Selecting mechanisms to acquire DSO flexibility services in the energy transition

COMILLAS UNIVERSIDAD PONTIFICIA

ICAI School of Engineering

Doctoral Thesis
Madrid, Spain 2025

Selecting mechanisms to acquire DSO flexibility services in the energy transition

Ph.D. Student: Fernando David Martín Utrilla

Supervisors: José Pablo Chaves Ávila
Rafael Cossent Arín

MADRID | May 15th, 2025

Summary

This thesis, presented as compendium of papers, is conducted in the context of uncertainty about the usefulness of flexibility for distribution networks to face the energy transition. While relevant articles were published about the benefits of flexibility solutions and demonstration projects had been carried out announcing a variety of new options for the operation of distribution networks, regulators have not been very proactive in implementing them. With a few exceptions such as the United Kingdom, implementation in Europe has been slow in recent years. Reasonable motivations for regulators' misgivings include the question of which is really the best mechanism for flexibility services, the value that this new mechanism could really provide and to what extent Transmission System Operators (TSOs) should intervene in these new solutions. The main objective of this thesis is to study the elements that must define the design and selection of mechanisms to acquire flexibility services for Distribution System Operators (DSOs) needs that could help an efficient implementation of flexibility provision to distribution networks. To accomplish this objective, this thesis follows a stepwise approach.

Firstly, a comprehensive decision-making framework to select the most suitable flexibility mechanism for a particular DSO need is proposed. Not all mechanisms enabling DSOs to access or acquire flexibility services, named flexibility mechanisms, are equally suitable to address the different problems and needs faced by DSOs. There is also a wide range of DSO operational needs and situations of the network (according to the voltage-level, timing, and type of service) which may require different flexibility mechanisms. Several key evaluation criteria should be considered when selecting the most appropriate mechanism (TSO-DSO coordination, market liquidity, generalization), which are detailed in this thesis. As a result, the most suitable mechanisms are highlighted as useful tools to solve the needs of the network at all voltage levels and adapted to each situation. The first paper of the compendium (Annex 1) is devoted to this stage.

In the second stage, a Cost-Benefit Analysis (CBA) is conducted to objectively assess these flexible alternatives, comparing the value of the flexible solution with the value of the traditional solution. The second paper of the compendium (Annex 2) is related to this analysis. To do this, four realistic use cases are selected in the Spanish context with real networks and probable future scenarios to perform comparisons and provide conclusions about the true value of flexibility. The first case is related to the connection of a wind farm to the 132kV grid, for which costly reinforcements are necessary. This is a situation repeated throughout the geography. The second case is an urban MV network in which electric vehicles are charged simultaneously. The third case involves maintenance work on a 132kV line that requires interrupting a large amount of power. The last case involves congestions in secondary substations due to the proliferation of photovoltaic generation in a residential area. All of them are cases that, in the scenario of energy transition, are likely to be reproduced in many places in a similar way.

The following steps are followed for each of the case studies. First, the real value of the traditional or business-as-usual (BAU) solution is identified. Secondly, following a comprehensive analysis of the costs involved, flexible solutions' costs are estimated. Finally, both solutions are compared to evaluate the value and possible sensitivities with respect to the variables considered, for example, the number of activations or kilometers of lines required, so

that some conclusions can be drawn about the value of flexibility in these likely situations. Results show that flexibility presents a different value depending on the use cases considered and that, in some cases, traditional solutions can be more competitive than alternatives with flexibility services. Network reinforcements in the distribution network have a long lifespan and provide reliable service to thousands of customers. However, flexibility services can be useful for accelerating decarbonization through flexible connections (i.e., non-firm connections) or short-term solutions to manage the distribution network operation, which are two specific flexibility mechanisms considered in the CBA assessment of the realistic cases.

The need for TSO-DSO coordination is assessed in the third stage, and is the topic addressed in the third paper of the compendium (Annex 3). In this regard, this thesis reviews the activities of TSOs and DSOs and their short- and long-term needs at different voltage levels. Similarly to how regular distribution network operations, despite continuously affecting the system balance operation, require no major coordination among system operators, DSO flexible solutions might also have a very small impact on the overall system. The literature has not previously analyzed where the limit beyond which coordination would be necessary is found. This question requires an analysis of the different DSO operations where the need for coordination is foreseen, and a case-by-case study considers the impacts created by the actions of the DSO managing flexible resources on the responsibilities of the TSO. Major coordination is deemed as the type of coordination that requires not only information exchange but also the other operator's approval or supervision. To that end, the application of a flexible tool is assimilated to real operational situations of the same scale. Then, the impact on the activities of the TSO in each of the different operational situations is studied, after selecting those operational situations for different voltage levels and timeframes as candidates to require such major coordination. The following method was adopted: Firstly, regular network operations are selected with an impact similar to that expected for the flexibility needs of the distribution network. Then, power flow analysis is performed with the network in a normal state and with the network after a regular operation to account for the number of additional overloads that may occur. This operation is repeated, raising the load in ten sections until the demand in the area is doubled in order to compare with and without the deemed operation (an opening maneuver or a load transfer) in different demand scenarios to verify the impact on the transmission network. Afterwards, the methodology is replicated considering that the TSO-DSO boundary is located at different voltage levels so as to reflect the situation in different countries where the subtransmission grid may be operated by a different type of grid operator. Results show that the additional overloads in the transmission grid created by equivalent network operations are negligible. So, there should also be no significant impact on TSO when regular local flexibility mechanisms are enabled for the distribution network. Concluding that major coordination would only be necessary when there is high power change and in the short term. The threshold of what is considered "high" depends on the voltage level at which the TSO-DSO border is located. In the Spanish case, where the subtransmission grid is operated by DSOs, this threshold could be set above 50MW for the studied area based on the results of this thesis.

The fourth stage is the one that corresponds to the regulatory recommendations and further research proposals, highlighting that the incorporation of flexible solutions would, therefore, be about enabling a toolbox of flexibility mechanisms so that the DSO can select the most appropriate one, with or without TSO-DSO major coordination, or with or without market liquidity. A more detailed study of the possibility of having sufficient liquidity for each type of network need in order to have an efficient competitive market would be required to shed light on the choice of the mechanism to acquire flexibility. Additionally, many uncertain parameters influence the efficiency of the flexible solution when compared to traditional solutions and can vary greatly, such as the lifespan of the assets, the value of lost load, the cost of energy or the cost of reinforcements, and whose magnitudes determine the true value of flexibility. Therefore, it is not possible to think of a one-size-fits-all solution. An individual study of each case is necessary to assess the value of flexibility. Finally, in order to improve liquidity for the market-based solutions to be optimal it is necessary to make an exhaustive analysis of the roles of the stakeholders, especially the flexibility aggregator, who is expected to play a key role concerning access to flexibility.

With this research, it was possible to highlight the diversity of both DSO needs and possible solutions, providing a decision framework to match each type of need with the optimal mechanism. It was possible also to determine which solutions may be more competitive than traditional solutions and under which conditions, adding more certainty about what the first steps for regulatory changes should be. And finally, with a detailed study on the impact of the flexibility enabled by the DSO on the responsibilities of the TSO, it was possible to establish a limit to the needs for TSO-DSO coordination to avoid unnecessary cost overruns.

All this work was useful to focus the efforts of implementing flexible solutions on those mechanisms and needs that result in an improvement, either in efficiency or in sustainability, or in both. Further studies would be needed to research deeper into these implementations. The final section proposes some possible future studies on flexible probabilistic planning, the need to measure liquidity, or a broader study of the sensitivities affecting cost-benefit analysis.

Contents

1 Introduction

1.1 Context

The decarbonization of the electricity generation mix drives a decentralization that requires revisiting markets, regulation, and other organizational practices within the power system. Additionally, electrification is seen as a central means to decarbonize other electricity uses in transport or heating. In this context, new forms of electrical energy consumption and new forms of distributed generation raise new requirements for Distribution System Operators (DSOs).

The grid needs can be met in the traditional way (e.g. investing in network assets). However, these needs can also be satisfied by acquiring flexibility services provided by the resources connected to the network [1]. These services must be adapted to the needs of the network itself. At the same time, the necessary enabling mechanism must be in place for that service request and delivery to occur. A flexibility mechanism is how system operators access and acquire flexibility services from third-party providers.

European regulation has been promoting this since at least 2019. Article 32 of the Directive 2019/944 [2] on common rules for the internal market for electricity states that “Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services”, and that DSOs “shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion”. Therefore, among the flexibility mechanisms, market-based mechanisms was set as the preferred option, although the regulator may choose other mechanisms for overall efficiency reasons.

European regulation establishes a network code which lays down the requirements in relation to demand response, energy storage, distributed generation and demand curtailment rules, including rules on aggregation, to contribute to market integration, non-discrimination, effective competition and the efficient functioning of the market pursuant to Article 59(1) of Regulation (EU) 2019/943 ([3], [4], [5]). But national regulations are still very incipient and there are many doubts about the best way to implement these flexibility solutions.

The Transmission System Operators (TSOs) face the challenge of managing electricity systems with decentralized generation and low inertia due to the foreseen disconnection of big synchronous fossil fuel-powered or nuclear generators that provide stability and also the need to ensure ancillary service providers that maintain the reliability of the system [6]. DSOs, on the other hand, have the challenge of maintaining the quality and reliability standards of the networks in a system that is increasingly moving beyond the traditional distribution function and taking on new duties becoming energy exchange spaces, as demand is increasingly intertwined with generation, and whose consumers will have more heterogeneous and more unpredictable profiles. DSOs will therefore need to develop the skills and facilities necessary to procure and effectively manage the contribution of potentially hundreds of thousands of increasingly active consumers to network security and quality of supply [7]. Furthermore, tackling the energy transition involves electrifying part of the energy demand. The distribution network is the means to bring generation to meet demand. But the necessary grid reinforcements, may be expensive, may not arrive in time, or may not even be possible for other reasons. This makes it necessary to optimize the use of the networks as much as possible. Thus, the future roadmap of a power distribution system shall include not exclusively network upgrades but also non-network solutions focusing on operation strategies exploiting the flexibility gathered from distributed energy resources (DER). [8]

Network needs that may occur as a result of the energy transition are therefore very diverse, and so the mechanisms to acquire DSO flexibility services, hereinafter referred to as flexibility mechanisms, used to address them. The selection and the value of the flexibility mechanisms, starting from the DSO's own needs, the applicability of the different flexibility mechanisms for each situation and a thorough analysis of the coordination needs between system operators are studied in this research.

There are doubts about the usefulness of flexibility as a whole, taking into account that it entails very significant changes in the way the network is operated and planned. The DSO needs are also changing and it is not always clear which of these mechanisms are more useful for a certain need. On top of that, DSOs are not familiar with the topic of market-based procurement of services and active management yet [9], and their responsibilities in this field should be revised in the regulation. Several outstanding barriers need to be overcome to utilize DER flexibility [10], such as the role of aggregators to unlock small DER flexibility, TSO-DSO data exchange or a thorough analysis of which coordination scheme is most suitable.

There is therefore still a lot of uncertainty about the usefulness and timeliness in the choice of each of the possible mechanisms of flexibility activation that this thesis aims to address at different stages. In the first stage, it is intended to shed light on the choice of the flexibility mechanism based on the needs of the DSO. In this thesis, a framework is developed to make this choice. There are some critical stages in which it is necessary to delve deeper. Therefore, the following phases of the thesis address them. Specifically, comparing the flexible solution with the traditional solution on the one hand and in the need for TSO-DSO coordination on the other hand. There are other stages, but having studied these two critical stages and knowing more about the available liquidity, it is possible to find out which family of flexibility mechanisms would be optimal given the ability to better solve the needs of the electricity system. This thesis focuses on the framework itself and also on these two critical steps of the framework.

1.2 Objective

The purpose of this research work carried out for the doctoral thesis entitled "**Selecting mechanisms to acquire DSO flexibility services in the energy transition**" is to analyze the different needs that may arise for DSOs due to the new requirements produced by the energy transition, explore which flexibility solutions could be applicable and explore the applicability in each case.

The main objective is summarized in these research questions:

- How should flexibility mechanisms be selected to provide DSO flexibility services?

- What mechanism better fits each DSO need?
- Is flexibility from grid users more efficient than traditional solutions?
- What kind of coordination between TSO and DSO is necessary?

These questions require addressing these specific objectives, also shown in Figure 1:

- Analise the traditional drivers and the **new drivers** on the planning and operation before comparing BAU solutions with flexibility solutions.
- Identify the existing **needs** of the network and the expected needs (location, procurement time, type of need) by analyzing the planning and operation drivers of the grid, also based on future scenarios.
- Study and assess the different mechanisms for procurement of flexibility by DSOs. Evaluate these **mechanisms to select** depending on different criteria.
- Quantify **the value of flexibility** solutions. Comparison with real network data between the flexibility solution with the traditional solution.
- Analise the **potential cross impacts** of DSO flexibility activation on TSO responsibilities to map out the coordination needs.
- Given that some alternatives are expected to impact the TSO responsibilities, analyze the need for major **coordination** of local DSO mechanisms with the operation of the transmission grid.
- Define a comprehensive framework for selecting flexibility products and provide **regulatory recommendations** for flexibility mechanisms to provide DSO flexibility services.

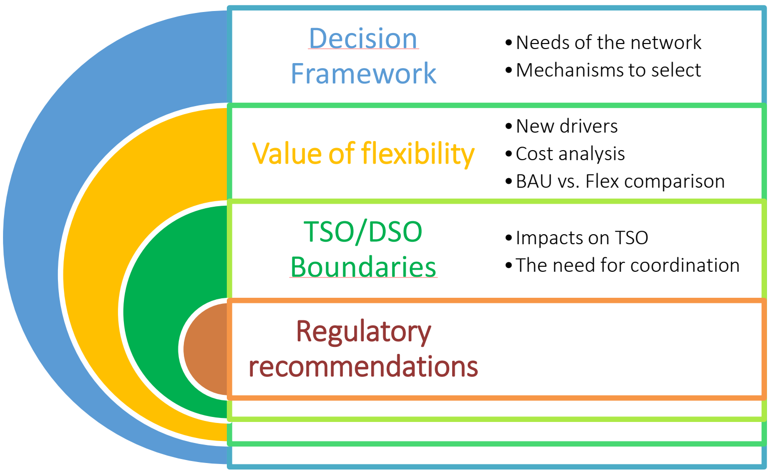


Figure 1: Specific objectives

1.3 Thesis Outline

This study is conducted in three stages. The first is a general one in which the different mechanisms to access flexibility must be appropriate according to the needs of the network studied. The second addresses the comparison of the flexible solution with the traditional solution. And the third is about the need for coordination between the electrical system operators, TSO and DSO. The expected result of this work is to reach regulatory recommendations that can lead to an efficient implementation of the flexibility mechanisms.

This section presents the roadmap of the thesis. The methodology is based on a decision framework for selecting flexibility mechanisms developed in the first stage with a review of the DSO's needs considering all possible solutions for the DSO. This methodology, represented in a simplified way in Figure 2, highlights two critical steps in developing the decision framework. It requires consequently answering two certain critical questions that need detailed studies regarding BAU/Flex comparison and TSO-DSO coordination. Therefore, three relevant questions arise, also represented in Figure 2.

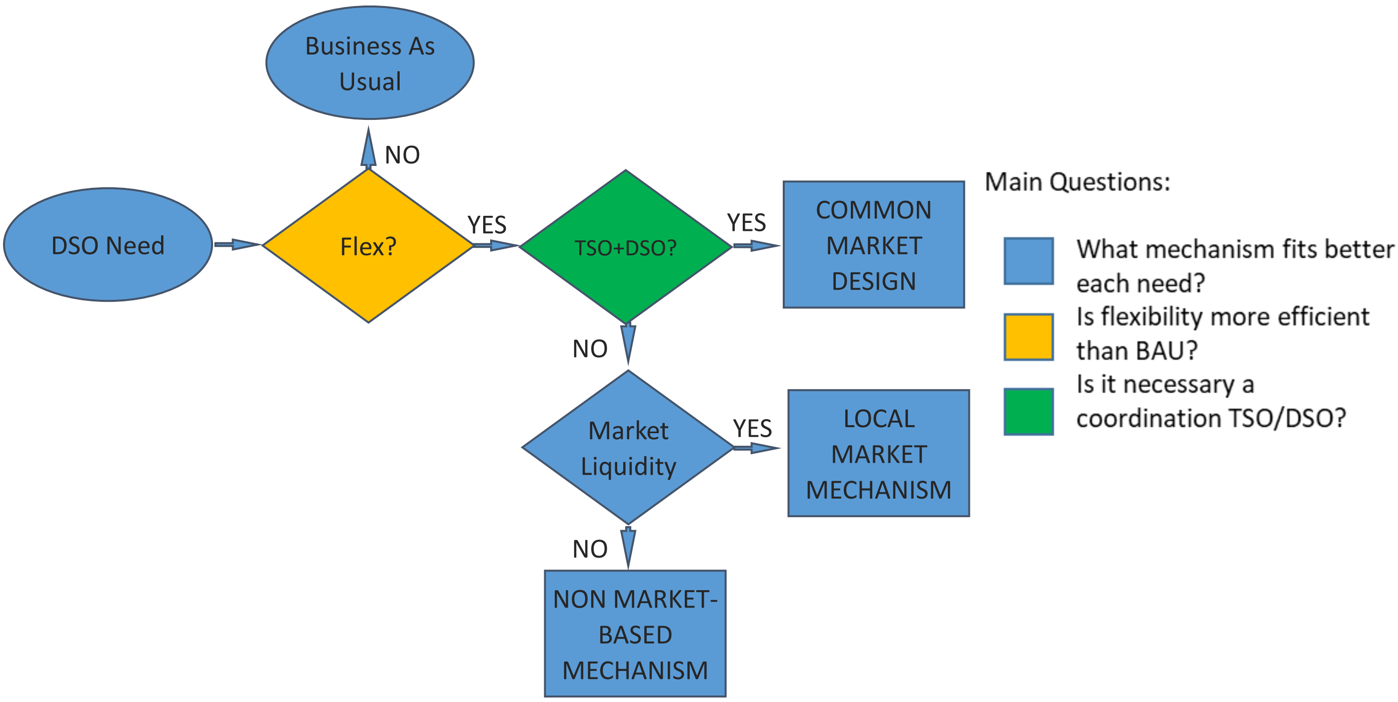


Figure 2 Decision framework and main questions of the first step

The three stages in which the study was performed answer respectively the three questions in Figure 2. Figure 3 presents the different steps of the study.

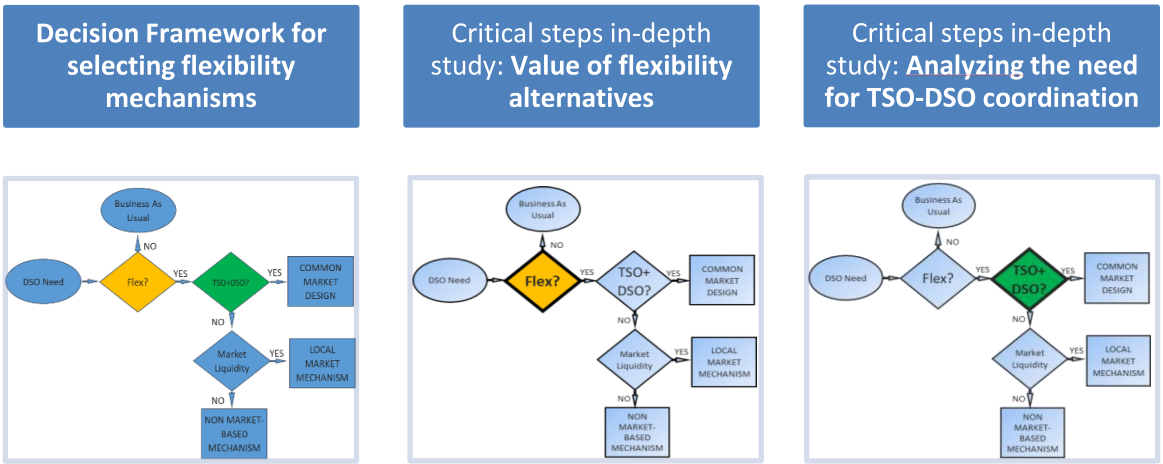


Figure 3 Stages of the study: Decision Framework, value of flexibility, and TSO-DSO coordination study.

The first stage of the three-step approach is the development of a decision framework for selecting flexibility mechanisms. To do so, the key criteria were identified to determine the more suitable mechanism to implement in each case, and also the real needs of the network were considered (the location, procurement time, type of need, liquidity, or coordination between operators) to choose the way to acquire flexibility for DSO use. Based on this, the decision framework considers all the different available mechanisms and, based on the DSO needs and the situation of the network, proposes the most suitable flexibility mechanism. As a result, the most suitable mechanisms are highlighted as useful tools to solve the needs of the network at all voltage levels and adapted to each situation. The corresponding results are published in the journal *Economics of Energy & Environmental Policy* (Annex 1).

The second stage refers to the step of opting for the flexibility solution against the traditional solution that is the first step and represents a definitive filter. To this end, given that the needs are so diverse, a broad-spectrum methodology aligned with the actual challenges of the energy transition for the planning of distribution network is proposed, as it includes a comprehensive analysis of the real costs and the type of needs. Based on it, four representative cases of the real network are taken to compare the application of flexible solutions versus business as usual. To select the representative cases, it is necessary to carry out a prior study of the drivers that may motivate the need and to place them in the context of energy transition. To study the costs of the flexible solution, it is necessary to draw up a list of needs for designing these tools and assign a cost for each use case. From the final conclusions, the aim is to extract those cases for which the flexible solution is clearly more efficient and to detect the sensitivity of those cases that depend on other factors. Results are published the journal *IEEE Access* as shown in Annex 2.

And finally, the last question is about the need for coordination with TSO needs that is crucial and determines following very different branches in the framework. Considering the need for coordination at this point is relevant to not including inefficient actions in the design of solutions. Coordination, understood as supervision or validation of other SOs' actions can become an entry barrier to participation in these markets. The needs of TSOs and DSOs are undoubtedly different. To carry out this study on the need for coordination, power flow modelling is used to simulate actions on the network similar to those resulting from applying a local flexible mechanism. In this way, the order of magnitude of the impact can be assessed. The results of this part of the research are published in the journal *Sustainable Energy, Grids and Networks* (Annex 3).

Finally, the framework is reviewed to draw up a list of regulatory recommendations mainly based on three topics that can be particularly useful to accelerate the energy transition and improve grid operation efficiency. These recommendations aim to contribute to the implementation of the flexibility toolbox maintaining grid reliability, long-term planning comparing flexibility with grid investments, and integrating these new solutions avoiding unnecessary barriers.

This thesis is organized as follows. Section 2 presents the decision framework, section 3 addresses the value of flexibility versus traditional solutions, section 4 reviews the need for TSO-DSO coordination. After that, section 5 presents the regulatory recommendations that are derived from the study and section 6 summarizes the conclusions, contributions and future work. The collection of papers that support the thesis is included in the annexes.

2 Building a decision framework for selecting flexibility mechanisms

This stage is related to the first paper of the compendium that makes up this thesis, included in Annex 2. The challenge is to encompass the wide variety of operational needs that the DSO has and try to match them with the diversity of options for flexibility activation mechanisms. Therefore, firstly, a study of the needs and mechanisms is carried out: the location, procurement time, type of service, and other characteristics that can influence the selection of flexibility mechanisms. On the other hand, the variety of mechanisms that might be selected is also studied. To relate these two sets, some relevant criteria were also studied in the choice of mechanism, such as the impact on the TSO's responsibility, the possible generalization of the problem or the potential market liquidity. Deeming all of them, a clear framework is developed to match DSO needs with the most suitable flexibility mechanism.

2.1 DSO needs and mechanisms to acquire DSO flexibility services

2.1.1 Flexibility mechanisms

A selection of mechanisms requires a prior study of what mechanisms might be available. To do so, a review of previous work was carried out ([11], [12]). Considering the following options:

- **Regulated payments or penalties**: What characterizes these mechanisms is an economic incentive for flexibility provision from the Flexibility Service Providers (FSPs), but there is no commitment for the provision. However, depending on the amount of the penalty, the commitment level would vary.
- **Bilateral Agreements**: A bilateral agreement requires a negotiation process between the two parties: the system operator and the FSP, who participates voluntarily. Connection agreements are considered also bilateral agreements, as long as they are voluntary and there is an agreement on the activation requirements.
- **Dynamic Tariffs**: A dynamic tariff means that the price signal is defined at shorter notice, possibly close to real-time [13]. Dynamic tariffs concern devising time (and locational) differentiated network tariffs which can be adjusted to reflect the necessary temporal and spatial cost variations.
- **Local Markets**: Local flexibility markets include long-term and short-term pools in which offers are received from FSPs. The DSO utilize flexibility based on its willingness to pay for it and the available fallback solutions and the type of flexibility product required. A local flexibility market seeks to promote competition among flexibility providers.
- **Common Markets**: Same concept as Local Markets but in this case Flexibility is selected in a unique market to satisfy both TSO and DSOs needs. Selection of flexibility bids by DSOs and TSOs is carried out in a coordinated process and takes into account the constraints of all the grids involved.

Bilateral agreements and market solutions are considered explicit flexibility as they commit individually to provide the service. Regulated payments or dynamic tariffs are considered implicit flexibility as there is a decision of the FSP to provide or not given an economic incentive. The Council of European Energy Regulators (CEER) proposes also different ways of accessing flexibility [13] that matches this list. CEER considers the active participation of new consumers and generators connected to distribution grids and their contribution to more efficient use of the networks by avoiding traditional costs of network assets sporadically used. The use of flexibility from customers may result in a cheaper and more sustainable electricity grid. In [1] the flexibility of the resources connected to the grid is addressed to cope with the energy transition challenges. In [13] different scenarios are considered in which alternative non-market-based mechanisms can be used to access flexible resources, although it emphasizes again that the market-based mechanism is the preferred option. In [14] it is mentioned that alternative connection agreements should also be assessed from the perspective of being a welcome addition to the 'toolbox' of the DSO. To what degree and in which form alternative contracts could (or should) be implemented should be assessed by European national regulators.

The Council of European Energy Regulators (CEER) perceives also the range of flexible solutions as a toolbox [15] from which the regulators could facilitate flexibility use at distribution level. This thesis aims to provide knowledge about the selection criteria of each mechanism.

To correctly define the operational needs of the DSO that can be solved by FSPs three components are clearly needed: Service to be provided, which determines the electrical parameters involved; voltage level, which determines the type of resources involved; and the timeframe, which determines the type of BAU solution.

2.1.2 DSO Needs - Services

In [16] System Operator (SO) Services are expected to be market-based procurement of balancing, voltage control and congestion management. However, DSO needs may not match the predefined SO services. For this reason, this thesis addresses an in-depth analysis of the DSO needs.

DSO needs vary greatly depending on the type of assets involved and the time frame. The needs determine the type of flexibility service. Some require active power management, while others require reactive power. Some needs require availability or reserve due to the uncertainty about the occurrence of specific events and some others needs require only flexibility activation. The needs required by DSOs are categorized based on whether they are based on availability or activation and whether they require active or reactive power. The services involved could be congestion management, voltage control, and controlled islanding. This list is not closed, and other services could be defined.

- **Congestion management** involves active power changes and/or availability to adjust to prevent network components from reaching their thermal limits. Issues such as investment deferral in network planning, phase balancing, extended assets lifetime, planned and unplanned maintenance operations or resilience in adverse weather events and hazards [17] could be considered mainly under the congestion management services framework as they are related to active power, requiring activation and/or availability of an active power upwards or downwards.
- **Voltage control** requires actions to maintain grid voltages within acceptable ranges. At lower voltage levels, it primarily requires active power management due to the high R/X ratio [18]. However, voltage issues are generally managed through reactive power flows

at higher voltage levels.

- **Controlled islanding** applies to small electrical islands that may arise when the network cannot keep a section of the network connected to the rest in case of network failures.

Availability products are expected to be related to long-term or forecasted needs, as short-term needs would require near real-time activations. There are other flexibility services that address the needs of TSOs, such as balancing, inertia, or black start. In these cases, the DSO could act as a facilitator of the services required by the TSO. However, as they are TSO services, they are not addressed in this study.

2.1.3 DSO Needs – Voltage level

The needs are also different depending on the voltage levels:

- **Low Voltage** (LV, <1kV, ~<100kW): LV networks, which comprise the majority of line kilometers in urban distribution systems, are the least attended due to the low individual criticality of the assets. However, the active management of these networks is becoming increasingly important due to the advancement of automation and the deployment of intelligent systems like advanced metering infrastructure.
- **Medium Voltage** (MV, ~1kV to ~36kV, ~>100kW and ~<5MW): MV networks, which are radially operated, have a significant presence in rural areas or where the overhead network coexists with the urban environment. Despite being similar to higher voltage equipment, they have a considerable level of automation and impact on the continuity of supply indices. Some elements can be very critical.
- **High Voltage** (HV, ~36kV to ~220kV, ~>5MW): HV networks, meshed grids, have operating requirements similar to those of transmission networks. Voltage control in these grids is conducted through reactive power flow management.

Some key characteristics of these three levels include differences in network type, operation, and factors considered when investing. Regarding criticality, LV assets, which feed fewer customers, are considered critical only occasionally. HV assets are more critical due to the number of customers they serve and the relevance of some facilities, such as large industries. MV assets fall in between. The controllability of network assets is also related to their criticality, with HV assets usually being fully automated, controlled, and even monitored with new parameters such as temperature. The digitalization process has contributed to reliability, with automation and control in MV and evolving to LV.

Regarding operation mode, HV networks are generally operated in a meshed mode, while LV and MV assets are operated radially. MV assets have adjacent feeders that assist in case of outages, especially in urban networks. Some other situations need to be considered in specific cases, such as potential social opposition and administrative or environmental constraints in investment works.

2.1.4 DSO Needs - Timeframe

Finally, the needs in network operation are very different depending on the procurement timeframes:

- **Long-term needs**: These are foreseen years or months in advance and are usually addressed with new investments in network assets. Flexibility alternatives may be justified based on deferral investment or even its avoidance. Article 32 of the EU Directive 2019/944 [2] stipulates that network development plans should provide transparency on the necessary medium and long-term flexibility services.
- **Short-term programmed needs**: These are part of the normal network operation for the maintenance of the elements. Interventions are programmed in advance with a predetermined schedule or work plan, and they require the preparation of the network to carry out the maintenance work.
- **Non-programmed short-term needs**: These are unforeseen needs requiring an intervention almost in real-time or just a few minutes or hours in advance, typically in the event of network failures. Due to their unpredictability, it is not possible to forecast these needs, making monitoring essential. Both activation and availability for critical situations or installations are valued in these cases.

While long-term BAU solutions are expected to be new network extensions and reinforcements, short-term BAU solutions typically involve recurrent operational cost actions, outages or quality issues.

Figure 4 graphically shows the characteristics of the needs, also considering availability as part of the definition of services to be considered at a later stage.

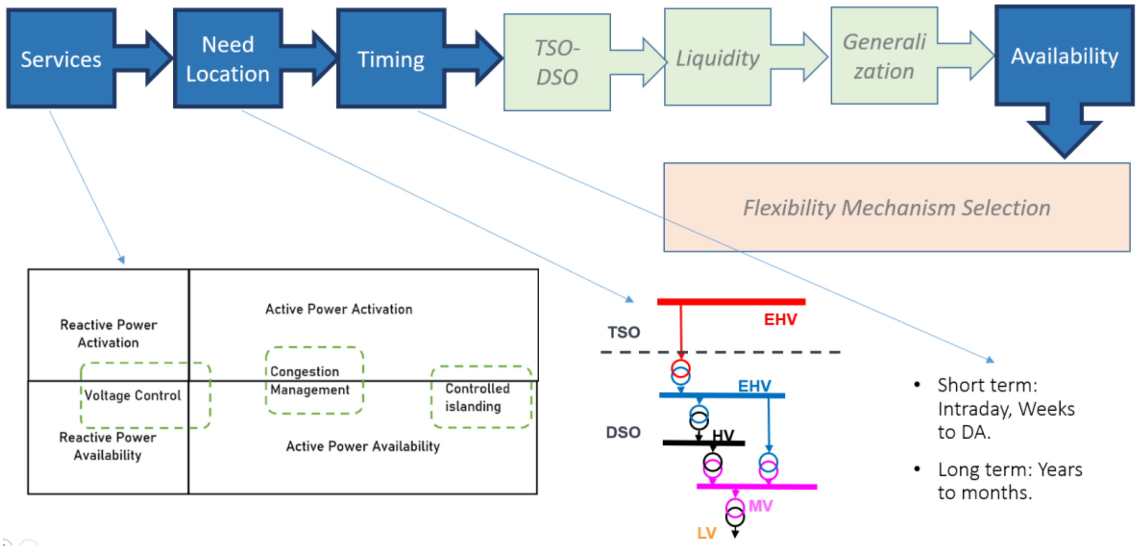


Figure 4. DSO Needs characteristics.

2.2 Criteria for selecting flexibility mechanisms for DSOs.

In this section, based on the variety of needs, the aim is to find the most suitable flexible mechanism.

The examples of local markets tested in Denmark [19] and the pioneering projects undertaken in the UK, Germany, the Netherlands and Norway described in [20] show a direct adaptation of the global framework to local needs, revealing the weaknesses of the lack of liquidity when trying to use the existing market mechanisms of wholesale markets for local needs. The architecture of markets, platforms and even products were designed with this approach in great detail in [19], [21] and [22]. But an adaptation of a global market for local DSO needs is not a local market. At least it is not specifically designed for local needs. The needs of DSOs are very different and require a detailed analysis before showing weaknesses, as the inappropriate tools may be used for each need. Thus, matching the flexibility mechanisms proposed in the literature and the real needs of the distribution network is paramount. This helps DSOs to focus on the most suitable mechanisms for their expected needs.

Similar approaches can be found, but without carrying out such a correspondence. A thorough assessment of the different options for flexibility mechanisms based on surveys among DSOs was performed in [11]. The results reflect the feasibility of solutions that is complementary to the results of this thesis. Besides, authors in [20] present an assessment of flexibility mechanisms according to six relevant design elements: 1) the integration with existing electricity markets, 2) the role of the market operator 3) reservation payment, 4) products standardization, 5) TSO-DSO cooperation, and 6) DSO-DSO cooperation. However, the scope and design of the different projects are very diverse, making it difficult to infer a generalization of the criteria.

The approach to selecting flexible mechanisms can be done from different perspectives. In this study, the priority is given to satisfying the needs, unlike other studies, as in the case of [23] with a supposed bottom-up perspective but leaving the satisfaction of the DSO need at the end of the analysis.

There are some relevant questions when it comes to proposing a flexible mechanism (Figure 2). The first and most obvious is whether flexibility solution is more economical than a traditional solution. This part forms the second stage of this thesis and is studied in more depth in section 3 of this document. This question depends on many factors: the type of need involved, the benefit offered by the traditional solution, and the benefit of the flexible solution. Or even considering the alternative of doing nothing and facing the need assuming some risks (e.g. [24], [25]) (section 3.2). This requires a detailed study of costs including CAPEX and OPEX (as in [24] and [26]) and a correct application to real use cases also considered in section 3.

Market liquidity can be defined in a simplified manner as the presence of enough traders on both the bid and offer sides of the market to reach an optimal transaction [27]. In a perfectly liquid market, an asset can be sold instantly with no loss of value. In fact, for a large number of participants on both the demand and supply sides, the ability to negotiate is practically zero, the market in perfect competition results in an efficient price. In contrast, in a market with limited liquidity, the buyer or seller may have bargaining power and influence the price.

When markets are still immature, liquidity is generally low. So, mechanisms to facilitate trading are needed in illiquid markets. Mechanisms such as bilateral agreements are therefore very appropriate for the most incipient markets. Some market mechanisms may develop sufficient liquidity, but others may remain illiquid, that depends on the level of competition gained. When more liquidity became available, auctions would be the next step to allow competition. Since services may be remunerated by activation and availability, the market could be cleared in different stages.

A relevant question to choose the best mechanism is to highlight the need for **coordination**

between TSO and DSO. Again, it is necessary to distinguish different needs, timing, and voltage levels, but in this case, with attention to the potential impact on the TSO level. In the cases of potential impact, it must be assessed by evaluating the effect on the transmission network, which could be addressed by comparing it with current ordinary scenarios to provide a realistic perspective. Section 4 is devoted to this analysis and aims to help to better define a threshold for the coordination needs.

Global problems would be exclusive to the overall system needs managed by the TSO, while local problems are network-specific, either from the TSO's network, the DSO's network, or both. Therefore, the DSO has only local problems under its responsibility. However, there may be a **local problem that is repeated throughout the network (e.g., solar overproduction)**, which becomes a generalized problem. In that case, specific mechanisms should be considered to avoid addressing individually a large number of similar problems at the same time.

A key aspect of market-based mechanisms to acquire services is the commitment to deliver the traded commodity, otherwise, the transaction does not take place (i.e., explicit flexibility). Tariff mechanisms, however, also provide economic incentives, but without a commitment to deliver the service beyond potential penalties (i.e., implicit flexibility). The implicit flexibility with dynamic tariffs or regulated payments is useful for generalized problems, avoiding the need to reach a previous agreement with each flexibility provider.

Figure 5 graphically shows the evaluation criteria. To determine the need for TSO-DSO coordination, the coordination scheme selected and the agreed thresholds must be considered. The liquidity level needs to be defined to decide whether a market can provide an efficient solution. And the generalization of the problem defines the tariff alternatives considering time and location granularities.

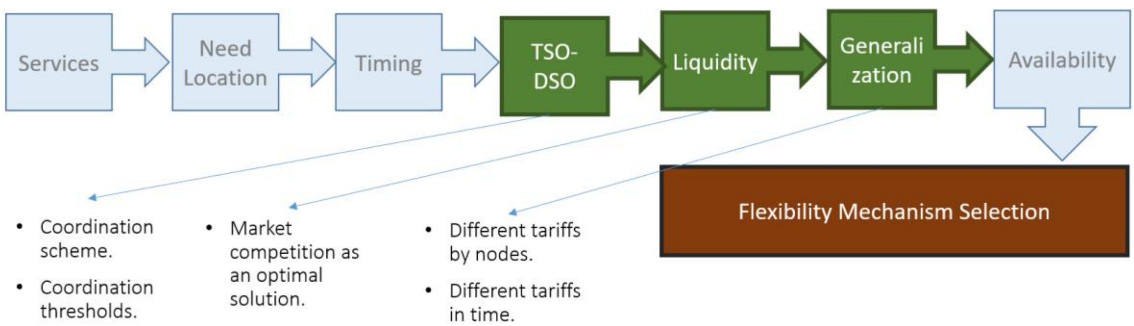


Figure 5. Evaluation Criteria.

2.3 Decision Framework for Selecting Flexibility Mechanisms in Distribution Grids

Each of the characteristics that can influence the design selection of flexibility mechanisms was studied individually. Identifying the needs faced by the DSO, their location in the network (LV, MV, HV) and the timeframe in which the need is managed. On the other hand, other relevant criteria were also studied in the choice of mechanisms, such as the impact on the TSO's responsibility, the possible generalization of the problem or the potential market liquidity.

Deeming all of them, a clear framework is developed to match DSO needs with the most suitable flexibility mechanism. The three types of mechanisms considered that encompass a different area in the decision framework are: local markets, common markets, and non-market-based mechanisms (e.g. network tariffs or bilateral contracts).

First area, some mechanisms must necessarily be coordinated with the TSO because of their impact on balancing or TSO grid. Then depending on the timeframe and the need, different type of common or coordinated markets may be used.

Second area, other situations in which there is not enough market liquidity, non-market-based mechanisms are selected, such as bilateral agreements for specific needs or dynamic tariffs for generalized needs.

And finally the third area, for situations in which there is sufficient liquidity and there is no impact on the TSO's operation, depending on the need and timeframe, different types of local markets can be selected.

The exclusive mechanisms for DSOs are still very unexplored in the literature and the lack of liquidity plays a key role. Market-based mechanisms, preferred by regulators, can provide optimal solutions when liquidity is high. Local DSO markets could work under those premises, but illiquid situations may occur in case of lack of maturity of the market and this situation may even persist. Thus, non-market mechanisms may also have a relevant role to play in the DSO environment.

The market design options, such as the timeframe, the exchange of information, the design of the traded product, the price formation, the cost or the barriers to entry and exit, are key factors that determine the existence of more or less liquidity and, therefore, the efficiency of a market-based mechanism. On the other hand, while products and services need to be developed to manage flexibility markets, they do not strongly influence the choice of mechanism, but it does impact liquidity.

Figure 6 shows the proposed decision framework, which is divided into three areas depending on the three types of mechanisms mentioned above: one related to common TSO-DSO mechanisms, another one related to non-market-based mechanisms and the last related to local market mechanisms.

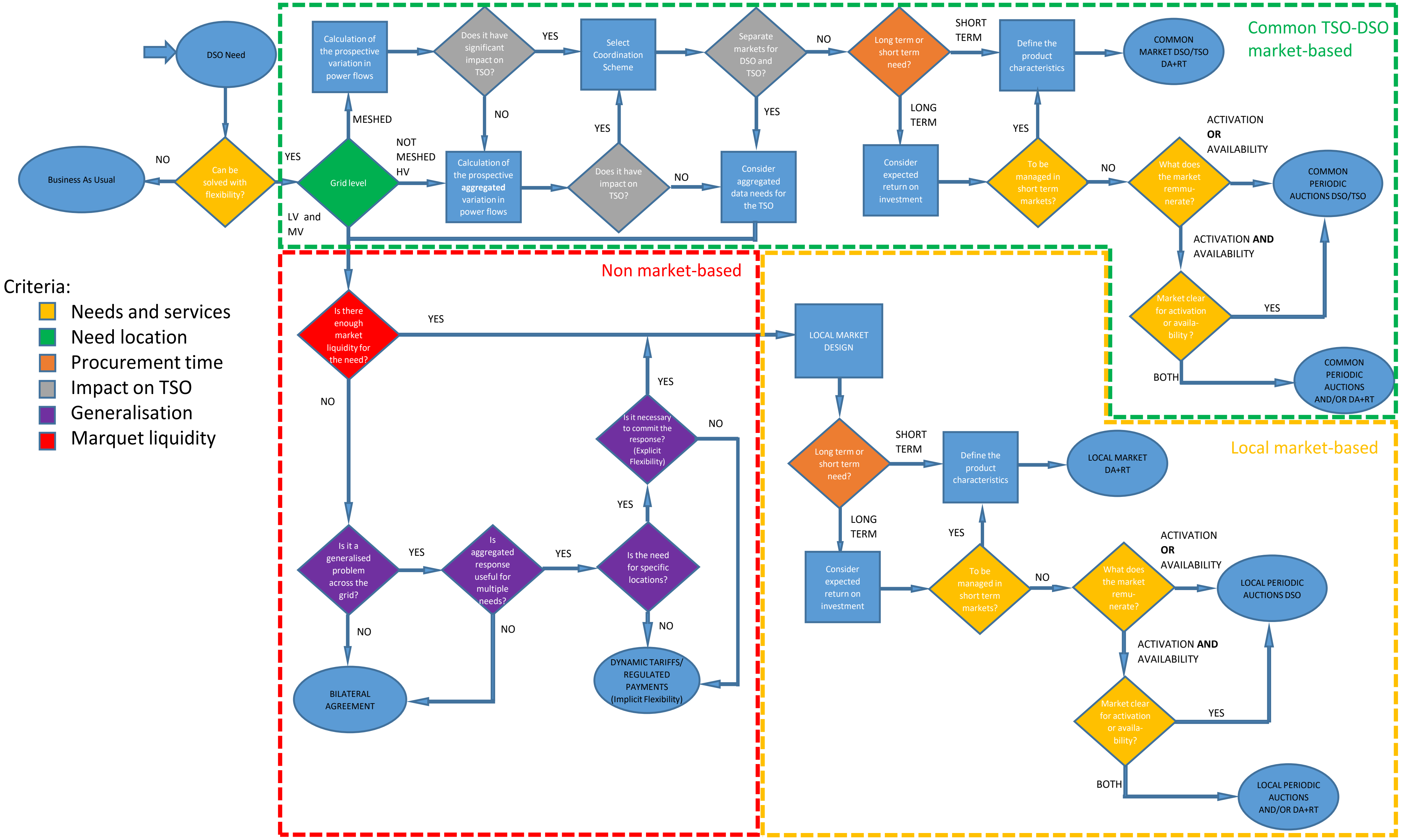


Figure 6 Decision Framework for Selecting Flexibility Mechanisms in Distribution Grids.

For a better understanding of the framework, the example of two specific needs could be chosen to select the optimal mechanism:

- Example 1. (see Figure 7) Flexible connection is required in the non-meshed HV network (without impact on TSO operation). In this case, the framework continues as follows:
  1. *Can the need be solved with flexibility?*: YES.
  2. Grid level: HV not meshed.
  3. *Does it have an impact on TSO?:* NO, it might be due to having an amount of requested power under the threshold that impacts the TSO duties.
  4. *Is there enough market liquidity for the need?:*NO, the need is local and specific to the connection.
  5. *Is it a generalized problem across the grid?:* NO, it is a single local need.

After answering these questions, the solution is a bilateral agreement in which flexible connections (non-firm) are included.

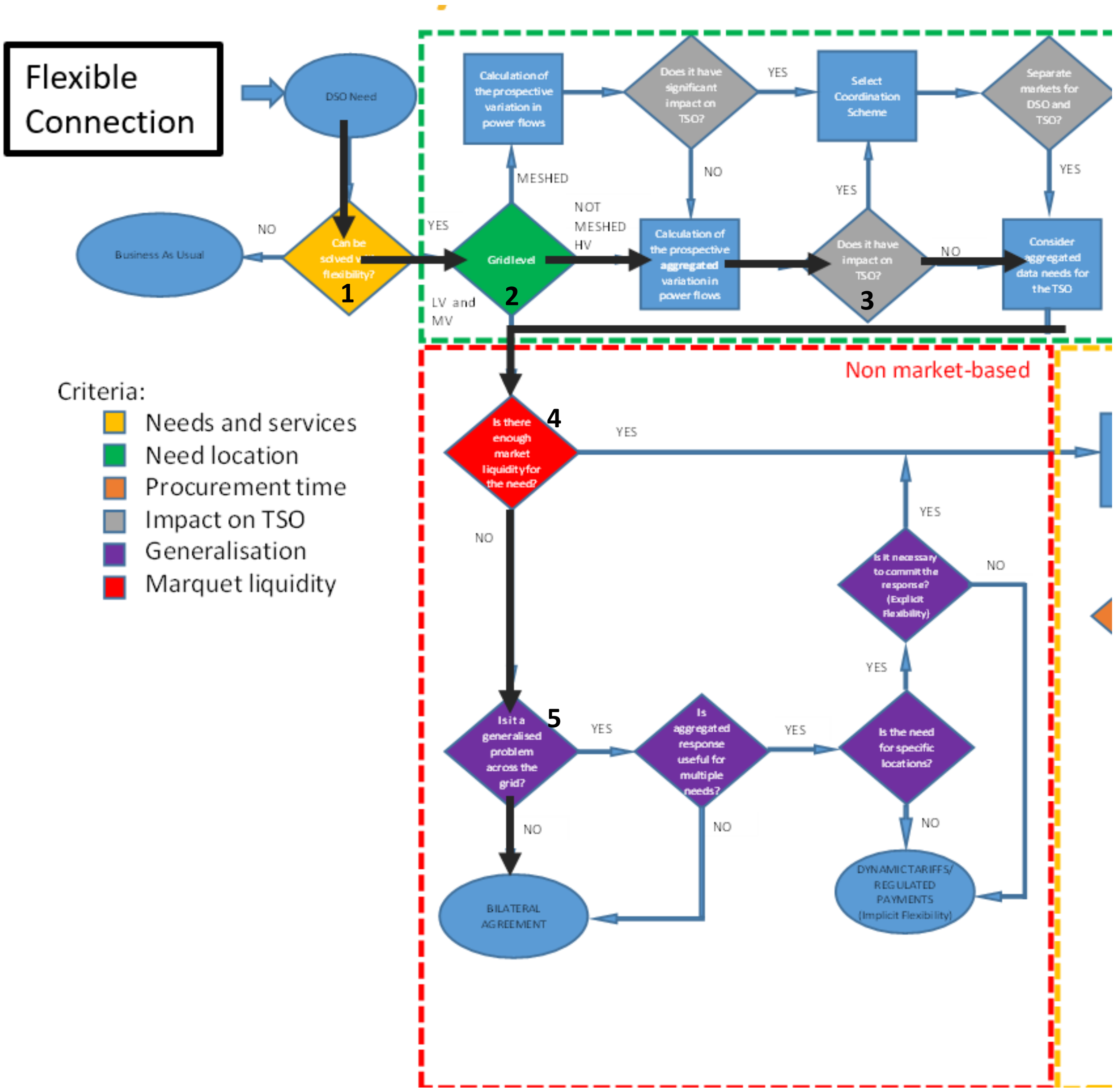


Figure 7 Decision Framework: Example 1: non-firm connection

- Example 2. (Figure 8 and Figure 9) Long Term Congestion in MV. In this case, the framework continues as follows:
    1. *Can the need be solved with flexibility?:* YES.
    2. *Grid level:* MV.
    3. *Is there enough market liquidity for the need?:* YES, DSO knows several DERs connected to the feeder that are flexible.

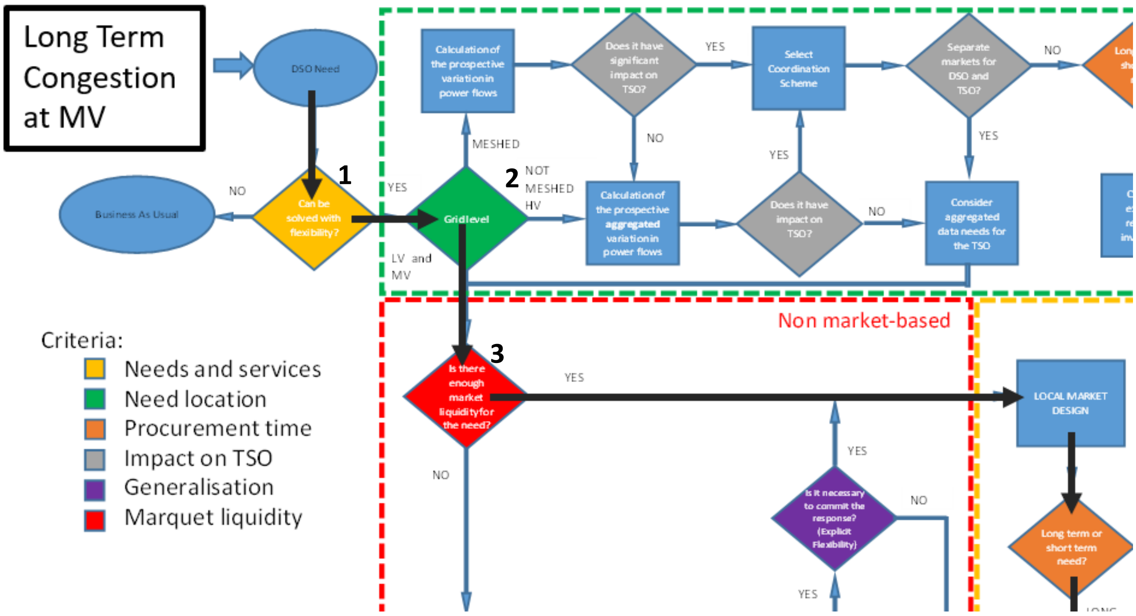


Figure 8 Decision Framework. Example 2: local market. First part.

4. *Is it a long-term or short-term need?: Long-term.*
5. *Could this long-term need be managed in short-term markets?: NO, there is a need of long-term commitment.*
6. *What does the market remunerate?: For example, only availability is remunerated in the selected product.*

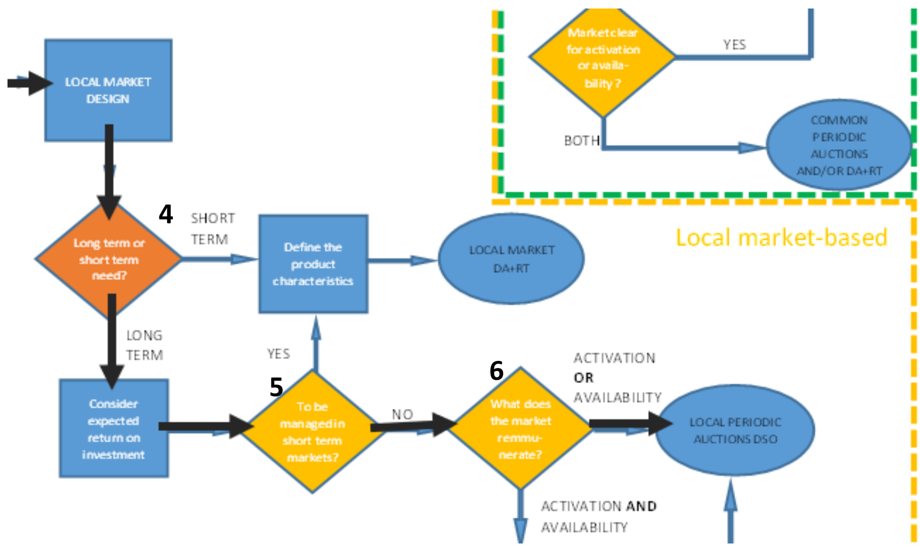


Figure 9 Decision Framework. Example 2: local market Second part.

After answering these questions, the solution is a local market.

This framework is only intended to select the most appropriate tool for each case in a given context. But the combination of alternatives offers solutions under a wider range of contexts. Moreover, for each specific need in a specific context, there is a tool that is the most appropriate but may not be a stand-alone solution. [28] performs a thorough study of efficient combination of flexibility acquisition mechanisms.

In addition, the behavior of network users is dynamic and constantly changing active and reactive power flows. Therefore, it is interesting to have a wide variety of options available and apply one or other depending on the specific circumstances. For this reason, the requirements on the same network element can be very different from one day to another or even between hours. This means that the criteria for choosing the best mechanism can also be dynamic. For example, there may be sufficient liquidity at some times, justifying a market mechanism only for some time slots. Or there could be some DSO requirements that need to be coordinated with the TSO because of the magnitude of the need but the coordination might not be essential other days at lower magnitudes. So, the combination is possible and, in some cases, but the coordination might not be essential or may even be desirable. For example, long-term needs could be met with short-term markets in cases of high liquidity to obtain perhaps more adjusted prices. Short-term and long-term needs might be combined in order to have an optimal result or also ensure commitment in different circumstances.

2.4 Conclusions on the decision framework for selecting flexibility mechanisms

Even if there have been many demonstration projects about flexibility solutions for DSO needs such as CoordiNet [29], EUniversal [30] or OneNet [31], it is difficult to have a real evaluation to assess the validity of the solutions in comparison with traditional ones. Either because they are more focused on the technical deployment that the project enables, or because there are no real market conditions, giving more optimistic results of the selected mechanisms in specific situations. This thesis tries to avoid biases by considering a wide range of real needs and enlarging the variety of mechanisms available and finding eventually the most efficient solution for each need.

The evaluation of the **characteristics** of realistic case studies is very diverse and not always generalizable. In many cases, by treating all the needs equally, without observing the important differences between them and the diversity that characterizes the DSO activity. For that reason, the decision to select a mechanism must consider the type of service needed, the location in the network and the timeframe.

The second conclusion is related to the selection of the flexibility mechanism, considering some **criteria** such as the type of need, the impact on the TSO grid or the market liquidity. There are many reasonable uncertainties about the real usefulness of flexibility solutions in the case of local needs, mainly due to the lack of liquidity they may have in the markets, the competitiveness of traditional solutions, or the impact on network users. Therefore, it is important to consider the functioning of DSOs’ activities when doing theoretical analysis, taking care of the coordination needs, liquidity and considering other non-market-based solutions and implicit flexibility solutions.

Non-market-based solutions are a chosen solution in case of low liquidity or immature markets. There are actions that should help to improve liquidity such as a proper information exchange among stakeholders, an accurate design of the traded product, an efficient price formation, considering costs and barriers, etc. Influencing liquidity might improve efficiency. It is necessary to maintain the perspective that the final objective of these services is to fulfil the needs of the distribution network at the lowest costs.

Sometimes, conventional solutions are much more efficient than flexibility solutions. Especially if they are considered in the long term. They are also highly reliable solutions with an adequate remuneration scheme. Therefore, flexibility solutions have the challenge of maintaining reliability and remuneration standards. A change should be justified when flexibility is supported by efficiency gains.

3 The value of flexibility versus traditional solutions

The second part of this thesis addresses the value of flexibility and its comparison with the traditional solution, which is the topic in this section and in the second paper of the compendium that makes up the thesis. This paper is included in Annex 2.

This section is structured into the following subsections. Firstly, the type of methodologies applied in the literature are analyzed. Secondly, the costs considered to assess the value of flexibility; and, thirdly, the use cases evaluated are presented.

Regarding the methodology, some references adopt a descriptive approach with no quantitative calculations. The publications that perform some form of quantitative evaluation can be divided into: papers that follow deterministic approaches, papers that implement analytical stochastic methodologies to model uncertainty, and papers that combine stochastic methods with optimization models. But with a poor approach on the cost analysis. The methodology framework proposed in this thesis considers a deterministic approach, but it could be extended to stochastic approaches.

Regarding to the costs considered, most of the references propose a quantification for the value of flexibility, while some others do a descriptive analysis, only two references [26] and [24] analyze the costs in greater detail by breaking down the Capex and Opex costs. A gap is found to make a detailed and comprehensive analysis of the flexibility costs to make an accurate comparison. Finally, as network flexibility needs are different depending on their driver, it is necessary to consider the driver that motivates it, i.e., integrating renewables, electric mobility, demand response, the electrification of other energy uses or a mix of them. The reviewed literature tends to target a single specific driver, with demand response being the most commonly studied. Many references do not even specify a driver. Therefore, a gap is also identified in considering the whole spectrum of drivers and the different needs generated by each driver.

Figure 10 shows the gaps to be filled in this second stage. Firstly, an analysis of the **drivers** that determine the present and future network planning is conducted. Then, a practical **CBA methodology** to evaluate the value of flexibility is proposed, including a complete **cost calculation** aligned with the real needs in managing distribution networks. This thesis also selects a set of representative **real case studies** and draws some conclusions on the real usefulness of implementing flexibility services in different cases. Conventional solutions and flexibility alternatives are analyzed, and an economic study of the possible solutions is carried out. Finally, considering the risks of dealing with more unpredictable parameters even close to real-time in a more dynamic way of operating the grid, a **sensitivity analysis** is necessary to calculate a range of cost-effective conditions for using flexibility.

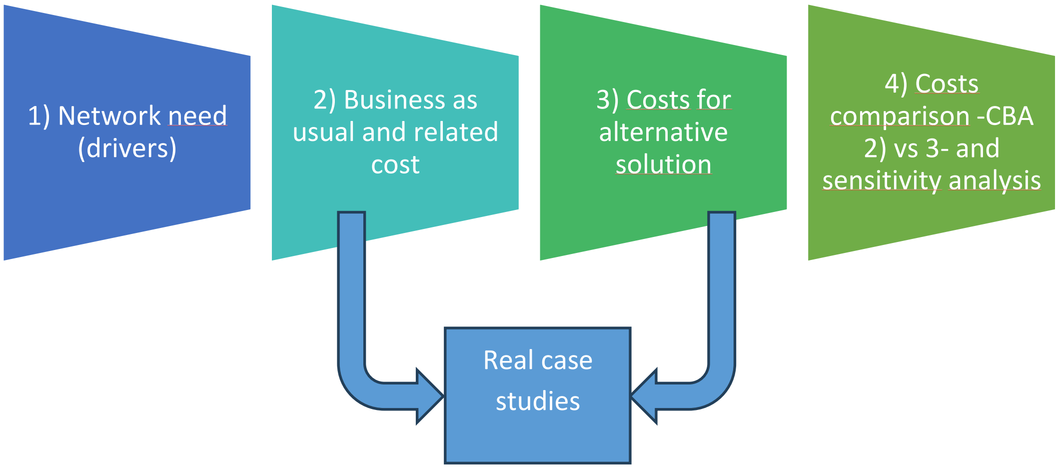


Figure 10 Methodology to compare the value of flexibility vs traditional solutions.

3.1 Drivers for grid needs and development

By thoroughly understanding the current and future drivers, which determine the grid's needs, it is possible to determine whether more focus on certain voltage levels or others is needed, or certain flexibility timeframes, etc. Also to find a more realistic context to select the real cases to analyze afterwards, it is necessary to delve deeper into the drivers that trigger the needs of the DSO. And, with all this, real case studies are proposed that are more in line with the real needs that make up the challenge of the energy transition.

This section analyzes the drivers that influence investment decisions in network growth or improvement, excluding investment decisions that are somewhat obligatory and are triggered by the replacement of damaged components or components that reach the end of their useful life and are replaced by other components with the same characteristics without representing an improvement or increase in network capacity per se.

The drivers for determining new investments on grids have historically been based on predictions of standard consumption profiles. These drivers of steady demand growth, city planning or new connections requests will continue to exist. As shown in [32], the new needs for decarbonization of the economy also bring about new drivers that can be broadly classified into new economic activities, electric mobility, electrification of heating and cooling, resiliency and other new uses of electricity. This section analyzes the old and the new drivers for network development. In [33], drivers are identified as "first indicators" referring to a classification in reliability indicators, economic, coordination among stakeholders that use the grid and renewable generation connections. In addition to these indicators, future challenges are addressed.

All drivers are considered at the same level as they impact network developments similarly. Table 1 summarizes the drivers for grid investments and relates them to their causes and challenges for grid development.

	Drivers		Cause	Challenges
Traditional Drivers	Ordinary demand growth		Increased energy flows in the grid.	Maintaining supply and reliability levels
	Extraordinary demand growth		New energy flows in the grid. Urban planning.	Integrate energy withdrawals and injections safely
	Maintain grid reliability		Improving the system reliability	Usually associated with regulatory incentives and a commitment to maintaining technical parameters within established limits
	Efficiency, digitalisation and other regulatory issues		Environmental concerns. Losses reduction. Cost reduction.	Regulatory compliance whilst containing or reducing cost levels.
New Drivers	Massive connection of DG		Energy flows in both directions that can generate new challenges for the grid.	Integrate sustainable generation. New planning tools are required.
	New Loads	New economic activities (e.g. electrification of industries, hydrogen production)	Unpredicted new energy demands as a consequence of the shift away from fossil fuels and motivated by policies outside the electricity sector	Identify unpredicted demands to do a specific plan for the new energy profile
		Electric mobility	Increase of energy consumption with the possibly high-power requirement but with the flexibility to charge at different times	Incentivise smart charging strategies.
		Electrification of heating and cooling	Increase of energy consumption with a certain flexibility	Make use of flexibility potential
	Resiliency		Frequent extreme weather events resulting from climate change	Maintaining continuity of the service and reliability at the required levels

Table 1 Drivers for grid investments. Source: own elaboration.

3.1.1 Traditional Drivers

3.1.1.1 Ordinary demand growth

Demand growth is a very relevant factor in determining grid planning. Especially in developing countries, electrification is directly linked to economic growth. It is stated in [34] that power grid infrastructure investment supports the economy. In countries where economic growth is not sustained, demand growth needs to be monitored because small increases can be significant when accumulated over several years. This effect can be compared with the boiling frog fable.

Forecasts based on historical data are the first input to consider when planning the network needs. Observing the network weaknesses at times of peak network stress indicates what future weaknesses may emerge. The data from previous consumption peaks must be corrected with other parameters such as the expected growth in demand or even the season's temperatures. After the creation of scenarios, typical network analyses are power flow calculations [35], power quality analysis [36] [37], short-circuit analysis and other dynamic analyses [32].

3.1.1.2 Extraordinary demand and generation growth

Even if there is expected global growth in demand, it is more difficult to predict some criticalities at the local level. Therefore, it is always necessary to study the impact on the grid of new grid requirements, both for demand and generation units, individually. Some regulations, such as the Spanish one [38], manage demand or generation growth due to high or low power requests differently, and the cost-sharing between the DSO and the user depends on the power requested. For instance, in Spain, extensions for new demands up to 100 kW at low voltage (LV) and 250 kW at high voltage (HV) on urbanized sites are covered by the DSO (shallow connection charges), whereas the connection costs for larger users or those located outside areas are born by the end-user (deep connection charges) [39]. In any case, requests for new connections should be an input into the planning of the distribution network.

As a result of city planning, demand growth can also be considered a specific unpredicted demand for the electricity grid or within the expected growth plans of the existing connection points depending on the legislation concerning urban planning.

3.1.1.3 Maintain grid reliability

Network reliability is also an aspect that has been historically considered for network planning, especially concerning transient stability analysis, protective relaying, reliability analysis or voltage control.

Depending on the incentives that the regulator sets on reliability parameters, the network planner may give emphasis to this issue. The electricity infrastructure and its quality are determining factors for the economic growth of an area. In [40], the quality of electricity supply is quantified as 18% of the quality of the overall infrastructure that impacts economic growth, although it can be a much higher percentage in certain economic activities. Ensuring adequate grid reliability requires the regulator to promote network quality improvements with sufficiently strong economic incentives.

The strong automation of networks in recent years has greatly improved the reliability of the networks, as shown in [41]. So, these incentives to improve reliability may find in flexibility a new alternative in which they can progress, and not only through the digitalization and automation of networks. Flexibility solutions entail an active management of the distributed energy resources (DERs) connected to the distribution grid on top of the management of the grid itself. Therefore, for the operation of the Distribution network, the area of action is significantly expanded, going beyond the network itself. These are also complementary resources to achieve reliability goals.

3.1.1.4 Efficiency, digitalisation and other regulated requests

DSOs have traditionally faced additional investment drivers related to energy efficiency improvements, e.g. loss reduction, or compliance with regulatory constraints. A notable example of the latter can be found in the need to adapt the network to new environmental regulations. For instance, Spanish DSOs had to make significant adaptations to their grids to ensure bird life well-being due to a new piece of legislation passed in 2008 [42].

At this point, it is relevant to highlight the driver of digitalization, which was fostered in Europe recently [43]. In short, it is about improving networks to seek efficiency and cost reduction. While it represents a relevant technological change, it is not a new driver anymore, as automation and smart meters have become business as usual in the last decades.

3.1.2 New Drivers and impacts on DSO grids

The new drivers impact the development of the distribution networks. Some of these impacts are difficult to predict due to the uncertainty of the new technologies, their adoption, possible incentives for different agents, or the difficulties of estimating the cash flows of the investments. But it is possible to draw some conclusions from certain evidence of phenomena which are already occurring.

3.1.2.1 Massive renewable distributed generation

Distributed generation, i.e. electric power generation connected to distribution networks or on the customer side of the meter [44], certainly represents the biggest impact on the grid. The paradigm shift from power distribution that is generated in a centralized manner and transported over many kilometers and distributed to consumption points to a new situation in which generation is connected to the distribution grid itself and the DSO has to manage the power exchanges between the parties involved and ensure that the grid continues to maintain reliability parameters. Making forecasts for network operation and planning in the presence of DG is becoming increasingly challenging. Furthermore, [45] identifies several conflicts arising from the new paradigm about protection schemes and reliability degradation. Protection issues such as grounding, reclosing, transformer connections or overcurrent need to be revised. More controllability is required because of the changes in power flows.

According to [46], distribution network planning and operation face great challenges in providing stable, secure, and dedicated service under a high level of uncertainty in network changes. This uncertainty can be overcome with data analytics and artificial intelligence approaches can extract useful information to construct more accurate network operation conditions for optimization. The peak load scenarios considered in traditional planning need to be replaced by a new way of forecasting that handles uncertainties and considers a combination of scenarios with different load assumptions and different generation assumptions. Parameters influencing both, such as meteorology, are also relevant inputs. So, there would be a transition to a stochastic approach in scenario building.

A review of different power distribution planning approaches is carried out in [47] showing the shift of modern planning towards more integrated, multi-objective, and distributed-generation integrated solutions with control functionalities, in comparison to the traditional models. By exploiting the capacity and control capabilities of the DERs instead of just connecting them to the network (the so-called "fit and forget" approach) can provide optimal planning solutions with significant cost savings. In this new scenario, it is necessary to adapt the generation to the grid's capacity at any given moment.

One of the highest costs would be the obligation to reinforce the grid before connecting new renewable generation units to maintain the fit and forget philosophy. In [48], special emphasis on flexible connection and increasing hosting capacity are tools that can accelerate the integration of renewable energies. Facilitating grid connection is undoubtedly a great incentive for promoting renewable generation and benefiting society.

Given that there are different types of generation technologies and different types of generating plants by volume, it is very difficult to predict the real effect on the distribution grid. The effect of a small solar generation in the low-voltage grid is very different from large wind farms connected to higher voltage levels. Therefore, the range of possible flexibility services may cover different alternatives.

Because of the rapid inclusion of a large share of renewable energy into the grid, it is necessary when planning [49], to consider the negative technical impacts of a high share of renewable energy penetration, such as uncertainty and variability, but also the need to increase the flexibility of power system planning and operation.

3.1.2.2 New Loads

The decarbonization challenge requires the electrification of new loads, being the most significant industrial processes, mobility, heating, and cooling sectors.

3.1.2.3 Industrial electrification

A large number of industries is highly dependent on different energy sources. Since the industrial revolution, the availability of energy sources was decisive for starting any economic activity. Many industrial sectors, whose main energy source is fossil fuels, can be electrified [50]. Some industrial sectors may be electrified directly (low-temperature thermal processes) or indirectly (e.g., hydrogen). These new businesses may lead to unforeseen increases in electricity demand [51].

3.1.2.4 Electric mobility

As mentioned in [32], uncertainties in data concerning EV (Electric Vehicle) penetration and utilization, battery charging criteria and drivers' habits make it difficult to predict and estimate EV impact on electric distribution networks. Under some assumptions, [52] aimed to predict the impact on distribution networks in large areas and concluded that significant investments could be avoided if EV charging is properly managed. Furthermore, considerations were made regarding the concentration of EV charging in specific areas (clustering) rather than the load being equally spread geographically. New grid requirements resulting from consumption from electric mobility are expected depending on the distribution of the chargers and charging mode.

The effect of electric mobility should be divided into different usages. A family vehicle may be connected to the same low-voltage grid that powers one's home or a similar grid nearby. The daily energy needs for regular commuting and vehicle parking times indicate that the energy can easily be shifted to times of higher grid availability. Figure 11 shows an example of this with great clarity. The energy-related to EV can be easily shifted, while the energy-related to heating shows less flexibility.

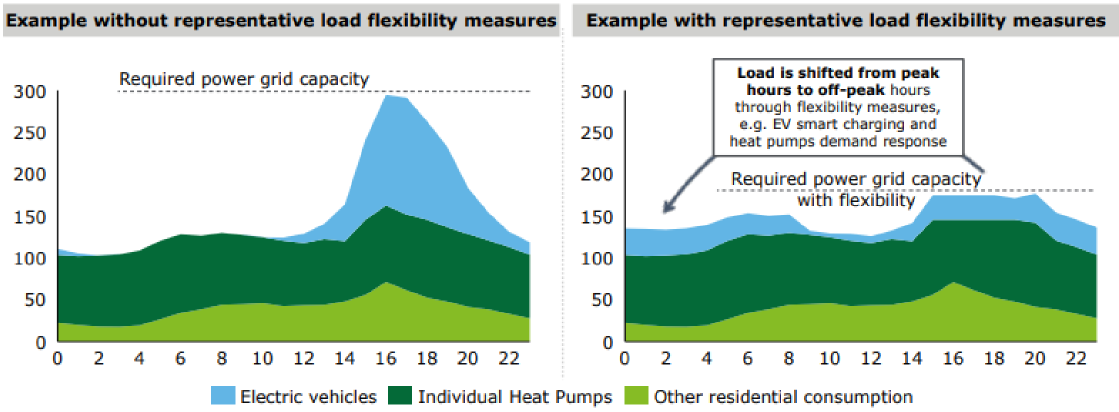


Figure 11 Illustrative average hourly electricity consumption in the low-voltage grid in the residential sector (48 houses, with each house having a heat pump and a BEV with a 3.7 kW single-phase charger) Source: [53]

For work-related transport, recharging times are not easy to cope with, and energy requirements are higher. Depending on the activity, the requirements change. For example, urban, intercity, or international transport have very different requirements. Sectoral studies would be necessary to draw valid conclusions. In any case, the need for higher-powered fast chargers is foreseen to be supplied along the route.

The case of domestic charging could be located at the low-voltage network, and as suggested in Annex 1 that reviews the different mechanisms available for DSO needs, flexible tariff solutions or local markets may allow for efficient grid use.

For fast charging points or high-capacity power charging point, connections to medium and high voltage distribution grids are expected. Depending on the driver patterns and charging requirements, this charging mode may provide flexibility to such voltage levels.

3.1.2.5 Electrification of heating and cooling

As a consequence of decarbonizing these energy uses, traditional fuel-based heating sources are expected to be replaced with electricity-fueled technologies such as heat pumps. [54], [55] and [56] conclude that there are impacts in LV grids even with penetrations under 30%. But there are currently uncertainties regarding the number, size and location of heat pumps and electric boilers deployed in the future. But as was already the case when air conditioning became popular in some cities, the proliferation of heat pumps as a substitute for other types of energy is to be expected.

The electrification of heating with solutions such as aerothermal or heat pumps as an alternative to diesel or natural gas heating systems is becoming increasingly competitive. Given the nature of consumption linked to temperature, it is to be expected that these solutions will stress the entire network from low voltage to medium or high voltage networks. Having to reduce power when required may create an inconvenience for grid users. Therefore, the flexibility of heating and cooling depends on the grid users' thermal storage and thermal comfort levels.

3.1.2.6 Resiliency

The energy transition in the distribution grid raises two big challenges in terms of grid resilience. On the one hand, there is resistance to severe weather events, and on the other hand, there is the difficulty of maintaining an efficient protection system with the proliferation of distributed generation.

Rapidly shifting extreme weather events resulting from climate change require more robust electricity grids. Severe storms, windstorms, droughts, or wildfires are sometimes related to grids or power generation. This can also add costs to the activity. As in the case of the fires in California in 2019 [57]. As mentioned in [58], power delivery systems are most vulnerable to storms and extreme weather events. Improving the overall security and efficiency of the power delivery system helps to hasten recovery from weather-related outages.

To comply with electrical risk protection standards, it is necessary to carry out the necessary operations and maneuvers to maintain and repair distribution installations. In the energy transition context, the requirement may be higher as energy sources (e.g. DG, storage) need to be controlled for opening and earthing as required in [59] for network operations and maneuvers as in Spain. Therefore, with more generators and batteries in the distribution network, the operation becomes more complicated, especially in LV and MV, due to the need to control the energy sources of all distributed generators when setting up the working area in the distribution networks.

A new DSO role of active management of flexibility also makes it possible to use distributed resources to improve the network service's conditions. So, even if the operation is more complicated, more tools are available to maintain the service during challenging atmospheric episodes. Short-term services based on flexibility, such as congestion management or controlled islanding, could provide more resiliency to the grid. Also, availability services can be activated in the short term.

Market-based flexibility mechanisms or bilateral contracts can be useful for short-term needs resulting from maintenance or fault repairs. Also, other solutions based on network flexibility, such as dynamic reconfiguration of the network or batteries can improve system performance.

3.1.3 Impact of new Drivers and traditional drivers. Drivers for case studies

This subsection presents the impact that new drivers could have, compared to that of traditional drivers and how case studies presented in the following sections fit the drivers. Table 1 shows the drivers related to new industries or new economic activities which are local and affected by other factors that are difficult to predict. Therefore, in this thesis, only the most easily predictable drivers are addressed, which are more generalizable across the network. Attempting to estimate the network impact from unpredictable growth or new economic activities would be both daring and difficult. For this reason, only four new drivers are addressed.

Table 2 summarizes each addressed driver, identifying the impacts on the planning process that would require new parameters or new paradigms, the impacts on the operation of the network, or new needs, if any, and the voltage level where the impact occurs.

Drivers	Impacts on planning	Impacts on operation	Location at the voltage level
Massive renewable DG	Transition to a stochastic approach. New forecasts.	Unpredictability, new controllability required, protection issues.	All distribution levels
Electric mobility	Depending on the charging modes. Uncontrolled charging may have a significant impact.	Depending on the charging modes. Uncontrolled charging may have a significant impact.	LV for domestic. MV or HV for fast charge.
Resiliency and maintenance	Design requirements may be revised and new investment needs may arise	Controllability needs, short-term forecasts, new data input, accurate optimal power flows	All distribution levels, especially LV and MV
Electrification of heating and cooling	Temperature sensitivity and Demand growth	None	LV in the first instance

Table 2 Impacts of addressed drivers for grid development on the planning and operation. Source: own elaboration.

The new drivers and the old drivers studied are not unrelated or mutually exclusive. The relationship between them is presented in Table 3. There is no one-to-one relationship between the drivers, as they are all directly or indirectly related. For example, grid reliability or efficiency is considered when planning the grid to connect extraordinary demand. By correlating the drivers, the aim is to place the new drivers in the context of the old drivers and how the selected use cases fit into the new and old drivers.

The massive connection of DG could be assimilated into the traditional driver of preparing the grid for ordinary forecasted demand. The difference is simply that the share of requests for generation connection is different. In the same way, the proliferation of requests for connection of larger generators that require an individualized study is expected, in the same way as for extraordinary demands due to the greater impact it has on the grid.

From the demand side, in the same way, the new drivers can be classified as the old ones with the difference in the number of requests referred to certain uses, such as mobility, heating & cooling, or the substitution of the type of energy used. All of them would fit into the old drivers related to demand growth. And finally, the issue of resilience is not new either. What is new is the intensity of weather events due to climate change. So, they may become more prominent. The network may need to be even more robust. This new driver would fit the old drivers of grid reliability and efficiency and other regulated issues, depending on the context (regulation, customer engagement, etc.)

Only new drivers were considered because of the expected importance of the energy transition. The distribution network is diverse even within the same country with a homogeneous regulatory framework. Consequently, it is extremely difficult to study representative cases of the global impact of these new drivers. Therefore, for purely illustrative purposes, several cases based on real network situations were proposed. These cases are only intended to bring to the reality of the network and the economic context to which they belong, the potential application of the new flexibility services intended to face the challenges of the new drivers. “Use case 1” is related to a new flexible connection for a generation plant, “Use case 2” is related to congestion management on MV network caused by EV load charging, “Use case 3” is related to the maintenance of a high-voltage, and ”Use case 4” is related to congestion management in LV network caused by distributed solar generation.

			Traditional drivers			
			Ordinary demand growth	Extra-ordinary demand growth	Grid reliability	Efficiency and other regulated issues
New drivers	Massive DG connection		Directly related: **Use case 4**	Directly related: **Use case 1**	(Indirectly related)	(Indirectly related)
	New Loads	Industrial processes	Directly related	Directly related	(Indirectly related)	(Indirectly related)
		Electro mobility	Directly related: **Use case 2**	Directly related	(Indirectly related)	(Indirectly related)
		Heating and cooling	Directly related	Directly related	(Indirectly related)	(Indirectly related)
	Resiliency		(Indirectly related)	(Indirectly related)	Directly related	Directly related: **Use case 3**

Table 3 Use cases selection regarding new drivers. Case 1 (DG connection in HV), Case 2 (EV in MV), Case 3 (Maintenance in HV), and Case 4 (DG connection in LV)

3.2 CBA Methodology

A simplified analytical methodology for the CBA analysis is presented in this section. The methodology has several stages, as shown in Figure 12, starting from the type of need, it makes an exhaustive analysis of the costs derived from the necessary flexibility solution, since the type of solution depends on the type of need, as concluded in the first paper of the compendium (Annex 1). Assessing the cost competitiveness of flexibility is not a simple task since, as mentioned in [60], casuistry is very diverse and highly country specific. Following this methodology, the competitiveness of flexibility versus BAU is quantified and evaluated. Afterwards, by selecting use cases related to some relevant drivers in the energy transition, it is possible to make a comparative analysis of various needs and various flexibility solutions following the same methodology.

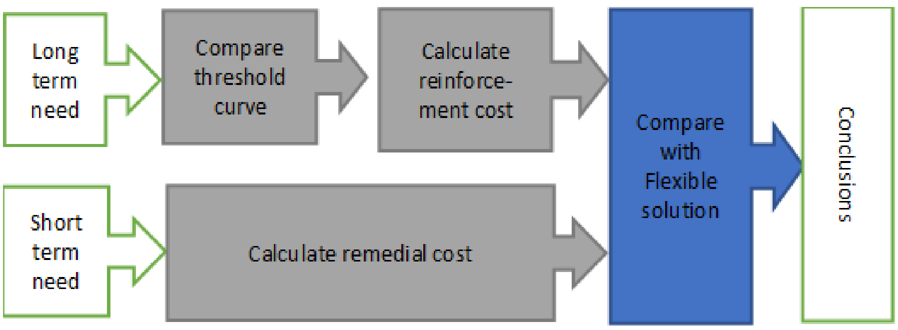


Figure 12 Comparing BAU and flexibility solutions.

3.2.1 Long-term and short-term needs

The needs of the network can be divided into long-term needs and short-term needs as indicated in Annex 1. For long-term needs, network reinforcements are compared with flexibility services, considering the risk of not reinforcing the grid. In the long term, when the costs of investments are calculated and compared with the costs of flexibility, comparable values must be considered, i.e. annual values. Therefore, the year in which a flexible or reinforcement solution begins and ends is also relevant because the needs are not the same every year. However, for short-term needs, the comparison is not made with the reinforcement cost, but with the cost of the alternative remedial action.

The different steps could include optimization functions, whether for the calculation of the best reinforcement solution, the calculation of the best flexibility solution, or the calculation of the network requirements by means of an optimal power flow (OPF). Indeed, all the costs considered can be studied and optimized. However, there is a preference for separating the methodology from the optimization methods that may exist in any part of the process, as can be seen in [61] or [62]. This study focuses on the methodology regardless of the type of calculation, optimization or type of model used in each step, which can be very diverse.

3.2.2 Traditional solution, Flexibility solution and the third alternative: do nothing

As studied in [60], reinforcing the network or contracting flexibility are not the only options. A third alternative would be to accept the risks of not contracting flexibility, nor reinforcing the grid. This concept is relevant because in the first years of a need, the period of the need can be so short that perhaps the most efficient thing to do is to take the risk of doing nothing.

This risk is difficult to model because it involves making a trade-off between the reliability of the network and the risk that the DSO wants to or can assume. It therefore depends on its strategic decisions. However, it is assumed that small punctual overloads in the distribution network are acceptable and do not affect the useful life of the assets [25]. The longer the duration of the overload or the larger the overload, even of short duration, the more unacceptable the risk becomes. This risk can be modelled with a time-load curve similar to the time-current one used by protective devices [63]. This risk is related to the amount of potential non-supplied energy in case of failure and the criticality of the consumptions involved.

Also if the overload is under a limit, it might be tolerated by the assets no matter the number of hours. Thus, either because it is of short duration or because the overload is low, there is the possibility of doing nothing. Depending on the position of the threshold curve (TC), as long as it is above the Use Duration Curve (UDC), analogue as the Load Duration Curve (LDC), a certain value can be chosen. Figure 13 shows the example of a UDC close to the TC that has both zones.

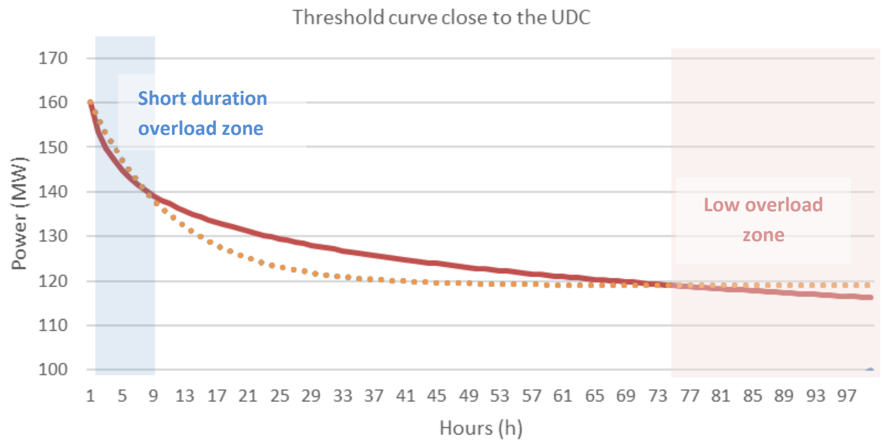


Figure 13 UDC close to the TC (dotted): There are different zones where no actions are considered: when being a few hours of overload or when being low overload. Source: own elaboration.

In the long term, the comparison of the UDC and the TC is used to opt for no action. In short-term operational needs scenarios, the risk of temporarily overloading certain elements may be more bearable, especially because there is less uncertainty and less risk of having made a wrong decision, as the remedial actions that compete with flexibility solutions also have a short-term duration and can be quickly activated. For this reason, the methodology considers the comparison with the TC only in the long term.

3.2.3 Costs considered

Obviously, the costs of traditional solutions are not the subject of this thesis. It is a calculation made in a traditional way and has to do with the cost of the materials, the projects process, and the labor used. In this study, the costs of the traditional solutions are provided by the DSO, that are those considered in the investment plans for the long-term timeframe and the costs for remedial actions in the short-term (normally operating expenses). There are similar calculations regarding materials and labor used as well, but they are different costs: investments and expenses.

The difficulty of comparison arises in the cost of flexibility. The calculation of the cost of a specific flexibility service follows the equation (1). This description is more complete than the one carried out in [64], which only considers flexibility activation costs. Following the same equation, the values vary depending on the service.

$$\boldsymbol{Cost}_{n,s}^{flex} = \boldsymbol{O}_{n,s}^{\mathbf{DSO\ Op}\ flex} + \boldsymbol{O}_{n,s}^{\mathbf{DSO\ Pl}\ flex} + \boldsymbol{C}_{n,s}^{\mathbf{Enab}\ flex} + \boldsymbol{Cost}_{n,s}^{\mathbf{Mkt}\ flex} + \boldsymbol{Cost}_{n,s}^{\mathbf{Agg}\ flex} \quad (1)$$

Where:

- $\boldsymbol{Cost}_{n,s}^{flex}$ is the annual cost (year n) of using a flexibility service s, including CAPEX and OPEX.
- $\boldsymbol{O}_{n,s}^{\mathbf{DSO\ Op}\ flex}$ is the OPEX Operation cost (year n) for the DSO in year n of using a flexibility service.
- $\boldsymbol{O}_{n,s}^{\mathbf{DSO\ Pl}\ flex}$ is the OPEX Planning cost (year n) for the DSO in year n of using a flexibility service.

- $\boldsymbol{C_{n,s}^{Enab\,flex}}$ is the CAPEX Enabling cost (year n) for the DSO in year n of using a flexibility service.
- $\boldsymbol{Cost_{n,s}^{\mathrm{Mkt}\,flex}}$ is the Market cost (year n) of using a flexibility service.
- $\boldsymbol{Cost_{n,s}^{FSP\,flex}}$ is the payment (year n) to the FSP for proving a flexibility service, including both CAPEX and OPEX as there is an investment to be made by the flexibility provider.

Figure 14 shows all the type of costs considered for every part of the equation (1).

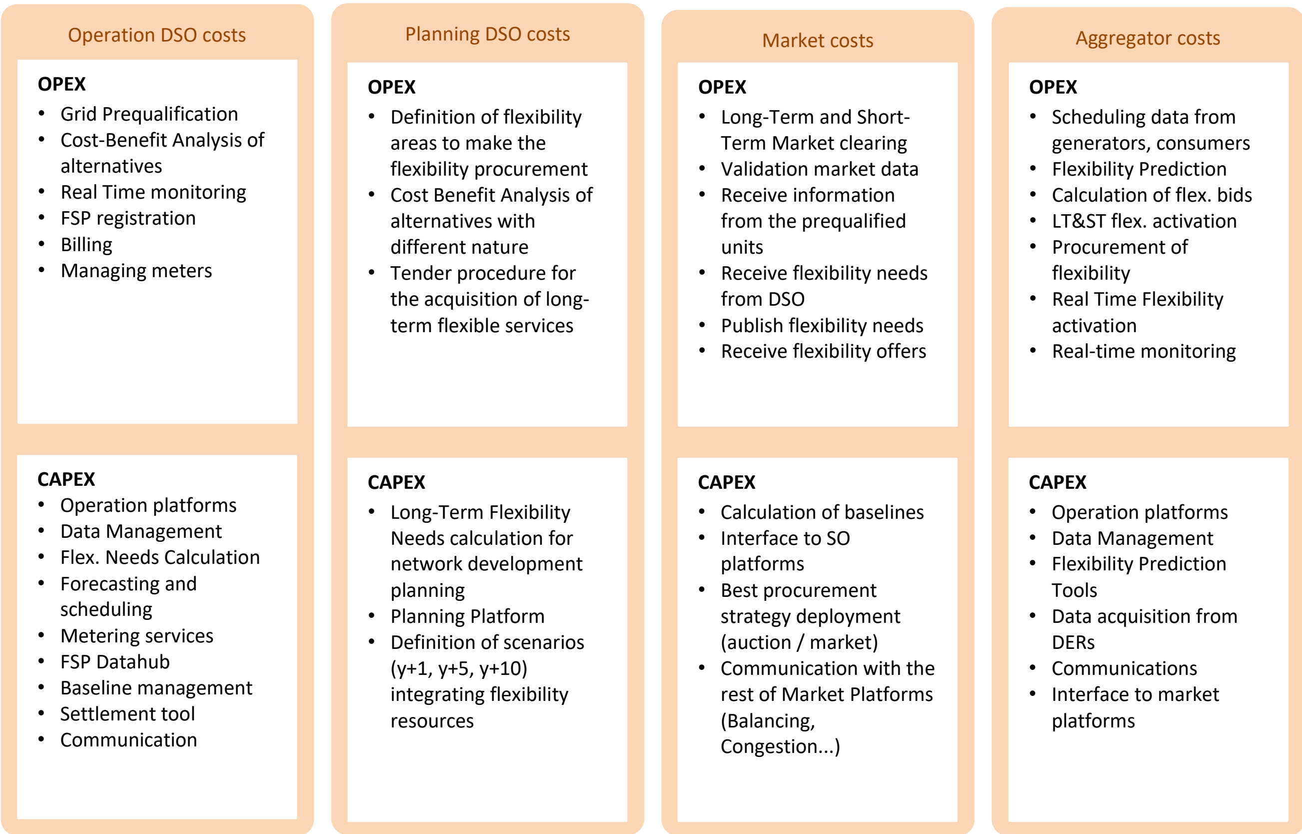


Figure 14 Flexibility costs considered in the CBA

Some of these costs are related to the number of hours of activation, some others to the number of FSPs involved, the number of connection requests, or the labor cost. The study finds proportionality with the hours of activation and with the number of FSPs, but the costs of each part of the process are input data. By taking reference data, it is possible to obtain formulas related to each of the realistic use cases to make the comparison considering the sensitivity to certain parameters.

3.3 Case studies for evaluation of flexibility solutions.

The four realistic grid scenarios selected from the energy transition drivers are shown in Figure 15.

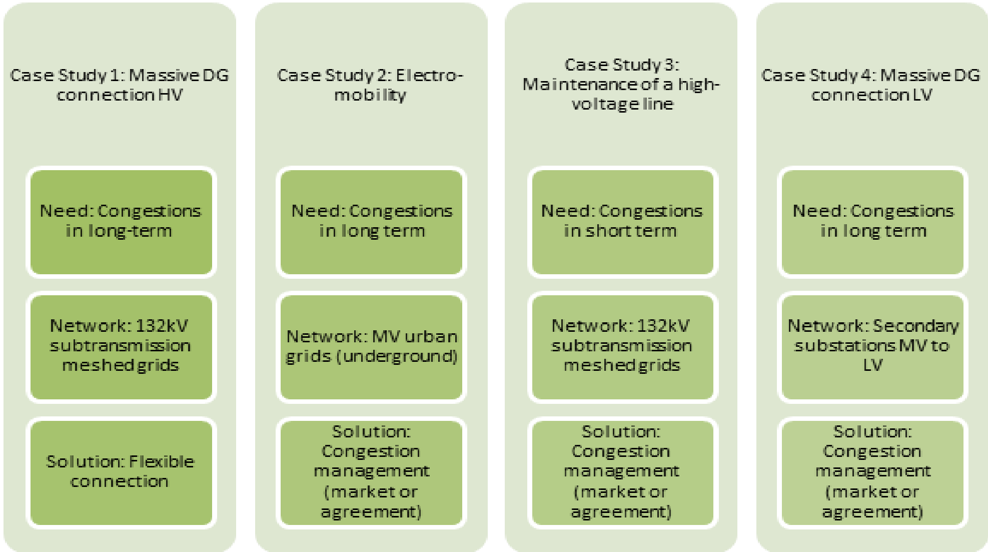


Figure 15 Case-studies selection: Case Study 1 (DG connection in HV), Case Study 2 (EV in MV), Case Study 3 (Maintenance in HV), and Case Study 4 (DG connection in LV)

All four case studies are based on network situations with realistic parameters from Spanish grids and are compatible with the values in the JRC DSO Observatory publications [65], [66] and [67].

Regarding large-scale distributed generation (DG) connection, two scenarios are chosen for the two renewable technologies that have proliferated the most: photovoltaic generation (Case Study 4 in Figure 15) and wind generation (Case Study 1 in Figure 15). These are the two most relevant technologies in the case of Spain, where the National Energy and Climate Plan (NECP) [68] foresees 62 GW will come from wind energy and 76 GW from solar photovoltaic. Both technologies already represent a high installed capacity in 2022 (27.5GW of wind and 13.6GW of PV). Photovoltaic capacity increased almost 3 times in Spain in four years [69], and wind generation connected to the distribution grid has become the first source of electricity in the country [70].

In the case of electromobility (Case Study 2 in Figure 15), the number of vehicles increased fourfold in the last four years [71] and the NECP also foresees a boost for electric vehicles [68]. This rate is higher than the electrification of other processes or heating and cooling. The resilience case (Case Study 3 in Figure 15) completes the list of case studies considering a short-term need in the network caused by a temporary asset unavailability. This situation is not new, although it may be more frequent with climate change in the case of extreme events.

The traditional solutions are compared to the corresponding alternatives with flexibility services and analyzed from technical and economic perspectives for these four case studies.

3.3.1 The example of case study 1: New flexible connection of renewable generation

As an example, this subsection shows the case study 1 (new flexible connections). As discussed above, allowing the connection of more generation capacity than the grid can evacuate at any time without reinforcement requires Active Network Management (ANM). A flexible connection [72] requires a service from the DSO, which would go to "no-fit, don't forget" and would require monitoring and control of the limits on the power injections and withdrawals by the DSO.

Some ongoing pilots are considering ANM with different approaches such as in [73] or [74] in the United Kingdom. Limitation control and active management are carried out automatically and require some investment to automate the execution of the algorithms. Note that limitation control can also be done manually in those cases where the investment in automating the solution is not more efficient than the manual solution itself.

The case of manual management is considered as an example. Due to the high penetration of generators in an area, there is a risk of overloading a 132kV sub-transmission line, which is occasionally open to avoid energy transfers that may occur when the 400kV line is open. In this case, where the transmission line runs parallel to the distribution line without any branches, the operations of TSO and DSO require special coordination. Any maneuver in the network should not cause congestion at any level. That is why a request for the connection of a new 50MW generator as shown in Figure 16 would require building a grid reinforcement in the 132kV network. The reinforcement required is costly, and the execution time is long, amounting to several years. This situation exceeds the thermal limit set for that system by 7.5MW. Therefore, there is a possibility to allow this wind farm to connect before building the reinforcement while the thermal limit is monitored and not violated by the impact of the wind farm by doing active management of the generation.

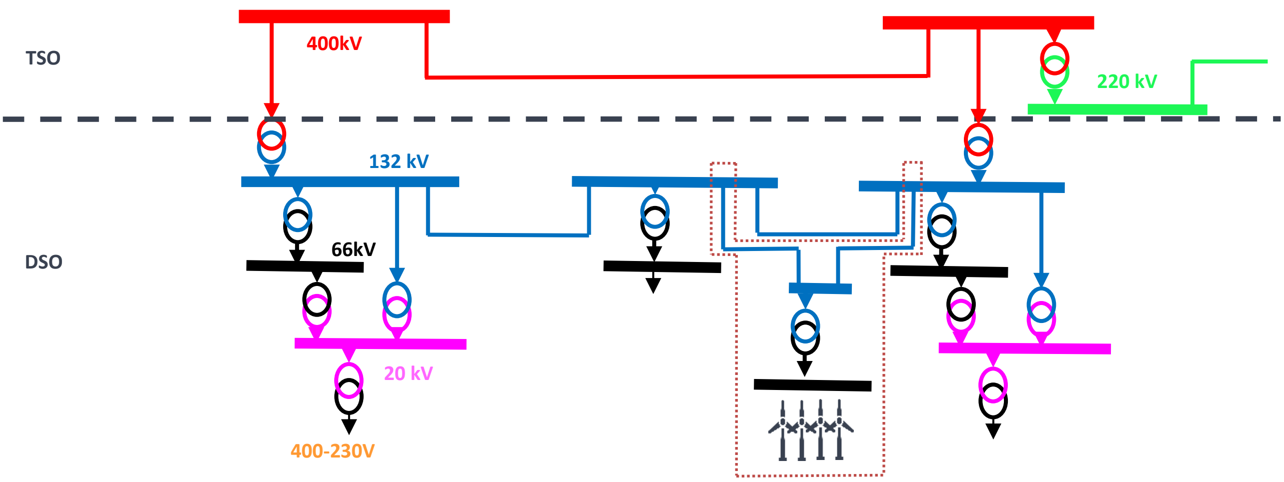


Figure 16 Case-study 1: Grid description

To maintain the reliability levels of the network and not jeopardize the current lines, the BAU solution would be:

- Construction of a 132kV to 20kV substation for power evacuation (this reinforcement is necessary to connect to the grid in any case, therefore considered out of the comparison)

- Construction of two 132kV lines with a total distance of 30 kilometers: 30km x 183,547€/km (code TI-1UX in [75]) = 5,506,410€

- Modification of substations to connect the new lines. 2 Bays 132kVx 413,270€/bay (code TI-91U in [75]) = 826,540€

Then, the costs for a new connection with the BAU approach would be 6,333,000€.

The lifetime of this investment is 40 years [76] and annualizing the cost considering a WACC of 5% gives an annualized cost of 369,075.59€.

According to the framework in Annex 1, the case of the flexible connection is based on a bilateral agreement. This agreement establishes the periods in which power curtailment is necessary to ensure compliance with grid requirements. These periods must be agreed based on a long-term forecast, as it is intended to be compared with a reinforcement of the grid.

By sorting the hours of one year from highest load to lowest load in descending order, the hours in which a solution is necessary are obtained. These hours are the ones exceeding the maximum of the 132kV line capacity, considering the generation and load curve in the energy flow in that line. This analysis results in 68 hours of curtailments of 7.5MW during working days. The resulting curtailment would be based on the actual needs and for all hours when congestions are forecasted. Following the methodology, the first step is the comparison with the threshold curve. Figure 17 shows the number of hours per year that are needed for wind generation to be curtailed. All of them are above the threshold curve. In this case, the use duration curve and the threshold curve intersect only once.

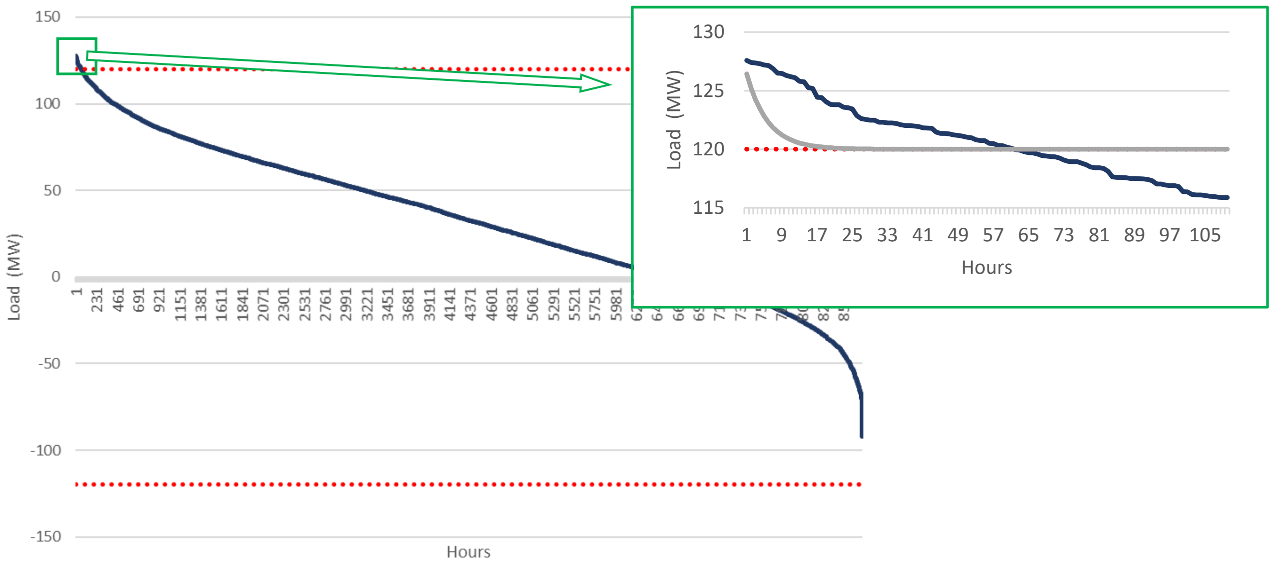


Figure 17 Case-study 1: Load Duration Curve in blue of a 132kV line for one year. Calculation of the hours to be curtailed. The threshold curve can be seen in grey in the zoom. Source: I-DE (Spanish DSO)

The annual cost of the flexibility service is assessed based on the methodology explained above. CAPEX costs are mainly sunk costs in terms of DSO and the market platforms. Annual operating costs per FSP (Figure 14) are considered as Prequalification (2.5h), Registration (2.5h), Planning costs as Cost Benefit Analysis (10h) and Definition of scenarios (10h). Annual operating costs per activation hour are: Monitoring (1h per activation h), Billing (1h per activation h) and Needs

Calculation (1h per activation h). All costs are based on person-hours. An automated solution would only be incorporated if it is more efficient than a non-automated solution. The value of hours was based on [77], considering the salary of an industrial engineer newly recruited plus corresponding employment charges in Spain [78].

In this case, a market is not necessary. Finally, in terms of Aggregation and FSP costs, operational expenses for monitoring and energy costs and some investments in communications and data acquisition are considered (200€ from the values used in CoordiNet [79]).). Despite the volatility to which the electricity market may be subject, a reference was sought and a price of energy of 40€/MWh was considered as in [80].

With all this:

$$\boldsymbol{Cost_1^{Act}} = (1+1+1+2)h \times \frac{40000€}{1760h} + 40€/MWh \times 7.5MW = 413.63€$$

$$\boldsymbol{Cost_1^{fsp}} = (2.5+2.5+10+10)h \times \frac{40000€}{1760h} + 200€ = 768.18€$$

From the UDC curve, the constants A and B are calculated:

$$\boldsymbol{Cost'^{flex}_n} = \boldsymbol{e}^{\frac{\mathbf{160.17}-\boldsymbol{P}}{9.534}} \times \boldsymbol{Cost_1^{Act}} + \boldsymbol{Cost_1^{fsp}} \boldsymbol{=} \boldsymbol{e}^{\frac{\mathbf{160.17}-\boldsymbol{P}}{9.534}} \times 413.63 + 768.18 = \mathbf{28{,}722.56€}$$

Table 4 summarizes the assessment of the case 1 (DG connection in HV).

Business As Usual: Reinforcement			Alternative with a flexibility service	
Investment cost	Years	Annual cost	Hours of activation	Annual Cost
6,333,000€	40	369,075.59€	68	28,722.56€

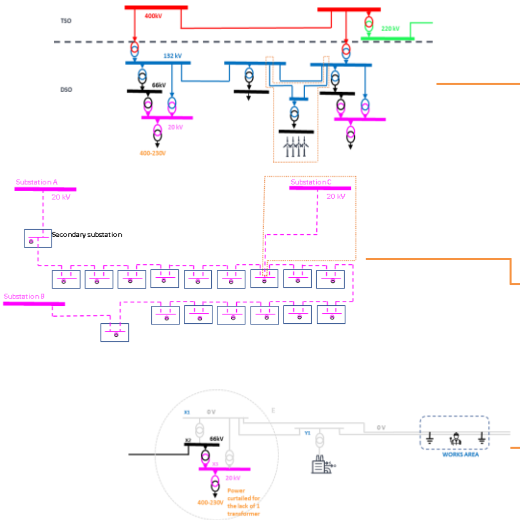
Table 4 Costs assessment for new flexible connections

The solution with flexibility is clearly cheaper, only a significantly lower reinforcement cost could reverse this situation. Another benefit associated with this solution is the anticipation of the connection during the period when the reinforcement is being executed. In this case, it is necessary to consider the life span of the generation facility itself, the grid extension to connect such a facility and the corresponding reinforcement. The value in producing earlier in time could be significant. For instance, for a 1500h/year production of 50MW, even with curtailment, at an average price of 30€/MWh it would mean 2.25M€ per year.

3.3.2 Results for all the realistic case studies

Calculations for all the realistic case studies can be found in Annex 2. Results are summarized in Figure 18. These results show that flexibility presents a different value depending on the case studies considered and that, under certain circumstances, traditional solutions can be more competitive than alternatives with flexibility services. Flexibility mechanisms can be particularly attractive solutions for new flexible connections (Case 1 (DG connection in HV)) and to ensure grid security during planned maintenance works (case 3 (Maintenance in HV), and Case Study 4

(DG connection in LV)). Moreover, flexible solutions can be useful while the reinforcement is being built as it may temporarily be the only solution (Case 2 (EV in MV) and Case Study 4 (DG connection in LV)). Network reinforcements in the distribution network have a long lifespan and provide reliable service to thousands of customers. However, flexibility services can be useful for accelerating decarbonization with flexible connections or as short-term solutions to manage the distribution network operation.



Case study	Annual cost BAU (k€)	Annual cost with a flexibility service (k€)	Evident benefit?
New flexible connection	369	28	Yes
Congestion on MV network	96	96	No
Maintenance works	711	0.44	Yes
Congestion on LV network	8	30	No

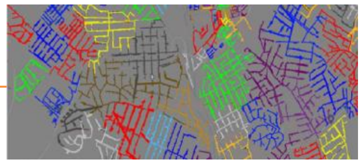


Figure 18 Realistic case-study results

Following the analysis carried out, certain parameters can vary greatly and induce a sensitivity analysis, such as the hours of activations of a flexibility solution, the implementation and operating costs for the DSO, the value of lost load or the remedial actions, the cost of reinforcements, or the cost of energy whose magnitudes determine the true value of flexibility. The values taken in this thesis try to be realistic and reflect situations as real as possible considering the expected penetration of distributed energy resources. Illustratively, Figure 19 shows an example of the analysis with the hours of activation. Case 1 (massive DG connection HV) turns out to be quite sensitive with respect to the hours of activations, finding a break-even point close to 210 hours. This is because flexible connections are designed for cases in which the peak of need is reached in a few hours a year. For the rest of the cases, a greater insensitivity is observed, although a number of hours greater than 80 hours also makes cases 2 (electromobility) and 4 (massive DG connection LV) unfeasible. Case 3 (maintenance of a HV line) is uniform by increasing the number of hours, but it is a different case, since what is valued in this case is the duration of the scheduled outage and it is compared to the interrupted supply. It is unreasonable to consider hundreds of hours in this case because this maintenance takes less than 10 hours every three years.

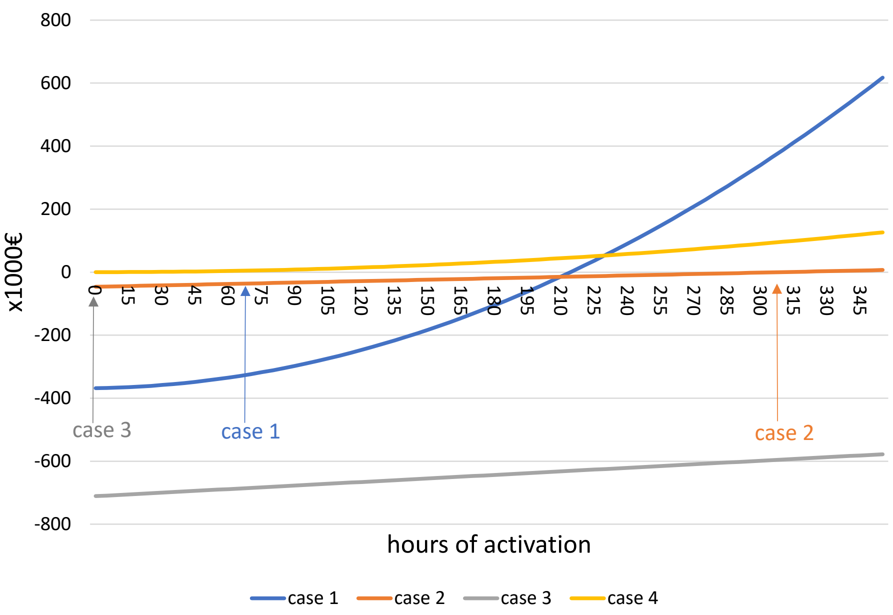


Figure 19 Sensitivity analysis of flexibility cost (x1000€) against the hours of activations.

A similar sensitivity analysis for the CBA with respect to other parameters is conducted and shown in Annex 2. The net value of flexibility (benefits minus costs) and its variation with respect to the energy price are also analyzed. It follows that the break-even point of Case 1 (DG connection in HV) is reached with a high value, which makes it cost-effective, and that of case 4 (DG connection in LV) with a value close to zero, which makes flexibility hardly viable in this case. Cases 2 (EV in MV) and 3(Maintenance in HV) are insensitive to the price of energy.

Another interesting sensitivity analysis tackles the variation with respect to the labor cost of the DSO in hours. This depends on the efficiency of the process and the digitalization and observability of the network, which allows the process to be automated and less costly without losing reliability. In this case, the conclusions are similar to the variation with the hours of activation. While it is true that this cost is not likely to grow with the maturity of the solution, but to decrease. Therefore, if the operational labor cost decreases as expected cases 1, 2 and 3 will continue to be viable. The viability of case 4 (DG connection in LV) depends on other variables such as the energy price.

It is also important to consider reinforcement costs (BAU cost) for new flexible connections and congestion management. In the case of flexible connections, the margin is very wide due to the low cost of activation. But in the case of congestion, the BAU solution must be very expensive for the flexible solution to be more efficient.

Throughout the study, the importance of considering all types of costs and not neglecting any that may be relevant to the viability of the solution is demonstrated. There are also sunk costs that need to be considered when studying the whole solution, but not to assess a specific flexibility application within a limited network area. For an FSP, the uncertainty of how often a service is required is also a barrier to investment. The cost of this uncertainty is not handled in the presented studies. The necessary information exchange and the transparency of the agents involved can alleviate this uncertainty. The grid congestion maps published by DSOs in Europe are an example of it ([81], [82], [83]).

3.4 Conclusions on the value of flexibility versus traditional solutions

A **methodology** to evaluate flexibility costs is proposed to make an **exhaustive description of the flexibility costs**, both OPEX and CAPEX of each of the stakeholders involved, providing formulas that simplify their study and a method of comparison depending on the needs' type. Then, an analysis of four representative and **realistic case studies** in Spain, accurately selected starting from representative drivers, is conducted to compare business-as-usual solutions with flexibility alternatives.

One of the conclusions is that flexibility services are highly **case-dependent** and they do not always outperform the traditional alternatives. Following the analysis carried out, certain parameters can vary greatly and induce a sensitivity analysis, such as the hours of activations of a flexibility solution, the implementation and operating costs for the DSO, the value of lost load or the remedial actions, the cost of reinforcements, or the cost of energy whose magnitudes determine the true value of flexibility. Therefore, **it is necessary to address a wide range of parameters before taken a decision**. The values taken in this thesis try to be realistic and reflect situations that are as real as possible considering the expected penetration of distributed energy resources.

The difficulties in obtaining real and reliable data to estimate costs are limitations of this research, not only for the access to the information but also for the immaturity of the process when identifying flexibility costs.

Overall, as case study 3 (Maintenance in HV) showed a more evident benefit, it can be concluded that the paradigm shift of flexibility services may be especially **useful from an operational perspective**, as it better exploits network potential in the short term. Case study 1 (DG connection in HV) allows concluding that flexibility services can help accelerate the **integration of distributed renewable generation through flexible connections**. The long-term use of flexibility requires to thoroughly assess each need to establish whether it can compete with BAU solutions considering their reliability, duration and the number of customers involved. But given that the needs of the network are progressing over time, flexible tools are valid to **postpone investments for a few years** as long as the number of hours of activations required is limited. Probably, when flexibility solutions are more **mature**, costs could be lower, markets would be more liquid and this substitution may be more evident in the long term.

As mentioned above, after analyzing the sensitivity of some parameters, the result of this study indicates that the number of activations or the cost of flexibility management are relevant. This is understandable because the number of activations, as in Case 1 (DG connection in HV), can significantly influence the cost of the flexible solution. And if it is a flexible solution that's expensive to manage, it's also logical that it will affect the CBA.

A wider range of use cases studied considering all costs faced by the different flexibility providers with the same methodology, would help to make informed decisions. Alternative methods to assess flexibility potential could provide more accurate estimated costs when the quantity and quality of data provided is enough.

4 Analysing the need for TSO-DSO coordination

To complete the study, a critical step in the mechanism selection flow presented in section 2 and related to the TSO-DSO coordination is also reviewed. This is addressed in the third paper of the compendium that makes up the thesis. This paper is included in Annex 3. As concluded in [84], interoperability between TSO, DSO and DER actors must be redefined and adapted to accommodate the evolving energy landscape. Coordination can be understood as 1) an exchange of information or technical requirements to operate safely [85], which in this thesis, is referred to as minor coordination; or 2) a mechanism by which responsibility and decision-making in operation are shared, hereby referred to as major coordination. The research question in this thesis is about when major coordination is necessary, at which TSO/DSO voltage levels, and for which TSO services, and, if necessary, what is the minimum size of the operations that need coordination.

Local flexibility markets allow DSOs to perform more efficient planning and operation of their networks. But TSO-DSO coordination is needed in any new process that could interfere with their responsibilities as transmission grid operators or with those responsibilities for balancing and stability of the electricity system. For this reason, this thesis presents a revision of potential coordination needs and representative case studies to evaluate the possible impacts of activation of flexibility in local markets in those TSO responsibilities.

4.1 Methodology to study the impact on TSO responsibilities of DSO operations

Figure 20 shows the methodology used to identify the coordination needs between Transmission System Operators (TSOs) and Distribution System Operators (DSOs) when implementing local flexibility markets. The process helps understand when TSO-DSO coordination is necessary, considering different types of needs, timing, and voltage levels. It involves splitting scenarios and addressing each separately to conclude differently for every case. Depending on the type of network, the timeframe, and the potential impact on TSO level. The potential coordination needs are classified considering timing and voltage levels, followed by selecting scenarios where major coordination is required.

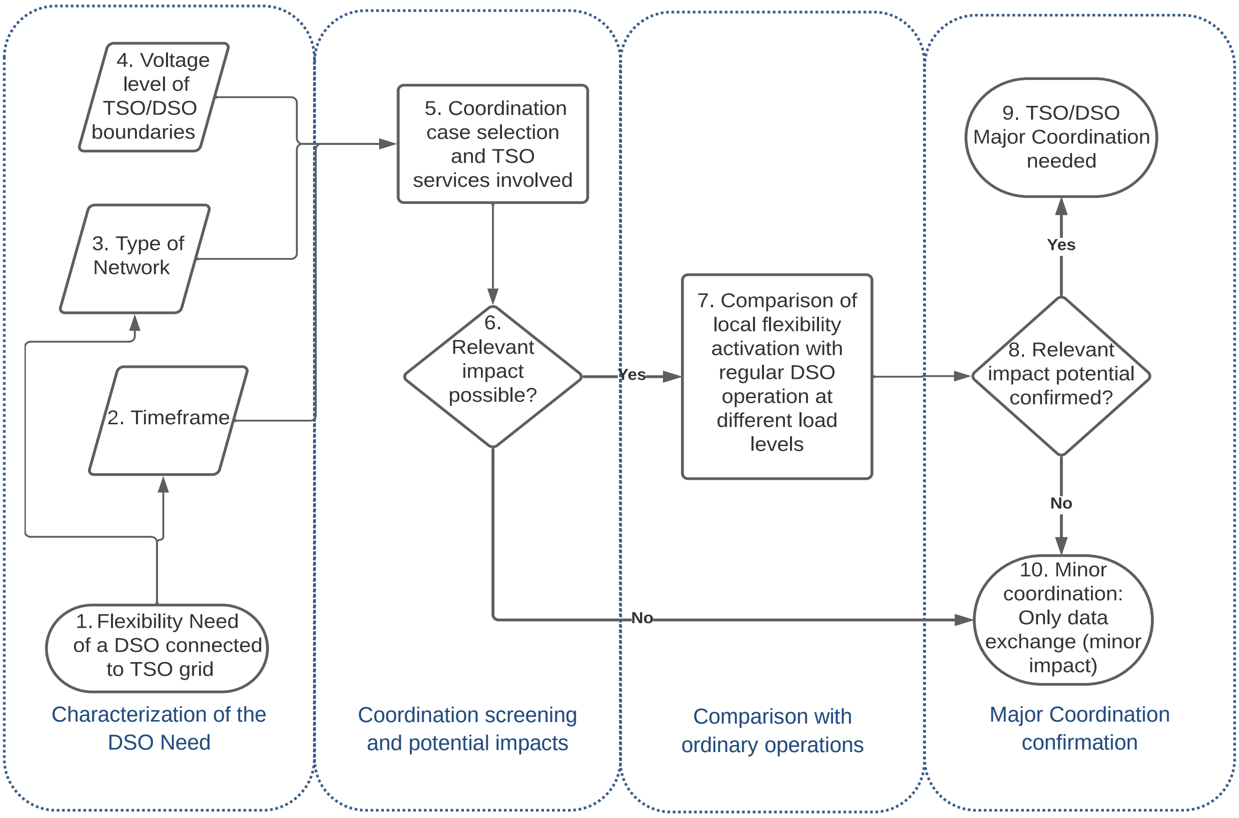


Figure 20 Methodology followed to study the impact on TSO responsibilities of regular operations in the DSO networks.

The methodology includes evaluating the effect of DSO operations on the transmission network and comparing it with current ordinary scenarios to provide a realistic perspective. In the first steps (1, 2, 3, and 4 in Figure 20), the necessary information is obtained to properly classify the type of need depending on coordination requirements, associated with specific requirements of a flexibility product (e.g. [20]). The type of network is relevant to have a reference for the size of the power flows managed at each voltage level. A three-phase LV line in Europe is typically in the load range of several tens or hundreds of kW depending on the ampacity of the cable [22]. In the case of the MV network, they can be up to 7 or 10 MW following the same reasoning. As a benchmark, the MV feeder type averages 10,5MW capacity considering the total power installed in secondary substations in each feeder [79]. The procurement timeframe selection is also needed to characterize the DSO need: long-term [from years to months], weeks to day-ahead procurement, or intraday procurement / real-time.

In each country, the limits of responsibility of TSOs and DSOs are different (TSO-DSO border level). To establish a methodology useful for any circumstance, it is necessary to consider the different types of borders. In this sense, as shown in Figure 21, three different levels are considered.

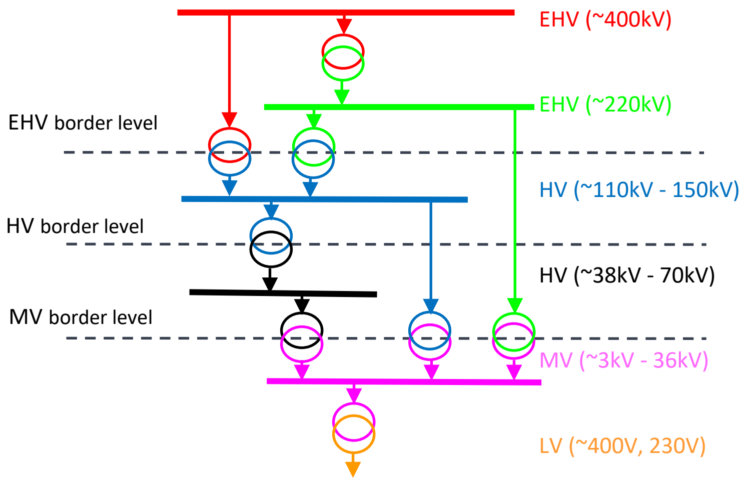


Figure 21 Possible TSO/DSO voltage responsibility borders considered

4.2 Services and responsibilities of the TSO potentially affected

In this subsection a list of the services and responsibilities of the TSO that may be affected by the needs is studied. As presented in [86] and [87], TSO services can be classified according to the needs:

Frequency services, including all the balancing needs [88]: Inertial response, Fast frequency response—FFR, Frequency Containment Reserve—FCR, Automatic Frequency Restoration Reserve—aFRR, Manual Frequency Restoration Reserve—mFRR, Replacement Reserve—RR, and Ramping.

Non-frequency services: Congestion Management (Corrective, Predictive), Voltage Control (Steady-State VC, Dynamic Reactive Power), Systems' inertia and stability (Synchronous Inertial Response—SIR, Fast Post Fault Active Power Recovery—FPFAPR, Dynamic reactive response—DRR), and System Restoration (Black-start capability); and System Adequacy (Last-resort tender, Strategic reserves, Capacity mechanisms).

4.2.1 Frequency services

Long-term flexibility solutions include long-term contracts used for assuring the availability of flexibility reserves with an activation market near real-time [89] [90]. Regarding frequency services and balancing services, the timeframe is **Day-Ahead and Real-Time**. So, for the Long-Term in any type of network and border between DSO and TSO at any voltage level, the impact is considered negligible. Only minor coordination might be required to consider the participation of some DERs in frequency services for the long term.

Regarding the Day-Ahead timeframe, a null impact on the balance is possible if the local flexibility market is cleared before other markets to integrate it into the offers for other markets. Flexibility activation certainty before the wholesale markets' timeframe makes minor coordination possible, as activations can be incorporated into the market positions. In addition, the impacts on the balance have no relation to the TSO-DSO border level.

Many **inertia and stability services** are based on availability activated if necessary. The availability service itself does not have conflicts. In the necessary data exchange, the DSO should have the information of such availabilities. Rotor Angle Stability solutions are expected to be activated in real time. There could be an expected conflict in the case that DSO activates in real-time a congestion service in the opposite direction to stability services deployed by the TSO, for which the TSO would have to activate further services to compensate for the DSO service activation. Presumably, this scenario would not happen without the proper information exchange.

In any case, although this exchange of information is desirable, it is expected that the activation of inertial services, the duration of which is few seconds or less than one second, does not affect the capacity of the distribution network beyond compatibility with the protection system. In some cases, the short duration of inertial services would not even be sufficient to trigger the action of the protections. Therefore, this exchange of information would take place especially to enable this coordination. Although the Real-Time and Day-Ahead timeframe is indicated to perform this check, because it would be sufficient, it could also be given in the Long-Term. Because of that, Day-Ahead and Real-Time scenarios were selected for minor coordination.

4.2.2 Non-frequency services

Congestions may cause a degradation of assets such as transformers or lines [91] or put the system in danger, therefore the redispatch of resources is required to avoid them. Managing the meshed network at different voltage levels always requires some coordination as the impacts are propagated. Meshed networks operate considering the upstream voltage level and vice versa. In Europe, it is mandatory to share the data of the observable grid among network operators [92] (e.g. structural data, scheduled unavailabilities and real-time data). Therefore, regarding Congestion Management, TSO-DSO coordination might be needed to seek mutual approval and consider cross-impacts in the Weeks to day-ahead, Intraday and Real-time timeframes, which are the regular operations timeframes in distribution grids.

The range of power magnitudes in MV or LV individually does not condition the operation at (EHV) level, even less in long-term projections. Being a transmission network, a load variation of less than 1% in the most affected asset could be expected. From hundreds of MW to around 1MW, considering simultaneity and meshed topology ([93], Annex 1). However, in case the border is at MV level and the HV/MV transformer belongs to the TSO which is not common practice (e.g. in France and Italy, where the TSO/DSO border is at MV level, HV/MV transformers belong to the DSO), this range of power might occasionally condition the operation of the transmission grid and major TSO-DSO coordination would be needed.

Regarding the TSO services related to **Voltage Control**, its activation must be specific to the operation of each network and any interference activating resources connected to other SO´s grid must be coordinated, as proposed in Art. 29.9 Reg. 2017/1485, [92]. In the same way, as in congestion management, operational coordination is necessary in Real-Time and Day-Ahead. In [94], a market-based TSO-DSO coordination scheme is proposed for voltage regulation. For that, the DSO is given priority in using DERs to solve distribution network constraints, however, significant flexibility remains for the TSO even during periods of peak demand and maximum export. Voltage control refers to a specific geographical location, voltage level, and system operator [91], it must be managed by local mechanisms. Any shared decision-making would only be in limited circumstances.

The coordination approach is similar to that of congestion management, since, although the priority must be established by the DSO before delivering flexibility services to the TSO, it is necessary to consider the overall result to obtain an optimal solution. In [95], this approach to overall efficiency is addressed. In it, TSO-DSO coordination approach is proposed for voltage regulation showing results of a Greek case study to leverage flexibility from distribution grids for over-voltages in the transmission grid.

Thus, with the same rational, TSO-DSO coordination might be needed for the Meshed Operated Grid to seek mutual approval and consider cross-impacts in regular operations (Day-Ahead and Real-Time), but not long-term. For the Radially Operated Grid Scenarios the range of power might condition the operation of the transmission grid only for borders at the MV level. Only in those cases major TSO-DSO coordination would be needed.

Regarding **System Restoration**, large disturbances can cause total or partial blackouts of power systems. Traditionally, power system restoration starts from a neighboring power system, but the proliferation of distributed generation resources enables parallel islands within the outage power system that could be connected gradually to the transmission system [96], [97]. Such an approach requires that islands within the distribution system can be successfully started up and operated in a stable manner, needing, in turn, a long-term planning to deploy the capacities and infrastructure to do that. That is why long-term data exchange may be needed. But logically, local needs for DSOs that trigger flexible solutions would not have any interference with the System Restoration Procedure.

System adequacy is part of the long-term grid planning procedure based on a deterministic criterion under which the sum of the total firm generation capacity should be higher than the expected peak demand plus a security margin. The firm capacity assigned to each generation technology is calculated depending on its availability to supply the peak load by applying a derating factor to the installed capacity [98].

There must be coordination between the planning of transmission and distribution networks (e.g. Art 55 [99]) and alignment, and especially in the scenario of decarbonization and electrification necessary to address the needs of the energy transition. Moreover, the application of flexibility solutions in DSOs' investment plans, as indicated in the European Directive [2] requires information on the flexibility services needed in the medium and long term.

The influence of flexibility on the long-term planning of the electricity system is still unknown [100], although long-term tenders to defer investments in the distribution network may become relevant [90], [101]. However, as mentioned for radially operated grids, the objective of this thesis addresses only the need for coordination in the operation stage. As in the previous case, information exchange at the interfaces would be sufficient to perform coherent operational decisions (minor coordination).

Table 5 shows a summary of the coordination needs according to the impacts produced by the activation of local flexibility by DSOs. The impact assessed here refers to an aggregated impact, not a one-off use of local flexibility. There might be a need for major coordination in the cases of congestion management and voltage control as local needs for Day-Ahead and Real-Time, in the cases of a mesh network when the TSO/DSO border is in HV or EHV, or in the case of a radial network when the border point is in MV.

TSO services	EHV border level						HV border level						MV border level		
	DSO need at radial network			DSO need at meshed network			DSO need at radial network			DSO need at meshed network			DSO need at radial network		
	Long-Term	Day Ahead	Real-Time	Long-Term	Day Ahead	Real-Time	Long-Term	Day Ahead	Real-Time	Long-Term	Day Ahead	Real-Time	Long-Term	Day Ahead	Real-Time
Frequency services	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼
Congestion Management	▼	▼	▼	▼	●	● Case 1	▼	▼	▼	▼	●	● Case 2	▼	●	● Case 3
Voltage Control	▼	▼	▼	▼	●	●	▼	▼	▼	▼	●	●	▼	●	●
Inertia and stability	○	▼	▼	○	▼	▼	○	▼	▼	○	▼	▼	○	▼	▼
System Restoration	▼	○	○	▼	○	○	▼	○	○	▼	○	○	▼	○	○
System Adequacy	▼	○	○	▼	○	○	▼	○	○	▼	○	○	▼	○	○

●: Major coordination may be required; ▼: Minor coordination required (Only data exchange); ○: No operational coordination needed

Table 5 Coordination needs and the impacts produced by the local flexibility activation by DSOs. (Highlighted in red are the three cases studied)

4.3 Case Studies with different TSO-DSO boundaries

Applying the methodology in section 4.1, after selecting the scenarios of a potentially relevant impact, a comparison is carried out in step 7 (Figure 20) to distinguish whether that need requires minor or major coordination. This step aims to make a real approximation to the impact of the activation of flexible resources that can be compared to the impact of an equivalent switch operation of the distribution network on the transmission network. If a DSO operation that currently occurs has an analogous effect and a negligible impact on the TSO network, the same effect has the activation of the flexible resources by the DSO. For that, a grid model in which a power flow can be run may be selected, and according to the specific border level (EHV, HV or MV), a certain amount of power change is evaluated to see the effect it has on the transmission level. Considering the type of network in which the need occurs, the most appropriate way to reach realistic conclusions is to take an amount of power expected at that voltage level.

The methodology described in the previous paragraph is applied to a Spanish electrical system, generating three different case studies with the same electrical system, but considering different TSO-DSO boundaries. The selected electrical system has a total peak load of 2697MW and 2.34 million customers. The load is progressively increased by different steps and repeating the power flow to see what could be expected after some years. The results of the power flow studies are processed to check loads before and after the equivalent switch operation and register the number of overloads exceeding 50%, 66% and 100% in the transmission system. Specifically, keeping the load below 66% is considered a benchmark of compliance with the N-1 contingency [102] (ensuring stability in the event of failure of any element) required in the meshed network. The comparison of the number of overloads after and before the operation provides insight into the effect of the operation on the transmission network. The aim is to obtain some thresholds from which greater coordination is necessary or not. These three cases are chosen from those cases where a potential need was foreseen (Table 5).

Figure 22 shows the results of applying the methodology to Case 1, corresponding to a border level at EHV level (DSO operating 132kV), which interrupts 48MW (at normal peak load) of a 132kV line, forcing it to redistribute the load in the transmission network. On the x-axis the different load levels are considered, reflecting on the y-axis the number of lines or transformers of the TSO grid overloaded. The curves represent the situation after and before the equivalent operation. The number of branches over exceeding 50%, 66% and 100% are registered after and before the equivalent switching for all the load levels considered (ten increasing steps until the load is doubled). In this case, the equivalent swich operation is an opening operation that breaks the mesh of the network. The number of overloads is similar after and before switching for all the load levels considered. In short, these operations do not compromise saturations in the transmission network.

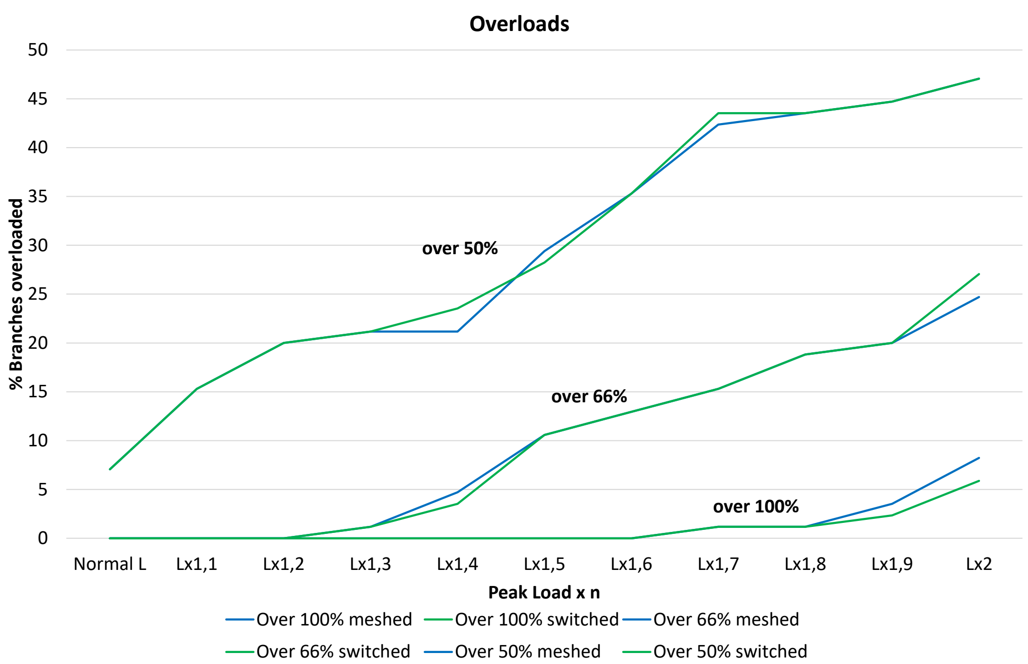


Figure 22: Number of branches exceeding different percentages of capacity in scenario 1 (DSO operating 132kV and TSO operating 400kV)

The results in case 2 and case 3 are similar, concluding that local flexibility activation by DSOs is expected to significantly impact TSO responsibilities when managing large power changes in the short term. Currently, load variations under normal operations in radial networks reach close to 5-8 MW (equivalent to one MV feeder) without requiring specific TSO-DSO coordination. Local flexibility of such magnitude should not require additional coordination either. Only when the TSO/DSO border is at MV, as it is a radial network, the power flow goes through another HV/MV transformer, the capacity of this HV/MV transformer must be considered. In the case of the DSO operating the 132kV grid (EHV border) as in Spain, moving a volume close to 50MW has almost no impact. Operating the 66kV grid (HV border), moving a volume close to 15MW has no impact.

Coordination between DSO and TSO could be mainly reduced to real-time information exchange without constituting additional coordination barriers, extra approvals, or compliance with unnecessary technical requirements.

These studies help establish thresholds for when significant impacts occur, suggesting that major coordination in this area is needed for power changes over 50MW at 132kV or over 15MW at 66kV. The findings indicate that minor coordination is generally sufficient for most DSO operations, as they do not significantly impact the transmission network. Major coordination is reserved for scenarios involving substantial power transfers. The area considered is significant because it corresponds to the 8,6% of the Spanish peninsular demand, being similar to other areas. However, similar studies could be conducted in other areas to establish global thresholds when possible.

4.4 Conclusions on the need for TSO-DSO coordination

TSO-DSO coordination can take place over different a range of services, network levels and timeframes. A comprehensive list of case studies considering all these relevant characteristics were assessed to detect major coordination needs (the type of coordination by which responsibility and decision-making in operation are shared) and then compared against conventional operating conditions that nowadays do not require any TSO-DSO major coordination. All possible TSO impacts are screened considering all services TSOs manage. If the volume of flexibility activated by DSOs is in the same order as current operational practices minor coordination (consisting of a simple exchange of information) is enough, and additional coordination would not be required. Coordination is less necessary for **variations imperceptible to the TSO.**

This methodology is worth assessing a specific DSO need. Therefore, to evaluate a spectrum of needs, it is necessary to reproduce the methodology as many times as necessary. A systematization of the process that allows a greater spectrum of scenarios and needs to be related would also allow for a broader map of coordination needs.

The methodology assumes a network with an expected significant load increase due to the electrification of energy demand and considers different demand scenarios. All different scenarios are investigated by identifying all possibilities in which coordination would be necessary; and from the proposed quantitative analysis, the threshold and the circumstances beyond which such major coordination is necessary. It is concluded that local markets would not impact the transmission network if they were not dedicated to the **short-term** management of the meshed distribution network. In addition, the necessary major coordination is limited to short-term scenarios in which the meshed networks move **significant volumes**. According to the cases analyzed in the studied area, representative of 8,6% of the peninsular demand in Spain, this threshold could be set at 50MW with a TSO/DSO border at EHV or above 15MW with a border at HV. Similar studies could be conducted in other areas to establish global thresholds when possible.

On the other hand, statistically representative values were chosen based on confidential data from the operations carried out by a control room with 2.34 million customers over 20 years. Since the size of the operations is a structural condition of the network, a stochastic analysis was not carried out. However, while MV size of operations has a more stable annual volume, data availability from HV and EHV networks are very different each year. Therefore, given the stochastic nature of the number of operations, future research could check if an increase in the number of DSO needs would affect the thresholds or how a change in the size of the operations or new technological developments would change them. For example, how the digitalization of networks could help reduce the size of operations and the coordination thresholds. Further research could also address the study with networks in scenarios with the proliferation of distributed generation or distributed storage.

These findings should help **remove the constraints** and barriers for flexibility providers to meet the criteria imposed by TSOs to participate in their services and provide flexibility with less strict requirements that could generally be the case of DSO services. Moreover, it would allow DSOs to have greater versatility **to tailor flexibility services** to providers' capabilities, thereby unlocking a **greater volume of flexibility**.

5 Regulatory Recommendations

The design of local flexibility procurement is being reviewed by national regulators. Furthermore, as mentioned above, the Network Code on Demand Side Flexibility, which lays down the requirements in relation to demand response, energy storage, distributed generation and demand curtailment rules, is being conducted [3], [4], [5]. Therefore, regulatory proposals on the topic are timely and necessary for a more accurate implementation. The recommendations are divided into the three main contributions of the thesis.

5.1 Regarding the decision framework.

As shown in section 3.1, in the complex world of a Distribution System Operator (DSO), the needs are very diverse in the timeframe and the challenges they face. They are as diverse as the areas and the locations the DSO supplies. Many considerations, such as anticipation or real-time needs, voltage level, active or reactive power requirements, play a part, making it clear there is no one-size-fits-all flexibility solution. The incorporation of flexible solutions would therefore be about enabling the **toolbox of flexibility mechanisms** mentioned in section 2.1 so that the DSO can select the most appropriate one.

As concluded in section 2.2, among the different tools available, local markets can provide optimal solutions when liquidity is high. Local DSO markets could work under those premises, but illiquid situations are likely to occur until these markets become mature. What is more, lack of liquidity may even be persistent in some areas even if local markets operate normally in others. This is where non-market mechanisms, such as bilateral agreements, step in to fill the gap, playing a crucial role in the DSO environment. **Non-market-based solutions** are a possible solution in case of low liquidity or immature markets. There are actions that should help to improve liquidity, such as proper information exchange among stakeholders, an accurate design of the traded product, efficient price formation, considering costs and barriers, etc.

To improve liquidity in the markets, it is necessary for those who have to deliver the service to be involved in a committed manner. Regulation should be focused on engaging **all relevant stakeholders**, including energy suppliers, aggregators, and consumers [103]. Some projects, such as BeFlexible [104], focus on this matter and provided interesting results ([105], [106]) focusing on the value chain and the pains and gains of the customers. The input of the customers shall provide valuable insights and foster a sense of ownership and cooperation.

Additionally, before any flexibility solution is implemented, an assessment of available technologies is necessary. Not only on the DSO side, as faced in [37], but also on the customers' side. This includes evaluating energy storage systems, demand response technologies, and advanced metering infrastructure for their suitability in providing flexibility services. In some way, these resources have to respond to the network's requirements in time, form, and duration. So there has to be compatibility. This evaluation is closely tied to the upgrading of existing infrastructure, which may involve enhancing grid connectivity, installing advanced metering infrastructure, and improving data management systems to manage the increased complexity and variability that come with flexibility services. These actions help increase liquidity in the flexibility markets, as expected in section 2.2, but also improve the sensitivity analysis regarding DSO costs mentioned in section 3.3.

How the market mechanisms are implemented is a key part of this process. The price formation process is crucial for the proper functioning of a market. This topic was addressed from the global perspective of TSO-DSO coordination as in [107], but should be addressed from a more local perspective of resources that do not access TSO services. On the other side, the design of product options, such as the timeframe, information exchange needs, costs, and barriers to entry and exit, also plays a significant role (literature review: [108]). These factors also influence market liquidity and, consequently, the efficiency of a market-based mechanism.

Before full-scale implementation, pilot projects ([29], [31], [104]) are necessary to evaluate the feasibility and effectiveness of flexibility services. These projects help identify potential issues and make necessary adjustments, ensuring that the implemented solutions are as effective and efficient as possible.

Since flexible solution requires new skills for the DSOs, investment in training and capacity building for all personnel involved in the implementation of flexibility services is another crucial step. Regulatory sandboxes may be used to overcome this gap by enabling and supporting the development of local flexibility mechanisms [109]. This ensures that they possess the necessary skills and knowledge to effectively manage and operate the new systems, linking back to the importance of stakeholder involvement.

Finally, coordination between the Transmission System Operator (TSO) and DSO is necessary, especially when the same resources provide services in separate markets, but in many cases it can be solved by minor coordination with a simple data exchange and a timeframe coordination of the different markets. Major coordination should be deemed only in some cases as explained in section 5.3 below.

5.2 Flexibility vs. traditional solutions comparison

The energy transition is changing the way DSOs plan and operate the grid. It is no longer just about peak demand-driven investments considered in the traditional drivers (section 3.1.1) in distribution networks but also about the new drivers studied in section 3.1.3, integrating distributed generation, new loads, and storage, which introduces more uncertainty. The need for new infrastructure is undeniable, but before investing, it is crucial to consider flexibility services as an alternative to traditional solutions, network reinforcements, and other operational solutions for short-term needs. These services can adjust to grid conditions and offer a solution to manage scenarios like peak demand with low local generation or vice versa.

Regulatory authorities play a crucial role in the development of methodological frameworks for integrating flexibility services into network planning and operation. This includes providing guidelines for comparing the costs involved (including OPEX and CAPEX) of flexibility services with traditional network reinforcements, as in [24] and in the second paper of the compendium (Annex 2). The efficiency of these flexible solutions, when compared to traditional ones, is influenced by certain parameters such as the lifespan of the assets, the value of lost load, the cost of energy, and the cost of reinforcements as shown in section 3.3. These parameters, which can vary greatly, determine the true value of flexibility.

A significant shift in the DSO operations is the introduction of flexible connections, or non-firm connections, proved to be efficient since 2013 [110], and confirmed in the second paper of the compendium (Annex 2). These are agreements that give the DSO the right to limit power injections or withdrawals during a specified time. This change not only accelerates the energy transition by allowing faster and cheaper connections and is being considered currently by the regulators [111]. Flexible connections allow DSOs to **accelerate the energy transition.**

A comprehensive **methodology for planning** is necessary, with a detailed analysis of costs. The fact that **probabilistic and dynamic studies are needed** to predict activation times in planning also opens the possibility of proposing a variety of solutions that also allow for comparison between them, given that probability must be considered at different stages. It could even be considered that the DSO could offer different solutions depending on the activation probability. Each alternative would have a firm power and non-firm, connection period and connection cost that may fit better the applicant's needs, allowing an acceleration in different electrifications (section 0).

Flexibility services also provide the DSO with the flexibility to use Distributed Generation (DG) to supply local demand in case of network failures or maintenance, especially in cases where the grid has a weak connection with the rest of the grid, increasing the **resiliency** considered as a driver in section 3.1.2.6. Controlled islanding has proved to be an efficient service for this purpose [29].

The responsibilities of the aggregator need to be thoroughly analyzed to redirect the tasks of searching for flexibility niches and incentivize customers to provide flexibility. It would increase market liquidity, key in the decision framework (section 2.2). Despite having the technology in place, conventional solutions may still be preferred by the DSO due to their reliability and the associated remuneration. Therefore, the implementation of flexibility mechanisms can only be justified if they deliver significant efficiencies when applying the comparison with traditional solutions as presented in section 3.3.

Barriers need to be removed to allow DSOs to tailor flexibility services to providers' capabilities to unlock a greater volume of flexibility. Further studies could address the quantification of the volumes of flexibility that can be found in the distribution network to compare with the volumes raised in this thesis.

Incentives play a crucial role in the adoption of flexible solutions. DSOs and flexibility providers must participate in the incentives or benefits to have sufficient motivation to participate in the markets. Even to compare the cheapest solution all the costs from a global point of view must be considered (section III.C in Annex 2), each agent that participates in the value chain is expected to make their comparison and for all of them, it has to be positive for the case to work. [105] has this approach. Additionally, penalties must be sized correctly to formalize commitments and maintain reliability in delivery.

DSOs face increasing uncertainties about the penetration of distributed energy resources (DERs) in the upcoming years. Flexibility services are considered especially valuable under these circumstances. They may allow the DSO to opt for more efficient solutions, being able to better optimize investments [112], [113]. This has a significant impact on the way the distribution network is operated and planned. The traditional deterministic network planning, where the decisions are fixed, may undervalue flexibility and result in a less efficient planning.

Traditional treatment of OPEX and CAPEX in DSO remuneration schemes directly impact the incentives of the DSO for flexibility solutions that are OPEX based. The traditional schemes could represent a barrier to the procurement of flexibility services [112]. Therefore, treating OPEX as equivalent to CAPEX in the regulatory framework, and even providing greater incentives to tip the balance towards the flexible solution is the best way to incentivize DSOs.

The risks associated with not reinforcing the network or contracting flexibility (section 3.2) must be considered, balancing reliability with strategic decisions. **Guidelines should be established for assessing and managing the risks associated** with flexibility services. This would help DSOs balance the need for reliability with the potential benefits of flexibility.

A broad-spectrum methodology (section III in Annex 2) that fits any type of model to solve any need is necessary. This involves integrating different types of algorithms and addressing the entire planning process. Considering the technical and economic perspectives, flexible services are expected to coexist alongside traditional solutions. Therefore, a detailed analysis of flexibility costs is important to make an accurate comparison with conventional solutions.

Finally, standard technological solutions should be developed for data exchange between DSOs and network users. This would facilitate the active management of networks and ensure that all parties have access to the necessary information. An adequate exchange of information improves the possibilities of engaging the client, coordinating agents and ultimately allowing the mechanisms considered in 2.1.1 to function properly. However, while the standardization of technological solutions can offer greater liquidity in the market, standardization is not always optimal. Standard products can be a barrier to DSO needs. If a DER can perfectly solve a local DSO problem but does not meet the requirements to fit the standard product, an opportunity is lost. With the low liquidity of some local needs, it could be the only viable solution. Given the diversity of needs and flexible resources in distribution networks, having the possibility of making customized solutions could eliminate barriers, which is a priority.

5.3 Regarding the TSO-DSO coordination.

The integration of DERs into the power system is a crucial aspect of any coordination mechanism between TSOs and DSOs, as it ensures secure and efficient grid operation. As concluded in section 4.3, this coordination is particularly necessary in short-term scenarios where the meshed networks move significant volumes. Based on the cases analyzed, the threshold for the major coordination in the network analyzed could be set at more than 50MW at 132kV or more than 15MW at 66kV. All the cases studied in Annex 3 reflect the very slight impact that the DSO activity has on the TSO responsibilities.

However, minor coordination through **data exchange** proposed in the introduction of section 4 **is a requirement** in every case. Information without interference would help to avoid barriers and additional costs. This level of coordination is usually sufficient for most scenarios where a

DSO activates flexibility in its own grids. This coordination ensures that the system operates smoothly and efficiently, ultimately benefiting the consumers it serves.

The creation and development of **local flexibility markets** is another important aspect. These markets must be useful and efficient for the system, avoiding unnecessary barriers or costs associated with unnecessary coordination mechanisms that may bring unnecessary costly coordination procedures as addressed in Annex 3.

Section 3.5 in Annex 1 addresses the concept of generalization mentioned in 2.2, which is crucial to understand the differences between TSO and DSO needs. DSO needs are exclusively local, and the generalization of a solution could help as long as the local need and solution are statistically repeated across the network. That is why standardization of solutions is positive for these cases, but it is also positive to allow for tailor-made solutions where the local need and the local solution are compatible with each other even if they are not compatible with the generalized standard.

Removing restrictions and barriers for flexibility providers is also crucial to unlock flexibility. This allows them to meet the criteria to participate in their services and to provide flexibility. As such, the requirements for DSO services (sections 2.1.2 and 2.1.4) should be **less strict than those for TSO** services (section 4.2).

Clear and efficient communication protocols between TSOs and DSOs are essential. This ensures that both parties have the necessary information to make informed decisions. Joint planning activities can further help align the objectives of TSOs and DSOs, ensuring that resources are used efficiently.

Finally, **transparency** in operations can help build trust **between TSOs and DSOs**, facilitating cooperation. Specifically, a fluid exchange of all observable electrical network parameters, the maneuvers performed during daily operations, and the interventions carried out on the network and their scheduling would greatly contribute to this transparency. This trust is crucial for the successful integration of DERs into the power system and the efficient operation of the grid.

6 Conclusions, contributions and future work

6.1 Conclusions

A decarbonized economy, allowing the integration of a more renewable and distributed generation and new uses of electricity, requires additional investments in a more digital and resilient grid. Flexibility mechanisms are emerging as a new paradigm in network operation and planning to improve economic efficiency. This thesis addresses the analysis of the characteristics and criteria that condition the selection of flexibility mechanisms for every possible situation.

Each characteristic that can influence the selection of flexibility mechanisms was studied individually. Identifying the needs faced by the DSOs, their location in the network (LV, MV, HV) and the timeframe in which the need is managed. On the other hand, other relevant criteria were also studied in the choice of mechanism, such as the impact on the TSO responsibilities, the possible generalization of the problem, or the potential market liquidity. Deeming all of them, a clear decision framework is developed to match DSO needs with the most suitable flexibility mechanism. The three main types of the mechanisms, corresponding to three areas of the framework, were identified: the first type corresponds to mechanisms which must necessarily be strongly coordinated with the TSO, the second type corresponds to market-based mechanisms that are mainly managed by the DSOs in local markets, and the third one to those for which non-market-based mechanisms are the best fit.

The exclusive mechanisms for DSOs are still very unexplored in the literature and the lack of liquidity plays a key role. This thesis presents an analysis of the drivers considered when planning a distribution network, including the value that flexibility can bring to the future challenges facing the distribution networks. Traditional drivers and new drivers can be envisaged as a consequence of the energy transition. Some of these drivers are very difficult to predict, but for others, their impact on the grid is becoming more evident. Previous flexibility assessments avoid comparison with real DSO traditional solutions and focus on the technical benefits of using flexibility. In this thesis, the value of the traditional solution is obtained and compared with the value of a flexibility service. Based on parameters that are as realistic as possible, four scenarios that could occur because of these drivers are analyzed and which could be an example of the real application of the new flexibility services.

Following the analysis conducted, certain parameters, such as the lifespan of the assets, the value of lost load, the cost of energy and reinforcements, whose magnitudes determine the true value of flexibility, can vary greatly. However, the values taken in this study try to be realistic and reflect situations that are as real as possible, although considered under certain assumptions. Based on the flexibility services considered, realistic case studies and comparing these with the traditional solutions, it can be concluded that flexibility services do not always outperform the traditional alternatives.

Flexible connections (i.e., agreements that give the DSO the right to limit power injections or withdrawals during a specified time) are a paradigm shift for the DSO but accelerate the energy transition by allowing faster and cheaper connections. Flexibility services and the possibility for the DSO to use DG to supply local demand in case of network failures or maintenance in cases where the grid has a weak connection with the rest of the grid are tremendously useful. Both solutions have an obvious benefit, as the alternative is disconnection.

In the case of seeking to avoid grid reinforcement, the benefit is not so obvious, and it would be necessary to identify those situations in which the motivation of active customers and the reliability of service delivery compensate for the reliability and security benefits of grid reinforcement. In the LV network, where fewer customers are involved, there is more room for the alternative with a flexibility service to be competitive in certain circumstances. However, flexibility is not always the best solution; in certain cases, traditional solutions outperform flexibility services. MV grid reinforcements can be very competitive in urban environments and difficult to replace with flexibility services. Subsequently, further studies would be necessary to determine under which conditions flexibility can compensate for the effect of the new drivers or whether traditional solutions still prevail as the most efficient solution.

Overall, it can be concluded that the paradigm shift of flexibility services may be especially useful from an operational perspective, as it allows for more optimal extraction of the potential of the network in the short term. For the long-term use of flexibility, it is necessary to thoroughly assess each need to establish whether flexibility service provision can compete with traditional solutions, such as network reinforcements, considering their reliability, duration and the number of customers involved.

The necessary coordination between DSO and TSO for the activation of flexibility services is widely analyzed in the current literature. However, this thesis argues that this coordination is less necessary for variations that are imperceptible to the transmission network. To check this assumption, all possible cases, defined in terms of voltage levels and needs timeframe, are compared against conventional operating conditions that nowadays do not require any TSO-DSO major coordination (the type of coordination by which responsibility and decision-making in operation are shared). If the volume of flexibility activated by DSOs is in the same order as current operational practices, minor coordination (consisting of a simple exchange of information) should be enough, and additional coordination would not be required.

Different scenarios are investigated by identifying all possibilities in which coordination would be necessary; and, from the proposed quantitative analysis, the threshold and the circumstances beyond which such major coordination is necessary. It is concluded that local markets would not affect the transmission network as long as they are not dedicated to the short-term management of the meshed distribution network. In addition, the necessary major coordination is limited to short-term scenarios in which the meshed networks move significant volumes. According to the cases analyzed, this threshold could be set at 50MW at 132kV or 15MW at 66kV for the studied area in this thesis, which is a significant area of the Spanish grid. Similar studies could be conducted in other areas to establish global thresholds when possible.

These findings should help remove the restrictions and barriers for flexibility providers to meet the criteria imposed by TSOs to participate in their services and provide flexibility with less strict requirements that could generally be the case with DSO services. Moreover, it would allow DSOs to have greater versatility to tailor flexibility services to providers' capabilities, thereby unlocking a greater volume of flexibility. Further studies could address the quantification of large-scale volumes of potential flexibility found in the distribution network involving different kinds of resources at different voltage levels.

Finally, based on the conclusions of the different studies, it was possible to draw up some timely regulatory recommendations to help in the implementation of the different flexibility mechanisms: the consideration of the different solutions as a toolbox, the need to consider the benefit of all participants, to also consider all types of costs, to eliminate all possible barriers and to consider the particularities of the needs of the DSO when compared to those of the TSO.

6.2 Thesis contributions

The expected contribution is to bring the range of possibilities offered by flexibility solutions closer to the reality of the distribution network, considering the diversity of network needs and the diversity of resources that can participate in these markets. The aim is to arrive at recommendations to avoid implementing inefficient solutions due to design failure.

To this end, contributions were made in three different stages:

i. In the first stage, the key criteria that determine the most suitable mechanism to implement in each case are identified and a comprehensive decision framework to select the flexibility mechanism is proposed, based on the DSO needs and the network conditions.

ii. In the second stage, a broad-spectrum methodology to assess the value of flexibility is proposed, aligned with the actual challenges of the energy transition for the distribution network planning, including a comprehensive analysis of the real costs and the type of needs. Based on it, four representative and realistic case studies compare the BAU (business as usual) solutions with flexibility services showing that the flexibility value depends on the case studies considered.

iii. In the third stage, a revision of all the possible scenarios of the DSO operation needs and their impacts on TSO responsibilities is presented, considering the possible borders between DSO and TSO at different voltage levels. Afterward, a methodology is proposed to analyze more deeply the impact of flexibility activation with an expected significant load increase.

- **Papers Published**

This thesis results in three journal publications stated below, each included in the Annexes 1, 2 and 3, respectively.

Martín Utrilla, F.D.; Chaves-Avila, J.P.; Cossent Arin, R. “Decision Framework for Selecting Flexibility Mechanisms in Distribution Grids.” Economics of Energy & Environmental Policy, 2022, vol. 11, no 2. DOI:10.5547/2160-5890.11.2.fmar

Martín Utrilla, F.D.; Chaves-Avila, J.P.; Cossent Arin, R. “Value of flexibility alternatives for real distribution networks in the context of the energy transition” IEEE Access, 2023, vol. 11, pp. 114250-114269, doi: 10.1109/ACCESS.2023.3322365.

Martín Utrilla, F.D.; Chaves-Avila, J.P.; Cossent Arin, R. "Analyzing the boundaries for TSO-DSO coordination when activating flexibility for DSO´s in networks with an expected significant load increase," Sustainable Energy, Grids and Networks. 2024, vol. 39, 101482, ISSN 2352-4677, doi: 10.1016/j.segan.2024.101482.

6.3 Future work

6.3.1 Related to Flexibility mechanisms

To further develop the proposed approach, the next step would be to continue **to study the nature of the uses of electricity** and the nature of the needs to match the solutions provided. In this way, it could be deduced whether the value of the flexibility provided, for example by electric vehicle charging, is used up by selecting an appropriate tariff or whether it makes sense to incentivize aggregated solutions to resolve congestion in the local market or even in a common market.

The proposed framework aims to guide the most appropriate **mechanisms,** but the authors acknowledge that these mechanisms are not implemented in isolation but **combined**. Future research should analyze compatible combinations and apply them to real case studies. The expected contribution is to bring the range of possibilities offered by flexibility solutions closer to the reality of the distribution network, considering the diversity of network needs and the diversity of resources that can participate in these markets. The aim is to arrive at recommendations to **avoid implementing inefficient solutions** due to a design failure.

Further studies could address the quantification of the volumes of **flexibility that can be found in the distribution network** to compare with the volumes raised in the studies and pilots. This assessment is dynamic and could be influenced by factors such as technological developments, adoption, customer engagement, and maturity of the market, among other factors.

Regarding market mechanisms, since they are more efficient with more market liquidity, it is necessary to try to find a way to **measure liquidity**. As well as developing a methodology that allows predicting it based on a limited number of parameters. The liquidity of a local market cannot be measured only by the number of potential flexibility providers at a given time, which is already difficult due to the variation. But it is also necessary to consider the response to the price of each MW upwards or downwards, not only due to its elasticity, but also due to its possible variation over time or even the possibility of depletion due to use or even due to other external factors that influence it (temperature, gas price, etc.). Many factors vary greatly over time and determine the willingness to participate. Market liquidity is therefore a complicated variable for the DSO to handle as it is a determining factor in deciding the best mechanism. To improve liquidity levels from the FSP's perspective, however, it is crucial to simplify management as much as possible. Proposing **simpler mechanisms** should mean easier implementation for the DSOs and a better understanding for the FSPs.

Another point of debate is that of market-standard flexibility products and tailor-made solutions. **Whether or not standard products increase liquidity** in local markets is a debate, since the possibility of adapting the service to the need of the location can allow a better adaptation to the available resources.

In the methodology for **comparing the flexible solution with the traditional solution**, this thesis starts from predictions, but there is a later stage in which there is already greater certainty about the cost of flexibility, which is **after-market clearing**. At this point, and depending on the flexibility product in question, it might be possible to **reassess** and consider changing the solution. If possible, it could be very useful to consider this option in the design of flexibility products. An alternative solution to this could be to cap the cost by imposing a price cap by the DSO. However, sending price ceiling signals to the market can lead to undesirable results. Therefore, it does not seem to be the optimal solution either. Finding a solution to the dilemma posed by the reassessment of the flexible solution after the market clearing could be an interesting topic for future research.

As for the **incentives for flexibility providers**, the costs of their investments are also relevant. And the more certainty they can have with the profitability of flexibility services, the more motivated they are to invest. On the other hand, the further in advance the DSO forecasts are, the greater the degree of uncertainty. Forecasting the next day's load curve has a much smaller error than forecasting the curve a month in advance, and even more so a year or several years in advance. Therefore, contracting for long-term flexibility in the predictability terms required by FSP would be more to cover the uncertainty of the forecast than to cover the needs of the grid itself. This **anticipation** for the DSO means being able to make more accurate predictions, which is also a challenge, since on the part of the system, it could be more cost-effective to wait for the short term or real time to manage the need only when it is needed. This trade-off between the cost of anticipation and the risk of working in the short term could also be the subject of future studies. Either to improve predictions for the DSO or to find short-term incentives for the FSPs.

There may be conditioning **factors that may interfere with the prioritization of the most efficient choice for solving grid needs**, such as decarbonization policies or social policies related to energy. To obtain the most efficient solution, there could be room also for other criteria that are sometimes difficult to parameterize (reliability of the solutions, social perception, customer effort). A better understanding of the non-quantifiable factors or even the social factors that could influence the selection of the best solution to solve a network need and that cannot be included in a CBA could help in decision-making, not only for flexibility solutions but also for traditional ones.

DSOs must also invest to put **flexibility solutions** in place. These investments mainly concern platforms and software that enable active management in real time and the possibility of flexible network planning. The simpler the products and flexibility mechanisms, the simpler these investments are. If these products and mechanisms become more complicated, these investments also become more complicated and more expensive. It is therefore advisable to **start with simpler solutions** to avoid the barrier of substantiating the first investments. Finding the roadmap of the simpler solutions with the quicker and more obvious benefits toward the more elaborate solutions that allow to make the most of flexible solutions could also be future research. That can be the only way to face the costly investments of the full flexibility operations to gradually move leveraging on the own benefits of the flexibility solutions.

6.3.2 Related to grid planning with flexibility

Flexible network planning requires addressing several challenges that also need to be studied. Deterministic **planning** must be replaced by one **based on probabilities**. These probabilities can be managed, both in the establishment of probable future scenarios considering, for example, the probability of failure of an asset; as in the establishment of the probable demand and generation curves; or even with the possible prices in flexibility services. Every stage of the planner's study process means a **probabilistic layer** that builds on the previous one. All these uncertainties also accumulate, resulting in risk-taking that competes with the efficiency of the system. This relationship between the **risks assumed**, including those related to flexibility solutions, the stability and reliability of the system, and the **efficiency of the system** is what should lead to the optimal solution. DSOs and regulators would have greater security if there were a simple and unique **methodology that provided the most efficient feasible solution** for each network need. This question of knowing which solution is optimal among all the possible ones would also provide a clear criterion for analyzing the investment plans of DSOs.

Several questions may arise about the optimal way of studying a request for a flexible connection, as the customers need to be aware of the probability of being activated. For example, it is not fully clear how to determine the probability of failure or the probability of a forecasted load curve used when authorizing a flexible connection. Likewise, DSO may face difficulties to decide what criteria should be used to determine whether an investment is required to solve a potential case of failure, whose probability is harder to predict than that of a regular congestion. These issues are directly linked to the management of uncertainty and it would be interesting to focus the planning of these flexibility solutions from a probabilistic point of view.

As for the **sensitivities** detected in the comparison of the flexible solution with the traditional solution, simple variations of each variable were assumed, but these variations **may include other variables that may not have a continuous behavior**. For example, flexible resources activated can often become fatigued over time and vary their response curve. On the other hand, traditional investments can also experience changes due to the evolution of the markets and rise or fall in price due to exogenous causes that totally unbalance the results accepted in the planning of the network.

The methodology framework proposed considers a deterministic approach, but it could be extended to stochastic approaches. In this thesis, the scope has been limited to performing a sensitivity analysis to address this shortcoming, but a stochastic analysis could be performed using a Monte Carlo or similar approach.

Flexibility solutions should allow for more efficient use of distribution networks, but the reliability of such solutions should also be reviewed. An economic study could be carried out to determine the cost to the system of maintaining such stability **and its impact on the system cost**. In the same way flexibility management involves planning with greater risks and probabilities in mind, the risks of relaxing some system operating criteria could be considered. Even if there was a higher risk of blackout, it could be more sustainable and affordable.

6.3.3 Related to TSO-DSO coordination

Regarding the **TSO-DSO limits**, additional studies should be carried out with a progressive **increase in distributed generation**. Similar results are expected, with the relevant difference that generation and demand would be progressively found in the distribution network. For TSOs, it is a challenge to manage the system stability when generation and demand are incorporated into the distribution network.

The study to determine the threshold beyond which greater coordination between DSO and TSO would be necessary was conducted on a representative network of the Spanish peninsular system and, therefore, the exact numerical values may not immediately applicable to other networks. Future research could address this issue by **studying other topologies** and attempting to arrive at results that can be extrapolated to other systems without the need to conduct individual studies of each part of the network.

References

[1] CEER - Council of European Energy Regulators, “Flexibility Use at Distribution Level,” 2018. [Online]. Available: https://www.ceer.eu/documents/104400/-/-/e5186abe-67eb-4bb5-1eb2-2237e1997bbc. [Accessed 12 09 2021].

[2] EU, “Directive 2019/944 on common rules for the internal market for electricity and amending Directive 2012/ 27/ EU,” 14 06 2019. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32019L0944&from=en. [Accessed 12 09 2021].

[3] EU Electricity Market Regulation, “REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity,” 05 06 2019. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943. [Accessed 02 02 2025].

[4] EUDSO Entity and ENTSO-E, “EUDSO Entity and ENTSO-E DRAFT Proposal for a Network Code on Demand Response,” 11 12 2023. [Online]. Available: https://consultations.entsoe.eu/markets/public-consultation-networkcode-demand-response/supporting_documents/Network%20Code%20Demand%20Response%20v1%20draft%20proposal.pdf. [Accessed 17 01 2024].

[5] European Union Agency for the Cooperation of Energy Regulators - ACER, “PC_2024_E_07 - Public consultation on the draft network code on demand response,” [Online]. Available: https://www.acer.europa.eu/documents/public-consultations/pc2024e07-public-consultation-draft-network-code-demand-response. [Accessed 01 01 2025].

[6] Z. Xu and S. Po, “The electricity market design for decentralized flexibility sources,” *Oxford Institute for Energy Studies,* 2019, doi: 10.26889/9781784671433.

[7] P. Baker, “Challenges facing distribution system operators in a decarbonised power system,” 06 2020 . [Online]. Available: https://www.raponline.org/wp-content/uploads/2023/09/rap-baker-dso-challenges-june-2020-final.pdf. [Accessed 2025 02 02].

[8] G. Celli, G. Pisano, S. Ruggeri, G. Giuseppe Soma, F. Pilo, C. Papa, C. Pregagnoli, L. de Carolis, S. Ferrero and F. Cazzato, “Distribution Systems as Catalysts for Energy Transition Embedding Flexibility in Large-Scale Applications,” *IEEE Access,* vol. 12, pp. 92227-92240, 2024 doi: 10.1109/ACCESS.2024.3421615..

[9] M. Baron, J. Chaves Ávila, K. Glennung, I. Vaitiekuté, N. Savopoulos, P. Josefsson, A. Sanjab, K. Kessels, G. Boultadakis, P. Mann, P. Butkus, N. Appleman, G. Migliavacca, D. Siface and M. Rossi, “CoordiNet & Interrface Joint Paper Coordination Schemes,

Products and Services for Grid Management," 2021. [Online]. Available: https://www.edsoforsmartgrids.eu/content/uploads/2024/05/CoordiNet_-_INTERRFACE_Position_Paper.pdf. [Accessed 2 1 2025].

[10] L. Lind, R. Cossent, J. Chaves-Ávila and T. Gómez, "Transmission and distribution coordination in power systems with high shares of distributed energy resources providing balancing and congestion management services," *WIREs Energy and Environment,* vol. 8, no. 6, 11 2019 doi: 10.1002/wene.357.

[11] J. Chaves, M. Troncia, L. Herding, N. Morell, O. Valarezo, K. Kessels, A. Delnooz, J. Vanschoenwinkel, J. Villar, J. Budke and J. Falcao., "Identification of relevant market mechanisms for the procurement of flexibility needs and grid services," *Deliverable D5.1 EUniversal Project,* 2021 https://euniversal.eu/documents/deliverable-d5-1/.

[12] T. Gómez, R. Cossent and J. Chaves Ávila, "Flexible network access, local flexibility market mechanisms and cost-reflective tariffs: three regulatory tools to foster decarbonized electricity networks," *Oxford Energy Forum,* vol. 124, pp. 18-21, 09 2020 https://repositorio.comillas.edu/xmlui/bitstream/handle/11531/56096/IIT-20-039A.pdf?sequence=-1.

[13] CEER - Council of European Energy Regulators, "Paper on DSO Procedures of Procurement of Flexibility CEER C19-DS-55-05," 16 07 2020. [Online]. Available: https://www.ceer.eu/publication/ceer-paper-on-dso-procedures-of-procurement-of-flexibility/. [Accessed 12 09 2021].

[14] CEER - Council of European Energy Regulators, "CEER Paper on Alternative Connection Agreements C23-DS-83-06," 2023. [Online]. Available: https://www.ceer.eu/documents/104400/-/-/e473b6de-03c9-61aa-2c6a-86f2e3aa8f08. [Accessed 1 10 2023].

[15] CEER - Council of European Energy Regulators, "CEER Guidelines of Good Practice for Flexibility Use at Distribution Level; A joint DSO response paper," 14 March 2017. [Online]. Available: https://www.ceer.eu/wp-content/uploads/2024/04/Guidelines-of-Good-Practice-for-Flexibility-Use-at-Distribution-Level-Consultation-Paper.pdf. [Accessed 15 04 2025].

[16] European Union Agency for the Cooperation of Energy Regulators, "Framework Guideline on Demand Response," 20 12 2020. [Online]. Available: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/FG_DemandResponse.pdf. [Accessed 08 12 2024].

[17] R. Bessa, "Use cases and requirements. Deliverable D1.2, InteGrid project.," 2017. [Online]. Available: https://integrid-h2020.eu/. [Accessed 02 02 2025].

[18] B. Blažic and I. Papic, "Voltage profile support in distribution networks – influence of the network R/X ratio," in *IEEE 13th International Power Electronics and Motion*

Control Conference (EPE/PEMC 2008), Poznan, Poland, 2008, ISBN 978-1-4244-1741-4, doi: 10.1109/epepemc.2008.4635641.

[19] C. Heinrich, C. Ziras, A. Syrri and H. Bindner, "EcoGrid 2.0: A large-scale field trial of a local flexibility market," *Applied Energy,* vol. 261, p. 114399, 03 2020, doi: 10.1016/j.apenergy.2019.114399.

[20] T. Schittekatte and L. Meeus, "Flexibility markets: Q&A with project pioneers," *Utilities Policy, RSCAS Working Papers 2019/39,* vol. 63, no. 101017, 2020, https://doi.org/10.1016/j.jup.2020.101017..

[21] X. Jin, Q. Wu and H. Jia, "Local flexibility markets: Literature review on concepts, models and clearing methods," *Applied Energy,* vol. 261, p. 114387, 03 2020, doi: 10.1016/j.apenergy.2019.114387.

[22] A. van der Veen, M. van der Laan, H. de Heer, E. Klaassen and W. van den Reek, "White paper Flexibility Value Chain 2018," 10 2018. [Online]. Available: https://www.usef.energy/app/uploads/2018/11/USEF-White-paper-Flexibility-Value-Chain-2018-version-1.0_Oct18.pdf. [Accessed 13 09 2021].

[23] Julian Huber, Simon Köppl, Nikolai Klempp, Melanie Schutz and Erik Heilmann, "Engineering Smart Market Platforms for Market Based Congestion Management," in *e-Energy '18: Proceedings of the Ninth International Conference on Future Energy Systems*, Karlsruhe, Germany, 2018, https://doi.org/10.1145/3208903.3214349.

[24] M. Moradijoz, M. Parsa Moghaddam and M. Haghifam, "A flexible active distribution system expansion planning model: A risk-based approach," *Energy,* vol. 145, no. ISSN 0360-5442, pp. 442-457, 2018 https://doi.org/10.1016/j.energy.2017.12.160.

[25] W. Fu, J. D. McCalley and V. Vittal, "Risk assessment for transformer loading," *IEEE Transactions on Power Systems,* vol. 16, no. 3, pp. 346-353, 2001, doi: 10.1109/59.932267.

[26] S. Klyapovskiy, S. You, A. Michiorri, G. Kariniotakis and H. W. & Bindner, "Incorporating flexibility options into distribution grid reinforcement planning: A techno-economic framework approach," *Applied Energy,* vol. 254, no. 113662, 2019 https://doi.org/10.1016/j.apenergy.2019.113662.

[27] A. B. Schmidt, "Modeling the birth of a liquid market," *Physica A: Statistical Mechanics and Its Applications,* vol. 283, no. 3-4, pp. 479-485, 08 2000 DOI: 10.1016/S0378-4371(00)00201-6.

[28] M. Troncia, M. Ruiz Hernández, E. Ormeño Mejía, J. Fernández García, N. Morell, L. Herding, O. Valarezo, S. Bindu, J. Chaves Ávila, T. Gomez, D. Davi Arderius, S. Gallego Amores, S. Cianotti, C. Manaresi, A. Christensson and A. Malot, "BeFlexible Project D1.1 – Regulatory framework for fostering flexibility deployment: roles, responsibility

of agents & flexibility mechanism designs," 29 02 2024. [Online]. Available: https://beflexible.eu/wp-content/uploads/2024/04/BeFlexible-D1.1-Regulatory-framework.pdf. [Accessed 02 02 2025].

[29] CoordiNet, "Project Web Site," 2019. [Online]. Available: https://coordinet-project.eu/. [Accessed 01 01 2022].

[30] EUniversal, "Project Web Site," 2020. [Online]. Available: https://euniversal.eu/. [Accessed 2 2 2022].

[31] OneNet, "Project Seb Site," 2020. [Online]. Available: https://onenet-project.eu/. [Accessed 2 2 2022].

[32] F. Pilo, S. Jupe, F. Silvestro, C. Abbey, A. Baitch, B. Bak-Jensen, C. Carter-Brown, G. Celli, K. E. Bakari, M. Fan, P. Georgilakis, T. Hearne, L. N. Ochoa, G. Petretto and J. Taylor, "Planning and Optimization Methods for Active Distribution Systems CIGRE Brochure, ISBN 978-2-85873-289-0," 08 2014. [Online]. Available: https://www.researchgate.net/publication/283569552_Planning_and_optimization_methods_for_active_distribution_systems. [Accessed 02 02 2025].

[33] Z. Luo, Y. Liu and C. Wang, "Review on Coordination and Planning of Active Distribution Network," in *5th International Conference on Power and Renewable Energy (ICPRE) (pp. 517-522). IEEE.*, Shanghai, China, 2020, doi: 10.1109/ICPRE51194.2020.9233134..

[34] Z. Xu, D. Kumar Das, W. Guo and W. Wei, "Does power grid infrastructure stimulate regional economic growth?," *Energy Policy,* vol. 155, no. 112296, 2021, doi: 10.1016/j.enpol.2021.112296.

[35] I. Roytelman, "Real-time Distribution Power Flow - lessons from practical implementations," in *IEEE PES Power Systems Conference and Exposition: 505-509.*, Atlanta, GA, 2006, DOI: 10.1109/PSCE.2006.296365.

[36] A. A. P. Bíscaro, R. A. F. Pereira, M. Kezunovic and J. R. S. Mantovani, "ntegrated Fault Location and Power-Quality Analysis in Electric Power Distribution Systems," *IEEE Transactions on Power Delivery,* vol. 31, no. 2, pp. 428-436, 2016, doi: 10.1109/TPWRD.2015.2464098..

[37] A. Luo, Q. Xu, F. Ma and Y. Chen, "Overview of power quality analysis and control technology for the smart grid," *Journal of Modern Power Systems and Clean Energy,* vol. 4, no. 1, pp. 1-9, 2016, doi: 10.1007/s40565-016-0185-8..

[38] Boletín Oficial del Estado, "Real Decreto 1955/2000, de 1 de diciembre, por el que se regulan las actividades de transporte, distribución, comercialización, suministro y procedimientos de autorización de instalaciones de energía eléctrica.," 01 12 2000. [Online]. Available: https://boe.es/buscar/pdf/2000/BOE-A-2000-24019-

consolidado.pdf. [Accessed 02 02 2025].

[39] Boletín Oficial del Estado, "Real Decreto 1048/2013, de 27 de diciembre, por el que se establece la metodología para el cálculo de la retribución de la actividad de distribución de energía eléctrica," 27 12 2013. [Online]. Available: https://www.boe.es/buscar/pdf/2013/BOE-A-2013-13767-consolidado.pdf. [Accessed 2021 11 1].

[40] T. Palei, "Assessing The Impact of Infrastructure on Economic Growth and Global Competitiveness," *Procedia Economics and Finance,* vol. 23, pp. 168-175, 2015 https://doi.org/10.1016/S2212-5671(15)00322-6.

[41] C. Girón, F. J. Rodríguez, L. G. d. Urtasum and S. Borroy, "Assessing the contribution of automation to the electric distribution network reliability," *International Journal of Electrical Power & Energy Systems,* vol. 97, pp. 120-126, 2018, doi: 10.1016/j.ijepes.2017.10.027..

[42] Boletín Oficial del Estado, "Real Decreto 1432/2008, de 29 de agosto, por el que se establecen medidas para la protección de la avifauna contra la colisión y la electrocución en líneas eléctricas de alta tensión," 29 08 2008. [Online]. Available: https://www.boe.es/eli/es/rd/2008/08/29/1432. [Accessed 02 02 2025].

[43] European Comission, «Digitalising the energy system - EU action plan (COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS),» 18 10 2022. [En línea]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022DC0552. [Último acceso: 01 04 2025].

[44] T. Ackermann, G. Andersson and L. Söder, "Distributed generation: a definition," *Electric Power Systems Research, ISSN 0378-7796,* vol. 57, no. 3, pp. 195-204, 2001, doi:10.1016/S0378-7796(01)00101-8.

[45] R. C. Dugan and T. E. McDermott, "Distributed generation," *IEEE Ind Appl. Mag.,* vol. 8, no. 2, p. 19–25, 2002, DOI: 10.1109/2943.985677.

[46] H. Liao, "Review on Distribution Network Optimization," *Energies,* vol. 12, p. 3369, 2019, doi:10.3390/en12173369.

[47] P. S. Georgilakis and N. D. Hatziargyriou, "A review of power distribution planning in the modern power systems era: Models, methods and future research," *Elsevier Electric Power Systems Research,* vol. 121, p. 89–100, 2015, doi: 10.1016/j.epsr.2014.12.010.

[48] F. D. Martín, M. Hable, R. Bessa, J. Lassila, C. Imboden and A. Krula, "Flexibility in active distribution systems," 1 2021. [Online]. Available: http://www.cired.net/cired-

working-groups/flexibility-in-active-distribution-systems-wg-2019-3. [Accessed 21 10 2021].

[49] O. M. Babatunde, J. L. Munda and Y. Hamam, "Power system flexibility: A review," *Energy Reports, 6, 101-106.,* Vols. 6, Supplement 2,, pp. 101-106, 2020. doi: 10.1016/j.egyr.2019.11.048..

[50] T. Gerres, J. P. C. Ávila, P. L. Llamas and T. G. S. Román, "A review of cross-sector decarbonisation potentials in the European energy intensive industry," *Journal of Cleaner Production,* vol. 210, pp. 585-601, 2019, doi: 10.1016/j.jclepro.2018.11.036.

[51] J. Blazquez, R. Fuentes and B. Manzano, "On some economic principles of the energy transition," *Energy Policy,* vol. 147, no. 111807, 2020, doi: 10.1016/j.enpol.2020.111807..

[52] L. Pieltain Fernández, T. Gómez San Román, R. Cossent Arín, C. Mateo Domingo and P. Frías, "Assessment of the Impact of Plug-in Electric Vehicles on Distribution Networks," *IEEE Transactions on Power Systems,* vol. 26, no. 1, pp. 206-213, 2011, doi: 10.1109/TPWRS.2010.2049133.

[53] Deloitte, Monitor; E.DSO; Eurelectric, "Connecting the Dots: Distribution grid investment to power the energy transition," 14 01 2021. [Online]. Available: https://www.eurelectric.org/publications/connecting-the-dots/. [Accessed 02 02 2025].

[54] A. Navarro-Espinosa and P. Mancarella, "Probabilistic modeling and assessment of the impact of electric heat pumps on low voltage distribution networks," *Applied Energy,* vol. 127, pp. 249-266, 2014, doi: 10.1016/j.apenergy.2014.04.026..

[55] M. Akmal, B. Fox, D. J. Morrow and T. Littler, "Impact of high penetration of heat pumps on low voltage distribution networks," *IEEE Trondheim PowerTech,* pp. 1-7, 2011, doi: 10.1109/PTC.2011.6019401..

[56] P. Mancarella, C. K. Gan and G. Strbac, "Evaluation of the impact of electric heat pumps and distributed CHP on LV networks," *IEEE Trondheim PowerTech,* pp. 1-7, 2011, doi: 10.1109/PTC.2011.6019297.

[57] California Public Utilities Comission, "Kincade Fire near Geyserville in California California - agreement PUC and PG&E," 12 03 2019. [Online]. Available: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M425/K880/425880669.pdf . [Accessed 2025 02 02].

[58] R. J. Campbell, "Weather-Related Power Outages and Electric System Resiliency (R42696)," 28 08 2012. [Online]. Available: https://crsreports.congress.gov/product/details?prodcode=R42696. [Accessed 02 02 2025].

[59] Boletín Oficial del Estado, "Real Decreto 614/2001, de 8 de junio, sobre disposiciones mínimas para la protección de la salud y seguridad de los trabajadores frente al riesgo eléctrico.," 08 06 2001. [Online]. Available: https://www.boe.es/eli/es/rd/2001/06/08/614/con. [Accessed 02 02 2025].

[60] A. González-Garrido, I. Gómez-Arriola, K. Kessels, J. Vanschoenwinkel, D. Davi, E. Faure, Y. Ruwaida, N. Etherden, L. L. and O. Valarezo, "CoordiNet Deliverable D6.3 – Economic assessment of proposed coordination schemes and products for system services," 08 08 2022. [Online]. Available: https://www.iit.comillas.edu/publicacion/informetecnico/es/289/Economic_assessment_of_proposed_coordination_schemes_and_products_for_system_services. [Accessed 02 02 2025].

[61] E-CUBE Strategy Consultants, "Étude sur les mécanismes de valorisation des flexibilités pour la gestion et le dimensionnement des réseaux publics de distribution d'électricité," 19 10 2017. [Online]. Available: https://www.cre.fr/Documents/Publications/Etudes/etude-sur-les-mecanismes-de-valorisation-des-flexibilites-pour-la-gestion-et-le-dimensionnement-des-reseaux-publics-de-distribution-d-electricite. [Accessed 11 01 2023].

[62] Scottish and Southern Electricity Networks, "EVALUATING FLEXIBILITY AS ALTERNATIVE TO TRADITIONAL NETWORK REINFORCEMENT," 07 2020. [Online]. Available: https://www.ssen.co.uk/globalassets/about-us/dso/200716-frontier-economics---evaluating-flexibility-as-alternative-to-network-reinforcement.pdf. [Accessed 2025 02 02].

[63] C. R. S. Pierre and T. E. Wolny, "Standardization of benchmarks for protective device time-current curves," *IEEE transactions on industry applications,* vol. 4, pp. 623-633, 1986, doi: 10.1109/TIA.1986.4504772.

[64] B. Tavares and F. Soares, "An innovative approach for distribution network reinforcement planning: Using DER flexibility to minimize investment under uncertainty," *Electric Power Systems Research,* vol. 183, no. 106272 ISSN 0378-7796, 2020 https://doi.org/10.1016/j.epsr.2020.106272.

[65] G. Prettico, F. Gangale, A. Mengolini, A. Lucas and G. Fulli, "Distribution System Operators Observatory 2016," *JRC Technical Reports,* 2016, doi: 10.2790/701791.

[66] G. Prettico, M. G. Flammini, N. Andreadou, S. Vitiello, G. Fulli and M. Masera, "Distribution System Operators observatory 2018," *JRC Science for Policy Report,* 2019, doi:10.2760/104777.

[67] G. Prettico, Marinopoulos and S. Vitiello, "Distribution System Operator Observatory 2020," *JRC Sience for Polisy Report,* 2020, doi:10.2760/791730, JRC123249..

[68] Ministerio para la transición energética y el reto demográfico, “Resolución de 30 de diciembre de 2020, de la Dirección General de Calidad y Evaluación Ambiental, por la que se formula la declaración ambiental estratégica del Plan Nacional Integrado de Energía y Clima 2021-2030.,” 11 01 2021. [Online]. Available: https://www.boe.es/boe/dias/2021/01/11/pdfs/BOE-A-2021-421.pdf. [Accessed 2022 11 06].

[69] International Renewable Energy Agency (IRENA), “RENEWABLE CAPACITY STATISTICS 2022,” 04 2022. [Online]. Available: https://www.irena.org/publications/2022/Apr/Renewable-Capacity-Statistics-2022. [Accessed 6 11 2022].

[70] Red Eléctrica, “Wind power becomes the main source of electricity generation in Spain in 2021,” Red Eléctrica, 16 12 2021. [Online]. Available: https://www.ree.es/en/press-office/news/press-release/2021/12/wind-power-becomes-main-source-electricity. [Accessed 05 10 2022].

[71] ANFAC - Asociación Española de Fabricantes de Automóviles y Camiones, “Reporte Anual,” 12 07 2022. [Online]. Available: https://anfac.com/categorias_publicaciones/informe-anual/. [Accessed 7 11 2022].

[72] CEER Council of Energy European Regulators, "Paper on Alternative Connection Agreements Ref: C23-DS-83-06," CEER, Brussels (Belgium), 2023.

[73] G. Boyd, “SPEN – DSO VISION,” in *Paper 1044 24 International Conference on Electricity Distribution , http://cired.net/publications/cired2017/pdfs/CIRED2017_1044_final.pdf*, Glasgow, 2017.

[74] L. Kane and G. Ault, “The cost of active network management schemes at distribution level,” *EWEA Annual Wind Energy Event 2013,* 2013.

[75] Boletín Oficial del Estado, “Orden IET/2660/2015, de 11 de diciembre, por la que se aprueban las instalaciones tipo y los valores unitarios de referencia de inversión, de operación y mantenimiento por elemento de inmovilizado y los valores unitarios de retribución...,” 11 12 2015. [Online]. Available: https://www.boe.es/eli/es/o/2015/12/11/iet2660. [Accessed 2022 10 10].

[76] CNMC, “Informe sobre la propuesta de orden por la que se aprueban las instalaciones tipo y los valores unitarios de referencia de inversión de operación y mantenimiento por elemento inmovilizado y los valores unitarios de retribución de otras tareas reguladas...,” Comisión Nacional de Mercados y Competencia, https://www.cnmc.es/file/125571/download, 2015.

[77] L. Tomás Balibrea, “Analysis of employability of Industrial Engineers graduated from the Spanish University,” in *21th International Congress on Project Management and*

Engineering, Cádiz, 2017 http://dspace.aeipro.com/xmlui/bitstream/handle/123456789/488.

[78] Instituto Nacional de la Seguridad Social, [Online]. Available: https://www.seg-social.es/wps/portal/wss/internet/Empresarios. [Accessed 06 09 2022].

[79] CoordiNet, "Project Web Site," 2019. [Online]. Available: https://coordinet-project.eu/.

[80] T. Gerres, J. Chaves-Ávila, F. Martin Martínez, M. Rivier Abbad, R. Cossent, Á. Sánchez Miralles and T. Gómez San Román, ""Rethinking the electricity market design: Remuneration mechanisms to reach high RES shares. Results from a Spanish case study"," *Energy Policy,* vol. 129, pp. 1320-1330, 2019.

[81] i-DE, "Mapa de Capacidad de conexión de generación," [Online]. Available: https://www.i-de.es/conexion-red-electrica/produccion-energia/mapa-capacidad-acceso. [Accessed 2023 07 27].

[82] National Grid, "Network capacity map," [Online]. Available: https://www.nationalgrid.co.uk/our-network/network-capacity-map/. [Accessed 01 01 2025].

[83] Liander, "Beschikbare capaciteit per regio," [Online]. Available: https://www.liander.nl/grootzakelijk/capaciteit-op-het-net/capaciteit-per-regio. [Accessed 01 01 2025].

[84] P. Betancourt-Paulino, H. Chamorro, M. Soleimani, F. Gonzalez-Longatt, V. Sood and W. Martinez, "On the perspective of grid architecture model with high TSO-DSO interaction," *IET Energy Syst. Integr.,* vol. 3, p. 1–12, 2021 https://doi.org/10.1049/esi2.12003.

[85] A. Papalexopoulos, R. Frowd and A. Birbas, "On the development of organized nodal local energy markets and a framework for the TSO-DSO coordination," *Electric Power Systems Research,* vol. 189, no. 106810, 2020 https://doi.org/10.1016/j.epsr.2020.106810.

[86] R. Silva, E. Alves, R. Ferreira, J. Villar and C. Gouveia, "Characterization of TSO and DSO Grid System Services and TSO-DSO Basic Coordination Mechanisms in the Current Decarbonization Context," *Energies,* vol. 14, p. 4451, 2021 https://doi.org/10.3390/en14154451.

[87] G. Migliavacca, TSO-DSO Interactions and Ancillary Services in Electricity Transmission and Distribution Networks: Modeling, Analysis and Case-Studies., Springer Nature., 2019 https://doi.org/10.1007/978-3-030-29203-4.

[88] European Commission, "Commission Regulation (EU) 2017/2195 of 23 November

2017 establishing a guideline on electricity balancing," 23 11 2017. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1485&from=ES. [Accessed 18 5 2024].

[89] A. Ramos, C. De Jonghe, V. Gómez and R. Belmans, "Realizing the smart grid's potential: Defining local markets for flexibility," *Utilities Policy,* vol. 40, p. 26–35, 2016 https://linkinghub.elsevier.com/retrieve/pii/S0957178716300820.

[90] T. Schittekatte and L. Meeus, "Flexibility markets: Q&A with project pioneers," *Utilities Policy,* vol. 63, p. 101017, 2020 https://doi.org/10.1016/j.jup.2020.101017.

[91] M. Caramanis, E. Ntakou, W. Hogan, A. Chakrabortty and J. Schoene, "Co-optimization of power and reserves in dynamic T&D power markets with nondispatchable renewable generation and distributed energy resources," *Proceedings of the IEEE,* vol. 104, no. 4, p. 807–836, Apr. 2016 doi: 10.1109/JPROC.2016.2520758.

[92] European Commission, "Comission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation," *Official Journal of the European Union,* 2017 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1485&from=ES.

[93] S. H. Elyas and Z. Wang, "Statistical analysis of transmission line capacities in electric power grids," *IEEE Power & Energy Society Innovative Smart Grid Technologies Conference,* pp. 1-5, 2016 DOI: 10.1109/ISGT.2016.7781263..

[94] C. Edmunds, S. Galloway, I. Elders and W. T. R. Bukhsh, "Design of a DSO-TSO balancing market coordination scheme for decentralised energy," *IET Generation, Transmission & Distribution,* vol. 14, no. 5, pp. 707-718, 2020 https://doi.org/10.1049/iet-gtd.2019.0865.

[95] A. Bachoumis, C. Kaskouras, G. Papaioannou and M. Sousounis, "TSO/DSO Coordination for Voltage Regulation on Transmission Level: A Greek Case Study," in *IEEE Madrid PowerTech*, Madrid, Spain, 2021 DOI: 10.1109/PowerTech46648.2021.9495021.

[96] F. Qiu, Y. Zhang, R. Yao and P. Du, "Power system restoration with renewable participation," *IEEE Transactions on Sustainable Energy,* vol. 14, no. 2, p. 1112–1121, 2023 DOI: 10.1109/TSTE.2022.3227166.

[97] W. Sun, C. Liu and L. Zhang, "Optimal generator start-up strategy for bulk power system," *IEEE Transactions on Power Systems,* vol. 26, no. 3, p. 1357–1366, 2011 DOI: 10.1109/TPWRS.2010.2089646.

[98] L. Söder, E. Tómasson, A. Estanqueiro, D. Flynn, B.-M. Hodge, J. Kiviluoma, M. Korpås, E. Neau, A. Couto, D. Pudjianto, G. Strbac, D. Burke, T. Gómez, K. Das, N. Cutululis, D. Van Hertem, H. Höschle, J. Matevosyan and S. von Roon, "Review of wind generation

within adequacy calculations and capacity markets for different power systems," *Renewable and Sustainable Energy Reviews,* vol. 119, p. 109540, 2020 https://doi.org/10.1016/j.rser.2019.109540.

[99] Electricity Market Regulation EU 2019/943, REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity, 2019 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943.

[100] M. Welsch, P. Deane, M. Howells, B. Ó Gallachóir, F. Rogan, M. Bazilian and H. Rogner, "Incorporating flexibility requirements into long-term energy system models – A case study on high levels of renewable electricity penetration in Ireland," *Applied Energy,* vol. 135, no. ISSN 0306-2619, pp. 600-615, 2014 https://doi.org/10.1016/j.apenergy.2014.08.072..

[101] O. Valarezo, T. Gómez, J. Chaves-Avila, L. Lind, M. Correa, D. Ulrich Ziegler and R. Escobar, "Analysis of New Flexibility Market Models in Europe," *Energies,* vol. 14, p. 3521, 2021 https://doi.org/10.3390/en14123521.

[102] H. L. Willis, "23. Distribution System Reliability Analysis Methods," in *Power Distribution Planning Reference Book*, CRC Press, 2004 https://doi.org/10.1201/9780824755386, pp. 819-832.

[103] A. Tzoumpas, A. Pinnarelli, A. Mink, A. Aguayo Mendoza, C. Montalvo, C. Valor, E. Borges, C., D. Ördög, F. Sainz, F. Garms, J. Höffken, M. Brenner-Fliesser, M. Kuivalainen, M. Prek, P. Ktenidis, V. Moreno and V. Krušvar, "Consumer and Citizen Engagement - Bridge WG Leadership Directorate-General for Energy," 11 2024. [Online]. Available: https://bridge-smart-grid-storage-systems-digital-projects.ec.europa.eu/sites/default/files/bridge-reports/consumer%20and%20citizen%20engagement%20working%20group-HZ0124024ENN_0.pdf. [Accessed 01 01 2025].

[104] BeFlexible Project Web Site (EU funded), 2022. [Online]. Available: https://beflexible.eu/. [Accessed 01 01 2025].

[105] C. Valor, V. Moreno, L. Ruiz, J. Villar, R. Mathews and P. Tobin, "BeFlexible Project D2.1 Value Propositions for market actors," 13 09 2023. [Online]. Available: https://beflexible.eu/wp-content/uploads/2023/10/BEFLEXIBLE-D2.1-Value-Propositions-for-market-actors.pdf. [Accessed 01 01 2025].

[106] R. Mathews, M. Kuivalainen, B. Murphy, A. Haider, C. Valor, V. Moreno and L. Ruiz, "BeFlexible Project D2.2 Engagement Strategy," 15 11 2023. [Online]. Available: https://beflexible.eu/wp-content/uploads/2023/12/BeFlexible-D2.2-Customer-Engagement.pdf. [Accessed 01 01 2025].

[107] J. M. Morales, S. Pineda and Y. Dvorkin, "Learning the Price Response of Active Distribution Networks for TSO-DSO Coordination," *IEEE Transactions on Power*

Systems, vol. 37, no. 4, pp. 2858-2868, 2022, doi: 10.1109/TPWRS.2021.3127343.

[108] J. Villar, R. Bessa and M. Matos, "Flexibility products and markets: Literature review," *Electric Power Systems Research, doi: 10.1016/j.epsr.2017.09.005,* vol. 154, pp. 329-340, 2018 http://dx.doi.org/10.1016/j.epsr.2017.09.005.

[109] M. Correa, T. Gomez and R. Cossent, "Local Flexibility Mechanisms for Electricity Distribution Through Regulatory Sandboxes: International Review and a Proposal for Spain," *IEEE Madrid PowerTech,* pp. 1-6, 2021 doi: 10.1109/PowerTech46648.2021.9494866.

[110] F. Fallahi, M. Nick, G. H. Riahy, S. H. Hosseinian and A. Doroudi, "The value of energy storage in optimal non-firm wind capacity connection to power systems," *Renewable Energy,* pp. Volume 64, Pages 34-42, 2014 http://dx.doi.org/10.1016/j.renene.2013.10.025.

[111] Comisión Nacional de los Mercados y la Competencia - CNMC (spanish regulator), "BOLETÍN OFICIAL DEL ESTADO," 27 09 2024. [Online]. Available: https://www.boe.es/boe/dias/2024/10/11/pdfs/BOE-A-2024-20760.pdf. [Accessed 01 01 2025].

[112] M. Ruiz, T. Gómez, J. Chaves and R. Cossent, "Regulatory Challenges for Energy Infrastructure—Do Electricity Distribution Remuneration Schemes in Europe Promote the Use of Flexibility from Connected Users?," *Curr Sustainable Renewable Energy Reports,* vol. 10, p. 112–117, 2023. https://doi.org/10.1007/s40518-023-00214-5.

[113] J. Schachter and P. Mancarella, "A critical review of Real Options thinking for valuing investment flexibility in Smart Grids and low carbon energy systems," *Renewable and Sustainable Energy Reviews,* vol. 56, no. ISSN 1364-0321, pp. 261-271, 2016 http://dx.doi.org/10.1016/j.rser.2015.11.071.

Annexes (Papers in the compendium):

Annex 1 (first paper in the compendium): “Decision Framework for Selecting Flexibility Mechanisms in Distribution Grids”

Economics of Energy & Environmental Policy, vol. 11, no. 2, 2022

https://doi.org/10.5547/2160-5890.11.2.fmar.

Annex 2 (second paper in the compendium): “Value of flexibility alternatives for real distribution networks in the context of the energy transition”

IEEE Access, , vol. 11, pp. 114250-114269,, vol. 11, pp. 114250-114269, 2023

doi: 10.1109/ACCESS.2023.3322365.

Annex 3 (third paper in the compendium): “Analyzing the boundaries for TSO-DSO coordination when activating flexibility for DSO´s in networks with an expected significant load increase”

S*ustainable Energy, Grids and Networks,* vol. 39, no. ISSN 2352-4677, p. 101482, 2024

https://doi.org/10.1016/j.segan.2024.101482.

Decision Framework for Selecting Flexibility Mechanisms in Distribution Grids

Fernando-David Martín-Utrilla,[a] José Pablo Chaves-Ávila,[b] and Rafael Cossent[b]*

ABSTRACT

The energy transition will lead to the coexistence of centralised and distributed energy resources (DER) and the increasing electrification of processes traditionally fed by other energy vectors. This scenario requires adapting distribution networks to integrate these new grid users while maintaining the reliability of the service. In this context, flexibility services from DER are presented as a new alternative that will allow more efficient use of the networks. However, not all flexibility mechanisms (as ways of accessing flexibility) are equally suitable to address the different problems and needs faced by distribution system operators (DSOs). This paper identifies the key criteria that determine the more suitable mechanism to implement in each case and discusses the different criteria to choose the way to acquire flexibility for DSO use. Based on this, the paper proposes a comprehensive decision framework to consider all the different available mechanisms and, based on the DSO needs and the situation of the network, proposes the most suitable flexibility mechanism. Additionally, several key criteria are used to evaluate the different flexibility mechanisms. As a result, the most suitable mechanisms are highlighted as useful tools to solve the needs of the network at all voltage levels and adapted to each situation.

Keywords: Flexibility procurement, distribution networks DSO, flexibility mechanisms

https://doi.org/10.5547/2160-5890.11.2.fmar

1. INTRODUCTION

Decarbonisation of the electricity generation mix is causing a decentralisation that requires revisiting markets, regulation and organisation of the power system. The use of electricity is in the spotlight. In this context, it becomes necessary to make room for new forms of electrical energy consumption and new forms of generation. Electric vehicles, distributed generation, and storage, among others, are going to pose new challenges for the electricity network. In addition, customers are increasingly eager to generate their energy following multiple motivations such as to have greater independence from the grid or to reduce their energy expenditures.

The active participation of new consumers and generators connected to distribution grids can contribute to more efficient use of the networks by avoiding traditional costs of network assets sporadically used. The use of flexibility from customers may result in a cheaper and more sustainable electricity grid (CEER 2018). This paper considers the flexibility as the capability

[a] i-DE Redes Eléctricas Inteligentes, Valencia Spain; and ICAI School of Engineering, Universidad Pontificia Comillas, Madrid Spain.
[b] Instituto de Investigación Tecnológica, ICAI School of Engineering, Universidad Pontificia Comillas. Madrid Spain.
* Corresponding author. E-mail: fmartin@iberdrola.es.

of the resources connected to the grid, from the generation side or demand side, to change their behaviour in response to a network need to cope with the energy transition challenges.

The grid needs can be met in the traditional way (i.e. investing in network assets), but these can also be satisfied through the acquisition of flexibility services provided by the resources connected to the network. These services must be adapted to the needs of the network itself. On the other hand, for that service request and delivery to occur, there must be a mechanism in place. A flexibility mechanism is how the system operators acquire flexibility services from third-party providers.

Flexibility can offer solutions to the grid in two different but closely related domains: TSO and DSO. The transmission system operators (TSOs) do not only face the challenge of managing electricity systems with decentralised generation and low inertia due to the inevitable disconnection of big synchronous fossil fuel-powered or nuclear generators that provide stability to the system, but also the need to ensure ancillary service providers that maintain the reliability of the system (Xu and Po 2019).

DSOs, on the other hand, have the challenge of maintaining the quality and reliability standards of the networks in a system that is increasingly moving away from the traditional distribution function of supplying energy from the upper voltage levels to the end-users. DSOs are also becoming an energy exchange space, as it is increasingly intertwined with generation and whose consumers will have more different and more unpredictable profiles. The utilisation of DER flexibility services requires a non-singular approach depending on the type of DER (Eid, et al. 2016). Both TSO and DSO challenges are very different, but the resources are the same. Hence the importance of having good coordination between agents who can operate in the same flexibility market or have the same resources providing services in separate markets.

Several authors and institutions have proposed their definition of flexibility services and their characteristics: balancing, congestion management and power quality control (such as voltage control or loss minimisation) (Jin, Wu and Jia 2020) (Villar, Bessa and Matos 2018) being the latter service also named as non-frequency ancillary service (E.DSO, et al. 2019). In (Hillberg, et al. 2019) these needs are categorised by power, energy, voltage, or transfer capacity. In (van der Veen, et al. 2018) a grid capacity management service is also considered but only differ from congestion management in the possibility of predicting the needs. This paper focuses on the services related to specific DSO needs: voltage control, congestion management and controlled islanding, as in (Olivella-Rosell, et al. 2018).

Several outstanding barriers need to be overcome to utilise DER flexibility (Lind, et al. 2019), such as the role of aggregators to unlock small DER flexibility, TSO-DSO data exchange or a thorough analysis of which coordination scheme is most suitable. Regarding DSOs flexibility procurement, Article 32 of the Directive 2019/944 (EU 2019) on common rules for the internal market for electricity sets that "Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services", and that DSOs "shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion". Therefore, among the ways of accessing flexibility, named as flexibility mechanisms, the market-based mechanism is the preferred option for flexibility procurement, although the regulator may circumstantially choose other mechanisms for overall efficiency reasons.

The examples of local markets tested in Denmark (Heinrich, et al. 2020) and the pioneering projects undertaken in the UK, Germany, the Netherlands and Norway described in (Schittekatte and Meeus 2019) show a clear adaptation of the global framework to local needs, revealing the weaknesses of the lack of liquidity when trying to use the existing market mechanisms of wholesale markets for local needs. The architecture of markets, platforms and even products have been designed with this approach in great detail in (Heinrich, et al. 2020), (Jin, Wu and Jia 2020) and (van der Veen, et al. 2018). These proposals are compatible with the options of this study.

Network needs that may occur as a result of the energy transition are very diverse, and so should be the flexibility mechanisms used to address them. This paper aims to cover the criteria that will condition the selection of the flexibility mechanisms starting from the DSO's own needs. Thus, the applicability of the different flexibility mechanisms for each situation will be studied. In other words, the gap to fill is matching the flexibility mechanisms proposed in the literature and the real needs of the distribution network. This will help DSOs to focus on the most suitable mechanisms for their expected needs.

Similar approaches can be found, but without carrying out such a correspondence. A thorough assessment of the different options for flexibility mechanisms based on surveys among DSOs was performed in (Chaves, et al. 2021). The results reflect the feasibility of solutions that is complementary to those proposed in this paper. Besides, the assessment done in (Schittekatte and Meeus 2019) resulting in six relevant options which have been considered: 1) the integration with existing electricity markets, 2) the role of the market operator 3) reservation payment, 4) products standardisation, 5) TSO-DSO cooperation, and 6) DSO-DSO cooperation. However, the scope and design of the different projects compared are very diverse, making it difficult to infer a generalisation of the criteria. The role of the market operator is not analysed in this paper but is supposed to be transparent and independent from market participants.

The remainder of this paper is organised as follows. First, section 2 addresses the flexibility mechanisms description and taxonomy. Section 3 discusses the different evaluation criteria that should be considered in the selection process such as the characterisation of the needs and services, location, procurement time, liquidity, need for coordination or generalisation of the needs. Next, section 4, which represents the core of this paper, presents the decision framework to select the most suitable flexibility mechanisms based on the needs of the DSO and the evaluation criteria previously discussed. Lastly, section 5 provides some concluding remarks.

2. FLEXIBILITY MECHANISMS

This section defines and discusses the different flexibility mechanisms considered in the study with the intention of not only listing them but also giving a brief description. A flexibility mechanism is considered in this paper as the way in which the system operators acquire flexibility from and the flexibility service providers.

2.1 Flexibility mechanisms: Description

This chapter describes the key aspects of the considered flexibility mechanisms based on (Chaves, et al. 2021) and (Gómez, Cossent and Chaves Ávila 2020):

- **Regulated payments or penalties**: What characterises these mechanisms is that there is a regulated price that incentivises the use of the tool. The effect is therefore similar to that of tariffs. The regulated remuneration of the flexibility provided by the Flexibility Service Providers (FSP) could be based on the actual costs of providing the service. Also, an obligation mechanism for flexibility provision defines the mandatory service provision from the FSPs. The service requested by the system operator to the FSPs is not remunerated, but instead, there could be penalties when not contributing with their flexibility.
- **Bilateral Agreements**: A bilateral agreement requires a negotiation process between the two parties: the system operator and the FSP. They could be exploited for existing connected resources and constrained situations or for the sake of a new connection to the electrical grid. The FSPs agrees to be curtailed in some periods.
- **Dynamic Tariffs**: A dynamic tariff means that the price signal is defined at shorter notice, possibly close to real-time (CEER 2020). Dynamic tariffs concern devising time (and locational) differentiated network tariffs which can be adjusted to reflect the necessary temporal and spatial cost variations. The grid users are incentivised to change their consumption and/or production according to the grid operation and future network needs.
- **Local Markets**: Local flexibility markets include long-term and short-term pools in which offers are received from FSPs. A long-term mechanism could be used in planning activities to procure flexibility by contracting through **Auctions** long in advance the potential service providers. The local market extension depends on the grid characteristics, i.e. the market area can encompass only a portion of the distribution network. The size of the local market is site-specific. The DSO will utilise flexibility based on its willingness to pay for it and the available fallback solutions and the type of flexibility product required. A local flexibility market seeks to promote competition among flexibility providers. A short-term mechanism could be contracted in the **Day Ahead**, when the need can be forecasted or near **Real Time**, for contingencies.
- **Common Markets**: Same concept as Local Markets for the long-term **Auctions** and the short-term in the **Day Ahead** or near **Real Time**, but in this case Flexibility is selected in a unique market to satisfy both TSO and DSOs needs. Selection of flexibility bids by DSOs and TSOs is carried out in a coordinated process and takes into account the constraints of all the grids involved. In section 3.4 the variants of coordination schemes corresponding to common markets are identified ("*Common*" or "*Integrated*" in Table 4).

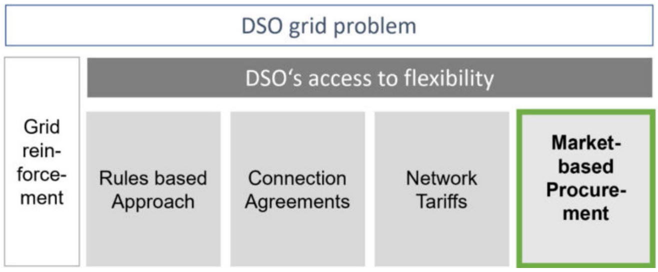
2.2 Flexibility mechanisms: taxonomy

The Council of European Energy Regulators (CEER 2020) highlights different ways of accessing flexibility which are summarised in Figure 1. This report proposes different scenarios in which alternative non-market-based mechanisms can be used to access flexible resources, although it emphasises again that the market-based mechanism is the preferred option.

Based on the classification shown in Figure 1, the following flexibility procurement mechanisms shown in Table 1 are considered along this paper. In this classification, tariffs, agreements, and rules have been included under non-market-based mechanisms. Although with different terminology that is intended to give a broader meaning. For instance, Bilateral Agreements could be arranged at connection time or later. In the case of market-based mechanisms, they are divided into local (i.e. DSO focussed) or common (i.e. for both TSO and DSO), de-

FIGURE 1

DSO options to access flexibility with an emphasis on market-based procurement.



Source: (CEER 2020), 21, Fig.1.

signed respectively for local or global needs, and these are further divided according to the time frame in which they are framed. In Table 1 the CEER Paper taxonomy is in the first column, the flexibility mechanisms considered in this paper in the second column, and the classification of mechanisms in the third one. The classification helps to simplify the interpretation of the framework in section 4.

TABLE 1

Flexibility mechanisms classification related to options in (CEER 2020).

DSO´s access to flexibility (CEER 2020)	**Flexibility mechanisms**	**Flexibility mechanisms classification**
Rules-based Approach	Regulated payments or penalties	Non-market-based mechanisms
Connection Agreements	Bilateral Agreements	
Network Tariffs	Dynamic Tariffs	
Market-based Procurement	Local Market Auction	Local-market-based mechanisms
	Local Market Day Ahead	
	Local Market near Real Time	
	Common Market Auction	Common-market-based mechanisms
	Common Market Day Ahead	
	Common Market near Real Time	

Source: Own elaboration 2021.

3. EVALUATION CRITERIA

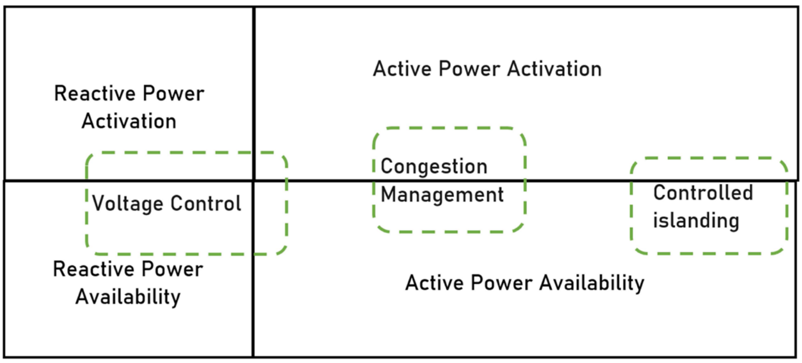
Considering criteria as the principles or standards by which a flexibility mechanism is selected, this section aims to analyse the relevant criteria for the proposed decision framework.

3.1 Needs and services

The DSOs have different needs. In this paper, DSO needs are considered as technical requirements in the network that can be solved by traditional methods (e.g. investments in network assets) and that are suitable to be solved by flexibility-based methods.

Figure 2 represents the different services required by the DSO related to whether the service is based on availability or activation and whether it requires using active or reactive power. Congestion management is related to active power, requiring activation and/or availability of an active power upwards or downwards to avoid network components reaching their thermal limits. In the case of voltage control, it requires actions to keep grid voltages within the acceptable ranges (Troncia, et al. 2021). In lower voltage levels, voltage control mainly requires active power management because of the high R/X ratio (Blažic and Papic 2008). However, voltage issues are generally managed through reactive power flows at higher voltage levels. Lastly, controlled islanding applies to small electrical islands that may arise due to the inability of the network to keep that piece of network connected to the rest in case of network failures.

FIGURE 2
Flexibility Services for DSOs.



Source: Own elaboration.

Availability products are expected to be related to long-term needs, or at least to forecasted needs since short-term needs would require activations close to real-time.

Other flexibility services specifically address TSO needs such as balancing, inertia or black-start. In these cases, the DSO could act as a facilitator of the services required by the TSO. However, these are not addressed in detail in this paper. Another issue to take into account is that not always the DSOs needs can be solved with flexibility services and traditionally investments may be required when it is the most efficient solution for the whole system considering the costs and benefits of the alternatives.

3.2 Need locations

How distribution networks are operated depends on the voltage level and, therefore, the needs of DSOs at each voltage level are very different. Considering International Electrotechnical Commission (IEC) standard voltages (IEC 2009), a division in Low Voltage (LV), Medium Voltage (MV) and High Voltage (HV) could be valid considering the different operation strategies, design criteria or network needs.

High Voltage, meshed grids (~>36kV and ~<220kV) (Strunz, et al. 2014): The operating requirements of the meshed grid system are very similar to those of the transmission networks. For example, in Spain, there is a very robust 132kV network that meets this description. This type of network sometimes covers the failure of the transmission networks. Voltage control is carried out through reactive flows management in these grids.

Medium Voltage, radially operated grids (~>1kV and ~<36kV) (Strunz, et al. 2014): MV voltage levels also have large kilometres of the network in rural areas or where the overhead network coexists with the urban environment. The equipment is similar to that of higher voltage, although it is radially operated, it presents a considerable level of automation, and it has a considerable impact on the quality of supply indices. Some specific elements can be very critical.

In some distribution systems, MV networks can be radially operated networks at different voltages (e.g. at 132kV, 66kV or 45kV). The failure of any element in a radial operation system causes a supply interruption. However, for simplification, the same treatment is given in this document to MV and HV radially operated networks.

Low Voltage (<1kV): Due to the role of these grids, the majority of line kilometres in distribution grids are within densely populated areas. The average ratio between LV costumers/MV costumers is 671 in Europe (Prettico, et al. 2019). However, it tends to be a less critical network due to the low collective impact of each asset. LV networks have specific regulations related to equipment and installations design, different components (cables, standardised products, protections, safety tools, etc.) and are the part of the electricity grid closer to the consumer. The active management of the LV network is becoming increasingly important as automation advances in the LV network due to the strong deployment of intelligent systems infrastructure, such as the communication grid for advanced metering. Some countries have already completed the smart meter roll-out in advance (for the target of 80% coverage by 2020) such as Spain where more than 99% has been deployed (Prettico, et al. 2019).

In Table 2 the three voltage levels are compared attending to their key different characteristics. This is not an exhaustive analysis of the ways of operating the different voltage levels, but a selection of the most significant characteristics in terms of the differences of each type of network, their operation or their conditioning factors when considering investment options.

In terms of criticality, as LV assets feed fewer customers, are considered critical only on a few occasions. HV assets are considered more critical not only for the number of customers but also for the relevance of some facilities such as big industries. MV is logically in the middle of both situations. The controllability is also related to the criticality of the network assets. Therefore, HV level assets are usually fully automated, controlled and can be even monitored with new parameters such as temperature to adapt the assets utilization rating. However, the digitalisation process has contributed to reliability (Girón, et al. 2018) with the automation and control in MV and evolving to LV.

When considering the operation mode, in the same way, the reliability required is essential. Therefore, HV networks are generally operated in a meshed mode, and LV and MV assets are designed to be operated radially. But MV assets have adjacent feeders that help in case of outages, especially in urban networks.

Social opposition, administrative and environmental constraints can be found when investment works are intended to be executed. HV investments are more likely to find opposition due to their size. On the other hand, LV and MV works are more standardised, as they are more common investments with lower opposition.

There are also more affordable operating solutions for critical situations such as portable generation sets for LV. Operational solutions in MV or HV will depend normally on the own DSO resources and the network configuration.

Finally, the way of managing voltage control is different depending on the voltage level due to the R/X ratio as mentioned in section 3.1.

All these characteristics influence the management of the grid depending on the voltage level, and therefore, a different assessment of flexibility mechanisms as an alternative.

TABLE 2
Characteristics of each voltage level grid operation.

Network characteristics	LV	MV	HV
Criticality	Seldom critical installations.	Strong impact on the quality of service. Some installations can be very critical.	Very critical installations whose unavailability means a high impact on the network.
Controllability	Low controllability of the networks and little automation (although this aspect is evolving). Some technological solutions consolidated in MV or HV are in the process of maturing in LV (e.g. On- load tap changer transformers)	High controllability. High automation, especially in urban areas. Non-meshed grids require customer-affecting operational manoeuvres that are increasingly automated. Automated operations under research for furtherer objectives. (e.g. dynamic reconfigurations for increasing capacity)	High and reliable controllability. Fully automated. The new solutions are aimed at improving the performance of the lines by monitoring their real capacity. (e.g. Dynamic Line Rating)
Operation mode	Radial operation and difficult service restoration from adjacent feeders.	Radial operation, usual and simple service restoration from adjacent feeders.	Mesh operation to ensure uninterrupted supply in case of failure.
Investment complexity	Highly standardised investment solutions with high relative costs in terms of costs per customer.	Highly standardised investment solutions are increasingly difficult to build due to social opposition, administrative and environmental constraints.	Very expensive investment solutions that are very difficult to build due to social opposition, administrative and environmental constraints.
Outage operation cost	Affordable operating solutions for critical situations (portable generation sets).	Low-cost operation solutions when there is sufficient infrastructure (meshed feeders) but high cost when there is none (mobile substations, provisional installations, etc.).	Operation solutions of high cost in case they are possible.
Voltage Control operation	Voltage control is linked to active power management and voltage drops.	Voltage control is more linked to active power management and voltage drops.	Voltage control is more linked to reactive power management than to voltage drops.

Source: Own elaboration.

3.3 Procurement time

Long term needs are foreseen years or months in advance and are usually solved with a new investment in network assets. Flexibility alternatives may be justified based on a deferral investment or even its avoidance. The aforementioned Article 32 of the (EU 2019) also stipulates that the network development plans "shall provide transparency on the medium and long-term flexibility services needed".

The second category of needs includes those that are part of the normal operation of the network for the maintenance of the elements. These are short term programmed needs, matching precisely with the options market and the spot market proposed in (Ottesen, Tomasgard and Fleten 2018): from several days to day-ahead or shorter. These needs have a common characteristic, which interventions are programmed in advance with a predetermined schedule or work plan, and that they require the preparation of the network to carry out the maintenance work.

Finally, there are the non-programmed short-term needs, unforeseen and requiring an intervention almost in real-time or just a few minutes or hours in advance. This is the usual situation of network failures. Due to its characteristic of unpredictability, it is not possible to make a forecast of the need. Monitoring is essential in these cases. Therefore, in this case, both activation and availability for critical situations or installations will be valued.

As mentioned above, short-term needs can be satisfied with flexible long-term solutions and vice versa. It is, therefore, necessary to decouple needs timeframe to procurement time-frame. A classification for procurement timeframes is shown in Table 3 based in (Ramos, et al. 2016) which is useful both for local and wholesale markets.

TABLE 3
Procurement Timeframes

Procurement timeframe	Potential usage
Long-term [from years to months] (LT)	These contracts allow buyers and sellers to contract services at prices and quantities time in advance to hedge risk. Flexibility capacity reservation for potential later use or even activation committed. Grid constraints are predicted in long-term periods.
Weeks to day-ahead (DA) procurement	The day-ahead market serves for scheduling resources at each hour of the following day (or even shorter). A more accurate forecast of the condition of the network is available in this timeframe. Unusual network conditions are foreseen at this time.
Intraday procurement / Real-time (RT)	Flexibility procured in real-time or close to real-time is useful to maintain system security.

Source: Own elaboration.

3.4 Impact on TSO grid

As both TSOs and DSOs will be procuring services provided by DERs (Lind, et al. 2019), coordination is already a concern from a practical point of view and for policymakers (EU 2019). There is agreement among various associations of DSOs and TSOs that such coordination is necessary and that there are different ways of doing this (E.DSO, et al. 2019). (Gerard, Rivero Puente and Six, Coordination between transmission and distribution system operators in the electricity sector 2018), (Papavasiliou and & Mezghani 2018), (Tohidi, Farrokhseresht and Gibescu 2018). Some demonstration projects (e.g. SmartNet Project[1] and CoordiNet Project[2]) are opening different possibilities to enable different options to obtain the highest efficiency. Table 4 shows the results of the different schemes provided in these works. The table shows the coordination schemes obtained in the CoordiNet project, which are deducted from the formulation of certain hypotheses that correspond to the answers to certain key questions: who buys, who sells, how many markets are there, who accesses the resources? The SmartNet project alternatives are considered among those options. INTERRFACE Project[3]

1. http://smartnet-project.eu/ (Accessed 14/09/2021).
2. https://coordinet-project.eu/ (Accessed 14/09/2021).
3. http://www.interrface.eu/ (Accessed 14/09/2021).

also addressed the issue from the point of view of previous works (E.DSO, et al. 2019), this approach is compared to CoordiNet project in (Baron, et al. 2021).

The number of markets and buyers allows inferring that Common and Integrated coordination schemes consider a common market. The Fragmented, Multi-Level and Distributed consider more than one market. That is, the coexistence of different markets among which there may be common markets as well. Thus, a common market, in the terms considered in this paper, could be accommodated within these five coordination schemes as long as TSO and DSO share needs in the same market.

TABLE 4
Coordination Schemes studied in the literature

Coordination Scheme	Description	Number of markets	Buyer
Centralised	TSO contracts flexibility from DER directly	1	TSO
Local	DSO operates the market for those connected to the distribution grid	1	DSO
Shared balancing (Fragmented)	DSO is responsible even for balancing in his distribution grid	≥1	DSO&TSO
Common	The operation is done by both system operators	1	DSO&TSO
Integrated	Allows also commercial parties to procure flexibility.	1	DSO&TSO& Commercial Party
Multi-Level	A combination of the Local Market Model and the Central Market Model	≥1	DSO&TSO
Distributed	Peers are the sole buyers and providers in the market	≥1	Peers

Source: Own elaboration based on deliverables CoordiNet D1.3 and SmartNet D1.3

Hadush and Meeus (2018) concluded that the need for cooperation and the solutions will depend on where structural congestion occurs. It is relevant to establish what coordination is necessary, whether it is a matter of exchanging information, obtaining authorisations, or sharing objectives to obtain solutions that optimise the system costs as a whole.

The activation of small FSPs may not have a significant impact on system balancing or TSO grid. Therefore, in order to simplify the implementation of flexibility solutions, it is necessary to consider to what extent such coordination between DSO and TSO is necessary. When the amount of flexibility needed is below a certain threshold, the flexibility mechanisms does not need to include strong TSO-DSO coordination. However, when it is above such threshold, there must be coordination or some kind of interaction to ensure system security.

A first sensible threshold for this insensitivity in active-power-based flexibility services could be set at **around 5MW** of instantaneous power. In fact, (CEER 2020) highlighted this threshold when it reviews the pilots and demos and their implications in imbalances. This first range (0–5MW) in which flexible variations do not affect the transmission network or the system operator is consistent with the volume of MV feeders, because of cable capacities. Indeed, such sizes have never required coordination with the TSO even for programmed interruptions.

The second threshold in active-power-based flexibility services could be established **around 50MW**. In the second range (5–50MW) there could be aggregated information from the DSO to the TSO. Finally, from 50MW upwards, also a coordination procedure must be established. A single market for DSO and TSO ("*Common*" or "*Integrated*" in Table 4) would fit these needs. Substation transformers are supposed to be in the range of 10 to 50 MVA.

These two thresholds of 50MW and 5MW are consistent with the dimensioning proposed in the particular standards for a transformer and a MV feeder set by the DSOs for Spain (DSOs, Spain n.d.) and match with the benchmarking in (Strunz, et al. 2014) and with the volumes managed at DSO's events in which there is no TSO participation.

3.5 Generalisation of the need through the system

Global problems would be exclusive to the overall system needs managed by the TSO while local problems are network-specific, either from the TSO's network, the DSO's network, or both. Therefore, the DSO has only local problems under its responsibility. However, there may be a local problem that is repeated throughout the entire network, it becomes a generalised problem. In that case, specific mechanisms should be considered to avoid addressing individually a large number of similar problems at the same time.

A key aspect of market-based mechanisms to acquire services is the commitment to deliver the traded commodity, otherwise, the transaction does not take place. Tariff mechanisms, however, have equally economic incentives, but without a commitment to deliver the service beyond potential penalties. Cost-reflective tariffs have arisen in response to concerns about the distribution of costs, avoid cross-subsidies and providing price signals to incentivise efficient investments in DER. The network can have very specific needs, in (Gómez, Cossent and Chaves Ávila 2020) differentiated tariffs for each node of the system is highlighted as a theoretical efficient solution. An in-depth study of dynamic network tariffs has been carried out in (Chaves, et al. 2021) and a methodology for network costs and generation costs due to network usage has been proposed. Furthermore, the difficulty of implementing locational variation in tariffs is recognised in (CEER 2020), mainly because of the public perception of fairness or legal constraints. Thus, dynamic tariffs are not the best mechanism for specific local issues and they could be considered for generalised local problems. Furthermore, if not properly designed, they can generate new inefficiencies. For example, unexpected responses could create new issues in the grid.

Apart from dynamic tariffs, customers behaviour can be modified by rules-based mechanisms that entail some kind of incentive to be followed. For instance, penalties are appropriate to trigger the mass installation of a particular technology when the cost of that new technology is lower than the penalty. But it is also necessary to consider the effect on efficiency losses, i.e. the value beyond which the penalty no longer incentivises the installation of the new technologies and generally these penalties are static and are not tailored to specific needs.

3.6 Market Liquidity: Network and Resources Influence

Market liquidity can be defined in a simplified manner as the presence of enough traders on both the bid and offer sides of the market to reach an optimal transaction (Schmidt 2000). In a perfectly liquid market, an asset can be sold instantly with no loss of value. In fact, for a large number of participants of demand and supply sides, the ability to negotiate is practically zero, the market in perfect competition results in an efficient price. In contrast, in a market with limited liquidity, the buyer or seller may have bargaining power and influence the price.

When markets are still immature, liquidity is generally low. So, mechanisms to facilitate trading are needed in illiquid markets. Mechanisms such as bilateral agreements are therefore very appropriate for the most incipient markets. Some market mechanisms will develop sufficient liquidity but others will remain illiquid, these will depend on the level of competition gained. When more liquidity became available, auctions would be the next step to allow competition. Since services may be remunerated by activation and availability, the market could be cleared in different stages.

Liquidity growth may lead to the evolution of market-based mechanisms in some areas of the network, in other areas such evolution will not take place, with non-market-based mechanisms remaining optimal. The following fourth elements will have a direct impact on liquidity growth.

I. **Timeframe** and **information** availability. Relevant information must be available to all stakeholders sufficiently in advance so that providers can make their decisions. This exchange of information will depend on the stage of the service. To this end, four different stages shown in Table 5 can be distinguished according to (E.DSO, et al. 2019).

   The different information flows will be different among the actors. The type of information required in each of the flows proposed in Figure 3 (in yellow flows related to DSO services) and for each stage of the process need to be analysed.

   As a result, the form and timeframe of that information exchange take place may have a direct impact on market liquidity in case the information disclosure is not made openly available for potentially FSPs.

II. **Product specifications**: Product **standardisation** among markets may, on one hand, facilitate participation, as it is not necessary to meet specific requirements for each market. With standard services, there is no need to revise the deployed technology, both hardware and software, and processes to adapt to a new service need. But for specific requirements and, due to particular providers characteristics, to facilitate participation in the market, the **product specifications could be adapted.**

III. Ability to influence the **price**. In case of illiquid market conditions, a wide variety of competition policies has been adopted across Europe to avoid dominant position liable to affect competition (e.g. Article 102 TFEU (EU 2008) or Act against Restraints of Competition, (Bundesgesetzblatt 2013) § 18 in Germany). The applicability of these policies needs to be considered for the considered market mechanisms.

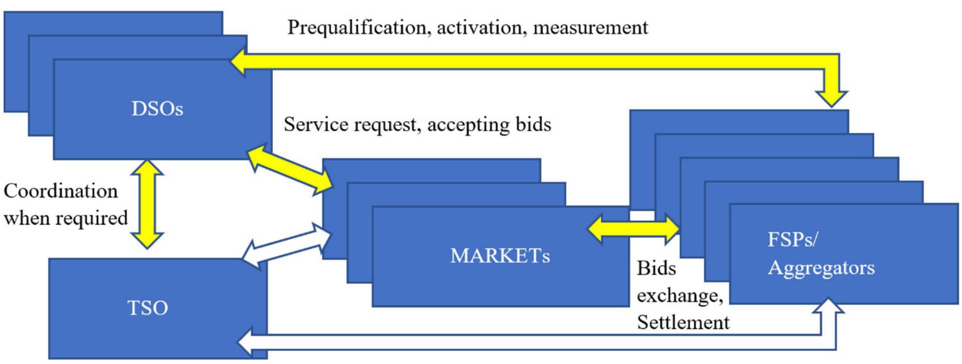
IV. **Cost structure**, **entry and exit barriers**: It will be necessary to consider the costs of market participation (e.g. necessary communications infrastructure), the costs of activation (whether the matching involves the implicit activation order or not and the possible activation infrastructure) or the costs of monitoring the transaction (whether the market window coincides with the availability window for accepting activations or not). The cost structure, **CAPEX** and **OPEX,** for participating in the market, as well as entering or exiting the market will be a factor for determining the trade-off between frequent markets (daily or weekly) or long-time markets. For instance, the cost of the remote system for receiving or sending information in real-time is a cost that needs to be considered in such a trade-off. As long as policies enable multiple revenue streams these costs assessments should consider the combination of revenues to be more accurate (Gardiner, et al. 2020). Finally, the lack of regulation is clearly a barrier to trade services.

TABLE 5
Information exchange in each process stage

Process Stage	Information Exchange
Prequalification	The technical and economic ability to participate in providing a service is verified. All attributes of the service need to be assessed.
Forecast and service request	Specifying technical requirements, such as location, measurement requirements, under-delivery consequences, over-delivery consequences, ramp rate.
Accepting bids and activation	Real-time commands or set-up points may be needed to be delivered. Compliance with the technical requirements of the product may require supervision.
Validation, measurement, and Settlement	The process to verify that the flexibility service provider has delivered according to the offer and the technical requirements of the product and calculation of financial exchanges between counterparties. A complementarity settlement process may be needed in case of application of penalties for non-delivery according to the commitments.

Source: Own elaboration.

FIGURE 3
Information exchange among stakeholders for providing grid services.



Source: (Martin Utrilla, et al. 2021).

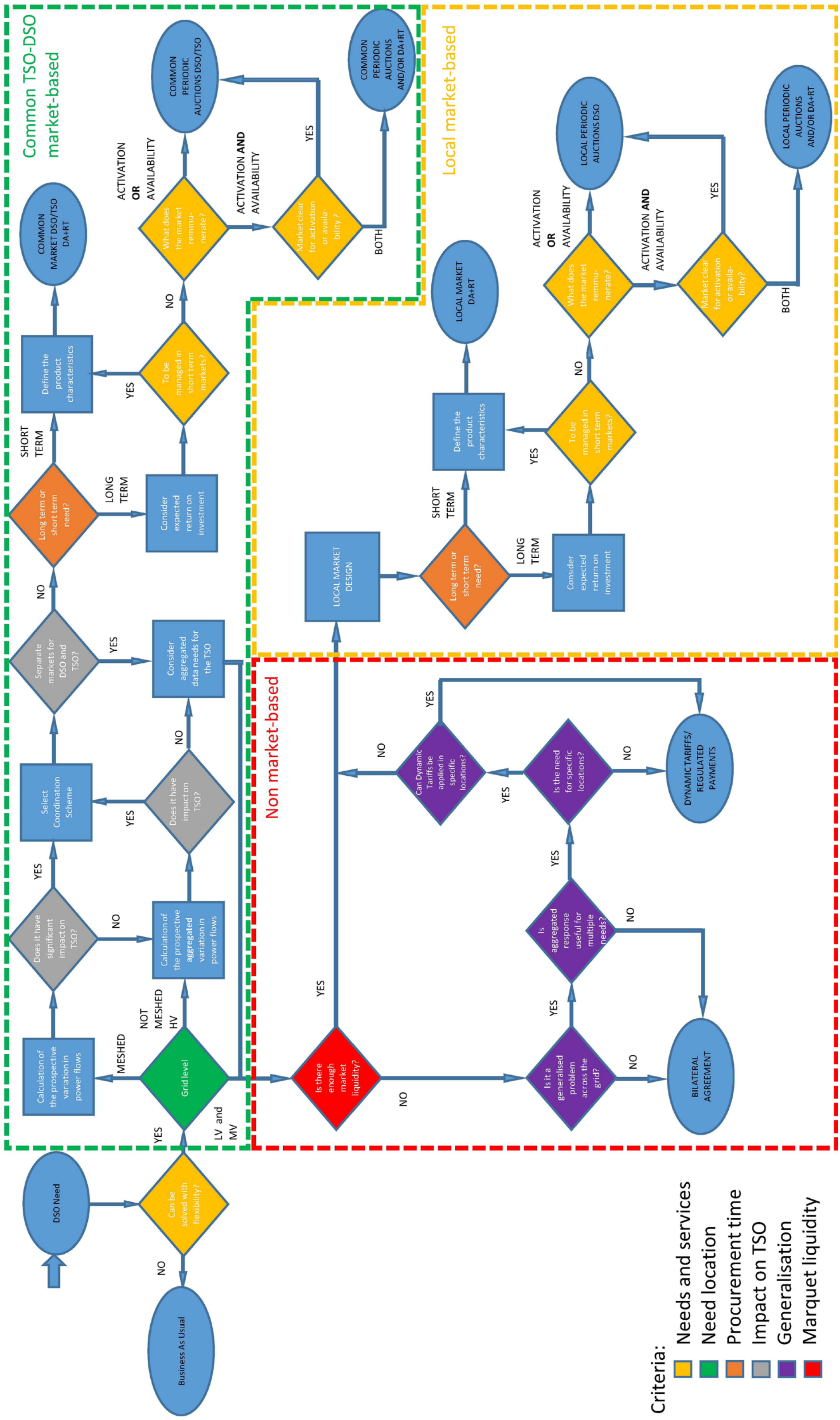
4. A DECISION FRAMEWORK TO EVALUATE THE MOST SUITABLE FLEXIBILITY PROCUREMENT MECHANISM

This section presents a decision framework for selecting the most suitable flexibility procurement mechanism based on the characteristics of the network, the DSO needs and the evaluation criteria described in previous chapters. The complete decision framework is shown in Figure 4. For a better interpretation of the application of the criteria, the link to each of them is indicated in the figure.

The DSO needs and their location presented in section 3 are key for some of the steps of the decision framework. The voltage level in which the need occurs is decisive as network operations and cost-benefit analysis are very different for each voltage level. As mentioned in section 3.2, big differences are impacting the costs for each type of network (Table 2). And

FIGURE 4

Decision framework proposed to determine the most suitable flexibility mechanism depending on DSO needs, network conditions and evaluation criteria.



Source: Own elaboration 2021.

lastly, the timing in which the need is required before the activation also determines the type of flexibility mechanism, especially in market-based mechanisms.

The question of TSO-DSO coordination, where the number of markets and the threshold to activate the coordination are decisive in the upper part of Figure 4. Market liquidity defines the efficiency of a market-based mechanism and determines whether a market-based mechanism could be the most suitable one. The generalisation of the need as local repeated issues will determine the suitability of dynamic tariffs. These criteria are decisive in the lower part of Figure 4, in which low liquidity could be found.

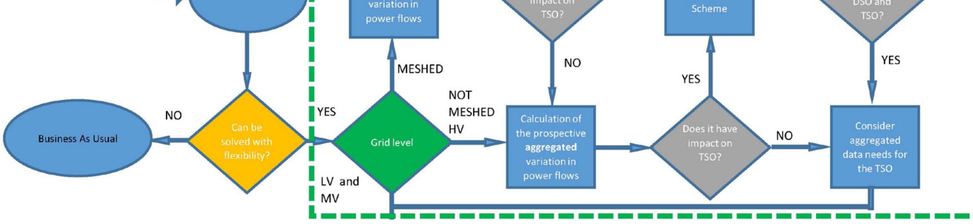
Thus, the proposed decision framework is divided into three following the classification in Table 1: one related to common TSO-DSO mechanisms, another one related to non-market-based mechanisms and the last related to local market mechanisms. In this framework, it is only intended to select the most appropriate tool for each case in a given context. But the combination of alternatives offers solutions under a wider range of contexts. Moreover, for each specific need in a specific context, there is a tool that is the most appropriate but may not be a stand-alone solution.

In addition, the behaviour of the network users is dynamic and constantly changing active and reactive power flows. Therefore, it is interesting to have a wide variety of options available and apply one or other depending on the specific circumstances. For this reason, the requirements on the same network element can be very different from one day to another or even between hours. This means that the criteria for choosing the best mechanism can also be dynamic. For example, there may be sufficient liquidity at some times, justifying a market mechanism only for some time slots. Or there could be some DSO requirements that need to be coordinated with the TSO because of the magnitude of the need but the coordination might not be essential other days at lower magnitudes. So the combination is possible and in some cases may even be desirable.

4.1 Common TSO-DSO market mechanisms

The first step in the decision framework as shown in Figure 5, after concluding that can be solved with flexibility services depending on the type of need, is to identify in which part of the network the need occurs. As discussed in section 3.4, non-meshed grids (LV and MV) that do not have a strong impact on the TSO network can be managed exclusively by the DSO. Every other need will follow the "upper" path of the **Common Market Mechanisms**. Both TSO and DSO need to calculate the prospective variations in power flows to find out what the impact

FIGURE 5
Common market mechanisms – part 1/2.



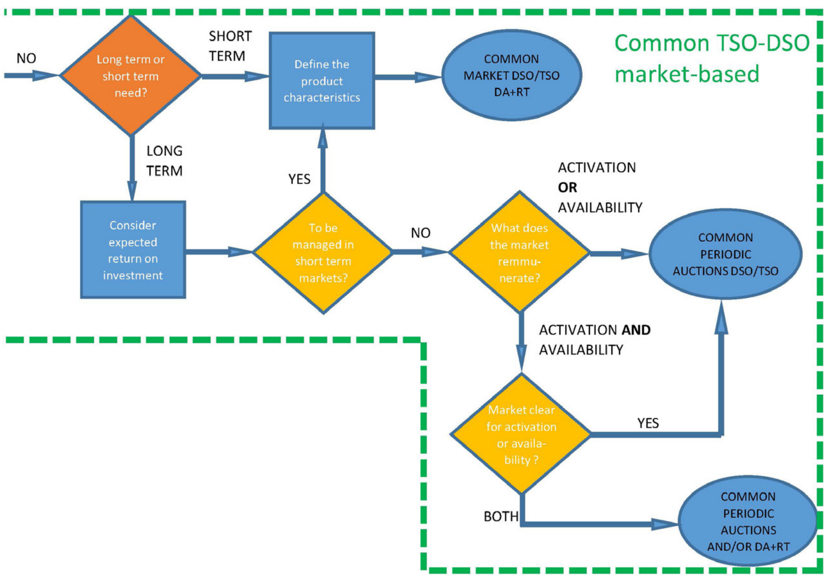
Source: Own elaboration 2021.

on each other's network would be, in aggregate or individual form. The thresholds suggested in section 3.4 are a reference that can be considered. Then the specific coordination scheme between TSO-DSO should be selected.

If there are separated markets, data must anyway flow in an aggregated manner to keep the TSO informed and local market mechanisms would play their role. If not, the solution follows the path of the Common Markets as shown in Figure 6. The criteria of the subsections 3.1, 3.2, 3.3 and 3.4 are relevant in this path. Enough liquidity is expected in this situation. For long-term needs, it is important to consider the return on investment for the flexibility provider. The commitment to delivery or the availability for a certain minimum time may be decisive for the FSP to participate in the market. In this way, and depending on the market liquidity, the decision to use short-term mechanisms for long-term needs can be taken. Some long-term needs (e.g. flexibility options considered as alternatives to traditional investments) can be managed in short term markets when they can provide reliable solutions because of market liquidity. Finally, the characteristics of the product to be traded would be considered.

FIGURE 6

Common market mechanisms – part 2/2.



Source: Own elaboration.

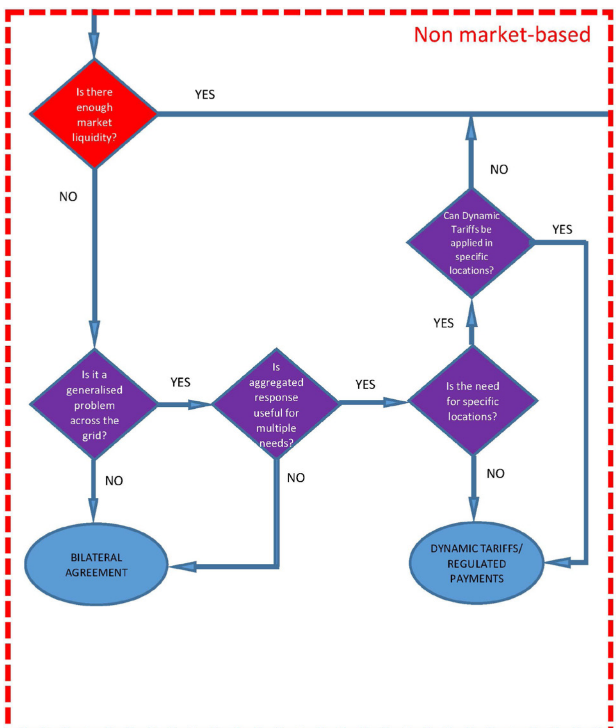
Short term markets (DA and RT as considered in section 3.3), are expected to be remunerated mostly for activation when forecasts are accurate enough. But also, there could be a combination of a long-term market for availability and a short-term market for the activation. For this reason, for long-term markets, the activation and availability may be cleared and their possible interaction with short-term markets (DA+RT) needs to be considered.

The type of the service and the timeframe of the need are relevant to choose the timeframe of the market. For voltage control service in meshed networks at the TSO-DSO interface, a common market mechanism is the most appropriate to account for the impact on both networks. Also, programmed maintenance at the extra-high-voltage network is a need that could be solved with a congestion service in the common market in the day ahead after the energy market schedules.

4.2 Non-market-based mechanisms and long-term needs

Where exclusive solutions of the DSO are considered, potential market liquidity determines whether the mechanism should be market-based or not. Figure 7 shows the part of the decision framework addressing these mechanisms. The criteria of subsections 3.1, 3.5 and 3.6 are relevant in this path. Given the assumption that market-based mechanisms are preferred as they are the most efficient solutions (CEER 2020), non-market-based mechanisms can only be accommodated when there is not enough liquidity and market-based mechanisms are not able to provide an optimal solution. If the need is generalised, and the response is useful for multiple needs, dynamic tariffs are adequate mechanisms. Otherwise, bilateral agreements would be more suitable to adapt to specific needs or where aggregation is not possible and resources must be managed individually. For the same reason, dynamic tariffs are not applied a priori to solve a problem in a specific location, because they address the whole system. However, if allowed, dynamic tariffs applied in specific locations can be considered as a flexibility mechanism. If not allowed, generalised problems in some specific locations could be managed in the market even with low liquidity.

FIGURE 7
Non-market-based mechanisms.



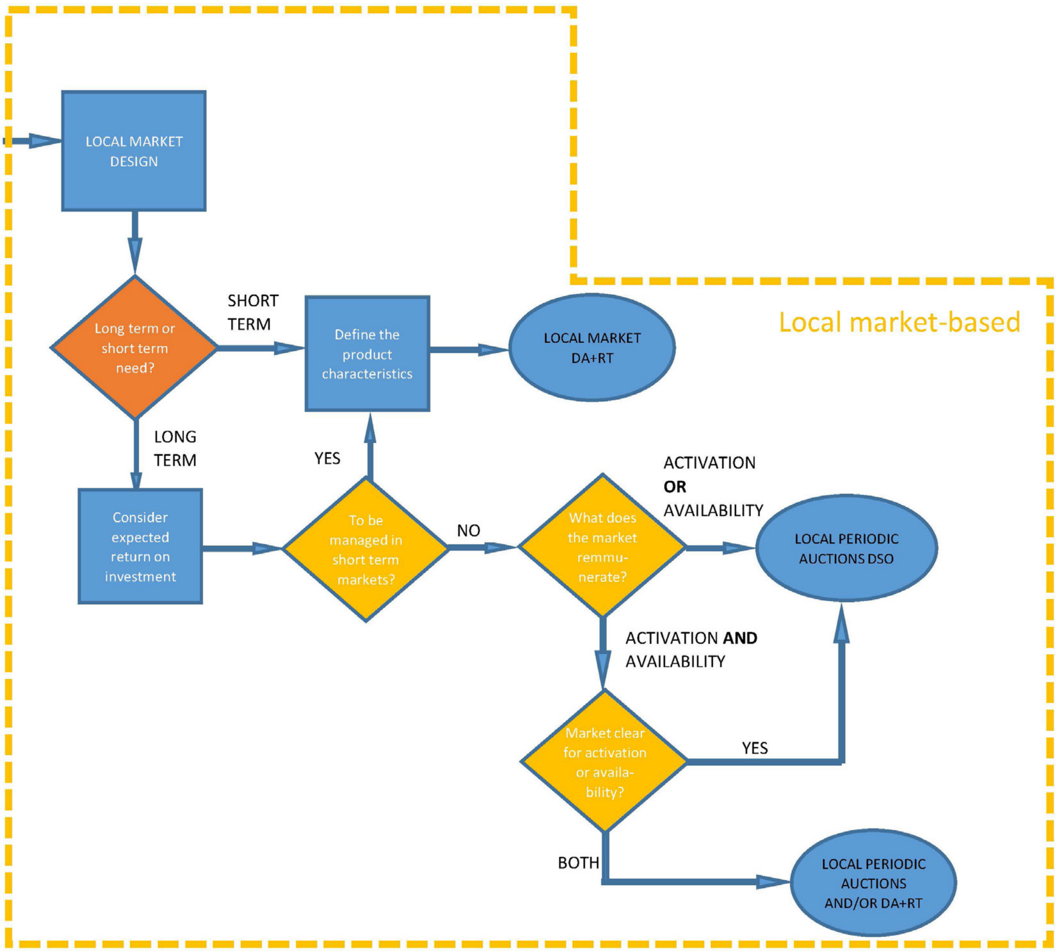
Source: Own elaboration 2021.

An example of non-based market mechanisms could be an agreement between a small generator connected to the LV grid and the DSO so that the generator can supply the distributor's customers at LV in the event of a failure at the secondary substation. This is a tailored-made solution that can hardly be competitive. Some problems can be generalised throughout the MV and LV networks when deploying new technologies that can be installed quickly or electrification of loads, such as the electrification of transport with electric cars, the electrification of heating and cooling or solar generation.

4.3 Local market-based mechanisms

Figure 8 addresses local market mechanisms. The criteria of subsections 3.1, 3.2, 3.3 and 3.6 are relevant in this path. Long-term solutions are more likely to be deployed in the early stages as they ensure the commitment to deliver the service at a given price. **Piclo Flex**[4] is a good example in the UK. It is a software solution that announces auctions that can be accessible to flexibility providers for a long-term flexibility service, as approved by the regulator (OFGEM 2019).

FIGURE 8
Local Market Mechanisms.



Source: Own elaboration 2021.

4. https://picloflex.com/ (Accessed 14/09/2021).

Within local market mechanisms, the decision framework is similar to the common market. As less liquidity is expected, long-term commitments could become more relevant. There also could be a combination of a long-term market for availability and a short-term market for the activation. In high liquidity scenarios, short-term commitments delivered by market-based mechanisms may be useful for long-term needs as it is more certain that there will exist any FSP to provide the service.

Auctions fit in congestion management for low liquidity situations or incipient markets. An application of such auctions can start with the publication of a need in an area fed by a MV feeder for consumers to curtail their power in those time slots where forecasts detect possible congestion in the coming months, resulting in a benefit related to network reinforcement deferral (Villar, Bessa and Matos 2018).

5. CONCLUSIONS

A decarbonised economy allowing the integration of a more renewable and distributed generation and new uses of electricity will require additional investments on a more digital and resilient grid. Flexibility mechanisms are emerging as a new paradigm in network operation and planning to achieve a more effective utilization of the assets. This paper addressed the analysis of the characteristics and criteria that condition the selection of the flexibility mechanisms for every possible situation.

Each of the characteristics that can influence the selection of flexibility mechanisms has been studied individually. Identifying the needs faced by the DSO, their location in the network (LV, MV, HV) and the timeframe in which the need is managed. On the other hand, other relevant criteria have also been studied in the choice of mechanisms, such as the impact on the TSO's responsibility, the possible generalisation of the problem or the potential market liquidity. Deeming all of them, a clear decision framework is developed to match DSO needs with the most suitable flexibility mechanism. The three types of situations were identified.

First, some mechanisms must necessarily be coordinated with the TSO because of their impact on balancing or TSO grid. Then depending on the timeframe and the need, different type of common or coordinated markets may be used.

Second, other situations in which there is not enough market liquidity, non-market-based mechanisms are selected, such as bilateral agreements for specific needs or dynamic tariffs for generalised needs.

And finally, for situations in which there is sufficient liquidity and there is no impact on the TSO's operation, depending on the need and timeframe, different types of local markets can be selected.

The exclusive mechanisms for DSOs are still very unexplored in the literature and the lack of liquidity plays a key role. Market-based mechanisms, preferred by regulators, can provide optimal solutions when liquidity is high. Local DSO markets could work under those premises but illiquid situations may occur in case of lack of maturity of the market and this situation may even persist. Thus, non-market mechanisms may also have a relevant role to play in the DSO environment.

The market design options, such as the timeframe, the exchange of information, the traded product, the price formation, the cost or the barriers to entry and exit, will determine the existence of more or less liquidity and, therefore, the efficiency of a market-based mechanism. On the other hand, while products and services need to be developed to manage flexibility markets, they do not strongly influence the choice of mechanism but it does impact liquidity.

To further develop this approach, the next steps would be to continue to study the nature of the uses of electricity and the nature of the needs to match the solutions provided. In this way, we could find out whether the value of the flexibility provided, for example by electric vehicle charging, is used up by selecting an appropriate tariff or whether it makes sense to incentivise aggregated solutions to resolve congestion in the local market or even the common market.

The design of local flexibility procurement is being reviewed by national regulators. In particular, it is necessary to make an exhaustive analysis of the aggregator's responsibilities to redirect the tasks of searching for flexibility niches and incentivise customers to provide flexibility. Even with the technology in place, conventional solutions may still be preferred by the DSO because of the reliability and the associated remuneration. So, only if flexibility mechanisms deliver significant efficiencies, the implementation of flexibility mechanisms can be justified.

The proposed framework aims to guide the most appropriate mechanisms but the authors acknowledge that these mechanisms are not implemented in isolation but in a combined manner. Future research should analyse compatible combinations and apply them to real case studies.

ACKNOWLEDGMENTS

The authors express their sincere gratitude for the comments received from Dr. Matteo Troncia from IIT-Comillas.

References

Baron, M., J.P Chaves Ávila, K Glennung, I. Vaitiekuté, N Savopoulos, P. Josefsson, A. Sanjab, et al. 2021. "CoordiNet & Interrface Joint Paper Coordination Schemes, Products and Services for Grid Management." Accessed 10 2, 2021. https://private.coordinet-project.eu//files/documentos/60c761bfb99d7Joint%20Paper%202021%20CoordiNet-INTERRFACE%20FINAL.pdf.

Blažic, B., and I. Papic. 2008. "Voltage profile support in distribution networks – influence of the network R/X ratio." Edited by IEEE. *IEEE 13th International Power Electronics and Motion Control Conference (EPE/PEMC 2008).* Poznan, Poland. 2510–2515. Accessed 09 12, 2021. https://doi.org/10.1109/EPEPEMC.2008.4635641.

Bundesgesetzblatt. 2013. *Act against Restraints of Competition (Competition Act – GWB).* 06. Accessed 09 12, 2021. https://www.gesetze-im-internet.de/englisch_gwb/englisch_gwb.html.

CEER. 2018. "Flexibility Use at Distribution Level." Distribution Systems Working Group, Council of European Energy Regulators. Accessed 09 12, 2021. https://www.ceer.eu/documents/104400/-/-/e5186abe-67eb-4bb5-1eb2-2237e1997bbc.

CEER. 2020. "Paper on DSO Procedures of Procurement of Flexibility." CEER C19-DS-55-05, Distribution Systems Working Group, Council of European Energy Regulators. Accessed 09 12, 2021. https://www.ceer.eu/documents/104400/-/-/f65ef568-dd7b-4f8c-d182-b04fc1656e58.

CEER. 2020. "Paper on Electricity Distribution Tariffs Supporting the Energy Transition." Distribution Systems Working Group, Council of European Energy Regulators. Accessed 09 12, 2021. https://www.ceer.eu/documents/104400/-/-/fd5890e1-894e-0a7a-21d9-fa22b6ec9da0.

CEER. 2020. "Paper on Electricity Distribution Tariffs Supporting the Energy Transition." C19-DS-55-04, Distribution Systems Working Group, Council of European Energy Regulators. Accessed 10 2, 2021. https://www.ceer.eu/documents/104400/-/-/fd5890e1-894e-0a7a-21d9-fa22b6ec9da0.

Chaves, J.P., M. Troncia, L. Herding, N. Morell, O. Valarezo, K. Kessels, A. Delnooz, et al. 2021. "EUniversal D5.1 Identification of relevant market mechanisms for the procurement of flexibility needs and grid services." Deliverable D5.1, EUniversal Project. Accessed 09 12, 2021. https://euniversal.eu/documents/deliverable-d5-1/.

Crain, W. M., and R. B. Ekelund. 1976. "Chadwick and Demsetz on Competition and Regulation." *The Journal of Law & Economics, Vol. 19, No. 1*, 04: 149–162. Accessed 09 13, 2021. http://www.jstor.org/stable/725316. https://doi.org/10.1086/466859./

Delnooz, A., J. Vanschoenwinkel, E. Rivero, and C. Madina. 2019. "CoordiNet Project D1.3 Definition of scenarios and products for the demonstration campaigns." Accessed 09 12, 2021. https://private.coordinet-project.eu//files/documentos/5d72415ced279Coordinet_Deliverable_1.3.pdf.

DSOs, Spain. n.d. "Especificaciones Particulares de Empresas Suministradoras." *http://www.f2i2.net/legislacionseguridadindustrial/EspecificacionesEmpresasSuministradoras.aspx.*

E.DSO, ENTSO-E, Eurelectric, Geode, and Cedec. 2019. "TSO – DSO REPORT - An integrated Aproach to Active System Management." Accessed 09 12, 2021. https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Position%20papers%20and%20reports/TSO-DSO_ASM_2019_190416.pdf.

Eid, Ch., P. Codani, Y. Perez, J. Reneses, and R. Hakvoort. 2016. "Managing electric flexibility from Distributed Energy Resources: A review of incentives for market design." *Renewable and Sustainable Energy Reviews* 64: 237–247. Accessed 09 12, 2021. https://doi.org/10.1016/j.rser.2016.06.008.

EU. 2019. *Directive 2019/944 on common rules for the internal market for electricity and amending Directive 2012/27/ EU.* Edited by L 158 Official Journal of the European Union. 14 06. Accessed 09 12, 2021. https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32019L0944&from=en.

—. 2008. *Treaty on the Functioning of the European Union, Article 102.* Edited by 09/05/2008 P. 0089 - 0089 Official Journal 115. Vers. EUR-Lex - 12008E102 - EN -. 05. Accessed 09 12, 2021. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A12008E102.

Gardiner, D., O. Schmidt, P. Heptonstall, R. Gross, and I. Staffell. 2020. "Quantifying the impact of policy on the investment case for residential electricity storage in the UK." *Journal of Energy Storage* 27: 101140. Accessed 09 12, 2021. https://doi.org/10.1016/j.est.2019.101140.

Gerard, H., E. I. Rivero Puente, and D Six. 2018. "Coordination between transmission and distribution system operators in the electricity sector: A conceptual framework." *Utilities Policy* (Elsevier) 50: 40–48. Accessed 09 12, 2021. https://doi.org/10.1016/j.jup.2017.09.011.

Gerard, H., E. Rivero, and D. Six. 2016. "SmartNet project Deliverable 1.3 Basic schemes for TSO-DSO coordination and ancillary services provision." Project H2020 Deliverable. Accessed 09 12, 2021. https://euniversal.eu/wp-content/uploads/2021/02/EUniversal_D5.1.pdf.

Girón, C., F. J. Rodríguez, L. Giménez de Urtasum, and S. Borroy. 2018. "Assessing the contribution of automation to the electric distribution network reliability." *International Journal of Electrical Power & Energy Systems* 97: 120–126. Accessed 09 12, 2021. https://doi.org/10.1016/j.ijepes.2017.10.027.

Gómez, T., R. Cossent, and J.P. Chaves Ávila. 2020. "Flexible network access, local flexibility market mechanisms and cost-reflective tariffs: three regulatory tools to foster decarbonized electricity networks." *Oxford Energy Forum* 124: 18–21. Accessed 09 12, 2021. https://repositorio.comillas.edu/xmlui/bitstream/handle/11531/56096/IIT-20-039A.pdf?sequence=-1.

Hadush, S. Y., and L. Meeus. 2018. "SO-TSO cooperation issues and solutions for distribution grid congestion management." *Energy Policy* (Elsevier) 120: 610–621. Accessed 09 12, 2021. https://doi.org/10.1016/j.enpol.2018.05.065.

Heinrich, C., Ch. Ziras, A.L.A. Syrri, and H.W. Bindner. 2020. "EcoGrid 2.0: A large-scale field trial of a local flexibility market." *Applied Energy* (Elsevier) 261: 114399. Accessed 09 13, 2021. https://doi.org/10.1016/j.apenergy.2019.114399.

Hillberg, E., A. Zegers, B. Herndler, S. Wong, J. Pompee, J.Y. Bourmaud, S. Lehnhoff, et al. 2019. "Flexibility needs in the future power system." *Int. Smart Grid Action Netw. - ISGAN Annex 6.* Accessed 09 13, 2021. https://doi.org/10.13140/RG.2.2.22580.71047.

Hou, Q., N. Zhang, E. Du, M. Miao, F. Peng, and C. Kang. 2019. "Probabilistic duck curve in high PV penetration power system: Concept, modeling, and empirical analysis in China." *Applied Energy* 242: 205–215. Accessed 09 12, 2021. https://doi.org/10.1016/j.apenergy.2019.03.067.

Howlader, H. O. R., M. M. Sediqi, A. M. Ibrahimi, and T. Senjyu. 2018. "Optimal Thermal Unit Commitment for Solving Duck Curve Problem by Introducing CSP, PSH and Demand Response." *IEEE Access* 6: 4834–4844 . Accessed 09 12, 2021. https://doi.org/10.1109/ACCESS.2018.2790967.

IEC. 2009. "IEC 60038 Standard Voltages ." *International Electrotechnical Commission.* Accessed 09 12, 2021. https://webstore.iec.ch/preview/info_iec60038%7Bed7.0%7Db.pdf.

Jin, X., Q. Wu, and H. Jia. 2020. "Local flexibility markets: Literature review on concepts, models and clearing methods." *Applied Energy* (Elsevier) 261: 114387. Accessed 09 12, 2021. https://doi.org/10.1016/j.apenergy.2019.114387.

Lind, L., R. Cossent, J.P. Chaves-Ávila, and T. Gómez. 2019. "Transmission and distribution coordination in power systems with high shares of distributed energy resources providing balancing and congestion management services." *WIREs Energy and Environment* 8 (6). Accessed 09 12, 2021. https://doi.org/ 10.1002/wene.357.

Martin Utrilla, F.D., M. Hable, R. Bessa, J. Lassila, C. Imboden, and A. Krula. 2021. *Flexibility in Active Distribution Systems.* WG 2019-3 Final Report, CIRED, International Conference on Electricity Distribution. Accessed 03 13, 2021. http://www.cired.net/cired-working-groups/flexibility-in-active-distribution-systems-wg-2019-3.

OFGEM. 2019. *Position paper Distribution System Operation.* Office of Gas and Electricity Markets. 08. Accessed 09 12, 2021. https://www.ofgem.gov.uk/system/files/docs/2019/08/position_paper_on_distribution_system_operation.pdf.

Olivella-Rosell, P., P. Lloret-Gallego, Í. Munné-Collado, R. Villafafila-Robles, A. Sumper, S.Ø. Ottessen, J. Rajasekharan, and B.A. Bremdal. 2018. "Local Flexibility Market Design for Aggregators Providing Multiple Flexibility Services at Distribution Network Level." *Energies* 11 (4): 822. Accessed 09 12, 2021. https://doi.org/10.3390/en11040822.

Ottesen, S. Ø., A. Tomasgard, and S.-E. Fleten. 2018. "Multi market bidding strategies for demand side flexibility aggregators in electricity markets." *Energy* 149: 120–134. Accessed 09 12, 2021. https://doi.org/10.1016/j.energy.2018.01.187.

Papavasiliou, A., and I. & Mezghani. 2018. "Coordination Schemes for the Integration of Transmission and Distribution System Operations." *Power Systems Computation Conference (PSCC).* Dublin: IEEE. 1–7. Accessed 09 12, 2021. https://doi.org/10.23919/pscc.2018.8443022.

Passey, R., N. Haghdadi, A. Bruce, and I. MacGill. 2017. "Designing more cost reflective electricity network tariffs with demand charges." *Energy Policy* 109: 642–649. Accessed 09 12, 2021. https://doi.org/10.1016/j.enpol.2017.07.045.

Piclo. 2021. *Piclo Flex Website* . Accessed 09 12, 2021. https://picloflex.com/.

Prettico, G., M. G. Flammini, N. Andreadou, S. Vitiello, G. Fulli, and M. Masera. 2019. *Distribution System Operators observatory 2018 Overview of the electricity distribution system in Europe.* European Commission. Joint Research Centre. Accessed 09 12, 2021. https://doi.org/10.2760/104777.

Ramos, A., C. De Jonghe, V. Gómez, and R. Belmans. 2016. "Realizing the smart grid's potential: Defining local markets for flexibility." *Utilities Policy* 40: 26–35. Accessed 09 12, 2021. https://doi.org/10.1016/j.jup.2016.03.006.

Sánchez-Jiménez, M., K. Stamatis, M. Kollau, M. Stantcheva, E. Busechian, P. Hermans, D. Guzeleva, G.E. Abrandt, W. Friedl, and P. Mandatova. 2015. "Regulatory Recommendations for the Deployment of Flexibility." *EG3 Report Smart Grid Task Force* 94. Accessed 09 12, 2021. https://ec.europa.eu/energy/sites/ener/files/documents/EG3%20Final%20-%20January%202015.pdf.

Schittekatte, T., and L. Meeus. 2019. "Flexibility markets: Q&A with project pioneers." RSCAS Working Papers 2019/39. Accessed 09 12, 2021. https://cadmus.eui.eu//handle/1814/63066.

Schmidt, A. B. 2000. "Modeling the birth of a liquid market." *Physica A: Statistical Mechanics and Its Applications* 283 (3–4): 479–485. Accessed 09 12, 2021. https://doi.org/10.1016/S0378-4371(00)00201-6.

Strunz, K, E. Abbasi, C. Abbey, C. Andrieu, U. Annakkage, S. Barsali, R.C. Campbell, et al. 2014. "Benchmark systems for network integration of renewable and distributed energy resources." *ELECTRA* 273 (ELT_273_8 Task Force C6.04.02 CIGRE WG C6.04): 85-89. Accessed 09 12, 2021. https://e-cigre.org/publication/ELT_273_8-benchmark-systems-for-network-integration-of-renewable-and-distributed-energy-resources.

Tohidi, Y., M. Farrokhseresht, and M. Gibescu. 2018. "A Review on Coordination Schemes Between Local and Central Electricity Markets." *15th International Conference on the European Energy Market (EEM).* Lodz: IEEE. 1–5. Accessed 09 12, 2021. https://doi.org/10.1109/eem.2018.8470004.

Troncia, M., J.P. Chaves Ávila, F. Pilo, and T. Gómez San Román. 2021. "Remuneration mechanisms for investment in reactive power flexibility." *Sustainable Energy, Grids and Networks* 27 (100507). https://doi.org/10.1016/j.segan.2021.100507.

van der Veen, A., M. van der Laan, H. de Heer, E Klaassen, and W. van den Reek. 2018. "White paper Flexibility Value Chain 2018." USEF Foundation . Accessed 09 13, 2021. https://www.usef.energy/app/uploads/2018/11/USEF-White-paper-Flexibility-Value-Chain-2018-version-1.0_Oct18.pdf.

Villar, J., R. Bessa, and M. Matos. 2018. "Flexibility products and markets: Literature review." *Electric Power Systems Research* 154: 329–340. Accessed 09 12, 2021. https://doi.org/10.1016/j.epsr.2017.09.005.

Xu, Z., and S. Po. 2019. "The electricity market design for decentralized flexibility sources." Oxford Institute for Energy Studies. Accessed 09 12, 2021. https://doi.org/10.26889/9781784671433.

IEEE Access
Multidisciplinary | Rapid Review | Open Access Journal

Received 23 September 2023, accepted 30 September 2023, date of publication 5 October 2023, date of current version 19 October 2023.

Digital Object Identifier 10.1109/ACCESS.2023.3322365

APPLIED RESEARCH

Value of Flexibility Alternatives for Real Distribution Networks in the Context of the Energy Transition

FERNANDO-DAVID MARTÍN-UTRILLA[1,2], JOSÉ PABLO CHAVES-ÁVILA[3], AND RAFAEL COSSENT[3]
[1]i-DE Redes Eléctricas Inteligentes, 46130 Valencia, Spain
[2]Comillas Pontifical University, 28015 Madrid, Spain
[3]Institute for Research in Technology (IIT), Comillas Pontifical University, 28015 Madrid, Spain

Corresponding author: Fernando-David Martín-Utrilla (fmartin@iberdrola.es)

ABSTRACT The distribution grid faces several challenges related to the decarbonisation of the economy, which require incorporating flexibility services alongside traditional grid reinforcement solutions to enable an efficient grid development. Flexibility services, as well as the needs that require them, are very diverse. Therefore, general estimations about the value of flexibility applicable to any given scenario are unfeasible or imprecise. This paper reviews the literature on the quantification of the value of flexibility and proposes a broad-spectrum methodology aligned with the actual challenges of the energy transition for the planning of distribution network as it includes a comprehensive analysis of the real costs and the type of needs. Based on it, four representative and realistic case studies compare the BAU (business as usual) solutions with flexibility services analysing the technical and economic perspectives. Results show that flexibility value depends on the case studies considered and that, under certain circumstances, BAU solutions can be more competitive than alternatives with flexibility services. Network reinforcements in the distribution network have a long lifespan and provide a reliable service to thousands of customers. However, flexibility services can be particularly useful for accelerating decarbonisation with flexible connections or short-term solutions to manage the distribution network operation.

INDEX TERMS Congestion management, flexibility evaluation, flexible connection, power distribution planning, systems operation.

I. INTRODUCTION

The energy transition brings a new paradigm in which dimensioning new grid components should not follow the same conventional approach anymore, i.e. infrastructure is no longer dimensioned solely for peak demand. Distribution System Operators (DSOs) will also need to study the effects of distributed generation (DG), new loads and storage and their reliability, which means dealing with more uncertainty. The unquestionable necessity in the investment of new infrastructures requires a prior review process in which network users with diverse profiles, including consumers, generators, storage units or a mix of them can have incentives to adjust to the grid conditions, becoming an alternative to traditional network reinforcements. Peak demand with low local generation or peak local generation with low demand are scenarios that can be actively managed by the DSO.

Digitalisation technologies enable active management of networks and data exchanges between DSOs and their grid users, or among system operators. However, the vision of an uninterruptible electricity supply as an essential service is still in force. The strategy of managing the power profile from network users, both demand and generation, according to the network conditions needs to be carefully reviewed. Some electricity usages are not flexible enough, and the flexibility services will not meet their goals if the incentives are insufficient to move away from the BAU (business as usual) solution.

The associate editor coordinating the review of this manuscript and approving it for publication was Qiang Li.

The use of flexibility in distribution networks has been addressed extensively in the literature as shown in [1], [2], and [3]. Flexibility has also been tested in different pilots from different purposes with convincing results. Projects such as CoordiNet [4], EUniversal [5] or OneNet [6] demonstrate that services based on the active management of grid-connected resources can provide efficient and beneficial services and products for the operation of the distribution network and enable efficient use of the distribution network focusing on TSO-DSO coordination, platform development, service design or market testing.

In this paper, a literature review is conducted on assessing flexibility in comparison to traditional solutions from different points of view: methodology, costs considered, and the drivers taken into account. A practical methodology to evaluate the value of flexibility is proposed, including a complete cost calculation aligned with the real needs in managing distribution networks. This paper also selects a set of representative case studies by making a prior analysis of the drivers that determine the present and future network planning and draws some conclusions on the real usefulness of implementing flexibility services in different cases. Conventional solutions and flexibility alternatives are analysed, and an economic study of the possible solutions is carried out. Finally, considering the risks of dealing with more unpredictable parameters even close to real-time in a more dynamic way of operating the grid, a sensitivity analysis is necessary to calculate a range of cost-effective conditions for using flexibility.

This paper continues as follows. Section II presents the literature review to guide the methodological approach. Section III describes the methodology used to evaluate flexibility solutions. Section IV describes four case studies where flexibility solutions can be alternatives to BAU network investment, compares the results of the case studies and discusses the relevant parameters where flexibility can be alternative for BAU investments. Finally, Section V draws the main conclusions.

II. LITERATURE REVIEW ON FLEXIBILITY EVALUATION

As a preliminary step, a literature review on three related topics has been carried. Firstly, the type of methodologies applied in the literature are analysed. Secondly, this section studies what inputs have been considered to assess the value of flexibility; and, thirdly, an analysis of what use cases have been evaluated is made. Given that the objective is to obtain an accurate estimation of the value of flexibility, all three aspects are decisive. Those references with a focus on the assessment of flexibility for networks were considered. Other references focused on the power system balance such as [7], [8] or [9] were not taken into consideration.

A. METHODOLOGIES

Traditional network planning studies consider the worst-case scenario and apply deterministic methods. With flexibility services, a greater number of scenarios must be considered, which require probabilistic or stochastic approaches. This vision can be applied to the modelling of uncertainties in the performance of flexibility solutions, traditional solutions and even in the calculation of grid requirements. As a result, methodologies can vary greatly and can be applied to different stages of the planning process.

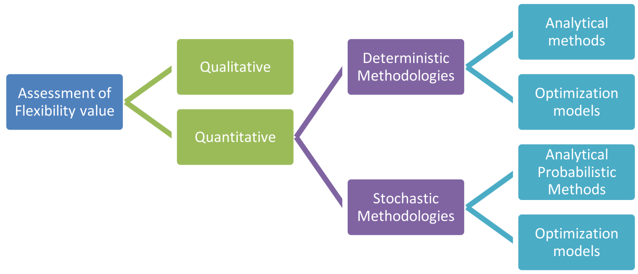


FIGURE 1. Methodologies classification obtained from the literature review Source: Own elaboration.

Methodologies for flexibility evaluation can be categorised as shown in Fig. 1. Some references adopt a descriptive approach with no quantitative calculations. Such is the case of [10], which provides some recommendations on market design and economic requirements for flexibility provision by electric vehicles (EV), or [11] that describes the evaluation mechanisms at the local level. Likewise, [12] proposes a synthesis of the costs and benefits, and [13] evaluates four projects from a qualitative perspective.

Turning to the publications that perform some form of quantitative evaluation, the first group of papers follow deterministic approaches, e.g. [14] performs a thorough cost-benefit analysis of implementing network flexibility for several case studies. Some references use optimisation methods such as in [15] in which the technical potential of flexibility alternatives are evaluated, as a theoretical upper limit for reference costs. Reference [16] applies the sector-coupling model GRIMSEL-FLEX (quadratic dispatch with perfect foresight), to optimize both the flexibility solution and the reinforcement solution simultaneously.

On the other hand, another family of papers implemented analytical stochastic methodologies to model uncertainty. For example, authors in [17] consider probabilities of different demand scenarios in the formulation, obtaining a distribution of flexibility values. Reference [18] evaluated a case study for the United Kingdom using a decision tree with variations in costs and probabilities of flexibility needs. Reference [19] applies an optimization model to a photovoltaic integration case study, minimizing the costs of flexibility. In [20] a real option valuation is performed based on scenario trees and Monte Carlo simulations to optimize grid investments.

Lastly, some publications combine stochastic methods with optimization models. Some of them use meta-heuristics, such as [21] where a genetic algorithm is used to solve a bi-level risk-based optimisation using a stochastic model to consider the uncertainty, or [22] which applies a particle swarm optimization algorithm to optimise flexible resources.

TABLE 1. Literature review and compliance with requirements.

Ref.	Electric mobility	Demand response	Distributed Generation	Mix of drivers	Not specified
[10]	x				
[12]		x			
[13]		x			
[15]		x			
[14]					x
[17]		x			
[18]					x
[19]			x		
[16]				x	
[21]			x		
[22]		x			
[20]					x
[23]					x
[24]		x			
[11]					x

Optimization-based papers present diverse objective functions, ranging from the minimization of the cost of the solution with reinforcement [21], minimization of flexibility costs [19], determination of optimal flexibility requirements [16],or a combination of the former [22].

Likewise, there is a range of optimization methods, which may be equally valid depending on the strategy or data available. Therefore, the methodology framework proposed must fit any type of model to solve and any type of need. Reference [23] proposes a planning framework that integrates different types of algorithms, addressing the entire planning process, including data collection.

This paper proposes an analytical methodology in several stages, under a simplified framework focused on carefully selecting the variables to be considered to make a more accurate assessment. This methodology could be improved, and different optimization methods could be integrated in the treatment of these variables, but before fine-tuning the result, it is necessary to approach the flexibility assessment in an adequate way without neglecting necessary and decisive variables without which it would be meaningless to impose complex optimization methods.

B. DRIVERS CONSIDERED

Network flexibility needs are different depending on their driver, i.e. integrating renewables, electric mobility, demand response, the electrification of other energy uses or a mix of them. As shown in Table 1, the reviewed references tend to target a single specific driver, being demand response the most commonly studied. Many references do not specify a driver, but rather a generic flexibility need without taking into account the specificities of each of them. Only [16] conducts a comprehensive study considering several possible drivers with the purpose of comparing flexibility options, albeit not considering the different grid needs generated.

To make a more accurate assessment of the flexible option, it is necessary to consider the driver that motivates it, both for network planning and operation. Not only because of the new flexibility there may be in reference to that driver, but also because of the network issues that may be created.

The drivers for determining short-term and long-term needs and new grid investments have historically been based on predictions of standard consumption profiles. The drivers of steady demand growth, city planning, or new connection requests will remain relevant. Nonetheless, as shown in [25], decarbonisation efforts bring about new drivers that can be broadly classified into new economic activities, electric mobility, electrification of heating and cooling, resiliency-driven investments, and other new uses of electricity (e.g. industrial processes). Table 2 analyses the old and the new drivers for network development and relates them to their effects and challenges for grid development.

Reference [26] presents a similar comparison as it identifies indicators used to evaluate the planning of the distribution network, sorting them into reliability indicators, economic indicators, coordination between actors and renewable generation connections, all of which are considered in this study. In addition to these indicators, a short list of future challenges is proposed.

C. COSTS AND BENEFITS CONSIDERED

The efficiency of flexibility in comparison to BAU solutions depends on several factors related to the grid, its users, and the flexibility providers. As summarized in Table 3, previous works have considered the following: flexibility costs (calculated or estimated), required investment and expenses to enable flexibility: capital expenditure (CAPEX) and operating expenditure (OPEX) breakdown, the frequency/duration of activations -which is a significant factor in the cost of flexibility, the cost of conventional solutions, and the realistic case study considered.

As shown in Table 3, most of the references propose a quantification for the value of flexibility, while some others do a descriptive analysis, such as [10], [13], [15], and [20]. Only two references [17] and [21] analyze the costs in greater detail by breaking down the Capex and Opex costs. Some others calculate flexible solutions without considering the duration of activation, such as [12], [14], [20] and [24]. Other references considered a very simple calculation of the conventional cost, such as [16], [18], [19], [22], and [23].

In summary, after the literature review, a gap is found to make a detailed analysis of the flexibility costs in order to make an accurate comparison. The flexibility value will depend on costs parameters faced by Flexibility Service Providers (FSPs), system operators and market operator, as well as the costs of the conventional solution, that need to be considered. The methodology must be based on trying to cover the entire possible spectrum of needs, so it must be simple and broad, with the possibility of fine-tuning and optimizing any part of the process.

III. METHODOLOGY: COST DESCRIPTION AND EVALUATION OF FLEXIBILITY SERVICES

The broad-spectrum methodology proposed starts from the type of need, regardless of the driver that motivates it. And then it makes an exhaustive analysis of the costs derived from

TABLE 2. Drivers for grid investments. Source: own elaboration.

	Drivers		Effects	Challenges
Traditional Drivers	Ordinary demand growth [30]		Increased energy flows in the grid.	Maintaining electricity supply and reliability levels
	Extraordinary demand growth		New energy flows in the grid. Urban planning.	Integrate new energy withdrawals safely
	Maintain grid reliability [36], [37]		Increasing complexity in ensuring the system reliability	Usually associated with regulatory incentives and a commitment to maintaining technical parameters within established limits
	Environmental concerns. Losses reduction. Cost reduction, other regulatory investments [38]		Different constraints and incentives for grid investments.	Regulatory compliance whilst containing cost levels.
New Drivers	Massive connection of DG [40], [41], [42], [43]		Energy flows in both directions that can generate new challenges for the grid.	Integrate sustainable generation. New planning tools are required.
	Electrification of energy uses	New economic activities (e.g., electrification of industries, hydrogen production)	Unpredicted new energy demands as a consequence of the shift away from fossil fuels and motivated by policies outside the electricity sector	Identify unpredicted demands to do a specific plan for the new energy profile
		Electric mobility [28], [45]	Increase of energy consumption with the possibly high-power requirement but with the flexibility to charge at different times	Incentivise smart charging strategies.
		Electrification of heating and cooling .[48],[49], [50]	Increase of energy consumption with a certain flexibility	Make use of flexibility potential
	Resiliency [53], [54]		Frequent extreme weather events resulting from climate change	Maintaining continuity of the service and reliability at the required levels

TABLE 3. Literature review on valuing DSO flexibility.

Ref.	Flex value quantification	Breakdown in CAPEX and OPEX	Duration of activations	BAU solution considered	BAU cost calculation	Realistic case study
[10]				x		
[12]	x			x		
[13]						
[15]				x		x
[14]	x			x		x
[17]	x	x	x	x	x	x
[18]	x		x	x		x
[19]	x		x			x
[16]	x					
[21]	x	x		x	x	x
[22]	x		x	x		x
[20]						
[23]	x		x			x
[24]	x					

the necessary flexibility solution, since the type of solution will depend on the type of need, as concluded in [27]. Assessing the cost competitiveness of flexibility is not a simple task since, as mentioned in [28], casuistry is very diverse and highly country specific. Following this methodology, the competitiveness of flexibility versus BAU is quantified and evaluated. Afterwards, by selecting use cases related to some relevant drivers in the energy transition, it is possible to make a comparative analysis of various needs and various flexibility solutions following the same methodology.

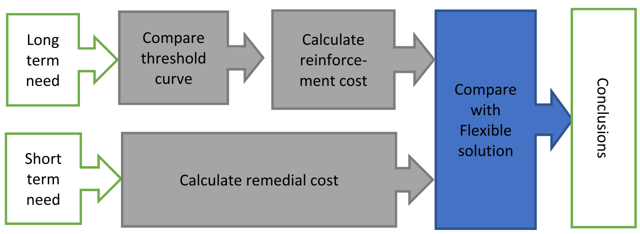


FIGURE 2. Methodology for comparing BAU and flexibility solutions. Source: own elaboration.

A. COSTS COMPARISON DEPENDING ON THE NEEDS

The needs of the network can be divided into long-term needs and short-term needs as indicated in [27]. For long-term needs, network reinforcements are compared with flexibility services, considering the risk of not reinforcing addressed in section B. However, for short-term needs, the comparison is not made with the reinforcement cost, but with the cost of the corresponding remedial action. Fig. 2 shows this methodology. The different steps could include optimization functions, whether for the calculation of the best reinforcement solution, the calculation of the best flexibility solution, or the calculation of the network requirements by means of an optimal power flow (OPF). Indeed, all the costs considered can be studied and optimized. However, there is a preference for separating the methodology from the optimisation methods that may exist in any part of the process, as can be seen in [11] or [18].

B. RISKS OF NOT REINFORCING AND NOT CONTRACTING FLEXIBILITY

As studied in [28], reinforcing the network or contracting flexibility are not the only options. A third alternative would be to accept the risks of not contracting flexibility, nor reinforcing the grid.

This risk is difficult to model because it involves making a trade-off between the reliability of the network and the risk that the DSO wants to or can assume. It therefore depends on its strategic decisions. However, it is assumed that small punctual overloads in the distribution network are acceptable and do not affect the useful life of the assets [29].

The longer the duration of the overload or the larger the overload, even of short duration, the more unacceptable the risk becomes. This risk can be modelled with a time-load curve similar to the time-current one used by protective devices [30].

In [29] a relationship between Load and Duration is established based on equal risk criterion. Different curves are defined depending on whether it is planned or emergency loading. These threshold curves (TC) depend on the strategy and according to its shape, it is proposed to be assimilated as a logarithmic curve as presented in (1) or in (2):.

$$\boldsymbol{h} = \boldsymbol{\beta} + \mathbf{log}_{\boldsymbol{\theta}}\,(\boldsymbol{\alpha} - \mathbf{P})\,;\,(\theta > 1) \tag{1}$$

$$\mathbf{P} = \boldsymbol{\alpha} + \boldsymbol{\theta}^{\wedge}(\boldsymbol{\beta} - \boldsymbol{h}) \tag{2}$$

where:

- $\boldsymbol{\alpha}, \boldsymbol{\beta}, \boldsymbol{\theta}$ are constants that determine the shape of the curve and that depend on the strategy. $\boldsymbol{\alpha}, \boldsymbol{\beta}$ allocate the curve in reference to the axis, which is useful to adjust the strategical situation as in Fig. 3 (emergency or long term), and $\boldsymbol{\theta}$ will define the slope and has to be more than one and positive, which will depend on the type of asset and the number of overloading hours that can support. A smaller $\boldsymbol{\theta}$ will determine a steeper curve and therefore a greater sensitivity to overloading. For example, an underground line would present a lower $\boldsymbol{\theta}$ than an overhead line.
- $\boldsymbol{P}$ is power in MW.

In the long term, this curve is not calculated for the purpose of obtaining the cost, but to have a threshold from which no action beyond the monitoring of the asset would be necessary. The scenarios presented in the previous figure on planned loading or emergency loading are measures that have to be configured depending on the risk to be taken by the DSO. Therefore, for the long term in this section no cost is considered. The DSO strategy considers a limit of hours below which neither flexibility services nor network reinforcement are necessary. When the load gets closer to this value, the network requires a planning action in line with the evolution of the need.

As can be seen in Fig. 3 different curves can be proposed depending on the risk that the DSO wants to assume. When alpha is high, the DSO assumes the risk of long-lasting high overloads, which is an operational decision that depends

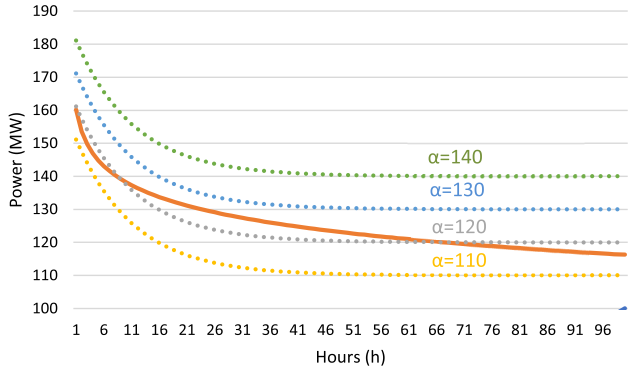


FIGURE 3. Threshold Curves TCs in dotted lines for no actions depending on the strategy (changing α which determines the admissible load for loads lasting many hours). In continuous line an expected UDC. In more emergency situations, greater limit curves will be considered and in more ordinary situations, lesser limit curves will be considered. Source: own elaboration.

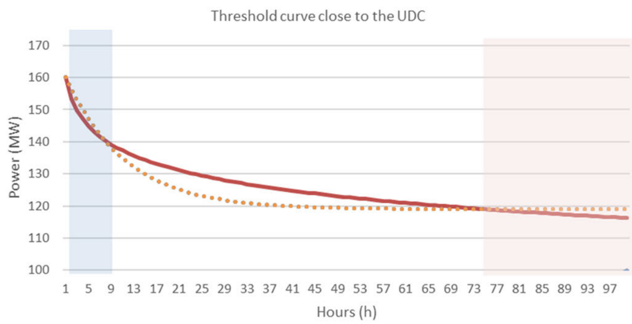


FIGURE 4. UDC close to the TC (dotted): There are different zones where no actions are considered: when being a few hours of overload or when being low overload. Source: own elaboration.

on the different risks to be assumed in different scenarios, configuring emergency scenarios or planning scenarios as proposed in [29]. Depending on the position of the threshold curve (TC), as long as it is above the Use Duration Curve (UDC), analogue as the Load Duration Curve (LDC), a certain value can be chosen. Thus, this curve may be completely above the UDC (when there is not enough saturation), or completely below the UDC (when a flexible solution or reinforcement is very necessary).

In some cases of mixed situations are possible as shown in Fig. 4 that, depending on the number of hours of need, long-term solutions are considered.

In the case that UDC and CT intersect more times, the most relevant intersection is the one that always has the TC curve above the UDC on the right. This point determines the number of hours that need to be considered as critical.

In short-term operational needs scenarios, the risk of temporarily overloading certain elements may be more bearable, especially because short-term needs can hardly be covered by network reinforcements. However, the remedial actions that can compete with flexibility solutions are different for each type of network. For example, for the work of replacing a transformer in a secondary substation due to failure or maintenance, a mobile generator can be installed so that customers do not suffer the interruption. The cost of installing a larger or smaller generator would compete with the flexibility offer. For this reason, there may occasionally be a cost to transcend this threshold in the short term.

C. FLEXIBILITY COSTS DESCRIPTION

The calculation of the cost of a specific flexibility service follows the equation (3). This description is more complete than the one carried out in [22], which only considers flexibility activation costs. Following the same equation, the values vary depending on the service.

$$Cost_{n,s}^{flex} = O_{n,s}^{\text{DSO Op } flex} + O_{n,s}^{\text{DSO Pl } flex} + C_{n,s}^{\text{Enab } flex} + Cost_{n,s}^{\text{Mkt } flex} + Cost_{n,s}^{\text{Agg } flex} \quad (3)$$

where:

- $Cost_{n,s}^{flex}$ is the annual cost (year n) of using a flexibility service s, including CAPEX and OPEX.
- $O_{n,s}^{\text{DSO Op } flex}$ is the OPEX Operation cost (year n) for the DSO in year n of using a flexibility service.
- $O_{n,s}^{\text{DSO Pl } flex}$ is the OPEX Planning cost (year n) for the DSO in year n of using a flexibility service.
- $C_{n,s}^{Enab\ flex}$ is the CAPEX Enabling cost (year n) for the DSO in year n of using a flexibility service.
- $Cost_{n,s}^{\text{Mkt } flex}$ is the Market cost (year n) of using a flexibility service.
- $Cost_{n,s}^{FSP\ flex}$ is the payment (year n) to the FSP for proving a flexibility service. Also including CAPEX and OPEX as there is an investment to be made by the flexibility provider.

A description of each term of the equation follows below.

1) DSO: OPEX AND CAPEX

Operating costs are separated from the planning costs (i.e. the costs of long-term requirements).

a: OPERATION OPEX COSTS

Based on the study conducted in [28], which considers Opex and Capex costs for every option; but also on other studies such as [31], with the same approach but comparing coordination schemes; [17], considering all relevant factors the annual costs of flexibility; and [22], with the methodology approach. The calculation follows the equation (4).

$$O_{n,s}^{\text{DSO Op } flex} = \text{h} \times O_{n,s}^{\text{DSO Op } Activ} + \text{fsp} \times O_{n,s}^{\text{DSO Op } FSP} \quad (4)$$

where:

- **h** are the hours of activation
- $O_{n,s}^{DSO\ Op\ Activ}$ is the cost for activation duration for the DSO
- **fsp** is the number of resources which provide the service
- $O_{n,s}^{\text{DSO Op } FSP}$ is the cost per FSP for the DSO.

These costs will be mainly linked to the costs associated with the prequalification process, the studies of short-term alternatives and monitoring. This cost will mainly depend on the hours of activations and the number of resources enabled.

The number of activations in hours may be calculated depending on the DSO's needs at any given time as shown in [23] or in [32]. For this purpose, for long-term congestion needs is useful to obtain a function of the UDC of the congested element. For other types of needs, for reactive power or voltages for example, the same method would apply. This data is necessary input for network planning, an optimized curve is assumed for each hour of network operation. To treat these curves it is necessary to filter out possible outliers due to extraordinary situations in the network.

The UDC is used for the calculation of network requirements. By observing that the format of the curve for different real cases is similar, a logarithmic formulation is adjusted to the following formula.

$$\mathbf{P} = -\mathbf{A} \times \mathbf{lnh} + \mathbf{B} \quad (5)$$

where:

- **P** is the power limit
- ***h*** is the hours of activation
- **A** and **B** are constants that depend on the load forecast

According to it, equation (4) can be re-written as:

$$h = \text{e}\hat{}((B-P)/A);\ O_n^{\text{DSO Op } flex} = \text{e}\hat{}((B-P)/A) \times O_n^{\text{DSO Op } Activ} + \text{fsp} \times O_n^{\text{DSO Op } FSP} \quad (6)$$

b: PLANNING OPEX COSTS

As for the planning process, the equation is as follows:

$$O_n^{\text{DSOPl } flex} = \mathbf{R} \times O_n^{\text{DSO Pl } FSP} \equiv k \times \text{fsp} \times O_n^{\text{DSO Pl } FSP} \quad (7)$$

where:

- **R** is the number of requests for connecting new resources that are referred to the service. This number is closely related to **fsp** and can be considered proportional to the service.
- $O_n^{\text{DSO Pl } FSP}$ is the cost per FSP.

Planning costs are linked mainly to the costs associated with cost-benefit studies of long-term alternatives and the definition of the need for investing in the network. Therefore, these costs depend on the number of requests and not so much on the activation.

c: ENABLING OPERATION AND PLANNING. CAPEX COSTS

Enabling costs refer to those necessary for the software and hardware required to start using flexibility. These are the most significant costs since enabling the solution requires putting in place tools for managing flexibility, monitoring, and managing data that are not necessary with traditional solutions. On the other hand, there is an initial cost to start the process and an annual cost to maintain it. The initial cost also includes monitoring and data management, training, and communication.

In terms of annual costs, maintenance and improvement costs of these tools are considered:

$$C_{n,s}^{Sunk\ flex} = C_{n,s}^{Plat\ flex} + C_{n,s}^{Mon\ flex} + C_{n,s}^{Dat\ flex} \quad (8)$$

where:

- $C_{n,s}^{\text{Plat}\,flex}$ is the annual cost of maintaining and improving the platforms. In this case, the operation and planning platforms for the calculation of the needs are included.
- $C_{n,s}^{\text{Mon}\,flex}$ is the annual cost of the monitoring infrastructure, including real-time data and set points.
- $C_{n,s}^{\text{Dat}\,flex}$ is the annual cost of the data management infrastructure, including sharing and acquisition platforms and data processing.

2) MARKET: OPEX AND CAPEX

As for the market costs, the equation is as presented in (9):

$$Cost_{n,s}^{\text{Mkt}\,flex} = \sum O_i^{\text{Clm}} + C_n^{\text{CAPEX Mkt Sys}} \tag{9}$$

where:

- O_i^{Clm} is the OPEX cost for all services of the long-term and short-term market clearing, validation market data, receive information from the prequalified units, receive flexibility Long-Term and Short-Term needs from DSO, Open the market and inform flexibility needs and Receive flexibility offers.
- $C_{n,s}^{\text{CAPEX MKT Sys}}$ is the CAPEX annualized cost of the calculation of baselines, interfaces to SO platforms, best procurement strategy deployment (auction / market) and communication with the rest of market platforms (balancing, congestion…)

$C_{n,s}^{\text{CAPEX MKT Sys}}$ is expected to be significantly higher than O_i^{Clm}, since it represents the entire investment in the market. The value $O_i^{\text{Clm}}$is also proportional to the number **fsp**, as it defines the maximum number of bids.

$$O_i^{\text{Clm}} \equiv \textbf{fsp} \times O_{i,s}^{\text{Clm}} \tag{10}$$

where:

- $O_{i,s}^{\text{Clm}}$ is the OPEX cost for a specific service **s** of the long-term or short-term market clearing, validation market data, receive information from the prequalified units, receive flexibility long-term and short-term needs from DSO, Open the market and inform flexibility needs and receive flexibility offers.

3) FLEXIBILITY SERVICE PROVIDER: OPEX AND CAPEX

As for the FSP costs, the costs are presented in (11).

$$Cost_{n,s}^{\text{Agg}\,flex} = \sum C_{i,s}^{\text{FSPm}} + \sum O_{j,s}^{\text{Actm}} + C_{n,s}^{\text{CAPEX Agg Sys}} \tag{11}$$

where:

- $C_{i,s}^{\text{FSPm}}$ is the OPEX cost of receiving scheduling data from generators, consumers, and flexibility Prediction
- $O_{j,s}^{\text{Actm}}$ is the OPEX cost of calculation of flexibility bids, long-term & short-term flexibility activation, procurement of flexibility, real time flexibility activation and real-time monitoring.
- $C_{n,s}^{\text{CAPEX Agg Sys}}$ is the CAPEX annualized cost of the operation platforms, data management, flexibility prediction tools, data acquisition from DERs, communications and interface to market platforms

As in previous cases, is proportional to the number of FSPs and is proportional to the number of activations in hours as presented in (12):

$$C_{i,s}^{\text{FSPm}} \equiv \textbf{fsp} \times Agg_{i,s}^{FSPm} \tag{12}$$

where:

- $Agg_{i,s}^{\text{FSPm}}$ is the OPEX cost to receive scheduling data from generators, consumers, and flexibility prediction for a specific service **s**

And

$$O_s^{\text{Actm}} \equiv \textbf{h} \times O_{j,s}^{\text{Actm}} \tag{13}$$

where:

- $O_{j,s}^{\text{Actm}}$ is the OPEX cost of calculation of flexibility bids, long-term & short-term flexibility activation, procurement of flexibility, real time flexibility activation and real-time monitoring for a specific service.

4) FLEXIBILITY COST FORMULA

Taking into account all the values and proportionalities deduced in the previous subsections, (14) can be deduced:

$$Cost_{n,s}^{flex} = \sum \textbf{h} \times Cost_{i,s}^{\text{Act}} + \sum \textbf{fsp} \times Cost_{i,s}^{\text{fsp}} + Cost^{Enab} \tag{14}$$

And for the long-term the equation is as in (15):

$$Cost_n^{flex} = \sum \text{e}\hat{}((B-P)/A) \times Cost_{i,s}^{\text{Act}} + \sum \textbf{fsp} \times Cost_{i,s}^{\text{fsp}} + Cost^{Enab} \tag{15}$$

where:

- $Cost_{i,s}^{\text{Act}}$ is the total cost that is proportional to the hours of activation.
- $Cost_{i,s}^{\text{fsp}}$ is the total cost that is proportional to the number of **FSP**.
- $Cost^{Enab}$ is the total cost that do not depend on the hours of activations or FSP participants in the service and remains constant for a year.
- **P** is the power limit
- **A** and **B** are constants that depend on the load forecast.
- **fsp** is the number of resources that are referred to the service

Since it will not be possible to manage the enabling costs at the time of the comparison, the flexibility costs is considered once the service has been enabled, and will therefore correspond to the following formula in (16):

$$Cost_{n,s}^{flex} = \sum \textbf{h} \times Cost_i^{\text{Act}} + \sum \textbf{fsp} \times Cost_{i,s}^{\text{fsp}} \tag{16}$$

And for the long-term is as in (17)

$$Cost_{n,s}^{flex} = \sum \text{e}\hat{}((B-P)/A) \times Cost_{i,s}^{\text{Act}} + \sum \textbf{fsp} \times Cost_{i,s}^{\text{fsp}} \tag{17}$$

5) LIST OF NOTATIONS

As a summary for a better understanding of the costs considered in this section, Table 4 shows the notations used in it.

IV. CASE STUDIES FOR EVALUATION OF FLEXIBILITY SOLUTIONS

As mentioned in section B, the selection of representative cases is triggered by new flexibility drivers. Fig. 5 summarizes the realistic case studies selected and their main characteristics.

All four case studies are based in network situations with realistic parameters from Spanish grids and compatible with the values in the Joint Research Center (JRC) DSO Observatory publications [33], [34], and [35].

Regarding large-scale DG connection, two scenarios are chosen for the two renewable technologies that have proliferated the most: photovoltaic generation and wind generation. These are the two most relevant technologies in the case of Spain, where the National Energy and Climate Plan (NECP) [36] foresees 62 GW will come from wind energy and 76 GW from solar photovoltaic. Both technologies already represent a high installed capacity in 2022 (27.5GW of wind and 13.6GW of photovoltaic, PV).

Photovoltaic capacity has increased almost 3 times in Spain in four years [37], and wind generation connected to the distribution grid has become the first source of electricity in the country [38].

In the case of electromobility, the number of vehicles has increased fourfold in the last four years [39] and the NECP also foresees a boost for electric vehicles [36]. This rate is higher than the electrification of other processes or heating and cooling. The resilience case completes the list of case studies considering a short-term need in the network caused by a temporary asset unavailability. This situation is not new, although it may be more frequent in the case of extreme weather conditions depending on the fragility of the grid [40].

All the case studies presented are framed in the Spanish context, considering the Spanish distribution networks, which according to the network characteristics described in [34] could be broadly representative for most of the European Union, which also have ambitious targets in their NECP [41].

For calculating reinforcement costs, the unit costs set in [42] by the Spanish regulator is considered. This is a public cost reference used by the regulator. The solution considered is based on a real network.

To perform the evaluation, the cost of investments related to BAU solutions are obtained from the information of different technologies that the Spanish regulator published in 2015 [43]. Since many costs are CAPEX, in order to annualise these costs, a WACC (Weighted Average Cost of Capital) of 5% has been considered to levelize the investment over the useful life, which is considered of 40 years following [43]. Regarding remedial BAU costs, an average Value of Lost Load (VoLL) of 7.9€/kWh is also considered [44] that provides a baseline for Spain. Similar values are found in [45],

TABLE 4. Notations related to costs description.

Notation	Units	Variable description
$Cost_{n,s}^{flex}$	Monetary unit (€)	Annual cost (year n) of using a flexibility service s, including CAPEX and OPEX
$O_{n,s}^{\text{DSO Op}\,flex}$	Monetary unit (€)	OPEX Operation cost (year n) for the DSO in year n of using a flexibility service s
h	Hours (h)	Hours of activation of the flexibility service
$O_{n,s}^{\text{DSO Op}\,Activ}$	Monetary unit (€)	Cost for activation duration for the DSO
fsp	Number	Number of resources which provide the service
$O_{n,s}^{\text{DSO Op}\,FSP}$	Monetary unit (€)	Cost per FSP for the DSO
$O_{n,s}^{\text{DSO Pl}\,flex}$	Monetary unit (€)	OPEX Planning cost (year n) for the DSO in year n of using a flexibility service.
$C_{n,s}^{\text{Enab}\,flex}$	Monetary unit (€)	CAPEX Enabling cost (year n) for the DSO in year n of using a flexibility service
R	Number	Number of requests for connecting new resources that are referred to the service
$O_{n}^{\text{DSO Pl}\,FSP}$	Monetary unit (€)	Cost per FSP
$C_{n,s}^{Sunk\,flex}$	Monetary unit (€)	Annual cost of enabling the flexible solution
$C_{n,s}^{Plat\,flex}$	Monetary unit (€)	Annual cost of maintaining and improving the platforms
$C_{n,s}^{Mon\,flex}$	Monetary unit (€)	Annual cost of the monitoring infrastructure, including real-time data and set points.
$C_{n,s}^{Dat\,flex}$	Monetary unit (€)	Annual cost of the data management infrastructure, including sharing and acquisition platforms and data processing.
$Cost_{n,s}^{\text{Mkt}\,flex}$	Monetary unit (€)	Flexibility market platform operating costs
O_{i}^{Clm}	Monetary unit (€)	OPEX cost for all services of the long-term and short-term market clearing, validation market data, receive information from the prequalified units, receive flexibility long-term and short-term needs from DSO, open the market, inform flexibility needs and receive flexibility offers.
$C_{n}^{\text{CAPEX Mkt Sys}}$	Monetary unit (€)	CAPEX annualized cost of the calculation of baselines, interfaces to SO platforms, best procurement strategy deployment (auction / market) and communication with the rest of market platforms (balancing, TSO congestion management)
$Cost_{n,s}^{\text{Agg}\,flex}$	Monetary unit (€)	Flexibility Service Provider and Aggregator costs
$C_{i,s}^{\text{FSPm}}$	Monetary unit (€)	OPEX cost of receiving scheduling data from generators, consumers, and flexibility Prediction
$O_{j,s}^{\text{Actm}}$	Monetary unit (€)	OPEX cost of calculation of flexibility bids, long-term & short-term flexibility activation, procurement of flexibility , real time flexibility activation and real-time monitoring.
$C_{n,s}^{\text{CAPEX Agg Sys}}$	Monetary unit (€)	CAPEX annualized cost of the operation platforms, data management, flexibility prediction tools, data acquisition
$Agg_{i,s}^{FSPm}$	Monetary unit (€)	OPEX cost to receive scheduling data from generators, consumers, and flexibility prediction for a specific service s

[46], and [47]. In all cases, there is a relevant component of CAPEX considered as sunk cost which relates to investment

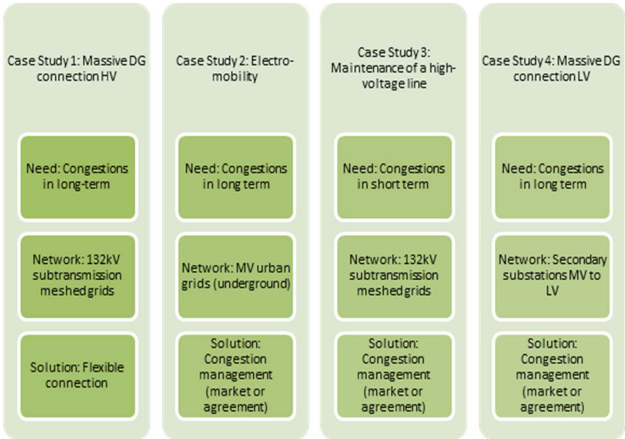


FIGURE 5. Summary of realistic case studies selected based on a Spanish distribution grid.

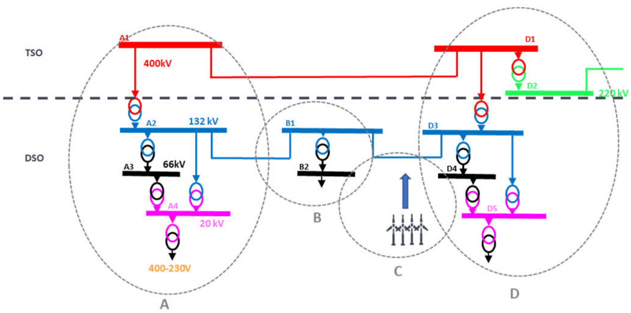


FIGURE 6. Single-line diagram of a new flexible connection. Red and green colors represent TSO voltage levels, and blue and black are related to sub-transmission voltage levels (operated by the DSO in this case). Source: i-DE (Spanish DSO).

in operating platforms, data exchange links between platforms and tools for flexibility management, planning and operation with flexibility, baseline calculation, market clearing, among others.

On the other hand, the cost of the traditional solution is also constant and independent of the hours of activations and the number of FSP for a given year. This cost is also calculated considering different scenarios that are not always comparable with a single flexible solution, so it is convenient to consider a fixed value of the traditional solution.

A. CASE STUDY 1: MASSIVE DG CONNECTION IN HV. NEW FLEXIBLE CONNECTION TO SUB-TRANSMISSION GRID OF RENEWABLE GENERATION

As discussed above, allowing the connection of more generation capacity that the grid can evacuate at any time without reinforcement requires Active Network Management (ANM). A flexible connection as a connection agreement described in [48] requires a service from the DSO, which would go to ''no-fit, don't forget'' and would require monitoring and control of the limits by the DSO.

Some ongoing pilots are considering ANM with different approaches such as in [49] or [50] in the United Kingdom. Limitation control and active management are carried out automatically and require some investment to automate the execution of the algorithms. Note that the limitation control can also be done manually in those cases where the investment of automating the solution is not more efficient than the manual solution itself.

1) GRID DESCRIPTION AND IDENTIFICATION OF THE NETWORK NEED

The case of manual management is considered as an example. Due to the high penetration of generators in an area (grid between city A and city D in Fig. 6) there is a risk of overloading a 132kV sub-transmission line, which is occasionally open to avoid energy transfers that may occur when the 400kV line between A and D is open.[1]

In this case, where the transmission line runs parallel to the distribution line without any branches, the operation of TSO and DSO requires special coordination. Any manoeuvres in the network should not cause congestion at any level. That is why a request for the connection of a new 50MW generator at point C in Fig. 6 would require to build a grid reinforcement in the 132kV network. The reinforcement required is costly, and the execution time is long, amounting to several years. This situation exceeds the thermal limit set for that system by 7.5MW. Therefore, there is a possibility to allow this wind farm to connect before building the reinforcement while the thermal limit is monitored and not violated by the impact of the wind farm by doing active management of the generation.

2) BUSINESS AS USUAL SOLUTION

The TC provided by the DSO is:

$$\boldsymbol{h} = \boldsymbol{\beta} + \log_{\boldsymbol{\theta}} (\boldsymbol{\alpha} - \mathbf{P}) = -\log_{1,23} (\mathbf{P} - \mathbf{120}) \tag{18}$$

Which is below the power needed as can be seen in Fig. 8, so either reinforcement or a flexible solution is needed.

To maintain the reliability levels of the network and to connect directly to substations in B and D and not jeopardize the current line running between them, the BAU solution would be (see Fig. 7):

- Construction of a 132kV to 20kV substation for power evacuation (this reinforcement is necessary to connect to the grid)

- Construction of two 132kV lines from B to C and from C to D with a total distance of several tens of kilometers.

- Modification of substations B and D to connect the new lines.

a: BAU SOLUTION COST

The costs for a new connection with the BAU approach would be 6,333,000€, obtained as follows:

- Construction of two 132kV lines:

30km x 183,547€/km (code TI-1UX in [42]) = 5,506,410€

[1]In Fig. 6, if A1-D1 line is open, energy from A1 to D1 may go through A2, B1 and D3.

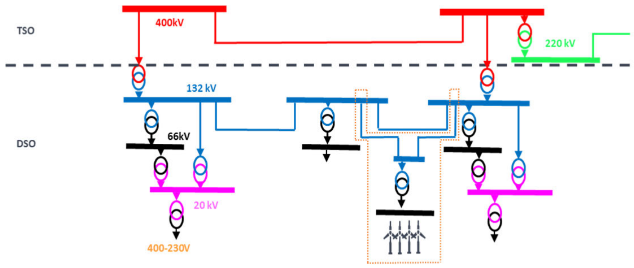


FIGURE 7. Single-line diagram for new connection including reinforcements. Source: i-DE (Spanish DSO).

- Modification of substations B and D to connect the new lines.

2 Bays 132kVx 413,270€/bay (code TI-91U in [42]) = 826,540€

The lifetime of this investment is considered to be 40 years [43] and annualising the cost considering a WACC of 5% gives an annualised cost of 369,075.59€.

3) ALTERNATIVE SOLUTION WITH A FLEXIBILITY SERVICE

According to the framework in [27], the case of the flexible connection is based on a bilateral agreement. This agreement establishes the periods in which power curtailment is necessary to ensure compliance with grid requirements. These periods must be agreed based on a long-term forecast, as it is intended to be compared with a reinforcement of the grid.

Fig. 8 shows the number of hours per year that are needed for wind generation to be curtailed. In this case the UDC and TC intersect only once. By sorting the hours of one year from highest load to lowest load in descending order, the hours in which a solution is necessary are obtained. These hours are the ones exceeding the maximum of the 132kV line capacity considering the generation and load curve in the energy flow in that line. This analysis results 68 hours of curtailments of 7.5MW during working days. The resulted curtailment would be based on the actual needs and for all hours when congestions are forecasted.

a: FLEXIBILITY SOLUTION COST

The annual cost of the flexibility service is assessed on the basis of the methodology explained above. CAPEX costs are mainly sunk costs in terms of DSO and market. Annual operating costs per fsp are considered as Prequalification (2.5h), Registration (2.5h), Planning costs as Cost Benefit Analysis (10h) and Definition of scenarios (10h). Annual operating costs per activation hour are: Monitoring (1h per activation h), Billing (1h per activation h) and Needs Calculation (1h per activation h). All costs are based on person-hours. An automated solution would only be incorporated if it is more efficient than a non-automated solution. The value of hours has been based on [51], considering the salary of an industrial engineer newly recruited plus corresponding employment charges in Spain [52].

In this case, a market is not necessary. Finally, in terms of Aggregation and FSP costs, operational expenses for

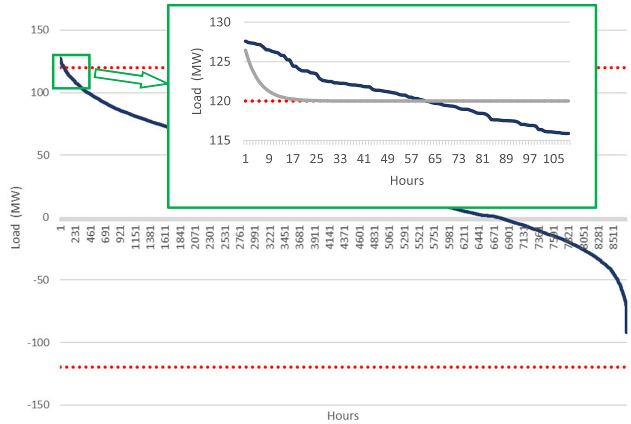


FIGURE 8. Load Duration Curve in blue of a 132kV line for one year. Calculation of the hours to be curtailed. The TC can be seen in grey in the zoom. Source: I-DE (Spanish DSO).

monitoring and energy costs and some investments in communications and data acquisition are considered (200€from the values used in CoordiNet [4]).). Despite the volatility to which the electricity market may be subject, a reference has been sought and a price of the energy of 40€/MWh has been considered as in [53].

With all this:

$$\begin{aligned} \boldsymbol{Cost_1^{Act}} &= (1+1+1+2)\,h \times \frac{40000€}{1760h} \\ &\quad + 40€/MWh \times 7.5MW = 413.63€ \\ \boldsymbol{Cost_1^{fsp}} &= (2.5+2.5+10+10)\,h \times \frac{40000€}{1760h} \\ &\quad + 200€ = 768.18€ \end{aligned}$$

From the UDC curve, the constants A and B are calculated:

$$\begin{aligned} \boldsymbol{Cost_n^{flex}} &= \boldsymbol{e}^{\frac{\mathbf{160.17-P}}{\mathbf{9.534}}} \times \boldsymbol{Cost_1^{Act}} + \boldsymbol{Cost_1^{fsp}} \\ &= \boldsymbol{e}^{\frac{\mathbf{160.17-P}}{\mathbf{9.534}}} \times 413.63 + 768.18 = \mathbf{28,722.56€} \end{aligned}$$

4) COMPARISON AND SENSITIVITY ANALYSIS

The main benefit of this action is actually accelerating the renewables integration and the transition to a more sustainable generation mix. The economic impact in terms of emissions reduction or other benefits could be addressed, but it is out of the scope of this analysis which focuses on the distribution system costs. Therefore, in this case the investments costs include connection costs, even if this cost is borne by the developer.

a: COMPARISON

Table 5 summarizes the assessment of the case 1.

The solution with flexibility is clearly cheaper, only a significant lower reinforcement cost could reverse this situation. Another benefit associated with this solution is the anticipation of the connection in the period when the reinforcement is being executed. In this case, it is necessary to consider the life span of the generation facility itself, the grid extension to connect such a facility and the corresponding reinforcement. The value in producing earlier in time could be significant.

TABLE 5. Costs assessment for new flexible connections.

Business As Usual: Reinforcement			Alternative with a flexibility service	
Investment cost	Years	Annual cost	Hours of activation	Annual Cost
6,333,000€	40	369,075.59€	68	28,722.56€

For instance, for a 1500h/year production of 50MW, even with curtailment, at an average price of 30€/MWh it would mean 2.25M€ per year.

b: SENSITIVITY ANALYSIS

If the required curtailment activation is larger, it could reach the reinforcement value. These conditions a priori should not change as the grid circumstances do not change. But the solution with flexibility is almost proportionally linked to the cost of energy, valued at 40€/MWh. With market prices in 2022, which are often several times higher, the flexible solution could be unfeasible. Market volatility would therefore call into question short-term market solutions for long-term needs. For this particular use case, if the energy price rises up to 712€/MW, the break-even point is found.

On the other hand, the BAU solution is also influenced by network needs and the distances of new lines. In this case, halving the number of line kilometers would also lower the cost of the BAU solution almost proportionally.

B. CASE STUDY 2: ELECTRO MOBILITY. CONGESTION ON MV NETWORK AS A RESULT OF ELECTRIC VEHICLE CHARGING

1) GRID DESCRIPTION AND IDENTIFICATION OF NEEDS

In this case, potential grid congestion is considered in the case of incorporating electric vehicle charging points. The grid to be considered is shown in Fig. 9. It represents a consolidated urban area.

Fig. 9 shows a 20 kV feeder that departs from a primary substation and travels through seventeen secondary substations over a distance of 10 km (compatible with a median 0.73km per MV supply point in [33]) until it reaches a switching centre where it is normally operated open on arrival. Several 20kV feeders with similar characteristics arrive at the switching centre.

Each secondary substations feeds several residential buildings, offices, shops, and commercial buildings. With an average of 200 customers per secondary substation (compatible with 0.95 percentile of 209 consumers per MV/LV substation in [33]), 90% are domestic. According to [54] and [55], and especially to [56] for typical load profiles, the usual peak load in Spain for this type of consumer would occur between 18:00 and 20:00 when both businesses and homes consume energy. If electric vehicles demand can be shifted, it is expected that the peak demand for charging occurs at that time.

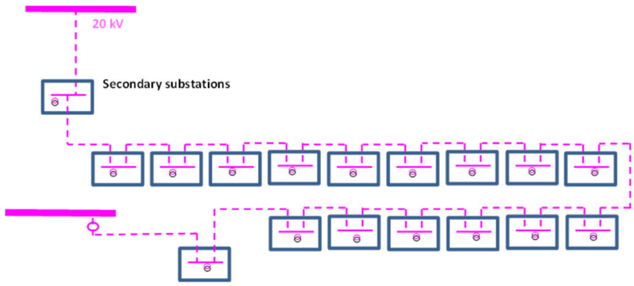


FIGURE 9. One-line diagram of simplified MV i-DE network representation. Source: i-DE (Spanish DSO).

The maximum load of the feeder in the year is 6MW. The capacity of the feeder is 12MW (240mm2), as the operation of the feeder is not at its nominal capacity due to the probability of failure. The load is only increased to support other feeders that may need it due to contingencies. In this case, an additional load of 4MW is expected.

The assumptions made in this case are related to the increasing demand for electric vehicles charging.

2) BUSINESS AS USUAL SOLUTION

No TC was provided in this case as the power needed largely exceeds the capacity limits. Assuming that half of the residential consumers have an electric vehicle charger and demand an average of 3.5 kW, (that would be a single-phase charging at 16A at LV, typical of a domestic slow charging point and compatible with contracted peak power 5.9 kVA per LV consumer in [33])for charging at peak times, consumption would double. Therefore, it would be necessary to reinforce the grid to alleviate this increase in load.

The reinforcement needs, highlighted in red in Fig. 10 are: - Increase in transformer power at substation C (in Fig. 10). This increase is expected to be the same in the rest of the adjacent areas. Therefore, increasing transformer power to 20kV at one substation would alleviate the problem at several neighbouring substations. For that reason, to make a proportional distribution of the costs, a 10% of the cost of a complete transformer substation is estimated. - New feeder with a distance of 10km, which may not be the shortest route considering urban constraints. - Reinforcement of the secondary substation to connect the new feeder.

a: BAU SOLUTION COST

The costs for the reinforcement would be 1,656,700€, obtained following three steps described below.

1. Increase in transformer power at the substation (10% of the cost):

0.1 × 16,610€(code TI-163V in [42]) = 1,661€1Bay 20kV x 77,657€/bay (code TI-105V in [42]) = 77,657€

2. New feeder with a distance of 10km.

10km x 155,456€/km (code TI-18UY in [42]) = 1,554,560€

3. Reinforcement of the secondary substation to connect the new feeder.

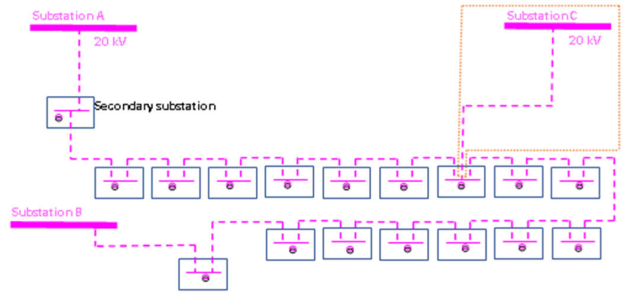


FIGURE 10. **Single-line diagram of simplified MV i-DE network representation including reinforcement (area in red). Source: i-DE (Spanish DSO).**

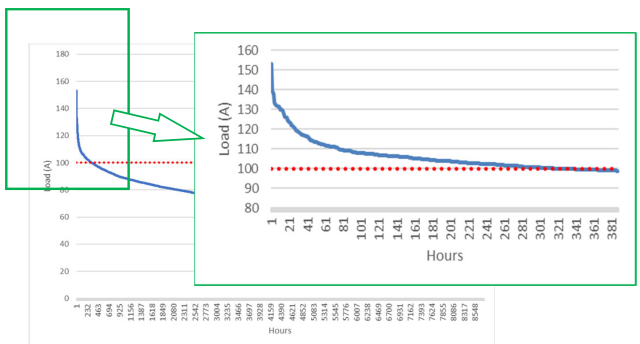


FIGURE 11. **Load Duration Curve of a MV line for one year. Calculation of the hours to be curtailed in the MV line during a year. Some extreme data refer to anomalous network situations. Source: i-DE (Spanish DSO).**

1 switching station x 22,818€/station (code TI-0CW in [42]) = 22,818€The lifetime of this investment is considered to be 40 years [43] and annualising the cost considering a WACC of 5% gives an annual cost of 96,549.43€.

3) ALTERNATIVE SOLUTION WITH A FLEXIBILITY SERVICE

The case of electric mobility would be eligible for different mechanisms according to [27] depending on the liquidity and the possibility of having dynamic tariffs as it is a generalised situation across the area. The recurrent cost of managing a special tariff for charging electric vehicles would not be high, as smart meters easily incorporate time discrimination. The market-based option, when there is greater liquidity, should provide more optimised value due to competition. Therefore, the illiquid version with bilateral agreements can be taken as a benchmark as an upper limit.

Considering the days when the MV network is most loaded and the possible increase in consumption generated by the charging points, to avoid overloading, it would be necessary to incentivise the shift of the consumption for 300 hours (mostly working days) of more than 3,000 recharging points. This calculation was obtained from the load duration curve of the medium voltage line (Fig. 11). Following the same method as in the previous case, ordering the hours of the year from highest load to lowest load in descending order, the 300 hours in which a solution is necessary are obtained, which are those which in the load duration curve are above the limit. These limitations fit the peak load hours of the typical consumption profile in Spain shown in Fig. 12.

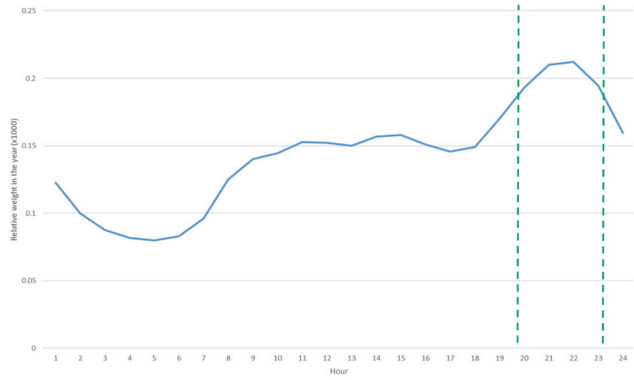


FIGURE 12. **Typical load profile in Spain fitting residential consumption (peak consumption in the evening). Source: REE (Spanish TSO).**

a: FLEXIBILITY SOLUTION COST

Under the same assumptions as in the previous case study, the operating costs related to activation hours considered are: an operational cost of activation (0,15€ per charging point and activation in terms of aggregation and FSP costs); and the operating costs related to the number of fsp are: Registration (0,25h per charging point), planning costs considered as Cost Benefit Analysis (10h) and Definition of scenarios (10h). All costs are based on person-hours. And operational expenses for managing schedules (1€ per charger and year); and some investments in communications (100€) and data acquisition (10€ per charger and year) are considered. All these values are based on the experience of the pilots conducted by i-DE (Spanish DSO) CoordiNet [4] and OneNet [6].

The obtained costs are:

$$\boldsymbol{Cost_2^{Act}} = \mathbf{3000} \times \mathbf{0.05} = 150€$$

$$\begin{aligned}\boldsymbol{Cost_2^{fsp}} &= 3000 \times \left(0.25h \times \frac{40000€}{1760h} + 1e + 10€\right) + 100€ \\ &= 50,\,145€\end{aligned}$$

From the UDC curve, the constants A and B are calculated:

$$\begin{aligned}\boldsymbol{Cost'^{flex}_n} &= \boldsymbol{e}\hat{}((\mathbf{160.17} - \boldsymbol{P})/(\mathbf{9.534})) \times \boldsymbol{Cost_1^{Act}} + \boldsymbol{Cost_1^{fsp}} \\ &= \boldsymbol{e}^{\frac{\mathbf{160.17}-\boldsymbol{P}}{\mathbf{9.534}}} \times \mathbf{150}\boldsymbol{C}\ 50145 = \mathbf{96,\,595}€\end{aligned}$$

4) COMPARISON AND SENSITIVITY ANALYSIS

The variation of the level of congestion over the years and compare it with the lifetime of the asset provide a more robust results in this case. However, the annualised value of the investment and the scenario with 3000 charging points are used to simplify the calculation.

a: COMPARISON

The assessment of the case is shown in Table 6.

In this case, both solutions' costs are tight. The largest driver of the aggregation cost is the activation cost transferred to the end-customer as an incentive. However, the price

TABLE 6. Costs assessment for Congestions in MV network due to electric vehicle charging.

Business As Usual: Reinforcement			Alternative with a flexibility service from EV charging	
Investment cost	Years	Annual cost	Hours of activation	Annual Cost
1,656,700€	40	96,549.43€	310	96,595€

received by each of the users of the 3000 charging points amounts to 15€ per year, which is not a very attractive figure for the effort required by the customer for a whole year. If the time of activation also increases, it makes the flexible solution costlier.

b: SENSITIVITY ANALYSIS

In this case, the cost of the BAU solution is influenced by the distances of the new lines. Again, half the number of line kilometres would lower the BAU cost almost proportionally.

The case study is almost at the break-even point itself. In addition to the factors that influence the cost of reinforcement, such as the distance to existing assets, the unit cost of reinforcements or the capacity of the current network, other parameters influence these needs. For example, the hours of activations or resources involved in congestion management. However, the cost per activation, even if doubled or tripled, would still be of little incentive value to the end user. Not even with significant economies of scale bringing the cost down would make the flexible option competitive enough to provide value to the end consumers. In the case studied, eliminating the aggregator's operating costs, the maximum price to be delivered to the customer would be 0.26€, which appears to be insufficient.

C. CASE STUDY 3: RELIABILITY. MAINTENANCE OF A HIGH-VOLTAGE LINE USING DG FLEXIBILITY

1) GRID DESCRIPTION AND IDENTIFICATION OF THE NETWORK NEED

As discussed above, the maintenance of a HV line is a traditional driver, but the case could be also representative of resiliency considerations. Besides, this case study shows that flexibility may also support in case of conventional needs/drivers. Fig. 13. shows the diagram explaining the case study. That is a request for work on a 132kV double circuit for three hours. According to [57], the average duration of programmed outages would be around one hour, but it includes many shorter MV works. A 132kV work has more demanding security requirements that require more time, so the three hours requested for this case are considered representative.

Two 132kV lines running in a double circuit, sharing poles, must be interrupted for some time due to scheduled maintenance works. These two lines feed a transformer substation located in area E in Fig. 13, which in turn feeds several MV feeders and a 66kV line. The only alternative to maintain the service to the MV and LV customers affected by the maintenance works is through the supply from the 66kV line, which also feeds the 20kV bus, but the total power required is 60MW and the 66kV line does not support that load. Moreover, the line capacity cannot be dedicated exclusively to this need, as it feeds other substations. As shown Fig. 13, a generator is connected to one of 132kV lines and is capable of supplying 50MW, fully relieving the needs of area E.

2) BUSINESS AS USUAL SOLUTION

In this case, following the methodology in section B, the TC will not be considered. It is the cost of the remedial actions that must be assessed. As shown in Fig. 14, when the two 132kV lines to the E substation are interrupted, the entire 132kV grid in the area is de-energised. Under normal network operation, it is not possible for the DSO to maintain an island on the 132kV network and manage the balancing, even locally. It is therefore necessary to limit the power in area E to meet the capacity of the 66kV network resulting in 30MW demand to be curtailed.

Regarding the BAU solution for short-term needs. No reinforcement is considered. The TC could be adapted depending on the emergency. But in this case study, excess power is too much to bear even for a short time. Therefore, it is necessary to consider remedial actions costs.

The result, in this case, is the interruption of a large part of the 60MW consumption at substation E, which cannot be fed from the 66kV line. Note that, in this case, since the DSO is addressing an operational need, grid reinforcements are not considered (at least in the short-term). Hence, the costs associated are purely operating costs. Small generators connected in LV grids may be a solution for smaller power requirements to supply some specific loads, but the number of units required may be significant.

a: BAU SOLUTION COST

As mentioned above, the assumption is that works occur during the daytime.

- The total cost of the load shedding, in terms of VoLL is 711,000€: 3h x 30MW x 7,900€/MWh = 711,000€

3) ALTERNATIVE SOLUTION WITH A FLEXIBILITY SERVICE

Enabling the generator to maintain the network island operation at 132kV and managing the appropriate quality parameters including voltages within ranges, and the area may not face any supply interruption. The generator must be committed to maintain power for the duration of the work. Given that this is a Combined Heat and Power (CHP) unit expected to be generating during the maintenance work, there is no additional costs of providing such as service. On the contrary, it is an opportunity to generate which was not possible under BAU conditions.

The case of the maintenance works can only be managed with short-term mechanisms, which are related to markets when there is liquidity or to bilateral contracts when there is not enough liquidity in the market, following the framework presented in [27]. As for the costs of a maintenance operation

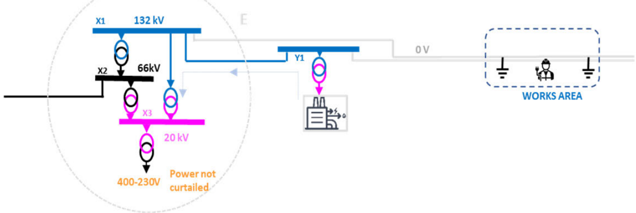


FIGURE 13. Single-line diagram of a grid for maintenance of a high-voltage line of i-DE network. Source: i-DE (Spanish DSO).

FIGURE 14. Single-line diagram during works in BAU situation. Source: i-DE (Spanish DSO).

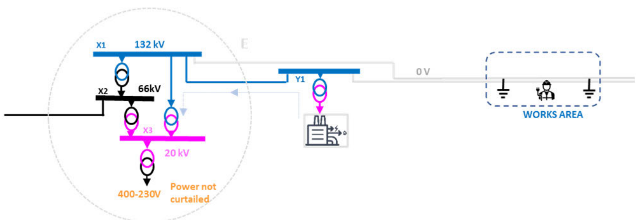


FIGURE 15. Single-line diagram during works with flexibility solution DSO acting as system operator. Source: i-DE (Spanish DSO).

as proposed, the recurrent cost of making a short-term market available would again depend on the liquidity of the market, leaving room for bilateral agreements in the absence of liquidity.

The cost of energy injection is assumed to be zero. If the network is missing, the production process does not stop as the thermal process keeps working and self-generating in island mode. As it is CHP unit, the thermal demand is assumed not flexible, therefore, the generation has to be available as far as the thermal process works. If thermal process were flexible, the CHP would request remuneration to keep supporting the grid and, therefore, the DSO would have to pay for the service availability to maintain grid reliability.

The presented need is occasional, and it is difficult to estimate future needs. However, given that the review periods of the installations are triennial [58], it is expected to have the same need at least once every three years.

a: FLEXIBILITY SOLUTION COST

In this case, activations do not depend on a UDC curve but on a specific need. To calculate the cost in this case the components considered are: Monitoring (hours of activation +0,5), Prequalification (2h/fsp), Cost Benefit Analysis (10h/fsp), Registration (2h/fsp), Billing (1,5h/fsp) and Needs Calculation (1h/fsp). It is not necessary to consider Planning costs as they are short-term needs nor market costs, as this need can only be solved by one FSP. With equation (14):

$$
\begin{aligned}
\boldsymbol{Cost_3^{flex}} &= \left(\boldsymbol{3h \times Cost_i^{Act}}\right) + \left(\boldsymbol{Cost_i^{fsp}}\right) \\
&= \left(3h \times \frac{40000€}{1760h}\right) \\
&\quad + \left((2+10+2+1.5+1)\,h \times \frac{40000€}{1760h}\right) = 443€
\end{aligned}
$$

TABLE 7. Costs assessment for maintenance works.

Business As Usual: outage			Alternative with a flexibility service	
Energy	VoLL	Intervention cost	Hours of activation	Annual Cost
90 MWh	7,900€/MWh	711,000€	3	443.18€

4) COMPARISON AND SENSITIVITY ANALYSIS

Numerous alternatives through the MV network can surely help in case of an outage, in addition to the power that the 66kV network involved can provide. In this case, the network is sufficiently interconnected so that it is considered that only half of the 60MW load is going to suffer an actual outage. The maintenance works could be expected to last 3 hours. This duration should have considered other efficient solutions such as shifting the work schedule to night-time to minimize the impact on end-users, but this is not always possible because of the labour legislation (e.g., European Directive [59]).

a: COMPARISON

Only the cost of the flexibility mechanism is considered. The assessment of the case is shown in Table 7.

In the short term the difference is obvious, but many sunk costs have been considered in this case. Uncertainty in short-term needs makes it difficult to generate costly investments at the local level. The sunk costs of operation, planning and market needs are for the system and not for the specific local situation. But the monitoring or resource management costs of the aggregator or FSP can only be considered as sunk costs if they are necessary for the regular operation of the network.

b: SENSITIVITY ANALYSIS

The difference costs above shows the amount the DSO could devote to the sunk costs. If the sunk cost figures do not break down individually, they should be calculated collectively considering that situations like this occur on the network on a daily basis.

On the other hand, there are also the sunk costs of the aggregator or FSP. If the interface with the market and the exchange of data is simple and cheap, and the operational costs of activation are not very significant, liquidity in these short-term markets would also improve.

Sunk costs aside, the cost of non-delivered energy or the value of lost load (VoLL) is always high. Therefore, considering the actual cost of the flexible option that requires only

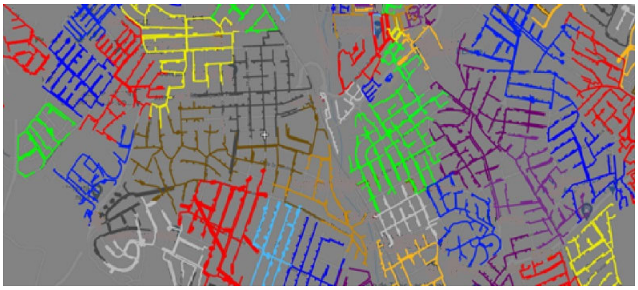


FIGURE 16. LV grid in the area of a single-family house. Each colour represents a different feeder. Source: i-DE (Spanish DSO).

a few DSO operator hours, there is no further analysis to be made. It seems the benefits from the flexibility service are enough to support this use case. Other variables such as the cost of energy are not significant. The big change is to enable the DSO to manage DG to avoid an outage.

D. CASE STUDY 4: MASSIVE DG CONNECTION LV. CONGESTION ON LV NETWORK AS A RESULT OF NEW ROOFTOP PV GENERATION

This case addresses the impact that the massive implementation of solar generation in the LV network of an area of single-family houses. Practically all of the consumption in the presented area is from single-family households with rooftop solar generation. The distribution network is dimensioned to evacuate the power that households have contracted, affected by a simultaneity factor which is not suitable for photovoltaic (PV) units. Therefore, the installation of PV generators could exceed the limits of the feeders or the substations and would require new reinforcements in the network. Generation is not expected to exceed the power of the individual evacuation line, which corresponds to the contracted power (i.e. purchased by the consumer) and is not affected by any simultaneity factor. The maximum consumption and maximum generation happen at different times of the day.

1) GRID DESCRIPTION AND IDENTIFICATION OF THE NETWORK NEED

In the considered network, selected choosing homogeneity in the load behavior and network design, there are 10 secondary substations in total with a very similar load profile, which have an average of 100 customers each. An aggregated load curve is used. The power of these substations is 400kVA and each of them has 6 LV feeders. Feeder length varies between 200m and 800m. It is assumed that each feeder admits a power of 200kW (150mm2 Al 400/220V) and that the average contracted power[2] is 5kW.

Half of the households have solar panels installed and are generating at full capacity at a time of low consumption, fitting typical load profiles D and F from [56]. Therefore, there would be a simultaneous generation of 500kW at the secondary substation and would exceed the nominal 400kVA, that according to the expected power factor of the PV units could be assimilated to an active power of 400kW. Any variation may be considered an admissible overload due to the small duration or amplitude. In this case, the LV feeders would not suffer capacity saturation with half of the households with PV units.

The assumptions in this case are related to the PV plants, but the grid considered is realistic.

[2]Contracted power: maximum power limitation to each customer according to contracting terms.

2) BUSINESS AS USUAL SOLUTION

As in previous cases, no TC was provided in this case, as the power needed largely exceeds the capacity limits. Nevertheless, as admitted by the distribution company of the area and supported by [29], short-lasting overloads are admitted, and it covers any variation produced by the assumed unity power factor hypothesis mentioned above. The reinforcement needs, in this case, would be as follows. Power upgrade in a transformer at all 10 secondary substations. No reinforcements would be necessary at higher voltage levels as the minimum demand curve is higher. Some secondary substations would not need upgrades and others would not be possible because they will be too large. Again, for the sake of simplicity, all upgrades are considered to be done evenly throughout the grid.

The same effect is expected in the rest of the adjacent areas, therefore reinforcements in the transformation capacity in the primary substation are needed in the same proportion. Given that a transformer in an urban area is designed to feed several different feeders, for the power calculated, 10% of the cost of a complete transformer is estimated. Even transformers are non-divisible, they are highly interconnected in urban networks, so it is assumed that 10% of the transformers need upgrading.

a: BAU SOLUTION COST

The Spanish catalogue [43] used does not include the option of upgrading the transformer. To arrive at a good approximation in the calculation, the cost of replacing a 630kVA transformer will be obtained by subtracting the cost of installing a (15kVA) substation, that is basically the room building, from the cost of installing a 630kVA substation, that is the room building and the transformer. This removes the costs of the substation, leaving the costs related to the power of the machine. The residual value of the decommissioned machine is not considered, but the decommissioning itself has a cost. Then, the power-related cost of installing a 630kVA transformer is then obtained.

- Power upgrade in the transformers at all 10 secondary substations: 141,090€, including:

- Cost of the secondary substation with 1 × 15kVA machine (code TI-22W in [42]): 23,947€.
- Cost of the secondary substation with 1 630kVA machine (code TI-39W in [42]): 38,056€.
- The estimated cost of installing the 630kVA machine in an existing structure: 14,109€.

The lifetime of this investment is 40 years [43] and annualising the cost with a WACC of 5% gives an annual cost of 8,222.47€.

3) ALTERNATIVE SOLUTION WITH A FLEXIBILITY SERVICE

Again, following the framework in [27], the case of LV congestions for solar generation is not very different from the case of MV in terms of the costs of the flexibility mechanism. The market liquidity or the generalisation factor for considering dynamic tariffs are also relevant here. The difference is that in this case the sum of consumption and generation must be considered for the demand forecast.

Solar generation reaches the maximum power during the central hours of the day, with an estimated 80% of the transformers' evacuation capacity being exceeded during the four central hours. This overload situation does not occur on non-working days because domestic consumption increases during these central hours. They would fit typical load profiles D and F from [56] corresponding to the Spanish case shown in Fig. 12. So, the need is to reduce power by 20% (100kW) for 4 hours per day on 200 days a year.

a: FLEXIBILITY SOLUTION COST

The annual operating costs considered are related to registration (0,25h per PV unit), cost benefit analysis (10h) and definition of scenarios (10h), also investments in communications (100€) and data acquisition (10€ per household and year) are considered. Regarding the activation costs, it will depend on the opportunity cost for the generation. A price of 0.0275€/kWh was considered for solar PV as in [53]. With all this:

$$\begin{aligned} Cost_4^{Act} &= \mathbf{0.0275€}/\text{kWh} \times 1000\text{kW} \times 200 \times 4\text{h} \\ &= 27.5€ \\ Cost_4^{fsp} &= \left((500 \times 0.25 + 20)\, h \times \frac{40000€}{1760h}\right) \\ &\quad + 500 \times 10 + 100 = 8,395.45€ \end{aligned}$$

From the UDC curve, the constants A and B are calculated:

$$\begin{aligned} Cost_4^{flex} &= e^{\frac{865.11-P}{9.737}} \times Cost_4^{Act} + Cost_4^{fsp} = e^{\frac{865.11-P}{9.737}} \\ &\quad \times 27.5 + 8395.45 = 30,445.07€ \end{aligned}$$

4) COMPARISON AND SENSITIVITY ANALYSIS

In this case, a residential area of 1,000 customers fed by 10 secondary substations is considered. The existence of a well-dimensioned network is also assumed. Obviously, the casuistry is enormous and although it cannot be extrapolated to all situations, the results provide an order of magnitude of the costs.

a: COMPARISON

The assessment of the case is shown in Table 8.

Similar to case 2, the flexible solution can be considered cheaper when the time of activation is small, and not for a sustained situation where activations have a daily occurrence.

TABLE 8. Costs assessment for congestions in LV.

Business As Usual: Reinforcement			Alternative with a flexibility service	
Investment cost	Years	Annual cost	Hours of activation	Annual Cost
141,090€	40	8,222.47€	800	30,445.07€

TABLE 9. Cost results for the different case studies.

Case study	Annual cost BAU	Annual cost with a flexibility service	Is there an evident benefit of the flexibility service?
1. New flexible connection	369,075.59€	28.722,56€	Yes
2. Congestion on MV network	96,549.43€	96,595€	No
3. Maintenance works	711,000€	443,18€	Yes
4. Congestion on LV network	8,222.47€	30,445.07€	No

This suggests that the solution would be useful for postponing investments rather than replacing them.

b: SENSITIVITY ANALYSIS

Here again, the activation costs are important. Smart meters could play a role in limiting these costs, as well as the inverter software applications of the PV panels themselves. The energy cost and the hours of activations are also relevant. In the BAU case, it is not so much the distances that matter but the grid design capacity itself. A multi-year plan is likely to be necessary to cater for the necessary upgrade for all these power increases and to coexist with flexible solutions as long as the time of activation is small.

The price of 0.0275€/kWh considered for solar PV generation in [53] could vary and affect the result. But even if it was reduced to a third, the overall conclusions would not change.

In the long-term, the alternative with a flexibility service does not seem economically viable. As the break-even point is reached with an energy price close to zero. So, it seems that it may be an option just to delay investment, as long as the time of activation is small.

E. DISCUSSION: COSTS COMPARISON: OF BAU VS FLEX SOLUTIONS

A summary of the costs of flexibility and business as usual solutions are shown in Table 9.

The results show that flexibility mechanisms can be particularly attractive solutions for new flexible connections (case 1) and to ensure grid security during planned maintenance works (case 3). Moreover, flexible solutions can

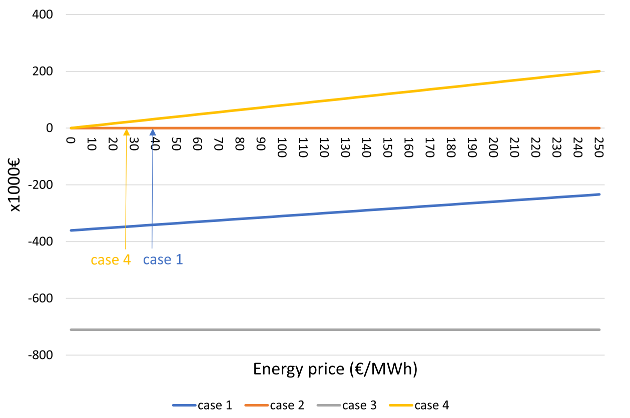


FIGURE 17. Net value (Flexibility - BAU) variation with the energy price. Source: own elaboration.

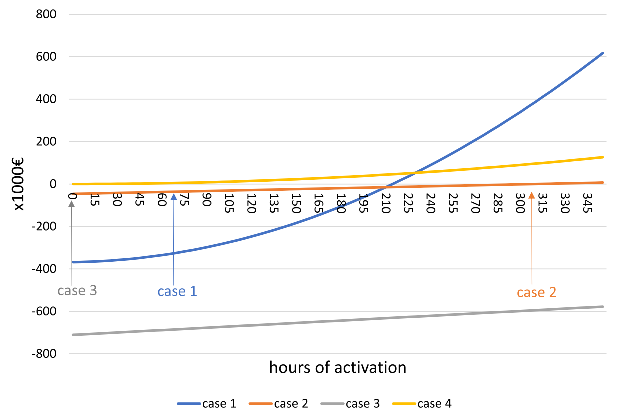


FIGURE 18. Net value (Flexibility - BAU) variation of the flexibility cost with the hours of activations. Source: own elaboration.

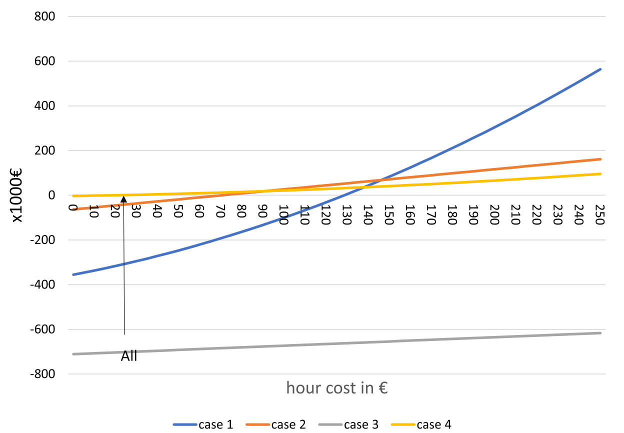


FIGURE 19. Net value (Flexibility - BAU) variation of the flexibility cost with the operational cost of the DSO. Source own elaboration.

be useful while the reinforcement is being built as it may temporarily be the only solution (cases 2 and 4). The competitiveness of the flexibility-based solution mainly in case 1 depend on the time of activation. This means that, in the case of few activations, there is a lot of margin compared to the traditional solution.

Fig. 17 shows the net value of flexibility (benefits minus costs) and its variation with respect to the energy price.

It follows that the break-even point of case 1 is reached with a high value, which makes it cost-effective, and that of case 4 with a value close to zero, which makes flexibility hardly viable in this case. This is consistent with the previous conclusions. Cases 2 and 3 being insensitive to the price of energy.

Regarding the variation with respect to the hours of activations, the conclusions are different. Fig. 18 represents this sensitivity. Case 1 turns out to be quite sensitive with respect to the hours of activations, finding a break-even point close to 210 hours. Which is also logical, because flexible connections are designed for cases in which the peak of need is reached in a few hours a year.

For the rest of the cases, a greater insensitivity is observed, although a number of hours greater than 80 hours also makes cases 2 and 4 unfeasible. Case 3 is uniform by increasing the number of hours, but it is a different case, since what is valued in this case is the duration of the scheduled outage and it is compared to interrupted supply. It is unreasonable to consider hundreds of hours in this case.

Finally, it is necessary to observe the variation with respect to the labour cost of the DSO in hours showed in Fig. 19. This will depend on the efficiency of the process and the digitalization and observability of the network, which will allow the process to be automated and less costly without losing reliability. In this case, the conclusions are similar to those of the variation with the hours of activations. While it is true that this cost is not likely to grow with the maturity of the solution, but to decrease. Therefore, if the operational labour cost decreases as expected cases 1, 2 and 3 will continue to be clearly viable. The viability for case 4 will depend on other variables such as the energy price.

It is also important to consider reinforcement costs (BAU cost) for new flexible connections as well as for congestion management. In the case of flexible connections the margin is very wide due to the low cost of activation. But in the case of congestion, the BAU solution must be very expensive to for the flexible solution to break-even. This variable will move up or down the curves in figures Fig.17, Fig. 18, and Fig. 19.

Throughout the study, the importance of taking into account all types of costs and not neglecting any that may be relevant to the viability of the solution is demonstrated.

There are also sunk costs that need to be considered when studying the whole solution, but not to assess a specific flexibility application within a limited network area. For an FSP, the uncertainty of how many times a service will be required is also a barrier to investment. The cost of this uncertainty is not handled in the presented studies. The necessary information exchange and the transparency of the agents involved can alleviate this uncertainty. The grid congestion maps published by DSOs in Europe are an example of this (e.g. [60], [61])

Based on the flexibility services considered, it can be concluded that flexibility services are highly case-dependent and do not always outperform the traditional alternatives.

Flexible connections (i.e., agreements that give the DSO the right to limit power injections or withdrawals during a specified time) are a paradigm shift for the DSO and accelerate the energy transition by allowing faster and cheaper connections. For example, for avoiding N-1 reinforcements that are sporadically used. Flexibility services and the possibility for the DSO to use DG to supply local demand in case of network failures or maintenance in cases where the grid has a weak connection with the rest of the grid are tremendously useful. Both solutions have an obvious benefit, as the alternative is to wait until reinforcements are made.

In the case of seeking to avoid grid reinforcement, the benefit is not so obvious, and it would be necessary to create a context in which the motivation of grid users and the reliability of service delivery compensate for the reliability and security benefits of grid reinforcement. For the case of congestion caused by PV generation, there is very little room to compensate for the operational costs of the flexible solution or the customer incentive. Only for zero energy prices scenario it could be a competitive solution. MV grid reinforcements can also be very competitive in urban environments and difficult to be replaced by flexibility services. Subsequently, further studies would be necessary to determine whether flexibility can compensate for the effect of the new drivers for grid reinforcements or whether BAU solutions still prevail as the most efficient solution.

V. CONCLUSION

This paper proposes a general method to evaluate the cost of flexibility for any type of need and that can be applied to any case study.

One of the main findings is that the value of flexibility depends on the type of need and associated characteristics such as the number of activations, the price of energy or the cost to the DSO. Therefore it is necessary to address a wide range of parameters before taken a decision.

The difficulties to obtain real data to estimate costs and the difficulties to obtain reliable data, not only for the access to the information but also for the immaturity of the process regarding to flexibility solutions for DSOs are the limitations of this research.

This paper performs a necessary comprehensive analysis of the real costs of flexible solutions to compare them with traditional solutions and avoid neglecting decisive parameters that may determine the effectiveness of the flexible solution against business-as-usual solutions not considered in previous papers. A descriptive methodology to evaluate flexibility costs is proposed to make an exhaustive description of the flexibility costs, both OPEX and CAPEX of each of the stakeholders involved, providing formulas that simplify their study and a method of comparison depending on the needs' type. Then, an analysis of four representative and realistic case studies in Spain, accurately selected starting from representative drivers, is conducted to compare business as usual solutions with flexibility alternatives. One case refers to a flexible connection of new distributed generation, the second considers congestion management in an urban MV feeder managing EV charge demand, the third case relates to programmed outages due to maintenance works, and the last one considers to congestion management in LV grids managing PV generation. Various network situations are selected, at different voltage levels; with diverse resources, with different types of generation and demand; and related to the new drivers, distributed generation, new flexible connections, and electric vehicle charging points. BAU solutions are proposed and compared with the corresponding flexible solution. Then, the value that flexibility can bring to the future challenges facing the distribution networks are assessed. Concluding that flexibility services are highly case-dependent and they do not always outperform the traditional alternatives.

Following the analysis carried out, certain parameters can vary greatly and induce a sensitivity analysis, such as the hours of activations of a flexibility solution, the implementation and operating costs for the DSO, the value of load lost or the remedial actions, the cost of reinforcements, or the cost of energy whose magnitudes determine the true value of flexibility. The values taken in this paper try to be realistic and reflect situations that are as real as possible considering the expected penetration of distributed energy resources.

Overall, it can be concluded that the paradigm shift of flexibility services may be especially useful from an operational perspective, as it allows more optimal extraction of the potential of the network in the short term. And it is also useful to accelerate the integration of distributed renewable generation by allowing flexible connections. For the long-term use of flexibility, it is necessary to thoroughly assess each need to establish whether flexibility services can compete with BAU solutions considering their reliability, duration and the number of customers involved. But given that the needs of the network are progressing over time, flexible tools are valid to postpone investments for a few years as long as the number of hours of activations required is limited.

A wider range of use cases studied considering all costs faced by the different flexibility providers with the same methodology would definitely help to take informed decisions. Alternative methods to assess flexibility potential could provide more accurate estimated costs when the quantity and quality of data provided is enough.

REFERENCES

[1] J. Villar, R. Bessa, and M. Matos, "Flexibility products and markets: Literature review," *Electr. Power Syst. Res.*, vol. 154, pp. 329–340, Jan. 2018.

[2] X. Jin, Q. Wu, and H. Jia, "Local flexibility markets: Literature review on concepts, models and clearing methods," *Appl. Energy*, vol. 261, Mar. 2020, Art. no. 114387.

[3] H. Kondziella and T. Bruckner, "Flexibility requirements of renewable energy based electricity systems—A review of research results and methodologies," *Renew. Sustain. Energy Rev.*, vol. 53, pp. 10–22, Jan. 2016.

[4] CoordiNet. (2019). *Project Web Site*. [Online]. Available: https://coordinet-project.eu/

[5] EUniversal. (2020). *Project Web Site*. Accessed: Feb. 2, 2022. [Online]. Available: https://euniversal.eu/

[6] OneNet. (2020). *Project Seb Site*. Accessed: Feb. 2, 2022. [Online]. Available: https://onenet-project.eu/

[7] J. Ma, V. Silva, R. Belhomme, D. S. Kirschen, and L. F. Ochoa, "Evaluating and planning flexibility in sustainable power systems," in *Proc. IEEE Power Energy Soc. Gen. Meeting*, Jul. 2013, pp. 1–11.

[8] A. Capasso, M. Falvo, R. Lamedica, S. Lauria, and S. Scalcino, "A new methodology for power systems flexibility evaluation," in *Proc. IEEE Russia Power Tech*, Jun. 2005, pp. 1–6.

[9] E. Lannoye, D. Flynn, and M. O'Malley, "Evaluation of power system flexibility," *IEEE Trans. Power Syst.*, vol. 27, no. 2, pp. 922–931, May 2012.

[10] K. Knezovic, M. Marinelli, P. Codani, and Y. Perez, "Distribution grid services and flexibility provision by electric vehicles: A review of options," in *Proc. 50th Int. Univ. Power Eng. Conf. (UPEC)*, Sep. 2015, pp. 1–6.

[11] E-CUBE Strategy Consultants, "Étude sur les mécanismes de valorisation des flexibilités pour la gestion et le dimensionnement des réseaux publics de distribution d'électricité," Étude mandatée par la Commission de régulation de l'énergie, Paris, France, Tech. Rep. 19102017, 2017.

[12] P. Bradley, M. Leach, and J. Torriti, "A review of the costs and benefits of demand response for electricity in the U.K.," *Energy Policy*, vol. 52, pp. 312–327, Jan. 2013.

[13] R. Fonteijn, M. Amstel, P. Nguyen, J. Morren, G. M. Bonnema, and H. Slootweg, "Evaluating flexibility values for congestion management in distribution networks within Dutch pilots," *J. Eng.*, vol. 2019, no. 18, pp. 5158–5162, Jul. 2019.

[14] E-CUBE Strategy Consultants, "Étude sur la valeur des flexibilités pour la gestion et le dimensionnement des réseaux de distribution," Étude mandatée par la Commission de régulation de l'énergie, Paris, France, Tech. Rep. 20012016, 2016.

[15] M. Vallés, J. Reneses, P. Frías, and C. Mateo, "Economic benefits of integrating active demand in distribution network planning: A Spanish case study," *Electr. Power Syst. Res.*, vol. 136, pp. 331–340, Jul. 2016.

[16] A. Rinaldi, S. Yilmaz, M. K. Patel, and D. Parra, "What adds more flexibility? An energy system analysis of storage, demand-side response, heating electrification, and distribution reinforcement," *Renew. Sustain. Energy Rev.*, vol. 167, Oct. 2022, Art. no. 112696.

[17] S. Klyapovskiy, S. You, A. Michiorri, G. Kariniotakis, and H. W. Bindner, "Incorporating flexibility options into distribution grid reinforcement planning: A techno-economic framework approach," *Appl. Energy*, vol. 254, Nov. 2019, Art. no. 113662.

[18] *Evaluating Flexibility as Alternative to Traditional Network Reinforcement*, Scottish Southern Electr. Netw., Frontier Econ., London, U.K., 2020.

[19] J. Holweger, C. Ballif, and N. Wyrsch, "Distributed flexibility as a cost-effective alternative to grid reinforcement," 2021, *arXiv:2109.07305*.

[20] J. A. Schachter and P. Mancarella, "A critical review of real options thinking for valuing investment flexibility in smart grids and low carbon energy systems," *Renew. Sustain. Energy Rev.*, vol. 56, pp. 261–271, Apr. 2016.

[21] M. Moradijoz, M. P. Moghaddam, and M. R. Haghifam, "A flexible active distribution system expansion planning model: A risk-based approach," *Energy*, vol. 145, pp. 442–457, Feb. 2018.

[22] B. Tavares and F. J. Soares, "An innovative approach for distribution network reinforcement planning: Using DER flexibility to minimize investment under uncertainty," *Electr. Power Syst. Res.*, vol. 183, Jun. 2020, Art. no. 106272.

[23] S. Klyapovskiy, S. You, H. Cai, and H. W. Bindner, "Incorporate flexibility in distribution grid planning through a framework solution," *Int. J. Electr. Power Energy Syst.*, vol. 111, pp. 66–78, Oct. 2019.

[24] P. Bradley, A. Coke, and M. Leach, "Financial incentive approaches for reducing peak electricity demand, experience from pilot trials with a U.K. Energy provider," *Energy Policy*, vol. 98, pp. 108–120, Nov. 2016.

[25] F. Pilo, S. Jupe, F. Silvestro, C. Abbey, A. Baitch, B. Bak-Jensen, C. Carter-Brown, G. Celli, K. E. Bakari, M. Fan, P. Georgilakis, T. Hearne, L. N. Ochoa, G. Petretto, and J. Taylor, "Paper planning and optimization methods for active distribution systems—An overview of CIGRE WG C6.19 activities," CIGRE Brochure, Lisbon, 2014.

[26] Z. Luo, Y. Liu, and C. Wang, "Review on coordination and planning of active distribution network," in *Proc. 5th Int. Conf. Power Renew. Energy (ICPRE)*, Sep. 2020, pp. 517–522.

[27] F.-D. Martín-Utrilla, J. P. Chaves-Ávila, and R. Cossent, "Decision framework for selecting flexibility mechanisms in distribution grids," *Econ. Energy Environ. Policy*, vol. 11, no. 2, pp. 1–22, 2022.

[28] A. González-Garrido, I. Gómez-Arriola, K. Kessels, J. Vanschoenwinkel, D. Davi, E. Faure, Y. Ruwaida, N. Etherden, and L. L. O. Valarezo, "CoordiNet deliverable D6.3—Economic assessment of proposed coordination schemes and products for system services," Aug. 2022. [Online]. Available: https://www.iit.comillas.edu/publicacion/informe-tecnico/es/289/Economic_assessment_of_proposed_coordination_schemes_and_products_for_system_services

[29] W. Fu, J. D. McCalley, and V. Vittal, "Risk assessment for transformer loading," *IEEE Trans. Power Syst.*, vol. 16, no. 3, pp. 346–353, Aug. 2001.

[30] C. R. S. Pierre and T. E. Wolny, "Standardization of benchmarks for protective device time-current curves," *IEEE Trans. Ind. Appl.*, vol. IA-22, no. 4, pp. 623–633, Jul. 1986.

[31] C. Madina, S. Riaño, I. Gómez, P. Kuusela, H. Aghaie, J. Jimeno, N. Ruiz, M. Rossi, and G. Migliavacca, "Paper no 1632 cost-benefit analysis of TSO-DSO coordination to operate flexibility markets," in *Proc. CIRED 25th Int. Conf. Electr. Distrib.*, Madrid, Spain, 2019.

[32] H. Seifi and M. Sepasian, *Electric Power System Planning: Issues, Algorithms and Solutions*. Tehran, Iran: Springer, 2011.

[33] G. Prettico, F. Gangale, A. Mengolini, A. Lucas, and G. Fulli, "Distribution system operators observatory: From European electricity distribution systems to representative distribution networks—EUR 27927 EN," Publications Office Eur. Union, Luxembourg, 2016.

[34] G. Prettico, M. G. Flammini, N. Andreadou, S. Vitiello, G. Fulli, and M. Masera, "Distribution system operators observatory 2018—Overview of the electricity distribution system in Europe—EUR 29615 EN," Publications Office Eur. Union, Luxembourg, 2019.

[35] G. Prettico, Marinopoulos, and S. Vitiello, "Distribution system operator observatory 2020: An in-depth look on distribution grids in Europe—EUR 30561 EN," Publications Office Eur. Union, Luxembourg, 2021.

[36] Ministerio para la transición energética y el reto demográfico. (Jan. 11, 2021). *Resolución de 30 de diciembre de 2020, de la Dirección General de Calidad y Evaluación Ambiental, por la que se formula la declaración ambiental estratégica del Plan Nacional Integrado de Energía y Clima 2021-2030*. Accessed: Nov. 6, 2022. [Online]. Available: https://www.boe.es/boe/dias/2021/01/11/pdfs/BOE-A-2021-421.pdf

[37] International Renewable Energy Agency (IRENA). (Apr. 2022). *Renewable Capacity Statistics 2022*. Accessed: Nov. 6, 2022. [Online]. Available: https://www.irena.org/publications/2022/Apr/Renewable-Capacity-Statistics-2022

[38] Red Eléctrica. (Dec. 16, 2021). *Wind Power Becomes the Main Source of Electricity Generation in Spain in 2021*. Accessed: Oct. 5, 2022. [Online]. Available: https://www.ree.es/en/press-office/news/press-release/2021/12/wind-power-becomes-main-source-electricity

[39] ANFAC—Asociación Española de Fabricantes de Automóviles y Camiones. (Jul. 12, 2022). *Reporte Anual*. Accessed: Nov. 7, 2022. [Online]. Available: https://anfac.com/categorias_publicaciones/informe-anual/

[40] M. Panteli and P. Mancarella, "Modeling and evaluating the resilience of critical electrical power infrastructure to extreme weather events," *IEEE Syst. J.*, vol. 11, no. 3, pp. 1733–1742, Sep. 2017.

[41] European Commission. *National Energy and Climate Plans*. Accessed: Nov. 7, 2022. [Online]. Available: https://ec.europa.eu/info/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en

[42] Boletín Oficial del Estado. (Dec. 11, 2015). *Orden IET/2660/2015, de 11 de Diciembre, por la que se Aprueban las Instalaciones tipo y los Valores Unitarios de Referencia de Inversión, de Operación y Mantenimiento por Elemento de Inmovilizado y los Valores Unitarios de Retribución*. Accessed: Oct. 10, 2022. [Online]. Available: https://www.boe.es/eli/es/o/2015/12/11/iet2660

[43] Comisión Nacional de Mercados y Competencia. (2015). *Informe Sobre la Propuesta de Orden por la que se Aprueban las Instalaciones Tipo y los Valores Unitarios de Referencia de Inversión de Operación y Mantenimiento por Elemento Inmovilizado y los Valores Unitarios de Retribución de Otras Tareas Reguladas*. [Online]. Available: https://www.cnmc.es/file/125571/download

[44] *Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe*, Cambridge Econ. Policy Associates Ltd, Agency Cooperation Energy Regulators ACER/OP/DIR/08/2013/LOT 2/RFS 10, Ljubljana, 2018.

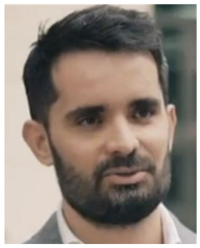
[45] D. Huo, M. V. Santos, D. M. Greenwood, N. S. Wade, and M. P. Resch, "Optimal battery sizing for a distribution network in Austria to maximise profits and reliability," in *Proc. CIRED Workshop*, Berlin, Germany, 2020, Paper 0042.

[46] J. E. C. Villa, "Probabilistic reliability assessment for system development in The Netherlands," M.S. thesis, Dept. Elect. Eng., Math. Comput. Sci. (EEMCS), TU Delft, Delft, The Netherlands, 2019.

[47] E. Leahy and R. S. J. Tol, "An estimate of the value of lost load for Ireland," *Energy Policy*, vol. 39, no. 3, pp. 1514–1520, Mar. 2011.

[48] *Paper on Alternative Connection Agreements Ref: C23-DS-83-06*, CEER Council Energy Eur. Regulators, CEER, Brussels, Belgium, 2023.
[49] G. Boyd, "SPEN—DSO vision," in *Proc. 24th Int. Conf. Electr. Distrib.*, Glasgow, Scotland, 2017, Paper 1044. [Online]. Available: http://cired.net/publications/cired2017/pdfs/CIRED2017_1044_final.pdf
[50] L. Kane and G. Ault, "The cost of active network management schemes at distribution level—PO.ID 310," EWEA Annu. Wind Energy Event, Vienna, 2013.
[51] L. T. Balibrea, "Analysis of employability of industrial engineers graduated from the Spanish University," in *Proc. 21st Int. Congr. Project Manag. Eng.*, Cádiz, Spain, 2017.
[52] *Instituto Nacional de la Seguridad Social*. Accessed: Sep. 6, 2022. [Online]. Available: https://www.seg-social.es/wps/portal/wss/internet/Empresarios
[53] T. Gerres, J. Chaves-Ávila, F. M. Martínez, M. R. Abbad, R. Cossent, Á. S. Miralles, and T. G. S. Román, "Rethinking the electricity market design: Remuneration mechanisms to reach high RES shares. Results from a Spanish case study," *Energy Policy*, vol. 129, pp. 1320–1330, Jun. 2019.
[54] M. S. Piscitelli, S. Brandi, and A. Capozzoli, "Recognition and classification of typical load profiles in buildings with non-intrusive learning approach," *Appl. Energy*, vol. 255, Dec. 2019, Art. no. 113727.
[55] D. Gerbec, S. Gasperic, and F. Gubina, "Determination and allocation of typical load profiles to the eligible consumers," in *Proc. IEEE Bologna Power Tech Conf.*, Jun. 2003, vol. 1, no. 1, p. 5.
[56] Z. Kmetty, "D4.1. Load profile classification, natural language energy for promoting consumer sustainable behaviour," 2016. Accessed: Sep. 15, 2023. [Online]. Available: https://ec.europa.eu/research/participants/documents/downloadPublic?documentIds=080166e5aba985df&appId=PPGMS
[57] Gobierno de España—Ministerio de Industria, Comercio y Turismo. *Sede Electrónica del Ministerio de Industria, Comercio y Turismo*. Accessed: Nov. 7, 2022. [Online]. Available: https://energia.serviciosmin.gob.es/Gecos/DatosPublicos/IndicesAgregados
[58] Boletín Oficial del Estado. (May 9, 2014). *Real Decreto 337/2014, de 9 de mayo, por el que se Aprueban el Reglamento Sobre Condiciones Técnicas y Garantías de Seguridad en Instalaciones Eléctricas de alta Tensión y sus Instrucciones Técnicas Complementarias ITC-RAT 01 a 23*. Accessed: Oct. 10, 2022. [Online]. Available: https://www.boe.es/eli/es/rd/2014/05/09/337/con
[59] *Directive 2003/88/EC Concerning Certain Aspects of the Organisation of Working Time*, Official Journal, EU Directive, Brussels, Belgium, pp. 0009–0019, Nov. 2003.
[60] N. Nederland. (2023). *Capaciteitskaart Invoeding Elektriciteitsnet*. Accessed: Jul. 27, 2023. [Online]. Available: https://capaciteitskaart.netbeheernederland.nl/
[61] i-DE. *Mapa de Capacidad de Conexión de Generación*. Accessed: Jul. 27, 2023. [Online]. Available: https://www.i-de.es/conexion-red-electrica/produccion-energia/mapa-capacidad-acceso

FERNANDO-DAVID MARTÍN-UTRILLA received the degree in law and the degree in business sciences from Universidad de Salamanca, the degree in marketing from Universidad Miguel Hernández, Elche, and the Master in Energy Business Management (M.B.A.) degree from Universidad Nebrija, Madrid. He is currently pursuing the Ph.D. degree in planning and regulation with the DSO Department. He is also with i-DE (Iberdrola), Valencia. He is also a Industrial Engineer with Universidad Politécnica Valencia. He joined Iberdrola, in 1999, and during 20 years, he has had different operational responsibilities in Salamanca, Alicante and Murcia in Spain, and Recife in Brazil. The last few years, he has been leading i-DE's DSO role in Spain being involved in strategic projects, such as CoordiNet, OneNet, and Flexener. He is coordinating the BeFlexible Project launched, in September 2022.



JOSÉ PABLO CHAVES-ÁVILA received the bachelor's degree in economics from the University of Costa Rica, Costa Rica, in 2008, the master's degree in electric power industry from the ICAI School of Engineering, Comillas Pontifical University, the Erasmus Mundus master's degree in economics and management of network industries, the master's degree in digital economics and network industries from Paris Sud-11, Paris, France, and the Erasmus Mundus Joint Ph.D. degree in sustainable energy technologies and strategies from the Delft University of Technology, The Netherlands, in 2014, under the joint program with Comillas Pontifical University and the Royal Institute of Technology (KTH), Sweden. He is currently a Research Professor with the Institute for Research in Technology (IIT), ICAI School of Engineering, Comillas Pontifical University. In August 2020, he was selected as a member of the Expert list of the Regional Commission of the Electrical Interconnection for Central American (CRIE) and he was appointed as a member of the ACER Expert Group on Demand Side Flexibility for EU Agency for the Cooperation of Energy Regulators (ACER), in September 2021. He has been a Visiting Scholar with the European University Institute, Italy; the Lawrence Berkeley National Laboratory, USA; and the Massachusetts Institute of Technology (MIT), USA. Since September 2016, he has been the Lead of the ISGAN Virtual Learning of the International Smart Grid Action Network.

RAFAEL COSSENT received the Industrial Engineering degree from the ICAI School of Engineering, Comillas Pontifical University, and the Ph.D. degree in electrical engineering from Comillas Pontifical University. He is currently a Researcher with the Institute for Research in Technology (IIT), ICAI School of Engineering, Comillas Pontifical University, where he acted as a Coordinator of the Research Unit on Smart and Sustainable Grids, between 2016 and 2021. Additionally, he is also the Co-Director of the Chair for Hydrogen Studies and he has previously acted as a Coordinator of the BP Chair in Energy and Sustainability. Besides his research activities, he teaches on the regulation of network activities in the power sector. Throughout his academic career, he has participated in over 50 research and consultancy projects dealing with power sector economics and regulation, integration of renewable and distributed generation, electric mobility, smart grids, and decarbonization and energy transition. He has published over 50 papers in national and international journals and conference proceedings on these topics. He has been a Visiting Researcher with INESC, Porto, Portugal, and Heriot-Watt University, Edimburgh, Scotland. He has contributed to the on-line education program of the Florence School of Regulation.

Sustainable Energy, Grids and Networks 39 (2024) 101482

Contents lists available at ScienceDirect

Sustainable Energy, Grids and Networks

journal homepage: www.elsevier.com/locate/segan

Analyzing the boundaries for TSO-DSO coordination when activating flexibility for DSO's in networks with an expected significant load increase

Fernando-David Martín-Utrilla [b,*], José Pablo Chaves-Ávila [a], Rafael Cossent [a]

[a] Institute for Research in Technology - IIT, ICAI School of Engineering, Universidad Pontificia Comillas – Alberto Aguilera, 25, Madrid 28015, Spain
[b] i-DE (Iberdrola Group) - Menorca, 19, 46023 Valencia, ICAI School of Engineering, Universidad Pontificia Comillas – Alberto Aguilera, 25, Madrid 28015, Spain

ARTICLE INFO

Keywords:
TSO–DSO coordination
Electricity market design
System services
Flexibility markets
Real casestudies

ABSTRACT

The Transmission System Operators (TSO) and Distribution System Operators (DSO) coordination literature deals with different coordination schemes or coordination methodologies. However, consumer actions or regular DSO operations continuously affect the system balance operation, and no major coordination is required as these actions individually have negligible impacts on the overall system. The literature has not previously analysed where the limit beyond which coordination is necessary. This question requires an analysis of the DSO operations where the need for coordination is foreseen and a case-by-case study of what type of impacts are created by the activation of the DSO flexibility resources on the responsibilities of the TSO. Such analysis helps to define thresholds and scenarios considering existing changes in distribution networks, which can be a reference for delimitating costly coordination procedures. This paper presents a revision of all the possible scenarios of the DSO operation needs and their impacts on TSO responsibilities considering the possible TSO/DSO borders at different voltage levels. Afterward, a methodology is proposed to analyse more deeply the impact of flexibility activation with an expected significant load increase. Representative case studies evaluate the possible impacts on TSO responsibilities of local flexibility activation. This paper concludes that the impact of local flexibility is expected to be significant when large power changes are managed in the short term, estimated in more than 50 MW if the DSO operates in 132 kV or more than 15 MW if the DSO operates up to 66 kV. At LV or MV level, minor coordination would be needed.

1. Introduction

Decarbonisation and energy sources decentralization have increased the focus on the use of flexibility tools in distribution networks. In Europe, EU regulation even requires regulators to incentivise distribution network flexibility [1]. This new paradigm makes it necessary to review the roles of the different actors, including the Distribution System Operators (DSO) and the Transmission System Operator (TSO). As concluded in [2], interoperability between TSO-DSO-DER actors must be redefined and adapted. Also in [3], it was concluded that coordination between DSOs and TSOs would become increasingly salient as more and more distributed resources interconnect to the grid and provide system services.

The DSO must manage demand and generation locally to solve network constraints and ensure a secure grid operation. In [4], local markets are identified as the most efficient option when comparing coordination schemes. The TSO faces the challenges of maintaining the balance of the system with dispersed generation sources, reduced system inertia, and their ability to perform an efficient balancing of the overall system [5].

TSO-DSO coordination is described as paramount since the DSOs have access to flexibility services [6], [7], that when used for DSO and TSO they are also called systems operators services [8]. Several types of coordination models or coordination schemes are studied, [9] and [10] present five coordination schemes to enhance interaction between system operators. The choice of the most suitable coordination scheme depends on several factors, namely, the type of flexibility service, the current state of the grid, the share of RES installed, the existing market design and the evolution of roles and responsibilities of system operators. The increased interaction between SOs will impact business processes, information exchanges, communication channels and ICT infrastructure. Making the necessary changes in those areas requires a paradigm shift in system operation.

Higher accuracy in the TSO-DSO information exchange process can

* Corresponding author.
E-mail address: fmartin@iberdrola.es (F.-D. Martín-Utrilla).

https://doi.org/10.1016/j.segan.2024.101482
Received 1 February 2024; Received in revised form 17 July 2024; Accepted 21 July 2024
Available online 23 July 2024

be achieved, [11] proposes a methodology based on the solution of a set of optimization problems that estimate the flexibility ranges at the distribution and transmission system operators (TSO-DSO) border nodes, suggesting that it is possible to identify a larger flexibility area even to provide services to the TSO.

Within these coordination models, the access to information and validations, or decision-making processes are arranged differently. Coordination can be understood as 1) an exchange of information or technical requirements to operate safely [12], which in this paper, we refer to as minor coordination; or 2) a mechanism by which responsibility and decision-making in operation are shared, as major coordination. Providing information, as long as it does not require waiting for a response through validation processes, does not create major challenges or excessive costs. [13] defines cooperation as a harmonized calculation methodology and a common grid model with shared scenarios and input data for the calculations, what means shared decision-making and therefore, major coordination. Even a single iteration, as proposed in [14] when proposing hierarchical coordination based on the bids of DERs with very close results compared with the results of centralized dispatch, shared operational decisions are considered major coordination due to the developments required to establish such systems.

The research question in this paper is about when major coordination is necessary, at which TSO/DSO voltage levels, and for which TSO services, and if necessary what is the minimum size of the operations that need coordination. This paper addresses this question because of the barriers, costs, and operational challenges coordination may create. Minor coordination is not questioned, as data exchange is not expected to be a barrier or a significant cost for activating local flexibility.

[15] shows the potential aspects of information exchange for TSO and DSO in different coordination schemes concluding that the common scheme leads to the overall least cost of flexibility procurement, corroborating with previous research. However, this research and others lack the barriers and costs of sharing or subordinating operational decisions for DSOs or TSOs. Also, the regulatory and economic environment greatly conditions the decision-making in the companies that assume the role of TSO and DSO, and it is extremely difficult for operational decisions that have economic repercussions to be shared. Regarding the use of local flexibility in which the DSO only procures flexibility to reduce the power flow in certain grids' elements arise concerns about the need for the TSO to re-balance the system, which might not be significant.

[16] also advocates for a more efficient dispatch from the TSO–DSO coordinated procurement over independent sequential procurements. At least, the inclusion of retailers in the joint dispatch is less attractive due to the lack of improvement in social welfare and the undesirable impacts on the DSO.

A literature review referring to TSO DSO coordination was carried out to verify how they have addressed potential limitations regarding the needs of the DSO and its impact on the management of the TSO. Most papers aim to compare several types of coordination and their needs or benefits. [9] analyses three core TSO-DSO coordination models, reviewing validation and dispatch responsibilities, and discusses solution techniques for coordination, acknowledging the coordination's complexity and cost. [17] uses linear approximations of the underlying network to solve optimization problems, and proposes a decentralised TSO-DSO scheme that reaches a near-least cost solution by respecting the privacy concerns of TSOs and DSOs. The cost of coordination is a recurring topic in the literature. When evaluating a coordination scheme in which the TSO and DSO markets are separated, [18] emphasizes the constraints boundaries represent, indicating that its flexibility could provide efficiency. [19], also evaluates different coordination schemes and highlights the importance of computational and administrative challenges in coordination in finding the optimal solution. However, the limits are not determined or studied in any case, which is the gap that this paper aims to fulfil.

This paper aims to determine the limits of the necessary major coordination, which is not straightforward because of the variety of available flexibility tools, circumstances in which flexibility can be useful and the responsibilities that TSOs and DSOs have in each country. The need for cooperation and solutions will depend on where structural congestion will occur and which borders will be managed [13]. This objective is relevant because implementing unnecessary coordination would bring extra costs to the systems. There could also be unnecessary barriers for the Flexibility Service Providers (FSPs) that need, for instance, to adapt to the TSO's services' requirements which are more complex and demanding instead of fulfilling only relaxed requirements to provide services to the DSO.

The paper is organized as follows: Section 2 addresses the methodology to identify TSO-DSO coordination needs and the impacts of local flexibility activation on the system and the transmission grids, it analyses the possible scenarios in which TSO-DSO major coordination may be needed depending on the voltage levels where DSO local needs occur. Section 3 presents three real case studies with a significant piece of the Spanish network, but selecting different voltage representative border levels between TSO and DSO for potential critical scenarios that may require coordination mechanisms in other contexts. Finally, in Section 4, some conclusions are drawn, and recommendations are provided to remove barriers that may hinder the creation and development of local flexibility mechanisms.

2. Methodology to identify TSO-DSO coordination needs

Fig. 1 shows the process followed by the proposed methodology and helps to understand the steps detailed in this section.

In the first step, the necessary information is obtained to properly classify the type of need depending on coordination requirements. Afterward, the input data is evaluated by screening the potential impact to assess whether a relevant impact is possible. After selecting the scenarios of relevant impact, a comparison is carried out to distinguish whether that need requires minor or major coordination. Each of the steps presented in Fig. 1 are presented below.

2.1. Characterization of the DSO need

2.1.1. Step 1: DSO flexibility needs

Flexibility services are based on a need for DSOs. This need must be associated with specific requirements of a flexibility product (e.g. [20]), the request to increase or decrease active or reactive power for a certain time is considered in this paper. Therefore, the methodology's first step is to identify a specific need. Then, the main inputs for this step are: kW / kvar, upward / downward, location and duration.

The location is an aspect that could be further studied, as in [21], that proposes a methodology capable of finding the relevant flexibility area while considering the technical grid constraints. But for this research, the location refers to the location of the limiting element that generates the need.

It is relevant to have a reference for the size of the power flows managed at each voltage level. A three-phase LV line in Europe is typically in the load range of several tens or hundreds of kW depending on the ampacity of the cable [22]. In the case of the MV network, they can be up to 7 or 10 MW following the same reasoning. As a benchmark, the MV feeder type averages 10.5 MW capacity considering the total power installed in secondary substations in each feeder [23].

2.1.2. Step 2: timeframe of the DSO need

The second step is the procurement timeframe selection. For that, the type of need must be assigned to one of the cases referred to in Table 1.

The needs require quite different operational treatments depending on the timeframe. Long-term markets could become more important for the cooperation between DSOs as well as between DSOs and microgrids [13]. For [24]. It is crucial to properly consider uncertainties (for

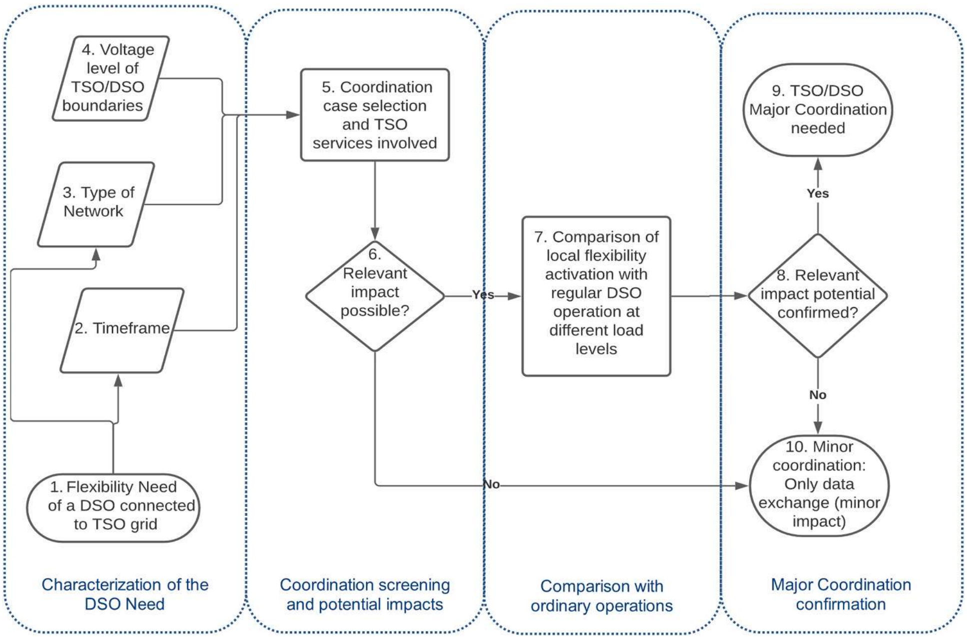


Fig. 1. Methodology followed to study the impact on TSO responsibilities of regular operations in the DSO networks.

Table 1
Procurement Timeframes.

Procurement timeframe	Potential usage
Long-term [from years to months]	Needs that normally compete with reinforcement or investment in the network, or with structural decisions. Grid constraints are predicted in long-term periods.
Weeks to day-ahead procurement	Operational needs that can be predicted in advance, normally referring to temporary unavailability due to maintenance work. Unusual network conditions are foreseen at this time.
Intraday procurement / Real-time	Operational needs that cannot be predicted in advance. Flexibility procured in real-time or close to real-time is useful to maintain system security.

instance, associated with forecasts) over different time scales to have the possibility of planning operations and controlling their feasibility and performance through the rolling operations phase.

As a complement to network planning, long-term flexibility markets are expected to address part of the long-term network needs for TSO-DSO networks (i.e. avoid or defer network investments). The scope of this paper is limited to the activation of flexibility from the point of view of network operation and not from the point of view of network planning.

2.1.3. Step 3: type of network where the DSO need is located

The needs of DSOs at each voltage level are very different in terms of the amount of power, and consequently, in terms of impact on TSO's responsibilities. Considering IEC standard voltages [25], a division in LV (<1 kV), MV(~>1 kV and ~<36 kV) and HV(~>36 kV and ~<220 kV) could be valid considering the different operation strategies, design criteria or network needs. HV networks are generally operated in a meshed mode, and LV and MV assets are operated radially. But MV assets have adjacent feeders that help in case of outages, especially in urban networks. The way of managing voltage control differs depending on the voltage level. While in LV and MV voltage control mainly requires active power management because of the high R/X ratio [26], at HV are generally managed through reactive power flows.

2.1.4. Step 4: voltage level of TSO/DSO borders

According to [13], the calculation and the allocation of the available capacity on the border will be challenged, and methodologies will need to be developed to increase the transparency of the approaches followed by the system operators. This will require increased cooperation and coordination between TSOs and DSOs, as well as between interconnected DSOs.

In each country, the limits of responsibility of TSOs and DSOs are different. To establish a methodology useful for any circumstance, it is necessary to consider the different types of borders. In this sense, as shown in Fig. 2, three different levels are considered according to the following description:

- Medium Voltage (MV) border level: The distribution company is responsible for LV and MV levels. (e.g. Italy, Belgium, Cyprus, Estonia, France, Latvia, or Lithuania) [27]
- High voltage (HV) border level: The distribution company is responsible for LV, MV and some HV levels under 110 kV. (e.g. Belgium, Denmark, Luxembourg, Netherlands, or Portugal)
- Extra-high voltage (EHV) border level: The distribution company is responsible for LV, MV and HV levels under 220 kV. (e.g. Austria, Bulgaria, Czech Republic, Germany, Spain, Finland, Greece, Hungary, Ireland, Poland, Romania, Sweden, Slovakia, Slovenia, United Kingdom, or Norway)

In this simplification, only the lines are considered, not the transformers. Knowing that when the operator of the highest voltage level also operates the transformer, only the lines are considered in this simplification, and coordination needs are greater. There are also distribution companies responsible only for LV levels. This situation is not considered a TSO/DSO border but a DSO/DSO border.

2.2. Coordination screening and potential impacts

2.2.1. Step 5.1: coordination case selection

Based on the same criteria defined in [28], this study considers the division between radially operated networks, normally referred to as LV and MV, and meshed operated networks, normally referred to as HV levels and above. On the other hand, the needs can be classified following the procurement timeframe as long-term, day-ahead and near

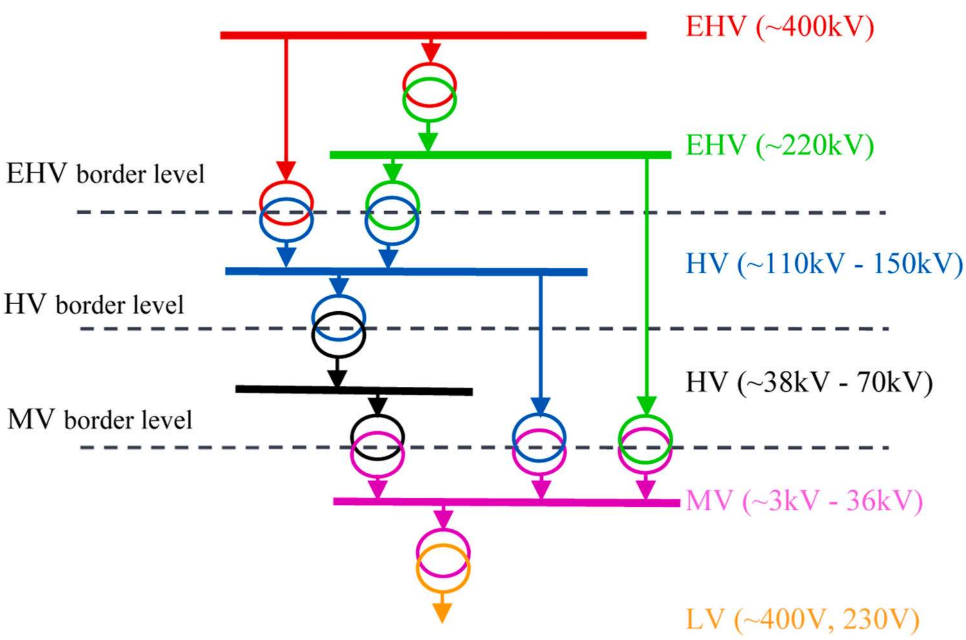


Fig. 2. Possible TSO/DSO voltage responsibility borders considered.

real-time.

As the voltage level of the TSO/DSO borders are relevant for the study, this first classification can be replied to all three cases considered in step 4. The fifteen cases shown in the classification proposed in Table 2. Having needs in the DSO meshed-operated network will not be possible if the DSO only operates MV and LV.

2.2.2. *Step 5.2: TSO services involved*

For each case study, it would be necessary to make a list of the services and responsibilities of the TSO that may be affected by the needs. As presented in [29] and [30], TSO services can be classified according to the needs:

Table 2
Classification of potential scenarios for TSO-DSO coordination considering the different voltage levels for TSO/DSO borders.

Classification depending on the need	Voltage levels for TSO/DSO borders		
	EHV border level	HV border level	MV border level
Long Term Radially Operated Grid	Long Term Radially Operated Grid, EHV border	Long Term Radially Operated Grid, HV border	Long Term Radially Operated Grid, MV border
Day Ahead Radially Operated Grid	Day Ahead Radially Operated Grid, EHV border	Day Ahead Radially Operated Grid, HV border	Day Ahead Radially Operated Grid, MV border
Real-Time Radially Operated Grid	Real-Time Radially Operated Grid, EHV border	Real-Time Radially Operated Grid, HV border	Real-Time Radially Operated Grid, MV border
Long Term Meshed Operated Grid	Long Term Meshed Operated Grid, EHV border	Long Term Meshed Operated Grid, HV border	*(Non-meshed operated)*
Day Ahead Meshed Operated Grid	Day Ahead Meshed Operated Grid, EHV border	Day Ahead Meshed Operated Grid, HV border	*(Non-meshed operated)*
Real-Time Meshed Operated Grid	Real-Time Meshed Operated Grid, EHV border	Real-Time Meshed Operated Grid, HV border	*(Non-meshed operated)*

A) Frequency services, including all the balancing needs [31]: Inertial response, Fast frequency response—FFR, Frequency Containment Reserve—FCR, Automatic Frequency Restoration Reserve—aFRR, Manual Frequency Restoration Reserve—mFRR, Replacement Reserve—RR, and Ramping.
B) Non-frequency services:

B1) Congestion Management (Corrective, Predictive)
B2) Voltage Control (Steady-State VC, Dynamic Reactive Power)
B3) Systems' inertia and stability (Synchronous Inertial Response—SIR, Fast Post Fault Active Power Recovery—FPFAPR, Dynamic reactive response—DRR)
B4) System Restoration (Black-start capability); and B5) System Adequacy (Last-resort tender, Strategic reserves, Capacity mechanisms).

Other sources, such as [3] classify the services into Energy Related Services (including A. B3 and B4), Network Related Services (B1 and B2), and Secondary Electricity Services (as not related to the grid such as Emissions Restrictions, Renewables Incentives, or Domestic Fuel Content Requirement)

2.2.2.1. *Frequency services.*

Long-term flexibility solutions include long-term contracts used for assuring the availability of flexibility reserves with an activation market near real-time [32] [33]. Regarding frequency services (A) and balancing services, the timeframe is Day-Ahead and Real-Time. So for the Long-Term in any type of network and border level, the impact is considered negligible. Only minor coordination might be required to consider the participation of some DERs in frequency services for the long term.

Regarding the Day-Ahead timeframe, a null impact on the balance is possible if the local flexibility market is cleared before other markets to integrate it into the offers for other markets. Flexibility activation certainty before the wholesale markets' timeframe makes minor coordination possible as activations can be incorporated into the market positions. In addition, the impacts on the balance have no relation to the TSO-DSO border level.

To better focus on the case of imbalances, Fig. 3 represents an example of congestion in the distribution network. The DSO needs to reduce 5 MW on one line. The expected imbalance would be 5 MW if the load was reduced. With flexibility activations, there would be a request to increase the generation output of one plant available by 2 MW, that

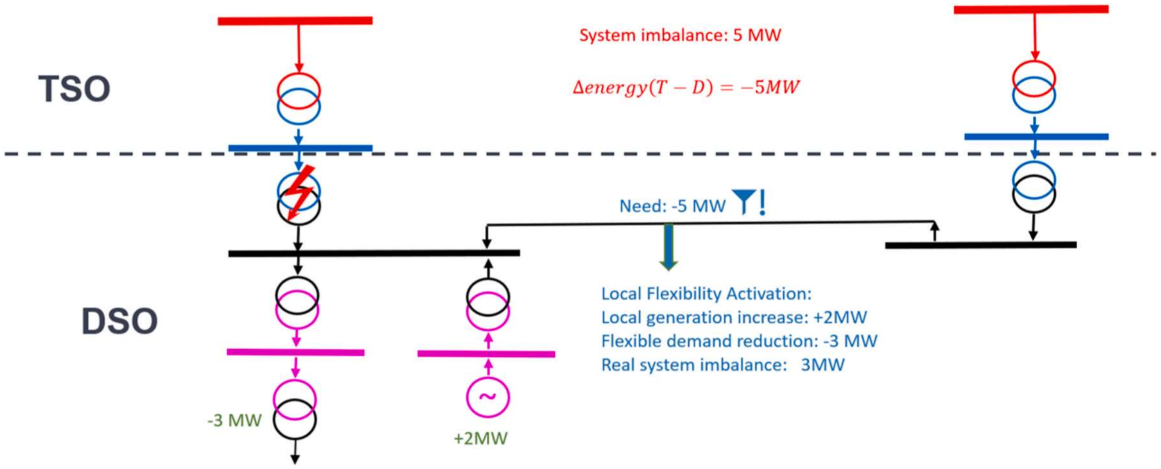


Fig. 3. Impact on the overall system balancing of local flexibility activation on the DSO level.

would replace other generation plants and reduce consumption by 3 MW. Finally, the imbalance would be only 3 MW, and the TSO would observe a difference of 5 MW in its area. From the example, it can be deduced that the action of the DSO is in the direction of correcting the imbalance. While inaction would lead to an imbalance of 5 MW, the natural action of applying flexibility services reduces this impact to 3 MW. In any case, as known sufficiently in advance, the offers presented in the energy markets by the participants must already consider this requirement. Therefore, no action should be taken by the TSO to manage this deviation.

In the case of real-time operation, there would have a clear effect as any variation means a new imbalance that needs to be amended (i.e. a

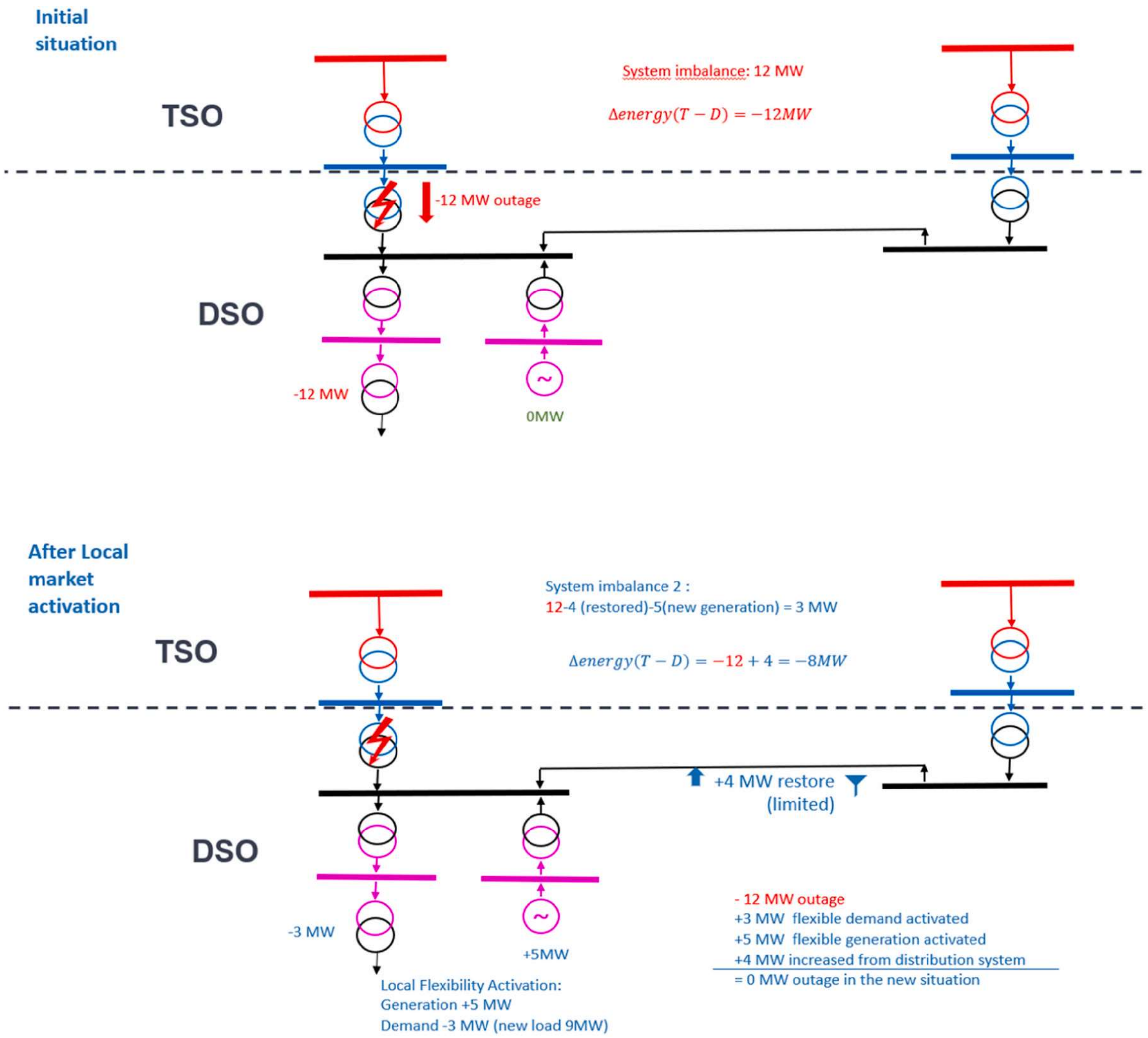


Fig. 4. Local flexibility activation in real-time.

necessary redispatch). However, the actual needs of the DSO in real time are always aimed at correcting unforeseen effects occurring in the distribution network. Therefore, real-time correction actions generally represent a correction (i.e. rebalance) of unforeseen deviations. In other words, real-time flexibility tools do not threaten the system balance. For example, a line failure resulting in non-served energy could create an imbalance of the same magnitude. Still, by activating flexibility to supply that energy (e.g. increasing local generation) the system balance can be re-established. Therefore, the sum of the DSO's actions will go in the direction of correcting the energy imbalances that will occur. Given that the actions conducted in DSO are made with DERs committed in previous timeframes, the TSO must have considered them previously, as minor coordination. Fig. 4 represents an example of a scenario: an outage due to a failure of a distribution line. It directly impacts 12 MW load lost and creates an initial imbalance of 12 MW. The DSO can restore some power from other lines, but limited to 4 MW. With flexibility activations, there would be a request to increase the generation output of one plant by 5 MW, which would not impact the balance being replaced with other generation plants and another request to reduce consumption by 3 MW. Altogether, the 12 MW impact of the outage would be neutralised with the 4 MW from the network, 5 MW from the generation and 3 MW of demand reduction. The final imbalance to manage in real-time would be reduced to 3 MW, and the TSO would observe a difference of 8 MW in its area. Although the example in the figure refers to loss of consumption, it would work the same in the opposite direction.

2.2.2.2. Congestion management. Congestions may cause a degradation of assets such as transformers or lines [34] or put in danger system, therefore the redispatch of resources is required to avoid them. Managing the meshed network at different voltage levels always requires some coordination as the impacts are propagated. Meshed networks operate considering the upstream voltage level and vice versa. In Europe, it is mandatory to share the data of the observable grid among network operators [35] (e.g. structural data, scheduled unavailabilities and real-time data). Therefore, regarding Congestion Management (B1), TSO-DSO coordination might be needed to seek mutual approval and consider cross-impacts in the Weeks to day-ahead, Intraday and Real-time timeframes, which are the regular operations timeframes in distribution grids.

The range of power magnitudes in MV or LV (Section 2.1.1) individually does not condition the operation at (EHV) level, even less in long-term projections. Being a transmission network, a load variation of less than 1 % in the most affected asset could be expected. From hundreds of MW to around 1 MW, considering simultaneity and meshed topology [36], [28]. However, in case the border is at MV level and the HV/MV transformer belongs to the TSO which is not common practice (e.g. in France and Italy, where the TSO/DSO border is at MV level, HV/MV transformers belong to the DSO), this range of power might occasionally condition the operation of the transmission grid and major TSO-DSO coordination would be needed.

2.2.2.3. Voltage control. Regarding the TSO services related to (B2) Voltage Control, its activation must be specific to the operation of each network and any interference activating resources connected to other SOs grid must be coordinated, as proposed in Art. 29.9 Reg. 2017/1485, [35]. In the same way, as in congestion management, operational coordination is necessary in the Real-Time and Day-Ahead. In [37], a market-based TSO-DSO coordination scheme is proposed for voltage regulation. For that, the DSO is given priority in using DERs to solve distribution network constraints, however, significant flexibility remains for the TSO even during periods of peak demand and maximum export. Voltage control refers to a specific geographical location, voltage level, and system operator [34], it must be managed by local mechanisms. Any shared decision-making would only be in limited circumstances.

The coordination approach is similar to that of congestion management, since, although the priority must be established by the DSO before delivering flexibility services to the TSO, it is necessary to consider the overall result to obtain an optimal solution. In [38] this approach to overall efficiency is addressed. In it, TSO-DSO coordination approach is proposed for voltage regulation showing results of a Greek case study to leverage flexibility from distribution grids for over-voltages in the transmission grid.

Thus, with the same rational, TSO-DSO coordination might be needed for the Meshed Operated Grid to seek mutual approval and consider cross-impacts in regular operations (Day-Ahead and Real-Time), but not long-term. For the Radially Operated Grid Scenarios the range of power might condition the operation of the transmission grid only for borders at MV level. Only in those cases major TSO-DSO coordination would be needed.

2.2.2.4. Inertia and stability. Many inertia and stability services are based on availability activated if necessary. The availability service itself does not have conflicts. In the necessary data exchange, the DSO should have the information of such availabilities. Rotor Angle Stability solutions are expected to be activated in real time. There could be an expected conflict in the case that DSO activates in real-time a congestion service in the opposite direction to stability services deployed by the TSO, for which the TSO would have to activate further services to compensate for the DSO service activation. Presumably, this scenario would not happen without the proper information exchange.

In any case, although this exchange of information is desirable, it is expected that the activation of inertial services, the duration of which is a few seconds or less than one second, will not affect the capacity of the distribution network beyond compatibility with the protections system. In some cases, the short duration of inertial services would not even be sufficient to trigger the action of the protections. Therefore, this exchange of information would take place especially to enable this coordination. Although the Real-Time and Day-Ahead timeframe is indicated to perform this check, because it would be sufficient, it could also be given in the Long-Term. Because of that, Day-Ahead and Real-Time scenarios were selected for minor coordination.

2.2.2.5. System restoration. Large disturbances can cause total or partial blackouts of power systems. Traditionally, power system restoration starts from a neighboring power system, but the proliferation of distributed generation resources enables parallel islands within the outage power system that could be connected gradually to the transmission system [39], [40]. Such an approach requires that islands within the distribution system can be successfully started up and operated in a stable manner, needing, in turn, a long-term planning to deploy the capacities and infrastructure to do that. That is why long-term data exchange may be needed. But logically, local needs for DSOs that trigger flexible solutions would not have any interference with the System Restoration Procedure.

2.2.2.6. System adequacy. System adequacy is part of the long-term grid planning procedure based on a deterministic criterion under which the sum of the total firm generation capacity should be higher than the expected peak demand plus a security margin. The firm capacity assigned to each generation technology is calculated depending on its availability to supply the peak load by applying a derating factor to the installed capacity [41].

There must be coordination between the planning of transmission and distribution networks (e.g. Art 55 [42]) and alignment, and especially in the scenario of decarbonization and electrification necessary to address the needs of the energy transition. Moreover, the application of flexibility solutions in DSOs' investment plans, as indicated in the European Directive [1] requires information on the flexibility services needed in the medium and long term.

The influence of flexibility on the long-term planning of the electricity system is still unknown [43], although long-term tenders to defer investments in the distribution network may become relevant [33], [44]. However, as mentioned for radially operated grids, the objective of this paper addresses only the need for coordination in the operation stage. As in the previous case, information exchange at the interfaces would be sufficient to perform coherent operational decisions (minor coordination).

Table 3 shows a summary of the coordination needs according to the impacts produced by the activation of local flexibility by DSOs. The impact assessed here refers to an aggregated impact, not a one-off use of local flexibility.

2.2.3. Step 6: relevant impact screening

According to the selection of coordination cases proposed in the previous section and the needs for major coordination, following this methodology the cases of minor coordination could be identified without further steps. Long-term flexibility markets, as part of the operational tools, negotiated long before the day ahead, should not affect any existing market mechanisms or any grid operation as they occur in advance. The activation of long-term commitments would have the effect of short-term activations previously discussed.

Flexibility activation certainty before the wholesale markets' timeframe makes minor coordination possible, avoiding energy imbalances. The real-time local markets for DSO needs are not expected to generate energy imbalances. As discussed in Section 2.2.2, DSO's real-time actions are always in the direction of correcting unforeseen imbalances, as DSOs objective is to maintain the service and to avoid curtailments or outages.

But other cases need to be analyzed. This would occur mainly in the cases of congestion management and voltage control as local needs for Day-Ahead and Real-Time, in the cases of a mesh network when the TSO/DSO border is in HV or EHV, or in the case of a radial network when the border point is in MV. This complementarity in active and reactive needs is interesting because, in some studies, the treatment is done jointly. In this regard, [45] proposes the new concept of active-reactive power (PQ) chart, which characterizes the short-term flexibility capability of active distribution networks.

2.3. Comparison of local flexibility activation with regular DSO operation at different load levels. Step 7

As mentioned in Section 2.1.1, a DSO flexibility need can be simplified based on relevant characteristics: power active or reactive, upwards or downwards, location and duration. A switch operation in the distribution grid that has the same effect is considered for this comparison. This step aims to make a real approximation of the impact of the activation of flexible resources that can be compared to the impact of a switch operation of the distribution network on the transmission network. If a DSO operation that currently occurs has an analogous effect and a negligible impact on the TSO network, the same effect will have the activation of the flexible resources by the DSO.

For that, a grid model in which a power flow can be run may be selected, and according to the specific border level (EHV, HV or MV), a certain amount of power change is evaluated to see the effect it has on the transmission level. Considering the type of network in which the need occurs, the most appropriate way to reach realistic conclusions is to take an amount of power expected at that voltage level.

The methodology in this step is as shown in Fig. 5:

- A real network, including TSO and DSO grids, is selected to assess the effect of the DSO flexibility services at TSO and DSO levels. To be comparable with the model used, a cascade of four different voltage levels, and at least three of these voltage levels should be meshed operated, to compare different TSO/DSO borders. And the network size should be representative of the area (Europe in our case) and

Table 3
Coordination needs and the impacts produced by the local flexibility activation by DSOs. (Indicating the three cases in Section 3.2).

	EHV border level						HV border level						MV border level		
	DSO need at radial network			DSO need at meshed network			DSO need at radial network			DSO need at meshed network			DSO need at radial network		
	Long-Term	Day Ahead	Real-Time	Long-Term	Day Ahead	Real-Time	Long-Term	Day Ahead	Real-Time	Long-Term	Day Ahead	Real-Time	Long-Term	Day Ahead	Real-Time
Frequency services	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼	▼
Congestion Management	▼	▼	▼	▼	●	● (Case1)	▼	▼	▼	▼	●	● (Case2)	▼	●	● (Case3)
Voltage Control	▼	▼	▼	▼	●	●	▼	▼	▼	▼	●	●	▼	●	●
Inertia and stability	○	▼	▼	○	▼	▼	○	▼	▼	○	▼	▼	○	▼	▼
System Restoration	▼	○	○	▼	○	○	▼	○	○	▼	○	○	▼	○	○
System Adequacy	▼	○	○	▼	○	○	▼	○	○	▼	○	○	▼	○	○

●: Major coordination may be required; ▼: Minor coordination required (Only data exchange); ○: No operational coordination needed

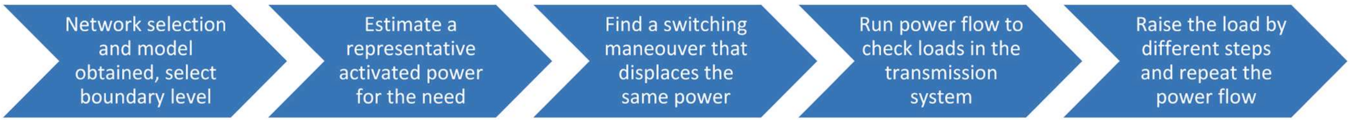


Fig. 5. Step 7: Comparison of local flexibility activation with regular DSO operation.

have enough complexity to represent the impact of the operations in these voltage levels (> 1 million customer area).

- As it is an electric circuit model, the TSO/DSO border level can be selected to assess other situations.
- Estimate flexible activated power for the need. This power amount represents the DSO need, so a representative amount of power according to what is managed at each voltage level is chosen to draw conclusions.
- Find a switching maneuver that displaces the same amount of power, it means an opening or closing operation of a maneuver element in which a similar effect (same amount of power displaced upwards or downwards) is produced.
- Run power flow to check loads before and after the manoeuvre and register the number of branches exceeding 50 %, 66 % and 100 % in the transmission system. Specifically, keeping the load below 66 % is considered a benchmark of compliance with the N-1 contingency [46] (ensuring stability in the event of failure of any element) required in the meshed network.
- As the methodology is for networks with an expected significant load increase. The load increases by different steps and repeating the power flow to see what could be expected after some years.
- The comparison of the number of overloads after and before the operation provides insight into the effect of the operation on the transmission network.

The aim is to demonstrate how such operations on the distribution network, which have equivalent or more impact on the transmission network than the flexibility activation, affect the transmission network. Finally, to set a reference boundary, establish a limit below which it can be considered that no further coordination other than data exchange is necessary.

2.4. Major coordination confirmation

2.4.1. Step 8: relevant impact potential confirmation

When the number of high loads or overloads in the transmission network is altered by the activation of flexibility in the distribution network, it may be considered that there is a clear need to coordinate so that the operation in a system operator (SO, either DSO or TSO) does not affect the operation of another DSO and therefore the search for mutual approval will be necessary. On the contrary, if the transmission network is not compromised in any case, not even with a reasonable expectation of growth, we can say that for that amount of power, greater coordination is not necessary and that lesser coordination would be sufficient.

2.4.2. Steps 9 and 10: TSO/DSO major coordination needed or only data exchange

Coordination can be understood as 1) an exchange of information or technical requirements to operate safely [12], which is defined as minor coordination in this paper; or 2) a mechanism by which responsibility and decision-making in the operation are shared, defined as major coordination. In all cases, the need for data exchange is not questioned. Providing information, as long as it does not require waiting for a response, does not create major challenges. However, when major coordination is necessary, barriers, costs, and operational challenges may arise.

3. Real case studies: application of the methodology to a real network considering different borders and quantitative results

3.1. Real DSO flexibility needs: the case in Spain

When congestions or voltage violations are detected early enough, corrective actions are taken. Making the cause-consequence link in the network's operating parameters is more complicated. However, unplanned interruptions make the effect more immediate and the network parameters easier to analyse. Compared to other EU countries, Spain shows a number of interruptions that are average as shown in Fig. 6, and they are taken as a benchmark. Some countries have exceptionally high rates due to exceptional situations, such as Ukraine. Logically, smaller countries may be more sensitive to this volatility. These extreme conditions also do not occur throughout the years, so it makes sense to take an average value as representative of the average system. Fig. 6 shows both planned and unplanned interruptions.

Indicators for Spain show that each customer can face less than 100 minutes of interruption (Fig. 7) and less than two interruptions per year [47]. In the case of Spain, 99.907 % of the customers are connected to the LV and MV networks. Therefore, these indicators refer mainly to interruptions of those voltage levels. Considering the values of a DSO in Spain,these values would mean that in a distribution network of 10 million customers, there would be an average hourly need to manage 1.9 MW overall, which is less relevant than the power of one MV feeder (near 5 MW as proposed in [28]) to recover the service. This data is directly related to the type of network, aerial or underground, and the number of supply points the MV feeders and substations have. This reference is comparable with the average value of capacity of MV/LV substation per LV consumer of 4.76 kVA mentioned in [48]. A transformer capacity utilization of less than 20 % would also mean less than 1.8 MW to manage as an average per hour of the year for 10 million customers. So, these references can be representative to other European countries.

As the voltage level of TSO/DSO borders in Spain are in EHV according to Fig. 2 and the need to manage the magnitudes in local flexibility markets in LV and MV levels have the same order of occurred averaged interruptions, there is no need for additional coordination between TSO and DSO. These variations already occur spontaneously and currently are not followed by any coordination or readjustment. A failure in a medium voltage feeder is managed directly by any DSO without coordinating with the TSO in Spain.

The operation of the meshed grid is noticeably different and requires a simulation of future scenarios to predict the impacts on the grid, for instance, through load flow analyses. This procurement timeframe brings together generation and demand forecasts from the wholesale market and the management of constraints by the TSO and forecasts of scheduled network manoeuvres and maintenance activities for both TSO and DSO.

Decisive factors in foreseeing the impact of the operation of one network on the other are: 1) structural information (networks configuration, substations, lines, transformers, loads, generators, etc.) and 2) real-time data (topology, active and reactive power, voltages, etc.), including the operation manoeuvres of TSO and DSO [35]. The impact of the management of the flexibility tools of one network on the other will be directly related to the coordination need, which can be compared with the normal operation of the networks where no cooperation is necessary.

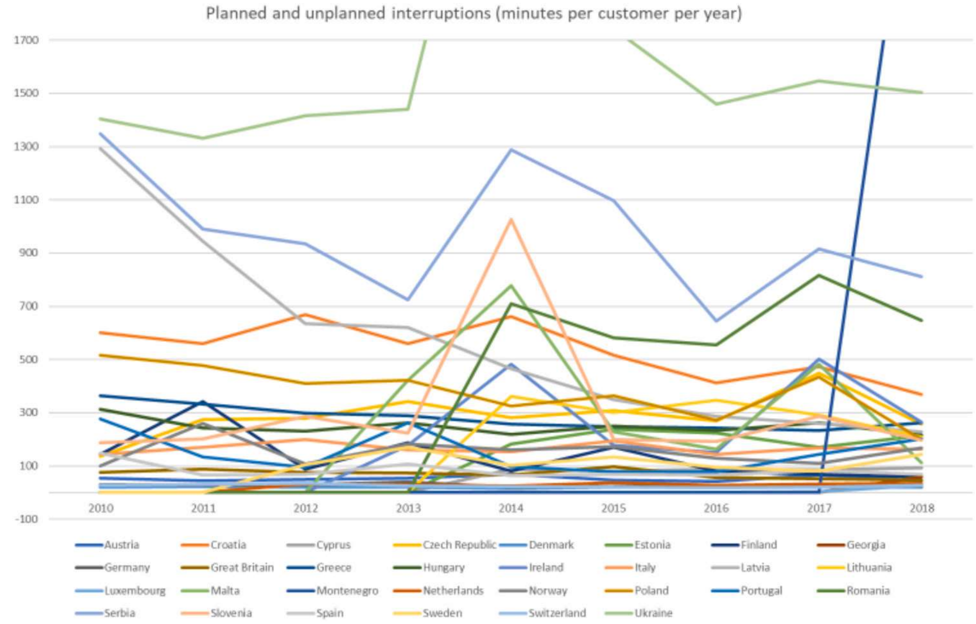


Fig. 6. Overall planned and unplanned long interruptions (minutes lost per year) in European countries. Source: [7].

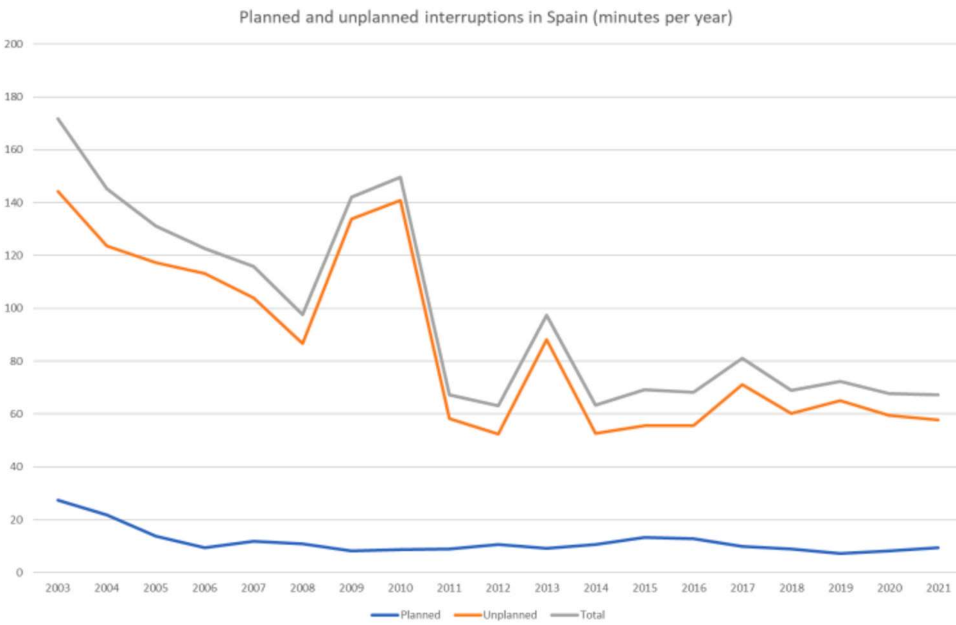


Fig. 7. Overall planned and unplanned interruptions in Spain (minutes per year) in European countries. Source: [47].

The purpose of this study is, therefore, to take representative ordinary cases of a real network, and observe the effect of applying the methodology. Table 4 presents a statistical analysis of the maneuvers in the distribution network. With these values, significant operations of a volume similar to that obtained for the percentile 75 corresponding to each voltage level might be selected.

Table 4
Statistical Analysis to select power needs magnitudes. Source: own elaboration.

	EHV (Case 1)	HV (Case 1)	MV (Case 1)
Nº operations/period	13	76	1017
Average power (kW)	29157	4362	3908
Standard deviation (kW)	36001	14106	6064
Percentile 75 (kW)	53439.05	13876.31	7998.10

3.2. Grid scenarios selection

3.2.1. Grids and operations selection

According to Section 2.2.3, and to choose the most useful and representative cases, three different real case studies in the Spanish network are selected with different voltage levels to simulate three different possible scenarios depending on the responsibility borders between TSO and DSO, as shown in Fig. 8. According to the network characteristics described in [48] could be broadly representative of most of the European Union, where there could be EHV, HV, or MV border levels.

In the first one, a 132 kV line belonging to the DSO network with a load of 48 MW is interrupted, potentially affecting 20.5 % of the meshed

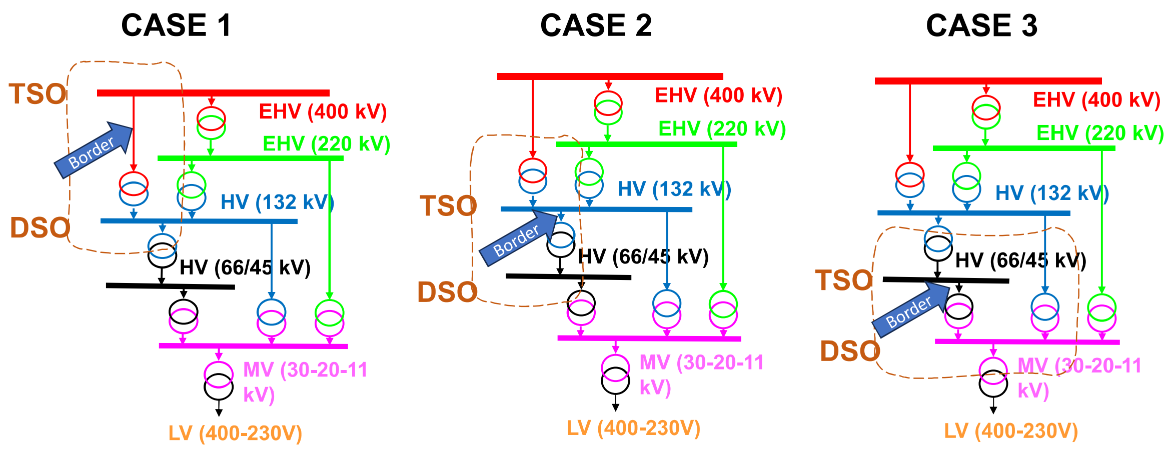


Fig. 8. Different voltage levels and TSO/DSO borders considered for the case studies. Case 1 is the actual case in Spain. Source: own elaboration of a simplified representation of i-DE (Spanish DSO) network.

grids that belong to the transmission grid (Case 1). This amount of power is close to the threshold of 50 MW proposed in [28] to define the need for TSO participation in DSO needs. In the second one, a 66 kV line belonging to DSO with a load of 12 MW is interrupted, potentially affecting 71.5 % of the meshed grids that belong to the transmission grid, considering the 132 kV grid as a TSO network (Case 2). It is close to the 15 MW, which corresponds to the average load of a 66 kV line, according to the information provided by the DSO. Different profiles could be selected to observe different scenarios with combinations of demand and generation. However, in the selected cases, the most unfavourable case is the peak demand, so, based on the TSO data obtained for the system [49], the hour of maximum total demand is chosen (Fig. 9). In the third case, in which 100 % of the meshed grids belong to the transmission grid, a part of the MV grid of an urban area loading 10 MW is transferred from a primary substation to another. An energy transfer was considered since a disconnection would not generate overloads.

3.2.2. Power flows and impacts on the TSO side

We simulate in PSS/E [50,51] a regular line switch on the network to observe variations in the upper voltage levels. These switches are common operations that redistribute load flows in the meshed network. The aim is to quantify the variation of flows at higher voltage levels under normal operation circumstances.

The load was then raised by different steps from current levels (+10 %, +20 %,., +100 %) until the load was doubled and the same network reconfiguration was carried out. The number of congestions detected in the grid is registered and reported.

Impacts on the TSO side are the possible congestions identified by PSS/E, which uses iterative techniques to solve the power system nonlinear algebraic equations by adjusting voltages at all systems branches to satisfy Kirchhoff's current laws and system demand as well [51]. The full Newton-Raphson method in PSS/E is selected to solve the steady-state power flow analysis.

3.2.3. Cases studies characteristics

The tests were performed on a real grid with real operation data with an expected significant load increase due to electrification of energy demand (e.g. electrification of transportation, industrial processes or heating). This area has a total peak load of 2697 MW and 2.34 million customers, as shown in Table 5, with 85 branches belonging to the 400 kV and 220 kV system, 296 branches of 400 kV, 220 kV, and 132 kV considered, and a total of 828 branches not including transformers to MV. So, the first case would consider the TSO as the operator of the 400 kV and 220 kV network, with the DSO the operator of the 132 kV network. The second case would add the 132 kV network to the TSO, being the DSO the operator of the 66 kV network and the third case would add all the HV voltage levels to the TSO. As mentioned before, all three case studies presented are framed in the Spanish context, which could be broadly representative of most of the EU systems. [48]

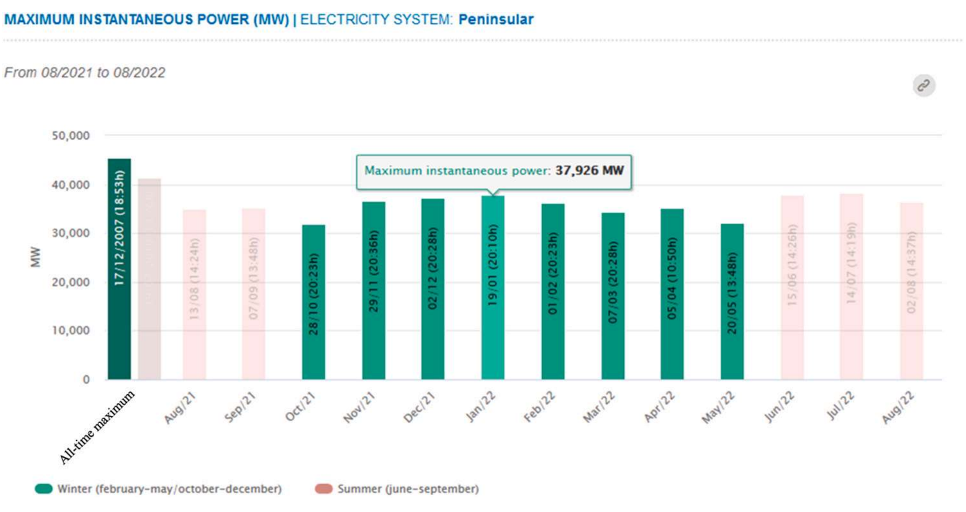


Fig. 9. Peak demand day selection. Source: Red Eléctrica de España (Spanish TSO) website.

Table 5
Case studies description. Source: own elaboration.

Total demand power: 2.7 GW	Case 1	Case 2	Case 3
TSO voltage levels	400 kV, 220 kV	400 kV, 220 kV, 132 kV	400 kV, 220 kV, 132 kV, 66 kV
DSO voltage levels	132 kV, 66k, 20 kV, LV	66 kV, 20 kV, LV	20 kV, LV
Branches in the TSO grid	85	296	828
Power interrupted	48 MW	12 MW	10 MW (transferred)

3.3. Results

Case 1. (considering TSO-DSO borders at 132 kV)

Fig. 10 shows the results of applying the methodology to Case 1, which interrupts 48 MW (at normal peak load) of a 132 kV line, forcing it to redistribute the load in the transmission network. On the x-axis the different load levels are considered, reflecting on the y-axis the number of lines or transformers overloaded. The curves represent the situation after and before the equivalent operation. The number of overloads is similar after and before switching for all the load levels considered. In short, these operations do not compromise saturations in the transmission network.

Case 2. (considering TSO-DSO borders at 66 kV)

The second case results in Fig. 11, shows equivalent results to those in the first case. On the x-axis the different load levels are considered reflecting on the y-axis the number of lines or transformers overloaded. The curves represent the situation after and before the equivalent operation. As the number of branches is much higher, the divergences between the network before and after switching are less noticeable. In this case, the switching action proposed by the operator as a regular operation interrupts 12 MW (at normal peak load) of a 66 kV line, forcing it to redistribute the load in the transmission network. Again, the transmission network congestions remain unaltered, and the N-1 criterium is not compromised with such an operation.

Case 3. (considering TSO-DSO borders at 20 kV)

The third case results are shown in Fig. 12, and this time, the results are different from the previous cases. Although significant transfers exist in the MV network, no changes are perceived in the number of branches in each step with or without switching. In that list of branches, the transformers to MT was excluded. The Case 3 would only be affected by the overload of the HV/MV transformer, whose overload would be reached with load levels greater than 150 % of the current load. (The case of the HV/MV transformer that powers the feeder must be considered if it is close to the capacity limit). For this reason, higher load scenarios are not contemplated because they would not be real. Equivalent results as in the first case. On the x-axis the different load levels are considered, reflecting on the y-axis the number of lines or transformers overloaded. The curves represent the situation after and before the equivalent operation. But, as there is no variation, only one curve is visible. The conclusion remains unaltered, and the N-1 criterium is not compromised with such an operation.

3.4. Lessons learnt from identifying potential coordination needs and the comparison with current DSO operations: implications for the need for TSO-DSO coordination in local markets

This section summarizes the main conclusions drawn from the numerical results of the real case studies:

a) Currently, load variations under normal operations in radial networks reach close to 5–8 MW (equivalent to one MV feeder) without requiring specific TSO-DSO coordination. Moreover, 1.9 MW would be an estimation of the DSO flexibility needs for a distribution area of 10 million customers (Section 3.1). Even with an energy transfer of 10 MW, the transmission network has no significant consequences. Therefore, local flexibility of such magnitude should not require additional coordination either. Only when the TSO/DSO border is at MV, the limit of the HV/MV transformer must be considered.

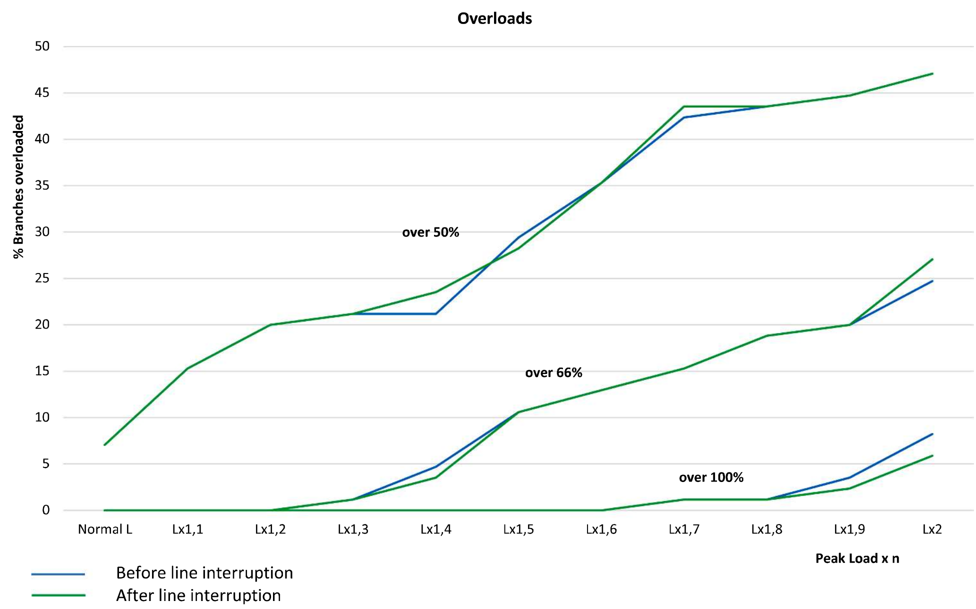


Fig. 10. Number of branches exceeding different percentages of capacity in scenario 1 (DSO operating 132 kV and TSO operating 400 kV).

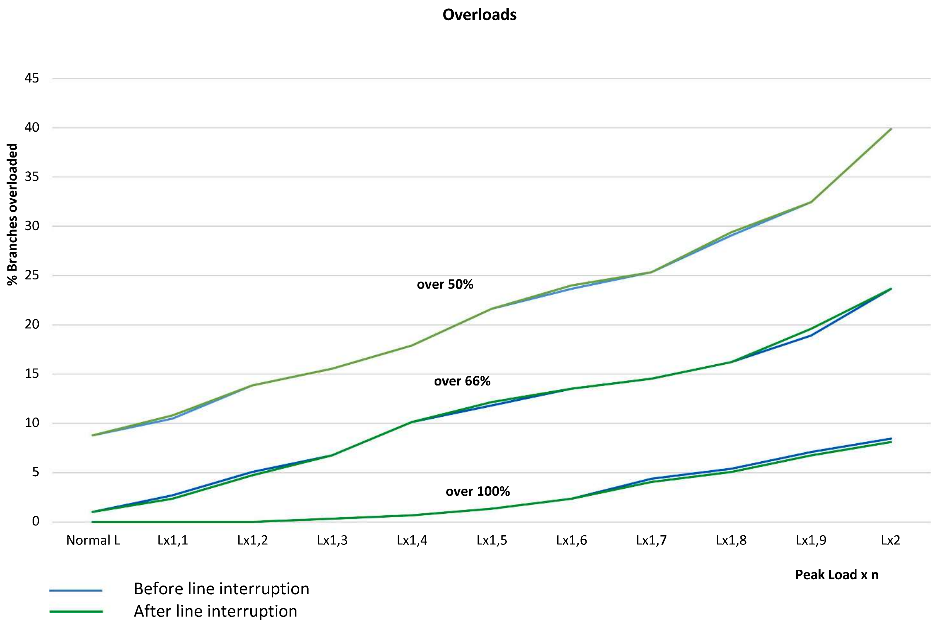


Fig. 11. Number of branches exceeding different percentages of capacity in scenario 2 (DSO operating 66 kV and TSO operating 132 kV).

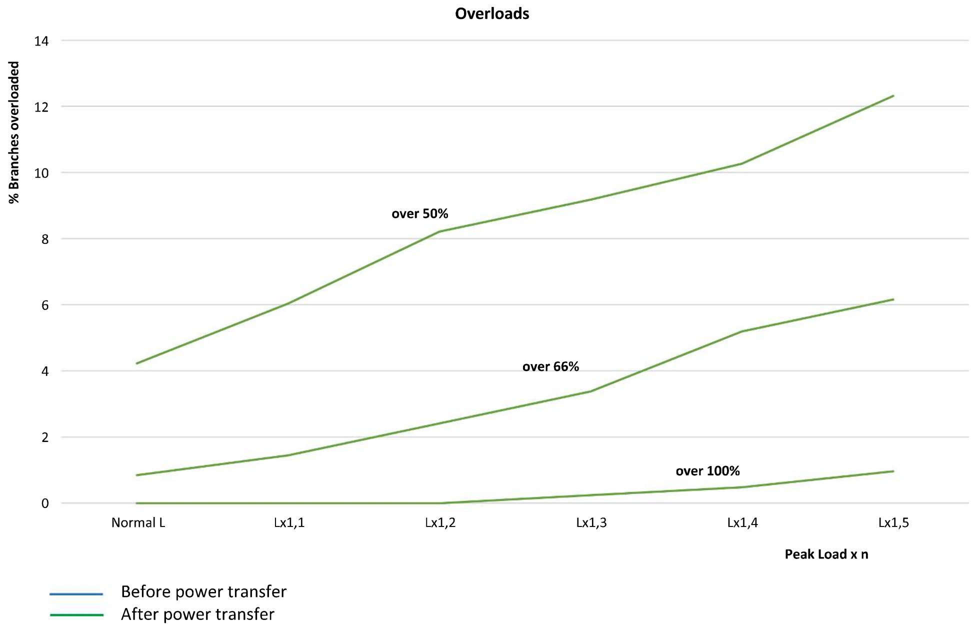


Fig. 12. Number of branches exceeding different percentages of capacity in scenario 2 (DSO operating 20 kV and TSO operating 66 kV).

b) The current operations of the DSO's meshed network have a limited impact on the TSO's network or system reliability. Then, local markets for similar quantities are not expected to have additional impacts as long as they transfer energy volumes similar to the operation manoeuvres. In the case of the DSO operating the 132 kV grid (EHV border) as it is in Spain, moving a volume close to 50 MW has almost no impact. Operating the 66 kV grid (HV border), moving a volume close to 15 MW has no impact.
c) Given that the DSO highest voltage level is normally at a HV level, at 66 kV or at 132 kV or similar, or even whether it is at MV, these conclusions obtained from case studies of the Spanish grid can be extrapolated to other countries no matter the size of the area or voltage level. Attention should be paid to how the grid is operated, as there may be a radial grid at high voltage or a medium voltage meshed grid that deserves special attention.

4. Conclusions

The necessary coordination between DSO and TSO for activating flexibility services has been addressed extensively in recent literature. However, this paper argues that this coordination is less necessary for variations imperceptible to the transmission network. To check this assumption, all possible cases, defined in terms of voltage levels, needs timeframe, and possible TSO/DSO border levels, are assessed to detect major coordination needs (the type of coordination by which responsibility and decision-making in operation are shared) and then compared against conventional operating conditions that nowadays do not require any TSO-DSO major coordination. All possible TSO impacts are screened, and considering all services TSOs manage. If the volume of flexibility activated by DSOs is in the same order as current operational practices, we argue that minor coordination (consisting of a simple exchange of information) is enough, and additional coordination would not be required.

This methodology is worth to assess a specific DSO need. Therefore, to evaluate a spectrum of needs, it is necessary to reproduce the methodology as many times as necessary. A systematization of the process that allows a greater spectrum of scenarios and needs to be related would also allow for a broader map of coordination needs.

The methodology assumes a network with an expected significant load increase due to electrification of energy demand and considers different demand scenarios. All different scenarios are investigated by identifying all possibilities in which coordination would be necessary; and from the proposed quantitative analysis, the threshold and the circumstances beyond which such major coordination is necessary. It is concluded that local markets would not impact the transmission network as long as they are not dedicated to the short-term management of the meshed distribution network. In addition, the necessary major coordination is limited to short-term scenarios in which the meshed networks move significant volumes. According to the cases analysed, this threshold could be set at >>50 MW with a TSO/DSO border at EHV or >>15 MW with a border at HV.

On the other hand, statistically representative values were chosen based on confidential data from the operations carried out by a control room with 2.34 million customers over 20 years. Since the size of the operations is a structural condition of the network, a stochastic analysis was not carried out. However, while MV size of operations has a more stable annual volume, data availability from HV and EHV networks are very different each year. Therefore, given the stochastic nature of the number of operations, future research could check if an increase in the number of DSO needs would affect the thresholds or how a change in the size of the operations or new technological developments would change them. For example, how the digitalization of networks could help reduce the size of operations and the coordination thresholds. Further research could also address the study with networks in scenarios with the proliferation of distributed generation or distributed storage.

These findings should help remove the restrictions and barriers for flexibility providers to meet the criteria imposed by TSOs to participate in their services and provide flexibility with less strict requirements that could generally be the case of DSO services. Moreover, it would allow DSOs to have greater versatility to tailor flexibility services to providers' capabilities, thereby unlocking a greater volume of flexibility.

Author statement

This paper has been prepared as part of the research carried out by Fernando David Martín Utrilla as a PhD student at the Universidad Pontificia de Comillas, the directors of the research being Dr. José Pablo Chaves Ávila and Dr. Rafael Cossent. All authors have contributed in the conceptualization, analysis, methodology and revision of the paper.

Data curation and investigation was done by Fernando David Martín Utrilla.

CRediT authorship contribution statement

Rafael Cossent: Writing – review & editing, Supervision, Methodology, Formal analysis, Conceptualization. **José Pablo Chaves-Ávila:** Writing – review & editing, Supervision, Methodology, Formal analysis, Conceptualization. **Fernando-David Martin-Utrilla:** Writing – review & editing, Writing – original draft, Supervision, Methodology, Formal analysis, Data curation, Conceptualization.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The data that has been used is confidential.

References

[1] EU, "Directive 2019/944 on common rules for the internal market for electricity and amending Directive 2012/ 27/ EU," 14 06 2019. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32019L0944&from=en. [Accessed 12 09 2021].
[2] P. Betancourt-Paulino, H. Chamorro, M. Soleimani, F. Gonzalez-Longatt, V. Sood, W. Martinez, "On the perspective of grid architecture model with high TSO-DSO interaction,", IET Energy Syst. Integr. vol. 3 (2021) 1–12, https://doi.org/10.1049/esi2.12003.
[3] M. Birk, J. Chaves-Ávila, T. Gómez and R. Tabors, "TSO/DSO coordination in a context of distributed energy resource penetration," *Proceedings of the EEIC,* MIT Energy Initiative Reports, pp. 2-3, 2017 https://ceepr.mit.edu/wp-content/uploads/2021/09/2017-017.pdf.
[4] N. Savvopoulos, T. Konstantinou and N. Hatziargyriou, "TSO-DSO Coordination in Decentralized Ancillary Services Markets," International Conference on Smart Energy Systems and Technologies (SEST), pp. pp. 1-6, 2019 DOI: 10.1109/SEST.2019.8849142.
[5] CEDEC. EDSO. ENTSOE, Eurelectric, GEODE, "TSO-DSO Data Management Report," 2016 https://www.entsoe.eu/2016/07/27/tso-dso-data-management-report/.
[6] European Commission, "Launching the public consultation process on a new energy market design," 2015 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2015%3A340%3AFIN.
[7] CEER, "7TH CEER Benchmarking Report on the Quality of Electricity and Gas Supply," Council of European Energy Regulators, 2022 https://www.ceer.eu/documents/104400/-/-/e19caae8-95cf-f048-0664-0720228881bb.
[8] EUDSO Entity and ENTSO-E, "EUDSO Entity and ENTSO-E DRAFT Proposal for a Network Code on Demand Response," 11 12 2023. [Online]. Available: https://consultations.entsoe.eu/markets/public-consultation-networkcode-demand-response/supporting_documents/Network%20Code%20Demand%20Response%20v1%20draft%20proposal.pdf. [Accessed 17 01 2024].
[9] A. Gonçalves Givisiez, K. Petrou, L. Ochoa, "A review on TSO-DSO coordination models and solution technique,", Electr. Power Syst. Res. vol. 189 (106659) (2020) https://doi.org/10.1016/j.epsr.2020.106659.
[10] H. Gerard, E.I. Rivero Puente, D. Six, "Coordination between transmission and distribution system operators in the electricity sector: a conceptual framework, Uti. Policy vol. 50 (2018) 40–48, https://linkinghub.elsevier.com/retrieve/pii/S0957178717301285.
[11] J. Silva, J. Sumaili, R.J. Bessa, L. Seca, M.A. Matos, V. Miranda, M. Caujolle, B. Goncer, M. Sebastian-Viana, "Estimating the active and reactive power flexibility area at the TSO-DSO interface,", IEEE Trans. Power Syst. vol. 33 (5) (2018) 4741–4750, https://doi.org/10.1109/TPWRS.2018.2805765.
[12] A. Papalexopoulos, R. Frowd, A. Birbas, "On the development of organized nodal local energy markets and a framework for the TSO-DSO coordination,", Electr. Power Syst. Res. vol. 189 (106810) (2020) https://doi.org/10.1016/j.epsr.2020.106810.
[13] S.Y. Hadush, L. Meeus, DSO-TSO cooperation issues and solutions for distribution grid congestion management, Energy Policy vol. 120 (09) (2018) 610–621, https://linkinghub.elsevier.com/retrieve/pii/S0301421518303823.
[14] Z. Yuan, M. Hesamzadeh, "Hierarchical coordination of TSO-DSO economic dispatch considering large-scale integration of distributed energy resources,", Appl. Energy vol. 195 (2017) 600–615, https://doi.org/10.1016/j.apenergy.2017.03.042.
[15] L. Lind, R. Cossent and P. Frías, "Evaluation of TSO–DSO Coordination Schemes for meshed-to-meshed configurations: Lessons learned from a realistic Swedish case study," Sustainable Energy, Grids and Networks, pp. vol. 35, p. 101125, Sep. 2023 DOI: 10.1016/j.segan.2023.101125.
[16] A. Vicente-Pastor, J. Nieto-Martin, D.W. Bunn, and A. Laur, "Evaluation of flexibility markets for retailer–DSO–TSO coordination, IEEE Trans. Power Syst. vol. 34 (3) (May 2019) 2003–2012, https://doi.org/10.1109/TPWRS.2018.2880123.
[17] F. Najibi, D. Apostolopoulou, E. Alonso, TSO-DSO coordination schemes to facilitate distributed resources integration, Sustainability vol. 13 (14) (2021) 7832, https://doi.org/10.20944/preprints202106.0089.v1.
[18] M. Rossi, G. Migliavacca, G. Viganò, D. Siface, C. Madina, I. Gomez, A. Morch, TSO-DSO coordination to acquire services from distribution grids: simulations, cost-benefit analysis and regulatory conclusions from the SmartNet project. Electr. Power Syst. Res. vol. 189 (2020) 106700 https://doi.org/10.1016/j.epsr.2020.106700.
[19] Y. Tohidi, M. Farrokhseresht and M. Gibescu, "A Review on Coordination Schemes Between Local and Central Electricity Markets," in *15th International Conference on the European Energy Market (EEM)*, Lodz, 2018 https://ieeexplore.ieee.org/document/8470004/.
[20] S. Vagropoulos, P.N. Biskas, A. Bakirtzis, "Market-based TSO-DSO coordination for enhanced flexibility services provision,", Electr. Power Syst. Res. vol. 208 (107883) (2022) https://doi.org/10.1016/j.epsr.2022.107883.
[21] J. Silva, J. Sumaili, R. Bessa, L. Seca, M. Matos, V. Miranda, The challenges of estimating the impact of distributed energy resources flexibility on the TSO/DSO boundary node operating points, Comput. Oper. Res. vol. 96 (ISSN 0305-0548) (2018) 294–304, https://doi.org/10.1016/j.cor.2017.06.004.

[22] IEEE, "IEEE Standard Power Cable Ampacity Tables," IEEE Std 835-1994, pp. 1-3151, 1994, doi: 10.1109/IEEESTD.1994.7297793.
[23] G. Prettico, F. Gangale, A. Mengolini, A. Lucas, G. Fulli, Distribution System Operators Observatory 2016, JRC Tech. Rep. (2016), https://doi.org/10.2790/701791.
[24] A. Saint-Pierre, P. Mancarella, "Active distribution system management: a dual-horizon scheduling framework for DSO/TSO interface under uncertainty,", IEEE Trans. Smart Grid vol. 8 (5) (2017) 2186–2197, https://doi.org/10.1109/TSG.2016.25.
[25] IEC, "IEC 60038 Standard Voltages," International Electrotechnical Commission, 2009 https://webstore.iec.ch/preview/info_iec60038%7Bed7.0%7Db.pdf.
[26] B. Blažic and I. Papic, "Voltage profile support in distribution networks – influence of the network R/X ratio," in *IEEE 13th International Power Electronics and Motion Control Conference (EPE/PEMC 2008)*, Poznan, Poland, 2008 http://ieeexplore.ieee.org/document/4635641/.
[27] Eurelectric, "Distribution Grids in Europe - Facts and Figures 2020," Brussels, 2020 https://cdn.eurelectric.org/media/5089/dso-facts-and-figures-11122020-compressed-2020-030-0721-01-e-h-6BF237D8.pdf.
[28] F. Martín Utrilla, J. Chaves-Ávila, R. Cossent Arín, Decision framework for selecting flexibility mechanisms in distribution grids, Econ. Energy Environ. Policy vol. 11 (2) (2022), https://doi.org/10.5547/2160-5890.11.2.fmar.
[29] R. Silva, E. Alves, R. Ferreira, J. Villar, C. Gouveia, "Characterization of TSO and DSO grid system services and TSO-DSO basic coordination mechanisms in the current decarbonization context,", Energies vol. 14 (2021) 4451, https://doi.org/10.3390/en14154451.
[30] G. Migliavacca, TSO-DSO interactions and ancillary services in electricity transmission and distribution networks: modeling, analysis and case-studies., Springer, Nature (2019), https://doi.org/10.1007/978-3-030-29203-4.
[31] European Commission, "Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing," 23 11 2017. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1485&from=ES. [Accessed 18 5 2024].
[32] A. Ramos, C. De Jonghe, V. Gómez, R. Belmans, Realizing the smart grid's potential: defining local markets for flexibility, Uti. Policy vol. 40 (2016) 26–35, https://linkinghub.elsevier.com/retrieve/pii/S0957178716300820.
[33] T. Schittekatte, L. Meeus, "Flexibility markets: Q&A with project pioneers,", Uti. Policy vol. 63 (2020) 101017 https://doi.org/10.1016/j.jup.2020.101017.
[34] M. Caramanis, E. Ntakou, W. Hogan, A. Chakrabortty, J. Schoene, "Co-optimization of power and reserves in dynamic T&D power markets with nondispatchable renewable generation and distributed energy resources,", Proc. IEEE vol. 104 (4) (Apr. 2016) 807–836, https://doi.org/10.1109/JPROC.2016.2520758.
[35] European Commission, "Comission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation," *Official Journal of the European Union,* 2017 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1485&from=ES.
[36] S.H. Elyas and Z. Wang, "Statistical analysis of transmission line capacities in electric power grids," IEEE Power & Energy Society Innovative Smart Grid Technologies Conference, pp. 1-5, 2016 DOI: 10.1109/ISGT.2016.7781263.
[37] C. Edmunds, S. Galloway, I. Elders, W.T.R. Bukhsh, "Design of a DSO-TSO balancing market coordination scheme for decentralised energy,", IET Gener., Transm. Distrib. vol. 14 (5) (2020) 707–718, https://doi.org/10.1049/iet-gtd.2019.0865.
[38] A. Bachoumis, C. Kaskouras, G. Papaioannou and M. Sousounis, "TSO/DSO Coordination for Voltage Regulation on Transmission Level: A Greek Case Study," in IEEE Madrid PowerTech, Madrid, Spain, 2021 DOI: 10.1109/PowerTech46648.2021.9495021.
[39] F. Qiu, Y. Zhang, R. Yao, P. Du, "Power system restoration with renewable participation,", IEEE Trans. Sustain. Energy vol. 14 (2) (2023) 1112–1121, https://doi.org/10.1109/TSTE.2022.3227166.
[40] W. Sun, C. Liu, L. Zhang, "Optimal generator start-up strategy for bulk power system,", IEEE Trans. Power Syst. vol. 26 (3) (2011) 1357–1366, https://doi.org/10.1109/TPWRS.2010.2089646.
[41] L. Söder, E. Tómasson, A. Estanqueiro, D. Flynn, B.-M. Hodge, J. Kiviluoma, M. Korpås, E. Neau, A. Couto, D. Pudjianto, G. Strbac, D. Burke, T. Gómez, K. Das, N. Cutululis, D. Van Hertem, H. Höschle, J. Matevosyan, S. von Roon, "Review of wind generation within adequacy calculations and capacity markets for different power systems,", Renew. Sustain. Energy Rev. vol. 119 (2020) 109540 https://doi.org/10.1016/j.rser.2019.109540.
[42] Electricity Market Regulation EU 2019/943, REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity, 2019 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943.
[43] M. Welsch, P. Deane, M. Howells, B.Ó. Gallachóir, F. Rogan, M. Bazilian, H. Rogner, Incorporating flexibility requirements into long-term energy system models – A case study on high levels of renewable electricity penetration in Ireland, Appl. Energy vol. 135 (ISSN 0306-2619) (2014) 600–615, https://doi.org/10.1016/j.apenergy.2014.08.072.
[44] O. Valarezo, T. Gómez, J. Chaves-Avila, L. Lind, M. Correa, D. Ulrich Ziegler, R. Escobar, "Analysis of new flexibility market models in Europe,", Energies vol. 14 (2021) 3521, https://doi.org/10.3390/en14123521.
[45] F. Capitanescu, TSO–DSO interaction: active distribution network power chart for TSO ancillary services provision, Electr. Power Syst. Res. Vols. 163 (Part A) (2018) 226–230, https://doi.org/10.1016/j.epsr.2018.06.009.
[46] H.L. Willis, "23. Distribution System Reliability Analysis Methods," in *Power Distribution Planning Reference Book*, CRC Press, 2004 https://doi.org/10.1201/9780824755386, pp. 819-832.
[47] Ministerio para la Transición Ecológica y el Reto Demográfico, "Calidad del servicio - Índices zonales agregados," [Online]. Available: https://energia.serviciosmin.gob.es/Gecos/DatosPublicos/IndicesAgregados. [Accessed 2023 11 30].
[48] G. Prettico, M.G. Flammini, N. Andreadou, S. Vitiello, G. Fulli, M. Masera, "Distribution System Operators observatory 2018,", JRC Sci. Policy Rep. (2019) https://doi.org/10.2760/104777.
[49] Red Eléctrica de España, "MAXIMUM INSTANTANEOUS POWER (MW) | ELECTRICITY SYSTEM:Peninsular," [Online]. Available: https://www.ree.es/en/datos/demand/maximum-instantaneous-capacity. [Accessed 27 11 2023].
[50] J. Núñez, J. Cepeda, G. Salazar, "Comparación Técnica entre los Programas de Simulación de Sistemas de Potencia DIgSILENT PowerFactory y PSS/E,", Rev. Técnica" Energ. ía" vol. 11 (1) (2015) 22–30, https://doi.org/10.37116/revistaenergia.v11.n1.2015.68.
[51] Siemens power technologies international, PSS®E 33.5 Program Operation Manual, Schenectady, NY, 2013 www.siemens.com/power-technologies.