Alexander

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Development of a Novel, Grid Safe Concept for Flexibility Provision from the LV Grid

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Executive summary

The widespread integration of variable renewable energy sources (RES) alongside the anticipated surge in electricity demand due to advanced electrification (e.g., heating and mobility) escalates the need for flexibility within the power systems. Consequently, the availability of flexibility from low voltage (LV) prosumers/consumers becomes paramount for ensuring both economic efficiency and system security. This heightened demand for flexibility, coupled with technological advancements, presents prosumers connected at the distribution network (DN) level with an economic incentive to adapt their energy consumption patterns, thereby offering flexibility to transmission and/or distribution system operators (TSO/DSO). The distributed energy resources (DERs) owned by these prosumers can offer flexibility, for instance, by pooling them together through a third-party aggregator serving as a flexibility service provider (FSP), depending on the size of the required flexibility service and the capacity that is available. Considering that activating such low voltage flexibility to resolve transmission-level issues could potentially lead to operational limit breaches (such as line congestions or voltage fluctuations) within distribution systems, it's crucial to incorporate distribution grid constraints into the flexibility procurement (market) process.

The grid constraints of the DSOs can be accounted for in different market stages, ranging from prequalification, procurement, activation, and settlement steps. In this deliverable, we assess the options of 1) not considering any DSOs constraints when TSO procures flexibility from DERs (named *no-DN*); 2) performing a static prequalification of DERs resources before they join the TSO flexibility market (named *prequalification-BaU,* as this resembles business as usual to a large extent in Belgium); 3) performing a detailed and dynamic prequalification of DERs generating limits constraining their participation in the TSO flexibility market (named *with-OE*, as the methods proposed in this step have focused on operating envelops); and 4) embedding the DSOs constraints in the procurement phase, together with the market clearing of the TSO-level market (named *full-DN*). We develop mathematical models for these different options to study their benefits and drawbacks in terms of market efficiency (procurement cost), market clearing speed, DSO grid safety guarantees, and volumes of discarded flexibility due to distribution grid constraints. We also evaluate the feasibility of implementing the proposed solutions for the grid-safe activation of distributed (LV) flexibility in the Belgian context. This feasibility is based on the market set-up (e.g., type of buyer, applicable products, etc.), the market clearing process (timing and complexity of the market clearing), TSO-DSO coordination (requirements regarding data sharing), data implications (requirements on data granularity, data sharing between market stakeholders), operational challenges and the resulting impact on the potential of flexibility participation, and finally the applicability of the different methods (which can depend on the state of the grid and the regulatory framework).

As a first finding, this deliverable identifies that Belgium applies the first two options: either prequalification does not take place (option *no-DN*), or it is done long before activation of flexibility through a Network Flexibility Study (NFS) (option *prequalification-BaU*). The general rules in all three Belgian regions are that DSO grid prequalification is done through an NFS, thus by the DSO prior to the start of the flexibility provision. Only prequalified FSP resources can submit offers to the TSO, and the DSO is not further involved in the TSO procurement process. The disadvantage of this method is that it can lead to the DSO blocking a large volume of flexibility for a longer period of time, as the result of the NFS remains valid for multiple months. Furthermore, the NFS procedure can induce burdens to the participation of LV-flexibility assets.

Results of implementing and simulating the *no-DN*, *with-OE*, *full-DN* options show that, depending on the option used, there is a trade-off between the TSO procurement cost and the grid-safety of the DSO network (the lack of the latter would induce ex-post costs to the DSO to perform corrective actions and may, hence, elevate the total system costs when considering both systems) when the TSO activates distribution-connected resources. More specifically, if the *no-DN* model is used, the TSO can have a lower flexibility procurement cost, at the expense of risking causing grid violations in the distribution network, which would then raise the operational costs of the DSO. On the other extreme, if a *full-DN* model is used, in which the distribution network constraints are embedded in the TSO market clearing process, the DSO grid is guaranteed to be safe, thus limiting any corrective actions needs by the DSO, but the procurement cost of the TSO increases, as its flexibility procurement becomes more constrained. On the other hand, the full-DN option requires a full network sharing by the DSO to a third party, which renders challenging its practical application potential. The prequalification method used (including different variations within the *with-OE* model depending on the operating envelope method used and the granularity at which it is applied, including, e.g., at resource, FSP, or transformer levels) can lead to better or worse results in terms of grid-safety and market procurement efficiency. For instance, if the DN-connected resources are prequalified per connection point and the calculated limits are included in the market clearing process, the DSO grid is more guaranteed to be safe after activation, while if the resources are prequalified in groups (e.g., aggregated for a certain FSP, or aggregated at the level of the transformer), grid violations can still happen when the TSO activates the grouped resources. Moreover, the prequalification of DN-connected resources with the operating envelopes method (*with-OE*) discards available flexibility from the distribution network in order to guarantee that the allowed volume does not cause grid violations when activated. This comes at the expense of a more costly flexibility procurement to the TSO. Finally, when a more detailed network model of the LV distribution grid (e.g., a full power flow representation considering phase unbalances) is used to prequalify the LV resources and calculate their operating envelopes, results show that controlling reactive power on the LV network could increase flexibility potential and counteract unbalances between phases. However, this could induce other effects such as increasing reactive losses on the LV network and modifying active/reactive setpoints on the transformers.

As a final finding, we identify that **it is fair to say there is no one-size-fits-all model to consider distribution grid constraints in the flexibility procurement by the TSO**. Depending on the context, different models might be more suited. One overarching contextual characteristic is the maturity of the flexibility market. In countries where there are already more grid violations, the market is more likely to be mature and models are more likely to be moving from *no-DN* towards the application of distribution grid constraints in the procurement process of LV-level flexibility for system services. However, in countries where flexibility procurement at LV-grid levels is still low, it is more likely to have the *no-DN* or *prequalification-BaU* models implemented as a first step. This is also the case in Belgium. Generally, the different distribution grids in Belgium do not yet face many violations. However, there is an urgency to start building up flexibility markets. To kick-start these markets, reducing barriers for the provision of LV-flexibility is of key importance. This can be achieved by, e.g., moving towards the no-prequalification (*no-DN*) model, especially if the risk if network constrain violation, at the LV level remains low. In Belgium, exemptions are given that imply no NFS is needed for LV-flexibility provision of specific products. A final contextual element is the regulation. In some countries or regions, regulation can determine which model is to be used. In Belgium, the general rule is that an NFS is applied.

Next to contextual elements, there are different design choices that need to be compared to determine which model is more suitable. For instance, if the *prequalification-BaU* method is to be used, its implementation is conducted well ahead of time, thus already determining which resources can offer flexibility. This creates transparency and certainty ahead of real-time for both the buyer and the seller of flexibility. The disadvantage of this method is that it might overly block flexibility, especially as compared to the setting closer to real-time, when more updated information is available and hence flexibility prequalification can be done more effectively and efficiently. This latter setting can be captured by the *with-OE* or *full-DN* counterparts. The model to be adopted is also closely linked to different roles and responsibilities that the DSO is willing to take up. DSOs pursuing more active roles given the operational constraints in their grids would be moving more in the direction of model *with-OE*. In addition, DSOs that do not have concerns for allowing the market operator (MO) of the market in which flexibility is procured to enforce network limits to safeguard their grid, would share their data in order to allow the MO to perform the market clearing (*full-DN*). However, this requires overcoming data sharing and privacy/confidentiality concerns. On top of that, they key issue is that the DSO is responsible for grid security in its own grid, implying that he cannot transfer this responsibility to other stakeholders that would use his data to check grid constraints. In addition, in model *prequalification-BaU*, the DSO controls the different flexibility resources, but in a more conservative way. Finally, the choice to opt for a specific model is also influenced by whether the model is implementable in practice. This depends on data availability, TSO-DSO coordination needs and possibilities, existing processes, and complexity. From a practical point of view, it is more likely that many DSOs will end up with models in the middle of the scale (e.g., the *prequalification-BaU* and *with-OE* models). These models put less pressure on data and coordination needs and are less computationally complex than the *full-DN* model.

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Abbreviation and acronyms

aFRR	Automatic Frequency Restoration Reserve
CEP	Clean Energy Package
CP	Chordal programming
CRM	Capacity Remuneration Mechanism
CU	Centralized Unit
DA	Day-ahead
DN	Distribution network
DSO	Distribution System Operator
EMD	Electricity Market Design
EAN	European Article Numbering
FCR	Frequency Containment Reserve
FRP	Flexibility Requesting Party
FSP	Flexibility Service Provider
GCT	Gate Closure Time
GIS	Geographic Information System
HV	High Voltage
ID	Intra-day
LV	Low Voltage
mFRR	Manual Frequency Restoration Reserve
MIG	Market Implementation Guide
MO	Market Operator
MV	Medium Voltage
NFS	Network Flexibility Study
NRA	National Regulatory Authority
OE	Operating Envelope
PF	Power Factor
RTCP	Real-Time Communication Platform
SDP	Semi-definite positive
SDR	Strategic Demand Reserve
SLP	Synthetic Load Profile
SO	System Operator
SOCP	Second-order conic programming
SPG	Service Providing Groups
SPU	Service Providing Units
ToE	Transfer of Energy
TSO	Transmission System Operator
UTOPF	Unbalanced three-phases optimal power flow

1. Introduction

1.1. Why do we need LV-flexibility?

It is well-known that European and global climate targets are having and will continue to have a significant impact on renewable variable generation (in particular from distributed resources) and on the increasing electrification of consumption (heating, industry, and mobility). For instance, EU electricity consumption is projected to rise by approximately 60% by 2030 [1]. Additionally, the grid will need to handle an increase in renewable energy of at least 42.5% of EU's energy consumption [2], as stated in the EU's binding renewable energy target for 2030.

This decentralization of generation and electrification of consumption causes, in particular, significant challenges in lower voltage levels where heat pumps, electric vehicles, roof top photovoltaic systems, among others, are being installed. This increases challenges in the LV-distribution grid linked to congestions, grid connection queues, increased consumption peaks, and voltage issues. Nevertheless, this energy transition is not possible without interconnected and stable energy networks [1], which can only be achieved if (a) grids are operated more efficiently, and (b) they are modernised and rolled out faster.

- Option (b) entails the traditional solution of grid reinforcement, which according to the Grid Action Plan is estimated to necessitate a €584 billion investment. Most investments are needed in distribution grids as almost half of them are over 40 years old [1].
- However, combined with option (a) these grid investments could be minimized due to a better usage of grid capacity which implies deployment of flexibility to adapt to variations in demand and generation and to relief the stress on the grid during operationally challenging time periods (e.g., under extreme heavy loading and/or light loading/high injection instances). A proper trade-off between grid reinforcement and flexibility is needed as both of them are indispensable to achieve an effective and cost-efficient energy transition.

This deliverable zooms in on the flexibility option which aims to limit costly grid expansions, and which aims to ensure system security through higher levels of flexibility. The Clean Energy Package (CEP) recognizes this need, especially through the Electricity Market Design (EMD) and the Electricity Market Regulation. In the latest proposal to improve the Union's electricity market design, the word flexibility is mentioned 86 times [3]. This recognition is an important step in the direction of opening all electricity markets for flexibility services. This is necessary as, in the past, flexibility was mostly needed by and offered to transmission system operators (TSOs) through transmission grid-connected resources. Yet, today, with increasing levels of distributed energy and demand assets located at the distribution grid, flexibility is also needed by distribution system operators (DSOs) and/or can be provided by distribution-level connected resources [4]. In particular, at LV-level, more demand flexibility is available due to the connection of new technologies such as batteries, electric vehicles, and heat pumps, but also due to the uptake of smart meters and digitalisation in general. In addition, due to the fact that there is more decentralization of production at the lower voltage levels (e.g., roof-top solar panels) and higher offtake from increasing electrification, more flexibility is now also required at lower voltage levels to deal with changes in loads. Moreover, the CEP also foresees more rights for consumers, which includes giving them the opportunity to become active participants in energy markets: the member states must ensure that any new rules facilitate individuals to produce, store or sell their own energy [5]. Clearly, not only is LV-flexibility becoming indispensable in this energy transition, but it is also increasingly available to support the energy system.

1.2. Accounting for grid constraints: the challenge

As a result, through the CEP, there is a push to ensure opening all flexibility markets to distribution-level connected flexibility resources. These resources can then offer their services to all grid operators, both DSO and TSO. In this report, we focus on distribution-level connected resources offering services to the TSO. However, to avoid unnecessary burden on the distribution grids, it is important to ensure that this flexibility offering to the TSO does not cause additional constraints on the distribution grid. Generally, flexibility procurement is implemented through a series of steps, ranging from prequalification, followed by procurement and activation, ending with verification and settlement. In this first step, flexibility resources are tested to ensure they are in line with a number of TSO-requirements, ensuring that what they are offering is capable of meeting the TSO's needs and the communication and technical requirements of delivering the service. This also implies that it is verified whether flexibility is not causing additional grid constraints (such as overflow and/or overvoltage). However, the challenge is that, in this case, the TSO can only investigate this grid safety aspect with respect to the transmission grid, i.e., the grid under its direct operational control. Yet, when an LV-connected resource adapts its consumption or generation profile to offer services to a TSO, it might cause violation of operational constraints in the distribution systems to which it is connected. This might imply that some households are, in response to a TSO request, suddenly increasing their load (for instance through fast EV-charging), causing high congestion peaks on the LV-grid. It is therefore important that when offering flexibility services to the TSO, the LV-connected resources are not jeopardizing the local grid functioning of the DSO. There are two key reasons for this: first of all, violating grid constraints endangers security of supply and quality of power; secondly, the potential of flexibility activation might be reduced due to local grid constraints preventing the actual provision of flexibility to the TSO [6].

In summary, when offering flexibility from the LV-level to the transmission system, grid constraints at different voltage levels are to be accounted for. The key challenge is therefore that, in case of two different grids, constraints of two different grid operators need to be taken into account.

Grid constraints are identified by calculating power flows in the affected grids. To describe grid constraints, the term "sensitivity" is used, measuring how a change of injection (withdrawal) of active/reactive power in a given node affects selected grid constraints [6]. Grid constraints can be considered in different market stages, as shown in Figure 1-1. Generally, there are 4 market stages: the prequalification stage, the procurement stage, the activation stage, and the settlement stage.

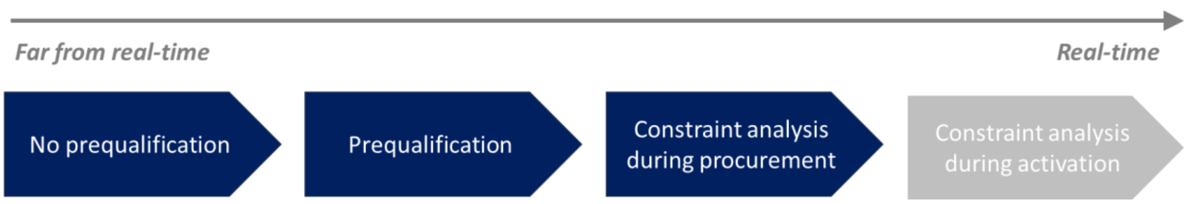

Figure 1-1: Market phases where constraint analysis can take place.

First of all, it is possible to skip any grid constraint analysis. In that case, the TSO would only consider its own grid, not accounting for possible grid constraints in the distribution grid when procuring flexibility from distribution-level resources. However, given the importance for grid security, the most well-known phase to verify grid constraints is the prequalification phase. In this phase, there are three types of prequalification [7]:

- Service provider prequalification, aimed at verifying whether the FSP fulfils the criteria for market access;

- Product prequalification, aimed at verifying technical capabilities and requirements to assess whether a specific unit can offer a sufficiently qualitative response to meet the required service;
- Grid prequalification, aimed at verifying whether activated flexibility does not cause new or additional grid constraints and/or whether the grid can indeed transport the delivered energy.

The goal of the grid prequalification phase is indeed to verify the grid-safety compliance of a specific resource to provide a service before the other market phases start, that is, before the procurement and the activation phases. The disadvantage of this method is that it is done beforehand, implying that not all information is available in its most updated state before real-time. In case a grid constraint analysis is done in the procurement phase, there can be less uncertainty on the grid and resources state, but that can induce additional complexity in the flexibility procurement (market clearing) process, which can be limiting especially under restrictive time limitations. Finally, it is also possible to take into account grid constraints during the activation phase. However, this depends on the time requirements of the product. In case of fast products, there is generally no sufficient time to check grid constraints. While in case of slow products, there can still be time available to perform network checks during activation. Nevertheless, it is pointed out that this should only be done in emergency situations or in case procurement is done long before activation [6]. In addition, when prequalification is done in real-time, it is generally not called prequalification. An example is for instance DROOP control, which is a mechanism to control appliances automatically in case (for instance) voltage crosses the allowed boundaries. It is typically done in an automated way. We will therefore not consider this phase in this deliverable. In later phases (such as the settlement phase), it is too late to perform a grid constraint analysis, especially when settlement takes place after activation.

The timing of accounting for grid constraints inevitably brings along challenges, summarized in Figure 1-2. The figure compares the different methods to account for DSO grid constraints in the flexibility procurement process, according to the timing. Whenever a method is green for a certain topic, it means the method has a positive impact, while red means the method has a negative impact to that topic. Topics are as follows:

- **Market set-up**: the market set-up determines which products are open for LV-flexibility provision, who is the buyer and whether or not prequalification of aggregated resources is possible.
- **Market clearing**: when grid constraints are accounted for during the market clearing, the market clearing inevitably becomes more computationally complex. In addition, there is more uncertainty from the perspective of the TSO, as it does not have the information beforehand on how much flexibility will be available.
- **Coordination**: it is in the interest of both system operators that flexibility is adequately procured. The TSO needs access to as much flexibility as possible to ensure efficient grid management and grid security. On the other hand, the DSO aims to ensure that no grid violations are caused by (potential) flexibility activations. As a result, both system operators need to communicate their needs/constraints (and thus data) with each other, or with third parties. However, data sharing is challenging for many reasons. First of all, sharing data implies that data needs to be updated in different servers/locations when there are changes in the data. Secondly, as each SO is responsible for its own grid security, grid data are often very sensitive and SOs are not always willing (or allowed) to share them [8].
- **Data Availability**: estimating grid constraints before procurement implies that there is less (or less-updated) data available, leading to more uncertainties. In addition, due to observability issues in distribution grids, data availability can be challenging even before real-time.
- **Operational challenge**: in case grid constraints are not properly accounted for, the DSO might precautionary block or restrict flexibility participation to ensure grid security. In case

prequalification is done long before procurement (static prequalification), this might imply that flexibility is blocked for a longer period of time.

- **Method Applicability**: it goes without saying that not all types of constraint analyses fit in all situations. We already indicated that in case of fast products, it is not possible to perform a constraint analysis during activation. However, in case a grid is experiencing (or is expected to experience) highly stressed and congested conditions, performing a grid constraint analysis becomes mandatory.

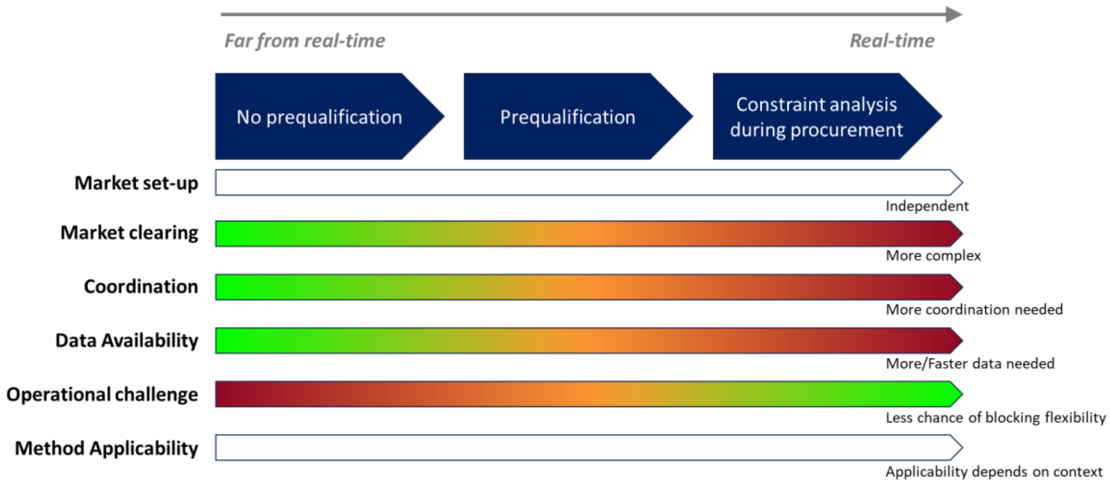

Figure 1-2: Challenges and benefits of performing a grid constraint analysis closer to real-time.

1.3. Objective of this deliverable

From the previous discussions, many challenges become evident. In this section, we describe which challenges form the main attention point of the objectives of this deliverable, that is: **in case the TSO has access to distribution grid connected flexibility, this could lead to distribution system constraint violations in case the distribution grid limitations are not taken into account as part of the TSO flexibility procurement.** As discussed in Section 1.2, to account for grid constraints, there are different methods of grid prequalification or other grid constraint-related checks [6]. Each method has its benefits, disadvantages or specific limitations.

To overcome the different challenges and to maximally benefit from the advantages, we assess different options to express grid constraints of the networks to which the distributed resources (in particular LV-ones) are connected and include them in the overall process of flexibility procurement. We also evaluate the feasibility of implementing the proposed solutions for the grid-safe activation of distributed (LV) flexibility in the Belgian context. This feasibility is based on the market set-up (type of buyer, applicable products, etc.), the market clearing process (timing and complexity of the market clearing), TSO-DSO coordination (requirements regarding data sharing), data implications (data granularity, data sharing between market stakeholders), operational challenges and the resulting impact on the potential of flexibility participation, and finally the applicability of the different methods (which can depend on the state of the grid and the regulatory framework). To reach these goals, we tackle the following three research questions.

1) How are LV grid constraints embedded in the current and emerging Belgian flexibility market designs and mechanisms (e.g., TSO-balancing services), allowing the grid-safe provision of LV flexibility to those markets?

In this first research question, answered in Chapter 2, we examine whether and how LV grid constraints are embedded in the current and emerging Belgian flexibility market designs and mechanisms (e.g., for TSO-balancing services). More specifically, we look into the current Belgian flexibility markets rules for LV flexibility provision. For Belgium, we notice that today, prequalification differs between the three regions and depending on the flexibility product offered (e.g., FCR, mFRR, aFRR, SDR, CRM). In some cases, we notice that no prequalification is required. In our overview Figure 1-3, this is depicted on the left side, representing TSO flexibility markets that do not consider any (form of) distribution network (DN) constraints (referred to as the *no-DN* market model). For instance, in the region of Flanders (Belgium), low voltage flexibility consumers (lower than 5 kVA for a mono phase connection or 10 kVA for a three-phase connection) cannot have their flexible power restricted in any sort [9]. Although sometimes deployed in TSO-level flexibility markets, this *no-DN* model can potentially result in grid violations when activating medium to low-voltage (LV) flexibility, particularly in instances where the distribution system experiences high load/generation conditions [10]. On the other hand, this setting reduces prequalification barriers or obstacles for LV-resources.

However, in most cases in Belgium, a Network Flexibility Study (NFS) is required. This is a type of static prequalification, using upfront static rules for categories of assets to calculate grid constraints. In this way, specific criteria are used to estimate the impact of an asset on the grid. In case of an unfavourable asset impact on the grid, the asset is not allowed to submit offers in flexibility markets. Unfortunately, the criteria used in a NFS do not necessarily closely link to the actual dynamically changing grid conditions [1]. The benefit of this method is, however, that the calculations are done by the DSO, who has the best available view of its own grid while also implying that the DSO would not need to share its data with other market stakeholders. The disadvantage is that this approach can be overly conservative in the sense of blocking high amounts of flexibility from participating or limiting grid access to new resources. There are therefore discussions in Belgium to move towards a more dynamic prequalification which would imply that flexibility is less likely to be blocked for a longer time period [52].

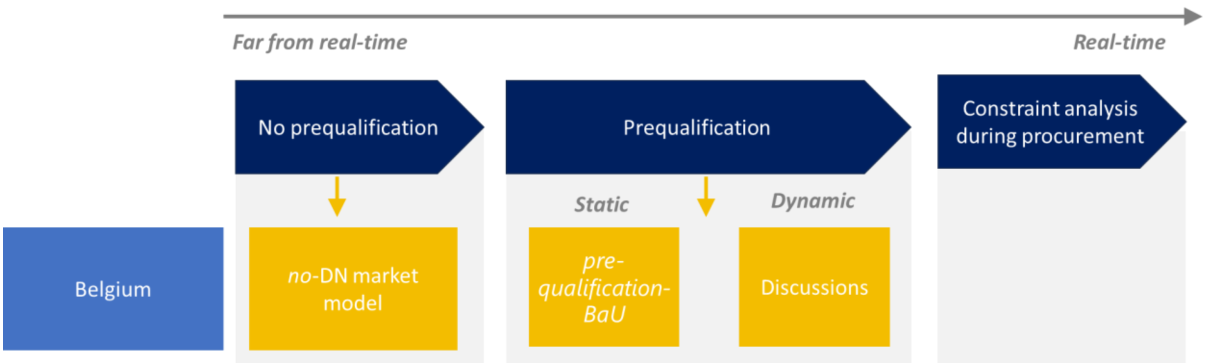

Figure 1-3: Belgian prequalification practices.

From the Belgian case, we learn that, in practice, there is a limited coordination between the DSO and the TSO. As distribution grid data are not available to the TSO, the distribution grid constraints are not included in the market clearing step of the system services procurement by the TSO. In general, detailed grid data are not always available for performing the prequalification of distributed resources willing to participate in transmission-level flexibility markets. Moreover, due to data sensitivity reasons, and challenges in continuously replicating data in multiple servers and databases, these detailed grid data, when available, cannot necessarily be shared between the different actors involved (DSO, TSO, market operator, or other third parties), preventing their use in the actual market clearing process. Therefore, we study different options to consider the question of properly representing distribution-grid constraints in the TSO-level flexibility market, whereby answering the following research question:

2) How flexibility markets for TSO-level system services (e.g., balancing) can dynamically express the constraints from distribution grids to allow for the safe provision of flexibility from distributed-connected resources?

On the right-hand side of Figure 1-4, the opposite model is showcased, where DN constraints are incorporated in the market clearing process, and we denote this model as *full-DN*. While it can be perceived as an "idealized market" in terms of grid safety and efficiency, integrating distribution system constraints into the TSO-level market formulation would require sharing potentially confidential data from DSOs with other SOs or third-party market operators (MOs), which could encounter operational and regulatory hurdles [11] [12]. In addition, it is the DSO only, which is responsible for grid security of the distribution grid, implying that it is not possible to hand over this responsibility to a third party. Given these challenges, the model has been implemented only in demonstration projects and in theory [13]. Furthermore, as discussed, the model is also more computationally complex, thus hindering its applicability.

Therefore, in Chapter 3, we investigate an alternative approach, focusing on expanding grid prequalification methods which are in the middle of Figure 1-4. As discussed in the Belgian case, the benefit of these methods is that they calculate locally (by the relevant DSOs) the provision limits of distributed-connected resources (or connection points or feeders) before the market clearing round. As such, **DSOs do not need to share their data with other market-related entities, while the calculated limits are able to capture the constraints of their grids**. The disadvantage of this setting is that, today, this is often done in a static way, blocking flexibility potentially for longer time periods and for larger volumes than needed. To cope with this, **we propose a dynamic grid prequalification model, based on operating envelopes (OEs) to better represent the DN grid constraints in the process of TSO flexibility procurement** while unlocking as much flexibility as possible from distributed-connected resources. We refer to this model as *with-OEs*. The development of OE methods allows DSOs to indicate the feasible operating flexibility regions for resources connected to their distribution grid, where those limits can then be imposed in the procurement/market-clearing process of system services without the need of sharing complete distribution network information.

All three types of models are implemented and simulated to evaluate their efficiency in terms of (i) flexibility procurement costs, (ii) their ability to maintain the safety of the distribution network, and (iii) their effectiveness in unlocking distributed flexibility.

Moreover, an extension of the prequalification model (*with-OEs*) to a 3-phase with unbalances network setting is studied in Chapter 4 to understand the possibilities and limitations of a detailed LV-network model implementation in a market (prequalification) environment. Analyses in terms of the type of data needed, the impact of phase imbalances on the available flexibility, the impact of reactive power provision on the OE limits, and the complexity to solve the detailed model are provided.

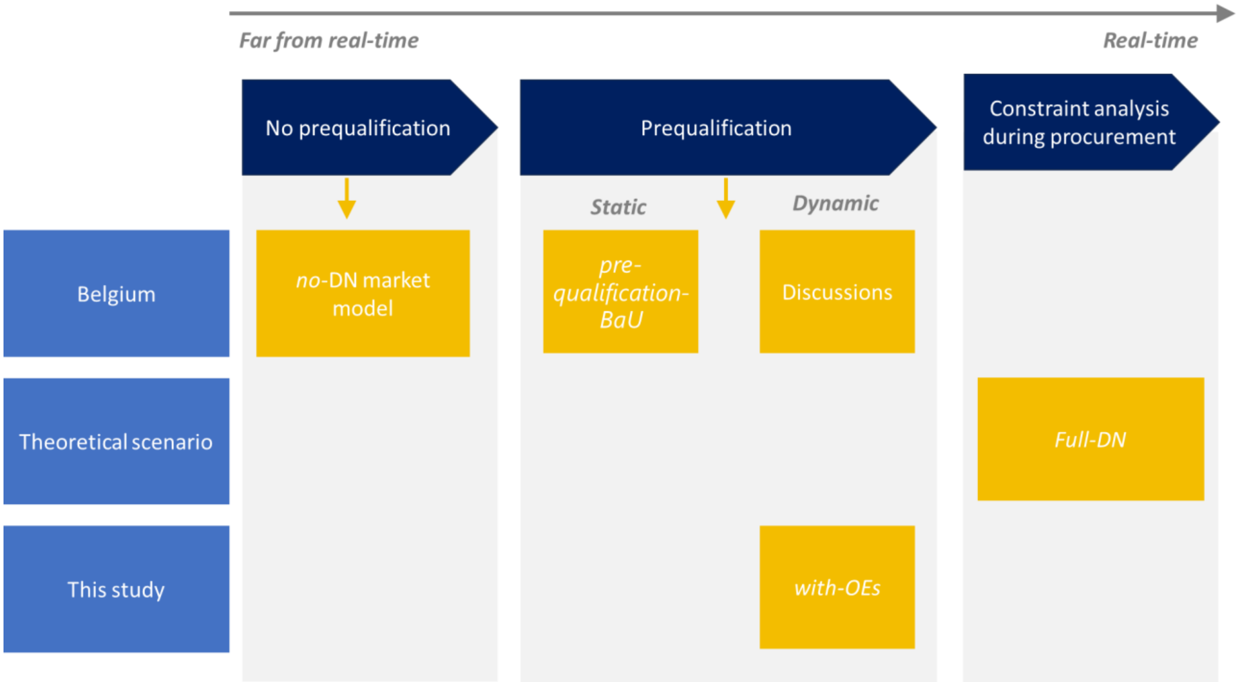

Figure 1-4: Models analysed in this deliverable.

Finally, we connect the aforementioned analyses (the different "DN representation in TSO-flexibility market" models of Chapters 3 and 4 to the Belgian context of Chapter 2) by tackling the last research question:

3) What are possible barriers for a consumer-centric but grid-safe procurement of flexibility from the distribution level, and do these barriers, and do these barriers differ across different Belgian regions? What harmonization steps are needed in Belgian flexibility markets to allow consumer-centric solutions for the dynamic inclusion of grid constraints in the flexibility acquisition process?

In chapter 5, we zoom deeper into the application of the three types of models in Figure 1-4 to the Belgian Flexibility Markets. For each of the differentiating characteristics (market set-up, data implications, TSO-DSO coordination, operational implications, market clearing and applicability), we discuss how they differ between the models. We identify barriers and challenges to implement the proposed solutions in Belgium.

2. TSO Flexibility Markets in Belgium

In the past, flexibility was mostly requested by the TSO who primarily requested flexibility from transmission grid connected resources. As a result, in Europe, and therefore also in Belgium, a significant part of transmission grid services is being covered by demand response from industrial resources [14]. As a result, originally and by design, these transmission grid services were mostly delivered by transmission grid-connected assets. However, in the future, the focus will need to be to include LV-distribution grid-connected resources as well [15] to tackle the increasing need for flexibility, thus the focus of the Alexander project is on LV-connected flexibility. This is due to the fact that, with the current decentralization of production and electrification of energy consumption, lower voltage levels are also in need of flexibility. In addition, the energy transition also puts additional pressure on transmission grids, as they are also suffering from aging infrastructure, making it hard to deal with variable and distributed generation and demand. Large industrial users are also electrifying their systems, implying increasing loads on transmission grids. Furthermore, the original flexibility providers were fossil fuel-based generation assets which are now being retired and phased out. In response to these changes, TSOs need new and more flexibility services with different requirements (such as inertia) [15]. This implies that TSOs also need a diversification of their flexibility resources. Consequently, flexibility from distribution grid-connected resources, both for DSOs and TSO, is gaining importance. As a result, transmission grid services are now being opened up for (LV-) distribution grid resources as well. In what follows, we discuss the steps taken and resulting regulation when distribution grid connected resources offer services to the TSO, with a focus to the Belgium context.

In what follows, we zoom into transmission ancillary services and the steps that are being taken in Belgium to open these services for distribution grid connected resources. Distribution grid services are not the focus of this deliverable. For the transmission grid, Elia, the Belgian TSO, is procuring products that can deliver certain services. In Belgium, 4 types of flexibility products exist: there are 4 balancing products (FCR, aFRR, mFRR) and one adequacy product (CRM). As indicated, the changing environment and upcoming challenges might require the TSO to procure additional products for new services that are required to tackle the upcoming grid challenges [15]. We detail the existing products as follows:

- Frequency Containment Reserve (FCR)
- Automatic Frequency Restoration Reserve (aFRR)
- Manual Frequency Restoration Reserve (mFRR)
- Capacity Remuneration Mechanism (CRM)

FCR, aFRR and mFRR are the balancing products Elia procures to keep or restore the system's frequency. CRM is the capacity mechanism to ensure the general energy security in Belgium in the period 2017-2027. It is introduced in response to the partial decommissioning of the Belgian nuclear generation capacity and resulting capacity shortages. Through the CRM, owners of electricity generation capacity get remunerated for their investments and costs, i.e., for their capacity/availability, which is different than the traditional revenue stream based on energy and services delivery [18]. Earlier, Elia also used to have SDR, which were the strategic reserves used as a transition product while working out and implementing the CRM [16][17] [21] [22]. SDR were the strategic reserves Elia is responsible for to offset any structural generation shortage during winter months Right now, SDR is replaced by CRM.

For the 4 services, Elia has set up processes that need to be followed if FSPs at the transmission grid want to offer these products. These steps range from signing the general framework, to different prequalification processes, to bidding procedures and activation and billing requirements. In this chapter we discuss the regulation and implementation steps taken to adapt the existing processes for transmission grid connected resources to distribution grid connected (lower voltage) resources.

2.1. Belgian flexibility regulation and framework

2.1.1. Background

The **Clean Energy Package** highlighted the need for more flexibility coming from demand response, including from distributed generation and storage. More specifically, article 17 of the EMD requires non-discriminatory access for final consumers to all electricity markets (wholesale markets and ancillary services markets, but also to relieve congestion at transmission and at distribution levels, etc.). As a result, when transposing the EU-regulation, Member States specified regulation that incentivized grid operators to open up markets. For Belgium, as shown in Figure 2-1, there are multiple levels of this regulation and the implementation thereof. First of all, there is the federal regulation. The federal government is, among others, responsible for the regulation regarding the HV-electricity grids (voltage higher than 70 kV) [19]. The regulation on federal level is written down in the electricity law of the 29th of April 1999 [20]. On top of that, there is the Royal conclusion of the 22th of April 2019, which contains the techncial rules for the management of and access to the transmission grid of electricity [21]. The regulator responsible for the control of the transmission grid is the CREG. The CREG set up a behavioural code which, among others, contains conditions related to offering ancillary services [22]. In line with EU regulation, since October 2022, the federal law defines that each end-consumer has the right to valorise its flexibility [20, p. Art. 19bis]. The grid operator is responsible for the management of flexibility data which are needed for the valorisation of flexibility [20, p. Art. 19ter]. As a result, Elia, the Belgian TSO, is opening up its products to LV consumers (as discussed in more detail later in this chapter).

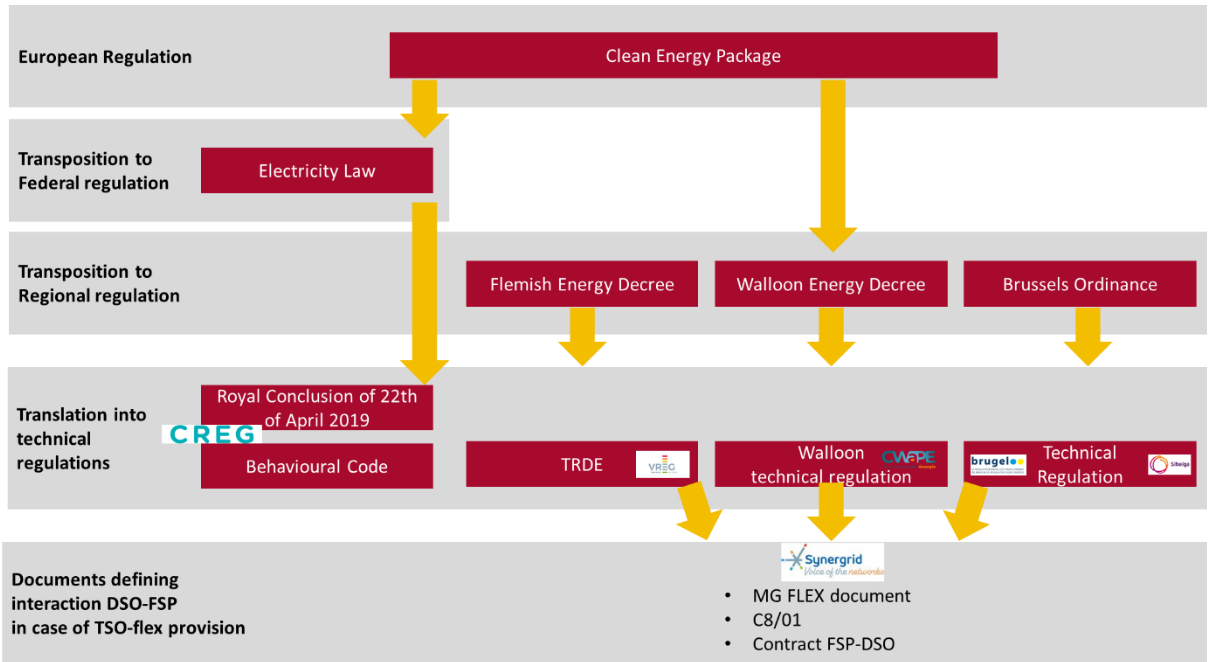

Figure 2-1: Overview regulation Belgium.

Furthermore, there are 3 different regions, which each also having their own **regional energy regulation**. For Flanders, this led to regulatory adaptations in the Energy Decree [23], for the Walloon region in the Walloon Energy Decree [24], and for Brussels in the Ordinance [25]. The regions are responsible for the distribution and local transport of electricity through grids with a nominal voltage of maximally 70 kV.

Following the regional regulations, the regional regulators (VREG for Flanders, CWaPE for the Walloon Region, and BRUGEL for the Brussels Capital Region) set up **technical regulations** which need to be followed by the system operators and other market actors. All these regulations contribute to requirements with which flexibility provision in the three Belgian regions need to be in line. This implies that system operators in each of the three regions had to set up functional requirements, procedures, contracts, etc., to ensure the implementation of the regulation was made possible. Given the fact that Belgium has three different regions and regulations, the system operators of the three regions collaborated through Synergrid (the Federation of all electricity- and gas network operators in Belgium). Synergrid, in name of all grid operators, organized consultation workshops and came up with **common documents** for the three regions: the MG FLEX document, the Synergrid technical regulations C8/01 and a model contract between the FSP and the DSO [26]. In Section 2.1.2 we will zoom in in more detail on these documents. However, it is to be pointed out that even though there have been significant efforts to harmonize the procedures over the three regions, there remain some differences between them due to regional differences in the regulation.

We refer the interested reader to Box 2.1 for more regulatory details. The box shows that all regions contain, for a large part, the same provisions, allowing Synergrid to work out common documents (the MG FLEX document, the Synergrid technical regulations C8/01 and a model contract between the FSP and the DSO). In Flanders, this is done explicitly by stating that the DSO is responsible for the implementation of the different rules, while in Brussels and Wallonia, the regulation points directly towards the documents (such as the Synergrid C8/01). In the remaining of the deliverable, we zoom into these final Synergrid documents, discussing all relevant elements for LV-flexibility and therefore implicitly also covering all important regulatory aspects.

Box 2.1: Regulatory provisions in the 3 Belgian regions

The Synergrid documents aim to cover the regulatory requirements of the three regions. As a result, the technical regulations in the different regions also refer to the Synergrid documents that have already been approved.

In **Brussels Capital Region**, the Ordinance **[25]** defines that any end customer has the right to offer flexibility services in a non-discriminatory manner in the electricity market **[25, p. Art. 26bis]**. Each end user has the right to do this through its supplier or an FSP of its choice. The competent authority should organize flexibility markets without prejudice to the technical requirements. Additionally, the system operator can prevent or limit flexibility activation, based on objective, transparent and non-discriminatory technical criteria **[25, p. Art. 26ter]**. However, if this is in violation of art26b, the end customer shall be compensated **[25, p. Art. 32 unsexies]**. Furthermore, technical regulations **[27]** of the Brussels Capital Region specify that all grid-connections need to follow Synergrid C2/112 and C1/107 and the additional regulations of the DSO **[27, p. Art. 3.18]**. The DSO can therefore define specific connection regulations depending on local characteristics of the grid. Furthermore, an FSP requires a contract with the DSO to provide flexibility services **[27, p. Art. 4.20 and 4.56]**. In addition, for new flexibility service points, the DSO can ask a grid study to examine the potential impact as specified in Synergrid C8/01.

In the **Walloon region** the Walloon Decree of May 2022 **[24]** specifies that it is up to the network managers to define all specifications for procured flexibility services. These specifications need to be approved by CWaPE. The technical regulations of CWaPE **[28]** specify the conditions for access to flexibility on the distribution grid **[28, p. Art. IV.26]**. Supply of flexibility services requires per access point a permit for flexibility services and a contract between the DSO and the supplier of flexibility services. It is also described how the DSO can restrict this flexibility and apply prequalification procedures for the delivery of flexibility by a specific access point **[28, p. Art. IV.36 and following]**. The rules that DSOs define for suppliers, suppliers of flexibility, grid users, and access holders are to be approved by CWaPE **[28, p. Art. I.22]**. Once approved, each request for access to flexibility therefore needs to follow the procedure requested by the DSO which is done through a specific form it has to foresee **[28, p. Art. IV.27]**. Each qualification of a flexibility access point is preceded by a grid study by the DSO to verify whether the supply of flexibility services does not cause constraints to its grid **[28, p. Art. IV.37]**. In the context of this study, the DSO also accounts for existing qualifications, risks at local level related to simultaneous behaviour of grid users and the recuperation of non-used or non-produced energy at later moments of time due to the activation of flexibility. The study is described in Synergrid regulations C8-01. It is also specified that prequalification lasts for a full year, but that the DSO is allowed to opt for a more dynamic prequalification procedure which takes into account grid constraints closer to real-time **[28, p. Art. IV.38]**. This procedure must be approved by CWaPE. The DSO, in case there are risks for operational security, must determine a procedure for the division of the available flexible volumes on its grid between the affected access points **[28, p. Art. IV.39]**. The DSO also maintains a flexibility register related to the access to flexibility **[28, p. Art. IV.40]**.

In **Flanders**, the energy decree **[23]** specifies commercial flexibility, reserved technical flexibility and unreserved technical flexibility. Everybody can offer flexibility according to non-discriminatory rules, without permission of other market stakeholders **[23, p. Art. 4.1.17/1]**. Flexibility can be offered individually or in an aggregated manner. Before access for flexibility services is possible, suppliers of flexibility need to sign an agreement with the SO of the grid in which they are connected. The SOs maintain a list with all flexibility service providers. The DSO is also responsible for the collection of all distribution grid data related to flexibility volumes, delivered flexibility per allocation or access point **[23, p. Art. 4.1.8/2]**. It also needs to manage a flexibility access and activation register. The VREG is responsible to set up the technical regulation (TRDE **[9]**) related to the responsibilities and rights of all the different market stakeholders and related to the management and access to the grid **[23, p. Art. 4.2.1]**. Division 7 of the TRDE specifies the market processes for flexibility on the distribution grid **[9, p. Art. 4.3.63]**. These market processes are determined through a consultation between the system operators, and the active market participants on the distribution grid (BRP, FSPs…). Furthermore, the DSO is responsible to communicate through its website transparently on all these processes and related documents. The DSOs are also required to publish on a yearly basis an evaluation report on the rules and to provide recommendations to VREG on possible improvements. The procedures should entail communication protocols and rules for the exchange of data between market parties, they should determine specific explanations related to data exchange between market parties specifically for flexibility on the low voltage distribution grid, they should specify what the methodology is related to the calculation of the flexibility volumes and reference curve (when applicable). As such the TRDE avoids repeating regulation and determination of procedures that it expects the DSOs to set up (through the Synergrid consultations). Finally, the VREG expects DSOs to set up uniform model contracts and regulations, technical requirements and procedures linked to the requirements in the TRDE **[9, p. Art. 1.2.4]**. All these documents need to be checked by VREG.

2.1.2. Regulation Transmission grid services by DSO-connected resources

In this section we zoom into the common regional documents set up by the DSOs and Synergrid, implementing the flexibility regulation. Indeed, one of the steps in opening up these markets for (LV-) distribution grid resources is that, in case FSPs at the distribution grid want to offer these services, additional processes related to the interaction between the DSO and the FSP need to be followed. These processes are also requested through the regulation discussed in the previous section. To establish these processes at the level of the distribution grid, Synergrid presented in January 2023 the “Synergrid Roadmap Flexibility”. The Roadmap is the result of Synergrid working groups and public consultations [29] and is presented to all regulators on the FORBEG (forum of all Belgian energy regulators). After this, a public consultation started in April 2023 in the context of the Product Design Group flexibility [29], after which on the 30th of June 2023 a first release of three documents was done for revision to all Belgian regulators.

- Document 1, the “Market Guide, MG FLEX” document serves to harmonize the activities of the Belgian DSOs, independent of the region in which they are active, for all available flexibility products of the different Flexibility Requesting Parties (FRPs). Nevertheless, the legal and regulatory framework is different in the three regions, implying that there might be some regionally different functional requirements. To cover this, where applicable, differences between the regions are indicated in the MG Flex document and will be highlighted below when relevant.

- Together with this document, a Document 2, a model contract between the DSO and the FSP is set up as well,
- and adaptations are made to a third Document, the technical regulations C8/01, which determines the procedure for qualification of installations of customers (e.g., regulation to follow when executing a Network Flexibility Study) for participation of the grid user to the flexibility services.

Synergrid submitted these three documents in name of Fluvius (Flemish DSO), SIBELGA (Brussels DSO) and ORES and RESA (Walloon DSOs) to the regulators of the different regions. BRUGEL approved the documents on the 22nd of August 2023, VREG approved the document after modifications on the 21st of March 2024 and CWaPE rejected them on the 22nd of September 2023, requesting modifications of the documents [30]. In the MG FLEX document, all the processes which are needed to offer a specific flexibility product to the TSO through a distribution-grid connected resource are detailed. In total, 5 types of processes are described:

- STRUCTURE, containing all activities linked to the collection and exchange of data needed in later processes. It entails, among others, prequalification processes to verify whether an FSP fulfils all requirements to offer a service;
- OPERATE, specifying all communication requirements related to the operation of a flexibility market;
- MEASURE, specifying all activities linked to reading, analysing and sharing FSP-data linked to a specific flexibility product;
- SETTLE, specifying all activities related to the allocation of flexibility volumes to market participants;
- BILLING, capturing all steps linked to invoicing between the DSO and the FSP related to flexibility.

In this deliverable we focus specifically on the grid prequalification steps required by distribution grid connected FSPs, delivering services to the TSO. In the next section, we therefore zoom into prequalification activities and requirements.

2.2. Prequalification for Transmission Grid Services

In general, FSPs willing to deliver flexibility services to a system operator need to comply with a number of requirements. Different types of requirements are in place to ensure an FSP can indeed deliver the requested service without violating grid constraints. In order to verify compliance with these requirements, generally three different types of prequalification exist: market-, product- and grid prequalification (see Section 1.2).

Table 2-1 gives an overview of all the products that Elia requests together with the prequalification processes per product. As indicated, only 3 of those services are open (FCR, aFRR and CRM) for LV flexibility provision (note that aFRR and CRM were opened only recently: since May 2024 [26]). An X in the table implies that a specific prequalification step is needed for MV and LV, unless there is a footnote stating exceptions. Each type of prequalification consists of a number of processes as indicated in the table below. However, there are differences between the products on how these processes are fulfilled. In the following sections, we zoom in on the steps needed for grid prequalification.

Table 2-1: Prequalification and processes per Elia product (replicated from market guide flexibility [26])

	FCR	aFRR	mFRR	CRM
Resources connected to				

HV/MV grid	X	X	X	X
LV grid	X	X		X
Market prequalification				
Agree to Terms and Conditions FSP	X	X	X	
DSO (grid) prequalification				
Sign FSP-DSO contract	X	X	X	X[1]
Contract Connection Check[2]	X	X	X	X[3]
Net Flex Study[4]		X	X	X[5]
Identification Delivery Point[6]	X	X	X	X
Set up ex-post data exchange			X	X
Set up real-time data exchange[7]		X		
Product prequalification				
Sign FSP-FRP contract	X	X	X	X
Start new service	X	X	X	X
Update service	X	X	X	X
Stop service	X	X	X	X
Determine Nominal Reference Power				X
Prequalification check and test by FRP	X	X	X	X
Baseline check by FRP		X		

2.2.1. Grid prequalification

Generally, to date, grid prequalification is often done in a static way, using upfront static rules for categories of assets, leading to criteria that do not necessarily link properly to grid reality [7]. In case of increasing LV participation in the coming years, this static prequalification can lead to a blocking of flexibility for longer time periods and larger volumes than required, which would result in grid reinforcements to accommodate higher loads or to limiting grid access. With increased grid visibility in the LV grids, alternative tools such as non-firm grid capacities, dynamic prequalification, flexible connections, tariffs, and technical rules could be used to reduce capacity margins [7]. All the later alternatives require a form of grid constraint analysis which identifies potential grid constraints closer to real-time. In the example of dynamic prequalification, this would imply that the DSO identifies ex-ante possible congestion constraints. Only in that case, flexibility activation will be limited instead of permanently blocked (as would be the case with static prequalification). Note that in the future, if grid constraints are integrated properly in the procurement phase, grid prequalification might become obsolete [7].

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[1] Not needed when Fast Track scenario is used (CRM exit-door). The Fast Track process is set-up to speed up the activation process of specific services to facilitate market access. This implies that some documents which are usually required (such as a NFS) are adapted.
[2] Only applicable for voltage >1 kV, not below 1 kV.
[3] Not needed when Fast Track scenario is used (CRM exit-door) or in case of Additional non-existing Delivery point.
[4] For region Flanders: as stated in TRDE [7, p. Art. 2.3.26]: in case of LV, flexible power will not be restricted when it is limited to 5 kVA for a mono phase connection or 10 kVA for three phase connection.
[5] Not needed when Fast Track scenario is used (CRM exit-door) or in case of Additional non-existing Delivery point. When the delivery point becomes existing, NFS is required.
[6] For LV, no separate request is needed: the identification used will always be the identification of the delivery point linked with the headmeter of the connection point.
[7] Today the DSOs and the Flexhub are not involved in the real-time data exchange for FCR.

As a result, the question is whether LV grid constraints can be embedded in the current and emerging Belgian flexibility market designs and mechanisms (e.g., for balancing services, congestion management, etc.), allowing the grid-safe provision of LV flexibility to those markets. In order to examine this, we start this section with an evaluation of the current grid prequalification methods and market designs in Belgium.

FSP-DSO contract
As shown in Section 2.1 when discussing the regulation regarding flexibility provision, a contract between the FSP and the DSO is required before one can continue with the other process steps. The contract describes the rights and obligations of both the DSO and the FSP with respect to the usage of flexibility of distribution grid users connected to the grid of the DSO. In the MG FLEX document, it is described that signing this contract by the DSO cannot take longer than 10 working days, limiting the time needed for this process step [26]. In the Walloon area, the step is slightly more complicated as the FSP needs a regional permit before it can offer flexibility services. Note that a model contract between the FSP-DSO has been approved by all regulators (see Section 2.1).

Contract connection check
Through a contract connection check, the FSP is notified about the information in the connection contract which might be important for flexibility products. This request can be done by the FSP (or grid user). For LV (lower than 1 kV), this step is not needed as the connection regulations[8] apply to them. An additional check is therefore not needed. In total, if a valid request for information is filed, the DSO should send the connection contract check within 15 days. Note that the Contract Connection Check is a condition for the Network Flexibility Study.

Network Flexibility Study
One of the key differences between the different products is the requirement of a Network Flexibility Study. An NFS is a study to verify whether flexibility activation would have an impact on the functioning of the distribution grid (for instance, causing congestion, negatively affecting the reliability and stability of the grid, causing problems linked to power quality, etc.). Based on the outcome of the NFS, a DSO can decide to limit or reject the provision of flexibility services for certain Connection Points to ensure that operational security limitations of the grid will be respected.

The qualification criteria and the procedure to be completed for an NFS are defined in the Synergrid C8-01 regulation [26]. Through this process, it is verified whether a grid user can participate in the provision of specific flexibility products through an FSP [31]. For each candidate flexibility provider, the grid operator completes analyses and calculations using simulations to indicate in which zones there could be potential problems. Green implies no risks for operational issues, indicating that all flexibility activations are allowed to take place. Red implies that there is a risk for operational security issues, indicating that activation of flexibility will be limited. In Flanders and in the Walloon region, the grid user needs to request this study to the DSO. In Brussels, only the FSP can do so [32]. An NFS takes in total 30 days. However, after this period, the DSO can always reevaluate the prequalified capacity in case there is an increased risk in the specific zone. FEBEG regrets the different approach in the various regions in general, as it makes it burdensome and complicated for market parties to manage [33]. Data required from the FSP to complete an NFS are described in the technical regulation C8-01 (for more information see Box 2.2). There are, however, exemptions for LV. The general rule is that the DSO has the right to add constraints for LV via the previously described NFS-procedure. However, this does not apply in the region of Flanders where, as stated in the TRDE [9, p. Art. 2.3.26], in case of LV, flexible

[8] The connection regulations are specified per DSO and are published on their website. The rules of Fluvius can for instance be found here: [91].

power will not be restricted when it is limited to 5 kVA for a mono phase connection or 10 kVA for three phase connection. In other cases, LV-connected resources do need an NFS, implying that they also need to provide the information in Box 2. However, note that in case the voltage level is less than or equal to 1kV, all the information requested in Box 2 can be added to the request for the start of a new flexibility service.

In case a new flexibility provider enters a specific zone, turning a zone from green to red, the users in this zone continue to be qualified for 12 months. For providers that submit a new request, specific constraints can be given.

In case the DSO re-evaluates a specific capacity through a new NFS (for instance when there is an increased risk in a specific zone), the prequalified capacity can only be lowered 12 months after this conclusion (with the exception of multi-year contracts). Furthermore, VREG points out that DSOs, according to the TRDE [9, p. Art. 1.5.3], always have the right to take exceptional and temporary measures in case there is an emergency situation to ensure the safety of the grid. However, VREG indicates that congestion is not an emergency situation and that it is part of the operational management of the grid (in line with the definition of the European Regulation 2019/943 [34]). Congestion, therefore, does not provide the right to the DSO to limit flexibility as the current regulatory framework gives the DSO the possibility to procure flexibility for local congestion management. The VREG emphasizes that the DSO needs to apply this regulatory framework [35].

Box 2.2: Network Flexibility Study (replicated from [36])

An FSP connected to a voltage level >1kV, when requesting a qualification, and thus a network flexibility study, needs to provide the following information to the DSO.

1. General information regarding the connection point:
- Offtake EAN (European Article Numbering) and, if applicable, injection EAN.
- Name of the grid user and address of the grid connection point.
- Number of the transformer (if known to the applicant) of the connection point. This information is usually indicated on the information plate on the door of the relevant cabin.

2. Information on the achievement of flexibility:
- Type of modulation:
o reduction of consumption
o increase of consumption
o reduction of production
o increase of production
o operation in island via a local electricity production
- Activatable power (kW)
- Possible hourly regulation of activation: indicating whether, from the point of view of the DSO, the flexibility 24h/24 7 days out of 7 can be used. In the opposite case, this indicates when the flexibility is actually available, for example: only during working days, from 8h to 18h, from January to May.

3. Information on energy recovery:
This information allows the DSO to evaluate any rebound effect on its grid:
- Type of recovery: specifies whether the energy not taken during the activation period is recovered at a later time. In the opposite case, i.e., if there is no displacement of the load, the other data of this paragraph do not need to be completed.

- Period of energy recovery: the requested information is to know after how much time the unused energy will have to be recovered. For example: the switched off energy will be recovered at t+4h after the activation of the flexibility.
- Duration and extent of energy recovery: maximum power and time duration of displacement of the load.

Via the Flex Hub Portal or via API (request for qualification of a connection point connected to the distribution network with voltage <= 1 kV), the applicant provides, in particular, the following data to the DSO. If the applicant is the distribution grid user itself, this can also be done by mail.
1. General information regarding the connection point:
- EAN
2. Information regarding the achievement of flexibility:
- Activatable power (kW) if known
- Requested flexible power (kW)
3. Information regarding the recovery of energy
Not applicable

Identification delivery point
It is indispensable that it is defined through which delivery point flexibility is provided. However, this separate identification of the delivery point is not needed if it is connected through the main meter of the connection point. For LV, the identification of the delivery point is always connected to the main meter of the connection point. Therefore, for LV, no separate request is needed. For flexibility services that are requested through the FlexHub, this process is done through the platform (the platforms are discussed under the next point).

Data exchange
Before proper prequalification (and other market processes can take place), proper data sharing between all market parties is important. In Belgium, there are multiple platforms to share and store energy data. In what follows, we give a brief overview of the existing models. However, it should be pointed out that there are still upcoming changes to further improve and link these models.

Broadly speaking, there are two core types of platforms: the Atrias Central platform, and the RTCP and Flexhub platform. ATRIAS was set up as a joint initiative by Belgium's largest distribution grid operators being Eandis and Infrax (now Fluvius), Sibelga, Ores and Resa [37]. The Atrias central data platform is developed to communicate consumer measurement data, technical information from their meter and relational information (e.g., supplier contract). The role of Atrias is literally to be a market facilitator [37] and to store data. The platform is developed in response to the roll-out of the digital meters, to, for instance, facilitate all data exchanges on the energy market (implying that energy consumers would be able to switch energy supplier more easily), follow their energy consumption in real-time, etc. In the past, there were different clearing houses[9], each with different data handling procedures. With Atrias, one central data system would be developed. Together with Atrias, a new central Market Implementation Guide was introduced (MIG 6) [38]. This market model was needed to support the efficient development of the related IT-processes [39]. The implementation of and the transition towards the new Atrias platform, was, however, not an easy one [40] and was only finalized in 2021.

[9] On the energy markets, many data are being exchanged (between energy suppliers and consumers, with the DSO, or with other potential third parties). All these data are transferred to a data system, the so called "clearing house". The clearing house ensures data are being transferred between the different parties. In the past, in Belgium, there were multiple clearing houses which are now bundled in one platform: Atrias.

The RTCP (Real-Time Communication Platform) and Flexhub platform are platforms that enable data flows for the measurement and validation of a number of services in the energy market. The Flexhub is an application that stores and structures flexibility related data [41]. More specifically, the FlexHub-platform was launched in 2018. This is a central IT-platform, developed by the largest Belgian grid operators (Eandis, Infrax, Ores, Resa and Sibelga, and the TSO Elia, with the participation of the DSOs AIEG, AIESH and Regie De Wavre). The data hub contains all required data needed to valorise flexibility [42]. It is therefore also called the Flexibility activation register. The idea of the FlexHub-platform was to build, implement and maintain an environment that contained a flexibility register, a flexibility activation register, a flexibility measurement register, etc. The platform needed to be accessible by multiple market stakeholders and system operators needed to be able to verify, check, adapt and export all data. Today, it is the only platform in Belgium for flexibility management [43]. The Flexhub[10] allows FSPs to consult and manage their Service Delivery Points Flex [44]. All Belgian grid operators work together on this central IT-system (data hub). Furthermore, the FlexHub-platform allows integration with existing applications such as existing back-ends with the system operators, back-ends with external market parties (such as suppliers, FSPs…) and real-time communication platforms (RTCP) [45]. The RTCP[11] is a platform that enables a secure exchange of real-time data between the assets of Grid Users and applications of Application Service Providers (e.g., the FSPs) [44]. More specifically, in the new aFRR design, the RTCP is used as a gateway to the FlexHub [46]. The results of this platform can, however, be requested by the FlexHub so both platforms are linked. However, as indicated above, not all platforms or data streams are well integrated as today, the DSOs and the Flexhub are not involved in the real-time data exchange for FCR. Only for mFRR and aFRR, a number of process steps are performed on the FlexHub [47]. The RTCP platform is, in summary, a flexibility registration register.

Furthermore, the integration and coordination between all models are not yet on point. For instance, there still occur manual interactions between the FlexHub and the central data platform [47]. Data handling on all platforms is performed according to European Data and GDPR regulation.

Latest steps regarding access for LV-flexibility

From Table 2-1, it became evident that there are differences between the services including the processes for each of these services. For DSO grid-prequalification, it can be seen that there are 6 process steps as indicated in Table 2-1. For FCR, quite some exemptions on these steps already exist for LV. Ex-post and real-time data exchange are not needed, and a network flexibility study is also not required. For all products, a Contract Connection Check is also not required for voltage levels below 1 kV, facilitating flexibility provision by lower voltage levels. For the identification of the delivery point, for LV, no separate request is needed: the identification used will always be the identification of the delivery point linked with the head meter of the connection point.

Since the 16th of May 2024, LV can participate in aFRR, CRM and FCR-markets. The plan is also to open up the mFRR market as soon as possible. aFRR and CRM are only opened up recently while FCR was already open. The speeding up of this process has started in the context of the European energy crises. Due to this, there was an increasing need for available flexibility resources on the distribution grid. As a result, in February 2023, during a Synergrid consultation workshop, the idea of a FastTrack for aFRR and CRM on LV was proposed. The purpose was to open on short notice the product aFRR and CRM for LV Customers in order to activate more kWh on the flexibility market. LV-consumers would be able to participate at all CRM-auctions (A-4 years). In case of an energy crisis, this could lead to more contribution of flexibility. The solution was proposed as a temporary solution in line with the ongoing energy crisis at the time and was targeted to remain for 2 years [48]. To ensure this was possible,

[10] The platform is web-based and can be accessed via [92].
[11] The platform is web-based and can be accessed via [93].

documents which are currently in place for LV (model agreement DSO-FSP, and the regulation C8/01 with regard to the NFS) had to be adapted for aFRR and CRM where needed.

The latest releases of the documents (Doc Release 2) contain provisions for the opening up of aFRR and CRM to Low Voltage resources. This implies among others:

- A simplified NFS-procedure
- Relaxed metering requirements
- Capabilities of grouping and pooling via LV Delivery Point Groups
- Automated Onboarding process for LV (= fast track)

The changes are only in place once the regulators have accepted and approved all documents. It is emphasized by Synergrid that the currently proposed “Fast Track aFRR LV” is only a temporary solution until the 31st of December 2025 to ensure the unlocking of the LV-flexibility potential in the short-run. This would allow all parties to gain further experience, which will allow shaping the final rules [49]. A similar discussion is finalized for a Fast Track Prequalification process for CRM. This is a process to be followed by a CRM Candidate that has the legal obligation to submit prequalification files according to the Electricity Law, article 7undecies, §8, irrespective of their participation goals [50]. For CRM, there are therefore three different prequalification tracks: standard, specific and fast-track [51]. Market parties emphasize that mFRR markets should also be opened up as soon as possible for LV. This will, however, only be part of document release 3 [49].

Finally, beyond the exemptions given with respect to the NFS, different stakeholders are further questioning the way the NFS is done as it is done only once for a longer period of time. Stakeholders are requesting a more dynamic approach [52] to avoid the pre-emptive capping of flexibility. This, however, highly depends, among others, on available data.

2.2.2. Product prequalification

Next to grid prequalification, product and market prequalification are needed. The system services product requirements are set up by Elia, the Belgian TSO. As indicated in the previous sections, Elia is opening up its markets for LV-flexibility resources. Recently, the aFRR and CRM markets have been opened. The FCR market is already open for a longer time, and all other markets are not yet open for LV-flexibility connected resources.

Nevertheless, product prequalification, in particular, has been discussed frequently with respect to its impact on LV-flexibility provision. Before LV-flexibility can indeed participate in flexibility markets, it is indispensable that product requirements are not discriminating or blocking LV-flexibility assets. In order to achieve this, it is important to consider that, in the future, DSOs might also procure products to resolve certain grid needs. In case DSOs define flexibility products, it would be beneficial to search for synergies between the DSO and TSO products. It is, therefore, important that both system operators coordinate their decisions. In the work towards an integrated market design, product requirements coordination should take all these aspects into account.

In Alexander D3.3, to be released after the current document, we also consider that DSOs, next to the TSO, are interested procuring grid services. A discussion on how products need to be adapted to answer the needs of both system operators, is therefore kept for D3.3.

2.3. Network Code Demand Side Flexibility

Even though we focus on Belgium, it is interesting to look into other examples. More specifically, it is to be pointed out that the preparation of a network code on demand side flexibility at the EU level is in advanced stages. This draft network code [53] specifies in art. 10.2(b) that it is in favour of simplified product prequalification processes, potentially even replacing product prequalification by ex-post verification for some services. For grid prequalification, it specifies that the Member States/Regions remain responsible for developing a procedure for grid prequalification as long as this procedure follows the principles as described in paragraph 4 of article 75 [53]. The procedure needs to ensure that the delivery of flexibility services does not compromise the safe operation of the connecting/intermediate grid(s). For grid prequalification, the draft network code points to conditional or long-term grid prequalification and dynamic or short-term grid prequalification.

Box 2.3 Art 75 of the draft network code

1. A procedure for grid prequalification shall be developed as part of the national terms and conditions pursuant to Article 69 (National implementation and condition for coordination) in accordance with Article 182 of Regulation (EU) 2017/1485.
2. Such a procedure shall ensure that the delivery of the balancing or congestion management and voltage control services by SPU/SPG does not compromise the safe operation of the connecting grid and, when applicable, of the intermediate grids.
3. Grid prequalification shall be performed by the grid prequalification responsible and, where applicable, this process shall also be coordinated with the intermediate system operator/s. The grid prequalification responsible shall be the connecting system operator.
4. The grid prequalification procedure shall follow the next principles:
(a) the connecting and intermediate system operators can specify limits when an activation might lead to not fulfilling the grid operational limits and procedures defined at national level. This shall be based on the foreseen status of the grid;
(b) the connecting and intermediate system operators shall minimize these limits, based on the implementation of network reconfigurations and the available data for each case;
(c) the data exchange during the grid prequalification procedure shall guarantee the protection of confidential information of all the involved parties; and
(d) the grid prequalification process shall be conducted with transparency.
5. The grid prequalification procedure shall result in a grid prequalification status that is:
(a) approved if the SPU/SPG can deliver the full capacity of the prequalified congestion management or voltage control service; or
(b) not approved if the SPU/SPG cannot deliver the congestion management or voltage control service; or
(c) conditionally prequalified if the grid prequalifying responsible set some limits on the time or quantity for delivery of the congestion management or voltage control service. The list of criteria for conditional grid prequalification shall be defined at national level.
6. Where grid prequalification status is not approved or conditionally prequalified, the grid prequalifying responsible shall argue, why the issue cannot be sufficiently tackled with setting temporary limits in a short-term procedure, according to Article 74 (Short-term procedures to account for DSO limits).
7. When performing a grid prequalification, the system operators may consider its own grid in one or more scenarios, i.e., assuming one or more infrastructure configurations and one or more set(s) of power flow profiles from/to SPG and distribution or transmission grids directly connected.
8. Once a grid prequalification has a status defined in the paragraph 3, the connecting or the intermediate system operator may update in line with Article 43 (CU (Centralized Unit) module procedures) this status or set new limits in coordination with the procuring system operator considering the network or system evolution.

9. Grid prequalifying responsible shall report to the NRA (National Regulatory Authority), at least yearly the reasons for the limitations referred to in this Article.

2.4. Summary and discussions

On our scale of different prequalification options (see Figure 1-4), Belgium is situated on the left side, where prequalification either does not take place, and when it does, it is performed long before the activation of flexibility through a Network Flexibility Study (NFS). The general rules in all three Belgian regions are that DSO grid prequalification is performed through an NFS which is completed by the DSO ex-ante to the start of the flexibility provision. Only prequalified FSP resources can submit offers to the TSO, and the DSO is further not involved in the TSO procurement process. The disadvantage of this mechanism that when LV-flexibility potential becomes more available, it might be blocked by the DSO for a longer period of time, as the result of the NFS remains valid for multiple months. Furthermore, it is argued that the NFS is a burden for LV-flexibility assets. It is claimed that it is a barrier for the role-out of LV-flexibility [7] [84]. As a result, there are two types of discussions currently ongoing in Belgium:

- On the one hand, actions have been taken to give exemptions to LV. As a result, in Flanders, in case of LV, flexible power will not be restricted when it is limited to 5 kVA for a mono phase connection or 10 kVA for three phase connection. Furthermore, depending on the product offered, an NFS is also not required (for instance in case of FCR). In other circumstances, the DSO has the right to add constraints for LV flexibility via the previously described NFS-procedure.
- On the other hand, there are discussions in Belgium to move from static prequalification towards dynamic prequalification [52]. This is a process that is influenced by data availability and coordination between system operators. However, it is also influenced by how such method would be implemented in practice. In the following chapter, we investigate different dynamic prequalification methods, and we compare them with other alternatives.

Figure 2-2 provides an overview of the models applied in Belgium.

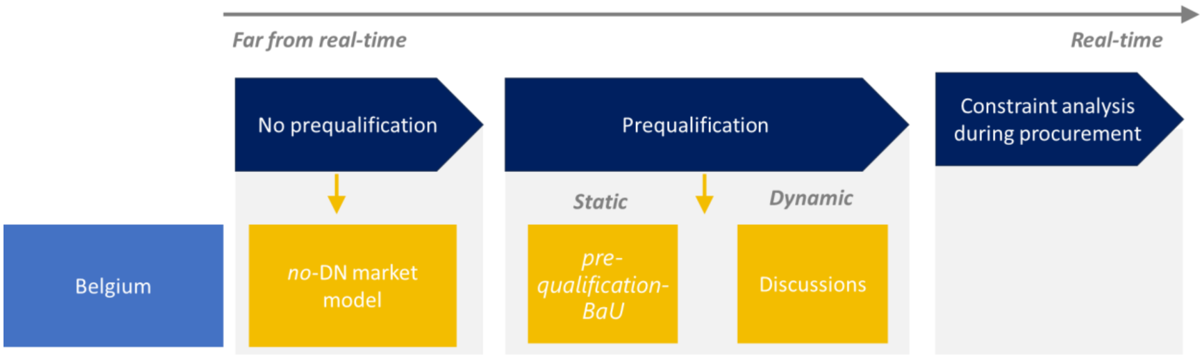

Figure 2-2: Belgian prequalification practices.

3. Grid-safe Provision of Low Voltage Flexibility

To unlock the LV flexibility while guaranteeing the operational security of the DN, we design a consumer-centric solution for the dynamic inclusion of distribution grid constraints in the process of flexibility activation for system services (e.g., balancing). We assess different options, based on operating envelopes (OEs) [54], to dynamically express the grid constraints and include them in the overall process of flexibility procurement and activation. As such, the following research question is answered in this chapter: **2) how flexibility markets for TSO-level system services (e.g., balancing) can dynamically express the constraints from distribution grids in the market procurement and activation processes to allow for the safe provision of flexibility from distributed-connected resources?** To answer to this question, one research direction is followed: **1) prequalification model for distributed-connected resources embedded in the TSO-level market design.** The prequalification of DERs is proposed to define the available flexibility capacity if there are grid threads (e.g., voltage violations, congestions), and its results are (directly or indirectly) embedded in the market procurement phase.

To place the work of this chapter within the scope of the deliverable, we copy here one of the figures of the Introduction (Chapter 1) containing all models analysed in this document: Figure 3-1. In this chapter, we propose a dynamic prequalification model with operating envelopes (*with-OEs* model in the figure). The idea is to have a more accurate prequalification process, while unlocking as much flexibility as possible subject to the distribution system constraints. We extend available prequalification processes in Belgium (e.g., based on NFS) which are more static and can block flexibility for a longer period of time. In this chapter, we also compare the prequalification *with-OE* model with two market models: the *no-DN* model in which no prequalification of distributed-connected resources is performed (which is another model implemented in Belgium for LV flexibility), and the theoretical *full-DN* model, in which the grid constraints are embedded in the market procurement phase.

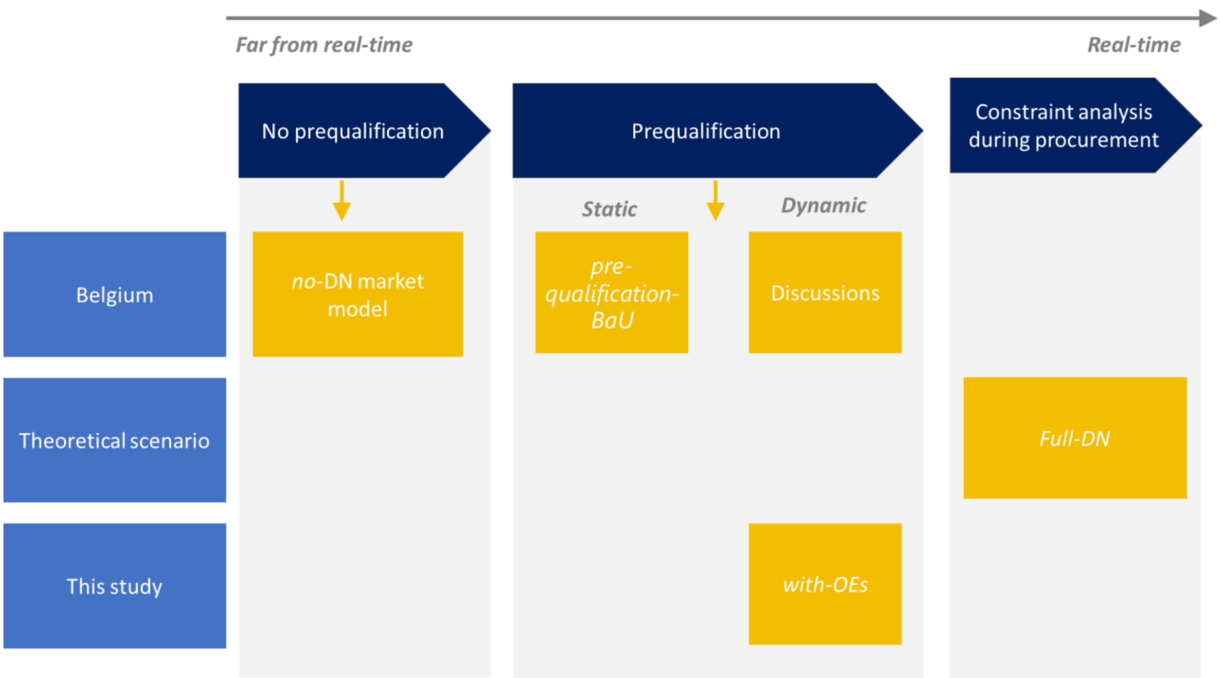

Figure 3-1: Models analysed in this deliverable.

3.1. Methodology

The outlined research direction and the *with-OE* market model proposed in this deliverable are illustrated by the market process depicted in Figure 3-2.

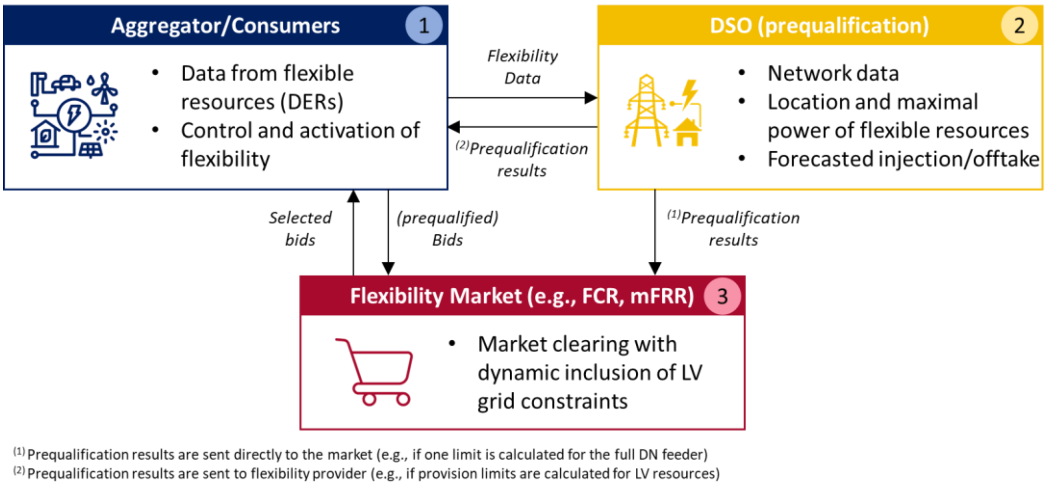

Figure 3-2: Prequalification of low-voltage resources methodology for the grid-safe provision of such flexibility to system services.

Low-voltage prosumers/consumers (FSPs)[12] who are interested in engaging in flexibility markets, either individually or as a group, provide their details to the DSO for grid prequalification. This information includes the maximum power capacity and direction of their flexibility resources, as well as their connection point and forecasted injection/offtake, if not already known by the DSO (e.g., connection points and smart meter data might be available to the DSO). Although this step is part of the theoretical formulation of the market design with grid prequalification we propose, we note that it is already in place in Belgium. As discussed in Section 2.2.1, LV-flexibility providers must perform a Network Flexibility Study (NFS) before starting the provision of flexibility to the TSO-level markets. As such, similar type of information is submitted to the DSO by the distribution connected FSP willing to engage in flexibility provision, e.g., offtake EAN and injection EAN, address of the connection point, expected flexibility modulation, information on energy recovery, etc. This proves that what we propose is aligned with DSOs procedures, and we show, in Chapter 5, what are the specific advancements our proposition delivers.

Subsequently, the DSO assesses the eligibility of these resources connected to its network, utilizing data from the FSPs, its own network data, and forecasted injection/offtake at various connection points. To address this stage, we propose diverse prequalification methods based on operating envelopes, which serve as a representation of the dynamic grid constraints of the system. Eventually, the prequalification outcomes are forwarded either to the flexibility market (option (1)) or back to the FSPs (option (2)). In the first option, the determined limits are integrated into the market clearing process to safeguard the distribution network from any adverse impacts. Conversely, in the second option, the calculated limits are communicated to the FSPs, prompting them to adjust the quantity of their bids when participating in the flexibility market. In both options, the procurement process for the flexibility market takes into account the distribution network (DN) limits determined by the OEs. We note that this step (prequalification using OEs) can be compared to the static NFS applied in Belgium for distribution connected FSPs. In the NFS, the results are submitted directly to the FSP, which means

[12] Considering that the focus of this deliverable is on low voltage prosumers/consumers participating in flexibility markets, either individually or aggregated, we use the words prosumers, consumers and FSPs interchangeably.

that option (2) is applied. However, in our proposition, the idea is to have a dynamic prequalification of resources/bids in order to avoid blocking large amounts of flexibility for a long duration of time.

Figure 3-3 offers a comprehensive overview of the multiple prequalification methods under investigation, alongside the benchmark models used for comparison, and the types of results analysed.

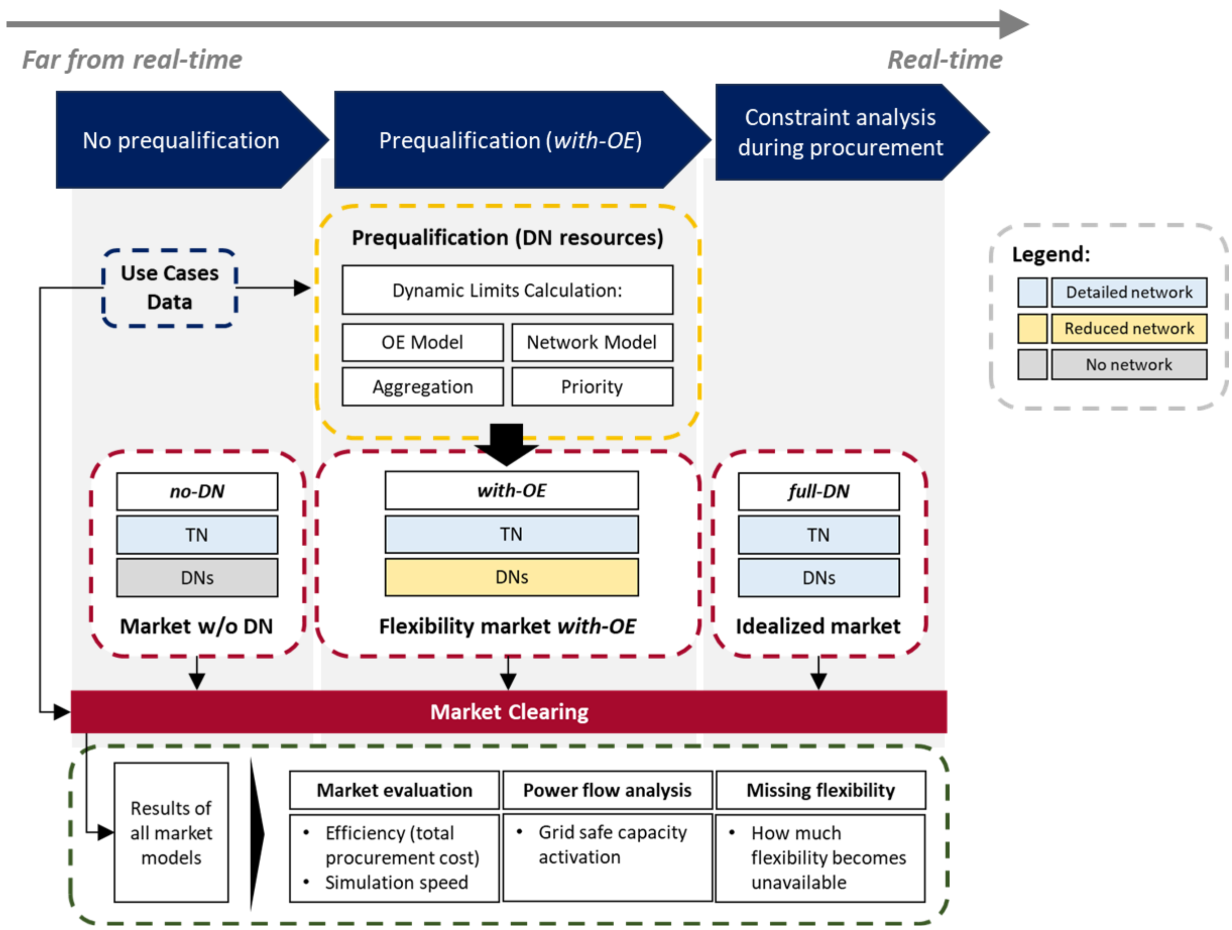

Figure 3-3: Prequalification methodology and its variations, along with a comparison with alternative practices, such as no distribution network represented in the market clearing (left), full distribution network represented in the market clearing (right).

On the left side, the flexibility market without considering the distribution network procurement is depicted, where DN constraints are omitted from the clearing process. This benchmark model is denoted as *no-DN*. For instance, as illustrated in Section 2.2, in FCR markets in Belgium, no grid prequalification is needed. Furthermore, low voltage flexibility assets are also not required to undergo grid prequalification in case they have a 5 kVA mono phase connection or 10 kVA three phase connection. As such, the grid constraints of the associated distribution network are not represented in the market clearing process. Although sometimes deployed in TSO-level flexibility markets, the *no-DN* model can potentially result in grid violations when activating medium to low-voltage (LV) flexibility, particularly in instances where the distribution system experiences high load/generation [10].

On the right side of Figure 3-3, the opposite model is showcased, where DN constraints are incorporated in the market clearing process (denoted as *full-DN*). Notably, this market design was proposed by the H2020 CoordiNet [8], its high efficiency was proved by the authors of [11], and it was applied in the Northern Demonstrator of the H2020 OneNet project [13].[13] While it can be perceived as an "idealized market" in terms of grid safety and efficiency, integrating distribution system constraints into the TSO-level market formulation would require sharing potentially confidential data from DSOs with other SOs or third-party market operators (MOs), which could encounter operational and regulatory hurdles [11] [12].

The proposed flexibility market with prequalification methods (referred as *with-OEs*), depicted in the middle part of Figure 3-3, addresses the limitations of both extreme models: it considers grid constraints in the process of flexibility provision from low voltage assets while not sharing the DSOs data with other market-related entities. In a first stage, the LV resources are dynamically prequalified (limited), using operating envelopes and the DN status. More specifically, the OEs are the feasible ranges in which the resources may operate [55] without jeopardizing the DN to which it is connected. This feasible range is calculated by solving at least one optimization problem, depending on which calculation method is applied. In general, the method aims to maximize the allowable amount of each flexibility resource that is safe for the distribution system, thus considering the DN grid constraints [56]. Multiple prequalification methods are tested by varying the:

- OE model: the calculation method applied. We study the two-step approach [57] and one-step approach [56]. In the former, the limits for upward and downward resources are computed separately through two optimization problems, each with a linear objective function. In the latter, these limits are determined within a single optimization problem utilizing a quadratic objective function. In both approaches, network constraints are accounted for, using one of the three network models discussed next.
- Network model: the power flow equations to represent the distribution system. We study the Power Transfer Distribution Factor (PTDF) [11], the Linearized Branch Flow (LinDistFlow) [58], and the Second-Order Cone Programming (SOCP) [58].
- Aggregation/grouping level: how the OE limits are aggregated. We study *per resource, per FSP,* and *per DN* [10]. In the first, each resource is individually limited, thus its bid quantity must be within the OE calculated range. In the second, an FSP can have multiple resources connected around the network, which are limited as a group, thus the sum of its resources must be in the OE calculated range. In the last, all resources in the distribution system are limited as one group, thus the sum of all resources quantities in that network must be in the OE calculated range.
- Priority weight: how the OE limits are divided between the multiple resources willing to provide flexibility. We study the *equal-based, price-based,* and *quantity-based* weights [55]. In the first, all resources/FSPs can be equally limited, thus no priority is given. In the second, resources/FSPs with cheaper prices are prioritised, thus are less limited. In the last, resources/FSPs with the largest quantity are prioritized.

In a second stage, the calculated OEs are included in the flexibility market model to guarantee the grid-safety procurement of resources from the DN. As already discussed, those limits are directly included in the market clearing algorithm – option (1) of Figure 3-2, or informed back to FSPs so they can limit their bids – option (2) of Figure 3-2. As such, the DN is partially represented in the market through this "reduced network" calculated as the OEs.

[13] We note that most of the projects/demonstrators presented here which applied a *full-DN* model focused on MV flexibility from the distribution networks [94]. Our focus is on analysing the potential of the different market designs in the LV grid levels as well, and the challenges to implement such models to the grid safe provision of LV flexibility.

In order to compare the three markets, we always consider that each FSP makes a price-quantity bid per resource it owns. Specifically in the case of the *with-OE* proposition, those bids are then limited by the calculated OEs following the chosen aggregation/grouping level (e.g., if the *per FSP* aggregation is chosen, the sum of the quantities of all resources/bids of this FSP is subjected to the OE limits, but not the individual ones).

The results of the three types of flexibility market models (*no-DN, with-OE, full-DN*) are then compared in terms of:

- Market evaluation: via the total procurement cost and the speed of the simulation (reflecting problem complexity). To normalize the first with respect to the results of the "idealized market" (*full-DN*), we divide the difference between the total cost of the flexibility market and the *full-DN* market by the absolute value of the total cost of the *full-DN*. This metric is denoted as *market (in)efficiency*, with mathematical symbol η. For instance, if the procurement cost of the *no-DN* is €80, of the *with-OE* is €110 and of the *full-DN* is €100, then $\eta = -20\%$, $\eta = 10\%$, and $\eta = 0\%$, respectively.
- Power flow analysis: via the calculation of the number of DN grid violations (congestions and voltage violations) when activating the selected flexibility of the market models. A power flow calculation is performed considering the grid status and the activation of the cleared flexibility. Any of the three network models can be used in this grid-check step, not necessarily the same used in the calculation of the OEs, and/or in the clearing of the *full-DN* market model. The number of grid violations, either related to line flows or voltage values, is counted.
- Missing flexibility: via unqualified flexibility metric. It is the total amount of flexibility quantity that is excluded from the market as a result of the OE constraints. For instance, if the upward flexibility available for the market was 2.5 MW, and the OE calculation limited it to 1.5 MW, then the unqualified flexibility is 40%. Downward and upward metrics are calculated separately. <u>This metric is only available for the *with-OE* models</u>.

To analyse and compare the performance of the different prequalification methods in the flexibility market procurement, also with respect to the benchmark market models, we propose a Monte Carlo-based methodology, depicted in Figure 3-4.

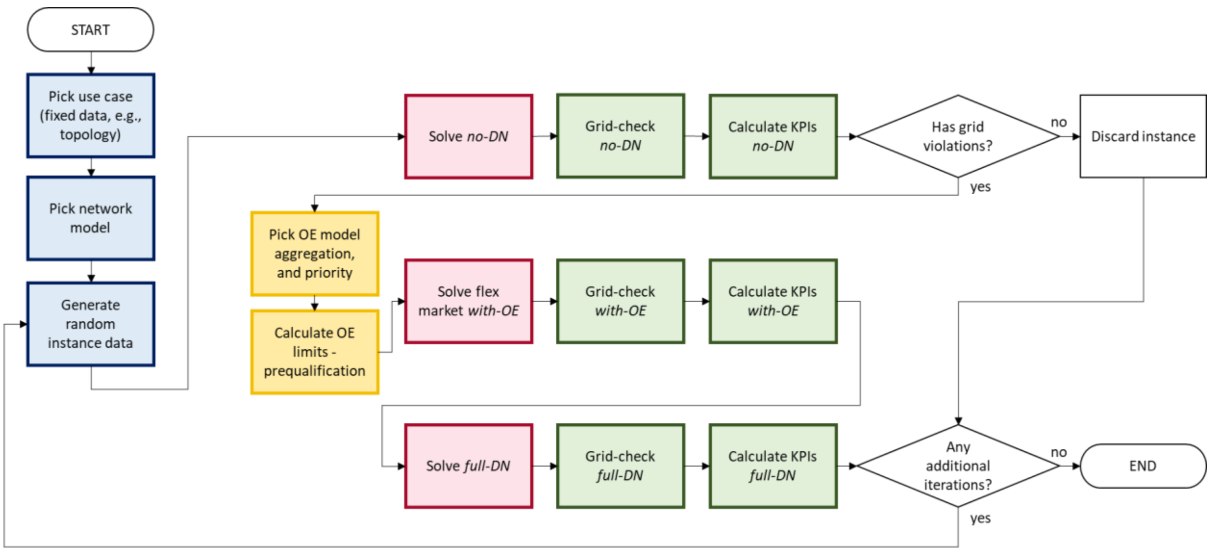

Figure 3-4: Monte Carlo-based methodology to analyse the performance of the proposed OE-based prequalification step in the flexibility market procurement.

The simulation starts from a specific use case data, with certain fixed information such as the topology of the interconnected transmission-distribution network. One of the three network models described above (PTDF, LinDistFlow, SOCP) is chosen to represent the DN in the prequalification step of the *with-OE* market model, and to represent the DN in the *full-DN* market model. Then, the Monte Carlo randomization begins, by generating the variable information of the use case data, which is:

- Injection/offtake of the nodes in the transmission and distribution systems.
- Number of resources each node can have of each type (upward/downward).
- Flexibility quantity of each resource (as a function of its node injection/offtake).
- (bid) Price of each resource (generated depending on the objective of the analysis, e.g., cheaper distribution-located resources than transmission-located resources to test the impact of clearing LV flexibility in the distribution grid).
- How many FSPs are available in the interconnected transmission-distribution system (as a function of the total number of resources generated). Can vary from one FSP owning all resources to having one FSP per resource.

As mentioned before, we consider that each FSP makes a price-quantity bid per resource it owns, using the values randomly generated for the resources as defined above.

Once all network information (fixed topology and random injection/offtake of the nodes) and all flexible resources information (location, quantity, price, direction, and FSP) are generated, the *no-DN* benchmark market model is run. The transmission-level network constraints are considered, but not the distribution-level ones. As such, this market procurement can select resources/bids from the distribution network that cause network violations (such as line congestion), depending on the network model used to represent the distribution grid. Therefore, a grid-check using one of the three network models is performed, and we calculate the total procurement cost and the total number of grid violations for this instance with this market model. If the generated instance has no grid violations when running the *no-DN* market model, then it is discarded: if this unrestricted market model (in terms of grid representation) returns a solution which is already grid-safe, then no other restricted model (e.g., *with-OE* or *full-DN*) would ever return a solution causing grid violations.

If the instance is kept in the simulation, we run the *with-OE* market model. For the combination of OE-model, aggregation/grouping level, and priority weight, we run the prequalification model to calculate the resources' limits, which are then embedded in the market clearing model as previously discussed. Similar to the *no-DN*, the market result passes a grid-check to calculate if the OE-prequalification model was able to represent the DN grid constraints, returning a grid-safe solution. The number of grid violations, together with the procurement cost and the unqualified flexibility KPIs are calculated for the market solution. More than one prequalification method (i.e., combination of OE-model, aggregation/grouping level, and priority weight) can be run in this step.

Next, the same process is performed for the *full-DN* market model. Here the market procurement is composed by both the transmission and distribution network constraints, the later according to the chosen network model (the same used to calculate the OEs). The solution of this market procurement also passes the grid-check, which returns grid violations only if the network model used to check the solution feasibility is more constrained than the network model used in the market clearing (e.g., if the market procurement used a PTDF model for the DN and the grid-check uses an SOCP model). Notice that all three market models consider the same DN network model in the prequalification-procurement phases (if applicable), e.g., if the prequalification of the *with-OE* is performed using a PTDF for the distribution system, the market clearing of the *full-DN* also includes the PTDF equations for the distribution system. Moreover, they all consider the same network model for the grid check (which does not need to be the same as the one used in the prequalification-procurement phases). The procurement cost and grid violations KPIs are also calculated for this market model.

New instances are generated and run, following the beforementioned process, until all planned Monte Carlo simulations are performed (e.g., 1,000).

3.2. Main Findings

3.2.1. Study Cases

We consider a test system consisting of the IEEE 14-bus transmission network connected with the Matpower 69-bus and 141-bus distribution networks [59], which are interconnected as shown in Figure 3-5[14]. We delineate two distinct study cases from this interconnected system:

- Case-1: Illustrates a scenario where the distribution systems exclusively comprise flexible (net) loads, and the TSO seeks downward flexibility to resolve a positive system imbalance.
- Case-2: Depicts a scenario where the distribution systems possess substantial generation capacity alongside flexible loads, and the TSO seeks upward flexibility to address a negative system imbalance.

In Case-2, the quantity of flexibility resources, on average, surpasses that of Case-1 by 160%. Case-1 serves as a portrayal of the current landscape, whereas Case-2 represents potential future scenarios where DNs exhibit significant flexibility potential.

In both instances, we assume that distribution-level flexibility resources are priced lower than transmission-level ones, reflecting a scenario wherein distributed flexibility bids are cleared. The distribution and transmission resources are randomly distributed. Additionally, the distribution systems are presumed to encounter no anticipated congestions, thus focusing on the utilization of distributed flexibility for system services, notably balancing.

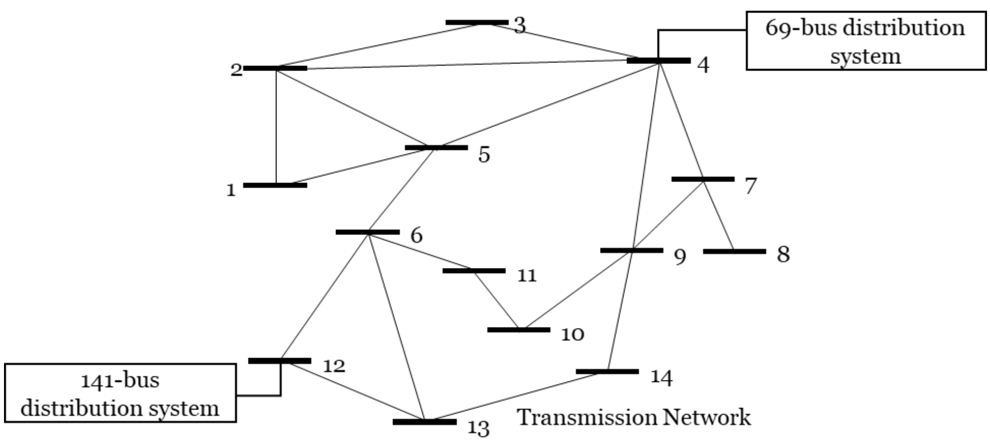

Figure 3-5: Interconnected network considered in the simulations.

We note that the data available for the considered cases refer to MV level grids. However, the analysis here is also valid for LV grids, because the nature of the considered MV distribution grids is the same as the LV grids (e.g., they are also radial). Moreover, the only differences will be on the order of magnitude of the problem's data, e.g., the nodes injections/offtakes are greater than 10 kW in the MV

[14] The envelopes are tested on a small to medium scale, causing no computational challenges. Large scale networks are still to be tested with this method.

cases we consider, while in the LV case they will be lower than 10 kW; the voltage level is 12.66 kV in the MV case we consider, while it will be around 230 V in the LV case. As such, the proposed methodology and conclusions from the case studies remain valid for LV distribution grids, given that only the order of magnitude of the numbers will be different. We are working on applying the methodology on an LV network from a Belgian DSO to corroborate our findings and results will be included in later deliverables of the Alexander project. Moreover, in Chapter 4, we consider an LV case using a more detailed network model of the LV distribution system (e.g., considering a model with 3-phases unbalanced).

3.2.2. Impact of the Aggregation Level

As mentioned in Section 3.1, the OE limits can be applied to each *per resource* or can be aggregated *per FSP*, and *per DN* and at the same time different network models can also be used to represent the distribution system. In this section, a comparison of using different network formulations (PTDF, LinDistFlow and SOCP) and different OE aggregations (*per FSP, per resource* and *per DN*) in terms of market evaluation, power flow analysis and missing flexibility is presented for Case–1 and Case–2. For highlighting the impact of aggregation levels the results presented below are based on only one set of simulations for Case–1 and Case–2, thus the Monte Carlo based approach in Figure 3-4 is not used.

<u>Case–1: heavily loaded DNs and a downward need from the TSO</u>

Figure 3-6 compares procurement costs and the number of grid violations for different OE groupings and network models for Case–1. The PTDF model results in the highest number of violations regardless of OE grouping. Interestingly, with PTDF network model limits on OE grouping do not reduce violations and have no positive impact as outcomes (in the form of OEs) have at least as many violations as those without network constraints (*no-DN*). This is because the PTDF model has the most relaxed constraints and poorly approximates the branch flow model, resulting in the lowest procurement costs due to a less-constrained feasibility space. Conversely, the LinDistFlow model provides a better network model approximation for OE calculation, reducing grid violations compared to the PTDF model. The SOCP model further lowers network violations, with the *per resource* OE achieving no constraint violations. These case-specific observations (i.e., may not be generalizable to any system) highlight the importance of the network model in OE calculation. Figure 3-6 also shows that larger OE groupings negatively impact grid security (*per DN* > *per FSP* > *per resource*), except for the PTDF model, which is less accurate than the branch flow model.

The procurement costs for OEs with the SOCP model are the highest and closest to the *full-DN* SOCP market, which guarantee grid security (no violations). When procurement costs are lower than the *full-DN* SOCP market, grid violations and/or imbalances (unfulfilled TSO needs) are expected, as those markets solve a less-constrained problem. These imbalances arise from unaccounted network losses during market clearing, as shown in Table 3-1. The *full-DN* SOCP market considers losses, leading to higher flexibility procurement costs at market clearing; other models must account for losses ex-post, incurring additional costs after the market clearing stage.

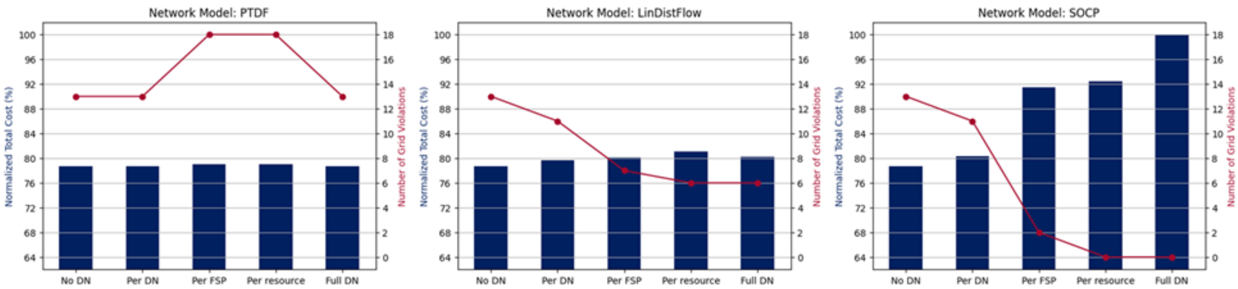

Figure 3-6: Prequalification impact on procurement cost and grid-safety for Case-1.

Table 3-1: Unfulfilled TSO's balancing need due to network losses for the Oes calculated with the SOCP model.

Case study ↓	No DN	Per DN	Per FSP	Per resource
Case-1	0.94 MW	0.93 MW	0.86 MW	0.85 MW
Case-2	0.42 MW	0.41 MW	0.40 MW	0.43 MW

Figure 3-7 shows the impact of different network models on the missing downward flexibility volume. The accurate SOCP model results in the highest missing flexibility volume due to stricter grid constraints, correlating with fewer grid violations. This volume limitation is due to the initial high loading condition in the distribution system and the TSO's need for additional downward flexibility (a further increase in consumption), leaving low remaining capacities in the distribution systems.

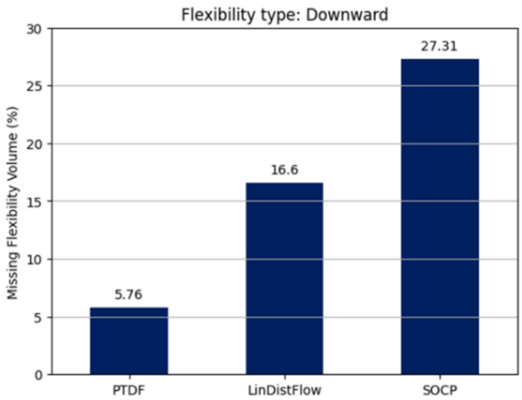

Figure 3-7: Missing downward flexibility volume for Case-1.

<u>Case–2: a lot of distributed generation and an upward need from the TSO</u>

Figure 3-8 presents a comparison of flexibility procurement costs and grid violations for different OE groupings and network models for Case–2. Similar to Case–1, there is a trade-off between lower procurement costs and the number of grid violations, albeit to a lesser extent. Regardless of the network model, OE grouping leads to increase in grid violations. The middle plot of Figure 3-8 shows that using the LinDistFlow model with per resource OEs achieves a completely grid-secure outcome.

Interestingly, in terms of grid security, OEs calculated with the LinDistFlow model outperform those with other network models, including the more complex SOCP model, which is a better approximation of the branch flow model used for the ex-post grid-check step. These results are in line with [60], which have found that the SOCP model is not suitable for these OE calculation methods. The lower procurement costs in *with-OE* markets, compared to the *full-DN* market using the SOCP model, are due to unaccounted network losses, as shown in Table 3-1 for OEs with SOCP network model. Figure 3-9 indicates that the missing flexibility volume, due to grid constraints, is highest for OEs calculated with the LinDistFlow model. This suggests that LinDistFlow OEs impose the strictest grid constraints, resulting in the lowest offered flexibility volume but the most grid-secure market clearing outcomes.

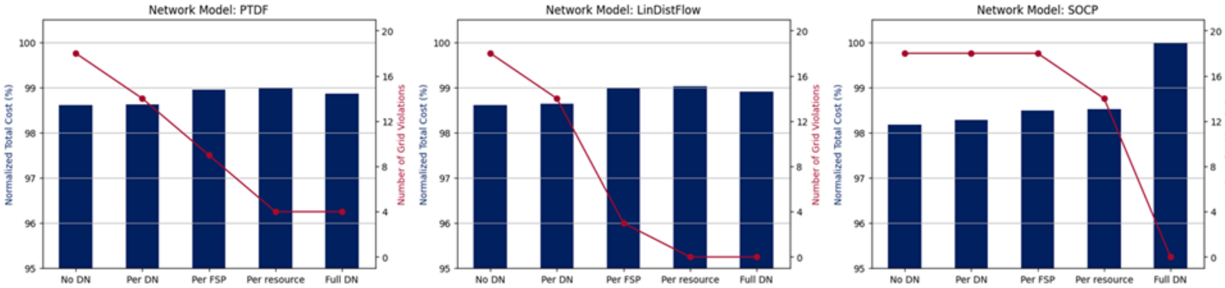

Figure 3-8: Prequalification impact on procurement cost and grid-safety for Case-2.

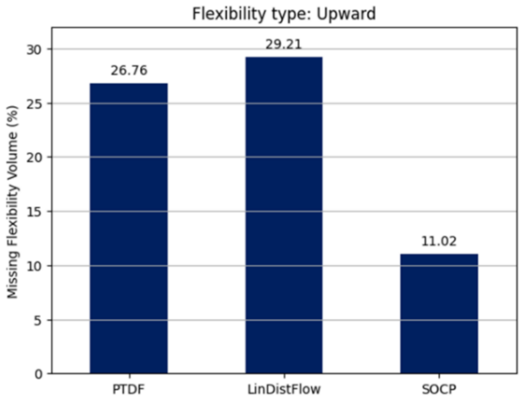

Figure 3-9: Missing upward flexibility volume for Case-2.

3.2.3. Impact of the Operating Envelope Calculation Method

The impact of using different aggregation levels and network models is presented in the Section 3.2.2 and it is seen that *per resource* OE outperforms the other aggregation levels. As already elaborated in Section 3.1, two different methods can be used to calculate the OEs and at the same time we can prioritize resources based on their price or quantity or give all the resources equal priority. In this section, a comparison of OE calculation methods (one-step and two-step) and prioritizing the resources based on price, weight and equal priority is presented. For this comparison, the OEs are calculated *per resource* with linearized branch flow model (LinDistFlow) based on [61]. For the flexibility market clearing, the PTDF model has been used. The comparison has been carried out with the Monte Carlo approach shown in Figure 3-4 to capture a wide range of DN states, flexibility volume, and price scenarios.

We find that, for Case–1, approximately 300 instances where the solution to the relaxed market clearing problem (*no-DN*) is not grid-safe, meaning there are grid constraint violations[15]. For Case–2, we find approximately 1,600 of such instances. The analysis with Case–2 leads to more instances as this test case includes more distributed resources, which in turn can lead to more grid violations in the *no-DN* scenario. The simulation results for Case–1 are illustrated in Figure 3-10[16] and Figure 3-11. From

[15] Instances where the solution to the relaxed market problem is grid-safe have been discarded, as they are not interesting because the OEs further restrict the resources, making the solutions to the OE-based markets also grid-safe.

[16] The *full-DN* is not shown in the top plot as all results are grid-safe, neither in the bottom plot as all results equal zero.

the top plot of Figure 3-10, it is evident that two-step OE calculation approach effectively ensures that the OE-based market-clearing outcomes are grid-safe, performing as well as the *full-DN*. Unfortunately, this is not the case for one-step OE calculation approach, where the cleared flexibility can still lead to grid violations.

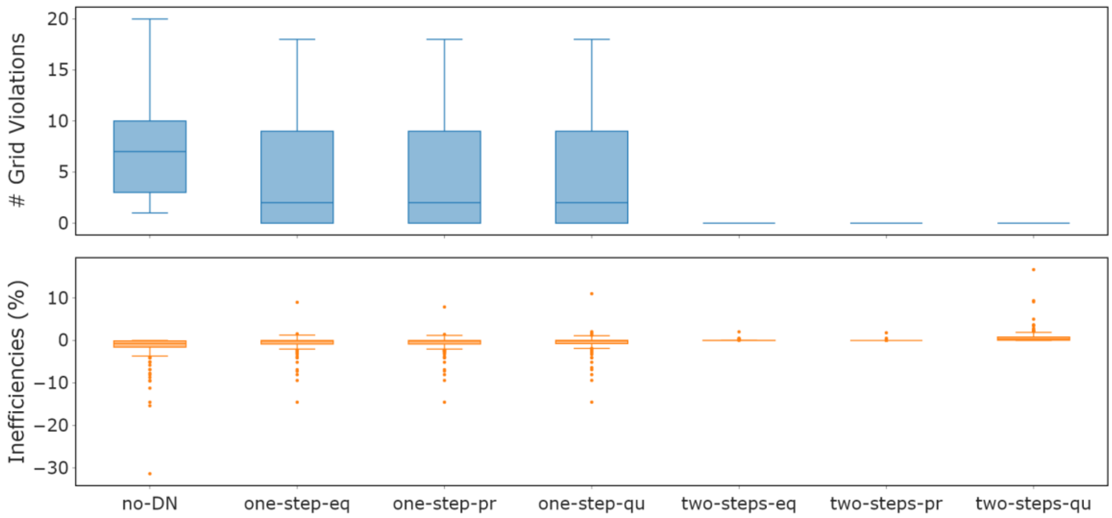

Figure 3-10: (Top) Comparison of total numbers of violations for Case–1. (Bottom) Comparison of market inefficiencies for Case–1. Note that $\eta = 0$ indicates the procurement cost is equal to that of the full-DN.

The bottom plot of Figure 3-10 shows that the two-step OE calculation approach results in non-negative inefficiencies, indicating that the cleared bids, while feasible, are suboptimal. Conversely, the one-step OE calculation approach achieves lower procurement costs by (partially) clearing unsafe flexibility, illustrating a trade-off between procurement cost and grid safety in the methods studied. Figure 3-11 illustrates the amount of flexibility disregarded due to the OE limits. The two-step OE calculation approach imposes stricter limits on downward flexibility than one-step OE calculation approach, which explains the differences in grid safety and efficiency results. Notably, for two-step OE calculation approach, despite a relatively high amount of unqualified flexibility (averaging around 20%), the loss in market efficiency is not significant. This demonstrates the effectiveness of the OE limits in restricting distribution-level resources. It is seen that on average, about 50% of the TSO's flexibility needs are met from the DN flexibility resources. Additionally, in Case–1, we observe that there is almost no restriction on upward flexibility when applying the OE methods, with a maximum of only 0.06% of upward bids being unqualified as seen in Figure 3-11. This is because this case involves only shiftable loads.

The sensitivity analysis of two-step OE calculation approach and one-step OE calculation approach with respect to the weights has been carried out for Case–1 and Case–2. For two-step OE calculation approach, market efficiency is optimal when using price-based or equal weights, aligning with the objective of these weight rules (see the bottom plot in Figure 3-10). The volume of unqualified flexibility increases with the quantity-based weight rule (see Figure 3-11), leading to worse market efficiency compared to price-based weights due to the unnecessary discard of flexibility (more restrictive operational limits), which in turn causes greater inefficiency. Conversely, one-step OE calculation approach is not sensitive to weights and its performance remains relatively consistent for different weight rules. Similar to the two-step OE calculation approach, the quantity-based weight rule leads to slightly higher unqualified flexibility but does not impact the one-step OE calculation approach's performance to other metrics.

The results for case–2 are similar to those of case–1 in terms of grid violations and market inefficiencies and hence the resulting plots are not included. The differences between the two cases are mainly in the scale of results: 1) the number of grid constraint violations can reach up to 35 in the no-DN and with one-step OE calculation approach scenarios; 2) Two-step OE calculation approach shows average market inefficiencies of 0, indicating that the OE-based market clears bids that are grid-safe and as efficient as the full-DN market, reinforcing the efficiency of two-step OE calculation approach. For the unqualified bids, two-step OE calculation approach restricts 30% of upward flexibility on average (see Figure 3-12), but only 5% of downward flexibility. This is due to the large amount of distributed resources available in this case. Despite these high restrictions, market efficiency is not impacted, suggesting most unqualified flexibility would not have been cleared anyway. Finally, one-step OE calculation approach usually does not impose restrictions on resources, as the OE limits match their technical limits, resulting in performance similar to the no-DN market in terms of grid violations and market efficiency.

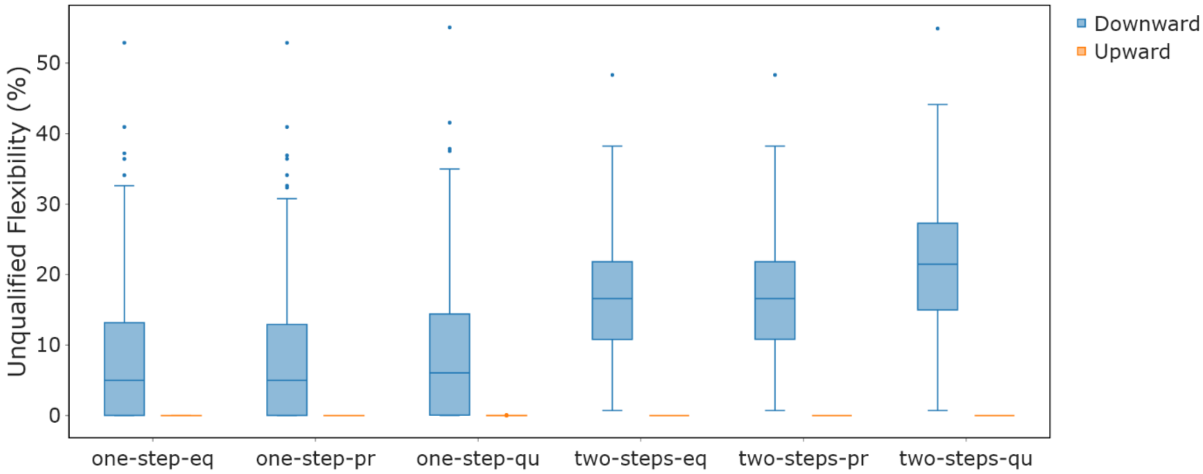

Figure 3-11: Comparison of unqualified flexibility for Case–1

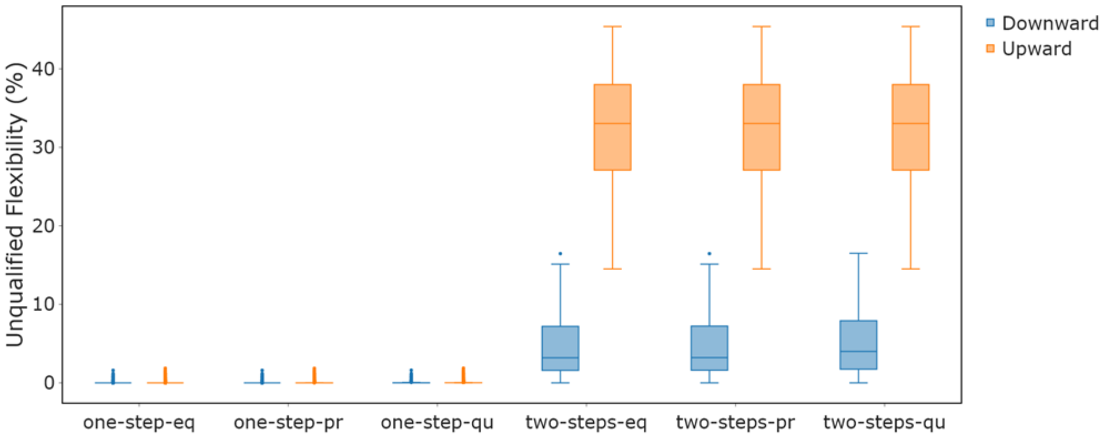

Figure 3-12: Comparison of unqualified flexibility for Case–2.

3.3. Related Publications

The work presented in this chapter has been published (or is under review) in the following conferences:

- Marques, Luciana; Ananduta, Wicak; Kaushal, Abhimanyu; Sanjab, Anibal. Embedding operating envelopes in the market design to unlock the flexibility potential of distribution grids in International Conference on Electricity Distribution (CIRED) 2024 Vienna Workshop. (Poster presentation) [10].
- Kaushal, Abhimanyu; Ananduta, Wicak; Marques, Luciana; Cuypers, Tom; Sanjab, Anibal. Operating envelopes for the grid-constrained use of distributed flexibility in balancing markets. Submitted to Innovative Smart Grids Technologies (ISGT) 2024. Pre-print available at https://arxiv.org/abs/2406.17398 [55].

4. LV Operating Envelope with 3-phases Unbalanced

As presented in previous sections, DSOs are facing upcoming challenges to ensure safe operation of the DN. This starts to be critical even at LV levels, as Figure 4-1 illustrates for main Brussels voltage levels. New assets such as photovoltaic panels (PV), heat pumps (HP) and electric vehicles (EV) are increasingly being installed, as well as new activities becoming available for LV assets, such as reserves extensively presented in Section 2.

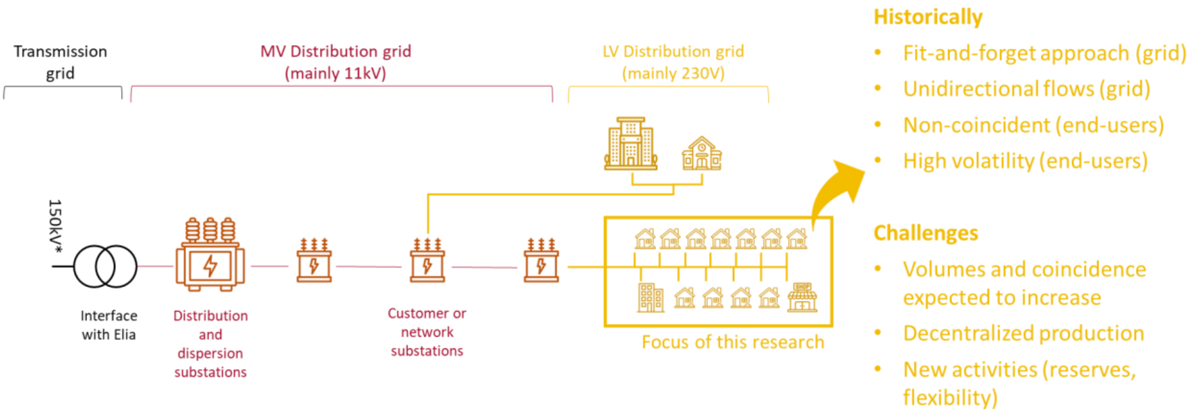

Figure 4-1: Illustration of voltage levels for the Brussels DN, highlighting the main challenges faced by DSOs.

Ensuring safe use of the grid is made more difficult by the fact that DSOs do not know which phase end-users are connected to, and phase connections can be highly unevenly distributed. This can lead to unexpected voltage or current congestions. When there is a congestion risk, DSOs need to define the maximum flexibility that can be unlocked by LV end-users while guaranteeing safe use of the grid by computing the day-ahead OE. In that context, the OE is defined as the maximum and minimum power available per end user while guaranteeing the absence of congestion (current and voltage) on the LV distribution grid. Compared to Section 3, this section therefore focuses on one of the three blocks presented previously, the calculation of the LV OE from the DSO point of view, as illustrated in Figure 4-2.

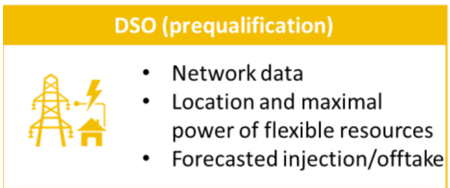

Figure 4-2: Similarly to Section 3, Section 4 focuses on the 3-phases unbalanced OE for LV DN as the prequalification step of the proposed market design.

As such, in this section we focus on the calculation of the OEs in the prequalification step of Figure 3-2 considering a detailed model of the LV grids, using a 3-phased unbalanced among end-users' connection. Moreover, we use LV-based load profiles and LV grid data (voltage levels of 400 V) to test the prequalification model of this section. One should note that the work presented in this Section extends the OE methods presented in Section 3 by implementing a more detailed network representation of the LV grid, as well as a more detailed case study. This allows for analysing the challenges of implementing such detailed models in terms of the type of data needed, the impact of phase unbalances on the available flexibility, the impact of reactive power provision on the OE limits, and the complexity to solve them.

We present an innovative method, a relaxed unbalanced three-phase optimal power flow, to compute the maximum day-ahead flexibility per LV end-user that can be unlocked while ensuring safe use of the LV DN. Additionally, this section shows interesting results on how controlling reactive power on the LV network could increase flexibility potential and counteract imbalances caused by unevenly distributed phase connections.

4.1. Methodology

This first subsection presents the methodology. It begins by presenting some background information on the OE principle, then briefly presenting the rationale for choosing the methodology for this section.

4.1.1. Operating Envelopes background

To provide some background, OE principle is defined in 2009 in [62]. The paper aimed to characterize the flexibility needed to include wind turbine generation in the California grid. Makarov's team publishes two years later a new paper considering load uncertainty in the model [63].

Later, paper [64] presented a method for assessing the ***available*** operational flexibility of a power system, compared to the previous concept of ***needed*** flexibility. This available flexibility is defined as the maximum technical capability of a single power system unit to modulate power and energy into the grid. The grid is considered as a copper plate and hence, internal constraints are not yet considered. Scientific literature then focused on LV DN, with LV loads and generators, where five household appliances are considered and modelled in [65]: washing machines, tumble dryers, dishwashers, domestic boilers, and EV.

The OE for power system is formally defined in [66]. The paper began with a state of the art on the principle of flexibility. It defined the flexibility at a certain time as the possible capacity of the system to provide flexible power for the next time steps. Flexibility is therefore represented in the form of a cone or an OE in a plan power versus time.

The OE concept is then used to ensure that load control does not exceed grid constraints. For example, paper [67] considered a building with PV, EV, thermal energy storage and HP and presents four strategies for controlling these LV loads and generators. An OE is then computed for each hourly electrical set point to assess the impact on the distribution grid constraints.

New methods are then used to compute the OE to reduce computation time, e.g., through probabilistic approach in [68] or through data-driven approach in [69]. The flexibility envelope concept is also applied on the distribution network in [70]. More recently, the OE is used to study the impacts of reconfiguration on the distribution network [71].

More recently, in paper [72] a phase voltage sensitivity analysis of an unbalanced distribution network is performed. The results concluded that congestion could occur even when all customers are within the limits of the single line OE and hence, imbalances cannot be neglected. In that context, in [73] the calculation of OE for the integration of DER in unbalanced distribution networks is studied. This is even more relevant since today DSOs do not necessarily know to which phase end-users are connected and strong unbalances can be unexpectedly observed on the LV distribution network. Nevertheless, this paper considered only linearization to implement an unbalanced 3-phases optimal power flow (UTOPF) for computing OE.

The methodology presented in this section is therefore innovative given the current state of the art by presenting a tractable and relaxed UTOPF with second-order conic programming (SOCP) relaxation. In addition, a case study with high phase unbalances highlights the impact of reactive power on the OE.

4.1.2. Relaxed UTOPF with SOCP relaxation

The methodology used to compute OE in this section is an UTOPF to capture the unbalanced connections and obtaining an exact result. In general, the power flow equations used as constraints are quadratic non-convex. Therefore, tractability and time computation represent challenges. Several methods exist in the literature to convexify OPF equations [74]: approximation methods [75], machine learning methods, and relaxation methods [76].

Approximation and relaxation approaches are compared for multiphase distribution grid in [77]. The case studies presented in the paper prove that convex relaxation is numerically exact, while the linearized approximation using the Lindistflow model leads to low accuracy when phase unbalances are high. Because that paper aimed to study a situation with strong unbalances, a relaxation method was preferred to a linearization method.

Regarding relaxation methods in general for OPF, paper [76] compares three convex relaxation methods: semi-definite positive (SDP), chordal programming (CP) and second-order cone programming (SOCP) relaxations. The exactness of these relaxations is discussed in [76] and more specifically for branching flow models in [78] and [79]. It is proven that for a radial network, SOCP relaxation should always be preferred because the solution is exact, and it is the tightest and simplest relaxation of the three [76].

Finally, PF equations can be modelled through Bus Injection Model (BIM) or Branch Flow Model (BFM). Branch Flow Model (BFM) is to be preferred to Bus Injection Model (BIM) because it is numerically more stable [76]. This section therefore focuses on a relaxed UTOPF on BFM with SOCP relaxation. As can be seen, here a more detailed network model is considered to calculate the OEs in the prequalification phase, taking into account phase unbalances as well. As such, an extension of the models proposed in Grid-safe Provision of Low Voltage Flexibility 3. For interested readers, the full formulation of these OE calculation model is will be available in [80] (paper under review).

4.2. Main findings

4.2.1. Case study

This sub-section first presents the benchmark grid studied, then the objective function implemented and finally presents the end-users load profiles.

Grid and phase connection – The reduced IEEE European LV Testfeeder is selected for the case study [81]. This grid is represented in Figure 4-3 with 55 end-users and their initial phase connections. Each end-user is connected to the grid with a maximum power capacity (in this case: 9.2kVA for a monophase 40A). In the results, a worst-case is considered with all end-users connected to the same phase, to highlight the worst and unrealistic unbalance case. Although it is unlikely that all end-users will be connected to the same feeder, DSOs currently do not necessarily know which phase the end user is connected to, and unexpected unbalances can arise.

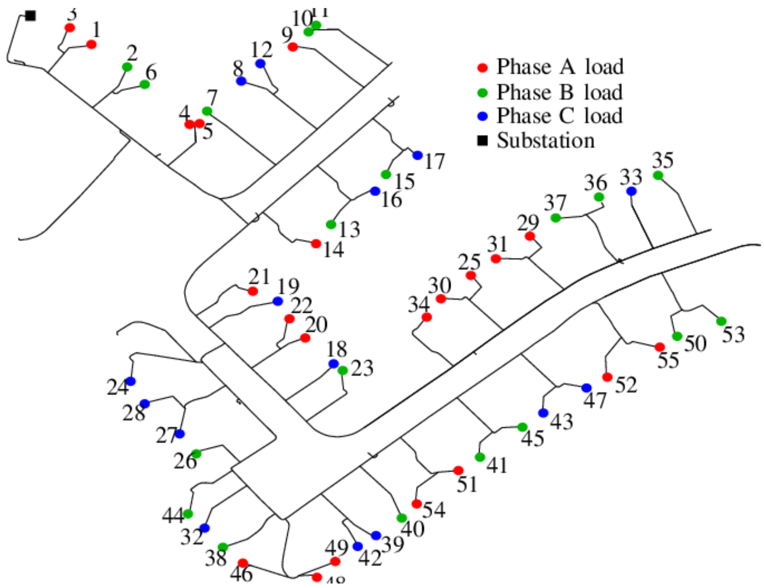

Figure 4-3: Reduced IEEE LV European Testfeeder

Objective function – A single objective function is implemented. The objective function optimizes the sum of active powers per household. This objective function should maximize the available flexibility, but it will be heterogeneously distributed among end-users. To compute the upper and lower flexibility envelopes, the objective function switches from maximization to minimization.

$$max \sum_{i \in C} p_{i,\phi} \qquad (14)$$

End-users load profiles – The load profiles, active and reactive power, considered in this paper are deterministic and come from the benchmark grid for a specific moment in the time series (12:00). This methodology does not aim to further refine the calculation of load profiles. However, two assumptions are considered for the reactive power of the OE: the reactive power per end user can either remain variable or be constrained to a fixed power factor (PF) (here, PF = 1, as analysed from real grid data in [82]).

Implementation – The problem is implemented in python, using the cvxpy software-based optimization language and the MOSEK solver. This choice is mainly motivated by the need for the software and the solver to support the SDP constraint.

4.2.2. Impact of phase unbalanced on OE

OEs are computed for each end-user for the four case studies. The left plot in Figure 4-4 shows the upper and lower OE for each end-user when the PF can vary for each end user. In this situation, the reactive power is considered a variable and is only limited by the maximum current that can be yielded through the injection connection. The blue curve (OE1) represents the initial scenario in which end-users are located on distinct phases, and the green curve (OE2) represents the scenario in which all end-users are located on the same phase. The right plot in Figure 4-4 similarly shows two upper and lower OE (OE3 and OE4). The difference between the two figures is that in the second figure the PF is fixed (PF = 1).

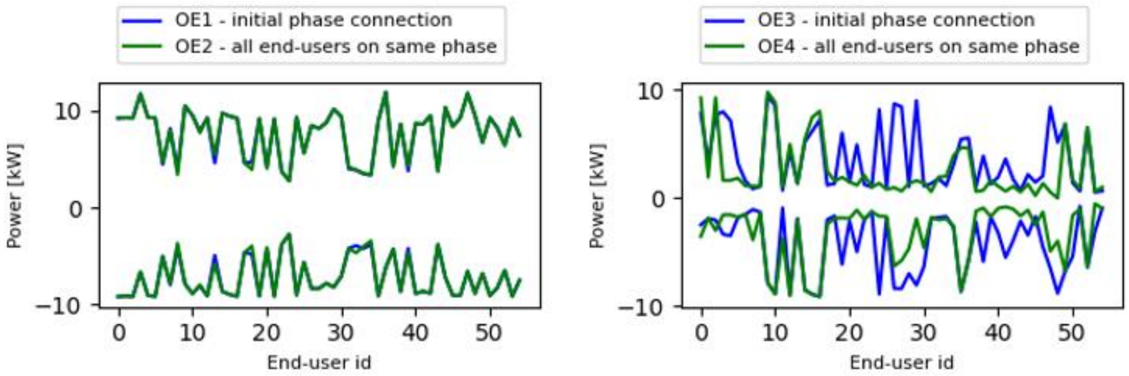

Figure 4-4: Two inferior and superiors OE with variable PF where end-users are connected on different phases (blue curve) and to the same phase (green curve).

The statistical data for each OE are summarized in Figure 4-5 in which OE1 represents the initial case study with variable PF, OE2 where all end-users are on the same phase with variable PF. OE3 and OE4 are both for fixed PF and represent respectively the initial situation and the situation where all end-users are on the same feeder. Upper OE4 presents some rounds on the figure, due to some negative values. By multiplying the average power value by the number of end-users, this figure shows that for OE1, the sum of the maximum active power is 422 kW and the minimum power is -393kW, for OE2, 422 kW and -393 kW, for OE3 204 kW and -239 kW, and for OE4 138 kW and -180 kW.

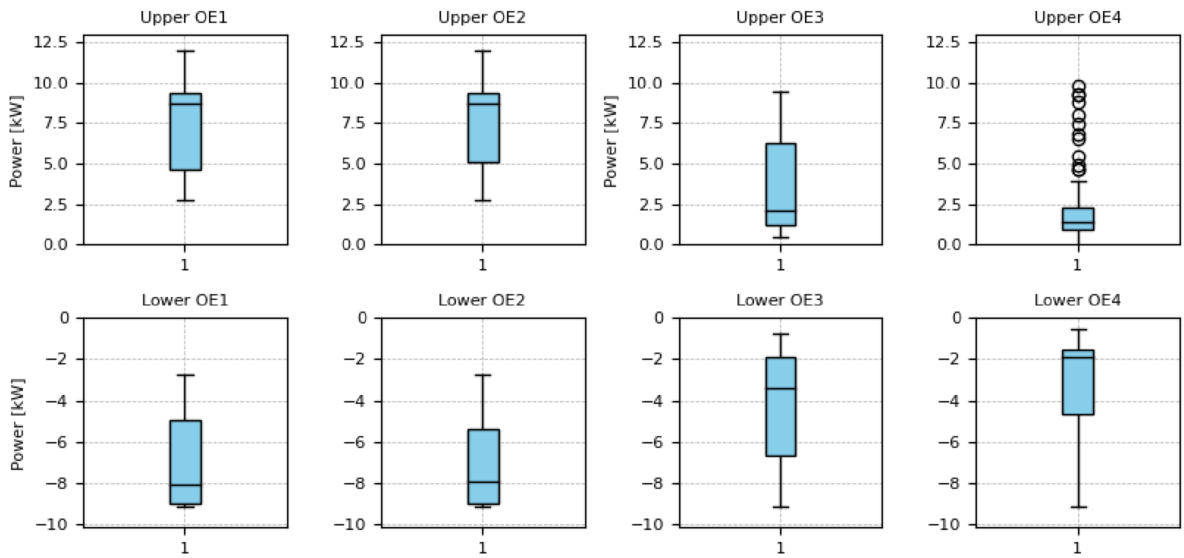

Figure 4-5: Summary of the four upper and lower OE.

The comparison between OE1 and OE2 is unexpected, because connecting all end-users to the same phase would normally result in a reduction in OE, which is not observable in the results. Indeed, the maximum available power on the feeder is 422kW and -393kW for both OE1 and OE2. This is because in OE1 and OE2, reactive power per end user is a variable. By maximizing the active power, the reactive power reaches certain values, different (Q and PF) for each end-user. Reactive power is therefore compensating for strong unbalances.

However, if PF is set to a fixed value and end-users are connected evenly among phases, when comparing OE1 and OE3, the magnitude of available power is reduced than when PF can vary. In addition, for a fixed PF and connecting all end-users on the same phase results in further reduction of the power amplitude, as shown by the comparison of OE3 and OE4. These results are more expected. This then raises the question: why should the power factor be set at a fixed value? Usually, the PF factor is set at fixed value between 0.9 and 1 for the LV distribution network.

Nevertheless, today, if an end-user injects or consumes, it is likely that the consumption or production will involve electronic equipment (e.g., inverters for PV, EV, domestic batteries). This electronic equipment may modify the reactive power command. The results show that if reactive power could be controlled, the OE could be increased, and unbalances could be compensated.

A result to be discussed is the computation time to obtain the result for a single upper or lower OE. The relaxed UTOPF with SOCP relaxation implemented on python runs between 31 and 36 seconds, for this grid with 55 end-users. If the tool is to be applied for a full distribution network, with millions of end-users, and the computation time scales proportionally to the number of end-users, this tool is not relevant to be used for intra-day operations. Indeed, for these applications, results must be obtained within 15 or 30 minutes. However, the relaxed UTOPF with SOCP relaxation could be used for static or day-ahead applications where several hours is an acceptable time frame to obtain results.

4.3. Related Publications

The work presented in this chapter has been published (or is under review) in the following conferences:

- Delchambre, Lionel; Almasalma, Hamada; Hendrick, Patrick; Henneaux, Pierre. Phase imbalance impact on operating envelope for low-voltage distribution grid. Submitted to Innovative Smart Grids Technologies (ISGT) 2024.

5. Application to the Belgian Flexibility Markets

Bringing together all insights from this deliverable leads us to the conclusion that numerous models exist, each accounting differently for network constraints. In Chapter 2, we built insights into prequalification practices in Belgium. In Chapter 3 and 4, we gained insights through development and testing on other possible alternatives for safeguarding the distribution grid when offering LV flexibility for system services.

In this chapter, we evaluate and compare the different models and we discuss their advantages and disadvantages together with their barriers and challenges. In total, this deliverable describes 4 main models:

- Model A (*no-DN*): the benchmark flexibility market model where the distribution network is not accounted for in any way (neither in a prequalification step nor in the market procurement/clearing phase). It is the leftmost model in Figure 1-4 and in Figure 3-3.
- Model B (*prequalification-BaU*): models that have a from of, typically static, (grid) prequalification prior to the market clearing. This model represents, for instance, the Network Flexibility Studies (NFS) performed in Belgium for certain LV flexibility assets and is shown as the second from the left model in Figure 1-4. This model is not implemented nor simulated in Chapters 3 and 4 given that its mathematical formulations are not publicly disclosed by the DSOs.
- Model C (*with-OEs*): models where prequalification is taken into account in the market clearing through operating envelopes. The difference with Model B is that this model considers more detailed network data, as well as more up-to-date data from consumption/generation and flexibility resources than Model B. As such, dynamic limits can be applied, making more LV flexibility available to TSO markets. This model is represented by the third from the left model in Figure 1-4, is detailed in Figure 3-2 and Figure 3-3, and is also the main model introduced and studied in Chapters 3 and 4. Note that multiple variations of the operating envelopes are used and compared in those chapters.
- Model D (*full-DN*): models where the entire distribution network representation is directly accounted for in the market clearing phase. This model is considered as the “idealized” model in terms of procurement cost efficiency and grid safety, and it is a theoretical benchmark given the practical challenges that would be associated with its implementation. It is the rightmost model in Figure 1-4 and in Figure 3-3.

In what follows, we give an overview of the differences between the models. We describe for each of the models what the market set-up is and how the market clearing is performed, how TSO-DSO coordination takes place, what consequences this has for data challenges and flexibility, and finally, we discuss under which conditions each of these models are appropriate to facilitate LV-flexibility provision. For each of these points, we align the discussion with the Belgian regulations and practices to understand which models are most applicable in the Belgian context.

Table 5-1: Overview of the models

		A – no-DN	B – Prequalification-BaU	C – with-OEs	D – full-DN
Market set-up	**Examples**	Belgium: exemptions for LV	Belgium: NFS	Australia	OneNet Northern Demo
Market set-up	**Buyer**	TSO			
Market set-up	**Applicable flexibility products**	In theory, all models can be applied to all types of flexibility products that are open for distribution-connected resources.			
Market set-up	**Prequalification of aggregated resources**	N.A.	Limits are calculated individually	Limits can be calculated individually or per group	N.A.
Market Clearing	**Accounting for Transmission network**	Yes	Yes	Yes	Yes
Market Clearing	**Accounting for Distribution network**	No	Partially (only reduced network data, potentially only technical data)	Partially (reduced network representation)	Yes, full network representation
Market Clearing	**Timing DER Grid prequalification**	N.A.	Prior to the market clearing	Prior to the market clearing	During the market clearing
Market Clearing	**Complexity**	Low	Low/Medium	Low/Medium	Medium/High
TSO-DSO Coordination	**Level of coordination between DSO-TSO**	No coordination	Minimal coordination	Efficient coordination	Full coordination
TSO-DSO Coordination	**Implications on roles and responsibilities**	DSO = passive and reactive role	DSO = flexibility gate keeper	DSO = Active Prequalification officer	DSO = Data sharing officer
Data implications	**Network Data challenges for the DSO**	No	Less detailed grid data are needed	Quite detailed grid data are needed (but not shared externally)	Detailed grid data are needed (but shared externally)
Data implications	**Network Data challenges for the MO**	No	No	No	Yes
Data implications	**Consumer data challenge for the DSO**	No	Some (e.g., FSP information)	Yes (e.g., bid information and smart meter data)	Yes (e.g., bid information and smart meter data)
Operational implications	**Restriction to flexibility participation**	No restrictions, but might indirectly block flexibility	More conservative go/no-go decision	Less restricting or the same as model D	Restricted to the feasible level that is actually

			(based, e.g., on worst case scenario)		possible for the grid
	Prequalification Frequency	N.A.	Static (e.g., when requested by FSP)	Dynamic (e.g., prior to each market clearing)	Dynamic (e.g., during each market clearing instance)
	Compatibility with existing DSO processes	Less favourable	Compatible	Compatible	Not compatible
	Compatibility with existing FSP processes	Compatible	Less favourable	Compatible	Compatible
Applicability	When do we need this model?	When the grid is not stressed in any condition and/or when there is almost no LV-flexibility participation. It can also help to kick-start an emerging market.	When there are grid visibility challenges and/or not all data are available.	When detailed grid model and metering data are available but cannot be shared.	When detailed grid model and meter data are available and can be shared, as well as the complexity is manageable
	Compatibility with existing EU regulation	All models are allowed as long as the delivery of flexibility services does not compromise the safe operation of the connecting/intermediate grid(s). It is up to the Member States to work out specific rules and procedures.			

Market set-up: In this deliverable, we are only looking at models where the TSO is the only buyer, procuring flexibility products from LV-grid connected resources. In Alexander D3.3, we will also zoom into models where the DSO is also a buyer of flexibility. As a result, the products procured on the markets discussed in this D3.2 are only TSO-ancillary services, which are open to be fulfilled by distribution-grid-connected resources.

Given the fact that the EU is recommending all markets to be opened up for all end-consumers, this implies that, in theory, the market set-up we describe here is for all products. However, in some markets, certain products cannot be provided by LV flexibility, meaning that none of the market models in the table would apply. Depending on the country and the type of product, some models are already linked to specific products. For instance, for some market products, no prequalification is required for LV resources (meaning that the *no-DN* market design applies). Furthermore, there are other market products in which some sort of grid prequalification is required for the LV resources, meaning that the *prequalification-BaU* or the *with-OE* market models apply. In the case of Belgium, the definition of which products fall under which of the abovementioned situations is described in Box 5.1 below. It is to be pointed out that when a product is prequalified closer to real-time, there is more uncertainty for both the buyer and the service provider whether they can join the market. As such, for products for which there are only a limited number of providers available, it might be recommended to get more certainty regarding prequalified resources further ahead of time.

Box 5.1 Products open for LV-flexibility provision in Belgium

In Belgium, only FCR, aFRR and CRM procurement are opened for LV-flexibility resources. This opening up has been speeded up in response to the recent energy crisis, increasing the need for flexibility by the TSO. Discussions are ongoing to open up mFRR markets as well before the end of 2024. There is, however, a difference in the chosen prequalification model in Belgium depending on the type of product procured. For FCR, there are exemptions in the sense that no prequalification is needed (model *no-DN* is applied). It is argued that this is because of the fact that there is only a limited impact on the grid. However, as proven by **[83]**, LV assets providing FCR could cause LV grid congestion. Indeed, two case studies in **[83]** must be considered: either the FSP provides FCR with each LV asset individually compensating for the frequency deviation, or the FSP compensates for the frequency deviation through aggregated flexibility across the entire portfolio. In the first case, there is a low probability that LV assets providing FCR will cause congestion, as the frequency deviation has a standard deviation of 0.02 Hz when looking at historical data (i.e., 10% of the maximum frequency deviation). A case study shows that there is a non-zero congestion risk if nine batteries [5 kW/10 kWh] are fully used to compensate for the frequency deviation modelled on historical data and applied on the reduced IEEE European LV test feeder (55 end users). In the other case, if the FSP optimizes the frequency compensation across the entire portfolio, it is possible that the LV assets locally provide full power when activated for the FCR, independent of the frequency deviation signal. This represents an unexpected activation of 5 kW assets on the LV network, leading to a risk of creating congestion in the distribution network. As such, the exemption of prequalification for FCR provision can be hazardous to the distribution grids to which these exempted LV resources are connected.

For aFRR and CRM, the DSO has the right to perform a Network Flexibility Study (NFS) to verify whether flexibility activation would have an impact on the functioning of the distribution grid (for instance, causing congestion, negatively affecting the stability of the grid, causing problems linked to power quality, etc.). Based on the outcome of the NFS, a DSO can decide to limit or reject the provision of flexibility services for certain Connection Points to ensure that operational security limitations of the grid will be respected. In that case, the *prequalification-BaU* model applies.

We note that currently in Belgium, the models *with-OE* and *full-DN* are not applied to any products for TSO ancillary services.

Finally, regarding the market-set up, it is to be noted that aggregation is allowed in Belgium. Some models can prequalify resources in an aggregative way, while others only prequalify individual resources. More specifically, in the *no-DN* model, this discussion does not apply given the fact that no calculations of the grid limits are done. In the case of the *full-DN* model, given that a full network model is used, and power flows are to be calculated, nomination of flexibility by connection point would be needed to be able to compute the power flows and voltages in the system. Hence, in the *full-DN*, aggregation is allowed, but the safety check for the grid would require nomination of this aggregated flexibility at nodal level. The *full-DN* process however does not require explicit prequalification, so this measure is to be taken as part of the procurement/market clearing process. In the *prequalification-BaU* model and the model *with-OE*, the discussion on aggregated prequalified resources applies as well in the prequalification step. In the models *with-OE*, it is possible to prequalify resources at different levels: that is, either individually, or in group (aggregated per FSP or per feeder for instance). In theory, this could be beneficial as it simplifies the procedure for the FSP. The FSP can prequalify a group of resources directly in this way. However, as indicated in Chapter 3, this comes at a higher risk from the point of view of the grid, as there is less guarantee for grid safety in this way. As a result, it is likely that (at least in the short-run), prequalification of resources would be needed on an individual basis. This means that, with regard to aggregated prequalification, there is no distinction between the models *with-OE* and the *prequalification-BaU* model which only prequalifies individual resources.

As pointed out in Box 5.1, the *prequalification-BaU* model (the NFS) is the method most frequently used in Belgium. However, as indicated in Chapter 2, there are quite some discussions related to the NFS. These are discussed in Box 5.2. Due to the fact that the NFS is seen as a barrier to LV-flexibility provision, some exemptions are given in which case it is not needed to go through the NFS procedure.

Box 5.2 NFS barrier

In Chapter 2, it was already indicated that there are quite some discussions related to the NFS in Belgium. It is argued that this study constitutes a large administrative burden as it slows down the prequalification process **[7]**. Febeliec indicates that consumers are currently free to consume whenever they want and within the range of the capacity of their grid connection. The NFS would therefore only be of added value if certain consumption behaviour and profiles of consumers are also limited, which would be unacceptable. They therefore advocate that, for most grid users, the NFS should be abolished, at all voltage levels, and at both regional and federal public grids **[84]**. It is for this reason that there are already exemptions to the NFS, yet it is argued that these exemptions should be broader **[84]**. This would mean a return to the *no-DN* model for most grid users, thus for distribution-connected resources as well.

For now, a NFS is not applicable to FCR and not for CRM when the Fast Track procedure is used. In addition, in Flanders, not all connection at LV receives automatic constraints. As stated in TRDE **[9, p. Art. 2.3.26]**: in the case of LV grids, flexible power will not be restricted when it is limited to 5 kVA for a mono-phase connection or 10 kVA for a three-phase connection. In other cases, LV connections do need to complete a Network Flexibility Study. As a result, in Brussel and Wallonia, for each aFRR connection point, a request for an NFS is needed, while this is not always the case in Flanders. FEBEG pointed out that the fact that there are different approaches in the three regions makes LV-flexibility provision more burdensome and complicated for market parties to manage and coordinate **[33]**.

Despite the fact that different parties welcome the exemption for an NFS in Flanders, ODE (Organisation Sustainable Energy in Belgium) criticizes that this 10 kVA limit for residential customers might even be too low, considering the electrification of heating and mobility **[85]**. In response to a public consultation, Fluvius indicated that such study is often a formality as in theory it is always possible to have conflicting congestions in the same zone **[86]**. Nevertheless, even in case there are exceptions, the DSO remains to have the right to require the FSP to complete a network flexibility study to monitor the impact on the grid and to secure operational grid safety **[32]**. In addition, it is possible that the DSO re-evaluates the prequalified power because of increased risk in that zone, i.e., 12 months after this verification the prequalified power can be reduced by the DSO (exception for certain multi-year contracts). This unilateral revision of the contract is criticized by FEBEG (Federation of Belgian Electricity and Gas Companies in Belgium) as this renders it challenging to offer contracts/solutions to consumers if these can be cancelled in the short term by the DSO **[33]**. The DSOs point out that a fixed period of 12 months in which qualification is guaranteed is the most they can provide to limit the risks for the grid **[49]**.

Note that NFS is still applicable to aFRR, mFRR and DA/ID. However, as discussed previously, with the opening up of aFRR for LV, there will be less strict requirements regarding the NFS for LV.

Market clearing: One key difference between the models is how the market clearing is done. In model A (*no-DN*), the market clearing only takes into account transmission grid data. There is no prequalification of flexibility resources connected to the distribution grid. The benefit of this is that the complexity of gathering data and the necessary information to be included in the model is very limited. From the perspective of both the market operator and the network operators, this model is therefore computationally not difficult. In all other three models (*prequalification-BaU, with-OE* and *full-DN*), distribution grid constraints are accounted for, implying that the grid data requirements for the DSO become more complex. However, there are different ways of fulfilling such requirements. In model B and C, distribution grid prequalification is done prior to the market clearing. The DSO determines beforehand which distribution grid flexibility assets are allowed to join the TSO-market clearing. In model B (*prequalification-BaU*), this can be done through, for instance, a Network Flexibility Study (NFS) or through a form of a traffic-light concept. In model C (*with-OEs*), distribution grid constraints are also taken into account prior to the market clearing in a separate step when the operating envelopes are computed. Although the two models (B and C) fall under the prequalification class, we make a distinction between what is done in practice now (model B) and a proposition for what can be done in the future (model C), when a higher observability of the DSO grids will be available and more data from distribution systems will be accessible. For instance, Network Flexibility Studies can be done with a more limited data or a limited set of criteria (such as past congestions, consumer complaints, or other issues in a specific region). In addition, in Belgium, this study is done in a more static way (e.g., requested by the FSP once it decides to offer flexibility to the TSO-level markets). That is why, in Table 5-1, we define that the distribution network is represented partially by reduced network data, potentially only operational data such as consumer complaints for this model. On the other hand, model C (*with-OEs*) requires a full observability of the DSO's grids by the DSOs, including topology and network parameters, expected injections/offtakes from the connection points, expected flexibility provision (or bids to be submitted to the market), etc. As such, this model can be applied closer to real-time (e.g. closer to the procurement and activation phases), with more accuracy on the grid-safety of the flexibility potential and in a more dynamic way. That is the reason why, in Table 5-1, we define that the distribution network is represented partially by a reduced network representation – the operating envelopes calculated using the full network representation and the consumers/FSPs data – in model C. Finally, in model D (*full-DN*), a fully detailed network representation is used in the market clearing. All the information is therefore accounted for directly in the market clearing in one joint step / one integrated model, together with the TSO data. The latter is therefore more computationally complex as more data and more detailed network models need to be accounted for in one single step.

As a result, the timing of the grid prequalification differs between models. In model A (*no-DN*) the distribution grid is not considered at all, so this aspect does not apply. For models B (*prequalification-BaU*) and C (*with-OEs*) the prequalification is performed prior to the market clearing, in a dedicated step as explained above – but can happen at differing time scales, where Model B is static while Model C can be dynamic and closer to real-time. In model D (*full-DN*), the prequalification of the distribution network is done during the market clearing, given that the grid constraints of the distribution systems are integrated into the TSO market-clearing model. Which models receive the preference depends on a trade-off that needs to be made between ensuring no flexibility resources are blocked unnecessarily (by prequalifying closer to the procurement phase when more information is available), and between providing certainty and clarity regarding how much flexibility can participate / is available in flexibility markets (by prequalifying earlier). Nevertheless, it should be noted that if the latter is an important argument, there are other mechanisms to reserve capacity ahead of the procurement phase, ensuring sufficient flexibility is available for the SO and increasing predictability.

The result of this difference in market clearing has great impact on the need for coordination between different stakeholders, data sharing, and flexibility availability. In addition, how the market clearing is done results in different computational loads. When grid constraints are not accounted for (*no-DN*), or when they are accounted for through a separate step (*prequalification-BaU* or *with-OEs*), the market clearing itself becomes computationally easier than when grid constraints are to be accounted for directly in the market clearing.

Level of Required TSO-DSO Coordination: As indicated during the discussion on how the market clearing takes place, it is clear that on the left extreme (model A: *no-DN*), we have models without a need for TSO-DSO coordination in the procurement and activation of flexibility. This is because distribution grid constraints are not accounted for. In this case, the TSO activation might not have the desired result for the DSO grid, meaning this activation could cause grid violations in the distribution system. As a result, the DSO will need to take actions on its side to restore its grid safety, which might include blocking certain flexibility assets or curtailing prosumers, and which can induce an (overall) more costly flexibility procurement due to the lack of coordination between the two types of SOs. That is why we identify the role of the DSO as "Passive and Reactive" in this market model. This market model should be avoided in the future, especially when more resources connected to the distribution grid offer flexibility. As shown in Section 3.2, in situations where the distribution grid is heavily loaded and the TSO is procuring downward flexibility, the activation of such flexibility in this distribution system can cause grid violations. Moreover, in a situation with a high volume of distributed generation and with TSOs procuring upward flexibility, the activation of the distributed flexibility can also lead to grid violations (such as over/under voltage). These two situations can already arise today and/or are very likely to happen in the future, when more distributed energy resources will be available.

In case there is a level of prequalification (Model B), the DSO can indicate beforehand which flexibility assets are permitted to offer flexibility. The TSO can then, in the market clearing, only use flexibility assets that are prequalified by the DSO. As such, the coordination between both SOs is minimal, with the DSO performing the grid prequalification role regardless of the market procurement of the TSOs. For instance, the timing of the *prequalification-BaU* is independent of the timing of the TSO flexibility market procurement (market clearing) as the first tends to be more static and to happen after a request from the willing FSP. As a result, DSO grid constraints are accounted for, but in a very conservative way. That is, given the fact that the DSO is not part of the market clearing, it might precautionary block specific flexibility assets, based on worst-case scenarios/analysis to guarantee that any activation of this flexibility will never cause grid issues. That is why we classify the role of the DSO as a "Flexibility Gate Keeper" in this market model. The impact of this precautionary/conservative strategy from the DSOs can be negative to the TSO because distributed flexibility might be blocked even during times with no grid-safety risks, which can reduce market liquidity and/or increase the flexibility procurement cost. As already mentioned in this section, Belgian DSOs apply NFSs which are a type of *prequalification-BaU* for distribution-grid-connected resources. On top of having the coordination challenges already mentioned in this paragraph, NFSs are also seen as an administrative burden and an additional discouraging barrier for LV flexibility (as was discussed in Box 5.2).

Models C and D implement more dynamic and detailed ways for the DSO to indicate its grid constraints, which, in turn, are more efficient and accurate than the previous models, and involve different levels of coordination between the TSO and the DSO. For the former (model C: *with-OE*), very detailed data are used by the DSO to calculate the operating envelopes, which includes not only network data but also the amounts of flexibility to be offered in the flexibility markets at certain times. However, only the reduced network representation – i.e., the limits on the flexibility resources calculated using the OEs by the DSO – is shared with the TSO, including sufficient information for the TSO to perform a market clearing that is (relatively) safe for the system as a whole. As such, a higher level of coordination between DSO and TSO is seen in this model: in terms of timing of the market (when the prequalification is more dynamic), in terms of up-to-date market data (e.g., what are the bids that FSPs are willing to submit in the TSO market so the DSO can prequalify them), and in terms of sharing the DSO's calculated limits (operating envelopes). Although more coordination is needed in this model, one can note that no confidential data is shared, and the roles (of the TSO as the market procurer/operator and of the DSO as the "Active Prequalification Officer") are well defined. As such, we consider that this leads to an efficient coordination between the two types of SOs.

In case of model D (*full-DN*), more coordination between TSO and DSO as well as the amount of data sharing is needed as compared to the other models. In this model, the DSO full network data must be included in the market clearing, meaning that it shall provide that information to the market operator of the TSO flexibility market (which can be the TSO itself or a third-party such as an independent market operator). That is why the DSO assumes a role of "Data Sharing Officer" in this model. As discussed in the next paragraph (linked to data implications), this data sharing can be very burdensome due to two main reasons: data would need to be maintained in different locations (e.g., control centres of DSOs and TSO market operator data centres), and DSOs might not necessarily be able to share this data with third parties (e.g., because of confidentiality rules) [8]. Moreover, higher costs might be involved with the data sharing aspect, together with timing challenges (i.e., for the DSO to provide the right information on time for each TSO market clearing). Another important challenge of this model is the transfer of responsibility to safeguard the distribution grid from the DSO to the TSO/market operator, which can prevent the DSOs from accepting its implementation. As such, the full coordination between the DSO and TSO required in the *full*-DN model might take up too much resources if compared to the previous ones.

Finally, it should be pointed out that coordination is not always feasible in practice. In non-mature or transitioning markets, it might therefore be recommended to opt for models that require less coordination. For Belgium, this challenge is discussed in Box 5.3.

Box 5.3 TSO-DSO coordination

Today, in Belgium, coordination between the transmission grid operator and the distribution grid operators is not very formally described. In Flanders, different market parties highlight the lack of coordination as an issue for the implementation of LV-flexibility markets. Without cooperation, there might be a lock-in of flexibility, or conflicting activation **[87]**. We zoom deeper in on this barrier in D3.3 of Alexander to be released after the publication of D3.2. However, while in the future TSO-DSO coordination might be the standard, in the short-run, solutions to deal with limited TSO-DSO coordination are needed. Model C, the operation envelopes, offers a good step-up in this transition period.

Data implications: As pointed out in the table, there are three types of data implications, namely data challenges for the DSO, either linked to network data or linked to consumer data, and data challenges for the MO linked to the acquisition of the required data.

First, only in model D (*full-DN*), data needs to be shared by the DSO with the MO. The MO can be an independent third party, or it can be the TSO. In case it is the TSO, high TSO-DSO coordination is required as discussed before. In case it is a third party, further coordination with other stakeholders is required. The models in the middle of the scale (models B and C) aim to find a balance in case there is no sufficient TSO-DSO coordination and/or when grid data sharing is in general difficult. In both cases, no distribution grid data are included in the market clearing. Instead, before the market clearing, some form of prequalification is done. In the model B, this is done through for instance a traffic light system or through a flexibility grid study which gives permission to some assets to join the market. As a result, the MO doesn't need the distribution network information. The DSO performs the required calculations internally and provides the information through prequalification to the MO. In model C, prequalification information is included in the form of operating envelopes that the DSO provides, representing the operational constraints of the distribution network without sharing the network detailed data. Thanks to this, the MO does not need the detailed customer and grid information. The MO only needs bid information and the envelopes (i.e., limits), which are calculated by the DSO and provided to the MO. The latter model therefore represents a situation in which the DSO prequalifies bids such that the bids that participate in the flexibility market have dynamic limits that act as a proxy of the network state and constraints. As a result, the latter model ensures that certain data sharing challenges (e.g., related to confidentiality of DN data and its maintenance in multiple servers) are solved, while ensuring that an (independent) MO can clear the market safely (i.e., indirectly taking into account distribution grid constraints) in the case where the OE calculation methods can guarantee grid safety (as different methods can offer different levels of safety, as discussed in Chapter 3). In addition, the operating envelopes also simplify TSO-DSO coordination regarding flexibility procurement and activation as fewer details need to be shared. As such, TSO-DSO coordination might become more efficient with regards to flexibility procurement and activation.

As a consequence, the choice of the model can resolve existing data-sharing constraints. In model D, a third party would need to have access to distribution grid data (topology information on nodes and lines, connections and other grid parameters, grid limits such as capacities). This is information that the DSO possesses, and which is, in practice, challenging to share with third parties due to network security and privacy issues, but also due to the fact that the information is updated frequently. Sharing information would imply that the information would have to be maintained and updated in multiple places/databases/servers. This implies that it continues to be challenging for an MO to include this information in the market clearing which implies that distribution grid constraints would potentially still be not accounted for correctly. In addition, the grid operator is the one and only entity responsible for grid security. It is therefore desired that it remains in control of decisions related to grid constraints. Model D implies that the market clearing is performed by a third party. For the MO, this would imply access to the DSO-grid data and for the DSO this requires a third party being partly in charge of grid security. This is, especially in today's transitioning markets, a key barrier for LV-flexibility provision. Model B and C offer a solution for this in the sense that distribution grid data sharing with a third party is not needed, while the DSO remains in charge of the data, the calculations, and the secure operation of its network.

Box 5.4 Data sharing

As discussed in Chapter 2, there are multiple data platforms in Belgium. There are platforms linked to the end-user data (Atrias), platforms linked to flexibility (Flexibility Hub), and platforms linked to specific products (aFRR). However, the collaboration between these platforms is not yet on point. Some parts are still done manually. In addition, some elements of the platforms are developed in the first place for the transmission grid operator and its users. As a result, today, parts of the platforms are still being adapted to distribution grid needs. Maintaining data on different platforms is therefore not desired at the current stage.

On top of the data sharing challenges, it is also to be highlighted that different models require a different quality or detail in data. Models C and D require a full grid network representation. Nevertheless, at an LV level, there are possible grid observability challenges for the grid operator, implying that some areas do not have a clear view of their grid. We note, here, that the network representation needed in Models C and D can be adapted based on the available information and the expected criticality of the different grid elements, thus limiting the hurdles of including a full network model. Model B, on the other hand, could allow for a NFS based on information that the grid operator has from operational parameters or from previously identified problems in the area (such as voltage problems). Nevertheless, NFS generally also requires quite detailed grid data. Only in case no grid prequalification is done, no data are required.

Finally, with respect to consumer data, all prequalification models require some level of information from consumers/FSPs. Model B (*prequalification-BaU*) requires less detailed information from FSP and from expected injection/offtake over the network (see Box 2.2 for a set of data needed in the Belgian NFS) than Models C and D. However, in case of model C (*with-OEs*) and D (*full-DN*), more details are needed especially regarding the FSP connection node, offered flexibility, and forecasts of injection and offtake profiles. This is, however, a key challenge for grid operators as digital meters are currently still being rolled-out. Furthermore, even if in the future, everybody in Belgium will have a digital meter, it is possible to have data inaccuracies. Having accurate consumer data is therefore a key challenge, and we discuss strategies to tackle it in Box 5.5.

Box 5.5 Limited Availability of Data

The availability and accuracy of data are critical for producing reliable results. However, the reality is often marked by incomplete or imperfect data. This section outlines strategies and considerations for running the proposed models when faced with limited data **[88]**.

The availability and quality of data heavily depend on regional regulations. Even in regions with advanced digital metering infrastructure, complete data availability is rare. Digital meters, if deployed, may not always provide real-time data, or may have gaps in coverage. Therefore, practical approaches must be adopted to work with the available data. The following scenarios outline potential limitations and corresponding approaches.

1. No load profile data and no grid data:

   In the absence of both load profile and grid data, running any of the models proposed in this deliverable is not feasible, apart from the *no-DN* model. For all the other models, not having any load profile data nor grid data is insufficient to estimate the needed information (e.g., network behaviour and power flows) to run them.

2. No load profile data, but with grid data:

   In case there are grid data, but only limited customer or load profile data, it is possible to use peak time estimates and worst-case scenarios. This can be achieved by relying on historical data, expert opinions, or established rules of thumb. While not precise, these estimates can provide a rough understanding of the network's behaviour under peak conditions, which allows to run certain power flows analysis and performs, for instance, network flexibility studies. In this situation, model B, the *Prequalification-BaU* model is probably the most appropriate.

3. Digital meter data (15-min to 30-min intervals)

   Two possibilities exist based on data representativeness:

   - Full rollout with representative data: In this case, data is available from all locations of interest. This ideal scenario allows the DSOs to leverage the data for various purposes:
     - Improving rules of thumb: Enhance existing load estimation methods by incorporating real-world data patterns.
     - Sampling: Utilize the data to select representative samples for analysis methodologies.
     - Load behaviour modelling: Develop models to describe load behaviour, acknowledging potential errors due to the loss of time-series information.
   - Partial rollout or non-representative data: In this case, data may not be available from all locations of interest. Here, strategies include:
     - Representative data sets: Employ historical data from similar consumers or locations to supplement the limited data.

- Disaggregation techniques: Disaggregate substation measurements (bus bar or feeder level, if available) to estimate individual consumer profiles. This can involve rule-of-thumb methods (e.g., dividing by yearly or peak consumption) or, in specific cases, utilizing synthetic load profiles (SLPs).

In this case, for those regions where there is a full roll-out of digital meters, it is possible to go for more advanced models such as model C (*with-OEs*) or such as model D (*full-DN*). However, in case one needs to rely on historical data, it is more probable that model B (*prequalification-BaU*) or C (*with-OEs*) are applied.

4. Limitations of grid data

The quality of grid data also significantly impacts the power flow model selection. Here are common limitations and potential solutions:

- Inaccurate open point (switch) data: Misregistered open points can lead to errors in network topology representation. Verification and correction of open point data are crucial.
- GIS database quality: The quality of the Geographic Information System (GIS) database significantly impacts the accuracy of network representation. Investigate the database's age and consider data validation procedures.
- Missing connection cable data: Connection cables can influence voltage and power flow calculations. This requires investigating the availability of cable data and considering potential estimation methods if data is missing.
- Unknown consumer phase connection: DSOs do not have complete information on which phase LV consumers are connected to. Techniques like voltage correlations or current fitting can be explored to infer phase connections.

Limited grid data availability presents challenges in running the proposed models. However, by employing a combination of estimation techniques, representative data sets, and disaggregation methods, it is possible to develop power flow models of varying complexity. The accuracy of the model will be directly related to the quality and representativeness of the available data. As such, depending on how detailed the grid data are, a solution applicable for models ranging from B to D is possible.

Operational implications: In model A (*no-DN*), flexibility is not restricted, even if this might not be feasible for the DSO. If markets are open, flexibility resources can participate in all of them. However, this might cause constraints on the distribution grid, implying that the DSO might take emergency actions that could block resources. In model B (*prequalification-BaU*), flexibility is restricted as it is decided ex-ante whether a specific resource in a specific area can participate. This binary decision might block or allow flexibility for a long period of time. In model C (*with-OEs*), the operating envelopes allocate the available hosting capacity to individual or aggregated connection points within a segment of the distribution network in each time interval. The flexibility prequalification is done through "ranges" as the model defines a range of power outputs that are allowed to being offered. For instance, an FSP can offer between 0.2 and 0.4 MW of flexibility. It is therefore less restricted than model B which uses more tight limits, even if the grid is not fully used. Finally, model D (*full-DN*) restricts flexibility to whatever is possible in practice, given the distribution grid constraints. As such, we can conclude that this one is the one which restrict ideally (and, thus, which is the most cost-effective one among grid-safe solutions).

All models that take into account grid constraints (*prequalification-BaU*, *with-OE* and *full-DN*) are performed over time, as the state of the network evolves. Their calculations can be done from real-time to a year ahead. However, providing such calculations close to real-time entails practical complexities (especially when no metered data are dynamically available), while a fixed schedule for a whole year would require accurate forecasts of the consumption/generation patterns for the LV consumers/prosumers.

Furthermore, related to the frequency at which the grid prequalification is done, it should be noted that in theory, this can be done in a static or dynamic way. Today, in Belgium, an NFS (which is an example of model B) is generally not repeated frequently for the same area, implying that a static approach is taken, but, in theory, it is possible to do it more frequently. Nevertheless, the static approach results in a go / no-go decision for flexibility resources to offer their flexibility. When resources are not allowed to offer flexibility, they are not allowed to do so for a prolonged time-period, even though there might be moments where they do not cause additional grid constraints. In Box 5.6 we show the main lines around which the current discussion in Belgium related to the NFS frequency revolves. In model C (*with-OEs*), the prequalification can also be calculated at any desired frequency, on the condition that data are available and computational resources are not an issue. However, this method is expected to be applied closer to the market clearing, in a more dynamic way, to be able to give to the market procurement phase up-to-date information on the available grid-safe flexibility in the distribution systems. In model D (*full-DN*), the prequalification is performed during the procurement phase, meaning that it has to be calculated when the market is cleared, as such being as dynamic as the market clearing step. It is important to note that the closer to the market clearing the prequalification of distribution-connected resources is performed, the more information is available about the network state and the more accurate the calculations related to the available and grid-safe flexibility are.

Box 5.6 NFS Frequency

As discussed in Chapter 2, in Belgium, an NFS is completed only once for a long period of time. In the future, when there is more data available, these calculations can occur faster (from daily to real time) **[31]**. Stakeholders are also requesting such a dynamic approach **[52]**. For instance, FEBEG is against the pre-emptive capping or prohibiting of market flexibility for a prolonged period of time. Future processes "should be based on an iterative exchange of information (from prediction to real-time information) between grid operators (risk of congestion, etc.) and flexibility service providers (available flexibility, planned flexibility actions, etc.) so that grid operators can manage congestion more in real-time by filtering out and cancelling closer to real-time activations of market flexibility" **[33]**.

Box 5.7 Data granularity

While there is a preference for prequalification closer to real-time (see previous box), there remains a data challenge. While we already discussed some data challenges, an additional data challenge is the frequency (or granularity) at which data are collected. The granularity in data, also determines the frequency at which it is possible to prequalify resources. In Belgium, different market parties indicated in the Synergrid consultation that real-time data communication is expensive and that this (together with the requested asset granularity, for instance, per individual device) might harm the business case of specific services (for instance aFRR for LV). For example, it remains to be investigated whether 4-second data are truly needed, and whether it is preferred to send data in an aggregated way. In addition, for Flanders, LV participants need an SMR3 (measurement regime 3) enabled meter to participate in aFRR LV. Some market participants fear that this might lead to unfair competition between the regions, as the requirement is only for Flanders. This is, however, due to the fact that in Brussels and Wallonia the smart meter roll-out is slower **[89]**. In addition, DSOs are transitioning from a central gateway to a local gateway. A local gateway allows for direct communication of measurement data. However, it is indicated by market participants that this is expensive and that it blocks usage of aggregated data from different private meters behind the same access point. In addition, a local gateway makes it harder to efficiently steer flexible devices on-line which is indispensable for a successful participation of LV-consumers in the flexibility market. Given the current challenges, the DSOs allow a transition period until the 31st of December 2026 in which the central gateway is still allowed.

Table 5-2: Measurement requirements replicated from ***[32]***

	FCR	aFRR	mFRR	ToE in DA/ID	CRM
Granularity of the data	2 seconds	4 seconds	15 mins	15 mins	15 mins
Frequency of the data	Real time and ex-post	Real time	Ex-post	Ex-post	Ex-post
Origin of the data	Submeter or regulated meter *(Today only private meters as there are no meter requirements of the DSO. Submeter only from third party.)*	Submeter or regulated meter *(aFRR is semi-regulated as there are measurement requirements in C8/06. Submeter only from third party.)*	Regulated meter or submeter	Regulated meter or submeter	Regulated meter or submeter

Finally, regarding the impact of processes of the SO and the FSPs, we discuss whether the different parties need to adapt depending on the prequalification model chosen. For the FSPs, it seems that in cases where there is no prequalification process, or when the prequalification process is more "automated", the FSP does not need to apply significant changes to its existing processes. This is because when there is no prequalification, the FSP is not required to do anything in terms of providing data for prequalification. In case that the DSO does specific calculations (*with-OE* (model C) or *full-DN* (model D)), the DSO matches these detailed grid data with consumer data which it can retrieve automatically (for instance, from smart meter data). However, in case the DSO does an NFS (model B), the DSO does not use smart meter data. Instead, the DSO requests specific data to the FSP (see also Box 2.2). In this case, the FSP would need to adapt its processes to ensure delivery of these data to the DSO.

From the perspective of the DSO, in case model A is chosen, there is no prequalification, which is less favourable for the applicability with other DSO processes. This is because there might be TSO flexibility activations that could lead to constraints violations on the distribution grid, requiring the DSO to take sudden corrective actions. Indeed, the DSO is responsible for distribution grid security. Therefore, it can be argued that the DSO already has these processes in place. However, in case LV-flexibility provision increases, these processes might come under pressure, requiring adaptation from the DSO in the model A scenario. Scenarios where the DSO can do prequalification checks beforehand are therefore more desired and compatible with existing processes. In case model D is chosen, the DSO would have to make significant adaptations in its processes as the DSO would need to adapt the timing of the prequalification process to the timing of the TSO market clearing. This model is therefore the least compatible with existing DSO processes.

Applicability: Today, LV-flexibility offers in flexibility markets are still very limited. As a result, in most Member States, there are only small volumes of LV flexibility, and it could be argued that those cannot yet have a large impact on grid constraints. In that case, model A (*no-DN*) could still be possible. It can be argued that when the grid is not stressed in any condition, this model is suited. In addition, it would be a good way to kick-start an emerging market (which can also be seen in Belgium where exemptions are given for the NFS in some cases).

However, given the speed-up of implementing LV-flexibility markets and the electrification of consumption assets, this situation is very unlikely to be realistic in all circumstances. As a result, there will be a move to models B (*prequalification-BaU*), C (*with-OEs*), and D (*full-DN*). Model D is only an option in case detailed grid data are available and can be shared with third parties, as well as if the resulting complexity of the market clearing is manageable. In case sufficient data are available but it is not possible or preferred to share them, model C becomes the most favourable. In case data are lacking and the DSO only has (for instance) insights into grid problems through operational parameters, model B would be best suited.

Furthermore, not only in Belgium, but also in other countries, non-LV-flexibility has been prioritized in the past. In Belgium, Thermovault indicated during the Synergrid workshops (see Chapter 2) that in 2022, LV was not yet considered. Indeed, the topic was only addressed in a second phase in 2023 as there are extra complications linked to, among others, more potential changes in the contract situation of the customer, more risk of congestion and data privacy. It was argued that today flexibility volumes from low voltage grids are very low and that high transactional costs need to be avoided to unlock the related flexibility volumes. Thermovault emphasises that there would be higher flexibility volumes available if the market would allow to unlock them [90].

In general, it is also criticized that often rules from higher voltage levels are translated to lower voltage levels, which cause significant barriers for low voltage [44]. Brugel highlights that this is mostly an issue for the prequalification processes and that exemptions such as those given in Flanders should be given everywhere in Belgium [44]. Another example of this was highlighted by Centrica during the Fast Track aFRR consultation where they criticized that metering specifications were reused from existing specifications for MV. This could have a limiting effect on overall participation [91].

Finally, the applicability of specific models is also influenced by EU, national and/or regional regulation. In Belgium, it is clear that an NFS (and thus model B) is required in most cases, yet that in some cases model A applies. The NCDR (network code demand response) leaves room for both conditional or long-term grid prequalification and dynamic or short-term grid prequalification. As a result, all models that are possible in theory, are also allowed by the EU as long as they ensure grid safety and do not cause discrimination between different grid users and flexibility providers.

6. Conclusion

In this deliverable, we assessed different options to express grid constraints of the networks to which the distributed resources (in particular, low voltage (LV)-ones) are connected and include them in the overall process of the transmission system operator (TSO) flexibility procurement. Four options were studied: 1) not considering any distribution system operators (DSOs) constraints when TSO procures flexibility from distributed energy resources (DERs) – named *no-DN*; 2) performing a static prequalification of DERs resources before they join the TSO flexibility market – named *prequalification-BaU*; 3) performing a detailed and dynamic prequalification of DERs – using operating envelopes – before they participate in the TSO flexibility market – named *with-OE*; and 4) embedding the DSOs constraints in the procurement phase, together with the market clearing of the TSO – named *full-DN*. We developed mathematical models for these different options to study their benefits and drawbacks in terms of market efficiency (procurement cost), market clearing speed, DSO grid safety guarantee, and discarded flexibility. We also evaluated the feasibility of implementing the proposed solutions for the grid-safe activation of distributed, LV flexibility in the Belgian context.

In a first step, we studied TSO flexibility markets in Belgium, including their regulatory framework, their specificities for LV-connected resources, and their grid prequalification methods. We identified that Belgium applies the first two options: either prequalification does not take place (option *no-DN*), or it is done long before activation of flexibility through a (static) Network Flexibility Study (NFS) (option *prequalification-BaU*). The general rules in all three Belgian regions are that DSO grid prequalification is done through an NFS which is done by the DSO prior to the start of the flexibility provision. Only prequalified flexibility service provider (FSP) resources can submit offers to the TSO and the DSO is further not involved in the TSO procurement process. The disadvantage of this is that in a situation where LV-flexibility participation increases, its potential might be blocked through this static mechanism by the DSO for a longer period of time, as the result of the NFS remains valid for multiple months. Furthermore, it is argued that the NFS can constitute a burden for LV-flexibility assets, and thus constitute a barrier for the role-out of LV-flexibility. As a result, there are two types of discussions in Belgium:

- On the one hand, actions have been taken to give exemptions to LV flexibility from being required to go through the NFS. As a result, in Flanders, in case of LV, flexible power will not be restricted when it is limited to 5 kVA for a mono phase connection or 10 kVA for a three-phase connection. Furthermore, depending on the product offered, an NFS is also not required (for instance in case of FCR). In other circumstances, the DSO has the right to add constraints for LV via the NFS-procedure.
- On the other hand, there are discussions in Belgium to move from static prequalification towards dynamic prequalification. This is a process that is influenced by data availability and coordination between system operators. However, it is also influenced by how such method would be implemented in practice.

In a second step, three out of the four options mentioned (1 – *no-DN*, 3 – *with-OE,* and 4 – *full-DN*) were mathematically modelled, implemented, and simulated. Results have shown that, depending on the option used, there is a trade-off between the TSO procurement cost and the grid-safety of the DSO network when the TSO activates distribution-connected resources. More specifically, if the *no-DN* model is used, the TSO can have a lower flexibility procurement cost, at the expense of possibly causing grid violations in the distribution network, inducing challenges and costs to the DSO to perform corrective actions. On the other extreme, if a *full-DN* model is used, in which the distribution network constraints are embedded in the TSO market clearing process, the DSO grid is guaranteed to be safe, but the procurement cost of the TSO would increase. In addition, the prequalification method used (variations of the *with-OE* model are possible) can lead to better or worse results in terms of grid-safety and market procurement efficiency. For instance, if the DN-connected resources are prequalified per connection point and the calculated limits are included in the procurement process, the DSO grid is more guaranteed to be safe after activation, while if the resources are prequalified in groups (e.g., aggregated for a certain FSP, or aggregated at the level of the transformer), grid violations can still happen when the TSO activates the resulting grouped resources. Moreover, the prequalification of DN-connected resources with the operating envelopes method (*with-OE*) discards available flexibility from the distribution network in order to guarantee that the allowed volumes do not cause grid violations when activated. This comes at the expense of a more costly flexibility procurement to the TSO. Finally, when a more detailed network model of the LV distribution grid (e.g., a relaxed UTOPF with SOCP relaxation considering phase unbalances) is used to prequalify the LV resources and calculate their operating envelopes, results have shown that controlling reactive power on the LV network could increase flexibility potential and counteract unbalances between phases. However, this could induce other effects such as increasing reactive losses on the LV network and modifying active/reactive setpoints on the transformers.

In a final step, we have evaluated how feasible it is to implement the studied four options for the grid-safe activation of distributed (LV) flexibility in the Belgian context. We identified that it is fair to say **there is no one-size-fits-all model to consider distribution grid constraints in the flexibility procurement by the TSO**. Depending on the context, different models can be more suited. This context is determined by the market set-up (e.g. different products and buyers), whether or not one wants to account for distribution grid constraints in the market clearing, the timing of the market clearing, the level of coordination between different stakeholders, the data available and the computational power that internal systems have to process these data, regulations regarding roles and responsibilities, compatibility with existing operational processes, grid characteristics and other regulatory constraints. Furthermore, one overarching contextual characteristic is the maturity of the flexibility market. In countries where there are already more grid violations, the market is more likely to be mature and models are more likely to be moving from *no-DN* towards *wit-OE*. However, in countries where flexibility procurement at LV-grid levels is still low, there is a higher likelihood to implement the *no-DN* or *prequalification-BaU* methods. This is also what we see in Belgium. Generally, the different distribution grids in Belgium do not yet face many grid violations. However, there is an urgency to start building up flexibility markets. To kick-start these markets, one is aiming to take away barriers for the provision of LV-flexibility. This can be done by moving towards the *no-DN* model. In Belgium, exemptions are given that imply no NFS is needed for LV-flexibility provision of specific products. A final contextual element is the regulation. In some countries or regions, regulation can determine which model is to be used. In Belgium, the general rule is that an NFS is applied.

Next to contextual elements, there are different design choices that need to be compared to determine which model is most suited. For instance, if one opts for *prequalification-BaU*, it is determined ahead of time which resources can offer flexibility. This creates transparency and certainty ahead of real-time for both the buyer and the seller of flexibility. The disadvantage of this approach, however, is that it might block flexibility unrightfully, especially as compared to when closer to real-time information is available which would allow a more efficient restriction to the available flexibility. The model chosen is also closely linked to different roles and responsibilities that the DSO is willing to take up. DSOs pursuing more active roles would be moving more in the direction of model *with-OE*, as compared to the traditional *no-DN* option. DSOs willing to keep the control over their networks while conservatively defining which DN-connected resources can participate in the flexibility markets would prefer model *prequalification-BaU.* DSOs who want to give control of grid-safety to the market operator (MO), would share their data in order to allow the MO to perform the market clearing (*full-DN*). Finally, the choice to opt for a specific model is also influenced by whether the model is implementable in practice. This depends on data availability, coordination needs, implementation that needs to be in line with existing processes and complexity. From a practical point of view, it is more likely that many SOs will end up with models in the middle of the scale (models *prequalification-BaU* and *with-OE*). These models put less pressure on data and coordination needs and are less computationally complex than model *full-DN*.

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