecting parties with a connected capacity greater than 5 MW.
- **Metering charge** compensates the system operator for the costs directly related to the installation and operation of metering equipment, including necessary converters, calibration and meter reading and is payable by all system users (I.e. withdrawing and injecting parties).
- **Charge for supplementary services** encompasses charges not covered by the components listed above and directly associated with the system user such as reminders and extraordinary meter readings.

Not all system charges are directly connected to a redispatch measure and must thus be excluded from the costs to be reimbursed for the redispatch measure. As different charges apply for infeed and load the additional costs from system charges resulting from redispatch provision the following paragraphs cover infeed and load separately.

Table 4 demonstrates the charges applicable to injecting parties. System admission charges, metering charges as well as charges for supplementary services are independent of the redispatch measure and may not be included in the costs for a redispatch measure. The charge for system losses and the system service charge are dependent on the energy injection and are thus influenced by redispatch measures. These system charges caused by the redispatch measure may thus be part of the RD costs.

System charge	application	to be reimbursed in RD cost	reason
System admission charge	once, at the time of grid connection	✘	Not influenced by redispatch
Charge for system losses*	per unit of energy delivered	✓	Share of the charges caused by the RD measure
System services charge*	per unit of energy delivered	✓	Share of the charges caused by the RD measure
Metering charge	per month	✘	Independent of RD measure
Charge for supplementary services	per year	✘	Independent of RD measure

* Relevant for power plants with a connected capacity > 5 MW

Table 4: System charges of injecting parties

The charges applicable to withdrawing parties are listed in Table 5. Analogous to injecting parties, system admission charges, system provision charges, metering charges as well as charges for supplementary services are independent of the redispatch measure and may not be included in the costs for a redispatch measure. However, the charge for system losses and the system utilization charge are dependent on the energy consumption as well as the power (in cases of peak demand) and thus in- or decrease due to redispatch measures. The energy parts of these system charges may thus be added for the energy associated with the redispatch measure. If the redispatch measure results in a new demand peak and consequently a capacity fee component (system utilization charge), such charges are to be attributed to the RD costs.

System charge	application	to be reimbursed in RD cost	reason
System admission charge & System provision charge	once, at the time of grid connection	✘	Not influenced by redispatch
System utilization charge	energy price per unit of energy delivered and capacity price for max capacity usage	✓	additional charges caused by the RD measure
Charge for system losses	per unit of energy delivered	✓	additional charges caused by the RD measure
Metering charge	per month	✘	Not influenced by redispatch
Charge for supplementary services	per year	✘	Not influenced by redispatch

Table 5: System charges of withdrawing parties

Similar to participation in the day-ahead and intraday energy market the system charges have to be considered in the price of a bid and varying fees due to different regions or grid levels must be considered.

Article 5 SNE-VO [13] reduces the system utilization charge for secondary and tertiary reserves. The benefit of applying such a regulation for redispatch would be equal charges for all withdrawing redispatch providers in terms of system utilization charges independent of their network level and a reduction of the price level of redispatch bids. The TSO/DSOs receive these system charges and the TSO/DSOs are also the parties paying for redispatch. Considering this, lower costs of redispatch are compensated by a reduced income from system charges and vice versa. The distribution of costs however would shift from the requesting system operator, which pays for redispatch, to the grid operator where the asset delivering the service is located. For the asset offering redispatch the net gain from offering redispatch should remain the same, as long as these charges can be reflected in the price of a redispatch bid. Furthermore, such a regulatory change would result in a higher organizational overhead to consider all the exceptions during the clearing of system charges for redispatch providing parties, to achieve lower bid prices during settlement of the activated redispatch bids.

Since providers of redispatch may include additional system charges resulting from redispatch in their bid-price, the current framework regarding system charges appears suitable for the provision of redispatch from small scale industrial units. A shift towards a different regulation regarding system charges does not appear warranted and would need detailed analysis regarding the resulting distribution of costs and benefits between Austrian TSO/DSOs which is outside the scope of this project.

3.3.3 Securing flexibility potential

The ElWOG [12] gives the system operator a number of options to ensure that enough redispatch potential is available to remediate congestions.

Producers are generally obliged to provide services (increase or decrease output) to remove congestions or maintain security of supply by direction of the control area manager as stated by Art. 23 (9) ElWOG [12]:

"(constitutional provision) If system congestions occur in the control area's transmission network, producer services are needed for their removal […] the producers, by direction of the control area manager in agreement with the affected distribution system operators, shall provide services (increase or reduce their output, change the availability of their power plants)."

This applies to all producers independent of their size. The control area manager shall enter contracts with producers to establish further details of such services, however the control area manager can also direct producers without a contract to increase or decrease their output to remove congestions.

Additionally, if a system analysis reveals the demand for a secured capacity for generation and/or load increase or reduction, such services may be secured as "grid reserve", through a transparent, non-discriminatory and market-oriented bidding procedure. Grid reserves may be procured for up to two years, one year or as a seasonal product (summer/winter). Producers may only participate if they have announced decommissioning within the period for with the grid reserve is secured. Consumers may participate, if they can offer at least 1 MW of demand reduction, and if they are able to reduce or shift their consumption temporarily, at least for 6 hours. Withdrawing parties must have an uninterruptable load of at least the provided power, the only exceptions are announced revision periods. This means that only parties with high availability are able to offer grid reserve.

This means that flexibility of industrial units or small scale distributed units may be secured via the grid reserve mechanism, if they can meet the grid reserve requirements, but no further options to secure capacities, such as short term capacity markets, for redispatch exist. In other European countries the regulatory framework differs. An overview of different regulatory solutions across Europe for different strategies aiming at ensuring sufficient flexibility potential for redispatch is given in deliverable 3.2.

4 VPP Perspective

Based on the requirements for provision of redispatch outlined in section 3 this chapter describes the view of a virtual power plant (**VPP**)

LV VPP: having assets on low voltage level (project partner Energie Kompass) – referenced as LV VPP in the text

MV VPP: having assets on medium voltage level (project partner EVN) – referenced as MV VPP in the text

with respect to roles, responsibilities and processes for providing redispatch. The roles and processes are first described based on Chapter 3 as interpreted by the VPP operators and then the resulting implementation for the VPPs participating in the project is indicated by blue boxes, such as the one above.

At the moment, the technical requirements limit the participation to assets with a minimum nominal power of 500kW and above. Furthermore, redispatch offers must have a minimum bid size of 1MW. A LV VPP would not be able to participate in the market under these conditions.

Nevertheless, this chapter serves

- as a check of WP 3.2 (where are open questions needing final determination)
- the consideration for project partners like Energie Kompass and EVN with respect to possibilities and arrangement of future participation

The draft documents [1]and presentations from Task 3.2, defining the redispatch requirements were used as input for the analysis from VPP perspective. The content of these document is now reflected in Section 3.

4.1 Roles and responsibilities

This chapter gives an overview of the actors' roles and responsibilities related to the redispatch process.

System operators (TSO and DSO's):

- execute capacity and network security analysis calculations
- Operate the Redispatch Platform
- Undertake prequalification procedures of redispatch providers and their assets
- Undertake redispatch test activations requests to verify the providers capability to provide redispatch
- Select the redispatch offers which are network compatible and most cost-efficient under consideration of their effectiveness
- Operate the balance group(s) for the congestion management, which receive/deliver redispatch energy from/to the FSP
- Validate the compliance with redispatch quality criteria (on base of measurement values requested from the FSP, if applicable)
- Validate the provided redispatch power via the measured values (profile counter is a prerequisite for participation – used for evaluating– always from the PCC) and temporal/local higher resolution measurement values (for proving the provision – 1 minute resolution - of individual assets behind the PCC, if applicable)

[1] 20220223_WP3_festgelegtePunkte.pptx, 20210921_Drittes_Arbeitsmeeting_Task3-2.pdf, 20220314_Arbeitsmeeting_Task3.2.pdf (not yet uploaded, recently discussed), I4RD_Baseline.pptx, 20211021_I4RD_Nachholeffekte.pdf, Vertragliche_Punkte.docx (not yet uploaded, recently discussed)

– Settlement of payments towards the providers

Providers of redispatch/FSPs (= VPP Operators):

– Registration at the Redispatch Platform as flexibility service provider (FSP)
– Provision of necessary master data
– Listing all participating assets (e.g., asset name, asset nominal power, metering point / network connection point)
– Apply for Prequalification of FSPs Infrastructure (IT and Processes) and of the of participating assets (metering points)
– Accept the conditions of participation of the Redispatch Platform
– Name a single point of contact (reachability of provider, name, e-mail, telephone, business hours, bank account for settlement of redispatch provision)
– Name the balance responsible party of the participating assets dealing with their schedules

LV VPP: Energie Burgenland

MV VPP: EVN VPP operator balance group. EVN clears with other balance groups, in case that assets in their pool are assigned to other balance groups

– Have an agreement with the asset owners, that they can control these assets for the purpose of redispatch provision (directly via telecontrol or API, but also indirectly via mail/call to the asset owner/operator – depending on the individual agreement)
– Report a D-1 schedule and update the schedule if applicable (at least for the aggregated offer, for DSO possibly also for individual assets/metering points – depending on the asset power in accordance to the market rules – SoMa – Chapter 3 and it's baselining methodology)
– Place offers on the Redispatch Platform
– Control the assets (directly or indirectly) according to the activation of the redispatch bids
– Inform the system operators immediately in case of reduction/failure of activated bid/power and coordinate the replacement procurement if possible
– Are willing to conduct at least once per year bilaterally agreed test redispatch activations by request of system operators for verification of their redispatch capabilities

Balancing responsible party of the assets:

– Processing of schedules between the redispatch assets and the redispatch balancing group
– Imbalance Management as usual (there is no change necessary for imbalance settlement)

LV VPP: For assets/metering points in the LV VPP as of today no schedules of assets are available. The balancing responsible party has at least the standardized load profiles of the metering points/assets. For the participation in on the redispatch platform the delivery of a schedule would be required

MV VPP report the d-1 schedules of (industry) assets (where the SoMa requires them anyway). In case of customers/assets, which do not report assets as for now, but want to be part of redispatch offers, the schedules will be demanded from the customers as the requirements for redispatch demand it. If they are available, they will also be sent to the balancing responsible parties of the assets.

Asset owners

- Have an agreement with the redispatch provider/FSP that his assets can be controlled for the purpose of redispatch (directly or indirectly)
- Must provide all necessary data (master data, metering point) and processes (test redispatch procedure, etc.) needed for prequalification for redispatch

  Have an agreement with the VPP operator with respect to settlement of redispatch provision / penalties

> **LV VPP:** For assets/metering points in the LV VPP as of today no schedules of assets are available. The balancing responsible party but has at least the standardized load profiles of the metering points/assets. For the participation in on the redispatch platform the delivery of a schedule would be required
>
> **MV VPP:** The asset owner must provide (as agreed) the information needed for the execution of the redispatch processes (e.g., d-1 schedules, schedule updates, available flexibility, information about catch up effects)

4.2 Redispatch process

The following subsections describe the different steps of the redispatch process from the perspective of a VPP. First the general process of data delivery is described followed by the placement of bids, the activation of bids, the service provision, reporting and settlement.

4.2.1 General process – data provision

The following data must be delivered independent of the placement of bids:

- Master data (one time when initially registering/at prequalification)
- D-1 schedule (baseline) until 14:30 h on the day before delivery/consumption – in 15-minute resolution

> **LV VPP:** Baseline calculated as average value of historical measurement readings (filtered by day type, if applicable); possible exception is the calculated forecast based on weather data for PV generation. The LV VPP baseline refers to the metering point.
>
> **MV VPP:** Reported by asset owner. The baseline refers to the metering point or to the individual providing assets behind it.

- There is currently no threshold for the forecast quality of the d-1 schedule defined as condition for participation.
- Update of schedule in case of changes due to e.g., intraday trades or correction of forecast errors.

> **LV VPP:** There will be no intraday trading in the LV VPP and no parallel marketing of ancillary services takes place. The d-1 schedule is equal to the redispatch baseline.
>
> **MV VPP:** According to the customers capabilities parallel marketing on intraday and ancillary services is possible. Indicative operating point for balancing power is delivered and used for balancing power calculation/clearing as of today. Measured power minus activated balancing power is equal to scheduled value plus redispatch power. this is monitored.

- Ex-post metered and measured values and higher resolution measured values (e.g.: 1 minute granularity), depending on the assets/FSPs baselining methodology.

4.2.2 Redispatch process – bids/offers

This chapter elaborates on the bid structures relevant to the VPP, how bids are placed and which information needs to be included in the bid.

For the **LV VPP** the following bid structures would be used:

- Regular block bids: Power value / Price / 15-minute time slice – indivisible (full power value to be activated)
- Profile block bid: Power values for several 15-minute time slices (profile) / one price for the whole profile offered (MWh) – indivisible (full power and complete profile to be ordered)

If a participant wants to offer bids for the whole day, this means that for regular block bids in a day-ahead bidding process 96 individual block bids – per power direction (positive/negative) – must be placed on the platform.

For the **MV VPP** also more complex bid structures (e.g., xor/and linked bids or at stage parent-child linking) could be applicable (customer dependent).

Bid placement:

- Gate opening at approx. 14:30h, gate closure at approx. 18:00h, after GCT the offers placed are firm and must be delivered if they are activated
- Bid acceptance announced presumably around 22:00h

Bid data:

- Separate offers for positive (increase in generation/decrease of load) and negative (decrease of generation/increase of load) flexibility in the form of the offer types above
- Expiry date/lead time: minimum lead time needed between bid acceptance and delivery (preferably stated as offer validity time) – provided, but can be left empty if irrelevant
- List of assets that are part of the bid
- Even if no offer is placed for one day, the d-1 schedule and some kind of "keep-alive" message shall be reported to the platform as a notification of the provider, that he is still interested in participation

Bid aggregation level:

Currently the aggregation on 110kV network level would be allowed; meaning that one could aggregate assets/metering points of the same 110kV network to one offer/bid

For the TSO data of assets connected to the distribution grid is sufficient on aggregation level, because the TSO is only concerned with the effect on the transmission grid. The DSO however needs the schedules for individual assets/metering points for his network security calculations.

The **LV VPP** will provide measurements of the metering point only – not from individual providing assets behind the metering point

The **MV VPP** will provide measurements from individual assets behind the metering point preferably – asset measurement devices are already/will be installed

Anticipatory/Catch Up effects:

If anticipatory or catch-up effects take place, an additional related schedule must be reported additionally to the Redispatch Platform along with the bid. The FSP must ensure that (e.g., 4h after redispatch provision has ended) no catch up of redispatch power takes place inside the envelope curve.

Schedules of the catch-up/anticipatory effects must be provided independent of the compliance with the envelope curve.

Interface/data format:

LV VPP:

- The LV VPP does not influence its assets prior to provision; therefore, no anticipatory effects will take place anyway and the LV VPP would not provide anticipatory/catch up schedules.
- In case there are assets/metering points in the offered pool, which show catch up effects by their nature, the local automation must take care that they take place only after 4h time difference to the ending of the redispatch (or outside the actual valid envelope curve). A schedule for these catch up effects must be provided as part as the bid-

MV VPP:

- The catch-up schedule will be transmitted along with the offer. According steering by the VPP system directly or via the customers automation equipment – depending on customer capabilities and needs.

The interface/data format will be defined later in the project.

Cost calculation:

LV VPP:

- From point of view of the LV VPP a market model would be preferred. However in case a cost based (+ markup) model is chosen the list of cost components (see Annex D: Cost components) is extensive and complete from LV VPP point of view.

MV VPP:

- From EVN point of view a transparent market (like reserve markets) with a merit order (weighted according to effectiveness) would be preferred. Cost based models do work only if the assets are obliged to participate.
- An attractive option from the MV VPP point of view would be a remuneration model, which utilizes indices based on the revenue opportunities on other markets (Intraday, reserve markets).

4.2.3 Redispatch process – bid acceptance

Accepted bids will be announced around 22:00h presumably to the providers/FSPs in the form of Yes/No (Accepted/Not accepted) information. They are to be interpreted as flexibility (+/-) to be provided relative to the baseline / schedule. The sum of all accepted bids could be interpreted as “redispatch schedule”. For regular block bids there will be an acceptance information per individual bid.

The interface/data format will be defined in a later stage of the project.

4.2.4 Redispatch process - provision

The after a bid was accepted the FSP is obliged to provide the agreed redispatch. The FSP must control (directly / indirectly) the providing assets according to the accepted bids.

The provision must take place in accordance with the defined redispatch quality criteria:

- Block provision: the offered power must be reached at least 5 minutes after the 15-minute time slice changes– in relation to the last valid baseline/schedule reported
- Ramping (from 5 minutes before until 5 minutes after the 15-minute time slice change) is desirable, but no hard prerequisite for redispatch provision
- The power values should be inside a range of 95% - 115% of the offered value
- The failure to provide redispatch must not happen “too often”
- In case the provider knows about incurred or foreseeable failures of redispatch provision (prior to or during provision) he shall inform the system operators immediately.

An aggregated asset pool can operate from TSO point of view with collateralization strategies – keep more available flexibility than offered, to be able to manage the shortfall of one of its assets by compensating with others. The DSO, however, must know the collateralization power of the assets to be able to calculate the network security (as the provision may be shifted from one asset in the pool to another).

For the **LV VPP** only the collateralized provision is reasonable – if the quality criteria would be applied per individual asset/metering point, redispatch would be no possible business model for LV VPP.

4.2.5 Redispatch process – reporting of measurements

The FSP must report the measurements, depending on the baselining methodology, per metering point / asset in up to 1 minute granularity of all assets providing redispatch for ex post verification purposes.

The measurements of assets / metering points in 1 minute granularity are recorded (as well as the aggregate totals) in the **VPP** system and are available for verification of redispatch provision.

The interface / data format will be defined in a later project stage.

4.2.6 Redispatch process – settlement of provision

A monthly settlement after the fact in electronic form will be provided by the system operators (per accepted offer).

The breakdown of the settlement towards the participating assets of the pool is done by the VPP operator, i.e. the FSP.

Every delta between accepted and provided redispatch energy will lead to imbalance cost for the FSP.

Upon request of the system operators or the regulatory authority the provider must deliver a detailed cost breakdown for verification by a financial auditor.

5 Summary

In this Deliverable requirements for redispatch provision were identified and analysed from the VPP perspective. The requirements for redispatch can be grouped into technical criteria, data exchange criteria and organisation criteria.

The **technical criteria** contain all information relevant to the technical requirements for the redispatch bid and the general timings related to the process. In general, any market participant, who is responsible for planning and operation of assets, that meet the minimum bid size, or multiple assets that meet the minimum asset size and can be aggregated to offer the minimum bid size, may register as a flexibility service provider (FSP) on the redispatch platform. The minimum bid size is defined at 1 MW. Starting from 1 MW the bid size may be increased by 0,5 MW increments up to the maximum bid size of 400 MW. Smaller assets may be aggregated to reach the minimum bid size. Aggregation is possible at 110 kV level (i.e. within federal provinces) and may be performed using assets with an installed capacity grater or equal to the minimum asset size of 0,5 MW and smaller or equal to the maximum asset size of 50 MW.

The bids themselves may be placed as 15-minute products with a corresponding price. Bids may be offered as simple bids or linked logically via an AND, an XOR or as a profile bid. In case any catch-up or anticipatory effects are related to the bid, it must be ensured, that they occur outside of an envelope curve as defined by the system operators and a corresponding schedule of the effect must be provided as part of the bid information. Gate opening time of the redispatch platform is defined at 14:30 day-ahead and gate closure time (GCT) at approx. 18:00 day ahead. The FSP has the option to communicate the required lead time to execute the bid via an expiration date, after which the bid cannot be activated anymore.

To be able to participate on the redispatch platform flexibility providers have to comply with the quality criteria laid out in this document: Observability, reliability and shape of energy delivery. Observability aims at ensuring, that system operators are able to effectively model the assets scheduled feed-in or consumption within their grid security analysis. All participating FSPs have to send day-ahead schedules for their assets until 14:30 and update them if necessary. FSPs have to ensure that these schedules are accurate and correspond with the actual measurements. The measurements have to be provided to monitor schedule accuracy and redispatch delivery. Furthermore, the reliability of the redispatch bids must be ensured. This means that the bids offered after GCT are firm and have to be delivered with the exact timing and amplitude as offered, if they are activated. It has to be ensured that nothing can interfere with the delivery of the redispatch bid (i.e. other services sold to the distribution grid operator or balancing). Finally, the energy delivery has to be of the required shape: At least 95% of offered power has to be obtained 5 minutes after the start of the delivery period. A minimum of 95% and a maximum of 115% of the power offered must be obtained. Any energy bought/sold as redispatch but not supplied results in imbalance energy and corresponding costs to the FSP.

The **data exchange criteria** specify that any master data, schedule data, measurements and if necessary real-time data required have to be provided. The schedule serves as the baseline. The schedule information in combination with the measurements taken is then used to validate redispatch delivery.

The **organisational criteria** encompass mainly the conditions of participation. To be able to participate on the redispatch platform the FSP and the corresponding assets have to undergo prequalification. The FSP has to accept the terms and conditions of the redispatch platform, which regulate the rights and obligations of a redispatch provider and grid operators.

All redispatch criteria have been analyzed from the **VPP perspective**. First the roles and responsibilities were clarified from the VPP perspective followed by a step-by-step review of the redispatch process. The following aspects were identified as hurdles:

- The technical requirements currently limit the participation to assets with a minimum nominal power of 500 kW and above. Furthermore, redispatch offers must have a minimum bid size of 1MW. A LV VPP would not be able to participate in the redispatch market under these conditions.
- Furthermore, for the LV VPP only a collateralized provision is reasonable, however, if the quality criteria would be applied per individual asset/metering point, redispatch would be no possible business model for LV VPP. Hence solutions for a redispatch provision including collateralization have to be found.
- In general, a market-based redispatch redispatch would be preferred. However, in case a cost based (+ markup) model is chosen the list of cost components (see Annex D: Cost components) is extensive and complete from LV VPP point of view.

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Annex A: Bid structure

Bid types

In general, the types of offers that are allowed in the day-ahead market of any power exchange (PX) are a crucial factor for the suppliers, as they have to define their bidding strategies according to the allowed bid types. Due to market responses and innovations, PX across the world allow a wide range of bid types. They can be split into three main groups, simple bids, block bids and complex bids (see Figure 17).

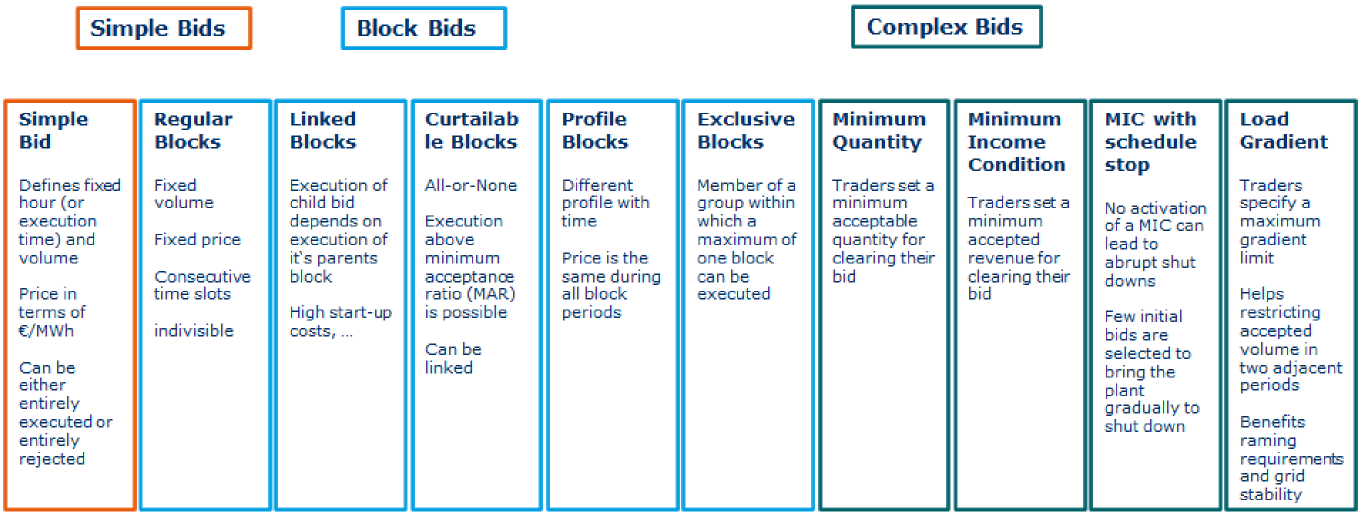

Figure 17 Bid types offered in day-ahead market of electricity power exchange (Source: based on [14])

Simple bids

The Simple bid is the most common and popular bid type allowed in any PX. Such offers define the fixed hour (or execution time) and volume at which the supplier can sell power, or the buyer can buy power. Furthermore, price in terms of €/MWh needs to be specified along with their execution time and volume. Simple bids can be either entirely executed or entirely rejected.

Block bids

Electric Power suppliers having generators with high start-up and shut-down cost are generally reluctant to submit hourly offers, as such bids are in general economically inefficient. Therefore, it is more viable for them to submit offers in blocks of some consecutive hours. The block products can be of standard and nonstandard types. Standard block offers have fixed length (number of consecutive hours) and execution time which is fixed by the PX. Non-standard blocks have user-defined length and user-defined execution time. In general, number and length of block offers are restricted to some predefined standard as it complicates the market clearing mechanism. Popular blocks are:

Regular blocks

This type of block bid is most frequently used. The seller specifies a fixed volume, fixed price, and consecutive time slot in which the bid has to be delivered if cleared. The bid is cleared if the average market clearing price over operation time horizon is more than a specified price limit. It is either fully accepted or fully rejected. Partial execution is not possible. Examples of standard block bids from EPEX Spot are Base Load, Evening, Early Morning, off-peak-1, and Sun Peak.

Linked blocks

Linked blocks are sets of blocks with a linked execution constraint, meaning the execution of a child block depends on the execution of its parent's block. In general, there are two different types of linked blocks.

Linked blocks are sets of blocks with a linked execution constraint, meaning the execution of a child block depends on the execution of its parent's block.

First, there are linked blocks where parent and child bids are linked within the same timestep. Such bids allow for a representation of the variation of electricity generation with regards to the market price. This is very useful for sellers having generators with high starting and shutdown cost. For example, there might be high cost of start-up and/or stop of production. Once these costs are covered, the producer can provide at a low marginal cost. Therefore, the seller can price the parent block high to cover the start and stop cost, then price child blocks low to include the extra volume with low marginal cost. A typical example of linked block bids is shown in Figure 18. Child-1 (C-1, C-2, C-3) can only be accepted after parent is accepted and Child-2 (C-11, C-12, C-13) can only be accepted once Child-1 (C-1) is accepted.

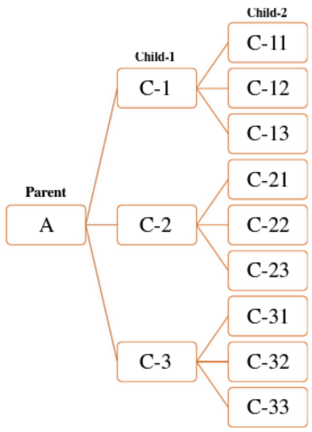

Figure 18 Parent-child arrangement in linked block bids (Source: [14])

The second type of linked blocks are bids where the linking occurs over time. This property is called linking in time or conditional linking. The aim is to switch the availability status of the bids over time to avoid unfeasible activations. Different possibilities for linking are summarized in Table 6. It is important that the bids have a unique ID, in order to be identifiable and to avoid unfeasible activations [15]. In general, the type contains either a number or a letter. For example, the TSO in Belgium indicates with a number that the bids initial status is 'available'. A letter, on the other hand, means that the initial status of the bid is 'unavailable' [15].

Table 6 Possible types of conditional links

name	initial status	effect
type 1	available	becomes **un**available if the linked bid is activated; type 1 linked bids may be used to reflect that the activation price of energy start-up modus drops in case of consecutive activation
type 2	available	becomes **un**available if the linked bid is **not** activated; an example for a type 2 linked bid would be the consideration of delivery points with a longer required time between two activations
type A	unavailable	Becomes available if the linked bid is activated; type A linked bids are the counterpart to type 1 linked bids and can also be used to reflect the start-up of an asset
type B	unavailable	Becomes available if the linked bid is **not** activated; as for type 2, type B linked bids are also used to e.g., reflect delivery points that require a certain time between the activations

Comparing regular block bids with linked bids identifies three fundamental challenges for regular block bids: First, regular block bids require market participants to express their flexibility in a standardized format and thus it is difficult to model different characteristics in block bids. Second, the types and parametrization of regular block-bids differ across the European countries (number of hours covered, number of conditionalities formulated, time of retrieval Missing alignment of these bid formats is a major challenge for market coupling. Third, start-up costs cannot

Parent-child bids allow for a precise representation of the capabilities of different technologies.

be represented explicitly in most regular block bids and hence need to be included in mark-ups of the bids. This reduces the efficiency on the market outcome, increases transaction costs, can discriminate against less informed (smaller) participants, and increase uncertainty for market participants. In contrast, parent-child bids allow all market participants to formulate their flexibility offer with a precise representation of their actual capabilities limited by the technology.

Curtailable blocks

Curtailable blocks are regular blocks that include the option to be partially executed. Partial execution is only possible under consideration of user defined thresholds (minimum accepted ratio).

This bid type represents sets of blocks which can be either entirely executed or entirely rejected (All-or-None). Under special conditions, it is also possible to execute these bids above a minimum acceptance ratio defined by traders. This means that the block bid can be partially executed as per user-defined parameter called minimum accepted ratio (MAR). MAR represents the percentage of the regular block bid which must be either fully accepted or rejected. Its value lies between [0 to 1] and [0 % to 100 %]. If MAR of any curtailable block bid is 0,5 then it is accepted only when at least 50 % of its total volume is fully cleared at the specified time period (see Figure 19). Otherwise, it is fully rejected. If MAR of any curtailable block bid is 1 then it becomes a regular block bid with all-or-nothing execution condition. Introducing a MAR reduces the risk of an order being rejected.

Moreover, curtailable blocks can be linked.

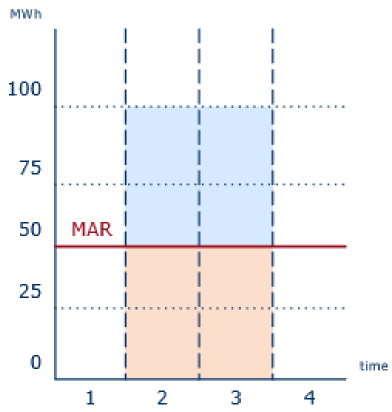

Figure 19 example of a curtailable block bid with MAR = 0,5

Profile blocks

Profile block bids are characterized through provision of a profile of different volumes for the time-units offered.

Profile block bids offer the possibility for providers to provide a profile with different volume over time. However, the price would be the same across all block periods. For market clearing, as price for the profile block bid a weighted average price is used instead of the average price, used for regular block bids. A typical representation of two profile block bids with varying quantity is shown in Figure 20.

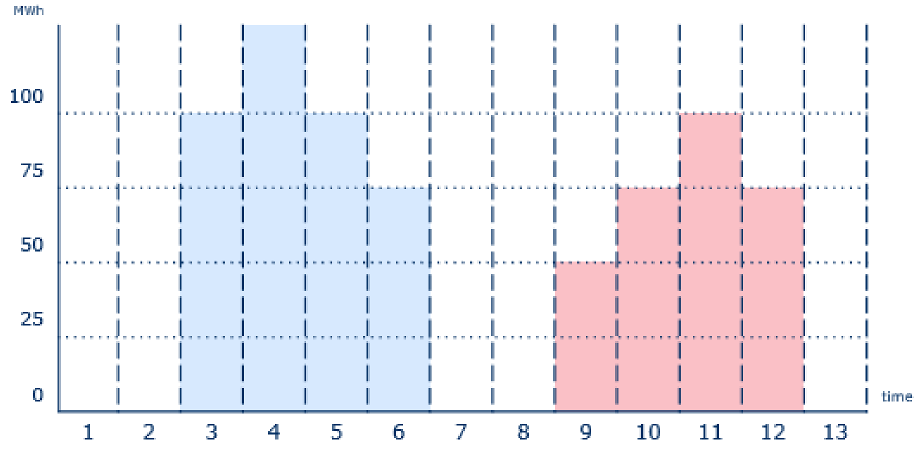

Figure 20 Example of two different profile block bids

Exclusive blocks

An exclusive block bid is a group of bids in which a maximum of one bid can be executed (during the same timestep).

An exclusive block bid is a member of an exclusive group of blocks within which a maximum of one block can be executed. This means that the bids are mutually exclusive (exactly one or none). Different maximum and minimum quantities, prices, directions and durations are possible. Figure 21 shows a group of exclusive bids, where the volumes and activation times of the different bids vary.

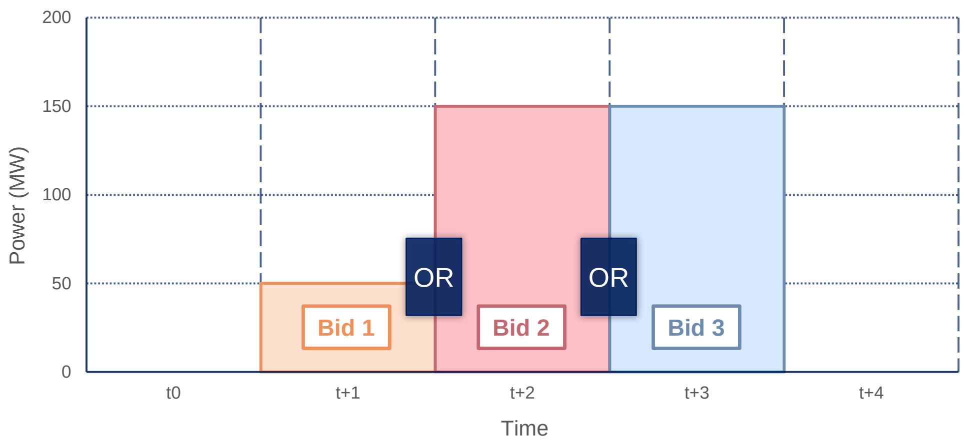

Figure 21 Group of exclusive bids

Loop blocks

Loop blocks are families of two blocks which are executed or rejected together (i.e., AND linked). These blocks allow to bundle and sell blocks jointly. Loop blocks may include power in- and decrease bids within one bundle. Therefore, they can reflect storage activities, with one block representing the storage phase and the other one the generation phase.

Complex bids

Complex bids are regular block bids. What makes them 'complex' is that they are subject to some specified execution condition and they can only be cleared if this condition is fulfilled. The following types of conditions exist:

Minimum quantity bid: Traders can set a minimum acceptable quantity for clearing their bid. This minimum acceptable quantity will be placed in multiple block bids as a subset of the entire bid. Minimum Quantity Block Bids help to optimize the selection of block bids and thereby minimize the chance of paradoxical rejection.

Minimum income condition (MIC): Allows market participants to place a bid with a required minimum revenue condition. Bids have to include fixed amount (€) and variable amount (€/MWh). Advantage of MIC bids is that they provide flexibility for participants to plan for their max revenue realization and they help to recover costs such as start-up costs in addition to variable costs.

MIC with scheduled stop: In general, if a MIC is not activated, then it may lead to an abrupt shut down of the generator. Schedule stop conditions can prevent such sudden shutdowns of generators by selecting few initial bids and hence bringing the plant gradually to shut down.

Load gradient bid: Traders have to specify a maximum gradient limit as some generation technologies cannot cope with high variation of delivered power. Proposing a load gradient helps restricting accepted volume in two adjacent periods and has the advantage of benefiting the ramping requirements of the power plants and would provide grid stability. Flexibility in the DA market could be increased, and technical criteria of ramping can be met (see Figure 22).

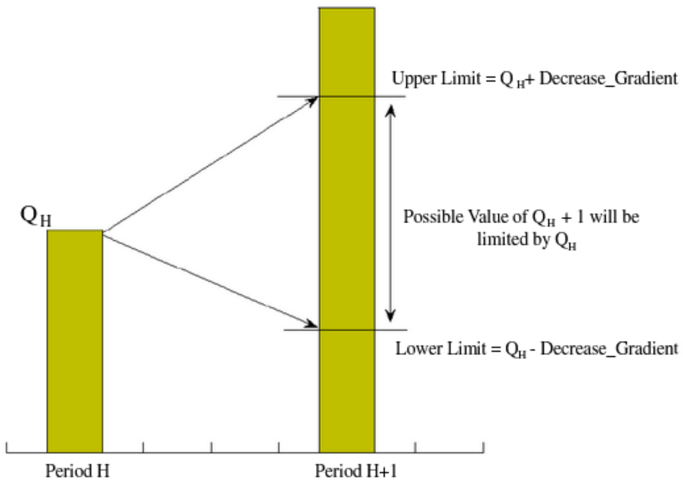

Figure 22 Example of a Load gradient bid (Source: [14])

Redispatch Bid Design for the Industrial Sector

Capabilities and restrictions of the industrial Sector

The key focus of this study is the integration of the industry sector into the Redispatch market. Therefore, a first evaluation of a possible bid structure for the industrial sector was conducted.

Based on AIT expert knowledge, preliminary projects and studies from Austria and Germany, on analysis of industrial energy use in Austria and the composition of the project consortium, the following industries were selected for closer examination:

- Pulp and paper
- Food production
- Iron and steel
- Chemicals and petrochemicals
- Stone, soils and cement
- Cross-sectional technologies

Here, cross-sectional technologies refer to production infrastructure equipment and systems that are used across all industries.

What all these sectors have in common is that it is not only the sectors themselves that are important, but also to a large extent the technical subcomponents used at the respective sites and the dimensioning of these subcomponents.

Pulp and Paper

Stock preparation of wastepaper or purchased market pulp

In the special case of pulper the following characteristics were determined: For a single production plant the connected load lies between 90 and 400 kW, where often several plants are combined per site [16]. The reduction potential is up to 100% for 15 minutes to a maximum of 3 hours several times a week. Announcement of activation the day before with a lead time for activation of at least 15 minutes was considered possible by the companies.

Mechanical pulp production

If the plant is used to full capacity, the installed power can be reduced by up to 100%.

Subcomponents in consortium

At the production site at ‘mondi’ a backpressure steam turbine (BPST) with variable operation point and a thermal energy storage (TES) are installed. There is no designated starting time, as these components are usually in operation. One BPST has an installed capacity of 35 t/h, and there are two more with 66 t/h. This results in 5,2 respectively 10,5 MW_{el}. Bids would be divisible, but providing flexibility goes along with steam loss. For now, 10 MW production capacity are already prequalified for balancing energy, so a minimum bid size of several hundred kW up to 1 MW would be easily attainable for this production site. Another important aspect is, that there are no catch-up effects following a flexibility activation.

Another, yet unexploited, possibility of providing positive flexibility would be the downtimes of the plant. Therefore, it would be necessary for the plant operator to know many hours to several days in advance if this flexibility will be needed in order to take appropriate precautions. Once production has been shut down, it can take between 4 and 12 hours for maintenance to be completed and the plant to start working again.

Food Production

Subcomponents in consortium

Dependent on the respective focus of the production site, there are a lot of possible combinations of installed subcomponents.

At the location of 'Wiesbauer' in Vienna, there is an installed Combined Heat and Power (CHP) plant, together with Fuel to Heat (F2H) and a connection to the grid. In general, lead time for activation for such types of plants is less than 1 hour, and the time periods in which the machine must run at least after insertion are really small. At the special case of 'Wiesbauer', 621 kW_{el} are installed and the min operation is assumed to be about 50 % of full load. Basically, bids can be delivered in 100 kW steps, but when the plant is not running it has to deliver at least 310 kW as first offer. This could be interpreted as a general divisibility of bids but with one "block" bid from offline state to min operation range to start. After this first bid the bid size can be chosen anywhere between min. part load to full load.

Another technology from 'Wiesbauer' that is also in use at 'Linauer' that can be used to provide flexibility is their cooling compressor and storage system. The cooling compressor system consists of several individual blocks. The installed capacities of these blocks are 2x250 kW, 1x160 kW, 2x22 kW and 1x132 kW. With these capacities, bids between 50 and 100 kW are considered as possible. The bids would be divisible. An important aspect in food industry is the high-quality standards that have to be met. This results in catch-up effects to be able to remain within a permissible temperature range.

Another installed technology enabling the provision of flexibility is the F2H in combination with a power to heat (P2H) system that will be in use at the new site of 'Linauer'. There are no catch-up effects associated with these technologies. The size of the components has not yet been determined but will probably be less than 1 MW. The resulting feasible minimum bid size will therefore probably be around 100 kW.

A combination of heat pumps (HP) together with TES is installed at 'Wiesbauer' in Reidling. The size of the component is 78,2 kW_{el} and it is assumed that a minimum bid size of 25 to 30 kW would be possible. The bids would be divisible, but there is a catch-up effect that have to be considered. The possible provision of flexibility with a HP and a TES is shown in figures Figure 23 - Figure 25.

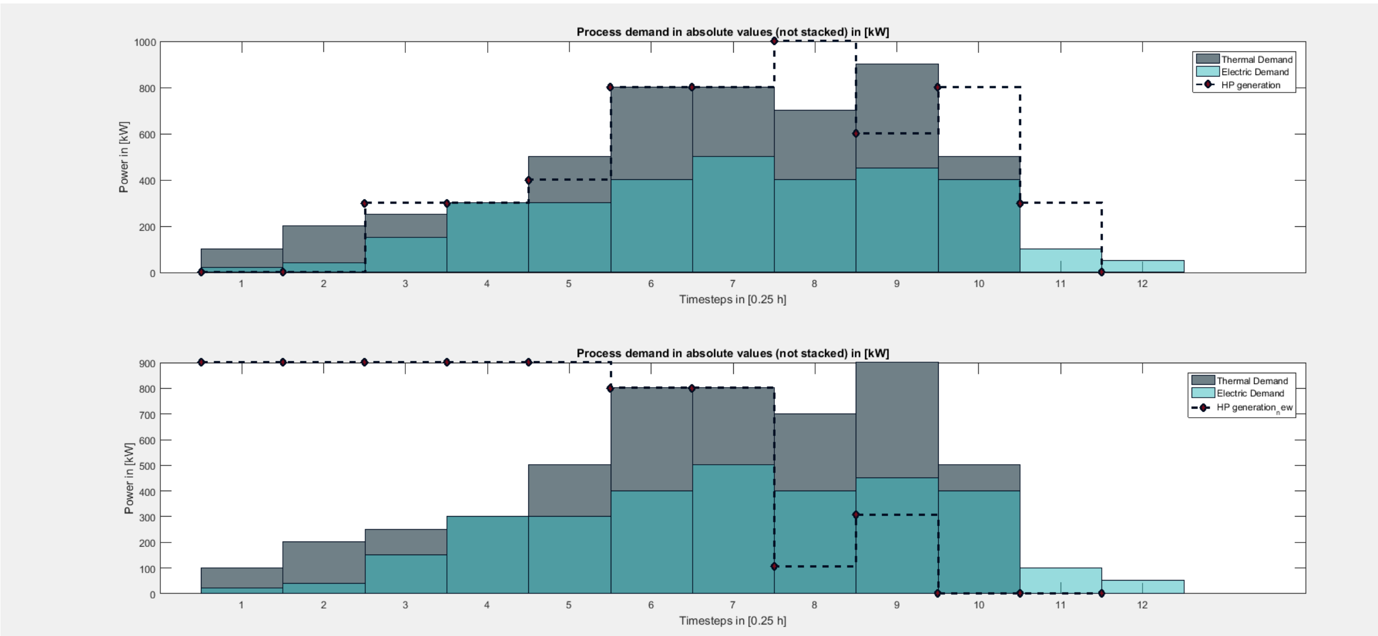

Figure 23 Possible Adaption of a HP generation profile in order to maximize the amount of positive flexibility that can be provided by this plant. Top: original profile; Bottom: adapted profile

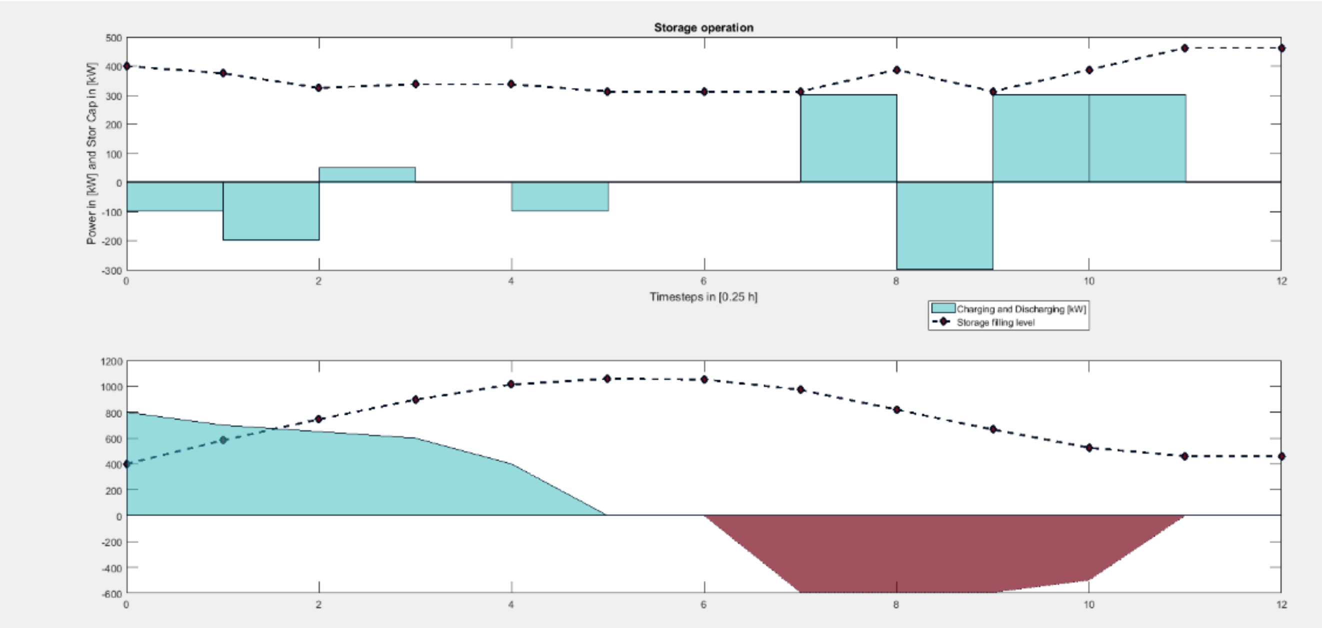

Figure 24 Top: original storage operation; Bottom: adapted storage operation

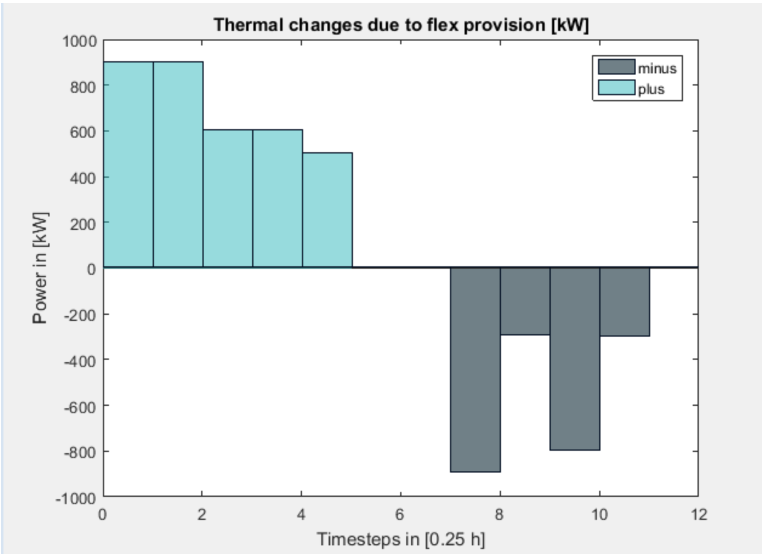

Figure 25 Optimized positive flexibility potential under the condition that there must be 2 time -steps between the provision of positive and negative flexibility

Another option for the food industry to provide flexibility would be to shift the start of batch processes. A key aspect here is that once the process is started, in most cases it is necessary to finish it completely. This results in indivisible bids with varying power, dependent on the actual production step. If the number of production hours is high, no flexibility potential might be available.

Iron and Steel

Melting

Due to efficiency reasons, the sites are usually operated at maximum power. Therefore, flexibility potential during operation is theoretically only possible in the form of power reduction. In addition, the operating point cannot be selected arbitrarily since damage to the unit and peripherals can occur in excessive partial load operation. As a result, the only option would be to shut down the site completely. The interruption must not take place at the end of the entire process and is only possible in the form of a complete deactivation of the electric arc. Lead time before activation is assumed to be around 60 minutes, whereby the flexibility can be activated only once a year on average.

Subcomponents in consortium

At the 'Voestalpine' construction site a fuel fired unit together with a storage is installed. The time it takes the system to start is about 1 hour, and it is assumed that the time the machine must then remain switched on is several hours. Typical sizes of such components are between 30 and 165 MW. Possible bids can achieve a minimum bid size up to 1 MW, maybe more.

Moreover, a gas turbine is installed at 'Voestalpine'. It can be started in less than an hour. The installed capacity is 38 MW, therefore, a minimum bid size of 100 kW up to 1 MW would be possible.

Both systems at 'Voestalpine' are able to provide flexibility, but catch-up effects have to be considered.

Chemistry

Chlorine production

Technically, the electrolyzers of the membrane process can be operated dynamically between 50 and 100 % of the maximum load. Though, the problem is that for most plants the utilization rate is above 95%. Therefore, power reduction would be tantamount to a production stoppage. A value of 15 to 30 minutes between half load and full load is considered realistic [17]. Information about availability can be prepared on a day-ahead basis, and only a few minutes would be needed for the actual notification to take the necessary action.

Air separation

Based on expert knowledge, the average occupancy rates lie between 75 and 100% of which up to 100% can also be flexibilized. The maximum possible retrieval period is between 1 and 4 days, dependent on the size of the production site and activation time is limited to maximum once a week.

Calcium carbide production

Short-term load reductions of just under 50% of the maximum load in half an hour are considered feasible [18] . Further, generally valid data on the frequency and duration of flexibility calls in calcium carbide production, could not be determined.

Stones, soils and cement

Raw material preparation and cement grinding

It is possible to reduce the performance or increase standing time of the mills which could have negative effects on their lifetime. Mills and presses can stop their production up to 12 hours, depending on operation situation and product stock.

Cross section technologies

On average, potential for flexibility can be provided for 30 to 60 minutes. The lead time for activation is relatively short and lies between a few seconds up to minutes, and the potential can be provided several times a day.

There are technologies where it is possible to run processes with flexible energy consumption. This flexible energy consumption could be used to generate indivisible bids on the flexibility market, with a potential size of up to a few 100 kW. An example of such processes would be paper grinding.

Possible Bid Types for the Industrial Sector

If the various industrial sectors are to be integrated into the redispatch process, it is very important to design the types of bids in such a way that they accommodate the options available to the industries as far as possible. Particular challenges here are the often variable generation profiles, the minimum active power, high start-up and shut-down costs, energy limits, resting times, production loops and catch-up effects. The following section discusses which types of bids would be appropriate to address these challenges.

Variable generation profiles

One way to handle the variable generation and demand profiles would be to introduce profile block bids. Profile blocks allow offering a different volume profile over time. This characteristic would enable the industry sector to model their bids according to their varying generation or demand profile.

Minimal active power

For many technical units, attention must be paid to their minimum effective power. This means that a minimum volume of the bid must be activated, otherwise the activation would be infeasible. There are different ways to deal with this problem.

First, it would be possible for the operator to offer an indivisible bid. An indivisible bid is a bid which can only be selected in its entirety. In terms of bid type, this would correspond to a regular block bid, which is either fully accepted or fully rejected. Partial execution is not possible. This solution would be easy to implement from an optimization point of view, but a disadvantage is that the entire bid may be rejected if smaller amounts of energy than the energy offered are required.

The second possibility would be to use curtailable bids. Per definition it is possible to execute curtailable bids above a minimum accepted ratio, which could be equal to the minimal active power. For instance, the part of the submitted order of a thermal unit, which is below the MAR would represent the technical minimum performance. The part above the MAR represents the variable potential of the unit. Using curtailable blocks enables a more granular optimisation of portfolios, but requires a much higher implementation effort.

An option that would be easier to implement would be to offer more (regular) block bids linked by a logical XOR (exclusive bids) during the same time-step.

To guarantee the execution of the bid including the volume of the minimal active power, a parent-child structure would also be possible.

Another possibility would be to use partially divisible bids. Partially divisible bids are defined as divisible to a minimum and are therefore similar to curtailable block bids in practice.

Start-up

To cover high start-up and shut-down cost, linked blocks are a viable option (see section **Linked blocks** in Annex A: Bid structure). In many applications it is the case that after the high start-up and shut-down costs are covered, flexibility can be provided at low marginal cost.

To reflect consecutive activation of the energy start-up modus of technical units, using linking in time could be an option. This linking can be achieved by connecting the bids with a logical AND. An example of the activation of units in start-up modus is given in Figure 26. In this example, there are two bids in total. First, the "start-up bid" (blue) and second, the "continued start-up bid" (orange). The 1st bid is indivisible (e.g., minimum active power of the technical unit) and priced with variable start-up cost. The second bid is available only after the start-up of the technical unit and can also be partially divisible (between Pmin and maximum offered volume). The price of the bid are the variable costs. The important point is that the second bid can be activated only if the first bid has been activated before. In the example in Figure 26 the status of availability of the 2nd bid changes after the activation of the 1st bid.

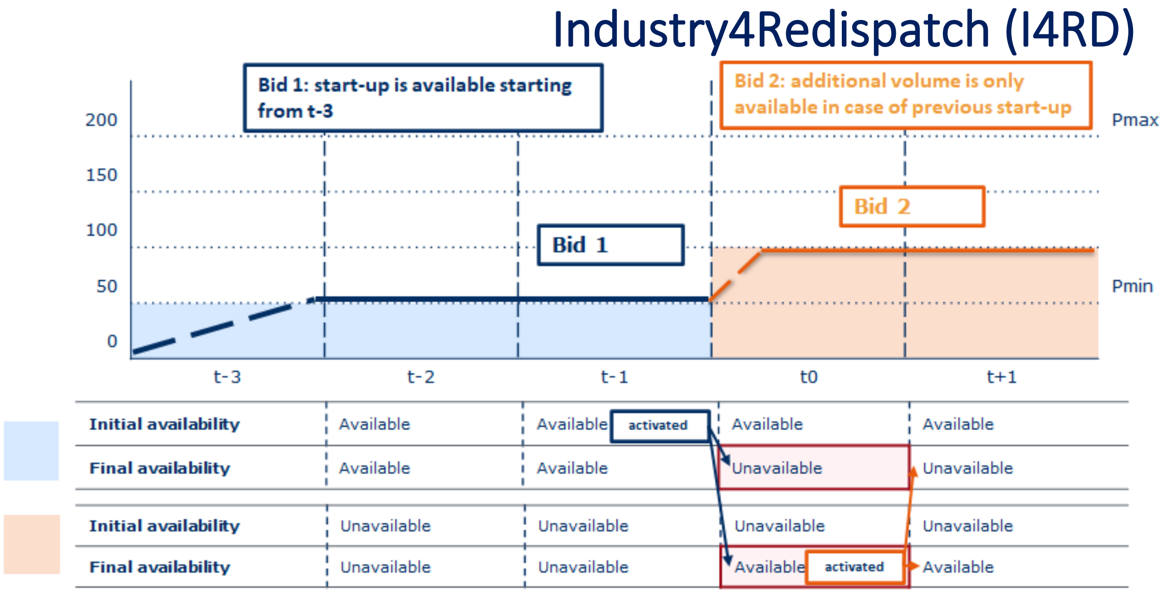

Figure 26 Linking in time to reflect consecutive activation of energy in start-up modus

Energy limits, downtimes

One way to display energy limits of technical units would be the usage of exclusive bids. This bid type could also be used to offer flexibilities through downtimes. Offering exclusive bids would have the benefit of making it possible for the flexibility requester to choose the most suitable bid from a pool of several possible offers. The drawback of this bid type is the complexity of the implementation. To generate different "optimal" exclusive bids several optimizations would be necessary by the industry.

Batch processes

Another peculiarity that has to be considered in the provision of flexibility by the industry are occurring production loops. Sometimes it might be necessary to completely run through a whole process after starting it, and thus different amounts of flexibility which are indivisible can be provided over this loop. One possibility to deal with are profile blocks. These can be used to represent the varying profiles.

Another possibility would be the representation as loop blocks. However, one has to keep in mind that loop blocks are executed or rejected together, so the entire bid may often be rejected if the flexibility offered is only needed in certain time increments.

In order to influence the start of a production process, it would be conceivable to work with exclusive (XOR linked) bids.

In case of batch processes linkage in time could represent the fact that flexibility bids occurring in a later state of the production process can be activated exclusively after activation of the first flexibility bid, representing the start of the first step of the production loop. The exclusiveness is needed to capture the different starting points of the process. Another way to model these restrictions would be profile blocks.

Summary

Table 7 gives an overview of the considered technologies and possible bid structures.

Table 7 Table 1: Description of preliminary possible bid structures for the industry sector

Industry	subcomponent	lead time for activation	min runtime	size component	divisibility bids	possible min bid size	catch-up effect	Possible bid type
PP[2]	BPST+TES	usually in operation	-	5,2+ 10,5+ 10,5 MW	Divisible	100 kW-1 MW	Probably no	Ev. linked blocks and profiles
FP[3]	CHP+F2H+Grid	< 1 h	< 1 h	621 kW	divisible	100 kW	Probably no	Ev. linked blocks and profiles, maybe curtailment blocks
	Cooling compressor + Storage	-	-	2x250 kW, 1x160kW, 2x22kW, 1x132kW	divisible	50-100 kW	yes	Most probably Profile blocks + catch up profile
	F2H + P2H	< 1 h	< 1 h	~ < 1 MW	divisible	100 kW	Probably no	Ev. linked blocks and profiles, maybe curtailment blocks
	HP + TES	< 1 h	< 1 h	78,2 kW el	divisible	25-30 kW	yes	Most probably Profile blocks + catch up profile
IS[4]	FFU + ST (CHP)	< 1 h	a few hours	30 – 165 MW	divisible	100 kW- 1 MW	Maybe/no	Ev. linked blocks and profiles
	GT	< 1 h	a few hours	38 MW	divisible	100 kW- 1 MW	Maybe/no	Ev. linked blocks and profiles

[2] Pulp and Paper

[3] Food Production

[4] Iron and Steel

Bid characteristics for Austrian- and international markets

The following is a summary of identified parameters that have the most relevance for characterizing bids at the various markets:

- Bid size: the minimum and maximum capacity, that can be offered as one bid by a single unit or by a pool of aggregated units
- Minimum size of a sub- unit of a pool
- Minimum bid increment is in most cases based on the minimum bid size
- Geographic information: the geographic location of the units providing the bid
- Complexity of bids
- Linking of bids
- Divisibility of bids

In Table 8 a comparison of these parameters for different markets is given.

Table 8: Current technical criteria for bids on the different markets for Austria and international cooperations (24.11.2021)

	Control Reserve			Spot market	Criteria for Redispatch suggested in this deliverable	Ref.
	FCR	aFRR	mFRR			
minimum bid size	1 MW			0,1 MWh	1 MW	[19], [20]
minimum bid increment	1 MW			0,1 MWh	0,5 MW	[20], [21], [22]
maximum bid size	25 MW (for indivisible bids)	no limit (PICASSO)	9 999 MW (MARI)	n.a.	400 MW	[19]
minimum/ maximum size of subunit of a pool	no limit	no limit	no limit	no limit	500 kW / 50 MW	[19]
complex bids	yes	no (PICASSO)	yes (MARI)	big blocks, loop blocks, curtailable blocks, exclusive blocks	exclusive bids, profile bids	[19], [23], [22]
bid linkage	-	no (PICASSO)	yes (MARI)	linked blocks are permitted	AND linked blocks	[19], [23]
divisibility	divisible or indivisible	divisible	divisible or indivisible	divisible or indivisible	indivisible	[24], [19], [23]
geographic information	-	-	bidding zone	-	per 110 kV grid of a DSO	[25]
aggregation	yes	yes	yes	yes	yes	[19]

Annex B: DSO bid design

A key focus of this study is to consider the electric distribution systems within the redispatch provision concept; however, it is a challenge for DSOs to operate their grids within safe and secure limits and simultaneously enable the activation of flexibility potentials for redispatch of different resources on different network levels and locations.

Flexibility resources which are connected to the distribution system vary in size, response time, controllability and monitorability. Moreover, there are various ways in which this flexibility could be used, either in the distribution or in the transmission grid.

The available potential depends on the connected generation capacity to the network. The following categories are stipulated by the RfG-VO in Art. 5 and specified in the Austrian TORs:

Type A: maximum capacity ≥ 0,8 kW and connection point below 110 kV general requirements: Fundamental requirements for frequency stability to avoid large-scale critical network conditions; limited automatic regulations

Type B: Maximum capacity ≥ 250 kW and connection point below 110 kV general requirements: automatic control systems, robustness, remote control technology

Type C: Maximum capacity ≥ 35 MW and connection point below 110 kV general requirements: voltage maintenance (reactive power), extended frequency maintenance, system management, and system recovery

Type D: Maximum capacity ≥ 50 MW or connection point ≥110 kV general requirements: extensive operational management and stability requirements

Concluding, the flexibility potential could range from < 100 kW aggregated on the low voltage level (connected at NE 6 transformer substation) to the free capacity available on medium voltage level if the connected assets enable this potential. It is crucial to note, that this potential can only be considered when the contracted connection power limits are not exceeded, and the transformer capacity and the network operation restrictions are not violated.

The minimum connected load capacity was defined within the consortium at 500 kW, since loads of this size are commonly connected to / visible within the SCADA system.

Bid Size at different network levels (5,6)

Different resources can offer their flexibility to be used for different services, as Table 9. The flexibility potential which can be offered by these resources connected to medium voltage (MV) and low voltage (LV) network levels, depends on the size of the generation units and the flexible loads connected to the network. The Potential can range from 100 kW aggregated on the low voltage level (at NE6 connection point) up to the free capacity available on the medium voltage level (up to 1 MW-5 MW). On higher voltage levels higher flexibility potentials are expected. Currently, NE7 cannot be considered due to lack of observability and automation.

Table 9 Network services and Units can provide these services through offering redispatch potential

Service	Resources	Market
Congestion management	RES, DSM CHP	Day-Ahead, Intraday, Near Real time
Voltage control	PV, Wind, CHP, DSM, aggregated EVs	short term, Day-Ahead, Intraday Near Real time
Islanding operation	DG, DSM, Storage	Long term, short term, Day-Ahead, Intraday, Near Real time

Flexibility resources can be PV in MV and LV network level, small scale generation, consumer aggregations, storage, DG and backup generators. Aggregation should be allowed by small-scale resources especially on the LV level, and participation in different markets is possible, especially the Day-Ahead and Intraday Markets. In addition, the bids activation can be requested by either DSO or TSO and occur at the aggregator itself. Therefore, the DSO needs the detailed information about the activated bids such as bid location and size for further validation to ensure secure and safe operation within the technical limits. In addition, aggregation is possible only for controllable resources aggregated in the same distribution grid area based on grid topological considerations.

Flexibility Product

In general, redispatch products should comply with the needs of system operators to perform economical and efficient network services [26]. The redispatch requirements should be clearly specified to ensure successful product design. The geographic information of redispatch bids is required for the calculation of sensitivities on the grid in order to calculate solutions for existing congestions and to ensure that the activation of bids does not cause a congestion in another system operator’s grid.

It is also necessary to keep the products open to future development. This will be the result of the joint activities of system operators, market participants, market operators and regulatory authorities. The development of a rigid standard should provide a common base for products but should also enable a dynamic development. This will lead as a first step to define a common list of attributes/ specifications that could be used, for specific product definition.

These specifications should be defined in a way that ensure effective participation of flexibility resources into the redispatch on DSO level and to be able to offer network services, such as congestion management.

An important aspect of flexibility calculation/redispatch product development is the possibility of combining different sources by aggregators. Any product that can be used for congestion management must include locational information, which by nature is essential for congestion management.

Annex C: Baseline

In order to be able to conduct a redispatch calculation, the TSOs depend on a reliable network security analysis and the resulting congestion forecast. The correct consideration of assets requires submission of reliable schedules. Moreover, after network security calculation, when flexibility services (especially redispatch) are activated, a methodology to monitor and verify this activation is required. The following section introduces the different requirements and challenges to consider when proposing such a methodology.

Definition Baseline

Considering baselines, it is important to note that depending on the flexibility service different types of baselines are relevant. A distinction has to be made between baselines for products with activation in real time, where the baseline represents the planned point of operation if the technical unit would not provide a service in that moment, and long-term planned flexibility products, such as redispatch, where the acceptance of the bid is already announced the day before and therefore, a schedule is needed several hours before activation.

Since most units that provide balancing energy or redispatch are used for more than one purpose at the same time, it is essential to define and monitor two values: the current measurement of generation or consumption and the baseline, which represents the planned point of operation if the unit would not be in activation (i.e., it would not

The Baseline represents the planned point of operation if the technical unit would not provide an ancillery service (e.g. redispatch) in that moment.

provide balancing energy or redispatch in that moment). Therefore, it is part of the so-called prequalification for the provision of flexibilities, to prove that the provider explicitly changed its behaviour on the instruction of the TSO, in order to provide the desired service. This proof is provided based on the so-called baseline. As mentioned before, the baseline, as shown in Figure 27, indicates how the plant would have behaved, if no flexibility activation had been triggered.

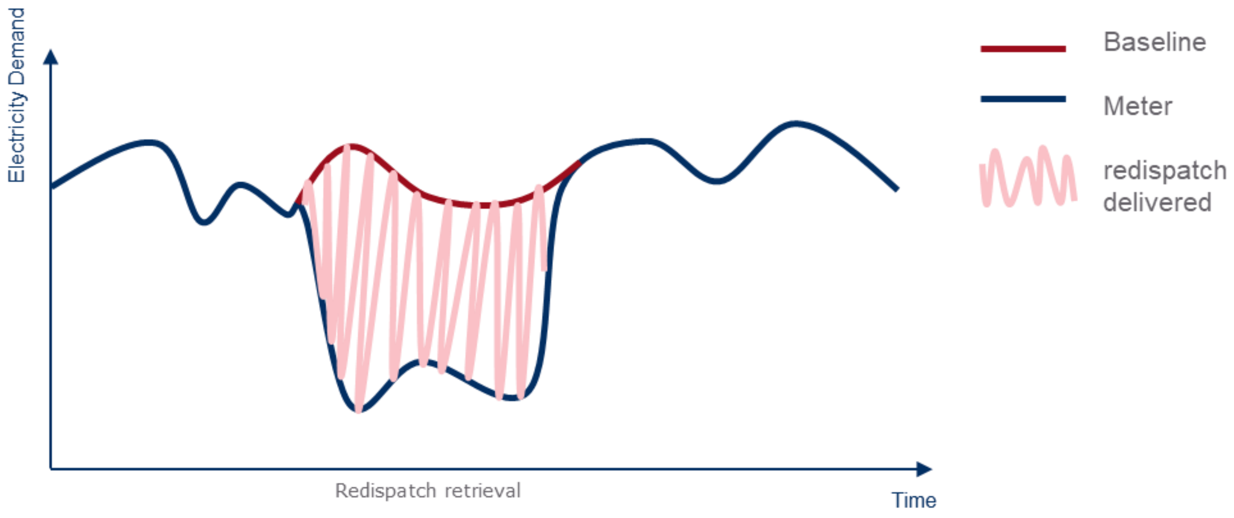

Figure 27 Baseline methodology

In general, there are different services for TSOs and DSOs that require a baseline calculation, e.g., demand side programs that provide reductions of a "business as usual" load or balancing energy services. Key differences in these programs can be broken down into event trigger, event frequency and deployment period and these differences lead to discrepancies between desirable baseline characteristics.

In this report we focus on baseline methods for industrial sites that participate in the redispatch process and therefore, many of the baseline methods used for balancing energy are, due to the retrieval information before real-time, inapplicable.

In general, it is possible that providers propose their own baseline method. The functionality of that methodology is then tested during the prequalification process. Usually, the quality of the baseline is verified during the prequalification process and ex-post.

The same principle for baseline determination is applied whether a unit is considered as a net generator or a net consumer [27]. The TSOs will use the values of activated flexibility submitted by the units to evaluate if the unit provides the requested power output within a tolerance band and if the unit reaches the requested power within the predefined full activation time (FAT). However, according to [28], it is good practice to establish a baseline for each individual plant in case a pool solution is considered.

In case of a pool solution a baseline should be established for each individual plant.

Important Baseline Characteristics

Every Baseline methodology should be based on four cornerstones [29]:

- **Accuracy:** Exactly the service that was actually provided is to be compensated.
- **Integrity:** Irregular consumption should not be encouraged, and irregular consumption should not influence baseline calculations.
- **Simplicity:** The baseline calculations should be simple and straight forward, in order to be understandable and calculable by all stakeholders.
- **Alignment:** By choosing a baseline methodology it is important to keep in mind the field of application (e.g., the flexibility for which the baseline should be used). A baseline methodology should minimize unintended consequences such as inadvertently penalizing real curtailment efforts.

It is important to find a good balance between these four aspects. A baseline designed to be resistant to manipulation can easily become so complex that the stakeholders involved can no longer perform the required calculations themselves. However, if the method chosen is too simple, market participants are tempted to exploit the baseline in their favor.

For different components that provide flexibility services, there are different ways to determine the baseline, each having its advantages and weaknesses in terms of simplicity or practicality. In greater detail, the following requirements must be met [28]:

- The calculation must be transparent and comprehensible
- Minimum level of accuracy must be met, including lack of prior knowledge and appropriate handling of weather-sensitive resources
- Reproducibility
- Consideration of characteristics of different types of facilities
- Simplicity and low computational costs
- Prevention of gambling

The baseline methodology needs to respect the requirements of the respective flexibility product and the baseline for an industry site should neither reward nor penalize a facility for the natural load variance caused by normal operations. Similarly, a baseline should appropriately account for factors inherent to typical business activities such as batch processing in a manufacturing facility. This is also where one of the major challenges in developing a baseline methodology becomes apparent, namely the inherent volatility of a consumer’s energy consumption. Most load profiles underly a variation within a normal week, month or year, depending on different business cycles, or even production based on an intermittent schedule according to seasonal demand. It gets even more complicated, when local weather conditions influence the variations in load.

Critical Baseline Elements

In general, one can group baselines by some key characteristics such as the type of data and the estimation method which generally governs how the selected data is used to evaluate the baseline for a dispatch event. These are primarily criteria that are relevant for creation of schedules or reference values shortly before real time.

Different baseline methodologies exist. They can be distinguished by a number of key criteria. These key elements are summarized and described in Table 10 and subsequently discussed in more detail.

Table 10 Overview of Key Baseline elements (based on [29])

Profile Baseline	Incorporates frequent granular measurement across similar days, resulting in a demand estimate that mimics the dynamic nature of a customer's demand curve over a 24-hour period.
Static Baseline	Generates a flat demand estimate representing the average demand during an extended time interval (such as a season), providing one demand estimate regardless of time of day or day of the week.
Measurement Granularity	Refers to size of time intervals used for discrete demand measurements (e.g., 5-minute).
Baseline Window	The window of time (typically days) over which demand data is collected in order to establish a baseline.
Exclusion Rules	Rules governing data within a baseline window that is included or excluded from the calculation (e.g., days of an event).
Baseline Adjustments	Changes to a calculated baseline based on actual demand or weather conditions on the day of a DR event.
Additive Adjustment	A fixed kW adjustment across all event time intervals.
Scalar Adjustment	A percentage multiplier across all event time intervals
Adjustment moment	The adjustment moment defines a vertical shift or a scaling constant by fixing the time when the baseline and actual consumption should match.
Adjustment Cap	A limit on the magnitude of a baseline adjustment.
Individual Baseline	The concept of calculating performance or applying exclusion rules at the individual site level, then summing those performance calculations to calculate the performance of an entire portfolio.
Portfolio Baseline	The concept of calculating performance or applying exclusion rules at the portfolio level.
Average Calculation	Baseline for a given time interval is calculated as the average demand observed across a number of similar time intervals.
Regression Calculation	Baseline calculation takes an extensive data set and determines the relationship between a number of different variables, such as weather, time of day and demand, among others.

The combination of these criteria depends on user consumption, weather dependency (incl. seasonal behavior) and should fit the participants load curve.

Profile or Static Baseline

For determination of a profile baseline, granular time interval data is used, intending to mimic the dynamic shape of a load profile.

In contrast, for a static baseline a simple average is used (e.g., average of the peak monthly demand over the previous corresponding delivery season).

Figure 28 shows a static and a profile baseline.

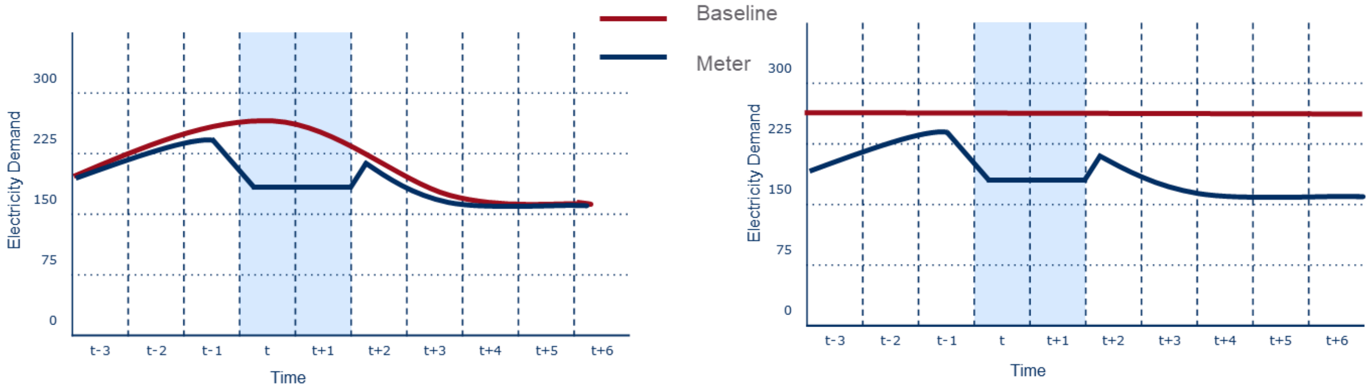

Figure 28 left: profile baseline; right: static baseline

Measurement Granularity and Communication Requirements

An appropriate timing interval for data collection and calculation is key for effective baseline methodology. In general, increased data granularity would lead to more accurate performance measurements, increased resource visibility for grid operator and an easier settlement process. The associated cost and technical characteristics of an ancillary service have to be considered when defining the granularity.

Baseline Window

Another crucial factor is the selection of the length of the baseline window. It is very tempting to use recent data since such data better approximates what the facility load would have been during an event. However, in case of redispatch, where retrieval events can be longer and the notification happens in advance, a short baseline window can exhibit problems of accuracy and can be susceptible for manipulation. Therefore, in case of redispatch, a longer baseline window would be preferable, preventing gaming.

It is generally accepted that a period of approximately 10 (non-event) business days reasonably represents consumption for normal operations [29]. In the special case of redispatch the exact baseline window is still to be determined.

Baseline Adjustments

Several factors affect a participant's load. For example, the first day of year that requires heating is likely to exhibit a quite different load profile than the preceding days. To accurately reflect such environmental circumstances in the baseline it is necessary to include appropriate adjustment mechanisms to avoid penalizing participants who are consuming more energy than on a reference day.

The goal of baseline adjustment is to adjust the initial baseline in order to make it a better fit for the load on an event day. Therefore, these adjustments use the most up-to-date information to inform the final position of the baseline, bringing the baseline into line with the pre-dispatched intervals on which the adjustment is based. As a result, the baseline starts the dispatch period relatively close to actual load and will only diverge of the load shape from the baseline if it is different from the actual profile of the day [30].

Such short-term adjustments should be based on the conditions either during or immediately preceding a redispatch event. Often easily verifiable data, such as temperature or load in the period prior to an event, is used as a basis for baseline adjustments. However, it would be preferable to limit the influence a participant has over this calculation [29].

In Figure 29 an example of the same- Day adjustment method is given, based on a plant with a weather-sensitive load profile. The actual meter data is displayed in blue, and a historical baseline calculation (displayed in red) is assumed.

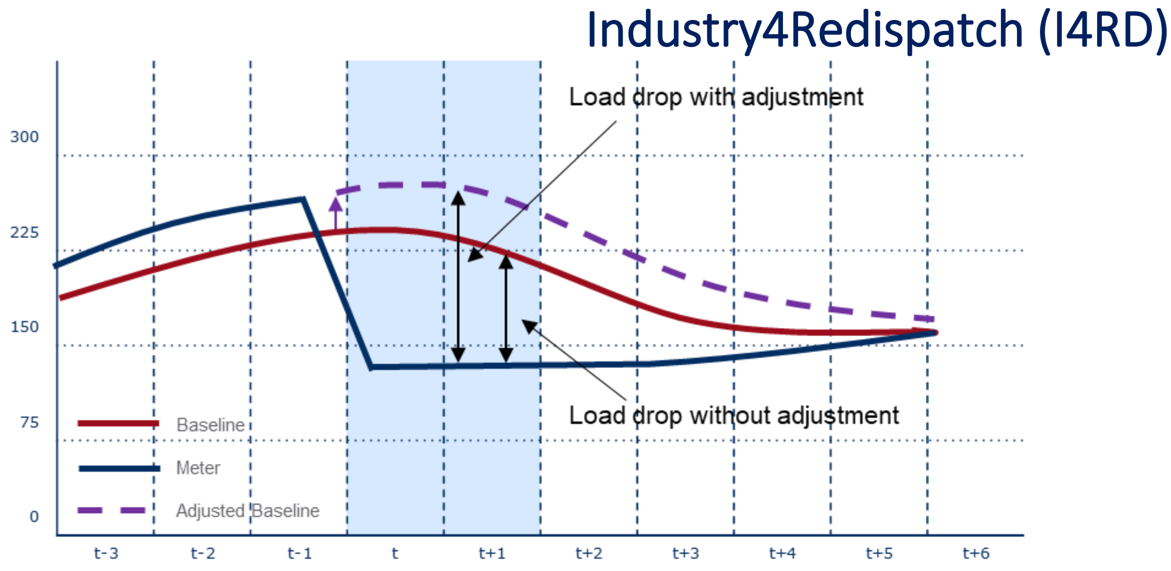

Figure 29 Example of same-day adjustment.

Adjustment window

The adjustment window refers to the specific intervals that are used to make adjustments. During this window the average difference between the baseline without adjustment and actual measurements is determined. Especially in redispatch, the definition of the adjustment window is highly relevant. Due to the nature of redispatch, participants know in advance, that redispatch will be retrieved so if the adjustment window is close to real time, there is room for manipulation.

There are two different methods that are commonly used to calculate adjustments. Namely, either a scalar is used, or the adjustment is calculated with an additive technique.

Scalar adjustment

The scalar technique is based on a percentage comparison. For example, if load on an event day prior to notification is measured to be 120 % of the calculated baseline, each time interval of the event baseline would be the product of the calculated baseline and 120 %.

Additive adjustment

The additive approach is to calculate the actual demand differences in kW (again prior to notification). If the participant's load is 70 kW above the calculated baseline, 70 kW is added to each interval in the actual event baseline.

From the participant's point of view an important aspect is whether these adjustments are carried out symmetrically (baseline adjustments up and down) or asymmetrically (baseline only adjusted up). Symmetric adjustment would maximize the accuracy of a baseline calculation, but in few exceptions, downward adjustments can have unintended negative consequences. One example would be production facilities with batch-processes (see Figure 30) where load is usually at one of two extremes: either very high or very low. If the plant has just finished a process and is setting up for the next run during the adjustment calculation window, the result of the adjustment calculation would distort the actual baseline. In such a case, it would be preferrable to just allow asymmetric baseline adjustment.

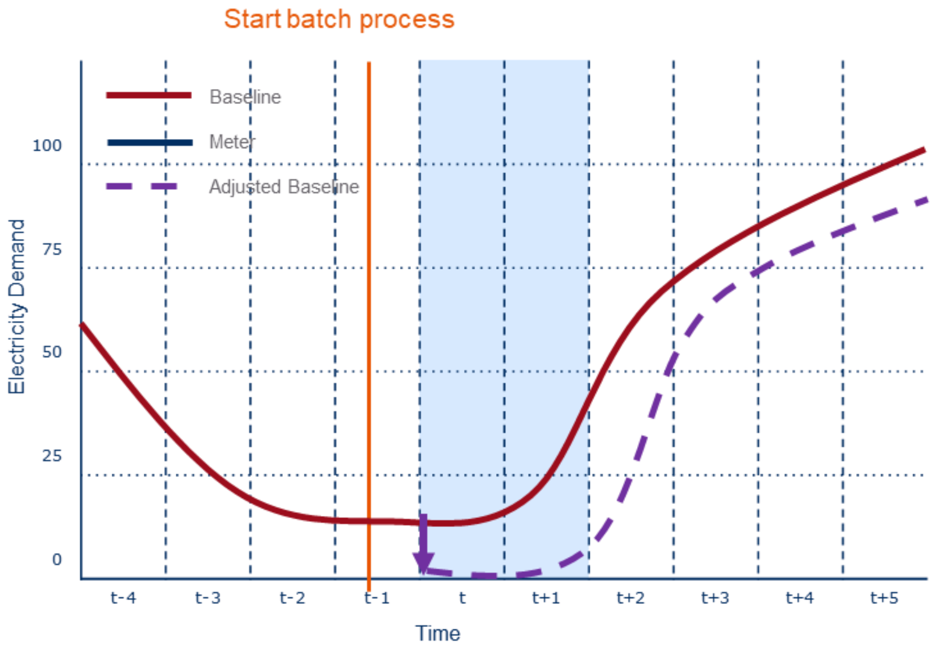

Figure 30 Symmetric baseline adjustment in case of a batch process

Finally, again the chosen time window on which the adjustment calculation is based is crucial. If the window includes time intervals subsequent to event notification (such as day ahead notification), symmetric adjustments could lead to participants maintaining load through the end of an adjustment period.

Adjustment moment

The provisional baseline resulted from the estimation method usually does not fully match the actual consumption even after the introduction of the adjustment method. The baseline adjustment moment is defined as the exact point in time at which the baseline and the actual consumption profiles exactly match. Challenge in the definition of such a point is to prevent gaming, as participants may intuitively enlarge or reduce their consumption before the adaption event to win unjustifiably better adaption efficiency and rewards [31, p. 3.].

Adjustment Cap

The goal of an adjustment cap is to limit the magnitude of any adjustments. Take for example a customer with an initial baseline of 100 kW exhibits demand of 130 kW prior to notification and assume that baseline adjustment is carried out in an additive way, the participants baseline would be increased by 30 kW. However, if the baseline methodology includes an adjustment cap, that additive adjustment would be limited, e.g., if the cap is 20 %, the additive adjustment would be 20 kW [20].

Adjustment caps can help to limit the (negative) impact of upward and downward adjustments. However, there is again the risk of underestimating participants performance despite real curtailment.

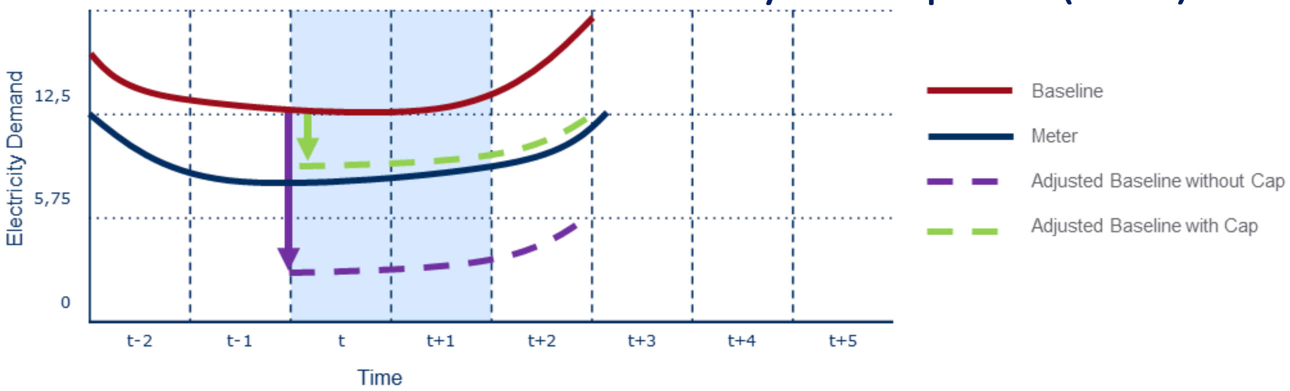

Figure 31 Example of an adjustment Cap to help limiting the negative impact of downward adjustment in case of a batch process

Individual Baseline or Portfolio Baseline

All above discussed components can either be applied at an individual component level or, if there are more than one component on a production site, at a "portfolio" level.

An important factor to consider is alignment. In case of defining exclusion rules, a portfolio approach could result in a random choice of exclusion days, whereas the individual approach chooses the days more in line with the participants actual load profile. Therefore, a portfolio method could lead to participants viewing their performance incentives not as the firm result of curtailment efforts, but as random results. Such situations should be avoided. Another benefit of individual baselines in favor of transparency is that the individual participant is capable of measuring their own performance in near real-time [29].

Metering points

Due to the planned integration of the industrial sector with various components behind the metering point, the definition of the metering point is important. In general, there are two approaches for the location of the measurements for flexibility providers (Figure 32).

The first and more common approach (case A), generally used for conventional power plants, represents the case where the power exchanged with the public grid is measured directly at the grid connection point (directly after/ in parallel to the billing meter). At the same time, it is used to provide the measurements to the TSO for the purpose of verification. The advantage of this method is that it is possible to measure and submit the direct effect on the public grid to the TSO and the billing meter can be used for validation of the power measurements. A disadvantage is that this approach results in the use of the sum of the facilities loads, non-flexible components and generators as the control variable, which may cause power fluctuations on the grid connection point.

The second option (case B), referred to as "meter behind the meter" uses measurements on unit level as control variables while measurements at the grid connection point and of further relevant units are monitored. In contrary to Case A, fluctuations caused by units which are irrelevant for the control can be separated from the relevant ones using this approach. A drawback is the difficulty of direct validation of the influence at the grid connection point. Statistical methods can be applied to evaluate the correlation between the control variable and the billing meter readings.

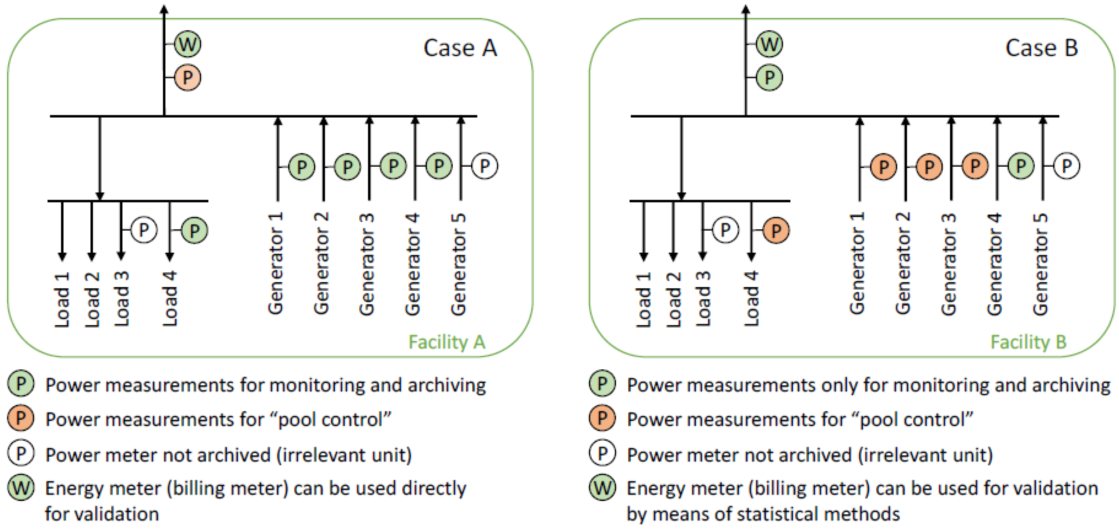

Figure 32 Possibilities to define the metering level (Source: [28])

Figure 33 shows such a measurement concept at an industrial site. The following information between industrial operator and system operator needs to be exchanged:

- Data 1 – forecasted data for flexible component (FC) A, FC B, FC C, energy exchanged with grid and redispatch potential
- Data 2 – information on redispatch bids
- Data 3 – adapted forecast for all components and total site (TRAFO level)

Data that must be measured in this process are the actual power exchange at TRAFO level, the actual power consumption and production of all FCs.

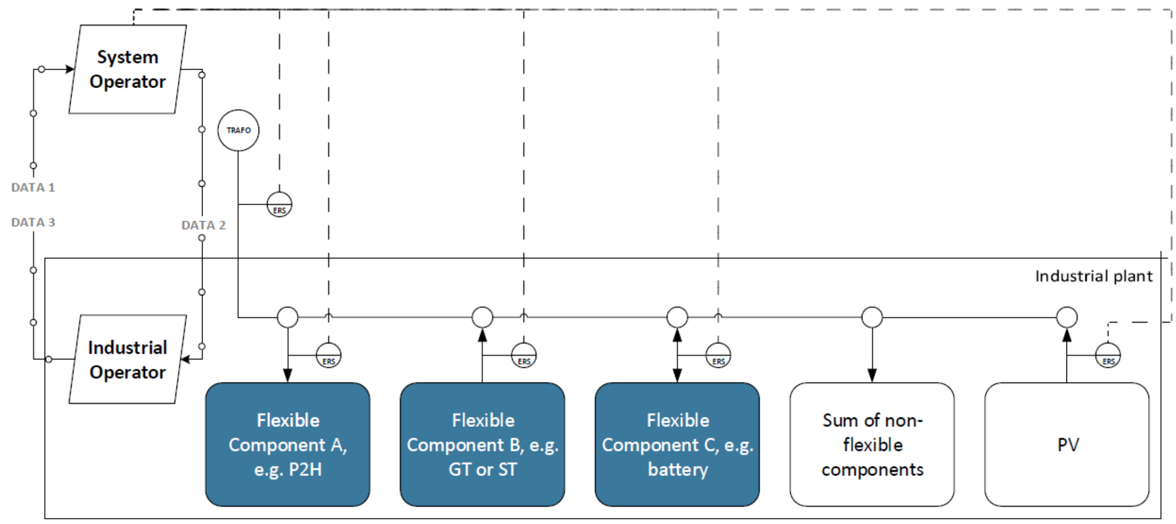

Figure 33 Measurement concept for a representative industrial site with three flexible components

Conclusions for Industry for Redispatch

Summarizing, for the special case of redispatch provision by industrial sites, the following baseline and scheduling aspects have to be considered:

In order to be able to model the varying load profiles of an industrial site, it will be favourable in most cases to use a profile baseline. This means that granular time interval data will be necessary. Concerning the definition of a baseline window, it might be necessary to consider day-ahead schedules and intraday adaptations as basis. Moreover, in order to prevent gaming, it will be necessary to conduct an analysis of historical data as comparison to the actual metered data.