Study on the Prequalification Process and Measurement and Communication Requirements for Low Voltage Units in Explicit Balancing Services, and Possible Developments to Simplify Their Participation

Study report – October 2025

Executive summary – barriers and recommendations

The present report summarizes the analysis conducted by Elia on the barriers to explicit balancing with low-voltage assets. The main analyzed barriers and Elia's recommendations are gathered in the following table

<table>
<tr><th>Topic</th><th>Barrier</th><th>Impacted explicit products</th><th>Recommendation</th></tr>
<tr><td rowspan="2">Measurement and metering</td><td>Barrier 1: Need for an enabled SMR3 head meter</td><td>aFRR
(mFRR in the future)</td><td>It must be emphasized that quarter-hourly allocation of head meter data is required to participate to aFRR and not necessarily SMR3 regime. Elia reiterates the importance of a swift deployment of smart meters and the application of quarter-hourly allocation by default as opposed to RLPs/SPPs.

Elia advocates for an alignment of the regional regulation in Wallonia with the Flemish one, in order for all quarterly-hours data to be taken into account in the allocation process. Alternatively, the application of the implicit consent as done in Brussels would also lift the barrier</td></tr>
<tr><td>Barrier 2: Need for a MID-compliant private submeter</td><td>aFRR</td><td>To avoid hindering flexibility development, Elia recommends pursuing several actions concurrently:
In the short term, it is crucial to clarify, in cooperation with the regulatory and legislative bodies, the applicability of MID for explicit balancing under ToE CSM when only aggregated data is used.
In the medium term, Elia proposes working with the regulatory and legislative bodies to explore the use of the directive's optionality clause, potentially allowing participation with non-MID compliant meters in Belgium.
Looking ahead, Elia suggests developing an advocacy coalition to drive changes at the EU level, either through sector-specific provisions in the Network Code on Demand Response or by seeking a modification of the MID directive itself. This comprehensive, staged approach is essential to ensure that regulatory frameworks do not unnecessarily hinder the rollout of flexibility services in Belgium.</td></tr>
<tr><td>Communication</td><td>Barrier 3: Local Gateway obligation</td><td>FCR, aFRR,
(mFRR in the future)</td><td>Given the above, Elia recommends switching toward central gateway as standard set-up at and to rely on a data validation control to mitigate the risk of data manipulation.
Elia recommends implementing a data control relying on a cross-check between quarter-hourly head meter data and private submeter data for delivery points using private measurement devices.</td></tr>
</table>

	Barrier 4: High volume of real-time data	FCR, aFRR	Elia recommends maintaining the real-time capability requirement at individual level but implementing event-driven communication for all delivery points in order to reduce the volume of data to be transmitted.
On-boarding	Barrier 5: Inadequate private meter commissioning process for low-voltage assets	FCR, aFRR	Elia suggests extending the procedure currently defined on Synergrid's website for aFRR to also include FCR. This would also lead to an extension of the certified asset database. For the avoidance of doubt, this certification specifically targets services for which MID is not required and does not replace the MID requirement where applicable.
	Barrier 6: Sub-optimal prequalification process to participate in capacity auctions	FCR, aFRR *(mFRR in the future)*	Considering the above, and the fact that prequalification impacts all voltage levels, Elia cannot take a final decision on a review of the prequalification process. Elia is however willing to reassess in the short term the need for PQ tests as well as the possibilities to simplify/limit the applications of a prequalification test and this for all voltage levels. This element is included in the 2026 roadmap and Elia expects the teams to start the work as soon as this incentive study is finished (i.e. Q1 2026).

Definitions - Acronyms

Name	Acronym	Definition
Balancing Service Provider	BSP	The Balancing Service Provider, as defined in article 2(6) of the EBGL
BRP_{source}	BRP_{source}	The Balance Responsible Party of the Access Point of the Grid User
BRP_{BSP}	BRP_{BSP}	The Balance Responsible Party, appointed by the BSP, to take in its balancing perimeter the responsibility for the energy volumes requested by ELIA to the BSP
Delivery Point DPPG	DP_{PG}	Delivery Point for which ELIA does not receive Daily Schedules;
Delivery Point DPSU	DP_{SU}	Delivery Point for which ELIA receives Daily Schedules (in MW), in accordance with the SA Contract
FSP-DSO Contract	FSP-DSO Contract	The FSP-DSO contract describes the mutual rights and obligations of the DSO and the FSP regarding the use by the FSP of flexibility of distribution grid users connected to the distribution grid managed by the DSO as part of the flexibility services that are described in the service catalogue of the contract
Grid User	GU	As defined in article 2 §1 (16) of the Code of Conduct for a Grid User connected to the ELIA Grid or to Public Distribution Grid; or as defined in article 2 §1 (12) of the Code of Conduct for a Grid User connected to a CDS
Low-Voltage Delivery Points	LVDP	Delivery Point that is connected at a voltage level below 1 kVA
Measuring Instruments Directive	MID	Directive 2014/32/EU (and formerly Directive 2004/22/EC), is a European Union legislation that establishes the requirements and standards for measuring instruments placed on the EU market
Message Implementation Guide – Version 6	MIG6	Sixth version of the market communication and data exchange protocol used in the Belgian energy market
Network Code on Demand Response	NCDR	Proposed European Union regulation that will establish common rules for demand-side flexibility in electricity markets to help integrate renewable energy
Original Equipment Manufacturers	OEM	Companies that design and produce equipment, components, or products that are then used or rebranded by another company. In essence, an OEM manufactures parts or systems that are used in another company's end products
Providing Group		Any subset of Delivery Points part of the Pool of the BSP
Smart Metering Regime 1 Smart Metering regime 3	SMR1 / SMR3	The type of metering regime that is applied to the head meter
Tase2/ICCP	Tase2/ICCP	Protocol that allows electricity system operators to exchange information securely and reliably in real time, enabling cross-system coordination required for a modern and interconnected power grid (based on IEC 60870-6)
Transfer of Energy	ToE	As defined in article 19bis §2 of the Electricity Act

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1.Introduction

In the recent years, Elia has adapted the Terms & Conditions BSP to allow low voltage units to participate in explicit balancing services, notably FCR and aFRR. The opening of the mFRR service to these units is also imminent. Despite these advances, several barriers to effective participation have been identified, particularly regarding:

- Measurement and communication requirements.
- The onboarding process of new units.

In a context of growing active resources in distribution and their increasing role in system flexibility, it is essential to facilitate their participation without compromising the quality of the service provided.

The study conducted by Elia analyzes these barriers and proposes concrete ways to overcome them. It was conducted in accordance with CREG decision B658E/89 dated 17 October 2024, which requests Elia to carry out this analysis within the framework of the incentive to promote system balancing referred to in Article 27 of the tariff methodology. The focus of the present study is on explicit flexibility, and especially FCR and aFRR as mFRR is not allowed yet in low voltage. The incentive directly supports Elia's intent to increase the number and diversity of assets capable of providing explicit flexibility, thereby strengthening system stability and market efficiency. By targeting the specific hurdles faced by LV assets, the initiative aims to unlock new sources of flexibility, which are increasingly crucial as distributed energy resources expand.

The document is organized to provide a comprehensive analysis of the barriers to explicit flexibility for low voltage assets and the pathways to overcoming them. The structure is as follows:

- Current Status of LV Assets for Explicit Flexibility: This initial section offers an overview of the present situation.
- Barriers: A dedicated segment clearly identifies the challenges currently impeding LV assets from delivering explicit flexibility. There is a specific distinction between the barriers addressed within this report and those excluded from its scope.
- Measurement and Metering: This section details the requirements and issues related to measurement and metering, crucial for enabling explicit flexibility at the asset level.
- Data Communication: the report examines the technical and procedural demands associated with reliable and efficient data communication, a prerequisite for real-time asset integration.
- On-boarding and prequalification: This part outlines the procedures and hurdles linked to the on-boarding of individual assets, including meter homologation and associated administrative processes.
- Conclusion: A final section summarizes the findings and reminds the objectives of the consultation.

In the report, six barriers have been addressed, namely:

1. The requirement for an SMR3 enabled headmeter,
2. The need for a MID-compliant private submeter,
3. The local Gateway obligation,
4. The high volume of real-time data handling,
5. The inadequate private meter commissioning process for low-voltage asset,
6. The sub-optimal prequalification process to participate in capacity auctions.

Each barrier is analyzed in detail and accompanied by a proposed way forward. The call for improvements in the process of prequalification to participate in capacity auctions has also been acknowledged and included in the action plan of Elia.

The consultation phase provides a structured opportunity for market stakeholders to assess and contribute to the development of effective solutions. Feedback gathered will inform future work, notably the finalization of implementation plans, which will follow after the conclusion of the consultation period.

2. Status of low-voltage flexibility in Belgium

Let's begin the study by summarizing the work carried out by Elia and the DSOs to open the balancing market to low-voltage assets in Belgium. The first product opened was FCR, introduced a few years ago. Although technically challenging for certain technologies due to the need for very fast response and high-frequency data sampling, process-wise, FCR is relatively straightforward. This is because FCR is a power-only product, considered symmetrical, which means it has no impact on energy metering and eliminates the need for processes such as Transfer of Energy.

In 2024, aFRR for low voltage was also opened, but without the possibility of Transfer of Energy, forcing market parties to negotiate opt-out agreements. In 2026, the last explicit balancing product, mFRR, will be opened—initially only via the head meter. Transfer of Energy will also be allowed at that time.

	FCR	aFRR	mFRR
Opening to LV assets	Open	Open	Head meter: Q1 2026 Submeter: Q1 2027
ToE (CSM only)	N/A	2026	Together with the opening of the market in LV

Elia observes significant shares of installed low-voltage flexibility in Belgium, with hundreds of megawatts of flexibility already unlocked[1]. However, not all unlocked flexibility participates in explicit markets or even reacts to price signals. In Belgium, owners of flexible assets can provide flexibility via different means.

- By submitting bids on markets such as DA, ID, or Balancing,
- Implicitly, through dynamic contracts with their supplier or by reacting to imbalance prices via an independent aggregator,
- By optimizing consumption locally (reducing grid tariffs and maximizing self-consumption).
- Combining multiple value streams is also possible.

In practice, Elia notes that only a very small share of these unlocked flexible assets participates in the explicit balancing market, and only in FCR nowadays. For aFRR and mFRR, there is currently no participation from low-voltage assets.

Concerning FCR, there are currently 17,000 low-voltage delivery points, representing a combined installed capacity of over 20 MW. This figure should be considered alongside the total 3,000 MW of FCR procured by the Core region and Belgium's Core share of FCR, which currently stands at 26 MW. Low voltage has become a cornerstone of FCR in Belgium.

[1] Unlocked: the asset effectively reacts to an incentive (Elia Balancing Services: FCR, FRR, CRM ; Reaction to energy market prices such as dynamics price contracts; Local optimization of capacity tariff or Self-consumption)

	FCR	aFRR	mFRR
Active volume	Around 20 MW	No active volume	No active volume
Active technology	Mostly home batteries and electric boilers	/	/

Hereunder is a graph showing the evolution of the registered delivery points. The sharp increase comes from the participation of LVDP in the FCR.

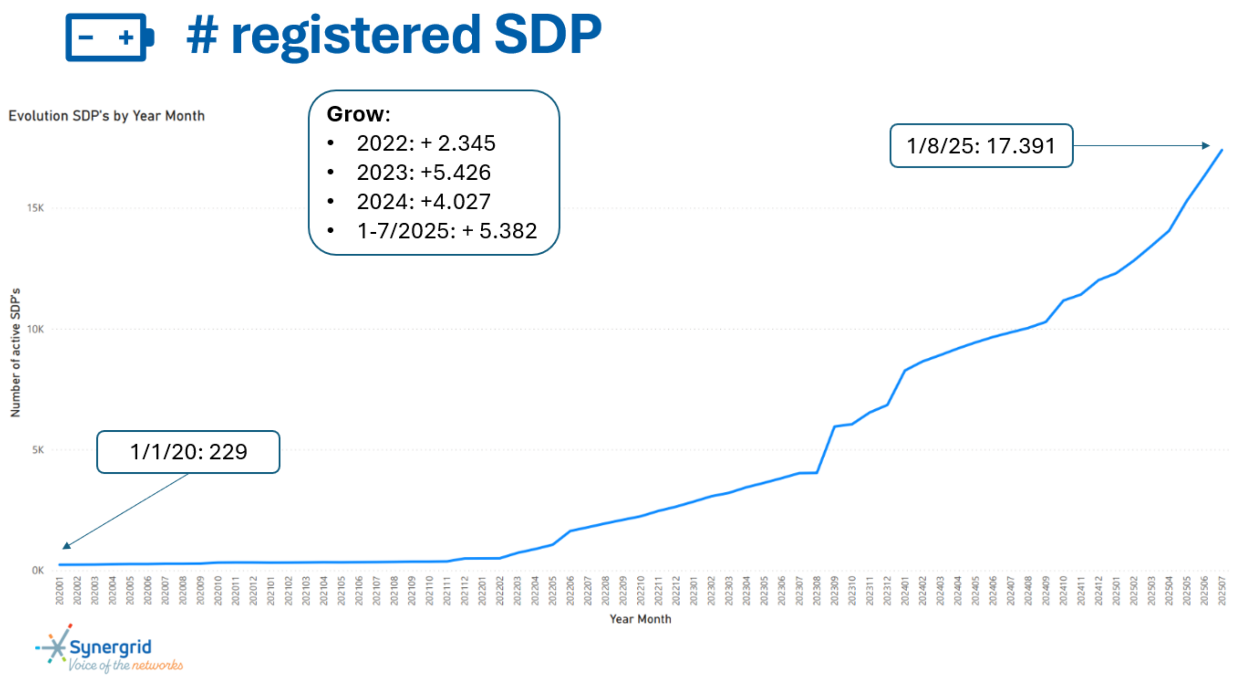

Figure 1 - Evolution of the number of prequalified Low voltage delivery points

3. Barriers hindering participation of low-voltage assets in the explicit balancing – Holistic view

Before going into the details of measurement processes, data communication, and onboarding related to the explicit balancing market in Belgium, this section presents a holistic view of the barriers perceived by the market parties. This holistic view naturally covers the scope of the study but is also deliberately broadened to ensure that Elia, can steer its vision and market development efforts effectively.

In this exercise, Elia benefited from comments shared by stakeholders during several past public consultations, particularly the Synergrid consultation on Document Release 2[2] and the one concerning Transfer of Energy[3]. Additionally, CREG had published a report on entry barriers for balancing. During the course of the exercise, Febeliec also shared its perspective, which was of course taken into account in this study.

After analyzing all available sources, bilateral exchanges were conducted with interested market participants to deepen our understanding of the key topics. In addition, an interactive public workshop was organized to foster broader discussion and collect further valuable insights. A summary of the workshop outcomes is included in Annex A.

Please note that the barriers discussed here have been formulated in general terms and are not tied to any specific balancing product. Product-specific details will be addressed in their respective dedicated sections.

3.1. Barriers part of the scope of this study

The workshop confirmed and deepened the understanding of several barriers within the main scope of the incentive. The outcomes are summarized in the tables below. Among the identified barriers, three were clearly recognized as the most impactful: the absence of **Transfer of Energy (ToE)** aFRR, the obligation to install a **Local Gateway** and the requirement for a **MID-certified sub-meter**. The absence of ToE for aFRR is not discussed further in this study as the opening is already planned to be implemented in the coming months (cf. ToE game plan). The two other elements will be addressed in detail in the study. In addition, the need for **an SMR3 enabled head meter**, the **volume of real-time data**, **obligations at the level of individual assets**, and concerns related to the **prequalification process** will also be covered.

The barrier concerning the use of the **Tase2/ICCP** protocol extends beyond low-voltage assets and will not be addressed in this study; however, it has been selected as a topic for a future incentive in 2026. Note that this requirement is also expected to disappear for FCR after the entry into force of the new T&C BSP FCR

[2] Available here: https://www.synergrid.be/nl/documentencentrum/openbare-raadpleging/documenten-flexibiliteit-najaar-2023

[3] Available here : https://www.synergrid.be/images/downloads/Public_Consultations/ToE_Design_note/ToE_design_note_CR.pdf

Efforts are ongoing **to shorten the onboarding process**, both through digitalization (via EPIC) and process evolution. The introduction of the new NCDR regulation will further support this direction. Finally, regarding requirements related to an **Energy Management Strategy**, maintaining these requirements is considered essential to ensure security of supply, given the evolving technology mix underpinning current balancing practices and the portfolio trading freedom granted by Elia.

Metering	Communication	On-boarding (Prequalification)
Need for MID compliant meters (ToE)	**Local Gateway obligation**	Lengthy on-boarding
Need for SMR3 headmeter (aFRR)	Tase2/ICCP requirement	Obligations on individual assets
	Need for real-time data at asset level	EMS requirements
	The volume of data to be transmitted	The prequalification test (*this is part of the incentive description but hasn't been explicitely mentionned by market parties. They however claim that a « portfolio extension without PQ test » would help)*

Figure 2 - Barriers mentioned by market parties that are in the scope of this study (items in bold are the ones mentioned as the most impactful by multiple actors)

3.2. Barriers out of the scope of this study

As explained, the objective of this part of the study is to build and formalize the most exhaustive possible view of the barriers to participation of low-voltage assets in explicit balancing. Several elements not directly related to measurement, communication, or onboarding were highlighted by market actors. Although outside the scope of the current incentive, Elia takes these items seriously and would like to add a few comments on each.

The table on the left presents the elements related to processes over which Elia has control (sometimes partial):

- The most frequently mentioned element, unanimously reported by the market as having a major impact, is the absence of **Transfer of Energy** for (low-voltage) aFRR. This barrier will be lifted in in 2026 as part of the ToE game plan.
- Improved dispatching of renewable units in the day-ahead market is anticipated following the transition to 15-minute MTUs[4] for the DA/ID markets. Furthermore, Elia is considering a further increase of the granularity of the current auctions for FRR, which might positively impact the participation of LVDPs.
- Elia understands that the current **penalty design** is perceived as inadequate by some market participants. This element goes beyond the scope of this study, but Elia commits to investigating it in the short term (see further on).
- The **interaction between TSO and DSO products** is indeed a concern that has been identified and further discussions with DSOs within Synergrid on this topic will be held.
- Elia acknowledges the feedback from the market parties suggesting that **implicit balancing is more attractive** than explicit balancing for the moment. This is one of the factors that led to the revision of the balancing philosophy.

[4] MTU stands for Market Time unit and is is the smallest discrete period over which market activities in the electricity sector are organized.

Other process-related barriers
Absence of ToE (aFRR)
Current MTU not suited for RES
Penalty design
Interaction with DSO products and non-time-of-use grid fees)
Imbalance price too interesting

Other technical-related barriers
Low revenue/capex ratio
Incompressible administrative work for LV
Uncertainty of future market conditions (large batteries etc.)
LV assets can easily overrule the steering
Explicit balancing will intrinsically remain complex for LV assets

Figure 3 - Barriers mentioned by market parties that are not in the scope of this study (items in bold are the ones mentioned as the most impactful by multiple actors)

Finally, it is important to mention that market actors have identified certain barriers that lie completely outside Elia's control. Obstacles such as the revenue-to-CAPEX ratio or the incompressible administrative burden inherent to operating a decentralized portfolio are entirely beyond Elia's influence such as, e.g., sales, contracting, settlement processes, etc.

It is also clear that several external factors—such as the connection to Picasso and MARI or the strong penetration of large-scale batteries—are currently transforming the Belgian and European balancing markets. The consequence has been a relatively sharp decrease in balancing capacity and balancing energy prices, as it can be seen in the graphs below. In addition, the further increase of large-scale batteries is creating additional uncertainty (at least with some market participants), on whether a positive business case for the participation of low-voltage flexibility to the explicit balancing markets can be realized, even if key barriers could be removed. <u>In this regard, Elia should be careful in allocating a large part of the available resources to develop this market segment</u>"

Concerning the decreasing opportunities of the explicit market, we can note the following:

- For FCR, there is a strong convergence between the Belgian prices and the prices in neighboring countries, suggesting that the competition is at the European level. High prices observed in 2023 and 2024 have reduced largely (firt graph.
- For aFRR capacity market, comparing the period of 1 January to 18 October, the total procurement cost has reduced from 69.9 M€ in 2024 to 21.2 M€ in 2025 (second graph).
- For aFRR energy market, the weighted average activation price has converged sharply after the connection to Picasso, as this market is now a competition at the European level (third graph).

These trends are likely to continue with the arrival of additional large-scale batteries and the further integration of European balancing markets.

Elia invites market actors to respond, and to formalize their messages or share any additional observations that have not been listed in this section.

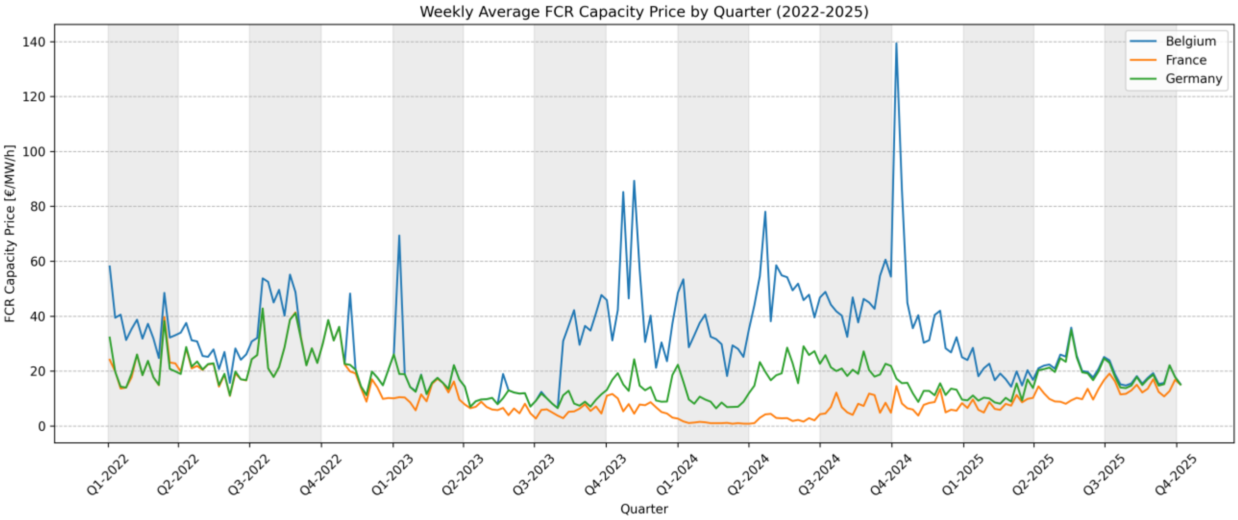

Figure 4- Evolution of the weekly average FCR price in Belgium, France, and Germany.

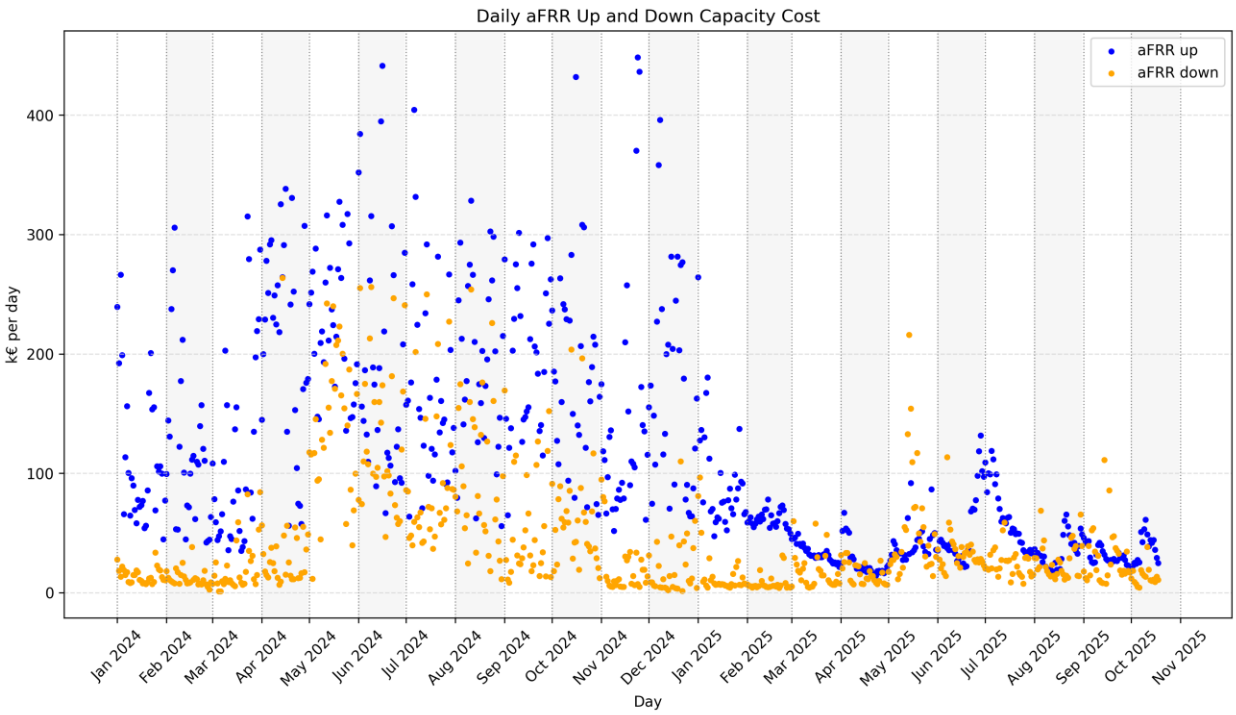

Figure 5- Evolution of the daily capacity cost for aFRR up and aFRR down in Belgium.

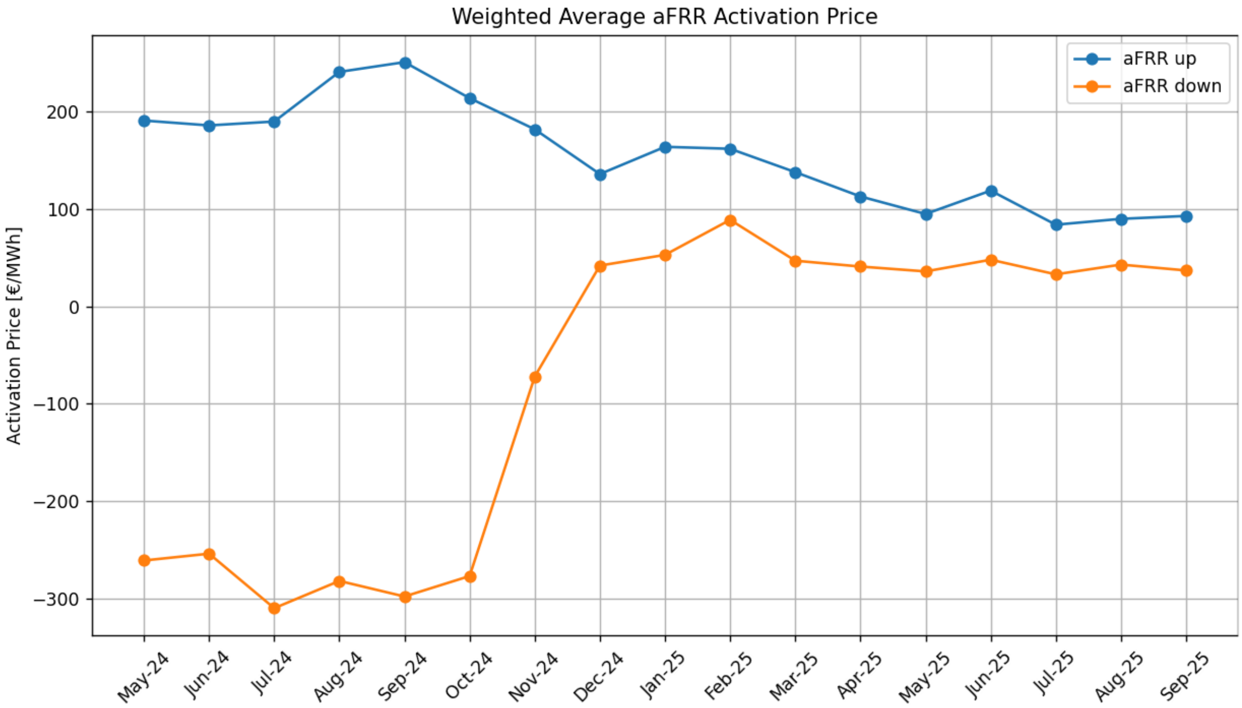

Figure 6 - Evolution of the monthly weighted average activation price for aFRR up and aFRR down since May 2024.

4. Measurement and metering requirements for low-voltage Balancing

4.1. Description of the current requirements

As preliminary remark, it's important to clarify a terminology item.

- Metering: is used for billing and settlement and focuses on energy integration over time (quarter-hours data). It is referring to energy, expressed in MWh.
- Measurement: is used for system operations and management and focuses on real-time electrical quantities It is referring to power, expressed in MW.

Measurement and Metering requirements for providing explicit balancing services with low-voltage delivery points in Belgium are currently defined in the T&C BSP as well as the FSP-DSO contract. Those requirements will be described in more details in this section. As a reminder, mFRR is not yet allowed in low voltage. The opening of this product will be opened soon.

Before elaborating on the detailed requirements, a few key concepts are clarified below.

4.1.1. Key concept 1: Head meters and submeters

Historically, flexibility services could only be delivered through the head meter, which is the main access point meter installed and managed by the System Operator (i.e. by the DSO for assets connected to a public distribution grid). This head meter must be compliant with the Measuring Instruments Directive (see later). It may be a smart meter capable of collecting quarter-hourly (QH) data or a non-smart device, but in all cases, it remains under the DSO's responsibility to ensure compliance. For smart meters, high-granularity data—up to one-second intervals—can be accessed through the P1 port[5], although this data flow is not managed by the DSO. To cope with electrification and decentralization, the delivery of a service is now also allowed via a submeter which is an additional meter placed downstream of the head meter. In contrast to the head meter, submeters (which can consist in an embedded or an additional meter), are privately owned and not supervised by system operators. Their accuracy and technical characteristics can therefore vary significantly, which is why specific compliance requirements have been introduced for these devices to participate to the FCR and/or aFRR Services.

[5] The P1 port of a smart meter is a standardized communication interface that allows end users or external devices, like home energy monitors, to access real-time consumption and production data directly from the smart meter. This port provides easy access to detailed meter readings and facilitates better energy management at the consumer level.

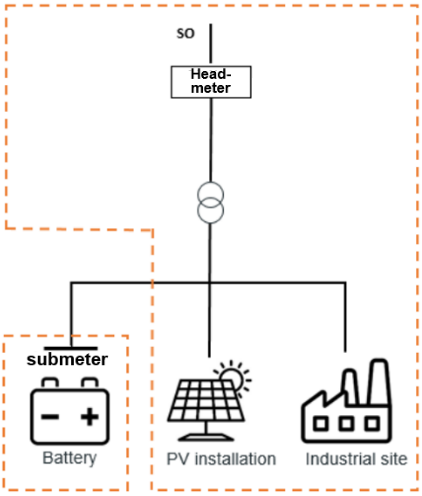

Figure 7 - Illustration of the concept of submetering

4.1.2. Key concept 2: SMR1 enabled smart meters and SMR3 enabled smart meters (at head meter level)

A too fast reading of the regional grid codes might suggest that only two situations exist: one where quarter-hourly data is available (where a smart meter is installed) and one where quarter-hourly data is not available (where there is no smart meter). In reality, it is a bit more complex, and it is important to understand that the existence of quarter-hourly data does not automatically mean that this data is accessible. Indeed, a smart meter can operate under SMR1 (Smart Metering Regime 1) or SMR3. In the first case, quarter-hourly data is measured and accessible by the DSO but not taken into account in the allocation process (see later). In the second case, the data is accessible by the DSO, included in the allocation, and shared with the supplier of the access point.

In all regions of Belgium, the default metering regime for all smart meters is SMR1. In Flanders and Wallonia, switching to SMR3 requires an explicit request and consent from the grid user. In the Brussels region, any grid user participating in the provision of a flexibility service is considered having implicitly given consent and is switched to SMR3.

As of the publication date of this report, smart meter penetration is very advanced in Flanders (>80%) but still limited in Brussels and Wallonia. As for the share of smart meters under SMR3, it is negligible in Wallonia and Brussels and represents only a few percent in Flanders.

4.1.3. Key concept 3: Metering allocation (under MIG6 context)

As part of the energy settlement process at the DSO level, there is always a deviation between the energy measured at the feeder level and the energy measured at all downstream access points. This is due to losses, missing data (particularly when there is no smart meter), certain unmeasured consumption (such as street lighting), etc. Consequently, there is an allocation process that distributes the energy among the different metering points (and therefore among the different BRPs). The purpose of this section is not to describe the allocation process in detail, but interested readers can refer to MIG6 or to the information available on the Synergrid Settlement Working Group website.[6]

When QH data is unavailable, allocation relies on standard profiles[7] calculated annually based on historical offtakes. However, these profiles can be distorted by the participation in flexibility. To avoid this distortion, use of QH data of the head meter for allocation is considered necessary for all the points participating in the delivery of a flexibility service. This is why, with the opening of explicit balancing market to low-voltage assets, Elia and the DSOs agreed that the use of 15-minutes data for the allocation is a necessity for providing any flexibility service (including balancing).

Currently, only data from SMR3 enabled meters is used for allocation. SMR1 data is currently not included in the process. Under the "*Settle2.0*" program, Flanders will begin using in the allocation the data from both SMR1 and SMR3 meters as of 2026.

4.1.4. Key concept 4: Measuring instruments Directive (MID)

The Measuring Instruments Directive (MID) 2014/32/EU is a directive by the European Union that seeks to harmonize many aspects of legal metrology across all member states of the EU. There is an obligation for each EU member country to transpose the MID directive into national legislation. In Belgium this is realized by the Royal Decree of the 15th of April 2016 which went into force on the 20th of April 2016. In the field of electricity, this directive provides some requirements concerning the measurement devices, including but not limited to a level of accuracy of 3.5% or better (maximum permissible error). It is evident that this directive has been designed for more generic metering and without the use case of flexibility delivered by LV assets (especially with an embedded meter) in mind.

In general, MID is applicable to active energy meters and when there is a service settlement from the measurement of this active energy. This yields the following applicability of MID:

- MID is never relevant for FCR as it is a pure power product for which energy metering is not needed.
- MID is not applicable to aFRR in the absence of Transfer of Energy because it only requires power measurements. If there is over/under delivery, there is a penalty based solely on power measurements (not energy).
- MID is currently applicable to aFRR with Transfer of Energy because corrections are done between parties in the settlement process based on energy (power measurements aggregation). This creates situations rather hard to understand where the same asset with the same meter could provide aFRR only if there is no ToE associated. This might create the situation with which a LVDP can participate only if his BSP has reached an opt-out agreement and not a ToE with his supplier annihilating the benefits of the opening of ToE aFRR and creating potentially, a difficulty for the LVDP to easily switch supplier.
- MID is needed for mFRR in all cases as all settlements are based on energy metering.

[6] https://www.synergrid.be/fr/concertation-du-marche/pdg-settlement
[7] For more insights on load profiles: https://www.synergrid.be/nl/documentencentrum/statistieken-gegevens/profielen-slp-spp-rlp

4.1.5. Overview of the requirements for LV participation in aFRR

The measurement requirements for the participation of a low voltage point in the aFRR service are described in several regulated documents[8]. The key reference document is of course the T&C BSP aFRR which states that the service can be delivered via a head meter or a submeter. The BSP is then invited to refer to Annex 3 in which the only general requirement applicable to all delivery points is the availability of 4seconds measurement data for injection and for offtake. Further conditions specific to delivery points connected to a public distribution grid are described in the FSP-DSO contract.

The FSP-DSO contract stipulates that the head meter at each delivery point must be a smart meter, and that the metered quarter-hour values must be used for allocation purposes. For detailed requirements regarding private sub-meters, the contract refers to Annex C8/06. This annex specifies requirements in the following areas:

- The use of current and voltage transformers, where applicable (typically not required for low voltage installations).
- The measurement sampling rate, which must support monitoring in 4-second intervals.
- The wiring and electrical grounding standards.
- The accuracy of measurement devices, defined by maximum permissible error limits.

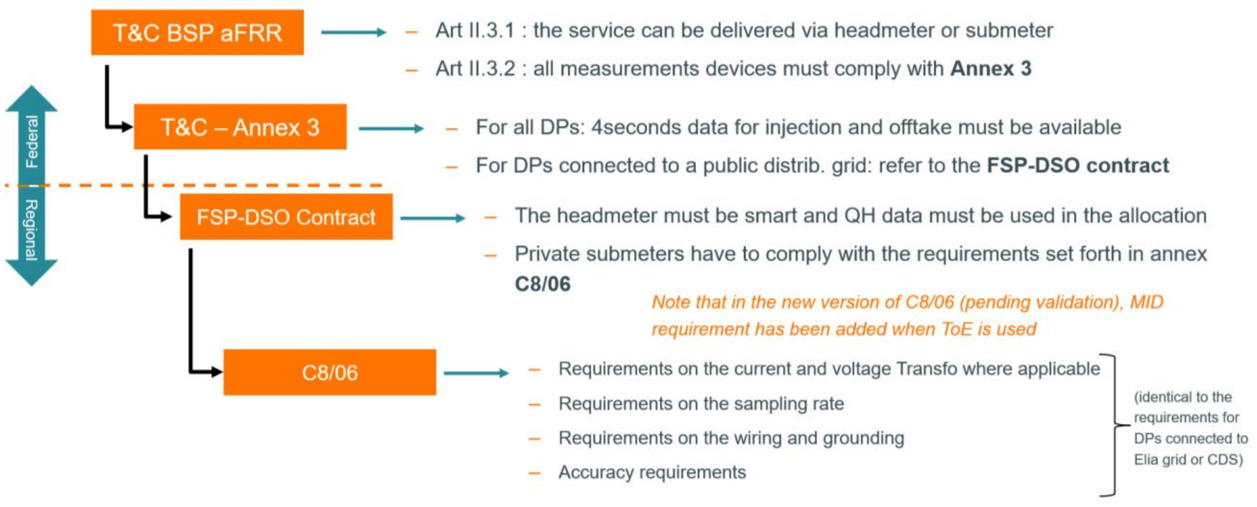

Figure 8 - Map of the current aFRR measurement requirements

The accuracy requirements specified in Annex C8/06 differ according to the asset's rated power. This differentiation is made possible by a requirement relaxation, which is grounded in the law of large numbers. The law suggests that, in theory, aggregating measurements from a group of assets yields greater overall accuracy compared to relying on individual measurements. For example, combining data from a pool of one hundred assets, each rated at one kilowatt and measured individually with devices allowing up to 10% error, results in a collective measurement error of only one

[8] Elia is investigating ways to gather requirements in a single document and ease the understanding

percent. Further details are available in Annex B. Based on this principle, threshold values have been established according to the rated power of the assets; these are compiled in the table below.

Vermogen van gemeten proces	VT	CT	Vermogensmeter
	Nauwkeurigheidsklasse	Nauwkeurigheidsklasse	Nauwkeurigheidsklasse /vereisten
≥ 10MVA	0,2	0,2S	0,2S of 0,25
≥ 5MVA à < 10MVA	0,2	0,2S	0,5S
≥ 1 MVA à < 5MVA	0,2	0,2	0,5
≥ 100 kVA à < 1MVA	0,5	0,5	1
≥ 32kVA en < 100kVA	NA	0,5[1]	2%[2,3]
≥ 11kVA en < 32kVA	NA	0,5[1]	3,5%[2,3]
≥ 4kVA en < 11kVA	NA	0,5[1]	6%[2,3]
< 4 kVA	NA	0,5[1]	10%[2,3]

[1] Indien vereist.
[2] Compliancy en gecertificeerd volgens de certificeringsprocedure beschreven in “General technical requirements for private measurement” zoals gepubliceerd op de ELIA website.
[3] Alleen van toepassing bij een minimaal biedvolume van 100kW.

Figure 9 - Required accuracy classes (extracted from Synergrid prescription C8/06

The future opening of Transfer of Energy in (low voltage) aFRR will however impact the measurement requirements. Indeed, as stated in the previous section, ToE currently leads to the applicability of the MID. For this reason, in the new version of the FSP-DSO contract (pending validation), a clarification has been made stating that all measurement devices used in a Transfer of Energy process must comply with the MID.

The applicability of MID cancels the accuracy relaxation previously introduced and imposes MID class A and its associated 3,5% maximum permissible error.

4.1.6. Overview of the requirements for LV participation in FCR

First of all, note that a revision of the FCR T&Cs is pending validation by the regulator. Aiming at harmonization and simplification, Elia has aligned the FCR measurement requirements with those of aFRR in this revision. Elia therefore expects that the measurement requirements for FCR will soon become identical to those detailed above. Nevertheless, for the sake of completeness, the measurement requirements currently in force for FCR are presented in this section.

As with aFRR, the measurement requirements for participation of a low voltage delivery point in the FCR service involve several regulated documents. The key reference is the T&C BSP FCR, which permits service provision via either a head meter or a submeter. The BSP should then consult Annex 3, which outlines general requirements for all delivery points. These include the availability of injection and offtake data in 2-second intervals, a data availability rate exceeding

95%, and an overall measurement chain accuracy of 1% or better. If this accuracy cannot be achieved, a derating factor is applied to the prequalified volume.

In the current T&C FCR, there are no references to the FSP-DSO contract for delivery points connected to the public distribution grid. Instead, the T&C point to the applicable regional grid codes, which set different accuracy standards depending on the region: 3.5% in Brussels and Flanders, and 2% in Wallonia.

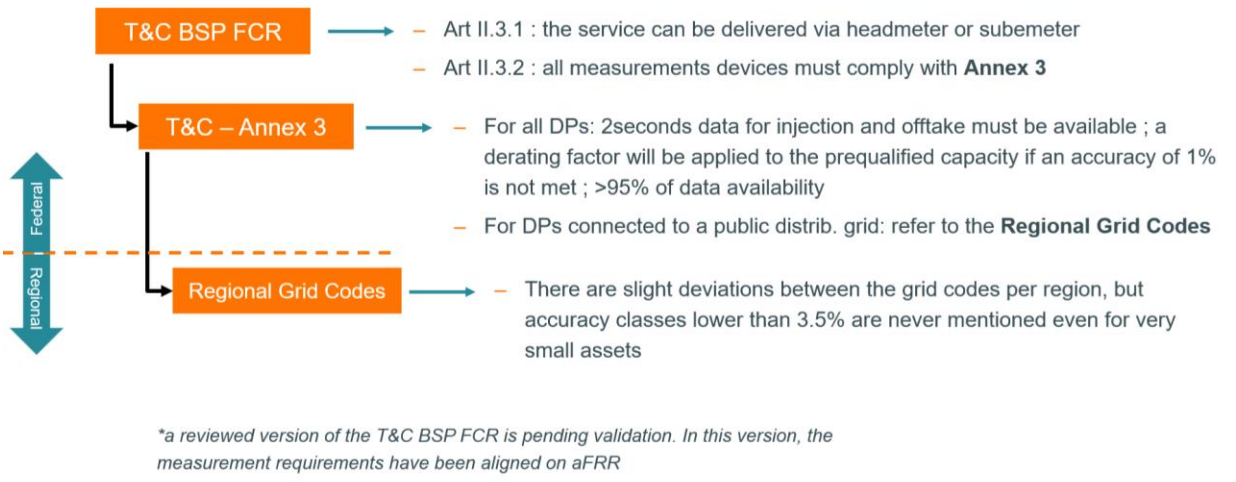

Figure 10 - Map of the current FCR measurement requirements

4.2. Barrier 1: Need for an enabled SMR3 head meter

Among the barriers to participation in aFRR reported by market players is the requirement to have an enabled SMR3 head meter available (even when the service is delivered via a private submeter). Analysis of this barrier highlights a confusion between the SMR3 regime and the inclusion of quarter-hourly data in the allocation process. In fact, the need for an SMR3 enabled meter is not mentioned anywhere. What is specified in the FSP-DSO contract, however, is that the head meter must record quarter-hourly values and that these data must be included in the allocation, but not necessarily communicated to the supplier. The regional grid codes also do not impose the presence of an SMR3 enabled meter for the delivery of flexibility services.

The confusion arises from the fact that until 2025, the two aspects were closely linked, since only data from SMR3 enabled meters were included in the allocation. But as explained in section 4.1.3, the situation will change in Flanders in 2026 through the Settle 2.0 program.

To fully understand the impact of this barrier today and what will change in the short term, it is necessary to analyze the situation region by region.

- In Wallonia, the smart meter rollout is delayed, creating an inherent barrier independent of the inclusion of data in the allocation, since most of the time quarter-hourly data is simply not available. However, it is important to note that even if the rollout accelerates, it is likely that most of the meters installed will be under SMR1 and therefore not included in the allocation (as in Wallonia, unlike Flanders as of 2026, will not make the allocation with QH data for all smart meters) , unless an explicit request is made to switch to SMR3, which involves an additional step, time, and therefore costs.

- In Brussels, the rollout of smart meters remains limited. However, through the concept of implicit consent, users who participate in flexibility services are automatically switched to SMR3, which ensures their data is included in the allocation process. While the availability of quarter-hourly data continues to be a challenge in Brussels, its inclusion in allocation is not an obstacle.
- In Flanders, the smart meter rollout is well advanced, creating significant potential for decentralized flexibility. Unfortunately, only a minority of smart meters are currently used for allocation purposes. This will change starting in 2026, when Fluvius, through the introduction of Settle 2.0, will begin incorporating data from all smart meters. As a result, all LVDP equipped with smart meters will be able to participate in explicit flexibility.

		Before 2026	As of 2026
FCR	/	N/A	
aFRR	Wallonia	Existence of QH data: ✗ QH data in allocation: ✗ Households eligible to Flex: ~0	Existence of QH data: ? QH data in allocation: ✗ Households eligible to Flex: ~0
	Brussels	Existence of QH data: ✗ QH data in allocation: ✓ Households eligible to Flex: ~0	Existence of QH data: ? QH data in allocation: ✓ Households eligible to Flex: ~0
	Flanders	Existence of QH data: ✓ QH data in allocation: ✗ Households eligible to Flex: ~140k	Existence of QH data: ✓ QH data in allocation: ✓ Households eligible to Flex: ~1,8M

Figure 11 - Summary of the barriers related to head meters per region

Recommendation of Elia:

It must be emphasized that quarter-hourly allocation of head meter data is required to participate to aFRR and not necessarily SMR3 regime. Elia reiterates the importance of a swift deployment of smart meters and the application of quarter-hourly allocation by default as opposed to RLPs/SPPs.

Elia advocates for an alignment of the regional regulation in Wallonia with the Flemish one, in order for all quarterly-hours data to be taken into account in the allocation process. Alternatively, the application of the implicit consent as done in Brussels would also lift the barrier

4.3. Barrier 2: Need for a MID-compliant private submeter

4.3.1. Barrier description and impact

Market participants have identified the MID requirement as one of the main obstacles to the participation of low-voltage assets in aFRR (and mFRR in the future). While the barrier is systematic for mFRR, Elia reminds the reader that MID is currently applicable to aFRR only with Transfer of Energy. It is important to note, even though this falls outside the scope of the present study, that MID also poses a significant barrier to arrangements where electricity supply is divided among multiple suppliers at a single delivery point—a concept often referred to as "supply split.

The MID overrides the accuracy relaxations introduced by Elia and the DSOs, enforcing a strict measurement accuracy of 3.5% or better—a standard that is rarely observed on embedded meters. Additionally, MID sets further requirements, such as the presence of a display screen to show measurement values[9], which few embedded meters possess.

Discussions with original equipment manufacturers (OEMs) led us to the following understanding of the penetration of MID meters amongst existing and future flexible assets in Belgium:

Technologies present in Belgium	Presence of MID meter today	Future outlook
Household Batteries	Low	Highly competitive market. It is expected to remain low
EV's (private charging poles)	Low/Medium	Mandatory since this year when repayment by the employer
EV's (public charging poles)	High	Already mandatory
Solar inverters	Low	Focus on lowest cost possible, MID not a priority of manufacturer. Expected to remain low.
Heat pump & E-boilers	Low	Low interest from OEMs who do not perceive the added value (even though the cost impact is smaller when compared to the cost of the asset when compared to inverters)

The majority of OEMs do not equip their devices with embedded MID-certified meters. Discussions with several OEMs indicate that the primary reason is straightforward: the additional cost is substantial, while the perceived benefits for manufacturers are limited. Integrating a MID meter directly into the device typically adds around €50 to the manufacturing cost, excluding any potential redesign expenses. For technologies with a global market, such as charging poles or inverters, it makes little sense for manufacturers to adapt their standard products solely to meet MID compliance.

The alternative to using the embedded meter is to install a separate dedicated meter. This induces a cost of ~300€ (plus installation costs) to be borne by the grid user or the BSP, therefore cannibalizing a potentially significant share of their revenues.

As conclusion, the MID requirement is a key barrier today and is likely to remain if no solution is found.

[9] Note that this requirement is currently being reviewed by the European Commission

4.3.2. Is MID Fit for Purpose?

While Elia's goal is to remove entry barriers and support the development of flexibility across all voltage levels, simply opposing MID without careful consideration would be inadequate. It is important for Elia to strike the right balance between making participation easier and upholding essential standards: Elia needs to ensure high-quality delivery of flexibility services, guarantee fair a remuneration for grid users, and encourage OEMs to integrate reliable measurement systems into their devices. Let us examine these items one by one.

Ensuring a qualitative delivery of flexibility services

Using inaccurate metering can result in "invisible" non-delivered volumes, contributing to Area Control Error (ACE) for the Belgian control zone and ultimately reducing operational security. Elia cannot accept a decline in the quality of balancing services. However, two important factors should be considered. First, the law of large numbers shows that when pooling a large number of flexible assets, the collective measurement accuracy improves, as individual deviations tend to cancel each other out. This statistical effect justifies relaxed metering requirements in cases where MID certification is not strictly necessary. Second, Elia allows a tolerance band for balancing services[10]. In addition, in contrast to regular invoices by Suppliers, the accuracy of the determination of the volume of flexibility that is supplied by a given Delivery Point is not solely dependent on the measurement/metering accuracy. Indeed, the volume of flexibility that is supplied is determined by taking the difference between the measurements and the baseline (i.e., the expected injections/offtake in absence of flexibility activations) and baselines can further introduce certain error margins (about 10% when decomposing the quality factor formula). In this context, it must be observed that the MID's maximum permissible error requirement of 3.5% is much more stringent than what would be needed to ensure a reasonable quality of the measurement of the service from a TSO perspective.

Guarantee a fair remuneration for grid users

In order to assess the fairness of the GU remuneration, the following two elements are considered.

From our understanding, most BSPs active in low voltage tend to remunerate the grid users based on allocation keys rather than based on a 1:1 matching with delivered flexibility (see illustration below). Therefore, increased precision on individual level would not automatically lead to improvements in the fairness of remuneration from the perspective of the grid user. Even in case of 1-1 link between delivered flexibility and remuneration, it must be highlighted that the supplied volume of flexibility follows from a calculation including a baseline. Hence, having measurement requirements that are significantly stricter than baseline accuracy requirements would not contribute to a fairer remuneration.

[10] For aFRR, the tolerance band is 15% in both directions.

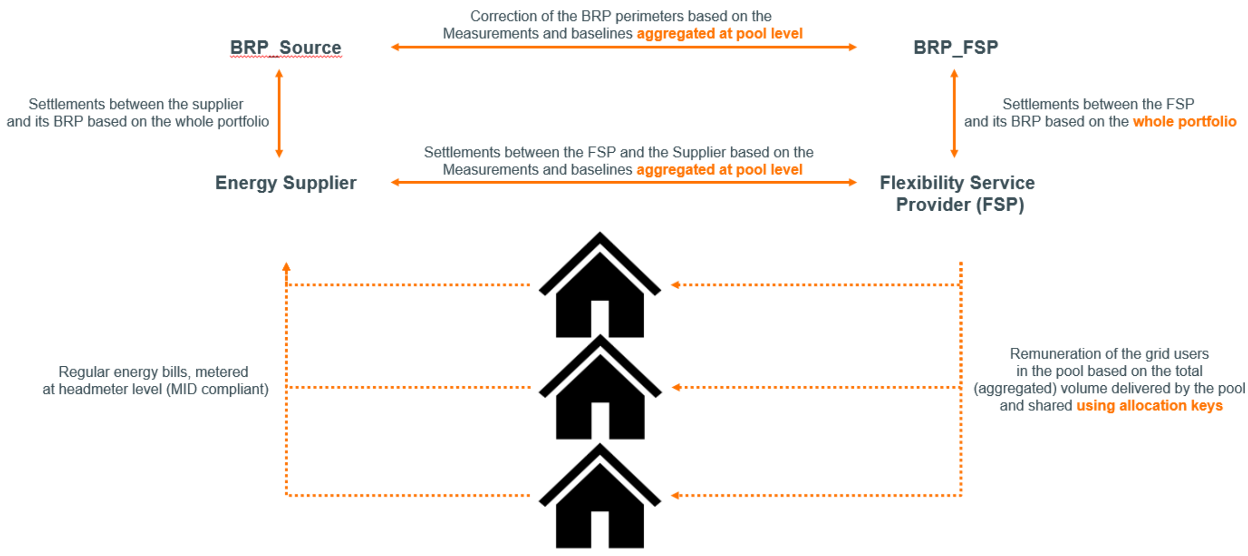

Figure 12 - Illustration of the financial fluxes in the case of ToE CSM

Furthermore, even if a perfect remuneration cannot be reached due to measurement inaccuracies, it should be re-minded that grid users participate to flexibility to reduce the operational costs of existing assets. As an illustration, let's consider someone having a heat pump. By participating in flexibility services, he could save 250€ per year. But because of his inaccurate measurement system, he would receive only 220€. MID says that this is unacceptable. Therefore, the grid user would not be allowed to participate and receive nothing which cannot be the objective of the MID.

Encourage OEMs to integrate reliable measurement systems into their devices

MID was designed to set a clear, understandable, and widely accepted certification framework for metering devices. However, when it comes to submetering, especially at the low-voltage asset level, very few embedded meters actually comply with MID standards as the purpose of these meters were generally for information purpose only, and not energy settlements. Most grid users are unaware of MID certification when purchasing appliances, meaning it is rarely a consideration in consumer decisions. Discussions with OEMs further reveal that few inverters—such as those for solar panels or home batteries—are compliant or likely to become compliant, given the fiercely competitive market. For heat pumps and residential electric boilers, MID compliance is not a priority for manufacturers (except for EV charging stations, where compliant MID submeters are much more frequent). Considering this, Elia believes that enforcing MID would not lead to an increased adoption of MID meters, but simply less DPs participating to explicit flexibility

In conclusion, Elia believes that the MID framework is not truly fit for purpose in the context of flexibility. While it establishes a common certification standard, it does not reflect the operational realities or requirements of balancing services, particularly for low-voltage assets and submetering. The limited market adoption, lack of awareness among consumers, and absence of clear incentives for OEMs demonstrate that MID compliance is more likely to limit the penetration of decentralized flexibility than significantly influence the quality of installed embedded meters. Elia is therefore convinced that a solution needs to be found for MID not to significantly hinder the development of decentralized flexibility.

4.3.3. Envisioned approaches and Recommendation

The table below presents the different approaches investigated for lifting the barrier.

Approach	Pro	Con
Investigate with the regulatory and legislative instances if the absence of 1:1 customer billing based on individual measurements constitutes a sufficient argument not to apply MID for explicit flexibility under ToE CSM. Also discuss precedents.	- Straightforward and rapid to implement. - Reduces regulatory burden for explicit flexibility with pooled revenue sharing.	- May be perceived as disadvantageous by suppliers. - Challenging to monitor and enforce (affects contracts between BSPs and grid users). - EU bodies may interpret the regulation differently. - Limited scope: addresses only explicit flexibility for ToE CSM; does not resolve other use cases (e.g., supply split, ToE CM).
Analyze with the regulatory and legislative instances the possibility to apply the MID's optionality clause[11] and define specific requirements within Belgian legislation (national level).	- Provides regulatory clarity with minimal ambiguity. - Has the potential to address all flexibility use cases, including supply split scenarios.	- Could raise concerns regarding fair competition and level playing field.
Introduce sector-specific provisions in the Network Code on Demand Response (NCDR) with priority over MID.	- Highly robust solution that precludes ambiguity. - Addresses all flexibility use cases simultaneously (including supply split). - Facilitates potential harmonization at the EU level.	- Implementation likely to take several years. - May raise concerns about competition and a level playing field
Advocate for modification of the MID directive at the EU level.	- Robust and definitive solution with no room for differing interpretations. - Enables harmonized and comprehensive regulation across all flexibility use cases. - Supports EU-wide consistency.	- Very lengthy legislative process, with no short-term impact. - Risk to lower the (already small) incentive for OEMs to improve meter accuracy on the long run

[11] There is an optionality clause in MID leaving the opportunity for member states to not apply MID in some cases if duly justified.

MID currently represents a significant barrier to the development of low-voltage flexibility and will have a substantial impact on the growth of low-voltage flexibility in Belgium, across all configurations. Recognizing the complexity and urgency of the issue, Elia believes that a parallel and multi-layered approach is required. Elia has already raised its concerns regarding the MID framework to ACER and the European Commission through public consultations in early and late 2025.

Recommendation of Elia:

To avoid hindering flexibility development, Elia recommends pursuing several actions concurrently:

- ➔ In the short term, it is crucial to clarify, in cooperation with the regulatory and legislative bodies, the applicability of MID for explicit balancing under ToE CSM when only aggregated data is used.
- ➔ In the medium term, Elia proposes working with the regulatory and legislative bodies to explore the use of the directive's optionality clause, potentially allowing participation with non-MID compliant meters in Belgium.
- ➔ Looking ahead, Elia suggests developing an advocacy coalition to drive changes at the EU level, either through sector-specific provisions in the Network Code on Demand Response or by seeking a modification of the MID directive itself. This comprehensive, staged approach is essential to ensure that regulatory frameworks do not unnecessarily hinder the rollout of flexibility services in Belgium.

5. Data Communication requirements for low-voltage Balancing

5.1. Description of the current requirements

5.1.1. General principle of communication for LV balancing

This section discusses the communication set-ups currently in place in Elia's grid for various balancing products. It aims at providing insights for those unfamiliar with (LV) data flows and (LV) balancing, offering a high-level overview.

In general, to provide any explicit balancing service to Elia, market parties must put in place three communication chains:

1. A two-way communication chain between the Elia's National Control Center and the control center of each BSP.
2. A two-way communication between the control center of the BSP and all the assets of their flexibility pool.
3. A one-way communication between the measurement system of the grid users and Elia.

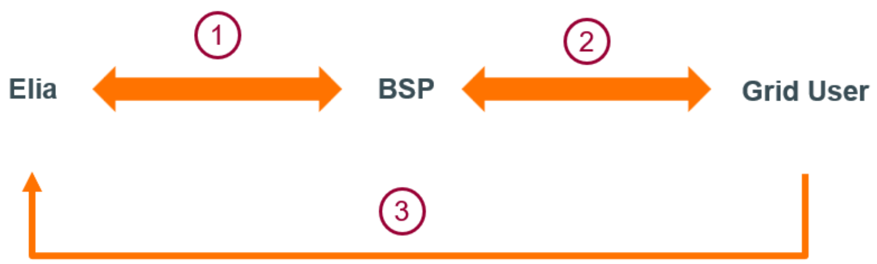

Figure 13 - General principle of communication

Communication between Elia NCC and BSP Control Center

One of the initial requirements for every new BSP is to establish a dedicated communication channel between their control center and Elia's National Control Center. This channel is essential for operational coordination: Elia uses it to send activation requests specifying the required volume, while BSPs use it to acknowledge receipt and report the volume actually activated. To ensure explicit balancing, except for mFRR, communication must follow the TASE.2/ICCP protocol.

Although setting up this connection can present technical challenges and is sometimes not straightforward, it is important to note that only such a single link is required for each BSP—regardless of the size of their portfolio or the number of connected assets. This means concretely that the complexity of establishing this communication channel does not increase with the scale of operations, as it serves exclusively as an interface between control centers.

Communication between BSP Control Center and Grid Users

Just as robust communication is needed between Elia's NCC and the BSP, reliable two-way communication must exist between the BSP control center and all assets in its pool. This enables BSPs to send set-points to their assets and receive real-time data on their status and response.

This internal communication is fully managed by the BSP and may contain proprietary elements. While Elia cannot monitor this channel, it is reasonable to assume that each BSP maintains at least partial real-time oversight of their assets' measurements, availability, and responses.

For decentralized assets, some BSPs use third-party data companies to collect large volumes of data, increasing both the complexity of data flows and GDPR compliance requirements.

Communication between Grid Users and Elia

Service delivery must always be validated using (among others) measurement data. For large, centralized units (DP_{SU}), this is not an issue as the access points are equipped with meters connected directly to Elia systems inherently comforting us that the data are correct. For smaller units, however, non-regulated (sub)meters are used. Data from such meters are extracted by the BSPs themselves (sometimes third parties) and sent to Elia. Since the whole chain is controlled by a private company having commercial interests, questions arise on how to validate the integrity and get comfort that data hasn't been manipulated. To tamper the manipulation risk, two things have been introduced by Elia when opening the explicit balancing market to DSO-connected assets: the local gateway obligation and the need to forward all data in real-time. Those two item will be discussed later in this report.

When Elia decided to open explicit balancing to low-voltage assets, it quickly became clear that the associated amount of measurement data would therefore grow significantly. Therefore, Elia and the DSOs decided to create two IT solutions commonly developed, updated, and maintained: "Flexhub" and "Real-Time Communication Platform" (RTCP). Furthermore, as in practice all low-voltage assets are connected to the distribution grid, a data governance set-up had to be decided with the DSOs.

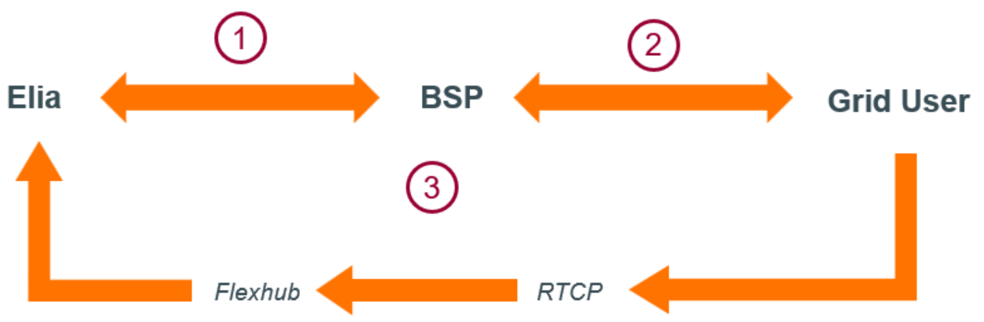

Figure 14 - Link between GU and Elia via RTCP and Flexhub

5.1.2. Key concept 5: Aggregation of data from individual LV delivery points

Data from the Low Voltage Delivery Points (LVDP) are collected and stored on Flexhub. Then an aggregation is performed at the Low Voltage Delivery Point Group (LVDPG) level, ensuring that all the details of what happens within a pool, while being stored and accessible, are handled in the Flexhub. Practically, Elia has only access to the level of LVDPG.

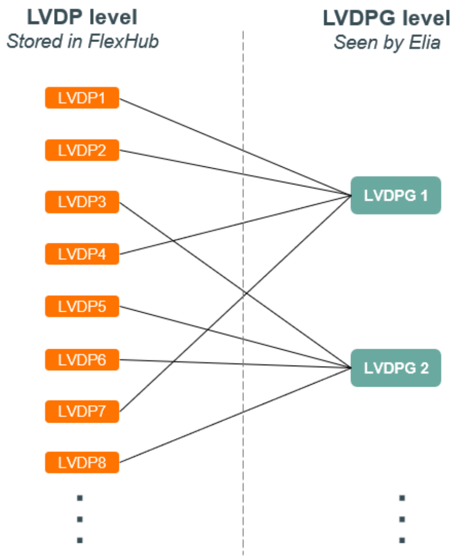

Figure 15 - LVDP and LVDPG levels

For Transfer of Energy purposes, the Flexhub can also aggregate data per BSP-BRP$_{BSP}$-Supplier -BRP$_{Supplier}$ (also labelled BRP source). This allows for the correction of settlement and imbalance volumes.

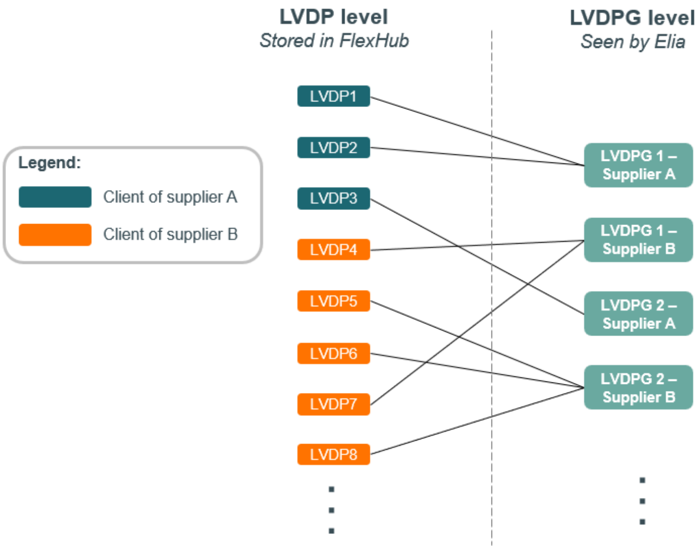

Figure 16 - LVDP and LVDPG levels

When considering a large pool of small assets providing together an explicit balancing service, it is reasonable to assume that not all assets will participate at all moments. Some assets will deliver the service while others may be temporarily unavailable to deliver flexibility.

For this reason, a binary variable per LV delivery point has been included in the data to be sent in order to indicate whether the delivery point is participating in the service delivery12. This binary variable allows for the filtering of base-line and measurement data of delivery points that did not participate in the provision of a service. Only the data of delivery points that participated in the delivery are aggregated. This approach helps to filter out unwanted changes in load not related to the delivery of a flexibility service, leading to better baseline and delivery controls. This reduces the risk for both the system operators and the BSP.

Figure 17 - LVDP and LVDPG levels

5.1.3. Key concept 6: Local Gateway and Central Gateway

The connection to the RTCP is always done through a gateway. A gateway is a device that connects different networks and allows them to communicate with each other. It acts as a bridge between two different systems, translating data from one format to another so that it can be understood on both sides. Two main concepts have been envisaged: central gateway and local gateway. In a fully local gateway set-up, each private measurement device is locally (i.e., on the premises of each asset) connected to a gateway, which is itself interfaced with the RTCP through an internet connection. This means that a gateway needs to be installed on-site at each location. It duplicates the metering information flow, collected on one side by the BSP and sent in parallel to the RTCP. This setup is heavier in terms of requirements, especially when scaling a portfolio with a large number of decentralized assets.

[12] Note that this concept has not been included in the design of mFRR LV currently pending validation.

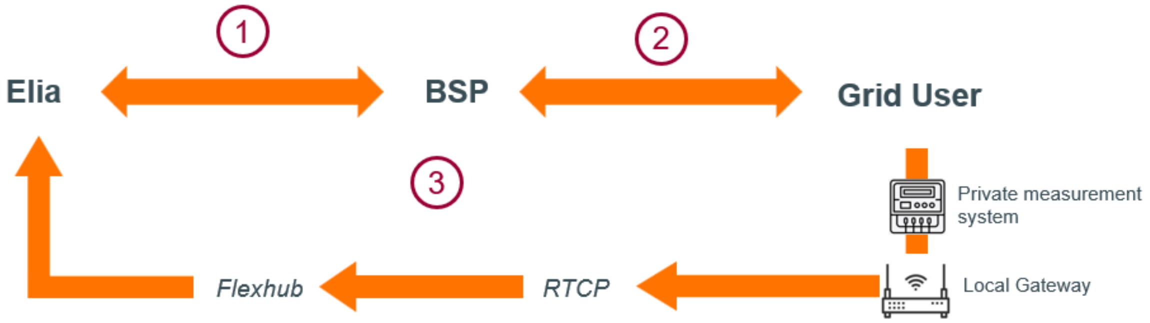

Figure 18 - Illustration of a local gateway set-up

In a fully central gateway set-up, the BSPs must collect the data from all the meters of their portfolio and send them to the Flexhub via a single gateway interfacing their control center with the RTCP. Elia has no view and no control over the technology used to collect the data from the individual sites. This setup constitutes much lower participation barrier compared to the local gateway.

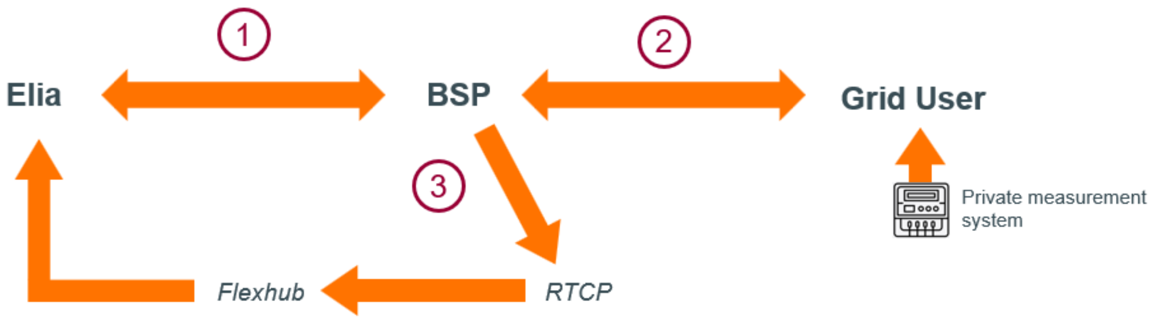

Figure 19 - Illustration of a central gateway set-up

5.1.4. aFRR Communication requirements

For aFRR, the timeseries sampling rate is 4 seconds. To participate in aFRR, assets or pools must be able to follow set-point signals (aFRRreq,tot) sent by Elia via the Tase2/ICCP protocol. Each BSP must report the total supplied aFRR volume, which is the sum of all volumes delivered by their DPs, to Elia through the same protocol.

Measurements from private systems ($DP_{measured}$(ts)) are sent to RTCP using either a local or central gateway. In practice, there are currently no active LVDPs for aFRR. All BSPs planning to involve LVDPs in aFRR prefer central gateway setups. For each DP, the BSP provides three additional timeseries: DP_{aFRR}(ts), $DP_{baseline}$(ts), and $DP_{aFRR,supplied}$(ts).

All four timeseries for each LVDP are stored in Flexhub. Aggregated values are then extracted from Flexhub for various Elia balancing processes, including settlement, activation controls, and Transfer of Energy (when allowed).

Data series	Timing	Granularity	Description and objective
$DP_{aFRR}(ts)$	Real-time	LVDP	Binary value indicating whether a Delivery Point is participating to the provision of the aFRR Requested. The value is set to 1 if the Delivery Point participates to the provision of the aFRR Requested and 0 otherwise
$DP_{baseline}(ts)$	60 seconds before real-time	LVDP	Value (in MW) representing the power that would have been measured at the Delivery Point without activation of the aFRR Service per Time Step.
$DP_{aFRR,supplied}(ts)$	Real-time	LVDP	Value (in MW) representing the aFRR Power supplied by a Delivery Point included in an aFRR Energy Bid per Time Step.
$DP_{measured}(ts)$	Real-time	LVDP	The net active power, i.e. the difference between gross Offtake and gross Injection measured at a Delivery Point per Time Step.
$aFRR_{req,tot}$	Real-time	BSP	The aFRR Power requested (in MW) by ELIA to a BSP at a certain Time Step for activation.
$aFRR_{supplied,tot}$ (+FCR correction)	Real-time	BSP	The quantity of aFRR Power (in MW) physically supplied by the BSP to ELIA during the activation of aFRR Energy Bids. The FCR correction is the value (in MW) representing the FCR power delivered by the Delivery Points participating to the provision of the aFRR Service, i.e. with a DPaFRR equal to 1[13]

The schematic below presents a schematic view of the data exchanges for aFRR in a local gateway setup.

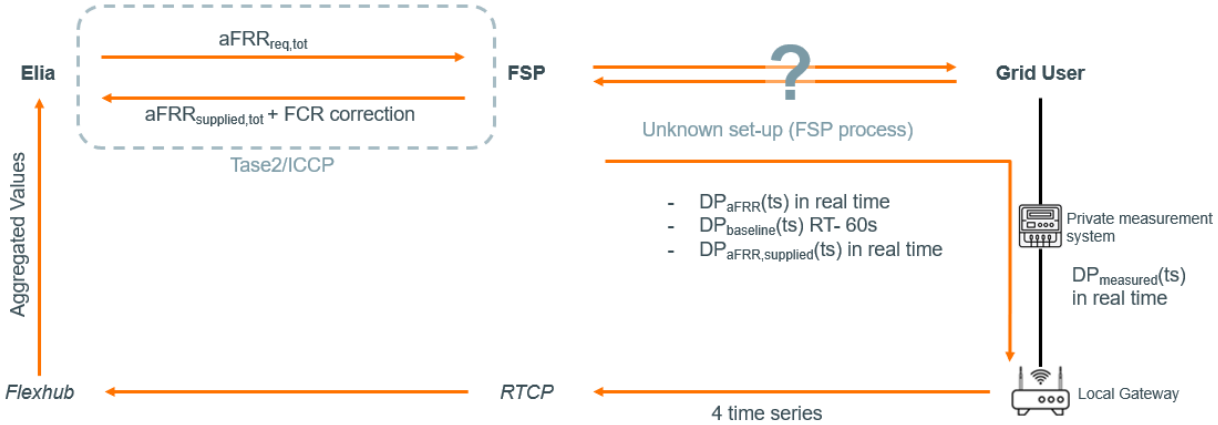

Figure 20 - aFRR Local Gateway Communication setup

Similarly, a similar schematic can be made for central gateway.

[13] After the entry into force of the new T&C BSP FCR, this value will no longer need to be sent by the BSP.

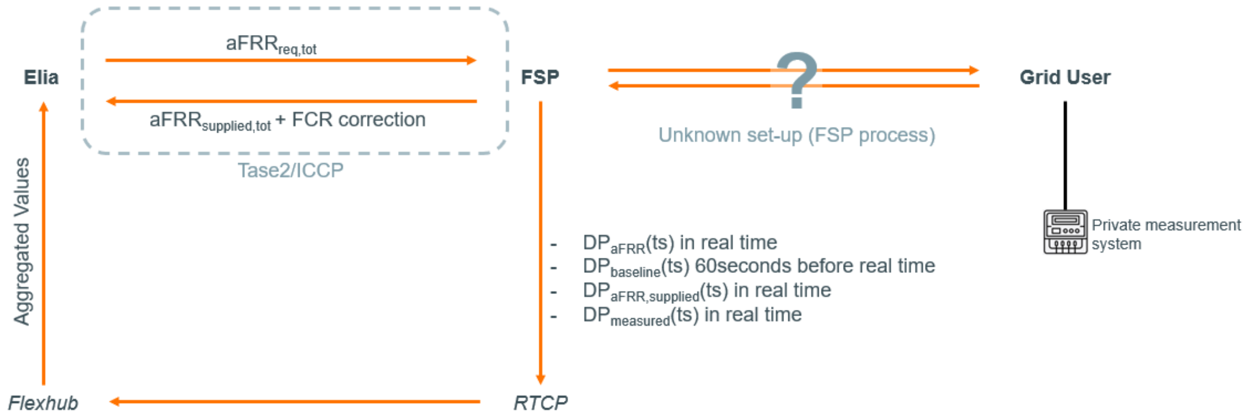

Figure 21 - aFRR Central Gateway Communication setup

5.1.5. FCR Communication requirements

First of all, note that a revision of the FCR T&Cs has been submitted to the CREG and has been validated on the day of the day of the finalization of this report. The entry into force of the new T&C is soon. Aiming at harmonization and simplification, Elia has aligned as much as possible the FCR communication requirements with those of aFRR in this revision. Elia therefore expects that the requirements for FCR will soon become closer to those detailed above. Nevertheless, for the sake of completeness, the measurement requirements currently in force for FCR are presented in this section.

Currently, FCR data are collected at a granularity of one sample every two seconds. In FCR operations, no centralized set-points are defined by Elia; assets respond locally to system frequency deviations. Communication between the Frequency Service Provider and Elia's National Control Center is unidirectional.

Measurement data from private systems are transmitted to the Real-Time Communication Platform via local or central gateways. In practice, all BSP with LVDPs active in FCR use a central gateway configuration. Additionally, for delivery points with limited energy reservoirs, Balancing Service Providers supply two supplementary time series for each LVDP, as outlined in the table below. The binary value DP_{FCR} does not identify the participating LVDPs within a LVDP group, but rather specify which group contributed to FCR provision. For cases where a LV delivery point is not LER (Limited Energy Reservoir), the process may differ, but this situation is uncommon in practice.

After the entry into force of the new T&C BSP FCR, the sampling interval will be increase from two seconds to four seconds, harmonizing it with the aFRR product. The requested data series will also be aligned with those for aFRR.

Data series	Timing	Granularity	Description and objective
$DP_{FCR}(ts)$	Real-time	LVDPG	Binary value indicating whether a Delivery Point Group is participating to the provision of the FCR Requested. The value is set to 1 if the Delivery Point Group participates to the provision of the FCR Requested and 0 otherwise.
$DP_{CH\text{-}DCH}(ts)$ (only for LER)	Real-time	LVDPG	The power used for charging/discharging (in MW) of a Delivery Point with Energy Limited Reservoir. This value is positive (respectively negative) for charging (respectively

			discharging) and sent for each Time Step. This value is used to correct the computation of the delivered volume (in the activation control).
$DP_{AV\text{-}Margin}$ (ts) (only for LER)	Real-time	LVDPG	The available margin (in MWh) of a Delivery Point with Energy Limited Reservoir indicates the remaining energy available for provision of the FCR Requested. The BSP only communicates the lowest absolute value between the available margin upwards and downwards.
$DP_{measured}$(ts)	Real-time	LVDP	The net active power, i.e. the difference between gross offtake and gross injection measured at a Delivery Point per Time Step.
$DP_{measured,tot}$(ts)	Real-time	LVDPG	The net active power aggregated at the level of the LVDPG (aggregated by the BSP).

5.2. Barrier 3: Local Gateway obligation

5.2.1. Description, impact and recommendation

It was concluded during the low-voltage market design phase that the central gateway was generating too high a risk of data manipulation, as 100% of the data would flow through the data center of the BSP. Conversely, having a part of the communication chain in the premises of the participating assets allows an easier possibility for the system operators to perform an audit.

During the discussions around the opening of explicit balancing to low voltage, some actors complained that enforcing local gateway would generate significant costs potentially endangering the business case and take a lot of time to adapt existing assets. Given this, it was decided to temporarily allow central gateway set-up to give the time to the actors to integrate the new gateway in their hardware and proceed to the switch. Since then, the temporary authorization to work with central gateway has been extended every year. Currently, based on the documents into force, the central gateway is allowed until 31 December 2026. An extension until 31 December 2027 has been included in document release 3 (pending validation)

In practice today, all low-voltage volume is delivered via central gateway, and it appears clearly that imposing local gateway for everyone would not only constitute a major barrier to further development of low voltage flexibility in Belgium but also put a significant part of the volume active today at risk.

Recommendation of Elia:
Given the above, Elia recommends switching toward central gateway as standard set-up at and to rely on a data validation control to mitigate the risk of data manipulation.

5.2.2. Possible validation controls

The table below presents the possible validation controls that could be put in place.

Approach	Explanation	Evaluation
Installing a temporary parallel meter	- Deploy a temporary parallel meter at a randomly selected, limited number of delivery points to provide a trusted reference for data comparison.	- Legally complex, as it requires access to private premises. - Implementation is financially demanding.
Third-Party Audit of the BSP	- Conduct a thorough review of the BSP's IT infrastructure to assess data integrity and security.	- Legally permitted, but technically challenging for an external auditor to reliably identify data manipulation.
Cross-checking Submeter Data with head meter Data	- Compare quarter-hourly energy metering at the head meter level, considered highly reliable, with flexibility content measured at the submeter level. While data for individual delivery points may be skewed by other appliances, statistical analysis across a large sample should reveal any manipulation.	- Realistically feasible, though it would require some implementation effort. - There remains a risk that a BSP may adjust measurement values within the quarter-hour period to maintain consistent energy totals while optimizing activation signals.
Using the P1 Port of the head meter	- Apply a similar comparison as above but utilizing one-second interval data from the head meter's P1 port.	- This method could deliver near-complete certainty regarding potential manipulation. However, the approach would generate significant data volumes, even for a subset of delivery points, and would necessitate accessing the user's premises to retrieve data from the DSO meter.

Recommendation of Elia:
Elia recommends implementing a cross-check between quarter-hourly head meter data and private submeter data for delivery points using private measurement devices.

Solutions that require physical intervention at the delivery point—such as installing a parallel meter—are deemed disproportionate, as they involve significant legal and financial obstacles for limited benefits. Similarly, using the P1 port on the head meter is complicated by the need for explicit user consent and, in many cases, the involvement of a technician. Additionally, conducting a third-party audit of the BSP's IT infrastructure would be both technically challenging to define and potentially intrusive to the BSP's business processes. Considering these factors, Elia will focus on the approach of cross-checking QH head meter data with private submeter data for DSO-connected delivery points as a standard control. Other controls may be applied if suspicious data is observed.

5.3. Barrier 4: High volume of real-time data

5.3.1. Introduction, impact and constraints of the current design

Some market participants have highlighted that requiring the exchange of large volumes of real-time data can pose a significant barrier for them. A deeper investigation revealed that, depending on the communication technology used by the BSP, the challenge may stem either from the sheer volume of data or from the requirement to transmit it in real time. When connections rely on local Wi-Fi, there is a risk of connection loss and data latency. Conversely, using a 4G connection mitigates these issues but makes data transmission costs prohibitive due to the high volumes involved.

What was clear and consistently agreed upon is that, in a central gateway set-up, the remaining main difficulty and cost lie in retrieving data from decentralized assets to the BSP's control center, rather than transmitting data between the BSP and Elia—which is not considered a major barrier.

Before presenting possible approaches to overcome this challenge, Elia would like to emphasize two constraints inherent to the current market design.

First, real-time data transmission is essential for managing baselines in explicit flexibility services (except for mFRR). The volume of flexibility is defined as the difference between the measured value and the baseline. For aFRR, the baseline operates on a declarative principle—meaning it is determined and communicated by the BSP in advance, rather than measured in real-time. Providing the baseline ahead of time is a fundamental requirement of the declarative approach, as without it, it would be impossible for Elia to check the veracity of the baseline. Allowing ex-post submission of declarative baselines would create a substantial risk of gaming. In this context, the design precludes any possibility of shifting exclusively to ex-post data and eliminating the need for all real-time measurements.

Second, disaggregated data at the level of each Low Voltage Delivery Point is required for the proper application of Transfer of Energy. To correctly calculate the energy volumes exchanged between BSP-BRP_{BSP}-Supplier -$BRP_{Supplier}$, Flexhub must collect detailed data for every individual LVDP. This is crucial because the BSP does not necessarily have visibility over the distribution of delivery points among suppliers, making comprehensive data collection at the individual level indispensable for accurate settlement and compliance.

5.3.2. Approaches considered and recommendation

In course of this exercise, four simplification approaches were considered, even though some quickly revealed not compatible with the constraints presented above. Those approaches are depicted on the below schematics.

Approach 1 – Allowing ex-post transmission of LVDP Data. $DP_{aFRR}(ts)$, $DP_{baseline}(ts)$, $DP_{aFRR,supplied}(ts)$ and $DP_{measured}(ts)$ (and similar for FCR) would in this case be transmitted ex-post.

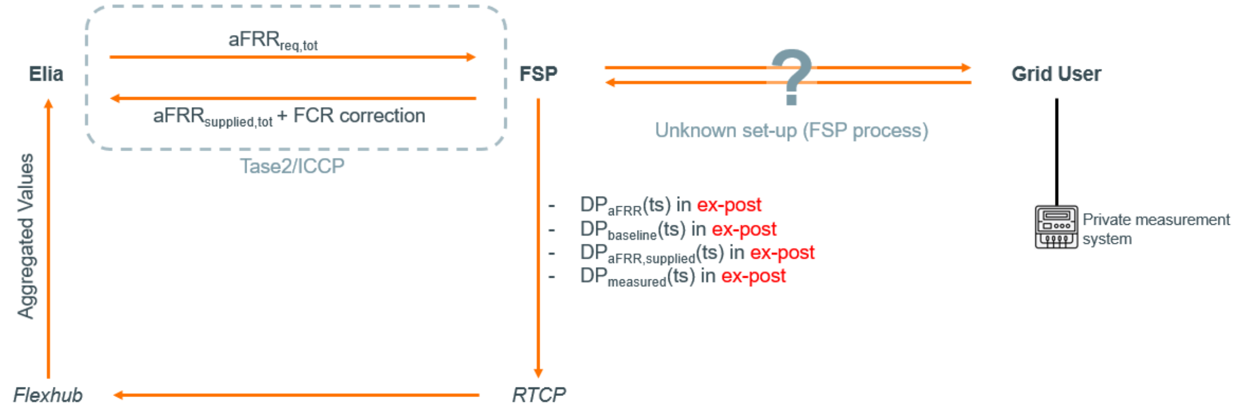

Figure 22 - Illustration of ex-post transmission

Approach 2 – Allowing ex-post transmission of LVDP Data except for the baseline. $DP_{aFRR}(ts)$, $DP_{aFRR,supplied}(ts)$ and $DP_{measured}(ts)$ would in this case be transmitted ex-post. $DP_{baseline}(ts)$ would remain real-time

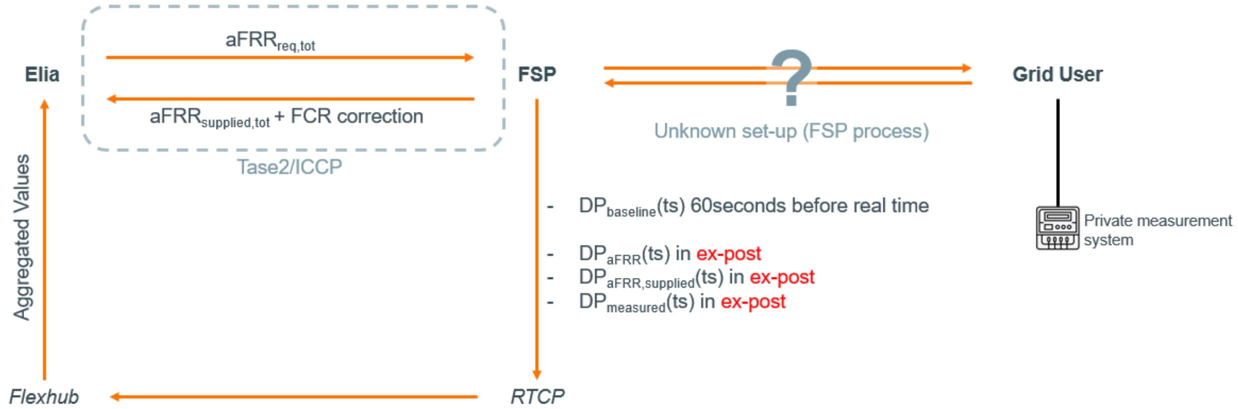

Figure 23 - Illustration of ex-post transmission, except baseline

Approach 3 – Request a subset of the pool data in real-time and the rest ex-post.

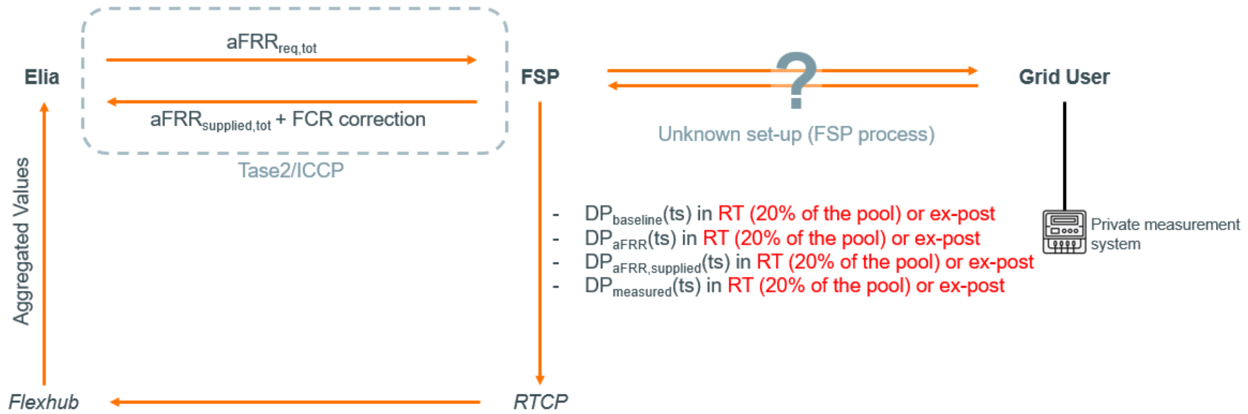

Figure 24 - Illustration of transmission of a subset of data

Approach 4 – Allowing event-driven messaging:

Event-based messaging is a communication method where data is transmitted in real time, but only when a significant change occurs in the underlying dataset. Rather than continuously sending all data, this approach ensures that information—such as measured power, baseline—is sent only when a change exceeds a certain threshold, which must be greater than the accuracy limit of the measurement. Each time such a change is detected, it triggers an “event” that initiates the immediate transmission of updated data. For any periods where there is no new event, missing values can be reconstructed by the Elia using the technique of applying the last available reported value. Elia will further investigate the operational aspects and feasibility of implementing event-based messaging should this recommendation be adopted.

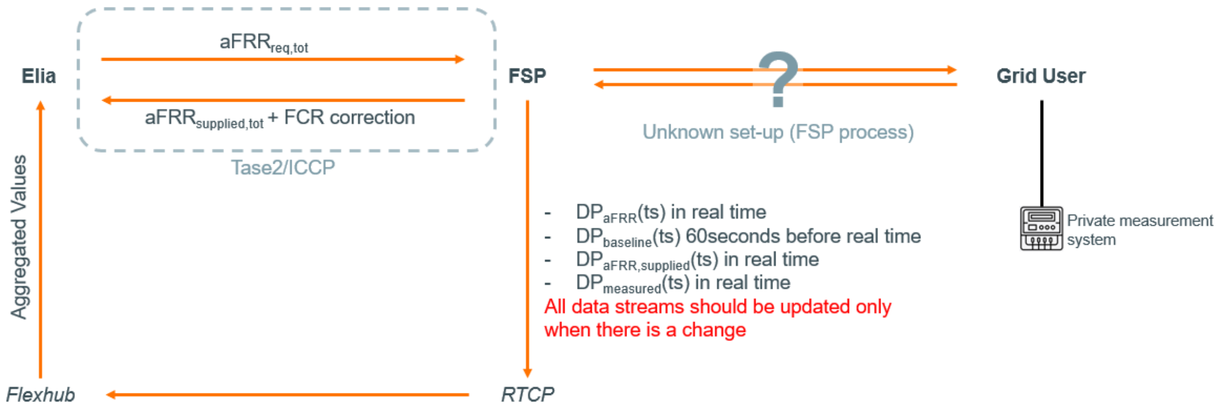

Figure 25 - Illustration of event-driven messaging

The table below presents summarizes the pros and cons of each approach:

Approach	Pros	Cons
Allowing ex-post transmission of LVDP Data	- Substantially lowers entry barriers for market participants.	- Inability to control baselines leading to an unacceptable risk of gaming.
Allowing ex-post transmission of LVDP Data except for the baseline	- Potentially slightly reduces the volume of real-time data transmitted.	- Requires real-time capability at the delivery point level, which delivers minimal or no actual cost reduction. - Real-time capability at LVDP may not comply with NCDR[14]

[14] In the latest version (https://www.acer.europa.eu/sites/default/files/documents/Recommendations_annex/ACER_Recommendation_01-2025_DR_NC-Annex1_Amended_DR_NC.pdf), article 54.8 states that *Service providers shall not be required to provide near real-time data at CU level for SPU(s) or SPG(s) that consist only of small CUs.*

Request a subset of the pool data in real-time and the rest ex-post	- Simplifies implementation and provides a tangible reduction in real-time data transmission.	- Still requires real-time capability at the delivery point level which may not comply with NCDR - Not compliant with ToE as it prohibits accurate computation of volumes.
Allowing event-driven messaging	- Significantly reduces the volume of real-time individual data transmitted.	- Real-time capability at the delivery point level remains necessary, which may not comply with NCDR.

In the existing market framework, approaches 1 and 3 are ruled out due to previously discussed constraints. Furthermore, the draft Network Code for Demand Response (NCDR) may pose additional challenges for certain approaches, as it is expected to forbid the requesting of real-time data from assets below a specified power threshold, although this requirement is still subject to confirmation and has not yet been implemented.

Recommendation of Elia:
Elia recommends maintaining the real-time capability requirement at individual level but implementing event-driven communication for all delivery points in order to reduce the volume of data to be transmitted.

Although Elia is open to taking every possible step to simplify entry barriers, it should be emphasized that the implementation of a communication chain between decentralized assets and the BSP is outside the scope of Elia teams' competences, and that the recommendation relies exclusively on the understanding built through exchanges with market participants. Elia therefore invites stakeholders to respond specifically to this section to clarify whether, in a central gateway set-up, the application of event-based messaging provides sufficient additional benefits to consider implementation.

6. Onboarding new Low-voltage Delivery points in a balancing portfolio

6.1. Description of the current requirements

This section outlines the onboarding pathway in practical terms, highlighting where processes become easier to scale as more assets are pooled together. It also points out the key steps that can be improved to open up explicit balancing opportunities for low-voltage assets.

A note on terminology: In this context, the term “onboarding” refers to the entire process of becoming a BSP. Within this, “prequalification” is defined as the specific testing step required to participate in capacity auctions. As such, prequalification is considered one part of onboarding. This may differ from the definitions used by other transmission system operators.

The onboarding process can be divided into three main parts as depicted on the following drawing.

Figure 26 - Main steps of the new assets on-boarding process

Phase 1: BSP Acceptance (Administrative Phase)

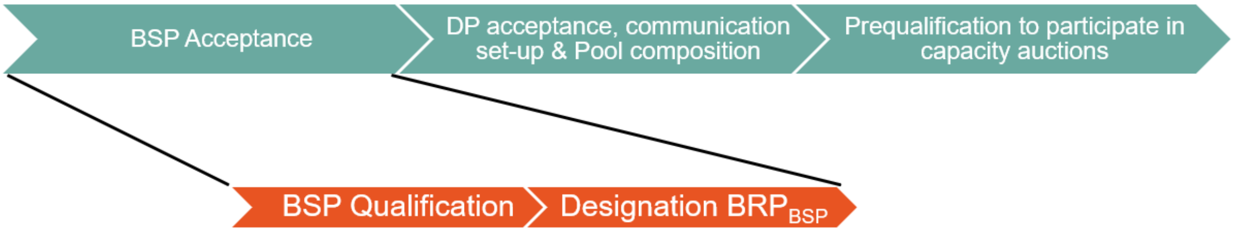

Figure 27 - Phase 1: BSP Acceptance

The initial phase involves administrative procedures, including contract signing and credit checks. Every BSP must nominate a Balance Responsible Party responsible for managing imbalances. If the BSP also acts as the BRP, this step is automatically fulfilled.

Phase 2: Delivery Point Onboarding

Figure 28 - Phase 2: Delivery Point Onboarding

The second phase focuses on accepting individual low-voltage delivery points. The BSP submits a list of LV Delivery Points for grouping into a Low-Voltage Delivery Point Group. For DSO-connected points, the DSO manages onboarding via the Flexhub, verifying the connection and, if needed, conducting a Net Flex Study to ensure flexibility does not threaten grid stability—a process called grid qualification.

The BSP must demonstrate user consent for flexibility aggregation and marketing, submitting proof as specified in the Terms and Conditions. Where Transfer of Energy applies, the BSP must also provide evidence of a ToE agreement between its BRP and the grid user's BRP. Details on ToE regimes are available in the ToE Design Note[15].

Next, where applicable, comes the private measurement system commissioning test. For low-voltage, individual commissioning at LV Delivery Point level is unrealistic. This is why Elia allowed meter homologation for FCR and aFRR in trial stage. This process will be discussed in detail further in this report.

After metering qualification, the BSP sets up the measurement system and connects it to the Real-Time Communication Platform via approved gateways, following Elia's Explanatory Note on Gateway Management[16]. Elia then tests the entire communication chain. Once passed, LVDPs are pooled into the LVDPG, allowing the BSP to bid in the balancing energy market.

Phase 3: Prequalification Test at Pool Level

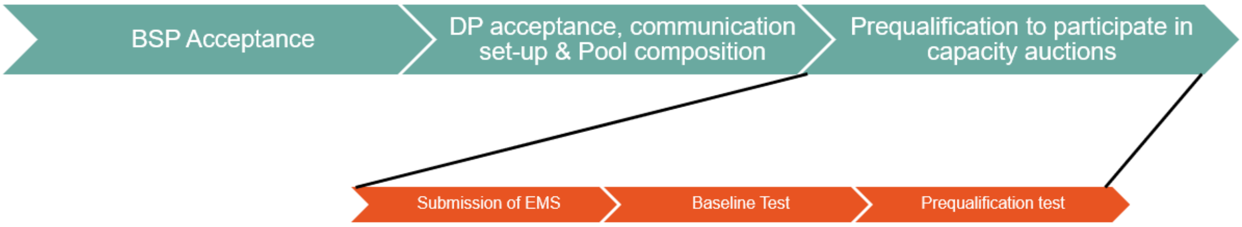

Figure 29 - Phase 3: Prequalification Test to participate in capacity auctions

[15] https://www.synergrid.be/images/downloads/Public_Consultations/ToE_Design_note/ToE_design_note_CR.pdf
[16] Available here: https://www.elia.be/en/electricity-market-and-system/system-services/technical-documentation-concerning-the-provision-of-ancillary-services

The third phase consists of a prequalification test at the asset pool level. BSPs operating limited energy reservoirs in their portfolios must submit an Energy Management Strategy (EMS), detailing plans to ensure reliable delivery of contracted services. More information can be found in the EMS Requirements document[17].

Thereafter, a baseline test is performed, during which Elia evaluates the accuracy and reliability of the pool's baseline data at the BSP pool level or at the level of all DPs participating to the baseline test. Further test instructions are outlined in the Terms and Conditions.

Once baselines are validated, a prequalification test follows. Elia sends activation signals to the BSP and observes whether the asset pool responds as required, including assessing maximum deliverable capacity. Successful completion authorizes the BSP to submit capacity bids and participate in the balancing capacity market.

6.2. Is the onboarding perceived as an entry barrier?

The BSP acceptance part consists mostly in administrative tasks that are unavoidable, but also do not constitute a big effort or entry barrier. Market participants however shared that setting-up the ICCP connection is quite complex and can really slow down the process. This led us to propose an incentive study for 2026 to investigate alternatives for aFRR.

The second main part of the onboarding process (DP acceptance) appears to be the longest one. Part of this is due to the need to set-up specific metering and communication channels. Although part of the second main part and exclusively for aFRR, one huge barrier shared by nearly all BSPs the difficulty to negotiate opt-out agreements with the suppliers as explained earlier in this report. This element alone, could even explain the huge difference of participation between FCR and aFRR in low voltage.

While the last part on prequalification to be able to take part in capacity auctions has not been reported as a major obstacle, some opportunities for improvement have been highlighted. Besides the fact that it is performed at the expense of the market parties and that the waiting time constitutes an opportunity cost, the current ex-ante prequalification test creates a grid users lock-in effect harming the competition in the market. Indeed, changing BSPs typically means one to two months of lost flexibility revenues due to the need for renewed onboarding and testing.

[17] See https://www.elia.be/en/electricity-market-and-system/system-services/technical-documentation-concerning-the-provision-of-ancillary-services

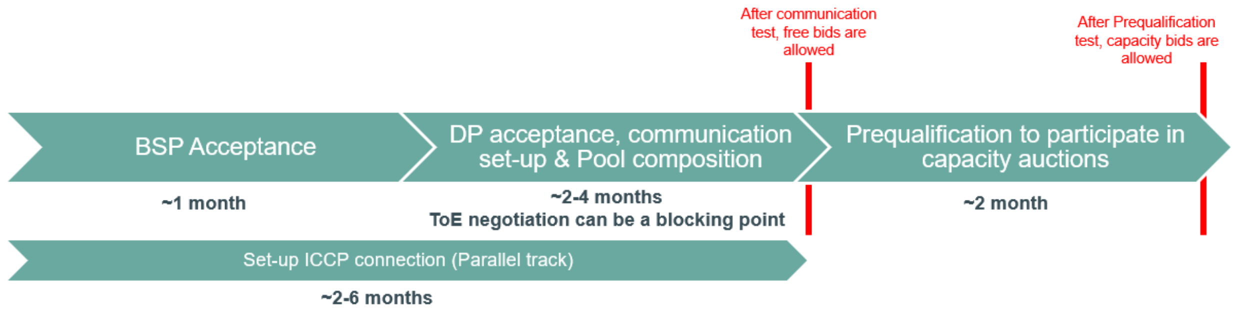

Figure 30 - Indicative timeline of the on-boarding process

In summary, market participants acknowledge that certain improvements can be made to the onboarding process, but emphasize that it is not a primary barrier that should be addressed with the highest priority.

6.3. Clarification of the scope of the POC

As per the description in CREG's decision, Elia is expected to investigate possibilities to simplify the prequalification for low-voltage assets, in particular examine possible approaches to prequalify a type of units and ensure it's realistic via a POC.

Three main elements must be distinguished.

First, there are the checks related to the measurement capabilities of individual devices (accuracy, sampling rate, MID compliance, etc.). It makes sense to link this element to a specific type of low-voltage assets, since it is possible to establish a 1:1 relationship between the measuring device and the asset without interaction with the pool or the internal processes of the BSP as the data is generated fully locally.

Next come the checks of all other technical capabilities of an individual asset, such as API performance, technological ability to follow a precise set-point with time steps adapted to balancing products, embedded data communication capabilities, etc. For this element, although there is a link to the asset's capabilities, there is also a strong impact from how the BSP configures its system. A certain battery model may follow a set-point perfectly when operated by a BSP A but not by BSP B. This falls under the responsibility, and to some extent the technology and expertise, of the BSP. Elia is convinced that an indicative label aimed at guiding BSPs in building their portfolio—and which would also provide an incentive to OEMs—would add value in the medium term to facilitate the development of decentralized flexibility. This is included in the concept of "Flex Ready Devices." However, Elia does not see this label as a way to completely eliminate certain checks. An analogy can be made with a building's energy performance certificate (EPC), which gives an indication of the potential energy performance of a dwelling but does not reflect its actual use. If someone overheats the dwelling while leaving the windows open, regardless of its energy efficiency, consumption will be high.

Finally, there is the prequalification part for participating in capacity auctions. For this step, Elia considers that a type-based prequalification is inadequate. It is up to BSPs to build a diversified portfolio and develop their "energy management strategy" to ensure they can always deliver the service. The prequalification process can be revised, but Elia strongly doubts the relevance of such a type-based asset prequalification.

Based on this analysis, Elia organized a discussion with CREG to align on the next steps for the POC. It was agreed to focus the POC on the first part (metering), while addressing the other two elements within the study.

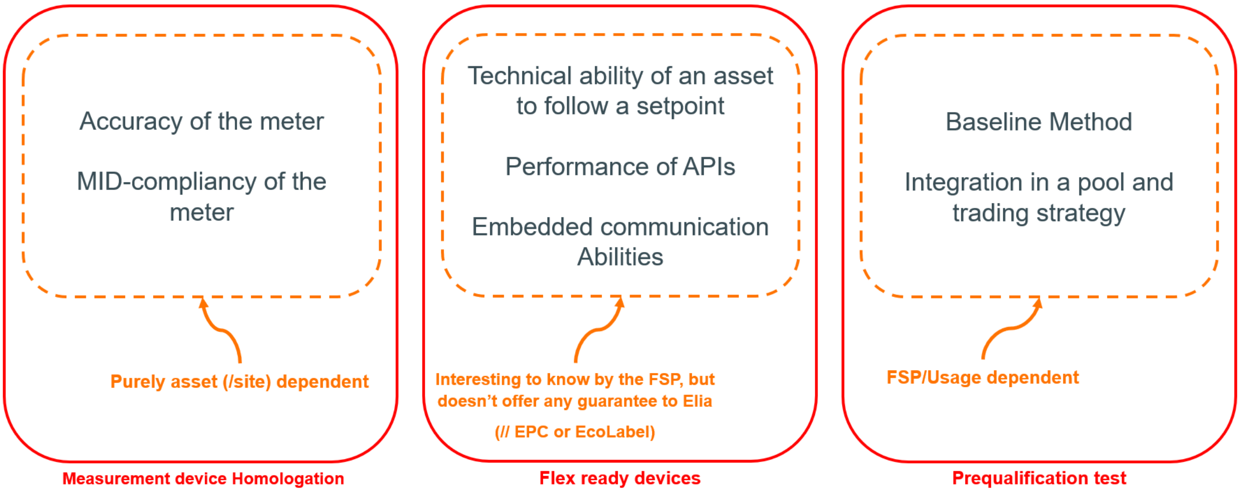

Figure 31 - Clarification of the scope of the on-boarding part of the study

6.4. Barrier 5: Inadequate private meter commissioning process for low-voltage assets

The Elia T&C BSP (for both aFRR and FCR[18]) only define the procedure for commissioning tests of private metering devices for assets connected to Elia's grid or to a CDS. This leaves a gap in the contract. It is clear that conducting individual commissioning tests for decentralized assets is completely unrealistic. This is why Elia has already implemented some temporary measures in "proof of concept" mode to test the procedure and gauge interest in a meter homologation mechanism for the onboarding of low voltage assets. It must be emphasized that the aim here is not to define which standard must be followed, but rather how to validate that the applicable standard is being respected.

For FCR, an internal procedure was established a few years ago. Interested BSPs must send a sample of 3 devices (per asset-type to be homologated) to an independent laboratory, which performs a test of the measurement capabilities and issues a report. The BSP must then submit this report to Elia, who will approve the participation of that asset model if the report shows compliance with the product requirements. This is a type-based asset homologation. For aFRR, it was decided during the opening to low-voltage to implement such a procedure directly via Synergrid. Any asset certified through this procedure is then added to a public database, informing all BSPs of the assets already homologated and therefore usable without further homologation effort.

The implementation of such a certification measure has been a clear success for FCR, since it contributed to the large participation of low-voltage observed in the FCR market. For aFRR, as stated above, success has not yet materialized. Elia is however convinced that the main reason for this is that the aFRR market remains unattractive for low-voltage

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[18] In a first phase, mFRR will be allowed only via the regulated headmeter.

due to the impact of other barriers (particularly the absence of Transfer of Energy) and doesn't especially reflect a lack of interest for homologation itself. It must be noted though that low awareness of the existence of this procedure and database has been highlighted through interactions with market participants.

Another key learning is that homologation requests consistently come from a BSP. Multiple discussions with OEMs have confirmed a very low perceived value of such a mechanism for them. The market is too niche (especially if it only covers Belgium) to generate strong interest on their side.

Looking ahead, it is now timely to formalize this procedure and make it more visible and better known to market participants.

Recommendation of Elia:
Elia suggests extending the procedure currently defined on Synergrid's website for aFRR to also include FCR. This would also lead to an extension of the certified asset database. For the avoidance of doubt, this certification specifically targets services for which MID is not required and does not replace the MID requirement where applicable.

6.5. Barrier 6: Sub-optimal prequalification process to participate in capacity auctions

The prequalification test as such was not mentioned as a major barrier to the participation of low-voltage assets in the explicit balancing market. However, it is clear that it represents an additional step that slows down the onboarding process. Moreover, certain disadvantages were highlighted by market participants. First, this test is carried out at the expense of the BSP (potentially passed on to grid users depending on the case). Then, there is a waiting period between the request for a test and its execution, as well as the analysis of the data to validate its success. During this period, market participants cannot valorize their capacity, thus generating an opportunity cost. Finally, the prequalification test as currently defined creates a perverse effect known as “grid-user lock-in.” Indeed, if a grid user valorizes their flexibility within a BSP's portfolio, switching to another BSP becomes difficult because, under the current setup, a new prequalification test is required, resulting in both opportunity costs and unpaid activation fees. This grid-user lock-in effect undermines market competitiveness and dynamism. Even though prequalification was not mentioned as a primary barrier, it is easy to understand that improvements are possible. The draft European network code on demand response (NCRD) also pushes in that direction.

Two main approaches have been studied. The first, called “in-market prequalification,” consists in offering market participants the possibility to request an increase in their energy bidding limit and to authorize the participation of their new units on the aFRR/mFRR balancing energy market. Once they have demonstrated that they can deliver the full volume (by being selected and activated in non-contracted balancing), their maximum capacity is increased, and they can begin participating in the capacity market.

The other alternative, called “ex-post verification,” involves taking a further step of trust towards market participants by directly increasing their prequalified capacity upon simple request for a temporary period, while ensuring that the full capacity has been delivered or by scheduling an availability test after the capacity increase.

Those two approaches, even if looking simple on paper, may bring some complexity in terms of implementation. Given that the design relies on portfolio-based offering, particular caution is required when establishing a process to simplify the re-prequalification of individual assets within a portfolio.

Another possibility to go even further in simplifying the process would be to even reconsider the need for a prequalification process under certain circumstances (and subject to SOGL compliance).

It is important to understand that revising the prequalification process goes far beyond the scope of this study, as it would not only concern low-voltage assets but all assets participating in the provision of balancing capacity. Hybrid HV-MV-LV pools can also be formed. Moreover, the NCDR is not yet finalized, and discussions are still ongoing regarding prequalification. A piece of the puzzle is therefore missing to make a final decision.

Recommendation of Elia:
Considering the above, and the fact that prequalification impacts all voltage levels, Elia cannot take a final decision on a review of the prequalification process. Elia is however willing to reassess in the short term the need for PQ tests as well as the possibilities to simplify/limit the applications of a prequalification test and this for all voltage levels. This element is included in the 2026 roadmap and Elia expects the teams to start the work as soon as this incentive study is finished (i.e. Q1 2026).

7. Conclusion and next steps

Low-voltage flexibility is recognized as a key element in shaping the future energy mix, providing essential support for explicit balancing services. To ensure that assets at the low-voltage level are allowed and enabled to participate in these services, Elia has conducted a dedicated study and collected feedback across the sector through bilateral meetings, a targeted workshop, and the present public consultation. This approach was aimed to ensure Elia is not missing any main barrier and has a complete view of the situation.

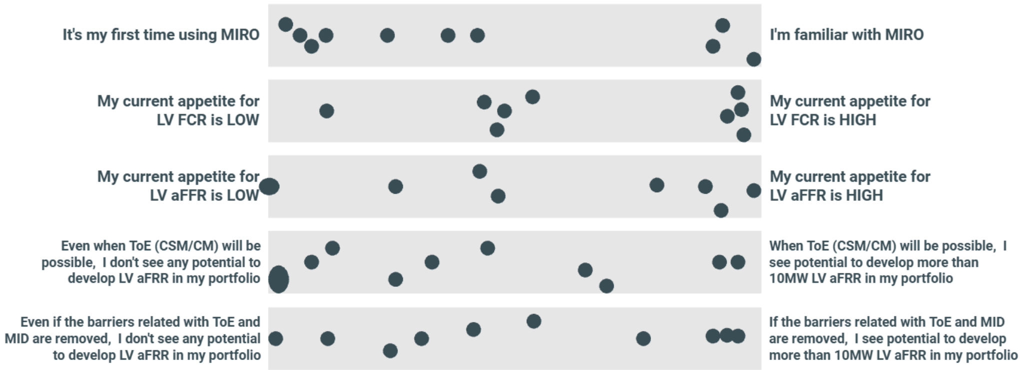
During this process, six primary barriers have been identified that currently limit the full participation of low-voltage assets in explicit balancing. These barriers are:

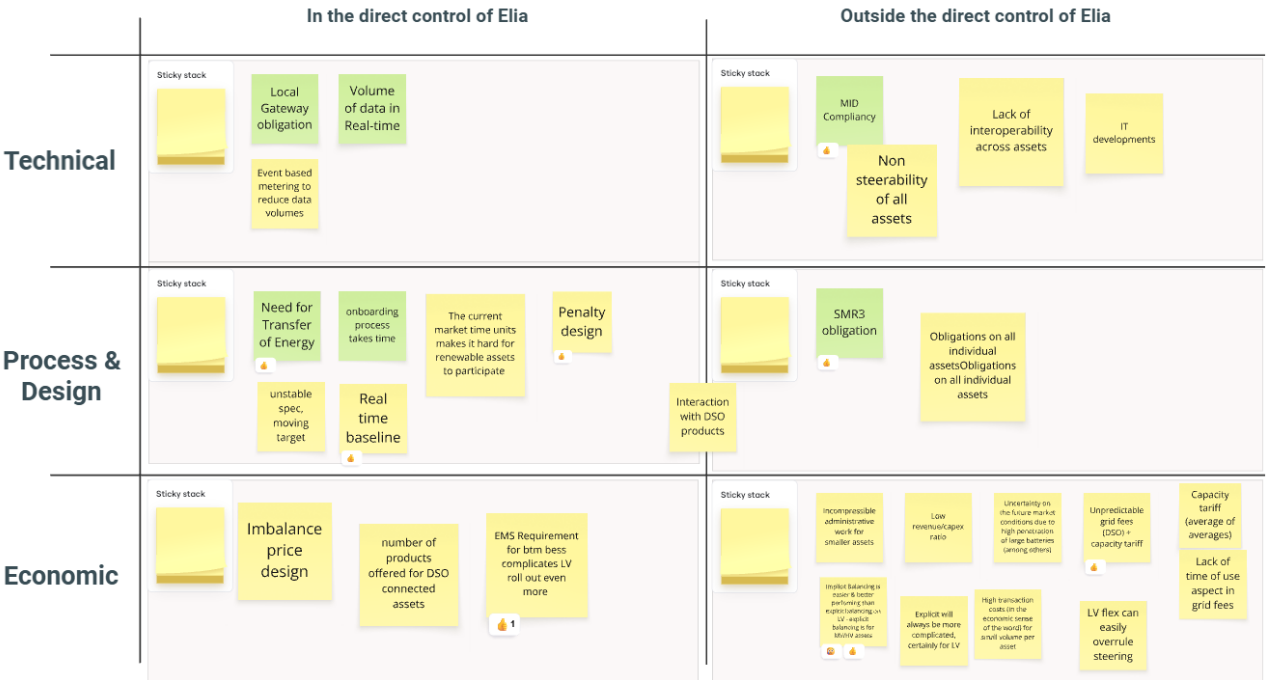
1. The need for SMR3 on the head meter.
2. The requirement for a MID-compliant private submeter.
3. The obligation to use a local gateway for data exchange.
4. The challenge of handling large volumes of real-time data.
5. The need to simplify the onboarding of individual assets through meter homologation.
6. The complexity of the prequalification procedure for participation in capacity auctions.

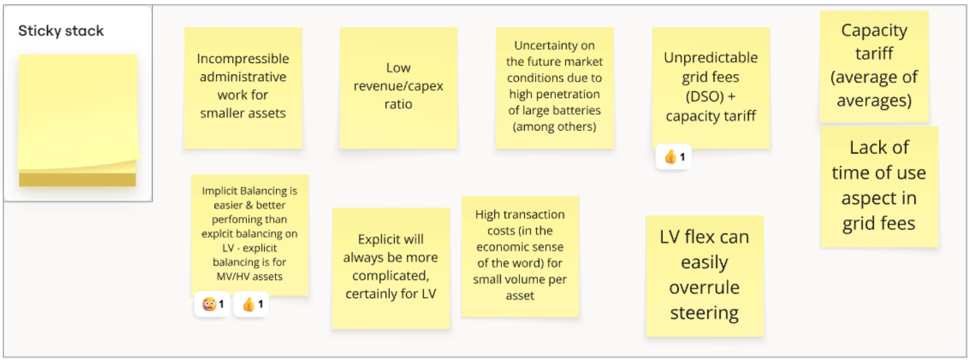
For the 5 first barriers, Elia has suggested potential ways forward. The last one goes beyond the scope of low voltage and will be addressed in Q1 2026. The purpose of this consultation is to gather comprehensive feedback from stakeholders regarding these solutions and proposals. Based on the collected input, Elia will establish a concrete implementation plan to further facilitate the integration of low-voltage flexibility into explicit balancing services, supporting the continued evolution of the energy system.

ANNEX A: Inputs shared by market parties during the workshop on LV barriers (26-06-25)

MIRO Board







Slido Questions

Multiple choice
13 votes

Poll settings

If Local Gateway were imposed as the only acceptable set-up, how much would it be a barrier to LV explicit balancing?

1 - no impact — 8%

2 - slowing down but not hindering the development — 8%

3 - hindering the development. To be addressed with medium priority — 8%

4 - hindering the development. To be be addressed with high priority — 62%

5 - sufficient to block the development of LV explicit balancing in Belgium — 15%

Multiple choice
13 votes

Poll settings

How much does the volume of data to be transmitted in real-time constitute a barrier to LV explicit balancing?

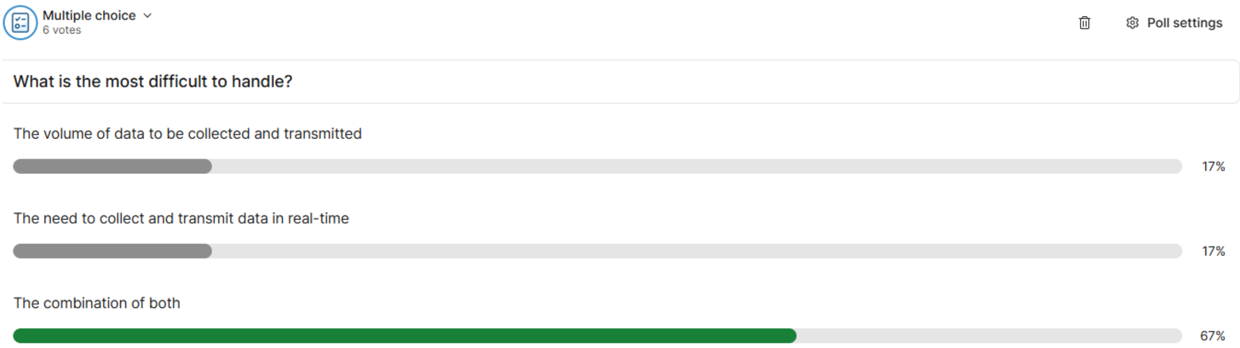
1 - no impact — 8%

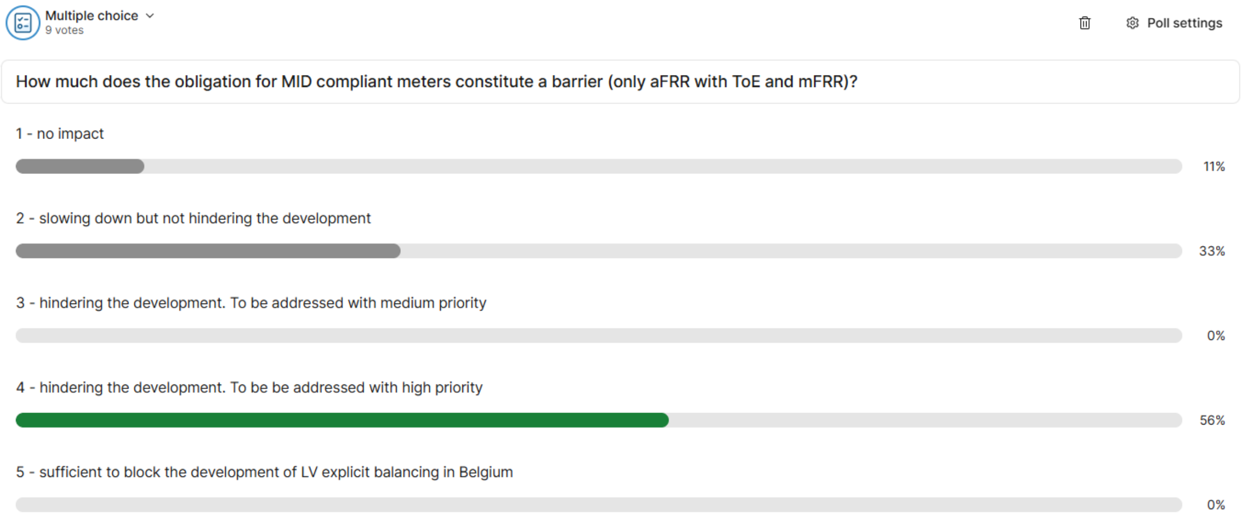
2 - slowing down but not hindering the development — 62%

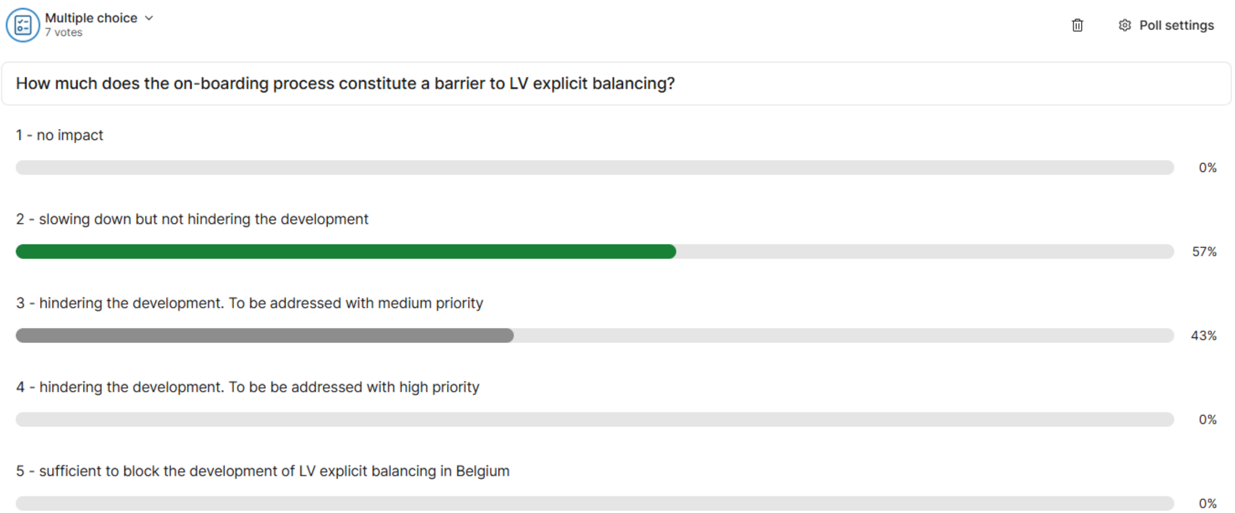
3 - hindering the development. To be addressed with medium priority — 23%

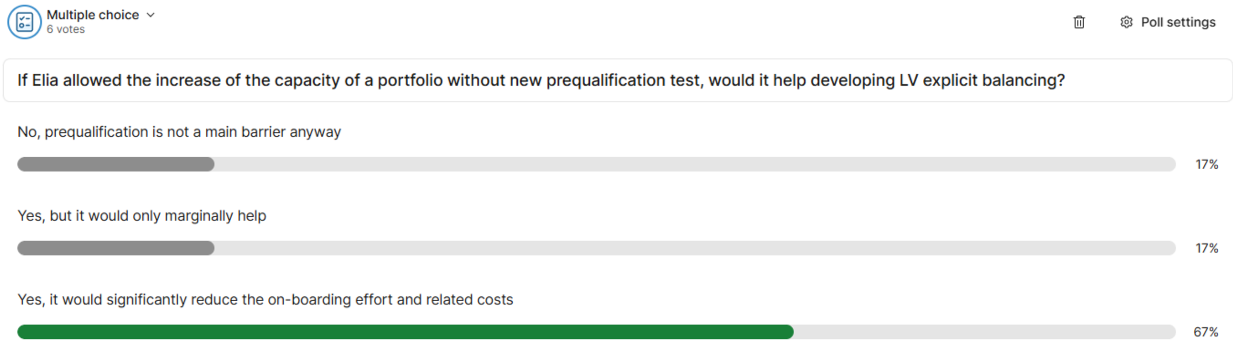
4 - hindering the development. To be be addressed with high priority — 8%

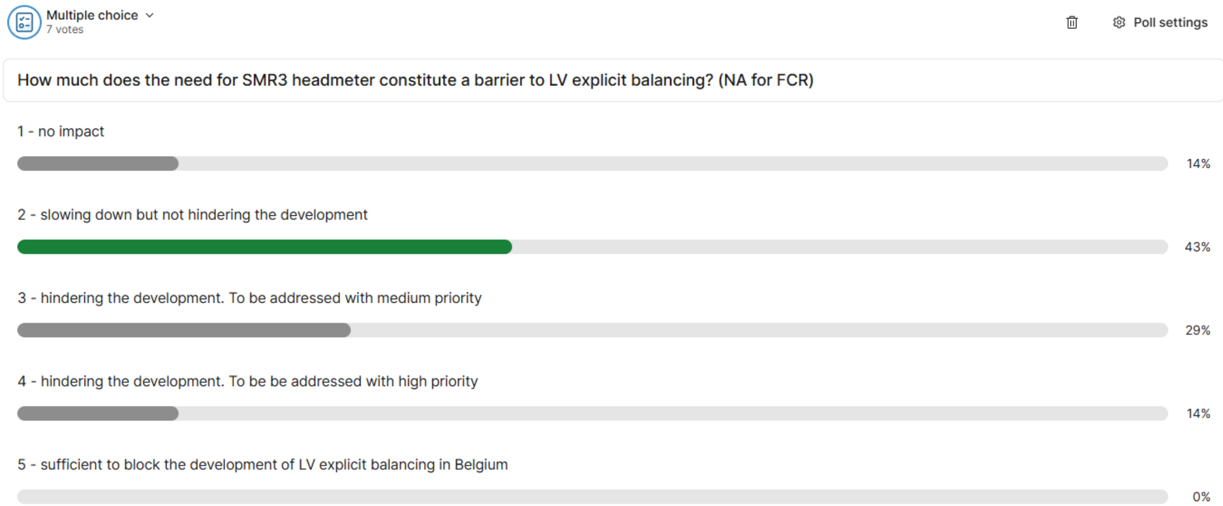
5 - sufficient to block the development of LV explicit balancing in Belgium — 0%

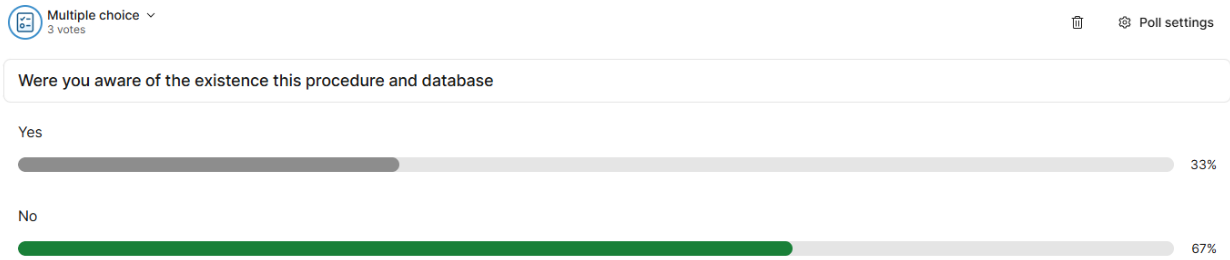

Multiple choice
6 votes
Poll settings
What is the most difficult to handle?
The volume of data to be collected and transmitted
17%
The need to collect and transmit data in real-time
17%
The combination of both
67%

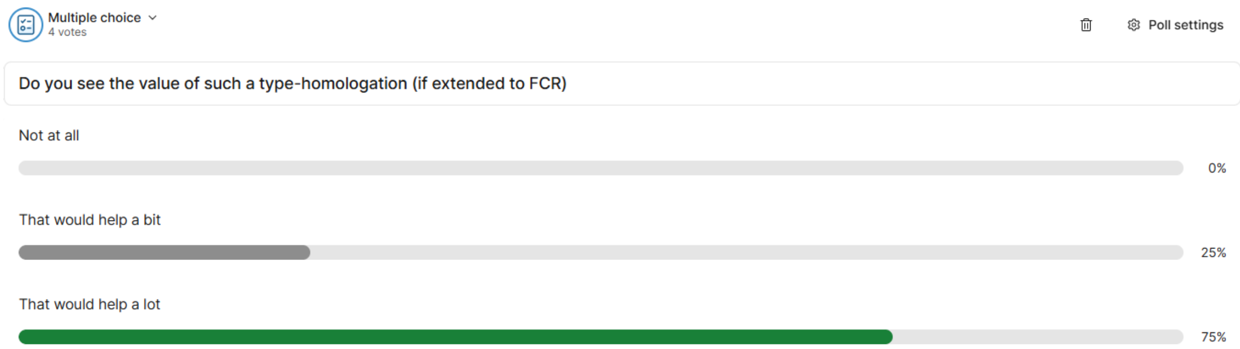

Multiple choice
9 votes
Poll settings
How much does the obligation for MID compliant meters constitute a barrier (only aFRR with ToE and mFRR)?
1 - no impact
11%
2 - slowing down but not hindering the development
33%
3 - hindering the development. To be addressed with medium priority
0%
4 - hindering the development. To be be addressed with high priority
56%
5 - sufficient to block the development of LV explicit balancing in Belgium
0%


Multiple choice
7 votes
Poll settings
How much does the on-boarding process constitute a barrier to LV explicit balancing?
1 - no impact
0%
2 - slowing down but not hindering the development
57%
3 - hindering the development. To be addressed with medium priority
43%
4 - hindering the development. To be be addressed with high priority
0%
5 - sufficient to block the development of LV explicit balancing in Belgium
0%


Multiple choice
6 votes
Poll settings
If Elia allowed the increase of the capacity of a portfolio without new prequalification test, would it help developing LV explicit balancing?
No, prequalification is not a main barrier anyway
17%
Yes, but it would only marginally help
17%
Yes, it would significantly reduce the on-boarding effort and related costs
67%


Multiple choice
7 votes
Poll settings
How much does the need for SMR3 headmeter constitute a barrier to LV explicit balancing? (NA for FCR)
1 - no impact
14%
2 - slowing down but not hindering the development
43%
3 - hindering the development. To be addressed with medium priority
29%
4 - hindering the development. To be be addressed with high priority
14%
5 - sufficient to block the development of LV explicit balancing in Belgium
0%


Multiple choice
3 votes
Poll settings
Were you aware of the existence this procedure and database
Yes
33%
No
67%


Multiple choice
4 votes
Poll settings
Do you see the value of such a type-homologation (if extended to FCR)
Not at all
0%
That would help a bit
25%
That would help a lot
75%

ANNEX B: Rationale behind lowering the accuracy for a large number of DPs

5.1.5 Statistical analysis

To enable demand side response for balancing services, future Balance Service Providers (BSP's) could combine small residential assets in one portfolio and make bids for balancing services. Nowadays, in practice, individual submeters have to comply with the minimum accuracy specified by the "≥100 kVA tot 250 kVA" group (see Table 5-9). However, if BSP's combine small assets to a size comparable to the size of one large asset that would be classified in the "≥100 kVA tot 250 kVA", the combined accuracy of all those small assets will have a better relative inaccuracy. This is because **the error propagation theory learns that a sum of relative inaccuracies propagates to a smaller relative inaccuracy compared to the total capacity**. This, in turn, is because with more assets, there is a larger chance that some of the errors cancel each other out while the capacity grows linearly.

Connected power	Voltage level connected to measuring setup	Minimal required accuracy class of parts of the measuring setup			
		TP	TI	Wh- meter	VArh- meter
≥ 20 MVA	HS	0.2	0.2s	0.2s	0.5
≥ 5 MVA < 20 MVA	HS	0.2	0.2	0.2	2
≥ 1 MVA < 5 MVA	HS	0.2	0.2	0.5	2
≥ 250 kVA < 1 MVA	HS	0.5	0.5	1	2
	LS (exceptional)	N/A	0.5	1	2
≥ 100 kVA < 250 kVA	HS	0.5	0.5	1	2
	LS	N/A	0.5	1	2
< 100 kVA	LS	N/A	1	Meters conform annex MI-003 of the Royal decision of 13 June 2006 concerning measurement equipment	

Table 5-9. Copy of Table 10. from Technical Regulations showing the minimum required accuracy for the components of a measuring device, depending on connection power and voltage level.

The objective of this section is to quantify this error propagation of the relative inaccuracy of small asset meters to the relative inaccuracy on BSP portfolio level (i.e., when all these small assets are combined in one bid by a BSP).

Furthermore, this quantification led to a recommended extension of Table 5-9 by splitting the "< 100 kVA" category in more categories with smaller asset size than 100 kW.

5.1.5.1 Assumptions for quantification error propagation

To quantify the error propagation and mathematically prove the relation between small asset meter inaccuracy and inaccuracy on a BSP portfolio level some assumptions have to be made.

1. The errors in small asset meters are independent of each other. Inaccuracy of asset meters are generally time interval related errors and therefore the error of one asset is generally different than for another asset. If errors are correlated, the quantified decrease in error propagation will be smaller up to a maximum of no decrease in relative inaccuracy when errors are fully correlated.
2. Small assets are combined in a portfolio. The minimal bid size of this portfolio relates to the size of assets normally in the "≥100 kVA tot 250 kVA" category of Table 5-9. In this quantification a minimum bid size of 100 kW is assumed.
3. No impact of possible difference between partial operation and/or flexibility provision compared nominal capacity when comparing small assets and large assets.

The inaccuracy of the flexibility provision is different than inaccuracy of the meter, which relate to the nominal capacity of the asset. **The factor between the effective inaccuracy of the flexible provision (due to inaccuracies in measurements, excluding inaccuracies of the baselines methodology) and the inaccuracy of the meter is dependent on the operation of the asset at that moment and which part of the nominal capacity is used for flexibility.**

In Figure 5-3 the flexible provision is displayed using more or less of its capacity than committed in the forward market. The forward position of the asset is displayed by the grey line (80% of the nominal capacity in this example). The flexibility can be provided by moving the grey line to the left (i.e., activating less of the asset capacity) or moving the grey line to the right (i.e. activating more of the asset capacity). By example the blue and red arrow show a flexible provision of 30 kW and 20 kW, respectively, while the absolute inaccuracy of flexibility provision (i.e., absolute inaccuracy of the meter at that ratio r_{act} of nominal capacity) is shown by the intersection of the yellow line with the blue or red arrow, respectively. In this example the asset has a relative meter inaccuracy ($\Delta_{rel}z$) of 1%. The relative inaccuracy of the provided flexibility is:

$$\Delta_{rel}flex = \Delta_{rel}z * \frac{r_{act}*nominal}{r_{flex}*nominal}, \qquad (1)$$

here r_{flex} is the ratio of flexible provision relative to the nominal capacity ($nominal$). The relative inaccuracy of the flexible provision is therefore dependent on the relative inaccuracy of the asset meter, which is specified by Table 5-9, and a factor (R) which is very dependent on the situation. Quantifying and assessing the impact of this factor is out of scope of this report. Table 5-9 does implicitly already assume some factor (R) and does formulate meter inaccuracy requirements only based on the relative inaccuracy of the meter ($\Delta_{rel}z$) and not on this factor (R) that is situation dependent. It is already known that enough accuracy of flexibility is given, while meters satisfy the requirements of Table 5-9. There is no indication that the average factor (R) for small assets would be much different compared to large assets or that the impact on flexibility provision inaccuracy is much different for small assets compared to large assets. Therefore, **it is assumed in this report that error propagation of flexibility provision by BSP portfolio's only depends on the relative inaccuracy of the small asset meters, while the impact of different operation of a high number of small assets compared to one large asset can be neglected.**

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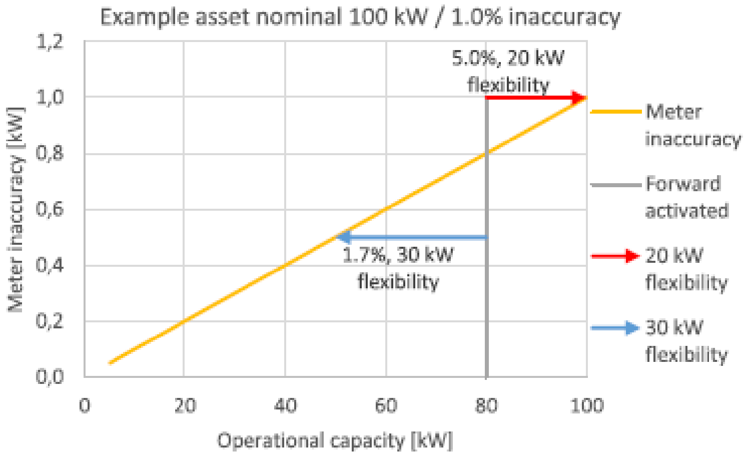

Figure 5-3. Example of inaccuracy flexibility provision versus meter inaccuracy.

5.1.5.2 Error propagation of a portfolio consisting of similar size small assets

The sign that is used for relative error based on capacity will be Δ_{rel}. The absolute standard deviation or sigma is denoted as σ, so relative inaccuracy can also be denoted as $\Delta_{rel} = \frac{\sigma\,[kW]}{capacity\,[kW]}$.

The requirement for smaller assets should propagate to an inaccuracy on BSP portfolio level that complies with today's requirements for larger assets. These requirements are given by Table 5-9. So, for Wh-meters the portfolio should comply to the requirement of 1% relative inaccuracy when the capacity (z) is 100 kW with n number of small assets with size x kW:

$$\Delta_{rel}z = \frac{\sigma_z}{z} \leq 0{,}01 \in \mathrm{z} = \mathrm{n} * \mathrm{x} = 100\ \mathrm{kW} \tag{2}$$

If z is measured m times than the standard deviation of z is defined as

$$\sigma_z = \sqrt{\frac{\sum_m (z_i - \bar{z})^2}{m}}. \tag{3}$$

where $z_i = x_1 + x_2 + \cdots x_n$. Following statistical theory, further explained in Annex B, independent errors in x_i will propagate to:

$$\sigma_z = \sqrt{\sigma_{x1}^2 + \sigma_{x2}^2 + \cdots + \sigma_{xn}^2}. \tag{4}$$

The error propagation of n assets with the same capacity and the same relative meter inaccuracy has to be determined. These assumptions transform equation (4) to:

$$\sigma_z = \sqrt{\sigma_x^2 * n}. \tag{5}$$

With z = n*x, the relative inaccuracy formula becomes

$$\frac{\sigma_z}{z} = \frac{1}{\sqrt{n}} * \frac{\sigma_x}{x}. \tag{6}$$

Applying this equation of error propagation, we can fill in the current requirement for large assets and suggested limitation, which is $\Delta_{rel}z \leq 0.01$ (1%) at z= n*x = 100 kW. With this limitation the following holds:

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$$\frac{\sigma_x}{x} \leq 0.01 * \sqrt{\frac{z}{x}} * 100\% \,, \tag{7}$$

$$\Delta_{rel} x \leq \frac{10}{\sqrt{x}}\% \;. \tag{8}$$

Equation (8) will be the main requirement formula for relative inaccuracy of small asset meters. A portfolio consisting of assets that comply to this formula would also comply to the requirements that are established for a BSP portfolio. In this report the limitation of a flexible provision of 100 kW with a relative inaccuracy of 1% is used in the final requirement for small assets meters (equation (8)). Table 5-10 show potential extra categories to be added to Table 5-9, which might be more workable as a requirement than a formula.

Capacity	Wh-meter maximum inaccuracy[9]
≥ 20 kW till 100 kW	2%
≥ 6 kW till 20 kW	3.5%
≥ 2 kW till 6 kW	5%
< 2 kW	10%

Table 5-10. Potential additional categories for Table 5-9.

Figure 5-4 and Table 5-11 show the error propagation if small assets are combined in one portfolio. The reduction of relative inaccuracy does not stop after 100 kW. If the portfolio size grows above 100 kW, then the relative inaccuracy of the portfolio will be smaller than 1%. The requirement formula or stepwise addition to Table 5-9 does however relate to a portfolio size of 100 kW, as discussed in assumption written in section 5.1.5.1. As an example, 100 assets providing 1 kW having 10% inaccuracy each will combined propagate to the same inaccuracy of an asset providing 100 kW flexibility with an inaccuracy of 1%.

Combined capacity [kW]	Small asset capacity [kW]	Number of assets (n)	Relative inaccuracy small asset meters [%]	Combined relative inaccuracy meters [%]
100	1	100	10.0%	1.00%
101	2.8	36	5.0%	0.83%
100	4	25	5.0%	1.00%
100	10	10	3.5%	1.11%
250	1	250	10.0%	0.63%
400	8	50	3.5%	0.50%

Table 5 11. Example table of submeter inaccuracy propagation.

[9] This accuracy numbers refer **to the accuracy calculated as in the IEC standards**, in particular the standards IEC 62053-21, IEC 62053-22, IEC 62053-23, and IEC 62053-24.

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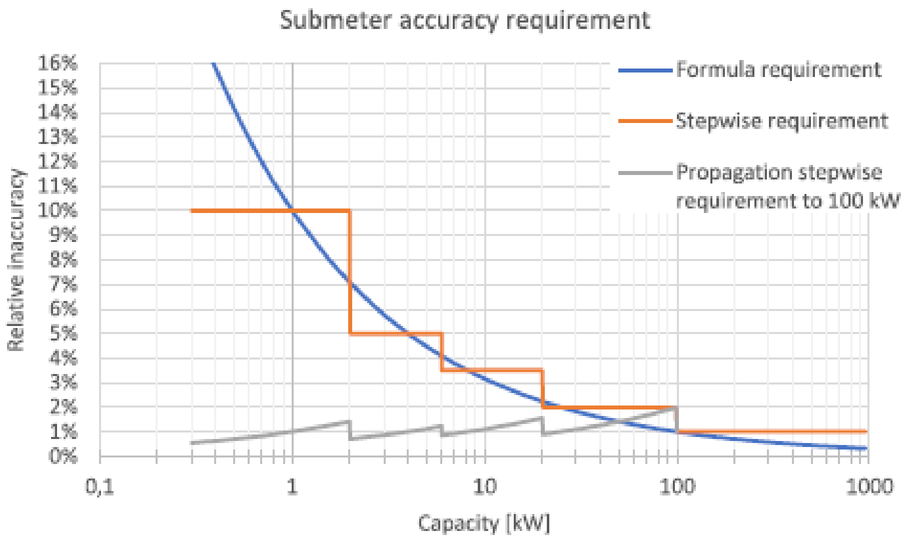

Figure 5-4. Asset nominal capacity versus required relative inaccuracy of the submeter.

The blue line shows the submeter requirement based on equation (8) and where the inaccuracy of a portfolio consisting of such assets propagate to. The orange line shows a more workable stepwise requirement based on equation (8). The grey line shows the propagation of the orange line to the inaccuracy of a portfolio of 100 kW. All assets below the blue or orange line would comply to the meter inaccuracy requirements on BSP portfolio level if they are combined in a bid of at least 100 kW.

The relative inaccuracy refers to a large part of the operational range, therefore, for lower partial operation (for instance 10% of nominal power) the inaccuracy does not grow disproportionately. This is established as the accuracy of meters is tested under load conditions (or different currents). According to the IEC standards the following test points are used: I_{min} ($0.05I_n$), $0.1I_n$, In and I_{max}. In is the nominal current, the normal operating range goes from $0.1I_n$, In and I_{max}. So, there are at least 3 test points that cover this range. The worst accuracy value measured must be used as declaration for the accuracy of the whole (current) range.

The proposed addition of smaller categories (Table 5-10) and their submeter inaccuracy requirements has made some compromises compared to the formula requirement (blue line in Figure 5-4). A portfolio that consists of assets that are at the higher end the category (e.g., portfolio with a 99kW asset) does not have an inaccuracy of maximum 1% at a portfolio size of 100 kW. This is depicted by the grey line, which shows the error propagation to a portfolio size of 100 kW with only small assets given by the x-value and submeter inaccuracy given by the orange line.

Every part of the orange line should be below the blue line to be absolutely certain that no portfolio exceeds the requirement of 1% inaccuracy at a portfolio size of 100 kW. Table 5-12 gives the maximum allowable small asset size for certain submeter accuracy categories, when all possible portfolios need to have an error propagation to a certain maximum 100 kW-sized portfolio inaccuracy. It can be seen that if a submeter categorization of (2%, 3.5%, 5%, 10%, Figure 5-5) is chosen, every asset above 4 kW and below or equal to 8.2 kW should have an accuracy of 3.5% (MID class A). Only below or equal to 4 kW a less accurate submeter of 5% could be allowed.

Table 5-12 gives the edges of certain submeter accuracy categories. It also gives the edges when it is decided to relax the requirement the portfolio inaccuracy requirement at 100 kW portfolio size. After all, the already established category "≥ 250 kVA < 1 MVA" with 1% accuracy meters also do have a higher inaccuracy compared to combining 4 assets/portfolios of 100 kW with 1% inaccuracy in one portfolio (which propagates to 0.5% inaccuracy).

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Submeter inaccuracy ↓	Maximum small asset size [kW] with maximum 100 kW portfolio inaccuracy		
	1%	1.5%	2%
2%	25.0	56.3	100.0
3.5%	8.2	18.4	32.7
4.5%	4.9	11.1	19.8
5%	4.0	9.0	16.0
6%	2.8	6.3	11.1
8%	1.6	3.5	6.3
10%	1.0	2.3	4.0

Table 5-12. Maximum small asset sizes for stepwise categories given the submeter inaccuracy (rows) and maximum inaccuracy at a portfolio size of 100 kW (columns).

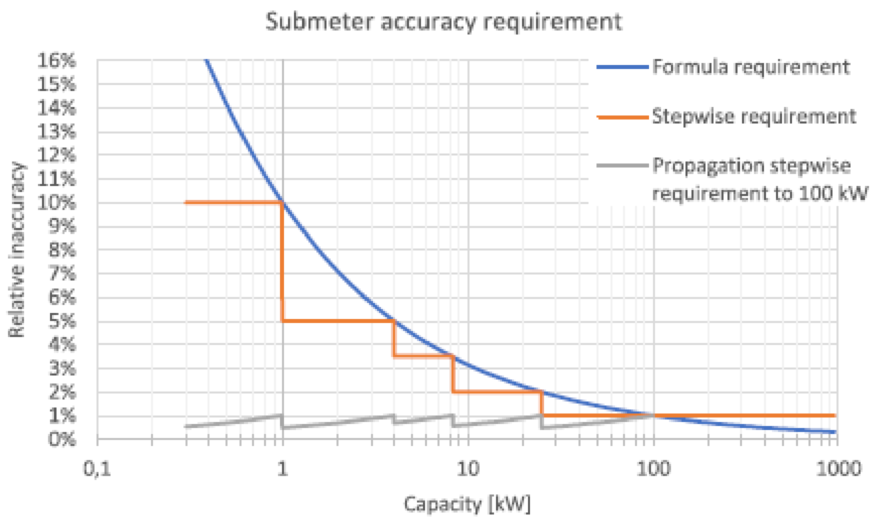

Figure 5-5. Adjusted stepwise categories where propagation to a 100-kW portfolio is always has a maximum inaccuracy of 1%

Taking into account the reasoning explained above, and results shown in Table 5-12, DNV recommends an extension of Table 5-9 by splitting the "< 100 kVA" category in more categories with smaller asset size than 100 kW, as shown below.

Capacity	Wh-meter maximum inaccuracy[10]
32.7-100 kW	2%

[10] This accuracy numbers refer **to the accuracy calculated as in the IEC standards**, in particular the standards IEC 62053-21, IEC 62053-22, IEC 62053-23, and IEC 62053-24.

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11.1 – 32.7 kW	3.5%
4 – 11.1 kW	6%
< 4 kW	10%

Table 5-13. Recommended Wh-meter maximum inaccuracy per capacity range

5.1.5.3 Portfolios with mixed sized assets

Equation (8) represents the requirement formula of a portfolio consisting of similar assets, providing the same flexibility with the same inaccuracy. Now the situation of two different sized assets can also be explored. The general constraint would be that all individual assets comply with equation (8). The question will be: "Does a portfolio of different sized assets also comply"?

To investigate this, a worst-case situation is assumed in which all the assets comply individually to the requirement table but not better than that.

$$\Delta_{rel}x = \frac{10}{\sqrt{x}}\% \; and \; \Delta_{rel}y = \frac{10}{\sqrt{y}}\% \, ,$$

where $\Delta_{rel}x$ is the relative inaccuracy of all assets with x kW capacity and $\Delta_{rel}y$ the relative inaccuracy of all assets with y kW capacity. The investigation is that the BSP portfolio of

$$z = l * x + k * y = 100 \, kW, \tag{9}$$

will also comply with the meter requirement on a BSP portfolio level (i.e. $\Delta_{rel}z$ = 1%). Here l is the number of assets with x kW capacity and k the number of assets with y kW capacity. This y can be writing in as a ratio relative to the size of assets with x kW capacity.

$$a = \frac{y}{x}, \tag{10}$$

$$z = (l + k * a)\, x \, . \tag{10}$$

Since both are at the requirement equation (8), σ_y can also be written with ratio a and σ_x following equation (5)

$$\sigma_y = \sqrt{\sigma_x^2 * a} \; . \tag{11}$$

Together with equation (4), the absolute inaccuracy of z become.

$$\begin{gathered} \sigma_z = \sqrt{\sigma_x^2 * l + \sigma_x^2 * a * k}\, , \\ \sigma_z = \sigma_x \sqrt{l + ak}\, . \end{gathered} \tag{12}$$

Together with equation (10), the result is the same as the requirement formula provided in equation (6), because $(l + ak) * x$ kW provides the same capacity as $l * x + k * y$ kW (i.e. $l + ak$ in equation (12) and (13) is similar to n in equation (5) and (6) or in other words inserting number for all symbols $(l + ak)$ will always be the same as n out of equations (8).

$$\frac{\sigma_z}{z} = \frac{1}{\sqrt{l + ak}} * \frac{\sigma_x}{x}. \tag{13}$$

This statistical analysis of a portfolio having two types of assets, having a different capacity, can be extrapolated to portfolios having a more diverse composition of assets using the same reasoning. Result of this reasoning is that: **If all asset meters in a portfolio comply with equation (8) and all meter inaccuracies are independent of each other,**

than the whole BSP portfolio is compliant to the meter inaccuracy requirement. No matter the size or the amount of different sized assets which are present in the BSP portfolio.

Figure 5-6 show an example of a BSP portfolio consisting of assets with two different asset capacities (x kW and y kW). All asset meters comply with equation (8) individually, however they all do not have a better accuracy than this requirement. Figure 5-6 is calculated with x being 1 kW and y being 4 kW. They therefore have an individual meter inaccuracy of 10% and 5%, respectively. The figure would yield to the same result when other values of x and y are selected as long as they have an individual meter inaccuracy as equation (8). In Table 5-14 some examples of BSP portfolio inaccuracies are shown.

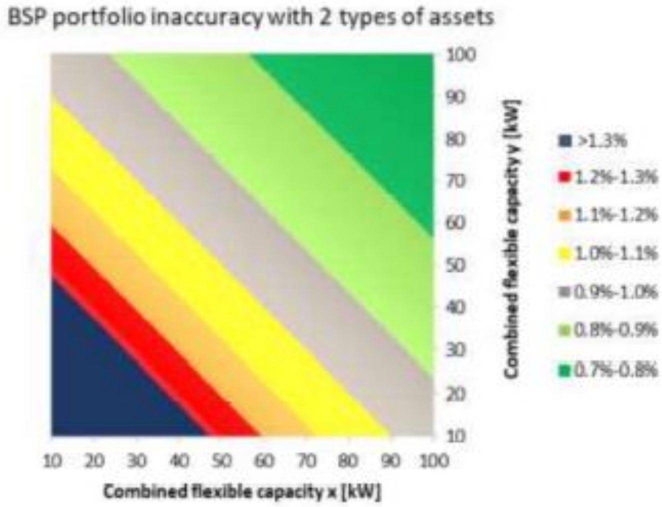

Figure 5-6 Contour chart showing the BSP portfolio inaccuracy, when assets of two different flexible capacities are combined in one portfolio.

The x-axis shows the combined flexible capacity of assets with x kW capacity and the y-axis the combined flexible capacity of assets with x kW capacity.

Small asset size x [kW]	Small asset size y [kW]	Number of assets x	Number of assets y	Portfolio size [kW]	Combined relative inaccuracy meters [%]
1	4	20	20	100	1.00%
2	10	5	9	100	1.00%
4	12	16	3	100	1.00%
1	15	85	1	100	1.00%
4	12	4	7	100	1.00%
3	6	16	42	300	0.58%
1	12	100	50	700	0.38%

Table 5-14. Example table of meter inaccuracy propagation with assets having two different flexible capacities, but all meters inaccuracies comply to equation (8).