MARKET ENABLING INTERFACE TO UNLOCK FLEXIBILITY SOLUTIONS FOR COST-EFFECTIVE MANAGEMENT OF SMARTER DISTRIBUTION GRIDS

Deliverable: D5.1

Identification of relevant market mechanisms for the procurement of flexibility needs and grid services

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Author(s)	Institution	Contact (*e-mail, phone*)
José Pablo Chaves	Comillas	jose.chaves@iit.comillas.edu
Matteo Troncia	Comillas	matteo.troncia@iit.comillas.edu
Leslie Herding	Comillas	leslie.herding@iit.comillas.edu
Nicolás Morell	Comillas	nicolas.morell@iit.comillas.edu
Orlando Valarezo	Comillas	orlando.valarezo@iit.comillas.edu
Kris Kessels	VITO	kris.kessels@vito.be
Annelies Delnooz	VITO	annelies.delnooz@vito.be
Janka Vanschoenwinkel	VITO	janka.vanschoenwinkel@vito.be
José Villar	INESCTEC	jose.villar@inesctec.pt
Jan Budke	Innogy/E.ON	jan.budke@eon.com
Joao Falcao	EDPD	joao.falcao@edp.pt
Pedro Marques	EDPD	carlospedro.marques@edp.pt
Carlos Cândido	EDPD	carlos.candido@edp.pt
Dominik Falkowski	Energa	dominik.falkowski@energa.pl
Miroslaw Matusewicz	Energa	miroslaw.matusewicz@energa.pl
Nicolas Métivier	Centrica	nicolas.metivier@centrica.com
Gesa Milzer	NODES	gesa.milzer@nodesmarket.com
Thomas Gueuning	N-SIDE	tgu@n-side.com
Pierre Crucifix	N-SIDE	pcu@n-side.com

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EASE	Brittney Elzarei	b.elzarei@ease-storage.eu	2021/01/29
EASE	Emin Aliyev	e.aliyev@ease-storage.eu	2021/01/29

Table of Contents

List of Figures

List of Tables

EUniversal UMEI

Abbreviations and Acronyms

Abbreviation	Meaning
ATC	Available Transfer Capacity
CapEx	Capital Expenditure
CEER	Council of European Energy Regulators
DAM	Day-Ahead Market
DER	Distributed Energy Resources
DG	Distributed Generation
DLMP	Distributional Locational Marginal Prices
DSO	Distribution System Operator
DNR	Distribution Network Reconfiguration
E.DSO	European Distribution System Operators
FSP	Flexibility Service Provider
FMO	Flexibility Market Operator
LMP	Locational Marginal Pricing
LRMC	Long-Run Marginal Cost
MO	Market Operator
NRA	National Regulatory Authority
PTDF	Power Transfer Distribution Factor
OpEx	Operational Expenditure
OPF	Optimal Power Flow
RES	Renewable Energy Sources
RCS	Remotely Controlled Switches
RTM	Real-Time Market
SRMC	Short Run Marginal Cost
TSO	Transmission System Operator
UMEI	Universal Market Enabling Interface
VPP	Virtual Power Plant

Executive Summary

Introduction

The EUniversal project, funded by the European Union, aims to develop a universal approach on the use of flexibility by Distribution System Operators (DSO) and their interaction with the new flexibility markets, enabled through the development of the concept of the Universal Market Enabling Interface (UMEI) – a unique approach to foster interoperability across Europe.

The UMEI represents an innovative, agnostic, adaptable, modular and evolutionary approach that will be the basis for developing new innovative services, market solutions and, above all, implementing the real mechanisms for the participation of active consumers, prosumers, and energy communities in the energy transition.

One of the EUniversal project's primary goals is to overcome existing limitations in the context of flexibility to be used by DSOs. The UMEI will be implemented to foster flexibility services provision and interlink active system management of distribution system operators with electricity markets.

The significant changes expected in the electricity system due to the energy transition and the related technology development with regards to digitalisation allow the customers to connect at distribution networks and be active participants by interacting with the system. Consumers with distributed energy resources can provide electricity back to the network by installing distributed generation and storage technologies, including electric vehicles. These technologies can provide a wide range of grid services and support grid planning and operation.

To take advantage of this potential, the European Commission in the Article 32 of the Directive (2019/944) requires the Member States to create incentives for DSOs to procure grid services with transparent, non-discriminatory market-based procedures, unless the regulatory authorities have established that such service procurement is not economically efficient or that such procurement would lead to severe market distortions or higher congestions. In this scenario, to solve grid problems, DSOs can resort to internal measures, including investments in network assets, or can also take advantage of third-party assets flexibility. This flexibility can be procured through different mechanisms. The acquisition of flexibility may not depend on one specific mechanism, but will rather consist of a combination. These mechanisms have to be carefully designed to adequately complement each other, provide coherent signals, and maximise the value from all resources. They can cover all timeframes from long-term planning to real-time operation.

This deliverable aims to identify the available options that DSOs have to acquire flexibility. Both market and non-market-based alternatives are considered. However, the focus is mainly on the former, since in compliance with the Directive non-market-based solutions should be an option only when economic efficiency cannot be guaranteed. This deliverable addresses this requirement by analysing different mechanisms to acquire grid services. The suitability of each of them is assessed considering relevant context attributes related to the DSO need and the Flexible Service Providers (FSP); and following a series of evaluation criteria.

The analysis of the mechanisms for acquiring grid service

The mechanisms to acquire grid services analysed are access and connection agreements, dynamic network tariffs, local flexibility markets, bilateral contracts, cost-based remuneration, and obligations.

In general terms, flexible access and connection agreements are agreements between the system operator and the FSP in which the latter agrees to have the connection curtailed in some periods. Dynamic tariffs concern devising time (and locational) differentiated network tariffs which can be adjusted to reflect the necessary temporal and spatial cost variations. Local flexibility markets include long-term and short-term pools in which offers are received from FSPs; the market is cleared according to the match between the demand for flexibility and offer. A bilateral contract is a binding agreement between the DSO and FSPs. Regarding grid services, one side is represented by the system operator while the other is the FSP. A cost-based mechanism deals with the remuneration of the flexibility provided by the FSP based on the actual costs of providing the service. The obligation mechanism for flexibility provision entails a mandatory service provision from the FSPs. All these mechanisms have specific features which are discussed in this report.

These mechanisms are evaluated for congestion management and voltage control, two of the main services tested in the EUniversal demonstrators. These mechanisms are discussed in detail to study strengths and weaknesses in light of grid service procurement. Each studied mechanism has different design elements that have to be carefully assessed before being implemented.

The proposed methodology for analysing the mechanisms for acquiring grid services aims to identify the most suitable one considering the characteristics of the needs for grid services. The underlying idea is that not all possible mechanisms for acquiring grid services have the same effectiveness if exploited in different grid contexts. The proposed methodology consists of three main steps: 1) description of each of the acquisition mechanisms; 2) analysis of the application of the mechanisms to acquire grid services to considered contexts; 3) assessment of the compliance of the mechanisms with the leading general regulatory principles.

The first step of the proposed methodology describes the crucial design elements of each mechanism for acquiring grid services from a standalone perspective. Each of the mechanisms has different elements that should be carefully considered when applied to different contexts to provide adequate solutions to the DSOs' needs.

As a second step, the context of the need for grid service has to be studied. In this deliverable, the context is defined as the set of characteristics or attributes of the DSO need. The mechanism for acquiring grid services has to be chosen according to context characteristic to enhance the flexibility procurement process. To this aim, the methodology identifies the subset of context attributes relevant for obtaining comprehensive information on DSO needs. The proposed set of context attributes includes aspects related to the grid needs (e.g., contracting timeframe, frequency of the need, the volume of the problem), to the affected grid area (e.g., grid topology, voltage level, the volume of available flexibility), and the potential FSPs in the area (e.g., size, FSP nominal voltage, number of expected FSP participants, and resources types of FSP). The attributes and the related metrics have been identified through a collaborative process which involved the project partners in an iterative survey.

Based on the identified context attributes and the defined metrics, the applicability of potential mechanisms for acquiring grid services is analysed qualitatively. The characteristics of each mechanism are discussed, considering the different context attributes to highlight possible gaps. The analysis outcome is a subset of eligible mechanisms valuable for being exploited in the actual context in which the DSO requires services.

The subset of eligible mechanisms is then assessed according to a set of evaluation criteria to determine compliance with the most acknowledged regulatory principles for promoting economic efficiency, transparency, reliability, customer engagement, equity, and considering implementation concerns. Each regulatory principle is discussed in detail to define relevant evaluation criteria to appraise the mechanisms for acquiring grid services. The definition and the relevance of the evaluation criteria have been obtained through a collaborative approach with project partners. Finally, the characteristics of each mechanism are studied individually according to the evaluation criteria. This step completes the overall evaluation of the mechanism for acquiring grid services.

Since the analysed mechanisms can be combined for emphasising the respective strengths while suppressing the respective drawbacks, this deliverable also addresses the qualitative analysis of the applicability of more complex mechanisms for acquiring grid services. A specific mechanism used as a standalone solution may fail to reduce network costs because it does not match with context attributes or evaluation criteria. For example, a local market mechanism is not suitable in the context in which the scarcity of potential providers would lead to market failures. Conversely, the combination of mechanisms can perform better. Congestion management and voltage control are considered independently. The combination of the mechanisms for acquiring grid services is made considering the same service and the same context in terms of network area and resources involved.

In defining the methodology and undertaking the appraisal of the market mechanisms, the stakeholders' point of view is assumed crucial. The perspective of stakeholders (DSOs and flexibility market operators), which will benefit from the assessment outcome, is essential to obtain an effective methodology. To this aim, the stakeholders' point of view on context attribute and evaluation criteria has been collected via surveys to identify the main aspects to be considered and understand the perceived relevance.

Conclusions and final remarks

The research activity described in this deliverable has led to the proposed methodology for appraising the mechanism for acquiring grid service and recommendations and guidelines to support identifying the most valuable mechanism according to the context characteristics. These aspects represent the main contributions of this deliverable.

Benefits and challenges related to the implementation of the studied mechanisms for acquiring grid services are identified and described in the deliverable.

Considering access and connection agreements, deep and shallowish connection charges, that incorporate the costs of network reinforcements needed to connect new installations, promote the efficient use of already existing hosting capacity. Flexible connections or non-firm access allow network reinforcements deferral. However, in some of the analysed countries, Portugal, Poland, and Spain, this is incompatible with current national regulation. In Ireland and the UK, non-firm generator access is in the implementation phase. Moreover, curtailment compensation or an agreement on predefined curtailment volumes between the DSO and the generators can balance the risk and benefit of flexible connections. Besides, transparency is a relevant factor and should be as high as possible in the connection and access processes.

Efficient dynamic network tariffs should send effective economic signals to customers to reduce network costs incentivising the development and efficient operation of new technologies (e.g., distributed generation, demand flexibility, storage, electric vehicles). To this aim, energy prices and network charges need to be highly granular in time and location. Smart metering deployment supports temporal granularity enhancement; however, determining critical tariff blocks and allocating costs is not straightforward. Locational granularity is challenging due to legal barriers, lack of data, high implementation costs, computing complexity of short-term and long-term costs, and other administrative burdens. A mild approach could include time-of-use charges, which are simpler to implement, even if less accurate. Furthermore, price differentiation can be based on voltage levels. Finally, residual network costs should be allocated in a non-distortive manner to avoid interfering with efficient price signals while considering allocative equity.

A local flexibility market is generally a technology-neutral solution to incentivise different assets to compete to provide grid services. Tailor-made solutions adapted to the DSO needs and FSPs characteristics are of interest. However, the implementation of these markets has many design challenges to be considered. Local flexibility markets may require complex coordination with existing markets and different agents. It is relevant to define the different agents' roles, functions, and responsibilities. These tailor-made solutions can become quite complex. Local flexibility market development requires standards for communication systems and information exchange. Concerns related to liquidity, grid representation and transparency are of utmost relevance. Furthermore, the characteristics of FSPs may affect the local market design. Trading local flexibility from resources that do not have their schedules requires developing and agreeing on a baseline methodology. Another challenge is that different resources may present rebound effects or specific technical constraints. Therefore, a balance between accounting for complex resource characteristics and a fast optimisation mechanism has to be found.

More regulated mechanisms, such as bilateral contracts, cost-based remuneration, and obligations, are alternatives when markets cannot work correctly due to market failures or implementation costs. When high transaction costs, high entry or exit barriers, the exercise of market power, low liquidity, uncertainty on market development, and high implementation costs strongly impact the functioning of market-based mechanisms a more regulated option can be considered. These regulated options may be alternatives that can manage market failures in standalone or in combination with other mechanisms previously discussed. In any case, obligations are the last option as they do not consider the involved cost to provide the services leading to under or overprovision.

The qualitative assessment was developed using an interactive approach and involving the DSOs and flexibility market operators participating in the EUniversal project. The assessment aims to evaluate the different market mechanisms' suitability for congestion management and voltage control.

According to the participants' point of view, almost the same set of context attributes can be used to describe the need for both congestion management and voltage control services. In general, the most relevant aspects when designing the mechanism for acquiring the grid services in each specific context are liquidity and the competition level. Moreover, the general view is that the mechanism for procuring grid services has to guarantee first operational security since it is exploited for solving grid issues. Then, economic efficiency and transparency are highlighted as relevant to achieve an economically optimal outcome for the participants.

In general terms, all the analysed mechanisms could work for congestion management but should be tailored to the specific context attributes. For voltage control, due to its local nature, bilateral contracts and obligations for guaranteeing a certain level of support may fit considering the attributes of this service. The use of flexible connection and access agreements, local flexibility markets, and cost-based mechanisms is case-specific and may work considering appropriate design aspects. Dynamic network tariffs do not fit well for voltage control.

In principle, a suitable mechanism for acquiring grid services for congestion management can be obtained combining different approaches, e.g., connection and access agreements can fit with the dynamic network tariffs, cost-based, and obligation mechanisms. Combining the connection and access agreements with local flexibility markets and bilateral contracts raises the challenge of the possible limitations introduced by the flexible connection agreements and the possibility of engaging on other mechanisms. Dynamic network tariffs can work in parallel with local flexibility markets and bilateral contracts; however, the interaction between the two mechanisms has to consider the context constraints. The interaction of the dynamic network tariffs and the cost-based mechanism is challenging because they are based on different principles. Local flexibility markets can be combined with bilateral contracts; however, the context constraints have to be considered to devise a valuable combined mechanism. Local flexibility markets and cost-based mechanisms can be exploited in a combined mechanism considering different service products such as capacity and activation mechanisms. Moreover, the combination of local flexibility markets with the obligation mechanism can be complementary. In this case, obligations intend to guarantee a minimum availability level and local markets intend to meet the specific requirements adapted to local characteristics.

For voltage control, fewer combinations are suitable due to the local characteristic of the service. Flexible connection and access agreements could be combined with local flexibility markets or bilateral contracts. However, as for congestion management, it raises the challenge about the possible limitations introduced in local markets participation by the flexible connection agreements as well as the timeframes and locations. Again, obligation mechanisms could guarantee minimum flexibility quantities. Then, the combination of local flexibility markets and bilateral contracts could be introduced considering different mechanisms depending on locations and level of potential competition (e.g. if in a certain area no competition is expected since the small number of FSPs, bilateral agreements may represent the most valuable mechanism to be adopted). Combining the local flexibility markets and the cost-based mechanisms could be achieved by using different mechanisms for capacity and activation. For capacity, a local market can guarantee investments in new resources to provide voltage control. In contrast, for activation, a cost-based method can guarantee an efficient allocation if costs are easily known.

1 Introduction

1.1 Document scope and structure

The EUniversal project, funded by the European Union, aims to develop a universal approach on the use of flexibility by Distribution System Operators (DSO) and their interaction with the new flexibility markets, enabled through the development of the concept of the Universal Market Enabling Interface (UMEI) – a unique approach to foster interoperability across Europe.

The UMEI represents an innovative, agnostic, adaptable, modular and evolutionary approach that will be the basis for the development of new innovative services, market solutions and, above all, implementing the real mechanisms for active customers' (e.g. consumer, prosumer, and energy communities) participation in the energy transition.

One of the primary goals of the EUniversal project is to overcome existing limitations in the context of flexibility to be used by Distribution System Operators (DSOs). The UMEI will be implemented to foster the provision of flexibility services and interlink active system management of distribution system operators with electricity markets.

With the expected increase of renewable generation connected to distribution networks and the increasing electrification of energy usages such as transportation, climatization of buildings, industrial processes, among others, the need for reinforced electricity distribution networks increases. Alternatives to traditional network investments, such as the use of flexibility by DSOs, can lead to more efficient use of the existing grid and potential deferral of network investments which finally leads to lower overall system costs.

As part of the main goal, the EUniversal project aims to develop a universal approach for the use of flexibility by DSOs and their interaction mechanisms to acquire flexibility. The EUniversal project directly addresses the requirement of Article 32 of the Directive (2019/944) [1] on common rules for the internal market of electricity which sets requirements on the use of flexibility in distribution networks; specifically, it stipulates that: "*Member states shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system*." Furthermore, the article states that "*distribution system operators 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*."

DSOs have various alternatives to solve grid problems; on the one hand, DSOs can resort internal measures, including investments in network assets. On the other hand, DSOs can take advantage from the flexibility of third-party assets procuring it through rule-based mechanisms, connection and access agreements, dynamic network charges and procurement of flexibility through local markets, bilateral contracts or cost-based mechanisms. The acquisition of flexibility may not depend on one specific mechanism, but will rather consist of a combination. These mechanisms have to be carefully designed to complement each other adequately, provide coherent investment signals, and maximise the value from all resources. They can cover all timeframes from long-term planning to real-time operation.

This deliverable specifically aims to identify the different available options that DSOs have to acquire flexibility. Both market and non-market-based alternatives are considered. However, the main focus is on the former in compliance with the Directive, since non-market-based solutions should be an option only when economic efficiency cannot be guaranteed. Furthermore, the Council of European Energy Regulators [2] highlights relevant design aspects for designing a framework to assess procedures for procuring flexibility by DSOs which are considered part of the guiding principles and attributes to be considered in this deliverable.

The rest of the document is organised as presented in Figure 1-1. Section 2 presents the methodology followed in this deliverable which includes the identification of relevant context attributes and the definition of the criteria used to evaluate the alternative mechanisms to acquire grid services. Chapter 3 describes acquisition mechanisms in detail including design alternatives for each of them. Chapter 4 describes the services considered in the EUniversal project and the relevant context attributes of the network and flexibility service providers. Chapter 5 illustrates the qualitative appraisal of the acquisition mechanisms considering both the evaluation criteria and context attributes with a focus on congestion management and voltage control. Chapter 6 summarises the main findings and points out the expected further steps for the extension of the analysis within the EUniversal project.

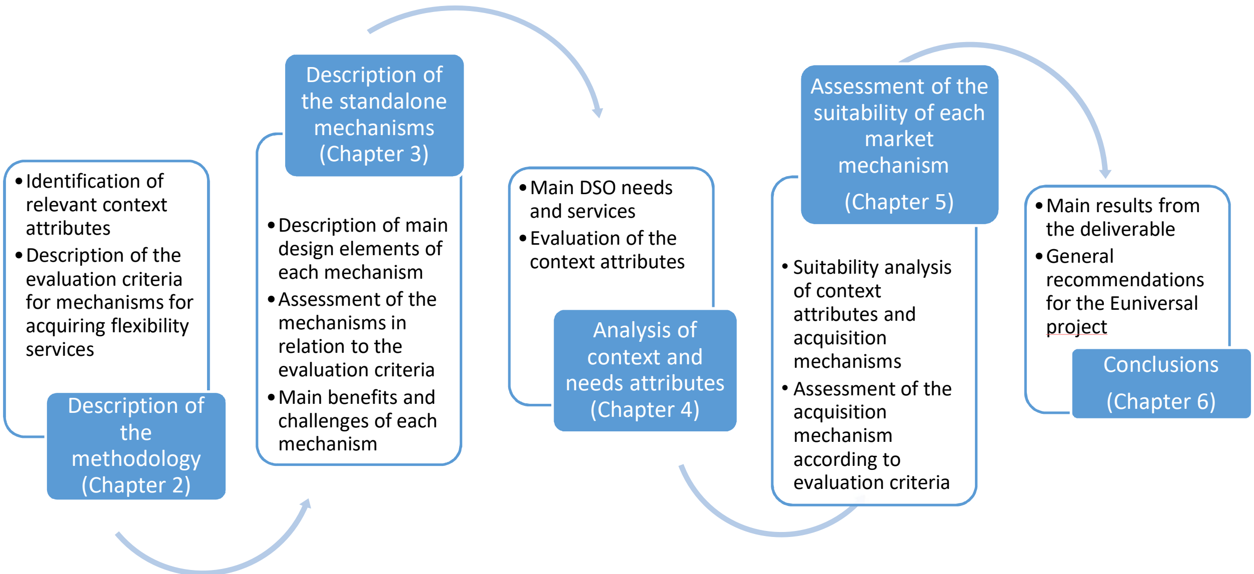

Figure 1-1. Organisation of the deliverable

1.2 Flexible resources characteristics

Any mechanism for acquiring grid services shall aim for technology neutrality. Therefore, it is relevant to have in mind the principal characteristics of flexible resources. Due to the great variety of resources which can support the power system by providing grid service with their flexibility, this section provides a brief and general description of the flexible resource characteristics. Deliverable D3.1 "Flexibility Toolbox" describes in detail the different technologies that could provide flexibility in the distribution and transmission system, such as different storage technologies and demand-side flexibility [3]. Table 1-1 reports the Flexibility Toolbox located at Distribution networks as reviewed in [3]. The assets that can provide flexibility to the distribution system are classified in Table 1-1 in terms of the timeframe provision and the capability to provide active and reactive power.

The short-, middle and long-term flexibilities refer to the capacity to change the load/generation over time. Flexibility at short-term refers to a period that goes from some minutes to some hours, medium-term from some days to some months, and long-term to any longer period [3]. For completeness, active power is defined as the real component of the power vector that produces the electricity used to power devices. Reactive power provision regards the provision of the imaginary component of the power vector that allows the whole system to maintain a constant and controlled voltage supply. If reactive power does not work correctly, there could be damages to the devices used in an electric system, such as transformers, capacitors, generation, transmission, and distribution equipment.

1.2.1 Characteristics of third-party resources

There are a wide variety of flexible technologies connected at distribution networks which can provide grid services such as demand-side sources, storage technologies, generators or even flexibility from DSO assets [3]. There is a wide range of technologies that can provide both active and reactive power at different timeframes. However, as recognised in Deliverable D3.1 [3], many of the flexibility toolbox solutions are not yet widely deployed on the market.

For storage technologies, some of the critical parameters to consider are the service duration and the consideration of the state of charge adjustment (fundamental for batteries with limited capacity), which are relevant to determine different response times. For residential and small commercial demand-side flexibility, it will be critical to integrate an energy management system to allow an automatic response. For demand-side resources, aggregation can be a key enabler for unlocking their flexibility. Besides, it is relevant to avoid entry barriers such as expensive communication systems or additional metering infrastructure. Smart EV charging, either unidirectional but even more with bidirectional possibilities, is potentially a big source of flexibility. As with other technologies, providing suitable economic incentives will be key to avoid rebound effects. Communication standards and protocols between the DSO and FSPs are key aspects to obtain relevant data for forecasting purposes as well as to enable the provision of flexibility from DER.

Industrial demand-side flexibility can move significant volumes, but on the other hand, it is dependent on diverse industrial processes which may need dedicated control and energy management systems to provide flexibility. As reported in [3], this flexibility can have a low availability cost but a high activation cost.

The rebound behaviour (also known as rebound effect or payback effect) can be defined as the over or underconsumption that happens before or after a flexibility activation [4], [5]. The rebound effect is especially relevant when flexibility from FSPs is aimed to solve congestions. Such timeframes can last several hours; hence, it is likely that rebound behaviour can aggravate a grid situation.

Depending on the market design and specific products, multiple mitigations can be considered:

- If the market clearing covers multiple periods, such as the day ahead spot market, the rebound effect can be inherently included in the product, for example, through linked/loop orders or equivalent. As such, the effect of the rebound is exposed to the clearing algorithm where it can be accounted for.

- In case the products are not supporting rebound effects, this can be mitigated through aggregation. The aggregator receives the congestion timeframe through the needs/order expressed by the DSO as part of the product, and then the aggregator needs to configure and optimise its pool to comply with the needs.
- Alternatively, one can characterise the volume of the rebound effect and constrain the optimisation algorithm in volume or time of the rebound effect, such as explored in [6]. So, the FSP will try to minimise the rebound, and the market can "learn" the effective rebound and take it into account in the clearing process.

Table 1-1. Flexibility Toolbox located at Distribution networks. Source: [3]

Flexible technologies	Flexibility at short-term	Flexibility at medium-term	Flexibility at long-term	Reactive power	Active power
Compressed Air Energy Storage	☺	☺	☺	☺	☺
Liquid Air Energy Storage	☺	☺	☺	☺	☺
Sensible Heat Thermal Storage	☺	☺	☺	☹	☺
Pumped hydro storage	☺	☺	☺	☺	☺
Thermochemical Storage	☺	☺	☺	☺	☺
Power to Hydrogen	☺	☺	☺	☺	☺
Supercapacitors	☺	☹	☹	☺	☺
Lead-acid Batteries	☺	☺	☹	☺	☺
Li-Ion Batteries	☺	☺	☹	☺	☺
Li-Polymer Batteries	☺	☺	☹	☺	☺
Li-S Batteries	☺	☺	☹	☺	☺
Metal-air Batteries	☺	☺	☹	☺	☺
Na-S Batteries	☺	☺	☹	☺	☺
Vanadium Redox Batteries	☺	☺	☹	☺	☺
Dynamic Line Rating	☺	☹	☹	☹	☺
Residential DR – Thermostatically Controlled Loads	☺	☺	☹	☹	☺
Residential DR /Shiftable loads	☺	☹	☹	☹	☺
Industrial loads	☺	☺	☹	☺	☺
Microgrids	☺	☺	☹	☺	☺
Smart charging	☺	☹	☹	☹	☺
Distribution network flexible assets and control	☺	☹	☹	☺	☹
Renewable self-consumption solutions	☺	☹	☹	☺	☺
Active power control of RES	☺	☹	☹	☹	☺

1.2.2 DSO owned flexibility technologies

DSOs can currently own and operate, under certain conditions, specific technologies which provide flexibility to the grid. However, these technologies can compete with third-party technologies. Therefore, regulation should create a level playing field between third party resources and those resources owned by the DSOs, to finally favour the minimum cost option from the system point of view. This section describes the flexibility that the resources owned by the DSO can provide to distribution system operation.

Distribution Network Reconfiguration (DNR) is a direct congestion management method directly implemented by the DSO in different time frames. The DNR integrates the control of the tie and sectionalising switches to adjust the network topology, changing the status of some normal-open switches and normal-closed switches, changing taps of transformers or setting the control of linear regulators. The potential benefits of the network reconfiguration are loss minimisation, improvement of the voltage profile, load balancing, increase in DER penetration, and reduced network operation costs. Therefore, DNR is an option to solve congestion and voltage problems.

DNR can be classified as a static or dynamic reconfiguration. The static reconfiguration considers the operation of manually and remotely controlled switches (RCS) to decide the distribution system topology fixed for a yearly, seasonal, monthly, or a shorter timeframe. The dynamic reconfiguration considers the change of the topological structure of the distribution network in real-time by changing the RCS to remove congestions [7]. The DNR problem is a highly complex combinatorial problem. Traditionally, the optimal network reconfiguration is formulated as a mixed-integer linear optimisation problem due to the binary variables representing the status of the switches and to the nonlinear characteristics of power flow constraints.

Given the explicit benefits of network reconfiguration (mentioned earlier), there has been a growing literature on the DNR problem over the past years, and it remains an actual working topic. The authors in [8] demonstrate that using an hourly network reconfiguration can significantly reduce both wind and solar curtailments for distribution systems with a high DG penetration. In [7], a multi-period Optimal Power Flow (OPF) is proposed to maximise the distributed generation hosting capacity using network reconfiguration. Here the dynamic reconfiguration has a better performance in terms of hosting capacity than the static approach. In [9], a dynamic DNR for a three-phase unbalanced distribution network is presented. The case studies illustrate that the power loss can be significantly reduced by implementing DNR.

Previous research has shown that co-optimising network topology and the dispatches of the DERs could further enhance such operational benefits. In [10], an optimal network reconfiguration model is proposed where the operations of voltage regulation devices and different types of DERs are co-optimised with unbalanced three-phase AC power flow constraints. Their findings highlight that network reconfiguration could significantly reduce distribution system operation costs.

A gap in the literature regarding network reconfiguration is that the stochastic behaviour of DER and the cost of switching are not considered. The switches tend to fatigue more easily during frequent operations. Although digitalisation and rollout of smart meters would determine an increased frequency of switching since the enabled active management of the distribution network, currently MV and especially LV grids do not have a large number of reconfiguration options. To select the best candidate switches, a pre-process is crucial for practical implementations of the dynamic DNR problem, reducing the number of binary variables into the optimisation problem. This implies better computational performance. For instance, [11] presents a method to identify the critical switches in a pre-process where the switches are categorised in terms of the reduction in DG curtailments by dynamic DNR. As a result, the most effective switches will be considered in the optimisation simulation. Extensive reviews of the more recent methods to solve the distribution network reconfigurations using heuristic, metaheuristic, and exact methods are presented in [12] and [13].

Compared to transmission systems, the distribution networks at MV and LV have been traditionally characterised by lower levels of observability and controllability. The DSO has historically fewer network resources that could be directly exploited as a source of flexibility. Under specific conditions, other potential flexibility solutions owned by the DSOs are energy storage devices (batteries)[1], voltage booster, and On Load-Tap Changers (OLTC) of transformers [14].

Voltage boosters and OLTC are network assets which are designed for keeping bus voltages within predefined limits, and they can therefore be exploited by the DSO for providing flexibility especially for voltage control [14], but to a certain degree also for congestion management. The participation of OLTC transformers in voltage regulation is effective. However, the real-time voltage control is limited to the capability of the technology employed to receive and respond to the setpoint signals. Moreover, extensive use of the OLTC switching mechanism implies higher CapEx and OpEx [15].

The energy storage devices connected to the grid through an inverter can provide flexibility by modifying the active and reactive power output according to the operation requirements. Therefore, the batteries can provide flexibility both for congestion management and voltage control [16]–[18].

Distribution energy storage devices are introduced in the planning stage as an alternative to network reinforcements and for solving congestion and voltage problems in [16]–[18]. In [17] a robust optimisation approach for storage siting and sizing is proposed for a distribution MV network. However, the ownership of storage devices by the distribution system operator could be restricted by the regulatory framework established by [1].

Furthermore, solid-state transformers and controllable shunt devices, such as reactors and capacitors banks, connected to the distribution network can be technically exploited by the DSO as a flexible asset for voltage control.

In [19], to minimise loss and to improve the voltage profile, a mixed-integer nonlinear programming approach for capacitor siting and sizing in radial/mesh distribution systems is used. In [20], a similar problem is solved by exploiting a Tabu search approach.

For addressing the voltage control issues, distribution system non-conventional reinforcement options are evaluated in [21]. The DNO Scottish Power Energy Networks (SPEN) analyses the introduction of STATCOMs in the four areas of the MV grid. The study shows that the use of STATCOMs is technically feasible and economically viable, but the Cost-Benefit Analysis (CBA) highlights that economic viability is highly case dependent.

The use of dynamic voltage regulation in the MV network in coordination between the OLTC of the HV/MV transformer is studied by the French DSO (Enedis) in [22]. The goal is to increase the hosting capacity of the distribution network by introducing a voltage regulation algorithm based on a Weighted Least Square Distribution State Estimator which coordinates the actions of the voltage control devices. Since the positive result of the simulation phase, Enedis is planning to test the voltage control framework on a pilot demonstrator.

In [23], the results obtained during a trial deployed in the Western Power Distribution (UK) network about a centralised voltage control are presented. To increase network capacity, the implemented System Voltage Optimisation (SVO) dynamically adjusts the set-point for the automatic voltage control of OLTC HV/MV transformer based on the actual network operating conditions evaluated in

[1] The EU Directive 2019/944 in article 36 states that Member States may allow distribution system operators to own, develop, manage or operate energy storage facilities in exceptional basis and under specific conditions when the market cannot deliver it.

real-time. The studies on 33 kV and 11 kV networks revealed a successful increase in the hosting capacity. However, this control scheme increases the number of tap changes and as such may shorten the expected lifetime of the transformer.

Finally, techniques such as the Dynamic Line Rating can represent a source of flexibility for the DSO for congestion management [24].

2 Overview of the methodology used in the deliverable

The proposed methodology aims to support the identification of the most suitable mechanism for acquiring grid services by the DSO from third party assets. This deliverable focuses mainly on two grid services: congestion management and voltage control, as these services will mainly be targeted by the EUniversal demonstrations. Since solving congestion and voltage problems is case-specific, the methodology proposed in this deliverable aims at assessing the applicability of the mechanisms for acquiring grid services considering the context characteristics of the DSO needs. The underlying idea is that not all possible mechanisms for acquiring grid services have the same effectiveness if exploited in different grid contexts. Therefore, the context of the need for grid service is studied to identify the main attributes for providing a comprehensive description. Moreover, evaluating the mechanisms for acquiring grid services is supported by a set of criteria that represent some key regulatory principles.

The proposed methodology consists of three main steps:

i. Description of each of the acquisition mechanism standalone

ii. Analysis of the application of the mechanisms to acquire grid services to considered contexts

iii. Assessment of the compliance of the mechanisms with the main general regulatory principles

The first step of the proposed methodology is focused on the **description of key design elements for each mechanism** for acquiring grid services from a standalone perspective. Each of the mechanisms has different elements that should be carefully considered when applied to different contexts to provide adequate solutions to the DSOs needs.

In this deliverable, the **context** is defined as a set of characteristics or attributes of the DSO needs and the resources which can satisfy those needs by providing grid services. The spatial context dimension ranges from a bus to an entire country. Furthermore, the network where the need occurs is part of the context and it can include parts of transmission and distribution networks simultaneously. In temporal terms, the context is defined by the procurement timescale.

The **context attributes** related to the DSO needs strongly influence the effectiveness of the mechanism for acquiring grid services which could be exploited. Therefore, the mechanism for acquiring grid services has to be chosen accordingly. To this aim, as a first step, the methodology identifies the subset of context attributes relevant for obtaining comprehensive information on DSO needs. The proposed set of context attributes consider complementary aspects which ensemble provide a comprehensive picture of the context of the need for grid service. These attributes are related to the grid needs (e.g., volume and frequency of the need for grid service), to the affected grid area (e.g., grid topology, voltage level, the volume of available flexibility), and the potential FSPs in the area (e.g., number and type of FSPs).

Based on the identified context attributes and the defined values, the applicability of potential mechanisms for acquiring grid services is analysed qualitatively. As described in section 5, the characteristics of each mechanism are discussed, considering the different context attributes to highlight possible gaps. The outcome of this analysis is a subset of eligible mechanisms valuable for being exploited in the actual context in which the DSO requires services.

The designed subset of eligible mechanisms is then assessed according to a conceptual framework structured in objective, principles, evaluation criteria, indicators, and means of verification [25]–[27].

- The objective is the goal that has to be achieved, the problem to be solved, the mission to be accomplished.
- The principles represent the fundamentals on which all the actions for achieving the objective have to be based on. In general, the principles are defined in terms of broad statements which

provide the essential elements to be considered in devising or assessing the actions to reach the objective. Principles can highlight allowed and forbidden paths for the actions.

- The criteria are second-order principles. Criteria represent the operational definition of the principles. Criteria are in line with the set of principles and it is possible to define specific criteria that realise a specific principle (between the principle and criteria sets exist the surjective or the bijective relationship). Criteria are defined to understand if the principles are met and identify the characteristics of the options that require to be evaluated. Therefore, criteria are defined to allow to measure how much each action considered to achieve the objectives is valuable.
- The indicators are the metrics defined to measure the extent to which each action met the criteria. The bijective relationship links the criteria and indicators sets. The indicators can be based on quantitative or qualitative metrics to measure how much each action regarding a specific criterion is valuable. Therefore, each indicator is the measurable counterpart of the related evaluation criterion. The definition of indicators is case-specific.
- The means of verification (or verifiers) enhance the realisation of the indicators used. In general, verifiers are extremely case-specific since they provide the desired condition of an indicator. Verifiers define thresholds for indicators value and the methods used for determining the measurement of the related indicators.

In this Deliverable, the objective of the overall assessment approach is to select the most suitable mechanism for acquiring grid services considering the context characteristics. The principles considered for devising the mechanism for acquiring the grid services, and hence, appraising them, are the general regulatory principles for promoting economic efficiency, transparency, reliability, customer engagement, equity, and considering implementation concerns. To appraise how much each mechanism for acquiring grid service is valuable, a set of evaluation criteria related to this principle are defined. Since this deliverable describes the formalisation of a general framework for appraising mechanisms for acquiring grid services and, considering indicators and verifiers are case-specific, the discussion of these two elements is out of the scope. However, it is worth to underline that, in case-specific exploitation of the proposed methodology, indicators and verifiers have to be defined according to the evaluation criteria to which they refer.

Therefore, the defined set of **evaluation criteria** is used for assessing the subset of eligible mechanisms for acquiring grid services in terms of their compliance with the general principles. This third step completes the evaluation made in step two, which assesses the mechanism concerning the context in which the mechanism has to be exploited.

The perspective of stakeholders (e.g., DSOs, market operators), which will benefit from the analysis outcome, has to be considered to obtain an effective methodology. To this aim, the stakeholders' point of view on context attribute and evaluation criteria has been collected through a questionnaire, which template is available in Annex I. Based on provided feedback, the collected information allows to identify the main aspects to be considered and understand the perceived relevance. Finally, the specificities of both congestion management and voltage control are described as well as the combination of the mechanisms.

For the sake of clarity, in section 2.1, a brief description of the context attributes is provided, while in section 2.2, the evaluation criteria are described.

2.1 Description of the context attributes

Context attributes strongly influence the effectiveness of the acquisition mechanism that could be exploited; therefore, the latter has to be chosen accordingly. A collaborative approach has been followed to identify the context attributes relevant for assessing the acquisition mechanisms suitability. For brevity, the result of the assessment is described in this section. A detailed explanation of the process used for defining the context attributes is provided in section 4.2.

For congestion management and voltage control, the aspects identified as relevant for describing the context and the need are **voltage level, contracting timeframe, frequency of the need, the volume of the problem, network type,** and **the ratio of the volume of flexibility available to the volume needed**. Moreover, **the FSP size, FSP nominal voltage, number of expected FSP participants,** and **resources types of FSP** are relevant aspects which have been considered for describing the system context.

The analysis of the context attributes, considered a whole, allows understanding the main requirements of the need and its characteristics. Moreover, the context attributes analysis allows to determine the conditions under which the acquisition mechanisms show the highest effectiveness. It is worth noting that combining the information provided by each context attribute allows describing the need for grid services.

In Table 2-1, an overview of the context attributes, considered in the qualitative analysis, is provided. Without loss of validity, only qualitative attributes are considered. For generality, since the attributes are complementary, all the attributes are considered for defining the overall description of the context of the need for grid service. The authors acknowledge that the definition of qualitative and quantitative values are highly case-specific. The attributes and the corresponding qualitative values in Table 2-1 represent the outcome of a survey which involved the project partners. For the sake of clarity, a detailed explanation of each context attribute and the corresponding values are provided in section 4.2, which addresses the topic of the context analysis.

Table 2-1. Context attributes relevant for acquisition mechanisms

Context attributes	Description	Qualitative values
Voltage level	The nominal voltage of the portion of the grid in which the contingency occurs	• High voltage • Medium voltage • Low voltage
Contracting timeframe	The period from the agreement between the parties to the expected moment of the service provision	• Real-time • Short-term • Long-Term
Frequency of the need	Number of occurrences that FSPs are required to provide the service considering a predefined time interval	• Low • Medium • High • Very High
Volume of the problem	Amount of active/reactive power required to overcome the grid problems	• High • Medium • Low
Network type	Network topology	• Radial • Meshed
FSP size	Specific size (and typology) of potential providers in terms of size and architecture	• Large FSP / Aggregation of small FSP • Small FSP / No Aggregation
FSP nominal voltage	The nominal voltage of the network to which each potential FSP is connected	• High voltage • Medium voltage • Low voltage
Number of expected FSP participants	Number of participants which can potentially provide the flexibility support	• Large • Medium • Small
Resources types of FSP	Typology of resources which represent the potential FSPs	• Generation • DSR • Storage
Ratio of the volume of flexibility available by the volume needed	Derived attribute, it provides a measure of the degree of competition and liquidity	• Low • Medium • High

2.2 Definition of the evaluation criteria for mechanisms for acquiring flexibility services

The guiding principles for designing the acquisition mechanisms, identified in this deliverable, include six main principles: **economic efficiency, transparency, equity, reliability, implementation concerns,** and **customer engagement**. While the first three principles are highlighted in [2] but also reliability is highlighted as one of the main objectives of any mechanism. In [28], implementation concerns and customer engagement are additional objectives to be considered. Even if the mechanism for acquiring grid services has to comply with the general regulatory principles, each mechanism satisfies these principles differently. In this Deliverable, each principle is broken down according to one or more criteria.

Depending on the mechanism, the economic efficiency principle can conflict with other principles such as equity or implementation concerns. Therefore, a balance between competing principles has to be achieved when considering alternative mechanisms or variations of them. The definition of each guiding principle is provided below. A more detailed description of these principles is provided in chapter 3.

Economic efficiency is the main guiding principle to guarantee an optimal allocation of resources, and it has different dimensions: short-term and long-term perspectives. Short-term efficiency refers to an optimal dispatch of resources that can be generators and demand and energy storage systems. In the short-term, investments options are not considered, but optimal energy flows and network constraints should be included. The long-term efficiency accounts for an optimal evolution of the system considering investment options from energy resources and networks. A key challenge when considering an efficient design of acquisition mechanisms at the distribution network is to incorporate acquisition mechanisms within the planning and operation of distribution networks, which is a regulated activity. This economic efficiency principle can be divided into different criteria [29]:

a. Allocative (static and dynamic) economic efficiency
b. No exercise of market power
c. Technology neutrality
d. Low entry barriers
e. Limited information asymmetry between the flexibility buyer and sellers
f. Limited uncertainty

The *allocative economic efficiency* measures the optimisation of the short-term and long-term distribution of goods or services considering the related demand. Allocative efficiency exists when the marginal cost equals the marginal utility of the good or service.

Market power is the ability of sellers to alter the market price of a good or service and to increase it above the actual marginal cost. Market power has to be avoided since it introduces distortions in allocating costs and benefits.

Technology neutrality ensures the absence of technical barriers for providing a service/good. If an acquisition mechanism is technologically neutral, the same regulatory principles are applied regardless of the technology adopted [30]. Therefore, any technology can be adopted if the product or service provided by different technologies is identical.

To allow the highest level of potential competition, the mechanism for acquiring grid services has to show *low entry barriers* for new providers. To illustrate, entry barriers are defined by start-up costs, regulation or switching costs. Considering grid services, product standardisation reduces entry barriers; however, ICT requirements may become an entry barrier.

The *asymmetry of information* exists when one of the parties has greater knowledge than the others. Economic efficiency is increased as the information asymmetry is reduced since a better level playing field is obtained.

Another element related to economic efficiency is the *management of uncertainties*. Efficient market prices are achieved if all factors are known. Unknown factors produce market instability and can lead to market uncertainty. Therefore, a mechanism for acquiring grid services, capable of reducing the impact of uncertainties, leads to an augmented economic efficiency.

Transparency is a general principle for designing mechanism since it allows to audit the processes related to service provision and the related costs. The higher the transparency of the mechanism for acquiring grid services, the higher the parties and other stakeholders' awareness. Transparency can be an essential factor for achieving social acceptance; a high level of transparency encourages customer participation in all the services. In this Deliverable the transparency principle is formalised by the namesake criterion which measures the level of transparency guaranteed by each mechanism for acquiring grid services.

A mechanism for acquiring grid services shows **equity** if it pursues fair conditions among the stakeholders. The definition of the equity principle has been proposed for tariffs; however, it can be generalised for covering all mechanisms to acquire grid services. The equity principle can be split into specific criteria [31]:

a. Allocative equity
b. Distributional equity
c. Transitional equity

A*llocative equity* is the criterion that evaluates if identical usages/exploitations are charged/paid equally. One of the main implications of allocative equity is that marginal consumption/production is charged/paid according to the marginal cost/value it creates. This can be assumed cost-reflective and would conduce to a more efficient system.

The *distributional equity* criterion evaluates if the burden on the involved subject is proportional to each user's economic capability. This is particularly relevant to allocate residual network costs as described in section 3.3.3.1.3.

The *transitional equity* criteria evaluated if a transition from an old to a new mechanism is being gradually implemented.

The **implementation** of each mechanism for acquiring grid services raises **concerns** which can be analysed considering:

a. Implementation costs (including transaction costs)
b. Complexity
c. Effectiveness
d. Alignment with EU market regulation.

The *implementation costs* criterion measures all the costs required to fully deploy the mechanism for acquiring grid services and establishing communication among the parties involved in the grid service provision.

The *complexity* criterion appraises the fact that each mechanism for acquiring grid services is characterised by a different level of complexity, which depends on the procedures adopted, the related features, the (market) algorithms used and the implementation requirements.

The *effectiveness* criterion appraises the capability of the adopted procedure in procuring the required quantity of goods and services without the risk of under/over procurement.

For real cases, implementing a mechanism for acquiring grid services cannot ignore compliance with the current and future regulatory frameworks. Since Europe is the project context, the *alignment with the current end expected EU market regulation* criterion is of interest.

The **customer engagement** principle regards the fact that customers aware of their electricity use are more willing to participate and take up an active role in the grid operation. Therefore, the *customer engagement* principle provides a measure of how the customers are involved in the flexibility provision, such as the volume of flexible active/reactive power.

The **reliability** principle of a mechanism for acquiring grid services refers to the certainty that the contracted FSPs deliver the contracted service. The related *reliability* appraises the extent to which each mechanism for acquiring grid service is reliable in delivering the actual volume of contracted services.

Table 2-2 resumes the definition provided for the general principles and the proposed evaluation criteria.

Table 2-2. Overview of the principles and the evaluation criteria

Principle	Criteria	Description
Economic efficiency [29]	Allocative economic efficiency	Optimality of the distribution of goods or services considering the related demand.
	No exercise of market power	The ability of FSPs of altering the market price of a good. It has to be limited.
	Technology neutrality [30]	Absence of specific technical barriers for participating in the service/good provision.
	Low entry barriers	Entry barriers are any aspect that can discourage the participation of new players.
	Limited information asymmetry	Unfair dissemination of the information among players. It has to be limited to prevent distortions.
	Limited uncertainty	Unknown factors produce market instability. The uncertainty has to be reduced to achieve efficient market prices.
Transparency	Transparency	Allowing auditing the processes related to service provision and the related costs.
Equity [31], [32]	Allocative equity	Is a general principle that pursues that identical usages/exploitations have to be charged/paid equally.
	Distributional equity	The burden should be proportional to the capability of each user.
	Transitional equity	It states that a transition from an old to a new mechanism should be gradually implemented.
Implementation concerns	Implementation costs	All the costs required for achieving a full deployment of the mechanism for acquiring DSO services.
	Complexity	The complexity related to the procedures, iterations, and algorithms that are required for implementing the mechanism.
	Effectiveness	The capability of the adopted procedures in procuring the required quantity of goods and services without the risk of under/over procurement.
	Alignment with EU market regulation	Compliance with current and future regulatory frameworks.
Customer engagement	Customer engagement	It provides a measure of the volume of flexible active/reactive power available from third-party users.
Reliability	Reliability	Ability to procure a sufficient amount of service for guaranteeing a secure operation of the power system.

3 Description of mechanisms for acquiring grid services

3.1 Introduction

DSOs can use a wide range of mechanisms to acquire flexibility from resources owned by other players of the distribution systems (e.g., distributed generators, prosumers, customers, aggregators). This chapter describes the key aspects of the following considered mechanisms:

a. Flexible access and connection agreements

Flexible access and connection agreements are agreements between the system operator and the FSPs in which the latter agrees to have the connection curtailed in some periods. Demand could be temporarily reduced during the periods of load peak demand, whereas generation could be curtailed to avoid network contingencies such as congestions or voltage issues. This mechanism is referred exclusively for a new connection to the electrical grid.

b. Dynamic network tariffs

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.

c. Local flexibility market

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 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.

d. Bilateral contract

A bilateral contract is a binding agreement between two parties. In the context of grid services, one side is represented by the system operator while the other is the FSP. A bilateral contract requires a negotiation process between the two parties. Differently than the flexible connection mechanism, the bilateral contract mechanism is in general exploited for existing connected resources and constrained situations.

e. Cost-based mechanism

A cost-based mechanism deals with the remuneration of the flexibility provided by the FSP based on the actual costs of providing the service. To illustrate, the cost-based mechanism for flexibility can determine the price of the service provided according to the opportunity cost of active power generation curtailment. The cost-based mechanism requires an acknowledged audit process of the provider's costs and financial margin that allows providers a return.

f. Obligation

The 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, the FSPs which are asked to participate in service provision are obliged to contribute with their flexibility.

Through these mechanisms, the DSOs can acquire flexibility services and compensate the FSPs for the costs of providing them. The exception for cost compensation is obligations, in which the DSO can use the flexibility of resources without compensation. However, this option would be the least preferred as it does not provide incentives to minimise the overall system costs. On the other hand, if the mechanism of obligation is implemented as a means of last resort and accompanied by other mechanisms, the overall system cost can still be reduced.

It is relevant to mention that the implementation of each mechanism (both for regulated and market-based) has costs that may vary depending on each specific realisation features. For example, bilateral contracts can contribute to price discovery (i.e. reducing information asymmetries) but require negotiations between the DSO and FSP. Cost-based remuneration, once set, has low implementation costs but, on the contrary, may entail higher costs related to the computation of the regulated prices. As described in section 3.4.1, different functions have to be implemented for markets (e.g., market-clearing, settlement) so that implementation costs cannot be negligible.

A brief description of the mechanisms for acquiring grid services is provided in this chapter. These mechanisms are considered standalone since each one envisions a single process to provide the grid service from FSPs. More complex mechanisms can be obtained by combining their features as further referred to in chapter 5. Each mechanism can be exploited to procure flexibility from FSPs for solving network congestion and voltage problems.

3.2 Access and connection agreements

A high share of renewable energy sources (RES) needs to be integrated into the grids to comply with decarbonisation targets while accommodating an increase in electricity demand. These new installations of intermittent RES are a challenge for current electricity networks with an elevated number of connection requests, requiring grid reinforcement to accommodate the increased amount of RES capacity [33]. In its Directive 2019/944/EC, the European Commission establishes that non-discriminatory access should be guaranteed to new users of the electricity grids, including RES and flexibility resources such as storage. The burden of the administrative process of acceding electricity networks should not lead to a barrier for the integration of RES in the form of distributed generation (DG). Furthermore, greater transparency about the grid access and connection process is considered to encourage active third-party participation [1]. In this context, **grid access** is understood as the right to inject or withdraw electricity to or from the network and the emerging legal conditions. **Grid connection** refers to the electrical coupling of a generation, demand, and storage facilities [34].

The needs of the different players involved in the access and connection process are to be addressed adequately to foster the energy transition. A user-friendly process is characterised by transparency and simplicity. Flexible management of generation and demand resources, including the exploitation of energy storage assets, can be a useful tool to encourage the integration of higher RES shares into the grids without putting operational security at risk. Flexible connections can also be applied to loads, but it is recognised that the main challenge is the connection of RES, which is the main issue addressed in this report. Although references to load flexible connection will be included it will not be analysed in detail.

This section aims at analysing the electricity grid access and connection procedure employed in European distribution networks. To understand current regulations in some of the European countries, a questionnaire was filled by EUniversal partners and DSOs, members of E.DSO, for different European countries: Portugal, Poland, Germany, Belgium (Flanders), Spain, the Netherlands and Ireland. The questionnaire covers topics such as the transparency of the access and connection process, the calculation and allocation of available hosting capacity and the availability of interruptible connection options. A blank version of the questionnaire can be found in Annex II.

Before the presentation of the access and connection procedure employed by DSOs, principles for the evaluation of efficient use of the networks are developed (section 3.2.1). Also, different options of the access and connection process design are discussed, focussing on the benefits of interruptible RES generation connections (section 3.2.2). It describes a flexibility mechanism that is finding its way into regulation recently and allows exploiting available hosting capacity while avoiding costly reinforcement [35], [36]. The answers to the questionnaire are presented together with the description of the access and connection process (section 3.2.2). A discussion of different recommendations for the regulatory design of the access and connection process sums up the options discussed in this part of the report (section 3.2.3).

3.2.1 Distribution grid access and connection design principles

From the principles already described in section 2.2, the ones relevant for assessing access and connection processes are described below.

Transparency. Transparency plays a major role in limiting discriminating behaviours [2]. When procuring grid services, the DSO have to communicate the process transparently to determine equal conditions among all potential providers. Transparency also concerns the timing used for sharing information; it has to avoid any possible discrimination among potential grid providers. Some of the essential content to be published by the DSO regards the contracted and activated capacities and the related remuneration. Transparency is achieved if an open tender is used for procuring flexibility. Motivation about the rejected tenders has to be provided to ensure the transparency of the mechanism.

Economic efficiency. Efficient use of the already available grid avoids unnecessary and inefficient network investments. Interruptible connections can help to defer or avoid costly reinforcement. Also, transaction expenses should be allocated efficiently to encourage new participants to connect to the network. Administrative processes and connection charges should not be an unnecessary burden for small DG installations.

Reliability. The integration of new fluctuating generators must not endanger a secure grid operation. When calculating the available hosting capacity in the distribution grid, the secure operation of the grid must be guaranteed.

Customer engagement. Distributed generation allows users to take a stand in the decarbonisation of electricity grids. In general, users should be offered a benefit for opting into a flexible connection option. Reductions in connection time and costs or financial compensations for the energy curtailed represent some options and might increase the user's interest for flexible connections of DG installations or high load curtailment or flexible loads which adapt to critical periods (e.g. electric cars, heat pumps).

Complexity. The efficient use of the existing network implies employing different sources of flexibility to guarantee a reliable operation at high levels of DG penetrations. Development of adequate regulation is needed to prioritise the exploitation of flexibility from third parties and avoid cross-subsidies. Moreover, the implementation of interruptible connections implies the need for new software to compute both, hosting capacity calculations and secure grid operation. Standardisation among different DSOs might allow diminishing implementation complexity.

The design of the grid access and connection process should be based on a compromise of these principles. For example, the most efficient allocation of grid capacity might collide with a reliable operation of the system. Also, economical efficient connection agreements might imply higher complexity. However, the shift from the traditional, centralised generation scenario towards a decarbonised electricity sector might require to rethink the weight given to the different principles. This shift is likely to require an advanced degree of information sharing among the different actors than a scenario with only a few, large generators acceding the electricity network.

The analysis of different access and connection procedures described by the DSOs in the questionnaires is based on these guiding principles. Regulatory recommendations for access and connection principles are derived considering a shift towards a decentralised electricity generation scenario.

3.2.2 Access and connection procedure description

DSOs and national regulators may opt for different procedures throughout the grid access and connection process. This section summarises different options for the regulation of electricity grid access and connection. For the description, the process is divided into several consecutive stages, each represented as a separate blue box in Figure 3-1. User segmentation is applied throughout all stages. The stages are described in the following sub-sections (3.2.2.1-3.2.2.5).

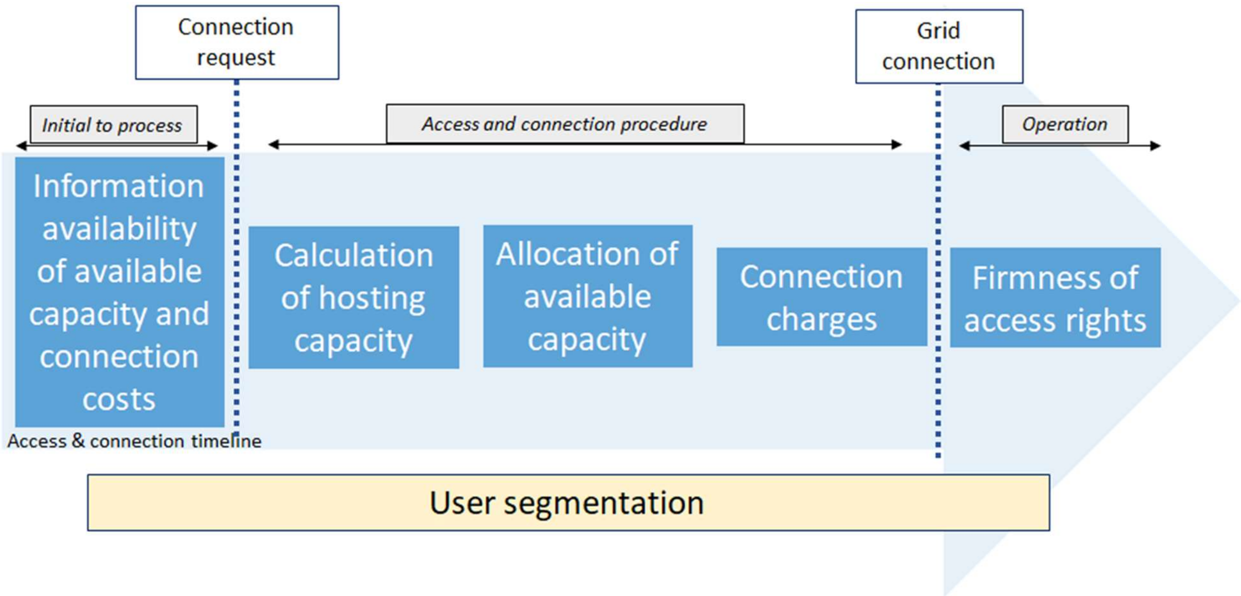

Figure 3-1. Distribution grid access and connection timeline

The different regulatory design options of the process stages are explained below with the feedback provided by a survey to the DSOs which are included for each of the process stages. A colour scheme is used for the representation of the answers. The assignment of the colours to the different options is of merely illustrative purpose and does not represent a ranking within the options.

3.2.2.1 Information availability

Directive 2019/944/EC seeks the empowerment of consumers to encourage participation in the energy market and the energy transition [1]. To achieve an increase in customer engagement, the availability of information is crucial. In terms of grid access and connection process, transparency refers to the possibility for users to foresee their chances of connection as well as the associated costs. Regular updates of the information are crucial for providing a transparent process of accessing electricity networks. However, it needs to be considered that information about hosting capacity publicly available in a large extend may provide insightful information to create market distortions on other markets mechanisms (e.g. gaming in local flexibility markets).

Table 3-1 summarises different approaches for DSOs or regulators to provide information on the available hosting capacity and connection charges. Information on available electricity grid hosting capacity and connection charges can be made available in the form of heat maps or look-up tables. This information is usually published by DSOs for informative purposes, as detailed connection studies are carried out once the connection request has been submitted. In the case of connection charges, cost catalogues can be provided as additional information on connection charges. This allows the user to verify the costs resulting from the individualised connection study. Whenever study results can be generalised, a binding publication of information might be possible. This is especially important for low voltage connections.

Table 3-1. Information availability approaches.

Source: [37]–[40]

Approach	Description	Impact
Informative publication	In most of the cases, an individualised analysis is carried out to evaluate the potential new user's impact on the grid. Consequently, information can only be published for guidance purposes and the final magnitude of hosting capacity or connection charges might vary.	Available hosting capacity Connection charges
Binding publication	In some cases, generalisation is possible and information is published on a binding basis.	Connection charges, mainly LV

Table 3-2 presents the answers to the publication of information provided by interviewed DSOs. The numbers correspond to the ones presented in Table 3-1, the table below includes a classification whether a specific update interval is provided by the DSO.

Table 3-2. DSO answers on information availability

Country	PL	DE	NL	IR	BE	PT	ES
References	[41], [42]	[43]–[47]	[48], [49]	[39], [50]–[53]	[54]–[57]	[58]–[65]	[34], [66]–[71]
Hosting capacity	Informative	No publication	Informative	Informative	No publication	Informative	Informative
Regular updates	X		x	*(x)*		x	x
Connection charges	Informative	Binding	Informative	Informative	Binding	Informative	Binding

Almost all countries have already implemented mechanisms to provide information on available hosting capacity as well as on connection charges. Germany does not publish available capacity because the regulation grants a general right to connect to the grid. In Belgium, available capacity is a result of the individual connection study and not included as public information. In Spain, the obligation of publishing available capacity is the object of a current reform process of enhancing grid access and connection transparency and was made compulsory in January 2021 [72]. In Ireland, the publication of available capacity started in Summer 2020 intending to be updated regularly. Information on connection charges is provided in all countries. In Germany, Belgium (Flemish region) and Spain, binding connection charges are published for LV demand.

3.2.2.2 Availability and allocation of hosting capacity

The computation of available capacity and the allocation procedure to those who request it are important steps to optimally use the existing network, minimise the needs for network reinforcements and obtain a cost-reflective allocation. Both process and design alternatives are described below.

3.2.2.2.1 *Calculation of available capacity*

The capacity available in a network can be determined based on different criteria as summarised in Table 3-3. Power-flow analysis allows the DSO to model the expected impact of a new connection on the grid operation. Although power flow analysis can contribute to guarantee a reliable grid operation, it can also be complex, especially as different operational scenarios have to be considered. A simpler approach is offered by employing short-circuit ratios and maximum thermal line capacities. This approach, however, is only applicable for evaluating the connection of users connecting to LV in order not to endanger system stability [67]. Furthermore, it is less robust to different operational scenarios.

Table 3-3. Hosting capacity calculation approaches.

Sources: [67], [68], [73]

Calculation approach	**Description**	**Advantages**	**Disadvantages**
Power-flow analysis	Computation of power-flow analysis	Reliability	Complexity
Short-circuit ratio & thermal line capacity	Electrical grid properties such as transformer station short-circuit ratios or thermal line capacities are considered	Simplicity	Situations of critical grid operation might not be sufficiently described

3.2.2.2.2 *Allocation of hosting capacity*

Once the available hosting capacity is determined, its allocation might be subject to different approaches as presented in Table 3-4. The most common approach is first-come-first-served, which implies the allocation of available capacity according to the order of permission applications. It is a simple and undiscriminating approach of capacity allocation. Consequently, the approach does not provide special incentives for the connection of RES generators where more capacity is available.

Alternative cost allocation procedures provide an incentive for the support of RES integration. Batch processing represents an approach where several applications are evaluated in a common process, reducing the evaluation costs. Auctions are a market-based allocation of hosting capacity. The product to be auctioned can be installed capacity or energy costs. In both, batch processing and auctions, the admission to the process can be limited to renewable generation technologies to foster the energy transition. If these options are not available, an alternative RES support mechanism is prioritising renewable generators grid connection over others whenever competition occurs.

Table 3-4. Generation hosting capacity allocation approaches

Source: [43], [52], [74]–[77]

Allocation approach	Description	Advantages	Disadvantages
First-come-first-served	Allocation of available capacity according to the order of permission applications	Simplicity	Lack of incentive to connect RES High dependency on order of applications Non-market-based allocation
Batch	Several applications are evaluated in a common process	Lower evaluation costs	Specific time frames for access and connection requests Non-market-based allocation
Auctions	Marked-based allocation of available grid capacity for the connection of new capacity	An incentive for cost-efficient generators	Complexity, especially for small users
RES priority	Granting priority to renewable energy generators in case of competition with other generators	Renewable energy incentive Simplicity	Non-market-based allocation Discrimination possible among different RES requests

Table 3-5 presents the answers provided by the DSOs on the methodologies applied for the calculation of available hosting capacity and its allocation.

Table 3-5. DSO answers on capacity calculation and allocation

Country	PL	DE		NL		IR		BE		PT		ES	
	[41], [42]	[43]–[47]		[48], [49]		[39], [50]–[53]		[54]–[57]		[58]–[65]		[34], [66]–[71]	
Calculation of hosting capacity	Power flow	Power flow		Power flow	Short-circuit	Power flow	Short-circuit	Short-circuit		Power flow	Short-circuit	Power flow	Power flow
Allocation of available capacity	First-come, first-served	First-come, first-served	RES priority	First-come, first-served		First-come, first-served	Batch	First-come, first-served	RES priority	First-come, first-served	Auctions	First-come, first-served	Auctions

The calculation of available hosting capacity is based on a power-flow analysis in most of the countries. This way, the secure operation of the grid is assured. Some countries include additional criteria such as short-circuit ratios or thermal line capacities. In Flanders, the standard approach for the calculation of available capacity of distribution grids does not include power-flow analysis. Available hosting capacity is based on already connected capacity. The available capacity is allocated with the first-come-first-served approach in all countries. Ireland has implemented batch processing for larger projects while Germany and Belgium (Flanders) provide priority to renewable projects. In

Spain, node capacities for specific demands have been available on request; however, currently, the renewable generation auction process is being reformed to foster the energy transition.

3.2.2.3 Connection charges

DSOs recover network reinforcement costs totally or partially through connection charges. Different approaches are also applied to DG connections. An overview of different connection cost approaches and their advantages and disadvantages is provided in Table 3-6. Deep connection charges provide strong locational signals for generators to connect at nodes with available hosting capacity. However, this approach might impede small DG users to connect. Especially in combination with a first-come-first-served capacity allocation methodology, connection costs can vary significantly according to the order of the connection request instead of the size of the potential new grid user. Shallow connection charges represent the contrary cost allocation approach in which reinforcement costs are born by the DSO and in consequence by all grid users through network tariffs. Although this approach results in the lowest connection costs, connection time might increase as the applicant needs to wait for the DSO to carry out the reinforcement work. Furthermore, generators have no incentive to connect to grid nodes with available hosting capacity. Shallowish connection charges are an intermediate approach in which new users pay a share of the reinforcement necessary for their connection. A locational signal for connecting where hosting capacity is available. Also, clear regulation on how to distribute costs between DSOs and users is required to guarantee non-discriminatory conditions to all potential grid users.

Table 3-7 presents the answers provided by the DSOs in the questionnaire on the application of connection charges.

Table 3-6. Connection cost approaches: description, advantages and disadvantages

Source: [78], [79]

Cost approach	Description	Advantages	Disadvantages
Deep	The user pays the total reinforcement cost necessary for the new connection.	Provides locational signals of the connection point with lowe cost. It is cost-reflective.	Lack of transparency if the cost computation is not transparent. Connection costs highly dependent on the order of capacity allocation Connection costs might be a burden that impedes DG participation, if not well-designed.
Shallowish	The user pays a proportion of the reinforcement costs. This proportion is usually based on the extent of use of the new installations by the new user.	Some locational signal is provided.	The requirement of a clear structure of cost-sharing between DSO and user to provide transparency. Not-fully cost-reflective.
Shallow	The system operator is in charge of paying grid reinforcement. Costs are recovered through the use of system charges paid by all users. The user pays only the assets for the physical connection to the network, no network reinforcement.	Lowest cost for new connections. Encourages DG connections. Simple for new connections.	Lack of locational signals Cross-subsides among customers

Table 3-7 presents the answers provided by the DSOs in the questionnaire on the application of connection charges.

Table 3-7. DSO answers on connection charges

Country	PL	DE	NL	IR	BE	PT	ES
	[41], [42]	[43]–[47]	[48], [49]	[39], [50]–[53]	[54]–[57]	[58]–[65]	[34], [66]–[71]
Connection charges	Shallow	Shallow & Shallowish	Deep	Deep & Shallow	Shallowish	Shallowish	Deep & Shallowish

Connection charges vary broadly between the different countries in consideration. In Poland, shallow connection charges are applied. This is also the case in Germany, except for shallowish connection charges for demand above 30 kW. In Ireland, demand connection charges are shallow while deep connection charges are applied for generators. In Belgium (Flanders) and Spain, shallowish charges are applied to generators. In Spain, the shallowish charging approach is limited to generators of up to 1 MW capacity at voltages up to 36 kV. For larger generators, deep connection charges are applied. Shallow connection charges are applied to demand of up to 100 kW contracted capacity in Spain.

3.2.2.4 Firmness of access rights

The efficient use of existing hosting capacity allows avoiding costly grid investments, when possible. As interruptible connection options represent a recent regulatory approach of expanding grid flexibility, this subsection provides a brief description of two different modalities of flexible access: non-firm and complimentary access. The benefits of these flexible access modalities are presented.

3.2.2.4.1 User compensation for interruptible connections

When increasing capacities of the same generation technology are connected in each other's technical proximity, the simultaneity of the generator's outputs (especially the case with RES) results in an additional challenge for secure grid operation. Often, reinforcement is required to assure the safety limits, established by the system operator, at all times. Due to conservative criteria employed by DSOs, to assure secure grid operation, reinforced network components might only be used several hours a year, if ever [36]. At the same time, costly reinforcement of network assets to integrate rather small DG generators might result in economic infeasibility of the project.

The allocation of flexible access rights instead of traditional firm access is a means to efficiently use existing hosting capacity while deferring network reinforcement. This allows the DSOs to relax the available capacity calculation criteria in exchange for converting firm connections into interruptible connections. Users obtain direct benefits of the avoided reinforcement: lower connection costs in the case of deep or shallowish connection charges and a faster connection (see Table 3-6 on connection charging approaches). Another design element is the financial compensation of the energy curtailed from being injected or withdrawn from the network.

In return, users agree that their DSO manages their injection/withdrawal of power to/from the grid at certain times. It is important to note that for the encouragement of user participation in this type of flexibility, information availability is crucial. Potential participants need to be able to predict the curtailment they might experience before connecting to the grid [80]. Especially for small DG users, increased complexity might lead to a preference of firm connections [81].

In the course of the Electricity Network Innovation Competition programme funded by Ofgem in Great Britain [82], different projects have analysed the benefits of non-firm generator connections in constrained distribution grids. Namely, these areas are the Shetland [83] and the Orkney [84] islands in the north of Scotland, Accelerating Renewable Connections (ARC) on the Scottish mainland [85] and March grid in England [86]. The projects employ non-firm (interruptible) connections for constraint management to achieve a deferral of network reinforcement. As a result of these pilot projects, the British regulator Ofgem published a discussion on non-firm access in the course of the Significant Code Review working papers published in Summer 2019 [35]. Also, non-firm generation connections have been included in the British Energy Networks Association's Engineering Recommendations for the connection of renewables [73], [87].

The lessons learnt in these projects served as a basis for serval scientific evaluation approaches of interruptible connections:

1. Generation curtailment can enable significant reductions in network reinforcement resulting beneficial for both, DSOs and generators [81], [88], [89].

2. Generators of different sizes might prefer different connection agreements. The project revealed that small wind generators prefer a reinforcement option to lower uncertainties [81].
3. However, offering non-firm options only to large generators leads to increased curtailment of large generators when connecting additional small generators [88].
4. The optimal solution might be a mixed approach of reinforcement and curtailment [90] or a curtailment mechanism based on different principles of access [88].
5. Smart connections mainly benefit DG generators. New incentives are required to shift benefits to wider society [91].
6. The application of curtailment to existing generators can help to significantly reduce reinforcement needs [89].

3.2.2.4.2 Flexible connection design approaches

Different regulators are starting to consider the implementation of flexible connection agreements. Different regulatory design options of non-firm access rights can be distinguished. Figure 3-2 shows a schematic representation of the different regulatory approaches regarding flexible connection agreements.

1. **Firm access** is the traditional form of grid access rights, meaning that the total contracted capacity can be injected/withdrawn at all times.
2. **Non-firm access** rights do not grant that possibility. Generation/demand may be subject to curtailment. Please note that in Figure 3-2 the capacity that may be curtailed is represented schematically as 100 % of the contracted capacity. However, the amount of maximum curtailment is subject of agreements between the DSO and the grid user. This mechanism is proposed for example by the British regulator, Ofgem [35].
3. The modality of **complimentary access** rights represents a mixture of the previous ones. As shown in the schematic representation in Figure 3-2, a firm access capacity might be complemented with additional capacity that may be subject to curtailment. This approach was part of a reform proposal from the Spanish regulator (Comisión Nacional de los Mercados y la Competencia – CNMC) [92].

In addition to the access types previously described, another two design aspects are whether these are optional choices or there is an obligation to have one of the access types. Furthermore, in the case of curtailment, it is relevant to consider if compensation is foreseen or not and how it is computed.

These approaches are contrasted with their advantages and disadvantages in the following section.

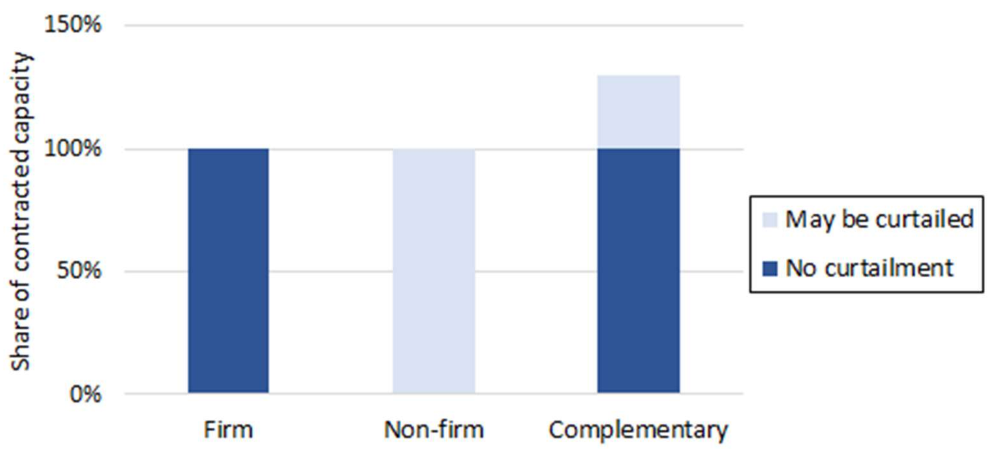

Figure 3-2. Schematic representation of flexible connection options

3.2.2.4.3 *Comparison of approaches and representation colour scheme*

The above-mentioned options of access rights are contrasted with their benefits and challenges in Table 3-8. Firm access is the easiest to understand but does not provide any flexibility to the DSO. As explained above, granting firm access might require the reinforcement of network components to be used only a few hours a year, leading to an over-cost that might make DG projects economically unfeasible in case of deep or shallowish connection charges. Non-firm access allows DSOs to operate their grids more flexible but comes along with complexity for users to understand curtailment procedures and DSOs to adjust their operation algorithms. Economic feasibility of the installation is difficult to predict due to uncertainty about potential levels of curtailment, especially when no compensation is foreseen. Also, national regulation might not foresee the possibility to implement interruptible connections. Complimentary access regulation reduces the uncertainty of future curtailment as a part of the contracted capacity is firm. However, as a firm part of the capacity is involved, network reinforcement may be necessary and endanger the financial feasibility of the project.

Table 3-9 presents the numeric scheme applied to represent the answers to the questionnaire regarding the availability of interruptible connection options. The overview of the answers describes the overall availability of flexible connection options, the users it applies to and the duration of the flexibility option. The user benefit is also included. The different user benefits of reduced connection time and costs have been discussed previously (see 3.2.2.4.1). An additional user benefit included in the table below is the possibility to connect to a congested network. It represents a temporary option to connect to congested grids while reinforcement is being carried out.

Table 3-8. Firm and non-firm access rights: advantages and disadvantages

Source: [35], [36], [92]

Access rights approach	**Advantages**	**Disadvantages**
Firm	Simplicity	Lack of flexibility Might require costly reinforcement of assets to be used a few hours a year
Non-firm	Avoidance of costly reinforcement for a few hours a year	Complexity, for both users to understand the extent of curtailment and DSO to operate the system Implementation complexity Uncertainty about the level of the curtailment, which could affect economic feasibility for the grid user
Complementary	Easier to understand the extent of curtailment Allows more DG to connect Lower reinforcement costs	Remaining complexity for DSO to operate the system Implementation complexity Reinforcement still necessary for firm access capacity

Table 3-9 presents the numeric scheme applied to represent the answers to the questionnaire regarding the availability of interruptible connection options. The overview of the answers describes the overall availability of flexible connection options, the users it applies to and the duration of the flexibility option. The user benefit is also included. The different user benefits of reduced connection time and costs have been discussed previously (see 3.2.2.4.1). An additional user benefit included in the table below is the possibility to connect to a congested network. It represents a temporary option to connect to congested grids while reinforcement is being carried out.

Table 3-9. Questionnaire representation scheme of flexible connection options

Mechanism	
	Non-firm
	Complementary
	No option available

User	
	RES generation
	Controllable loads

User compensation	
	Reduced connection time and cost
	Reduced grid tariff
	Connection to congested network

Table 3-10 represents the DSOs' answers to the questionnaire on flexible connection options. Apart from the options introduced in the colour scheme, the table includes information available on the permanency of the flexible connection options.

Table 3-10. DSO answers on flexible connection options

Country	PL	DE	NL	IR	BE	PT	ES
References	[41], [42]	[43]–[47]	[48], [49]	[39], [50]–[53]	[54]–[57]	[58]–[65]	[34], [66]–[71]
Mechanism	Not available	Complementary	Complementary	Non-firm	Non-firm	Not available	Not available
User		Controllable loads	RES	*N/A*	RES		
Permanent flexible connection?		Yes	No	Yes	No		
User compensation		Reduced grid tariff	Connection to congested network	Reduced time and cost	Connection to congested network		

Interruptible connections are being employed by only some of the countries. In Germany, DSOs are obliged to offer a complimentary flexible connection to controllable loads. This connection is permanent. In the Netherlands and the Flemish region of Belgium, DSOs might offer non-firm connections as a temporary solution in congested regions. This access modality is limited to the time frame the DSO needs to carry out grid reinforcement. In Ireland, the implementation of non-firm access is still in the implementation phase.

3.2.2.5 User segmentation

Throughout the whole access and connection process, requirements can be adapted as a function of different user classifications as presented in Table 3-11. The most straight-forward classification is the division based on the user type, i.e. demand or generation. It is beneficial to classify grid users according to their use pattern to accurately depict the network use and guarantee a reliable operation. The generation and demand categories include the users which are also equipped with storage devices. Storage behaves over time as a consumer or generator depending on the operating status of the related asset. It is recognised that the direct connection of energy storage facilities could be possible. However, since the peculiarity of the storage asset features, specific insights are required, the detailed discussion on storage is out of the scope of this document and will be a matter of future research activities.

Furthermore, a division can be made according to the size of the required capacity of the grid user, considered through contracted capacity or voltage level. This classification allows for establishing abbreviated procedures for smaller users to simplify the access and connection process.

Another approach to additionally classify generators is based on the technology type. A distinction generally made is between renewable and non-renewable generators to allow the implementation of RES or DG priority mechanisms such as capacity allocation (see description in Table 3-4). Granting priority to renewable generation facilities supports the decarbonisation process. However, large shares of intermittent generation challenge grid operation.

The segmentation of grid users according to their (nodal or zonal) location within the grid allows the DSO to send locational signals for efficient use of existing grid hosting capacity.

Table 3-11. User segmentation approaches: description and benefits

Source: [39], [50], [67], [73], [87], [93], [94]

Option	Segmentation approach	Description	Benefits
	User type	Demand and generation are treated differently in the grid access and connection process.	Different grid interaction of generation and demand is described adequately Reliable grid operation
	Electric properties	Classification according to properties such as capacity or voltage level	Allows simplification of procedures for smaller users
	Location	Classification according to the node or zone the user wishes to connect to	Signals for new capacity to connect to nodes/zones with available hosting capacity

Table 3-12 presents the DSOs' answers on whether they apply user segmentation for capacity allocation and connection charges.

Table 3-12. DSO answers on user segmentation

Country	PL	DE	NL	IR	BE	PT	ES
	[41], [42]	[43]–[47]	[48], [49]	[39], [50]–[53]	[54]–[57]	[58]–[65]	[34], [66]–[71]
Capacity allocation	None	None	None	None		None	
Connection charges							

In the majority of countries, all users have to fulfil the same requirements for capacity allocation. In the Flemish region of Belgium and Spain, the assignation methodology varies in function of user type and electric properties. For example, small DG in Spain does not need to deposit a financial guarantee to initialise the access and connection procedure. Concerning connection charges, all countries perform a user segmentation according to a user type (i.e. generation and demand). The majority also considers electrical parameters such as voltage level or capacity. Locational differences are considered in NL and PT.

3.2.3 Recommendations for access and connection agreements

The results from the questionnaire have shown that DSOs from several European countries are redesigning their access and connection procedures. Greater variances can be observed in the application of connection charges and the option for interruptible connections. These mechanisms are valid for all grid users; therefore, a technology-neutral approach is adopted related to the impact of the connected assets have on the network independently of their nature (i.e. generation, demand, storage).

When designing **connection charges**, economic efficiency needs to be guaranteed. As pointed out in section 3.2.2.3, deep and shallowish connection charges promote an efficient allocation of already existing hosting capacity of the network by sending locational signals for new connections. However, the interaction of the connection charging approach with the allocation of hosting capacity needs to be analysed carefully to encourage customer engagement in the decarbonisation of the electricity sector. When assigning capacity in the temporal order of applications, installations might face the reinforcement cost of rather expensive network components leading to the economic unfeasibility of a connection. For example, Spanish regulation considers a new connection unfeasible if the economic conditions of the connection are superior to 50 % of the project's budget, resulting in a denial of access [66].

Applying shallowish connection charges to small users may encourage customer participation in the energy transition while guaranteeing a locational signal for large RES [95]. This approach assumes that small users have a limited impact on distribution grid costs. An example is the Spanish regulation where shallowish connection charges are applied to generators below 1 MW and deep connection charges to those above [67]. Another alternative is the employment of permanent interruptible connections as an alternative option to reinforcement. It represents another approach to encourage more efficient use of existing grid capacity by unlocking flexibility.

The main benefit of permanent **flexible connections** is economic efficiency as it allows the deferral of network reinforcement. On the contrary, the main obstacle observed in Portugal, Poland and Spain is the incompatibility with current national regulation. In these countries, DSOs reported that non-firm access options do not form part of the regulation of the electricity sector. In Ireland, the participating DSO stated that permanent non-firm generator access is in the implementation phase. This is also observed in Great Britain [35]. When implementing flexible connections, the regulatory framework of this mechanism needs to be designed carefully to respect the access and connection principles pointed out in section 3.2.1.

The lessons learnt in the interruptible connection projects presented in section 3.2.2.4.1 show that generation curtailment can enable significant reductions in network reinforcement resulting in benefits for both, DSOs and generators. Depending on the connection charging approach, the avoidance of reinforcement expenses is a direct benefit either for the DSO (shallow or shallowish charges) or the user (deep or shallowish charges). Additionally, the avoidance of grid construction work leads to a reduction of connection time when applying for permanent non-firm access. This benefits the rapid grid integration of new RES generators. However, the optimal solution might be a mixed approach of reinforcement and curtailment or injection/withdrawals shifting, e.g. to guarantee a continued connection of new grid users reducing the reinforcements required [90].

DSOs are required to adapt their algorithms to determine the most efficient use of their network when employing flexible connections. While doing so, they need to consider additional factors such as the non-discriminatory treatment of potential new grid users. Exceptions could be represented by a RES priority capacity allocation or additional criteria defined by national regulation.

As pointed out in section 3.2.2.4.1, generators of different sizes might prefer different connection agreements. As reported in a survey made in Great Britain [81], large generators have shown to be more receptive to the benefits of a non-firm connection. Smaller generators are found to prefer the certainty of a reinforcement option. Regulators and DSOs need to ensure that the contractual framework is easy to understand to encourage all grid users to participate in providing flexibility in distribution grids. The transparency of the process is an important factor and should be as high as possible. One measure could be to include the maximum amount of annual curtailment in the access and connection contracts to reduce the uncertainty. Also, the grid user should be made aware of the cost of avoided reinforcement. Allowing users to contrast the savings in connection cost with the value of curtailed energy might help to promote flexible connections.

3.3 Dynamic network tariffs

Today, networks tariff structures mostly do not provide time and location varying prices [96]. Grid users in distribution do not receive signals for rational grid usage and remain rather passive. DSOs and TSOs are expected to ensure that the system limits are respected. Nevertheless, stakeholders owning or managing distributed energy technologies at different voltage levels are becoming increasingly capable of adjusting their behaviour to the specific grid and final electricity prices, which include energy prices and regulated charges. The introduction of smart meters speeds up this process.

With the clean energy package, Europe is also emphasizing end-consumer empowerment. In this framework, it introduces EU Regulation 2019/943 [97] in which article 18 (7) and (8) requires national regulatory authorities to consider time-differentiated network tariffs. Network tariffs can, therefore, be adjusted [32], [98] to ensure that they reflect the necessary temporal and spatial cost variations.

Electricity invoices are formed of a variety of components (Figure 3-3 shows the split of the components in the EU for 2017, where taxes also include policy costs). These components can be grouped in different categories: energy (i.e. associated with generation costs at different timescales from investments[2] to system balancing), networks, policy and taxes[3]. Notice that all these components are not necessarily indexed to energy consumption (€/kWh). Instead, part of these costs can be charged by network capacity (€/kW) or fixed (€/customer). However, for comparative purposes, all components of the electricity invoice are transposed to volumetric terms (€/kWh). The allocation of each component should be properly designed and should be analysed in detail as they form the price signal provided to customers. However, the EUniversal project focusses specifically on network costs and how to allocate them in a cost-efficient way.

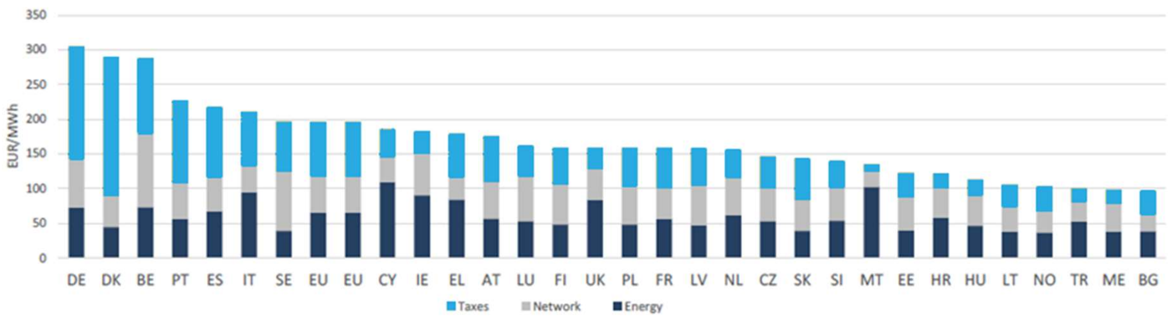

Figure 3-3. EU household's electricity invoice by components in 2017

Source: [99]

Different costs are included within the network tariff among countries, which can bring huge differences when comparing electricity tariffs of different countries. For this reason, a sound cost segmentation is the first step for the development of a transparent and efficient electricity tariff. In section 3.3.1 tariff design principles are introduced to provide a grounded basis on which an efficient

[2] Note that investments costs can be split in the energy category and policy costs, especially when referring to renewables.

[3] Policy costs and taxes are sometimes grouped in a single category as it happens in Figure 3-3 but, while the former are referred charges used to recover policy costs such as renewable supports, subsidisation of certain social programs, costs of institutions (system operator, market operator, regulator, etc.), among others, the latter depend mainly on general taxation policies.

methodology can be built. Section 3.3.2 shows the different cost allocation approaches that are applied and a brief comparison remarking the advantages and disadvantages of each approach. Finally, the principles are applied to the cost allocation methodology. This methodology is based on the segmentation of network costs among short-term marginal costs, long-term marginal costs and residual costs. An extended discussion on the implications and issues that regulators must consider for the development of this methodology is provided. Finally, the benefits derived from the implementation of this methodology are also granted.

3.3.1 **Tariff design principles**

Previously to the development of a tariff structure, the defined principles in section 2.2 need to be recalled to be applied specifically to network tariffs. To build an efficient grid, the main principles, highlighted within the literature, on which an electricity network tariff should be built are economic efficiency, equity and transparency [31], [100]. These principles are in line with the ones proposed in [98], but cost recovery is not stated as a principle but rather as an objective that all tariffs should fulfil. However, it is recognised that there is not a clear cut between objectives and principles. Furthermore, the referred principles are not easy to quantify. For this reason, previous principles are divided into easily measurable objectives.

As previously defined in section 2.2, **economic efficiency** aims to maximise social welfare. However, not only short term but also long-term social welfare should be maximised. Following this principle, to incentivize a rational grid usage, electricity network tariffs should send efficient economic signals to grid users. Behind the principle of economic efficiency, some other objectives can be derived:

- Cost reflectivity: electricity tariffs reflect the costs of delivering the service, recognizing that they may vary by time, location, and quality of service. Regarding decentralisation, a level playing field should be built for both centralized and decentralized energy resources and technologies.
- Symmetry: those costs that depend on consumption and injection of energy or power should be charged/rewarded following the same methodology within a certain locational and temporal granularity.
- Predictability: users should be able to estimate their future payments before they use the electricity network.
- Technology neutral: network tariffs should not depend on the particular activities for which electricity is used or the technology used to withdraw or inject energy into the grid.
- Minimisation of cross-subsidies: one user's actions should not negatively affect other user's charges. This is particularly relevant when a consumer decides to completely disconnect from the grid and self-provide his energy needs through alternative sources. In this case, the electricity system or the rest of consumers should not bear the part of the fixed costs that were covered by the disconnected consumer and that remain in the system. The implementation of an exit fee may be a solution to charge such non-paid costs from those consumers who disconnect from the grid to avoid the death spiral effect [101].

For tariff designs, and specifically for residual network costs allocation, the **equity** principle is relevant, and it can be split into three specific subprinciples: allocative, distributional and transitional equity.

- Allocative equity: Identical network usages should be charged equally. Identical network usage refers to comparable location and consumption patterns, regardless of the payer's nature, final energy usage, or appliances behind the meter.
- Distributional equity: charges should be proportional to the economic capability of each user. This is a critical issue when allocating residual costs, which are those costs that have no cost-driver and cannot be recovered following economically efficient signals.

- Transitional equity: a transition from an old to a new tariff scheme should be gradually implemented.

Finally, **transparency** and **simplicity** contribute to verify whether and in which degree the other principles are being fulfilled. Therefore, network tariffs should be open-access and well explained, so that most of the population can understand them.

Digitalisation can provide higher transparency to dynamic network tariffs by providing real-time access to data. Besides, digitalisation enables a wider spectrum of tariff designs. However, regarding simplicity, retailers – or DSOs, depending on each national regulation – are charging regulated tariffs together with the commodity cost and retail margins into final prices. Retailers or DSOs could find value in creating simplified final prices that can be easily understood by passive consumers. In addition, retailers or DSOs could opt for offering more sophisticated final prices where they find a value getting the flexibility from active consumers which would most probably react to these more dynamic prices via an automated response.

3.3.2 Cost allocation approaches

In this section, the different methods that have been proposed to allocate network costs to users are shown. The authors in [102] summarize different cost allocation approaches and compare, for instance:

- Postage Stamp: charges are allocated based on average embedded cost and the magnitude of customer's transacted energy. This methodology is used because of its simplicity, but the signals sent by this methodology are not economically efficient.
- Contract Path: through this method, charges are allocated according to the specified geographical distance between generator and consumer, regardless of the physical path, and costs are assigned through a post-stamp rate, the further from generation, the more expensive. Similarly, to Postage-stamp methodology, the main merit of this methodology is the simplicity. However, the incentives offered by this methodology do not consider a decentralized power system with different kind of customers inside a postal code zone.
- Marginal Participation: it allocates costs based on the short-term marginal impact that a system user has on the electricity flow of each network asset, calculated as the change in the flow when the injection or withdrawal at a node is increased by 1 MW [103]. The main issue for this methodology is the computational costs that are needed for its implementation. Additionally, individual network assets costs are required for the development of this methodology.
- Average Participation: charges are calculated for each network asset and they are allocated according to a proportional sharing of flows into and out of any node. Therefore, a network asset's cost is shared among users, either producers or consumers, according to their usage of the asset, calculated as the amount of energy that flows through it due to users' actions.
- MW-Mile: flow-based pricing scheme where power flow and the distance between points of injection and withdrawal reflect network costs, but it is only applicable to bilateral transactions where the points of injection and reception are known. The MW-mile method ensures the full recovery of costs and reflects the actual usage of networks, but needs the location of each injection and withdrawal, which is not realistic for distribution networks.
- AMP-Mile: based on marginal changes in power flows in an asset for both active and reactive power injections multiplied by those injections. However, this methodology is only realistically applicable to radial networks since currents are relative to the thermal capacity of the network [104]. Additionally, this methodology does not recover full embedded costs unless the system is fully loaded.
- Short-term marginal cost (STMC): the marginal cost of accommodating a marginal increase of power, which is calculated using the optimal power flow method. Although this

methodology sends short-term efficient time and location differentiated price signals to both generation and demand, its surplus is insufficient for the total network costs recovery.
- Long-Term Marginal Cost (LTMC): the marginal cost of supplying an additional unit of energy, when the installed capacity of the system is allowed to increase optimally in response to the marginal increase in demand.

Table 3-13 summarizes the advantages and disadvantages of the aforementioned network cost allocation approaches.

This report looks specifically at the two last cost allocation approaches, i.e. the two marginal pricing approaches, as in general, these approaches are known to give efficient economic signals. Marginal prices reflect marginal costs of an extra unit of demand or generation on the network considering both timeframes the short-term (i.e. with current network assets) and long-term (i.e. considering network investments).

In a short-term marginal cost (STMC) approach, one takes the network infrastructure as being fixed. As such, only energy injections and withdrawals can change over time to manage network constraints. This would imply that STMC charges provide signals to grid users energy injections and withdrawals to stay within network limits. On the contrary, the long-term network infrastructure is also variable. LTMC, therefore, takes into account both the cost of network infrastructure development and operational costs [105].

The following sections discuss both STMC and LTMC approaches in more detail and their advantages and disadvantages. However, it should be noted that there are different views in the literature regarding whether these two approaches can complement one another, or should be used separately. Some studies (such as the MIT Utility of the Future Study [106], [102]) assume both approaches can complement each other, implying that consumers can be charged both an STMC and an LTMC, on the condition that these charges relate to different types of costs. Figure 3-4 presents an example of the complementarity among the different short- and long-term price signals. By applying locational marginal prices an economic surplus can be obtained which can be used to partially recover network costs. Also, long-term marginal costs provide information about future network costs while residual network costs would be designed to recover the remaining costs (if any).

Table 3-13. Advantages and disadvantages of network cost allocation approaches. Source: [102]

Name	Advantages	Disadvantages
Postage Stamp	Simplicity	Does not consider actual system usage and congestions Does not provide locational pricing signals
Contract Path	Simplicity	Does not reflect actual flows as the contracted path can be different from the actual path
Marginal Participation	Sends efficient locational signals	Computationally extensive Requires individual network asset costs
Average Participation	Reflects how much of the demand of a certain load point comes from a particular generator, and vice versa	Does not consider counterflows, and the tracing of power flows is not based on engineering principles Requires individual network asset cost
MW- Mile	Ensures full recovery of fixed network costs	Only applicable to bilateral transactions Does not provide economically efficient signals to customers
Amp-Mile	Provides signals based on location and peak usage, so it provides the right incentives for the optimal location of DG in the distribution network	Only applicable on radial networks Does not fully recover embedded costs unless the network is fully loaded
Short-term marginal cost	Sends short-term efficient time and location signals differentiated to load and generation	Its surplus is not enough to cover network costs
LTMC allocation methodologies	Simpler calculation compared to LMP (see section 3.3.3.1.1), providing economic signals based on the actual network usage	Reinforcement cost scenarios are difficult to predict and to evaluate

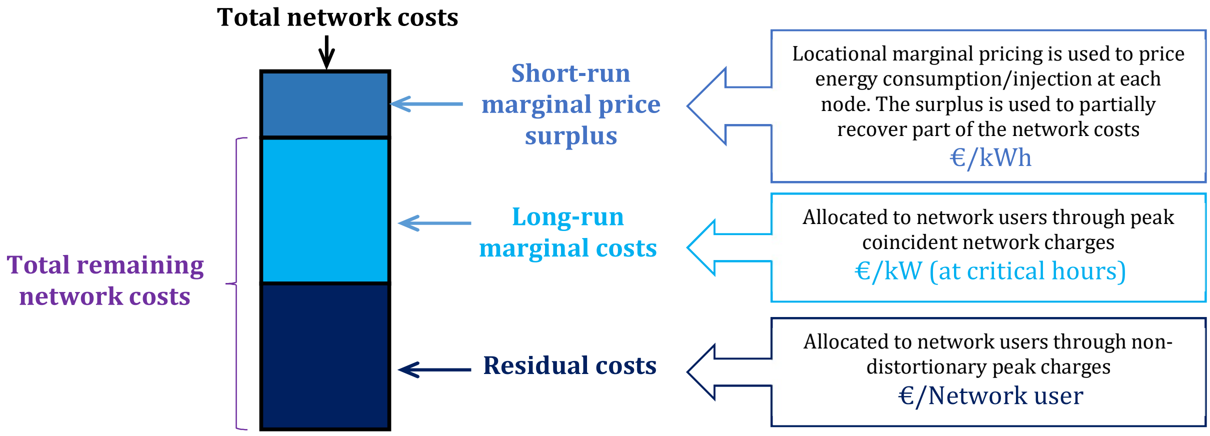

Figure 3-4. Distribution network cost recovery through short-term, long-term and residual charges

Source: [102]

Existing distribution network tariffs vary considerably among countries. Some countries have already implemented the design aspects introduced in section 3.3.1, such as the separation between residual and long-term - or forward-looking costs. Network charges can be applied under different forms: energy charges (€/kWh), capacity charges (€/kW of contracted capacity or maximum demand) and fixed charges (€/grid user characteristics[4]). Additionally, charges can differ according to the time when energy is injected or consumed (temporal granularity), and according to the geographical location (i.e. locational granularity) of the user or the system location of the user (LV, MV, HV). Table 3-14 shows a summarized overview of the different network charges within the European countries included in Table 5 of Deliverable 1.1 of EUniversal project. Issues about the benefits of each of the allocation methodologies will be further discussed.

[4] Fixed charges can be based on different variables, e.g. customer category, income level, or fuse size, among others.

Table 3-14. Overview of distribution network tariffs in European countries

Source: [107]

Country	Residual and Fwd.-Looking costs distinction	Tariff components			Granularity			Customer categories
	No distinction	Fixed	Volume	Capacity	Locational	Temporal energy	Temporal capacity	
Belgium, Brussels (Sibelga, 2020)			X	X		2 periods		LV<56 kVA or LV>56kVA w/o metering point
			X	X		2 periods		Trans MV, MV, Trans LV, LV>56kVA
Belgium , Flanders (VREG, 2020a; VREG, 2020b; VREG, 2020c; VREG, 2020d)			X		X	2 periods		Household and small companies
		X	X		X	2 periods		Prosumers without smart metering
			X	X	X	2 periods		Big companies
Belgium, Wallonia (CWaPE, 2019; CWaPE, 2020)			X		X	4 periods		LV<56 kVA or LV>56kVA w/o metering point
			X	X	X	2 periods		Trans MV, MV, Trans LV, LV>56kVA
France (Enedis, 2019b)			X	X		2 periods 2 seasons		LV <36kVA
			X	X		2 periods 2 seasons	2 periods 2 seasons	LV >36kVA
			X	X		2 periods 2 seasons + 1period	2 periods 2 seasons + 1period	MV, HV

Country	Residual and Fwd.-Looking costs distinction	Tariff components			Granularity			Customer categories
	No distinction	Fixed	Volume	Capacity	Locational	Temporal energy	Temporal capacity	
Germany (Bonn-Netz, 2020; MITNETZ STROM, n.d.; N-ERGIE Netz, 2020)	X	X	X		X			**All voltage levels without metering of load profiles**
	X		X	X	X			All voltage levels with metering of load profiles
	X		X		X			Interruptible consumer installations
Norway (CEER, 2020; Eriksen & Mook, 2020)		X	X	(X)	X			LV<100kW
		X	X	X	X			LV>100kW, MV, HV
Poland (Ministerstwo Energii, 2019; PGE Dystrybucja, 2020)		X	X		X	1 or 2 periods		Households and small LV customers
			X	X	X	1, 2 or 3 periods		Large consumers at LV, all MV, all HV
Portugal (EDP distribuição, 2018; ERSE, 2019)			X	X		1, 2 or 3 periods		LV
	X		X	X		4 periods 2 seasons		MV, HV
Spain (CNMC, 2019/2020)			X	X		3 periods	2 periods	LV
			X	X		3 periods 4 seasons	3 periods 4 seasons	MV, HV
The UK (Ofgem, 2019; WPD, 2018)	X	X	X		X	1, 2 or 3 periods		Domestic and small business
		X	X	X	X	3 periods		Large business
	X	X	X	X	X	X	X	LV, MV, HV

3.3.3 Methodology for dynamic network tariffs

A network tariff consists of a set of charges allocated to different customer categories to collect the allowed regulated network income for a DSO. While cost-recovery is the main objective for a DSO, this principle is complemented with, all aforementioned tariff design principles to obtain an efficient and equitable tariff design. Therefore, a sound methodology should contain, at least, the following four steps, as shown in Figure 3-5[5]:

1. Cost segmentation and cost-drivers identification,
2. Cost allocation approach to grid users following the aforementioned tariff design principles,
3. Types of charges,
4. Granularity definition.

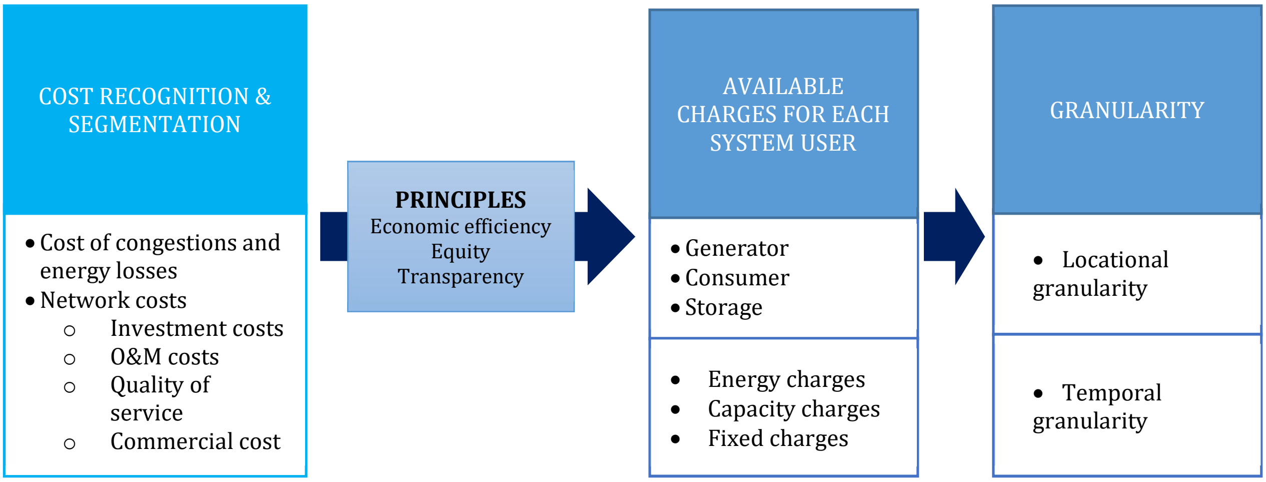

Figure 3-5. Allocation methodology for network costs and generation costs due to network usage

3.3.3.1 Cost segmentation and cost-drivers identification

The main issue in the distribution cost allocation is the analysis of the cost causality and the identification of the cost drivers. Network costs have a diverse nature and can be grouped into:

- Network investments: the necessary assets to connect all customers and exchange energy among them. This includes, among others, infrastructure investment costs, substation and electric power lines, facilities, and switching equipment.
- Operation and maintenance costs: the assets and operational expenditures needed to adequately operate and optimize grid efficiency and to extend its lifespan, including maintenance crews and dispatching centres, among others.
- Quality of service costs: there are quality requirements for DSOs to supply the electricity within ranges. Notice that additional network investments and O&M are necessary for the fulfilment of these requirements.
- Commercial costs: administrative costs for customer attention such as employees' costs, building and metering costs, etc.

Costs of network constraints and energy losses are due to flowing energy through the network. Hence, they should not be included as network costs, but as generation costs. If the energy generation

[5] Since storage assets are neither a classical generator nor consumer, it would require specific insights given its attributes. But, as a general criterion, double charging should be avoided.

price is zero, energy losses cost is valued at a price zero. Therefore, energy losses should be assigned at the marginal price of generation, i.e. as a generation cost. The same happens with congestion costs. In the case of congestion in a network node to be solved through a redispatch mechanism, the cost of solving the congestion should be the marginal cost of generation – or demand reduction – in this specific node.

The aforementioned segmentation is based on physical or functional assets following the differentiation of assets included in the recognized remuneration for the distribution business. Segmentation based on physical assets is useful for financial and accounting activities to track network costs as well as it fulfils transparency principles. However, cost allocation demands a different segmentation, one more focused on the efficiency and equity principles. Therefore, the social welfare maximisation objective leads to tariff designs that are mainly focused on minimizing both the short-term and long-term network expansion costs. To develop a more efficient than current tariff structures, and more aligned with the tariff design principles, network costs should be divided into short-term, long-term and residual costs [108]. The objective of the methodology is to signal the marginal increment of costs due to any customer's action, which can include an increment in any of the previous physical groups. Therefore, any of the costs of the aforementioned physically differentiated groups could be included in any of these three cost segments. The alternative cost segmentation is:

- Short-term marginal costs are energy costs, not network costs. However, these short-term costs are related to the cost of increasing/decreasing generation/demand to cope with congestions and energy losses that occur due to energy flows through networks mainly. Therefore, short-term marginal costs are described and addressed in this document.
- Long-term costs are associated with the future needed reinforcements and investments if the network usage continues to grow in the maximum demand periods. Long-term costs can be obtained as the network expansion cost from the current situation to the long-term considered futures. This could be computed using a generation-demand network expansion model, considering different scenarios to characterize the evolution patterns of the network. The main trigger for future network investments is the maximum peak usage of each network element, i.e. the maximum amount of energy that flows through the element due to the aggregation of all the generation and demand. Therefore, for long-term marginal costs, the main cost driver is the maximum network flow in each network component.
- Residual costs are the proportion of the total network costs that are not recovered through short-term surpluses or long-term charges. There is no driver so these costs are calculated as the remaining part of the total recognized regulated costs after recovering short term and long-term network costs. Since there is no driver, economic efficiency principles are useless, and residual costs allocation will therefore be driven by equity principles.

It is important to note that long-term costs and residual costs depend on both the current grid and the foreseen grid usage.

The following steps of the methodology are approached at each cost segment: short-term marginal costs, long-term marginal costs, and residual costs. Figure 3-6 shows a schematic view on how to allocate network costs among the different charges. Variations from this approach will be further described to account for implementation constraints.

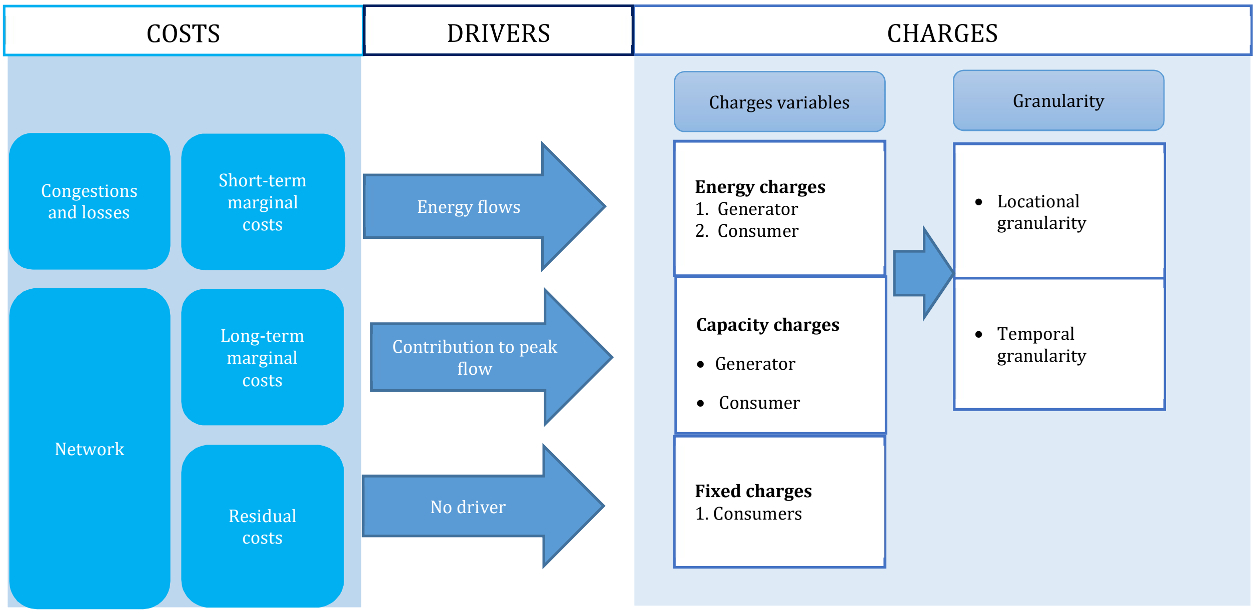

Figure 3-6. Methodology for network tariff design. Cost segmentation, drivers and charges.

3.3.3.1.1 Short-term marginal costs allocation

In practice, electricity grids are not copper plates and thus are subject to physical constraints. In theory, price-setting strategies that reflect these constraints are therefore recommended because if prices do not take constraints into account, there is a need to (for instance) re-dispatch units when internal congestion occurs. This section zooms in on short-run marginal (network) costs (SRMC) as a methodology to determine tariff terms. SRMC assumes that network constraints are tackled by increasing/reducing generation and demand in or close to real-time [109]. Short-run marginal costs, therefore, reflect the operational costs at a specific moment at a specific node if the energy injection and withdrawal at that node at that specific time moment increases with one unit [105]. This implies that, in theory, a true short-run marginal cost reflects the generation costs due to losses and network constraints (although reactive power impacts are generally disregarded) at each moment in the operational time frame and therefore allows prices to vary both in time and by location. This is necessary as real-time network conditions are considered in the cost calculation. As such, the method gives very accurate signals to users to incentive them to adapt their behaviour.

To the best of our knowledge, there is only one method that is well-known to implement SRMC, that is Locational Marginal Pricing (LMP). LMP is derived from nodal pricing, which reflects prices for electricity consumed or generated at each given network node [110]. Nodal pricing / LMP, therefore, includes the cost of energy, and the cost of delivering energy (grids losses, transmission constraints cost). Network constraints are therefore explicitly considered in the market clearing algorithm of the wholesale markets. LMPs reflect the marginal increase in costs of a marginal increase in power through a specific network node [102]. Looking at Figure 3-6, LMP, therefore, focusses on energy charges with a very high locational and temporal granularity.

Two important points should be noted when discussing LMP. First of all, LMP sets prices of electricity across the high voltage transmission system. Even though the EUniversal project focuses on low and medium voltage distribution grids, this deliverable looks briefly into LMP as some important principles and mechanisms can be learnt from it. Transmission level LMP was implemented in the US in Pennsylvania-New Jersey Maryland (PJM) in 1998. Given its success, the Federal Energy Regulatory Commission (FERC) made it part of its standard market design proposal and in the end, all US electricity markets moved to nodal congestion management [111]. In New Zealand, nodal pricing was introduced in 1997.

As explained further, some methods translate LMP processes from the transmission to the distribution grids. Secondly, it should also be emphasized that LMP is currently not the approach taken in Europe, as in Europe electricity spot markets only consider interconnection network capacity and, in the Nordic countries and Italy, few zones within the country. Only after energy trading is closed, network operators evaluate the network impacts and apply (if necessary) different mechanisms (such as congestion management) to cure potential constraints. Instead of using nodal pricing, Europe uses zonal pricing, which implies that market participants trade energy within a predefined geographical area. The European Internal Electricity Market is, therefore, based on the concept of specific bidding zones. Bidding zones are often linked to the national borders of the different member states. However, some countries do apply multiple bidding zones (there are 2 bidding zones in Denmark, 6 in Italy, 5 in Norway and 4 in Sweden) [110]. The price differences between these zones reflect the grid congestion between them and the electricity traded within a bidding zone is assumed to be unrestricted. Thus, the zonal pricing approach assumes that trade within one zone is unlimited and that there is no structural congestion internally [111]. This implies that there is only one uniform price per bidding zone, which is against the idea of SRMC. Therefore, zonal pricing is based on strong simplifications of the physical characteristics of the electricity grid [111]. Nevertheless, it is reported that congestion in Central-Western Europe is for 86% of the time caused by internal lines within one zone [110]. It, therefore, seems that with higher levels of renewables, the zonal European market design could complicate the efficiency of integration of more distributed resources as large European bidding zones do not explicitly consider network constraints.

In what follows, the document will discuss three major forms of SRMC calculation. Firstly, the description of LMP is provided, as academics claim this is the most efficient electricity market organisation [112]. Since LMP is originally designed for transmission grids, it is also discussed an extension of LMPs to distribution grids. Finally, for regions such as Europe, that are currently still sticking to zonal pricing, it is discussed a possible way to approximate locational pricing.

LMP for transmission grids

LMP is based on allowing wholesale electricity prices to vary by location (nodal pricing) and time (usually at hourly but up to minute basis) [109]. LMPs are typically calculated using Optimal Power Flow (OPF) methods[6]. OPF methods can model both AC and DC flows. AC OPF models are more accurate than DC OPF models as they capture the constraints of real power flows and voltages [111]. Yet, AC OPF models are up to 60 times slower than DC OPF models [114]. As a result, DC OPF models are more commonly used for LMP calculation. For brevity, details on the model itself are not provided, it should be noted that depending on how the model looks like, LMPs consist of different cost components. In general, LMP comprises three elements: energy, congestions and losses [115]. They respectively represent the marginal cost of energy, the marginal cost of congestions and the marginal cost of losses [116]. Depending on the simplification used, when using a DC power flow model approximation, the marginal cost of losses is not fully calculated or not considered at all.

Therefore, it should be emphasized that LMP takes into account both generation and network constraints [113]. Furthermore, even though the marginal cost is assumed to be the most efficient short-term cost signal, there are, however, problems with LMP which depend on the different components (generation, losses, congestion) or which are related to the fact that LMPs do not

[6] For congestion management in transmission systems, the different methods can be grouped into three groups: Optimal flow (OPF) based method, price area congestion control method, transaction-based method [113].

consider non-convexities such as start-up costs. To solve this, extensions to LMP are proposed throughout the years. Some examples of extensions can be found through the following references ([117], [118], [119], [120], [121]), though this is not the scope of this report.

LMP for distribution grids

LMP is widely accepted by several transmission system operators in both day-ahead and real-time markets. A possible extension to the distribution system is only discussed rarely. Today, no power system uses distribution LMPs [106]. Compared to the transmission grid, to the best of our knowledge, there are only **limited methods available that do so**. Nevertheless, distribution grids become more active and therefore, it is important to give proper signals. In this context, it is considered that some pricing mechanisms from the transmission grid can be applied in the distribution grid as well (for instance, nodal pricing) [106], [122]. Yet, some adjustments in methodology would be needed to better allocate costs regarding voltage control, losses, generation… This is because there are differences between distribution and transmission grids that should be considered. In the transmission grid, there are significantly fewer losses than in the distribution grid. Yet, congestion costs are higher in the transmission grid than in most distribution grids (although this might change in the future). However, distributed generation could also lead to issues regarding over-voltage, system unbalances and active and reactive power losses. [123] "*Proper DG allocation have a severe impact on power loss, voltage profile, line loadability, operational cost, reliability of power supply, pollution and stability issues of distribution systems.*" [124] (p. 1245).

As such, when calculated for the distribution grid, the LMP is also called DLMP (distributional locational marginal prices). DLMP mostly consists of a marginal cost for losses and an energy price (in regions where the energy price is integrated with LMP) [102]. This methodology can be used for computing the locational value of energy flows mainly related to losses but also network constraints.

As indicated previously, the DC-OPF model is generally used for transmission grids. However, generally, power losses are not considered in such linearisation of the DC-OPF equations [125]. As losses are more significant in distribution grids, the error-margin would increase, leading to a need for more complex power flow models for the distribution grid. Therefore, early approaches to DLMP highly focus on loss allocation/reduction (voltage improvement), investigating the actual contribution of real power loss by each consumer [116]. This is done, for instance, by adopting marginal losses coefficients to deploy power loss calculations or by using game theory to model the spot price. As argued in [116], DLMP usually consists of two parts: **active and reactive power price**. LMPs can thus be calculated both for active and reactive power. Reactive power prices, however, can be very volatile and could lead to the exercise of market power [106].

While previous work mostly focused on the marginal costs of losses in distribution grids, more recent work is also paying attention to concepts for congestion management in distribution networks that have large levels of DER. These concepts are, in some cases, then extended to DLMP [125]-[126].

Administrative charges

Europe does not implement LMPs. Therefore, a potential alternative method to LMPs could be the implementation of administratively set charges that imitate LMPs to determine the network tariffs. The cost difference between the nodes could then, for instance, approximate the distribution grid cost.

Such SRMC-based network charges can be set "administratively", implying that costs are analysed in real-time and as such are updated on a highly dynamic basis to indicate whether network constraints are close to their limit or not. One could also set annually determined "static" charges, yet, these are not compatible with the principles of SRMC [109]. Administratively SRMC charges can be set ex-ante or ex-post.

If **SRMC charges are set ex-ante**, an administrative charge is set based on forecasted network conditions. The marginal costs would therefore approximate the costs of resolving constraints ahead of time. As this would be determined close to real-time, forecasting errors of the network state and market dynamics would be reduced, and as such, the method would be quite accurate. However, this might not outweigh the fact that forecasting costs a lot of effort, and users are exposed to highly volatile and sometimes unforeseeable charges which do not entirely reflect all network costs [109].

Alternatively, one could set **SRMC charges ex-post**. This would imply that charges are determined based on the costs incurred to resolve constraints in real-time (for instance, curtailment actions that the DSO took). The benefit of this is that no forecasting is needed to determine the costs. Yet, it would still be a repetitive and complicated process, with volatile and not sufficiently predictable prices. In addition, users might (wrongly) try to forecast prices themselves to adapt accordingly [109].

Finally, the discussion on SRMC concludes by looking back at the discussion on principles in section 3.3.1. When it comes to principles regarding transparency and simplicity, it is clear that SRMC is not scoring well. In the case of a zonal market such as Europe, a switch towards nodal pricing would be very complex and cumbersome. Nodal pricing requires regulatory and institutional changes to set (among others) new roles and responsibilities. Furthermore, European markets are highly increasing the integration of distributed resources, which would imply that nodal pricing should be extended to the distribution level as well [111]. Finally, for SRMC to be effective, stakeholders need to be well informed promptly about the different prices to alter their behaviour accordingly.

When it comes to economic efficiency, SRMC is scoring well in the sense that it aims to be highly cost-reflective as it considers differences in time and location. This comes, however, at the expense of predictability of costs as users will find it harder to predict price changes. It also comes at the expense of equity concerns as similar users at different locations can be charged differently.

3.3.3.1.2 Long-term marginal costs allocation

The long-term marginal costs appear when new investments in network infrastructure would be needed. In this case, network charges are based on the cost of developing the network and whether the behaviour of grid users will increase or decrease these costs. Therefore, those customers causing a higher network flow should be economically signalled so they know the economic consequences of their consumption or generation patterns for the DSOs. Thus, according to the cost-reflectivity and symmetry criteria to allocate long-term network costs, generators and customers should be treated equally. Furthermore, active customers highlight the need for this symmetry because they can consume power from the grid and also inject power in other periods.

Several different methods could be used to estimate long term costs. Figure 3-7 outlines these options, illustrating how the key high-level choice of which costs should be modelled influences the options that can be taken on many subsequent design choices.

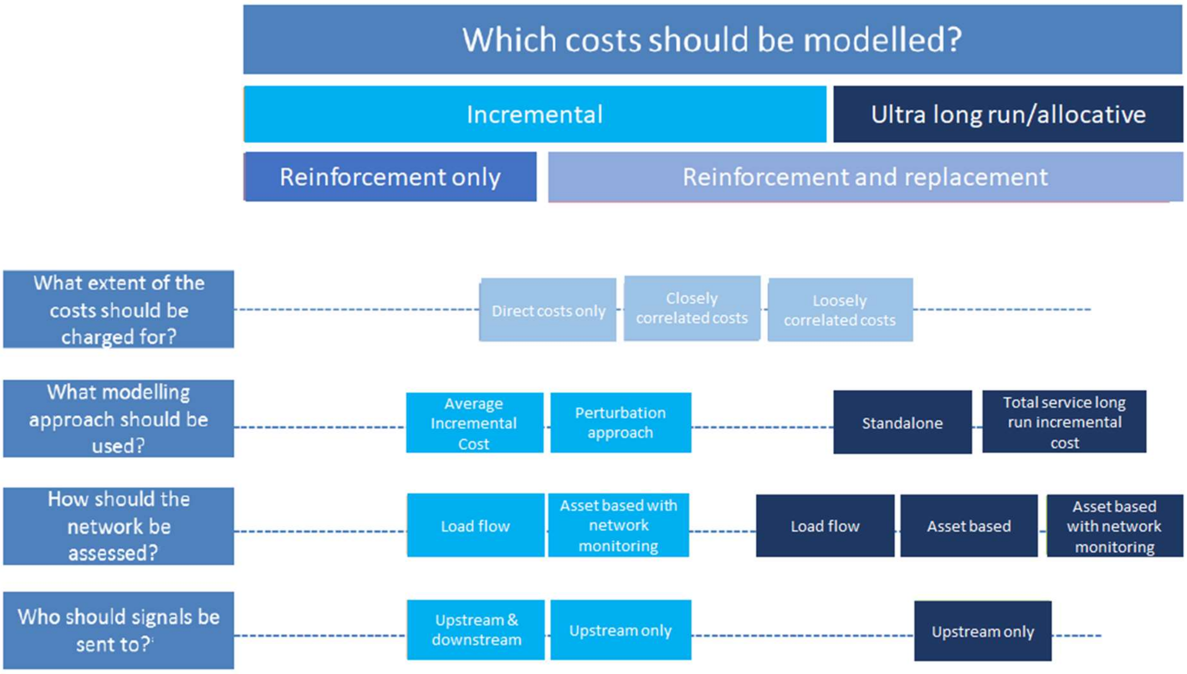

Figure 3-7. Key design elements for LRMC approach.

Source: [109]

A key distinction between methodologies is whether to focus on signalling network costs that are likely to be incurred in the near term or not:

- Incremental costs: indicate where/when network costs will result within a given timeframe (timeframe is also to be discussed). A further distinction could be among methodologies signalling just reinforcement costs or also considering future replacements of network assets, e.g. from ageing assets.
- Ultra long-run or allocative costs: based on the idea that, in the future, a marginal addition of demand or generation will require either investment in new network capacity or replacement of existing capacity. In this case, the strength of the signal provided is not impacted by how long in the future those costs might be incurred. For these costs, the calculation timeframe is sufficiently long (more than 40 years) that in some point in the future, a replacement or reinforcement will be needed, and signals are softer over time.

The extent of the costs that can be associated with reinforcement or replacement is a key decision to be considered. The network cost model could just consider costs that are directly involved with a particular reinforcement or replacement and are related to the physical asset, such as the overhead lines or underground cables that are installed to reinforce an area of the network. While direct costs include just the electrical assets required for the network reinforcement or replacement, closely correlated costs could include civil works, network repair and maintenance until business rates and smart meters costs. At the other end of the spectrum, there are costs which are only very loosely correlated to the costs involved in developing and maintaining network capacity.

It is necessary to have an appropriate representation of the network to determine how grid users in a given location are contributing to offset future network costs.

The high-level alternative options for this network modelling are:

- Load flow modelling, where a simulated representation of the network is created to show how energy will flow across the network at peak times.

- Asset-based modelling, where a model is created based on the mix of assets and/or a measure of the amount of network (e.g. distance of cables and/or overhead lines) and assumptions about how power will flow over those assets.
- Asset-based modelling with network monitoring, where an asset-based model could be supplemented with either real-time network monitoring based on DSO SCADA or based on a periodic review of substation load indices providing inputs of long-term forecasts. It can act as a proxy for load flow modelling to allow better-informed judgements than a pure asset-based model about how power is flowing and, potentially, on how close is the need for reinforcement or replacement of assets.

A further design decision is how to calculate the marginal cost of an additional unit of demand or generation on the network. Different options apply depending on the choice of ultra versus incremental long-run marginal cost approach and may rely on certain approaches for representing and assessing the network. There are two broad options for an incremental LRMC approach:

- Average Incremental Cost. The LRMC is derived by dividing the additional cost of forecast network build by the forecast size of the demand increment.
- Perturbation-based Marginal Cost. The LRMC is derived by subtracting the marginal cost of a best forecast network build scenario from the cost of that scenario plus a small, permanent increment of demand or generation.

There are two broad options for an ultra LRMC approach:

- Standalone Approach. The LRMC is derived from the costs of meeting a small increment of demand or generation.
- Total Service Long Run Incremental Cost. The LRMC is obtained by dividing the full cost of a hypothetical optimised network by the capacity served.

It is also important to consider which costs will be signalled to different users, i.e., whether generation and demand should receive equal but opposite charges/credits, and whether charges should be based on a user's impact on upstream costs (i.e. costs at the voltage they are connected to and above) only or also on any downstream cost that they contribute to.

There are several options which concern the locational granularity aspects. On the one hand, users can be classified depending on the nodal or zonal charging approaches. Nodal charging is a fully granular option for setting network charges which would involve setting a customer-specific charge for grid users. Zonal charging is a less granular option for network charging, which would involve setting averaged charges on a zonal basis to reflect variations in users or networks within each zone. On the other hand, more granular charges could be achieved regarding nodal granularity (primary or distribution substation level) to improve cost reflectivity below the point at which a customer-specific charge is produced.

Note that the main driver for long-term costs is the maximum peak utilisation of network assets which can be related to the dominant flow either from energy withdrawn or injected. Following the economic efficiency principle, the first best charge to allocate long-term marginal costs would be to implement peak-coincident forward-looking charges (€/kW) that measure customers' contribution to the maximum flows for each network element in the periods of maximum utilisation. This economic signal would incentivize user responses to reduce network peak flows and therefore delay future grid investments.

Peak coincident network charges vary with time since they anticipate investment costs which are necessary at certain times in a year. For example, if a feeder is congested (or close to being congested in the near future), those grid users who contribute to the anticipated congestion in the near future should be signalled to shift their consumption, because if they continue with, or increase, their peak consumption at these hours, new investments will be triggered in the long-run.

The principle of economic efficiency leads us to design peak coincident network charges with a high level of locational granularity to incentivize efficient grid user responses, depending on the particular network components that are expected to be congested.

Following a cost-reflectivity principle, peak coincident network charges should be calculated for each grid user depending on its point of connection to the grid. The considered network should be divided into the lowest level of technical network asset, i.e. from the transformer to feeder. Then, for each element, the number of hours in which the expected peak flows exceed the threshold (according to the security margin selected) are considered. All grid users contributing to these peak flows are charged proportionally to their contribution to the potential future investment or incremental cost associated with the expansion of this network component. However, the contribution to grid usage is challenging to calculate.

Therefore, long-term network costs should be signalled through element-by-element peak coincident network charges that minimise network usage in peak periods, as well as boost flexible resources, from either generation or demand. These charges would be time-dependent, capacity-based charges and dependent on the location of each user in the network.

3.3.3.1.3 Residual costs allocation

Residual charges are designed to recover the rest of the relevant network's costs once long-term and short-term costs have been levied, and should not send signals to users. These charges are required because short-term and long-term charges do not usually recover the costs of the whole network.

Residual charges should be levied only on final demand customers, and not on generation connected to the system [127]. The main issue of charging generation plants with residual costs, which are not cost-reflective, is that generators would translate these costs in their sales to the market, passing them to the customers, and causing inefficient responses from the customers' side. Therefore, residual charges should be solely allocated to customers.

There is no optimal solution for allocating residual costs. However, some methodologies better meet these charges' objectives by following some principles and criteria above, such as equity and cost-reflectivity:

1. Equity principle leads to the design of residual costs allocation in a way that consumers are discriminated by their income level, rather than by the amount of their consumption or their peak usage. High-income households can have more efficient appliances, so they may have similar energy consumption as low-income households. Moreover, if high-income households have solar panels, their peak can be much smaller than low-income households without solar panels.
2. Economic efficiency is seen as the robustness of the cost-recovery objective against consumption pattern modifications made by the electric system users. Cost reflectivity is not an essential design criterion for these costs since there exists no connection between residual costs and energy consumption or contracted capacity.
3. Minimisation of cross-subsidies is an important feature of residual costs recovery. This means that some consumers should not obtain certain benefits that finally others will pay for. These criteria are divided into resistant to cross-subsidies derived from the installation of self-production, resistant to cross-subsidies derived from storage technologies implementation, and resistant to cross-subsidies derived from customer aggregation in a single supply point.
4. Implementation barriers should also be considered as costs of the application of a new methodology cannot be higher than the benefits derived from it. Main implementation barriers can be discussed under the topics of an adaptable tariff to new customers, and the difficulty of getting the necessary data to apply the new methodology.

5. Predictability is also a fundamental criterion for the allocation of these costs. Significant changes in the allocation methodology would lead to bill uncertainty for consumers.
6. Transparency plays an important role in this matter. The calculation method for residual costs must be public and objective.

Several alternative charges are proposed to recover policy costs (i.e. regulated costs non-related to networks); those that are closer to the principles and criteria defined in section 3.3.1 are highlighted in the following.

1. Fixed charge based on income levels or their proxies (e.g. property taxes)

Progressive charges differentiating among related to the income level would be favourable to equity principles regardless of the consumption level. For commercial and industrial consumers, yearly profits of the businesses could be variables used as a proxy of income level. This charge would be resistant to modifications of consumptions patterns, DER installations or consumer aggregation.

2. Contracted capacity charges applied at peak and mid-peak periods

Among volumetric or capacity charges, capacity charges are preferable since they are only modifiable until a certain extent since consumers will have to contract enough capacity to meet their maximum consumption level. Only peak and mid-peak periods -i.e. hours of maximum utilisation- are considered for this charge. This approach would, for example, not introduce any barrier for the electric vehicle charging at valley hours. This approach is resistant to self-consumption deployment since peak demand will hardly coincide with the generation peak, especially winter peaks. On the other hand, it is less resistant to storage deployment. Batteries can modify required contracted power by shifting consumption among hours.

3. Fixed charge based on historical consumption

The principal idea of this alternative is looking for a cost-responsibility for each supply point. Thus, it could be considered that historical consumption is a reasonable index for the costs associated with the annual deficit or, partially, for the renewable costs. Presumably, higher-income consumers usually hold higher consumption levels than low-income consumers. Hence, it follows the distributional equity criteria. Furthermore, it is remarkable that low-income consumers may possess less efficient household appliances, and the lack of sufficient financial means to invest in flexible appliances, which would increase their consumption levels and their fixed charge payments. Additional implementation barriers for this methodology are charge calculation for new buildings, unfair charges for new household tenants if they have different consumption patterns than previous tenants, and changes of the existing population such as the expansion of the family, renovation, etc.

Table 3-5 synthesizes the three considered alternatives for the residual costs allocation and their suitability for the criteria previously mentioned. While a positive signal means that methodologies adequately answer the criteria, a negative signal means the contrary. An equal signal means that it is not the best neither the worst alternative concerning the considered criterion. Predictability and transparency criteria are not included since all three methodologies are expected to adequately follow them.

The British regulator is proposing to recover residual network costs through a fixed charge for domestic customers depending on the aggregated net consumption of the customer category where they are classified —equal payment for customers classified under the same category. There are other alternatives to allocate residual costs through fixed charges among all the customers following equity principles, such as an uneven fixed charge that reflects past consumption behaviours, for example, according to the historical contracted capacity and electricity consumption [128].

Table 3-15. Alternatives for residual costs allocation

Source: [65].

Considered criteria		Fixed charge based on income levels or their proxies	Contracted capacity charges applied at peak and mid-peak periods	Fixed charge based on historical consumption
Equity: discrimination among income-levels		+	=	=
Economic efficiency: not avoidable by customers to ensure cost-recovery		+	+	+
Minimisation of cross-subsidies	Resistant to self-producing	+	−	=
	Resistant to storage	+	−	+
	Resistant to customer aggregation	+	−	+
Implementation barriers	Adaptive to new customers	+	+	−
	Easy to implement	−	+	+

3.3.3.2 Benefits and challenges of applying efficient network tariffs

To end the discussion on dynamic tariffs, this section summarizes the benefits and challenges of applying efficient network charges regarding the three different components: short-run, long-run and residual.

<u>Advantages and challenges of applying short-run marginal costs</u>

First of all, when it comes to SRMC (or nodal pricing), it became clear that there are some key benefits:

- SRMC or nodal pricing has a higher spatial granularity and therefore provides more accurate market signals to guide operational decisions [110]. Real-time nodal pricing can consider most relevant physical constraints, although it should not be forgotten that they ignore most non-convexities such as start-up costs. Local real-time grid conditions are, however, better signalled [129].
- Also, there are incentives to make investments only in those regions (nodes) that show higher price differences [110].
- The accuracy and transparency of the costs become clearer and there are less hidden congestion costs or less cost socialisation [111].
- Nodal pricing is also increasing efficiency in the dispatch of the generating units and as such reduces re-dispatching costs [110], [129]. Without nodal pricing, more remedial actions (such as redispatch and counter trading) would be needed [111].
- SRMC increases the possibility to engage with a wider range of users [130].

Nevertheless, SRMC also has some clear disadvantages and it should be examined to which extent the benefits of SRMC outweigh these disadvantages:

  - In Europe and some other regions, it would take a significant amount of changes before such SRMC charges could be set in practice. Implementation costs would be very high, as current distribution grid charges in those regions are rather static and not even close to the level of spatial and temporal granularity needed for SRMC [109].

- Implementing SRMC requires a lot of network data and prices at distribution level [109]. The computational burden would be significant. Widespread network monitoring would be needed, and forecasting the network cost of action is difficult. As recognized in [131], more network data might be required than currently available to them. In addition, they state that the administrative burden on the DSO would be too large.
- SRMC exposes consumers to more volatile charges [109]. Network charges need to be updated on a very frequent basis [110]. For consumers, predicting or anticipating these charges would be extremely difficult [131]. As such, SRMC charges are set, the ability of a market to accurately forecast SRMC charges would determine how effectively it can respond. Sufficiently predictable charges are, therefore, needed [109]. This is especially the case when ex-post SRMC charges are used because in those cases, consumers only see the charges in real-time (based on the real costs). Consumers will have to forecast themselves to prepare their response.
- It is also claimed that nodal pricing could give more market power to some market players since it does not take into account whether there is an adequate competition [110], [129].
- Another potential disadvantage of SRMC is that it does not reflect distribution network infrastructure costs sufficiently [109]. It is said that system operators do not receive accurate signals for grid expansion and that it does not ensure the recovery of fixed grid costs [129]. [106] explains that over the lifetime of a network, DLMPs only recover a fraction of the cost of network investments. This is because there are non-economically justifiable engineering design requirements, planning errors, and a risk aversion to power system failures. While DLMPs might therefore provide accurate short-run signals, they are not adequate for the recovery of long-run network costs. They do not provide users with information on what the impact of their behaviour is on future network investments. However, this issue can be solved by complementing SRMC with LRMC as discussed previously. This characteristic of SRMC is the reason why LRMC signals are needed.

As indicated previously, the advantages and disadvantages might vary depending on how SRMC is implemented. For instance, zonal pricing is assumed to increase liquidity and competition more than nodal pricing [109]. Therefore, it is anticipated that some form of hybrid charging might be interesting, in which, case nodal charging would be used up to a certain voltage level and, zonal charging would be applied below that point.

In the case of DLMP, prices are based on wholesale markets. This implies that market participants can buy long-term products to hedge against volatile prices [109]. Yet, the hedging framework could very complex especially at earlier implementation without previous experiences. Furthermore, although ex-ante and ex-post SRMC have approximately the same disadvantages and advantages as DLMP, it should be highlighted that DLMP is based on wholesale markets, while administratively set SRMCs are based on some sort of simulation or estimation. This implies that truly implementing DLMPs suggests actual market-based pricing which would imply very extended reformations for Europe. Such reformations would not be necessary an administrative setting of SRMC charges.

Furthermore, as discussed earlier, there can be different temporal and spatial degrees in implementing SRMC. A mild approach could be to include time-variant charges. These are simpler to implement and provide more predictability for consumers. The trade-off is that they are less accurate as they take real-time grid conditions less into account. With regard to location, besides the already explained difference between nodal versus zonal pricing, price differentiation can be applied at voltage levels within a zone or even at a national level.

To conclude, even though SRMC, especially in the form of DLMP, is assumed to be ideal from a theoretical point of view, it is fair to say that the disadvantages clearly show that it is hard to manage in practice [109].

<u>Advantages and challenges of applying LRMC</u>

The LRMC can offer an answer to some of the disadvantages of the SRMC. Some strong advantages are:

- It allows signalling long-term network costs, providing long-term economic efficiency and sustainability to the electricity system.
- Peak-coincident network charges allocate long-term network costs in a cost-reflective manner, sending adequate economic signals to consumers based on the effect of their consumption patterns in long-run network reinforcement.
- A higher locational and temporal granularity allows improving the economic efficiency of the signals provided by the electricity tariff, incentivizing new technologies (DER, such as storage, and electric vehicles) development when they are economically efficient in the long term.

Challenges:

- It is not clear which costs should be included in the long-term cost calculation: reinforcement costs, or reinforcement and replacement costs, direct or indirect costs, closely and loosely related costs.
- It is difficult to find an adequate degree of locational granularity which balances the economic efficiency and equity principles and at the same time, maintaining a suitable level of computation complexity.
- The identification and definition of the periods where LRMC is applied is not straightforward. This may require an exhaustive analysis of several future scenarios for network developments based on expected grid users evolution.

LRMC is the internationally predominant approach for network charging [109]. This has lower implementation challenges in comparison with the SRMC approach. However, in the LRMC-based approach, further attention is still needed to decide which network infrastructure costs are to be modelled. As explained earlier, this can lead to either the "incremental cost approach" or the "ultra-long run/allocative cost approach". In the latter case, the remaining lifespan of the existing network is not considered, implying that the signals given are not influenced by how far in the future costs take place. Finally, it is important to determine which costs are charged for. The focus can be rather on direct costs (e.g. real physical assets), closely correlated costs (e.g., civil works, network repair and maintenance), and loosely correlated costs (such as call centres) [109].

Both SRMC and LRMC may face opposition considering equity criterion as the networks have been designed according to historical criteria from DSOs and regulations without considering grid users preferences. High charges may be a result of planning errors or certain regulations out of grid users' control.

<u>Advantages and challenges of applying Residual Costs</u>

Finally, there are some true distinct advantages of having a separate approach for residual cost charging:

- It does not distort the efficient signals provided by LRMC and SRMC, and thus not create cross-subsidies among different customer categories.

- Residual costs calculation as the remaining total network costs after applying LRMC and SRMC ensures cost recovery and economic sustainability of the electricity system.
- Residual costs allocation to demand consumers, and not on the generation side, avoids inefficient responses of consumers, caused if these costs are applied to generation and they are translated to demand through electricity markets.
- Fixed charges can equitably allocate residual network costs among customers.

Nevertheless, this method as well faces some challenges:

- There is no optimal solution for allocating residual costs. While a fixed charge based on income levels is the alternative that best satisfies most principles, implementation issues, such as the need for personal information about income levels, are difficult to overcome. Other alternatives, such as contracted capacity charges, may interfere with efficient price signals.
- It is difficult to find an adequate degree of locational granularity which ensures the equity principle and does not send any economic signal to customers.

As such, while it is necessary to separate residual costs from long-term network costs, further research is necessary to find a balance on how to charge these costs.

3.4 Local flexibility markets

Local flexibility market mechanisms are being implemented or researched in different European countries, such as the United Kingdom, the Netherlands, Sweden or Norway. Moreover, several H2020 European research projects, such as Integrid, CoordiNet, INTERRFACE, among others, are also exploring different design alternatives. Some local market platforms in operation or piloting phase such as enera, ETPA (used for GOPACS TSO-DSO coordination platform), Piclo Flex, NODES and Cornwall LEM, are demonstrating the possibilities of new business models in this area.

All these initiatives differ in many ways. This section describes the design and implementation aspects of local flexibility markets. Nine different aspects have been considered as relevant, based on a literature review and on the experience of the DSOs and market operators that participate in the EUniversal project:

1. Functions performed by the local flexibility market
2. Service and product characteristics
3. Flexible resources characteristics
4. Geographical scope and network representation
5. Supply and demand representation
6. Timing of the market
7. Pricing and market clearing process
8. Integration with existing markets
9. Implementation considerations

As highlighted by CEER, a well-functioning market with free competition for procuring flexibility by the DSO must fulfil the following conditions [2]:

1. Full information
2. Rational actors
3. Standardised products
4. Liquidity
5. Low entry and exit costs
6. Low transaction costs

In the context of grid services provision, **full information** includes information availability of location and quantity of the needs, understanding the involved costs when providing the service, knowing the procurement rules and the roles of the actors, etc. In markets designed for providing flexibility at the distribution level, due to lack of monitoring of the network, constraints on data disclosure, full relevant information availability may become a challenge or might also cause gaming effects and reduce the efficient functioning of markets.

Rationality of the actors is a general assumption for the efficient outcome of all markets. However, it does not necessarily need to be fulfilled. Bounded rationally and other limitations on decision making would affect market outcomes, but these limitations do not affect a particular mechanism. An important challenge on the implementation of market-based mechanisms comes from engaging new actors such as consumers without or with limited technical knowledge.

Product standardisation lowers entry barriers and helps to trade flexibility among DSOs or even with TSOs, but should not lead to an extensive exclusion of flexibility technologies. Product design is a crucial aspect that will be developed in the EUniversal project. Further insights on this aspect can be found in section 3.4.2. As introduced in section 2, specific characteristics of DSO needs and FSP characteristics require specific product parameters which make product standardisation not always desirable.

Liquidity in local flexibility markets can be restricted by different aspects including technical and economic ones such as:

a) **Technical nature of the service**. Some services are by nature local, such as voltage control in a network node. The provision of voltage control is more effective by resources located closer to the node as losses due to reactive power flow increase with distance. This limits the potential participants providing the service.
b) **Network topology**. The network topology influences the sensitivity of the resources for providing a service. For congestion management, in radial networks, the sensitivity coefficients are equals to 0 or 1 for active power since losses neglected. In meshed grids, the value of the sensitivity coefficients ranges between 0 and 1.
c) **Potential flexibility providers.** The flexible resources that can provide services may be limited as certain demand, storage or generation units may be relatively inflexible or may face higher costs for providing flexibility.
d) **Customer engagement**. The participation of customers requires the engagement of customers in the provision of the service at different stages: evaluation of flexibility potential, prequalification to be able to provide the service, service delivery, etc. This becomes a challenge when for the service provider it is not the core of their activities or business.
e) **Uncertainty and risk aversion** have been signalled as key elements that affect the market outcome [132]. New local flexibility markets may have significant uncertainties related to market development and future market outcomes, especially if contracts have a short duration and cannot be combined within one flexibility service provider with other services (i.e. revenue stacking). As in other markets such as capacity markets, bilateral contracts may reduce the uncertainties and risks and incentivise investments [132]. This is also true for other more regulated mechanisms which reduce the future payments risks.

Low liquidity can cause the risk of market power execution and, as a result, high prices; however, this does not necessarily incentivize new investments if the volumes are low so that the investment is not economical.

Entry and exit costs. Flexibility provision has entry costs related to the complexity of the services, communication requirements, prequalification criteria, control systems, among others. If the cost to enter the market are too high or cannot be used for other purposes they disincentivize participation.

Transaction costs. Running the market, settlement, billing, etc., imply costs that may overcome the benefits of procuring grid services.

Another aspect of flexibility markets is the potential threat of strategic bidding and gaming. An example of undesired gaming behaviour is the intentional submission of untrue schedules to cause erroneous forecasts which turn to expected factitious problems in the network which is then solved by the unfair flexibility provider ("inc/dec gaming") [133], [134].

Before implementing a more regulated mechanism, it has to be checked whether a **market flaw, barrier or gaming possibility can be solved through a market design intervention or market monitoring**. For instance, the process of solving congestion management has to be carefully designed to avoid incentives of creating artificial constraints either in the congestion management market itself or in the energy market. Besides, the imbalance settlement should be well-designed to limit such opportunities. Another option to limit market power is to include price caps that can be based on reference costs or the cost for alternative network investments or RES curtailment.

When the abovementioned conditions are not met, alternative solutions to markets should be considered, such as more regulated mechanisms, see section 0. The final objective must be to ensure economic efficiency on the procurement of flexibility and avoid market distortions or exacerbation of system requirements. More regulated mechanisms require regulatory interventions such as assumptions on costs, negotiation of contracts or computation of fixed payments either when required to deliver a service or as a permanent incentive to provide a service. In many countries, voltage control, when not mandatory, have been traditionally provided through more regulated mechanisms such as bilateral agreements or regulated prices [135].

3.4.1 Functions of a local flexibility market

Local markets help to unlock the flexibility from DERs to be used for providing grid services and therefore avoid or postpone traditional network investments. The implementation of local market organisational structure, however, requires a series of functions divided into five main phases [28], as presented in Figure 3-8.

Local flexibility markets are closely connected with the operation of the distribution network, which is a monopoly activity managed by DSOs. The tasks performed by DSOs may vary depending on the market design and the regulatory framework which is still to be developed. For some of these functions, it is clear that the DSO is better placed to perform them. But, for some functions, there are grey areas of who should execute some of the activities; however, they are needed to enable the local flexibility markets functioning. Usually, DSOs have no or little experience in operating a market place to procure grid services. Moreover, neutrality is required for operating a market. A neutral entity can ensure fair and equal treatment of all market participants and the correct operation of a local flexibility market. Therefore, some of the functions related to the procurement of grid services can be performed by an independent market operator.

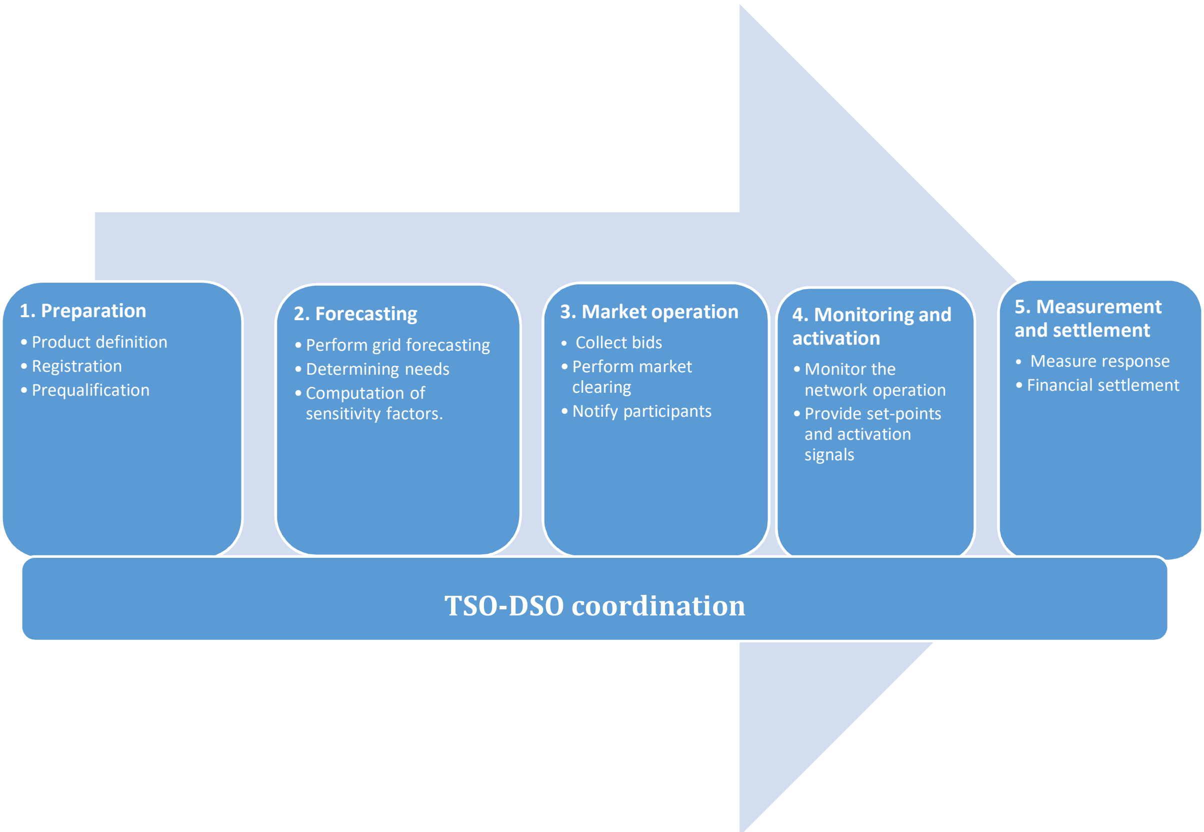

Figure 3-8. Phases and functions to enable local flexibility markets

Source: adapted from [28]

The functions to enable local flexibility markets for each of the phases are described below.

1. Preparation phase. A starting point for local market functioning is the definition of the product traded, including the technical parameters for the service(s) that the DSO needs (see

section 3.4.2). The product parameters may depend, not only on the DSO needs but also on the available flexible resources' capabilities. Trade-offs exist between harmonizing products (even with other markets), solving local needs (chapter 4 analyses in more detail all services considered and context attributes) and adapting the product to the local flexibility (see section 1.2 for details on flexible resources). Once the product is defined, a process is needed to register sites and assets owned by the FSPs and connected to the grid to provide flexibility. Then, a technical prequalification has to be performed to assess the compliance with the technical product parameters and the compatibility of the different systems used by the DSO, FMO and FSP. The preparation phase functions can be performed by the DSO or in collaboration with the FMO.

2. Forecasting phase. The DSO estimates the grid status using algorithms as an OPF, which becomes a more important task given the massive penetration of DERs. The DSO needs to assess the impact of flexible resources based on load and generation forecasting. As part of the grid assessment, different grid topologies can be considered (see section 1.2.2). The DSO has to define its flexibility needs and, in the contexts in which auctions take place, the relevant geographical scope for the market. One of the main outcomes of this phase is the computation of the sensitivity factors[7] based on the locations of the FSP assets and the impact on solving a grid constraint (see section 3.4.3) as well as the potential bid limitations (if a bid activation can violate more constraints). Alternatively, if the market platform has the grid information, an OPF could be used as a technical clearing of the market that considers grid constraints. In both cases, the outcome can depend on the network configuration and a comprehensive set of grid data describing the electrical properties of the distribution grid. These functions can only be performed by the DSO.
3. Market operation/bid selection phase. In this phase, bids are collected, and the market process clearing is performed. Market-clearing is an important function. Market clearing can involve the economic and technical data (e.g. optimisation process to select the optimal set of orders, potentially including switching measures based on comprehensive grid data). The resulting prices will be based on the selected remuneration method (pay as clear or pay as bid). Once computed, the resulting prices have to be communicated to market participants. Therefore, clearing notification to market participants is required. The optimisation process could be both an independent FMO and the DSO. DSO should be in charge of the optimisation process in the cases in which, to achieve the most efficient results, the market-clearing depends on comprehensive grid data that cannot be shared outside of the DSO boundaries for regulatory reasons. In general, a high dependency on comprehensive grid data raises in the context of TSO/DSO coordination and network reconfiguration. Where auctions do not depend on grid data, so that the impact of a set of bids is (nearly) the same, the selection process can be carried out by independent FMOs (based on the sole merit order principle). The collection of bids, the notification and contract management can be performed by FMOs.
4. Monitoring and activation phase. Once the market is cleared, the grid monitoring, when required, and activation of selected FSPs have to be performed. This is a function closely related to DSO grid operation and most probably will be performed by the DSO.
5. Measurement and settlement phase. The measurement and financial settlement have to be performed to compensate for the service delivered or penalize the lack of response. To perform these functions, it is required to import and clean the measurement data obtained from the meter installed in the point of connection of each FSPs. The DSO or another independent actor should be responsible for the metering activities. The financial settlement would require to compare the measurements with the commitments to deliver the service if cleared in the market. For some services, a baseline (schedule without considering the

[7] Definition IEEE: "*Sensitivity Factor in Power System are linear estimates of the change in line flow with a change in power at a bus*" [136].

flexibility activation) is required for the time interval of the contract or dispatch. As part of this last phase, it is needed to manage the payment process: invoice creation from the settlement and money transfer. Finally, management of financial guarantees and market monitoring can be relevant functions to perform. These functions are one of the main core activities of FMOs.

6. TSO and DSO coordination. Depending on the service and the network considered coordination with the TSO may be required to coordinate flexibilities procurement between DSO and TSO and mitigate conflict situations. The coordination can take place at all different phases and different models are possible (see section 3.4.8).

Nowadays, the DSO performs functions under the forecasting, monitoring, activation phases, measurement, settlement, plus the TSO-DSO coordination as part of their system operation role. Moreover, as mentioned in point 3, DSO may be in charge of prequalification and market operation/bid selection the cases in which the market-clearing depends on comprehensive grid data that cannot be shared outside of the DSO boundaries for regulatory reasons. In the H2020 project EU-SysFlex [137], these functions were allocated to a new role "Optimisation Operator" to assess the impact of the allocation of such role to system operators, market operators or third parties, also based on centralized[8] and decentralized[9] optimisation schemes. It was concluded that decentralized optimisation appears more relevant for grids where DSOs need locational products to solve voltage and congestion problems. Furthermore, it was also concluded that the allocation of the Optimisation Operator role to any actor different from the individual DSO/TSO would cause significant governance and regulation challenges. The results of this project will be considered in the definition of criteria for the qualitative assessment of market design options in EUniversal and the final assessment in chapter 5.

3.4.2 Services and product characteristics

Markets can be used to trigger change within the energy system, by providing economic signals to determine which assets are used and when they should be used. When creating a market mechanism for trading local flexibility, all parties must be treated equally. The local service required and its value determine the willingness of an asset owner to offer its flexibility to the market, and thus, what type of flexibility is utilised. This creates competition between the flexibility asset owners as the market creates a merit order stack, where the merit order is solely based on the type of flexibility being offered, the bidding price and on the geographical location. The market will be used to create price signals in the local network area, which will ideally provide transparency of the scarcity or availability of flexibility.

This deliverable specifically focuses on local markets to trade grid services. The focus will be mainly on congestions management and voltage control. Other services will not be specifically addressed.

For a local market, the flexibility deriving from an asset has to comply with the requirements specified into products that reflect both the technical potential and its limitations. Distinctive parameters are commonly used to determine the product. Basic data parameters are generally used for asset classification and the determination of the asset location providing necessary information about the asset type and targeted markets. Other parameters like price per reservation and activation, quantity, real or reactive power, or maximum upward or downward times, serve to

[8] Definition EU-SysFlex: A single algorithm (run by a single Optimisation Operator) performs the optimisation for both transmission and distribution levels, considering all grid constraints.

[9] Definition EU-SysFlex: Several algorithms do the optimisation for different levels (run by the respective Optimisation Operator for each SO, thus at least one for transmission level, and one for distribution level) and require to be coordinated.

appropriately characterize the flexibility offered. Ultimately, time parameters allow the FSP to precisely determine the product to be offered and enable the buyer (in our case the DSO) to effectively choose the best flexible solution for the identified constraint at a lower cost. Time parameters cover the information about when the flexibility can be provided, in which time granularity and in case of consecutive activations, how much rest time is needed between one activation and another.

Given the heterogeneity of networks, however, the range of products may change depending on topography, population, industrial density and activity focus and the network itself.

As part of the market product definition, a set of technical attributes are defined representing the parameters and constraints attached to the offer exchanged by market participants. While some of the attributes are linked to technical dispatch characteristics of specific flexible resources, they also need to be reflected in a generic way so that they can cover a wider range of technologies (following the technological neutrality principle). The capability to support flexibility products from an aggregated set of distributed flexible resources is a key feature of a local market design. The product definition and the corresponding processes related to the acquisition and exploitation of grid services shall allow FSPs to optimize their portfolios close to real-time whilst providing sufficient locational information to support the grid operator to forecast the flexibility needs.

Due to the local characteristics of the market, a key aspect to consider is whether the traded product can be harmonized considering specific values for products attributes (as the ones presented in Table 3-16) or whether these products attributes can be adapted to local grids and FSPs characteristics (e.g. activation times, longer preparation periods, etc.). One of the main benefits of harmonized products is the increased standardisation and, therefore, the better comparability of bids and lower entry barriers for FSPs. As a drawback, harmonized products can decrease liquidity if certain FSPs are excluded due to too strict requirements. Higher liquidity for the different use cases of flexibility can be obtained if the products can be used for different services, e.g. congestion management and balancing, congestion management for TSO and DSO needs, etc. Especially, the combination of balancing and congestion management must be carefully assessed, since balancing requires faster reaction times so that a joint product could decrease the liquidity for congestion management [137]. Another possibility to increase liquidity is to include the locational information on energy markets such as the intraday market, so bids submitted for the intraday market can be used to solve local problems if they are in the affected location. The GOPACs initiative utilizes intraday market bids, including locational information to solve local congestions [138].

Table 3-16 shows examples of attributes for reserve or energy products, explored in the context of the CoordiNet project[10].

[10] In particular, we refer here to the CoordiNet D1.3 [139].

Table 3-16. Common attributes of reserve and energy products.

Source: Adapted from [139]

Characteristic	Definition
Preparation period	The period between the request by the SO and the start of the ramping period.
Ramping period	The period during which the input and/or output of power will be increased or decreased until the requested amount is reached.
Full activation time	The period between the activation request by the SO and the corresponding full delivery of the concerned product.
Minimum/maximum quantity	The power (or change in power) which is offered, and which will be reached at the end of the full activation time. The minimum quantity represents the minimum amount of power for one bid. The maximum quantity represents the maximum amount of power for one bid.
Minimum/maximum duration of a delivery time interval	The minimum/maximum is a feature of the FSP and stands for the length of the delivery time interval during which the service provider delivers the full requested change of power in-feed to or the full requested withdrawals from the system. It represents a feature that characterises the FSPs according to the measures that are used for providing grid service. This parameter is analogous to the minimum functioning time for thermal power plant and influences the participation in the mechanism for providing grid service.
Deactivation period	The period for ramping from full delivery to a set point, or full withdrawal back to a set point.
Granularity	The smallest increment in volume of a bid.
Validity period	The period when the bid offered by the FSP can be activated, where all the characteristics of the product are respected. The validity period is defined by a start and end time.
Mode of activation	The mode of activation of bids, i.e. manual or automatic. Automatic activation is done automatically during the validity period (with little or no direct human control), whereas a manual activation is done at the request of the SO.
Availability price	Price for keeping the flexibility available (mostly expressed in €/MW/hour of availability)
Activation price	Price for the flexibility delivered (mostly expressed in €/MWh)
Divisibility	The possibility for a system operator to use only part of the quantity offered with bids by the service provider, either in terms of power activation or time duration. A distinction is made between divisible and indivisible bids.
Locational information included	This attribute determines whether certain locational information needs to be included in the bid (e.g. identification of Load Frequency Control area, congested area)
Recovery period	Minimum duration between the end of the deactivation period and the following activation.
Aggregation allowed	This attribute determines whether a grouped offering of power by covering several units via an aggregator is allowed.
Symmetric/asymmetric product	This attribute determines whether only symmetric products or also asymmetric products are allowed. For a symmetric product, upward regulation volume and downward regulation volume has to be equal.

3.4.3 Geographical scope and network representation

The targeted market area of a local flexibility market is linked to a location which is defined by a grid node or a set of grid nodes whereby the flexibility within that area that can solve the local need is traded (see Figure 3-9). The location can consist of an aggregated grid area and can be defined through one of the options below:

a) One or multiple nodes (s) corresponding to a specific voltage level (such as high/medium/low substation or feeder). Then, the location covers the network downstream the node if it can be assumed as radial.
b) A set of nodes that could be spread over multiple substations or feeders. A simplified generic definition principle can be used to define the influenced area in case of meshed network and designed by the DSO depending on network study analysis.
c) No aggregated grid area might be determined if the impact of the flexibilities to the grid is too diverse, which especially can take place in meshed grids. In this case, the aggregation of flexibilities is not possible. Nonetheless, the DSO shall provide information on which area bids are needed considering that network reconfigurations are not so static as they have been generally considered.

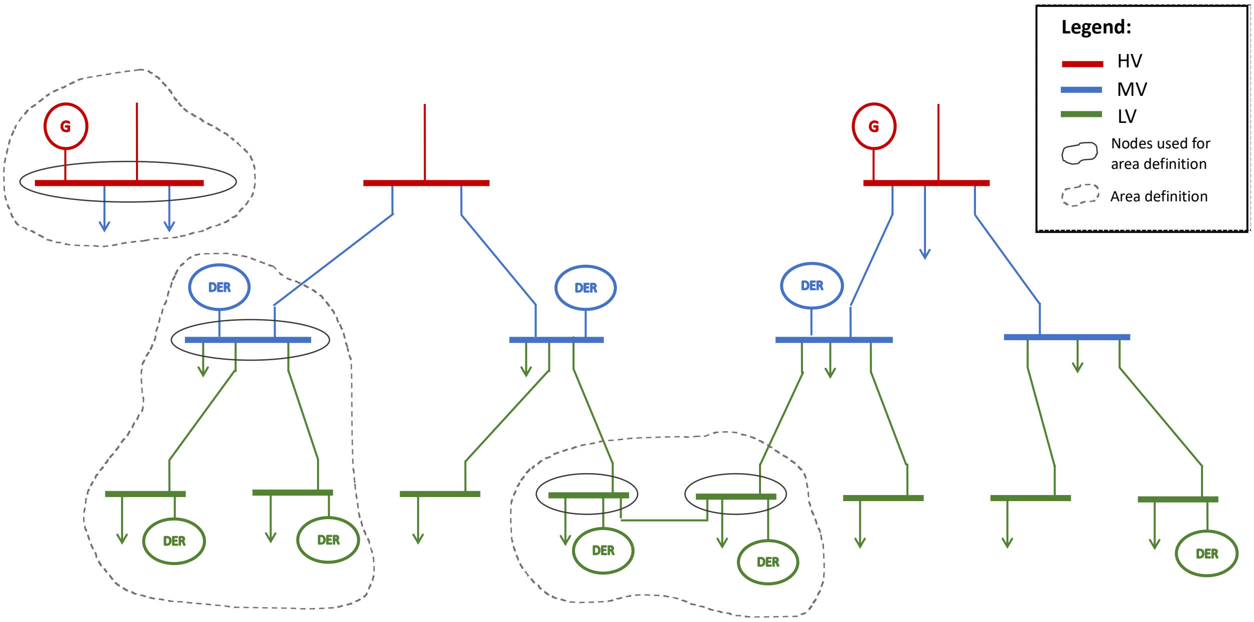

Figure 3-9. Market area definition examples

The lifecycle of an area definition can also be defined and created:

- Statically: the area definition can stay the same over a long period (e.g. based on seasonal grid parameters). This can be valid if the distribution grid topology and switching plans generally do not have an impact on the defined area.
- Dynamically: it can evolve frequently based on network study and topology analysis performed in look ahead and then applied as part of the configuration for the corresponding market day. While it allows the DSO to tailor the area based on its actual needs for network services to be covered (such as voltage / current congestions or balancing), it implies that:
  - the DSO can run power flow analysis ideally at lower voltage levels based on distributed generation/load forecasts and switching plans (which can be difficult depending on the grid observability required to prepare such data inputs)
  - the aggregator/FSP can re-optimize his set of resources each time based on new area definitions received.

The trade of flexibility has to stay within the limits of the network capacities and the impact of each FSP should be properly accounted, e.g. through sensitivities factors. The contracted flexibility volumes do not always serve the needs of the distribution grid. Therefore, before the contracts are created, there is a need as part of the flexibility selection mechanism for TSO-DSO coordination, define priorities and network capacity checks (i.e. the cases in which the local market platform is being used as a route to TSO services, enabling the DSO simply to validate that the flexibility complies with distribution grid constraint) as well as determine the contribution of flexibilities towards the need. Hence the DSO may need to compute the capacities of its grid and the sensitivities at different levels to:

- Either share these data with the local market or the FSP so that they can be used as constraints and sensitivities as part of the optimisation processes. Both constraints and sensitivities are needed by the clearing process to validate that the clearing solution (i.e. the set of selected matched orders) does not violate the limits exposed by the DSO and that the selected orders also solve the DSO problem efficiently. The set of data needed can be very comprehensive, describing in detail the electrical properties of the grid between the relevant nodes.
- Or integrate such information in its optimisation process for selecting the most efficient flexibilities. In this case, the process can also include switching options. [137]

The format and granularity used to express the network capacities (not the sensitivities) will depend then on the type of market (nodal or zonal) and to whom the data are targeted to (or used by): the FSP, local market or the DSO directly. It can be represented as capacities:

- Between 2 aggregated / bidding areas
- At the aggregated node level
- At each DER connection point

3.4.4 Market characterisation

A great variety of market design can be obtained across different initiatives. How demand and supply side are formed determines the market functioning and the clearing algorithm. Two main categories are described: one-sided (section 3.4.4.1) and two-sided markets (section 3.4.4.2). In both market designs, the clearing price can follow a pay-as-bid or marginal pricing scheme (see section 3.4.6).

The clearing can take place on the marketplace directly, especially when a merit order can easily be created because of identical impacts of the individual bids on the grid. The impact on the grid refers to the chance to create new scarcities (congestions or voltage problems) elsewhere in the grid by activating flexibility, but it also refers to the sensitivity (range 0 to 1) of the flexibility towards the scarcity to be solved. The likelihood for a similar impact on the grid is higher in radial grid structures and especially for congestion problems. In meshed grids, sensitivity values differ a lot and must be considered when selecting flexibility bids.

The clearing can also take place on the DSO side, where based on its grid information, the DSO selects the most efficient bids to strives for social welfare maximisation. The bid selection may also be computed together with switching options as the combination of using flexibility and switching can be more efficient than a stepwise approach.

3.4.4.1 One-sided market

A one-side market is a market where the buyer (in our case the DSO) determines the required quantities and the FSPs (i.e. loads, generators, storage, aggregators or representatives) bid quantities and prices to meet such requirements. Examples of these markets are balancing markets in Europe where the TSO forecast the balancing needs and BSPs send bids to increase or decrease energy injections or withdrawals. A clearing algorithm determines the resulting price.

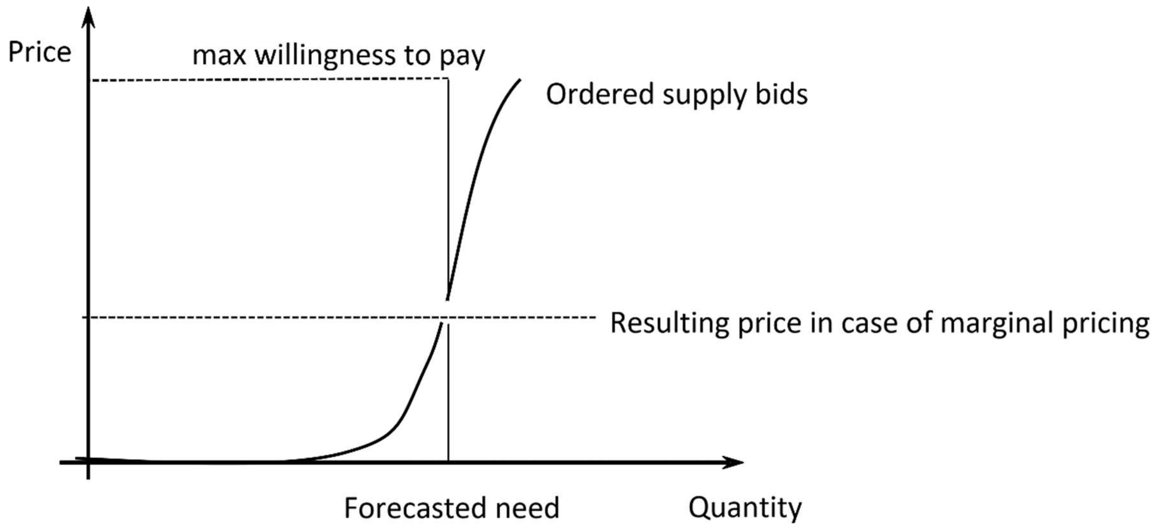

Figure 3-10. Schematic representation of a one-sided market

3.4.4.2 Two-sided markets

In a **two-sided market**, market participants (buyers and FSPs, directly or through intermediaries) determine the demand and supply sides in **market exchange** and a clearing process determines the market outcome: cleared prices and quantities. This market scheme might be used if the DSO's requested quantity is price-sensitive. Such case might only happen if the DSO has a fallback option to guarantee a safe grid operation, thus making use of other solutions which might have a lower price but are not part of the market (e.g. curtailing RES). It could be possible that in this market design DSOs or TSOs can also place their bids to buy flexibility with specific prices and in competition with third-party bids.

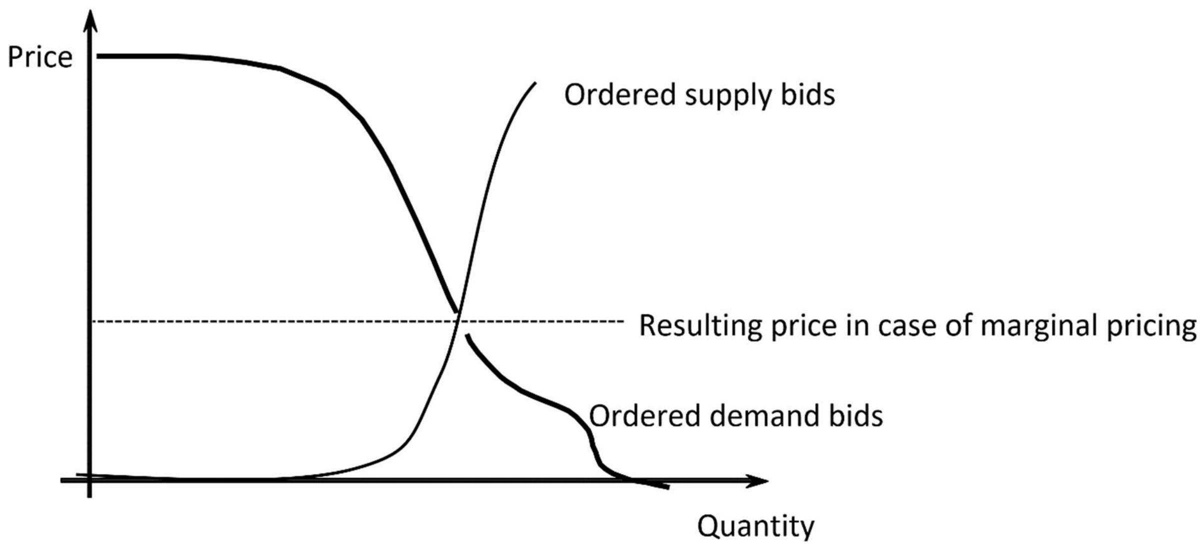

Figure 3-11. Schematic representation of a two-sided market

A **peer2peer market** is a two-sided or multi-sided market, but the main difference is that there is not a market exchange entity, but rather exchanges occur in a platform (which is not managed by a central power exchange) where transactions are settled among the participants usually automatically through the platform. The purpose and scope of these markets may vary, and sometimes techno-economic aspects are combined with social motivations.

3.4.5 Timing of the market

The following parameters can be used to specify the different periods of a market for both "closed gate auction" markets and continuous markets as described in Figure 3-12.

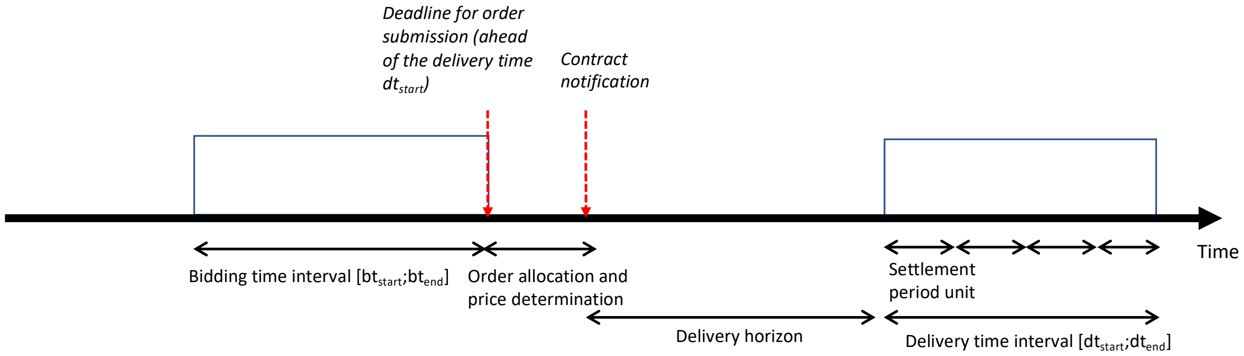

Figure 3-12. Relevant time parameters for market designs

In the closed gate auction model, there are specific and predefined gate opening and closure times, corresponding to the time interval in which the market participants are allowed to trade. Following the gate closure, an auction clearing process is executed to match the buy and sell orders (according to a pay-as-bid or a pay-as-cleared approach).

The continuous auction model enables continuous trading by the market participants. Orders can be submitted and matched up to a specific time, defined as a duration before the service can be delivered (lead time or delivery horizon). Continuous trading is based on the first-come-first-served principle and the pricing rule is pay-as-bid.

Table 3-17 describes each of the time parameters which are applicable both for the closed gate closure markets and continuous markets. The values are configuration examples and should not be considered as recommendations.

Table 3-17. Description of relevant time parameters

Timing parameters	Description	Example for the day-ahead market[11]	Example for intraday continuous market[11]
Bidding time interval [bt_{start};bt_{end}[12]]	Time interval when buy/sell orders can be submitted by market participants	*[0:00; 12:00] the day before the delivery*	*From 15:00 in day-ahead up to 1h before product expiration on the delivery day*
***[If auction]* frequency**	How often the auctions are triggered	*Daily*	*Not applicable (not an auction market)*
Contract notification	The time when results are published, and participants are notified about their contracts	*55 min after bt_{end}*	*5 min after contract creation (or order allocation)* *No time required for price determination (pay as bid)*
Delivery horizon	How long ahead the contracts are created compared to the start of the delivery time interval	*D-1*	*Up to 30min (lead time)*
Delivery time interval [dt_{start};dt_{end}]	Time interval corresponding to the physical delivery	*Full market delivery day or parts of it can be 30 min, 1h, multiple hours.*	*Full market delivery day or parts of it can be 30 min, 1h, multiple hours.*
Settlement period unit	Time unit used for settlement	*1h, 30min, 15 min*	*1h, 30min, 15 min*
Metering	The time when the metering data shall be received.	*Before baselining / settlement*	*Before baselining / settlement*
Settlement time	The time when the settlement is executed after the delivery	*D+1 at 12:00*	*D+1 at 12:00*

3.4.6 Pricing and market clearing

Market participants submit their bids to the market. FSPs submit incremental bids, as price-quantity pairs for each period of the delivery horizon, representing the price at which FSPs are willing to supply their flexibility. Similarly, buyers submit decremental bids, as price-quantity pairs, representing the price at which they are willing to buy their flexibility. In case of a one-sided market, the buy bids can potentially be replaced by a so-called price taking order (i.e. a demand bid with high buy bid price). Depending on the available market products, buyers and FSPs may also express additional constraints, see section 3.4.2. Note that bids are associated with a delivery period or with a delivery horizon since complex conditions can affect all the delivery periods of a bid. A common visualisation of submitted bids consists of aggregating all sell/buy bids to construct the supply and demand curve for a specific location. The two prevalent approaches for determining the market price(s) are (i) pay-as-clear and (ii) pay-as-bid.

In a pay-as-clear scheme, the market price corresponds to the intersection of supply and demand curves. All supply orders that are below this market price (in-the-money) are accepted, whereas all supply orders above the market price (out-of-money) are rejected. Similarly, demand orders above

[11] Some parameter value examples are extracted from the wholesale day-ahead / Intraday continuous markets operated by EPEX SPOT (https://www.epexspot.com/sites/default/files/download_center_files/Day-Ahead%20MRC%20Processes%20%2802.07.2019%29.pdf)

[12] bt_{end} is typically called the GCT (Gate Closure Time).

the market price are accepted, whereas demand orders below the market price are rejected. Thus, the intersection between the demand and supply curve sets the cleared quantity, which is the traded volume.

In a pay-as-clear scheme, all accepted bids pay or are paid the same price. This scheme incentivizes market participants to bid at their marginal price. A drawback of this pricing scheme, in case of congestions, is that a generation company, with a big portfolio of units in a constrained area, may have an incentive to bid higher than the marginal cost with the marginal unit to increase prices and the income from the rest of the units.

In a pay-as-bid scheme, accepted bids receive their bidding price. The market price is thus different for market participants bidding at different prices. This approach is intuitive and simple. The main drawback is that it does not incentivize the market participants to bid at their marginal cost, which can thus lead to higher bidding prices.

In the literature, pay-as-clear is being described as more efficient pricing, especially in case of sufficient competition with several benefits [140]:

- Incentives for participants to bid at short-run marginal costs
- Easier for the capacity to bid and participate – particularly smaller players
- More efficient dispatch
- A clear reference price for providing the service to act as an incentive to FSPs

On the other hand, pay-as-clear is more challenging for congestion management and voltage control, if the bids do not have the same impact on the grid and therefore cannot be simply ordered by the bidding price.

In case of a one-sided market, the demand-supply curve can be represented either by (i) considering a fixed price demand, so-called price-taking order or by (ii) considering no demand curve and imposing a fixed supply volume to be accepted. This is illustrated in Figure 3-10. The acceptance of a fixed supply volume might be needed if the DSO has no fallback option (such as RES curtailment at opportunity costs) and therefore needs a certain volume to guarantee the safety of its system.

Market clearing[13] can be performed by solving an optimisation problem by the market operator or by the buyer of the service (DSO or TSO), especially when comprehensive grid data is needed. The market-clearing process includes different processes, as described below.

The market-clearing optimisation process for closed-gate auctions maximises social welfare such that:

1. Supply and demand are balanced, based on sensitivities or impact factors, where necessary, as in the case of congestions
2. Technical constraints expressed by bidders are satisfied
3. No paradoxically accepted bids (PAB): no market participant loses money[14]
4. Network constraints are satisfied

The **social welfare**, expressed in euros, can be represented as the area between the demand and the supply curves, i.e. the area marked in green in Figure 3-13. The social welfare corresponds to the consumer benefits minus supplier costs and is thus a natural function to maximise.

[13] The term "market clearing" does not indicate which role carries out the clearing. Therefore, the clearing can be carried out by the market or the DSO.

[14] This point will be deepened later on in this section. The key idea is the fact that no out-of-the-money block is required to participate in the final transaction given a price that is not micro-economically profitable at its individual level (despite requiring the participation of this block would lead to a higher social welfare).

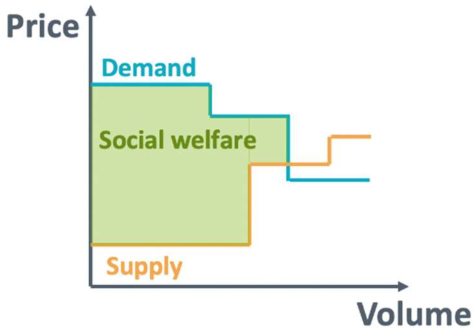

Figure 3-13. Social welfare representation

Technical constraints of bidders depend on designed **product attributes**, see section 3.4.2. A complex trade-off is required for such products to allow market participants to express their technical constraints while keeping the optimisation computationally tractable.

In the presence of more complex products such as all-or-nothing blocks products, special care is required to avoid accepting bids that increase social welfare at the cost of losing money. Such "**paradoxically accepted orders**" are usually not allowed by market rules. These orders are described in detail in [141], revealing the existence of a paradoxically accepted offer in an energy market aiming to maximise social welfare. The bids submitted to the markets are given in Table 3-18, and 1-hour periods are considered so that using MW means talking about MWh at the same time.

Table 3-18. Market bids leading to a paradoxically accepted bid.

Source: [141]

Bids	Quantity	Limit price (€/MW)	Min. accepted ratio
A. Sell bid	50	30	-
B. Buy bid	50	130	-
C. Sell bid	40	40	-
D. Sell block bid	200	60	1
E. Buy block bid	200	90	1

A graphic representation of these bids is given within the green frame of Figure 3-14. If social welfare is aimed to be maximised, a microeconomic property ensures that this maximisation is reached at the intersection of the supply and demand curves. On top of that, it is also ensured that the equality in quantity between supply and demand is respected, which is important in electrical markets. However, selecting prices and quantities given by the curves crossing point could lead to the apparition of a PAB, in particular with block bids such in our example.

With respect the block bids requirement, a first solution allowing to trade 250 MW (quantity at the crossing) would be to accept the bids A, B, D and E while rejecting C. However, when searching for a compatible price with these activations, bid D requires a price of at least 60 EUR/MWh. In that case, the bid C (at 40 EUR/MWh, lower than 60 EUR/MWh) would be in-the-money, i.e. would be accepted by the market. So, it is required that the cleared price has to be strictly lower than 40 EUR/MWh to exclude it, but then bid D would be paradoxically accepted, i.e. would be required to participate while losing money in a microeconomic individual perspective.

Figure 3-14 Graphical representation of market-clearing leading to a paradoxically accepted bid

Two solutions can solve this issue. One could imagine a side-payment to compensate for this type of loss for D while preserving high social welfare. As a reminder, D would be paid strictly lower than 40 EUR/MWh, while he proposed a selling bid at 60 EUR/MWh. Implementing such kind of side-payment is called adopting a non-uniform pricing (NUP) approach in market design jargon. However, it is not what is followed by common market rules which prefer to simply forbid paradoxically accepted bids. Unfortunately, this second option with uniform pricing at all time has the drawback to potentially reduce the total social welfare. By doing so, in our example, only order A and B would be traded, leading to the social welfare of (130-30)*50 = 5000 instead of 5000 + (90-60)*200 = 11 000 with a NUP approach.

Network constraints can be issued to the optimisation algorithm with a view on the impact of orders activations in the network. This guarantees that volumes cleared by the market can solve the problems and that they do not create new network issues. Each critical grid element at each relevant voltage level must be considered as well as the sensitivities of all resources (which are the variables) towards these critical grid elements or by using an OPF computation. Compared to the needed data for cross-border market coupling, the complexity increases because each “zone” can have flexibility and the number of critical branches across all voltage levels is way higher. Instead, the current cross-border market coupling only considers critical grid elements at TSO level and the number of variables depends on the markets to be coupled. Therefore, the matrix for congestion management within zones and across voltage levels leads to a heavy increase in complexity. Note that this matrix must be changed each time the topology changes and that the optimum can be a combination of a topological change and flexibility use. For these reasons and due to the allocation of system operation responsibility to system operators, the allocation of the optimisation algorithm for congestion management/voltage control to third parties such as market operators would lead to several technical and regulatory challenges (see also [137] for a detailed analysis). On the other hand, the allocation of the optimisation algorithm to each system operator is in line with the current allocation of responsibilities and leads to lower technical and regulatory challenges (e.g. data exchange, fallback solutions, etc.).

For comparison reasons with the described congestion management process needs, the two common approaches to represent the network constraints for cross-network areas are described: available transfer capacity models (ATC) and flow-based models (using PTDFs). Their descriptions are given below:

1. ATC constraints limit the amount of energy that can flow through a line to a fixed amount per period. It leads to easier models and computations, but do not take profit of inter-dependencies between lines by neglecting the fact that energy transmission over some lines can help to distress other ones.
2. The flow-based models take profit of this specification of electrical networks through power transfer distributions factors (PTDFs). By studying the organisation of the network, the network constraints at each node or zone consider the impact of increasing or decreasing the flow reaching a point of the network through a line on the other lines connected to this point. A comparison of these constraints is displayed in Figure 3-15; it can be observed that both types of constraints remain linear, with the ATC ones being stricter than the flow-based constraints.

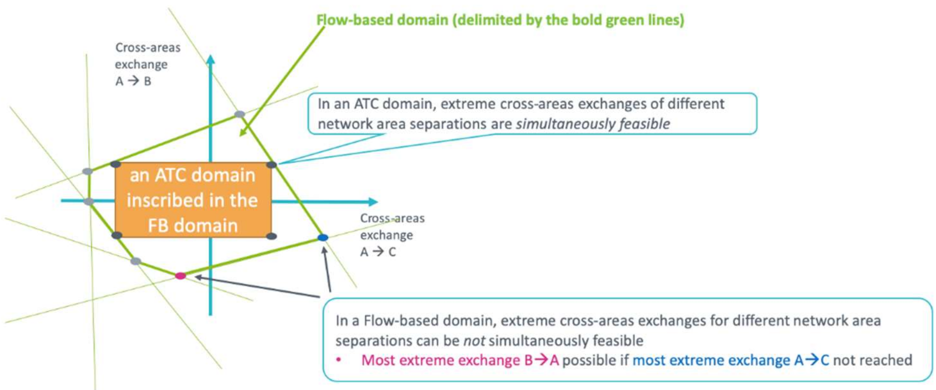

Figure 3-15. Comparison between ATC and Flow-based constraints

These constraints are not as detailed as power flows, but there is a trade-off between the gain in computation efficiency and the loss in precision at this step of the process.

Finally, the optimisation process produces cleared volumes: the acceptance fraction and volume of each bid are communicated to the market participants and the system operator. Prices are obtained by solving a second optimisation problem called the price problem or dual problem. In a pay-as-bid pricing scheme, prices are trivially derived from the bidding prices of each participant.

In a pay-as-clear pricing scheme, it is required to solve another optimisation program called the dual problem. The so-called dual variables associated with the power-balance constraints correspond to the cleared price. In a situation without network representation, the dual variable of the unique power-balance constraint results into the market-clearing price. The resulting price corresponds again to the crossing of supply-demand curves, see Figure 3-13. If a network representation is considered by the market, then each location has a corresponding power-balance constraint, and the corresponding dual variables are used to set the market cleared prices of each location. Such prices may be different, for instance, in case of congestion, or if losses and tariffs are applied. As an example of a situation with different market prices in different locations, assume that a supply bid at 40€/MWh in location A is activated to be matched both with a demand bid at the same location A and with a demand bid at another location B. Figure 3-16 assumes that 10% losses apply when flowing electricity from location A to B and 10 MWh is exported from A to B. Due to the 10% losses, only 9MWh will be delivered in B. The market-clearing price at B will then be 10/9 * 40 = 44.4 €/MWh.

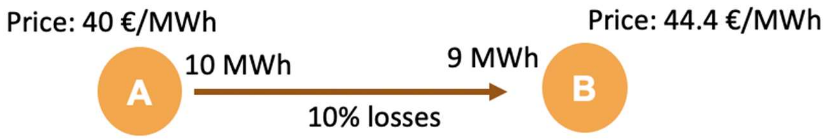

Figure 3-16. Energy losses consideration in the pricing

Price and volume indeterminacies occur when supply and demand curves do not cross in a unique point, as illustrated in Figure 3-17. In that case, several (price, volume) combinations produce the same social welfare. Market rules determine how to solve these indeterminacies.

Price indeterminacies are usually solved by setting the market cleared priced as the last selling bid or as the middle of the vertical intersection segment. The latter is often considered as the fairest option that equally satisfies buyers and FSPs. In the presence of more advanced market requirements, the middle point may sometimes not be feasible, for instance, in the case of blocks bids. In that case, the closest feasible price is set as the market price. If no price is feasible (i.e. if no price satisfies all market participants and market rules), the solution of the primal problem is rejected, and a new solution is searched.

Volume indeterminacies can be solved by maximizing the traded volumes. Alternatively, it can be solved by minimizing the traded volumes while keeping the same social welfare.

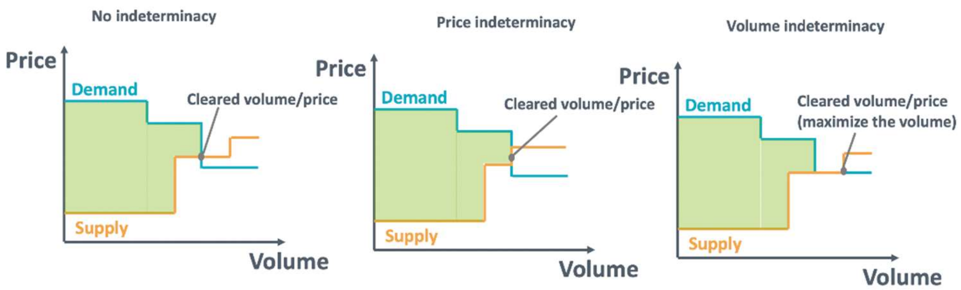

Figure 3-17. Illustration of price/volume indeterminacy and corresponding cleared volume/price

Previously, the optimisation process was described for one single period, but it can be generalized to cross-periodical optimisation. The main advantage of the multi-period optimisation is to enable the possibility to consider bidding constraints (e.g. min activation time, rebound effects) and network constraint (e.g. ramping of a line, congestion timeframe) spanning over multiple periods. With a single period optimisation, such constraints are ignored, resulting in a smaller efficiency and, in case of rebound effects, grid constraints could be violated.

The total social welfare can be expressed as the sum of the social welfare of each period. Bidding and network constraints have to consider for each period, and there should not be any paradoxically accepted bids. Although a multi-period optimisation improves social welfare optimisation, it requires high computation time and is more complex to understand the resulting prices. Additionally, some additional bidding or network constraints may link the different periods, see section 3.4.3.

3.4.7 Additional implementation considerations: metering requirements, baseline, settlement

3.4.7.1 Metering

The requirements of the resolution of the metering data (period duration) depend on the services provided and on the settlement period. As a minimum requirement, the granularity of the metering data shall be higher than the one used for the settlement period (e.g. for a 30min settlement period, the metering data resolution shall correspond to a period equal or smaller than 30min).

When the resource is directly connected to the grid, the metering data can be used at the connection point level.

When the flexibility is linked to one or several assets behind the meter at the connection point, 2 options can be selected in terms of location for metering data:

a) Either at the site level: the metering data corresponding to the measurements at the grid connection point of the site
b) Or at the asset level.

Although the metering data captured at the site level will represent the physical service delivered to the grid for the operator, it may not accurately represent the service provided by the asset(s). In case of metering at the site level, the overall site consumption needs to be predictable enough and not too high compared to the contracted flexibility volumes so that the overall consumption does significantly affect the calculated baseline at the site level when baselines are needed.

In case of network operators decide to validate the metering data, there is a risk that flexibility providers controlling assets behind-the-meter are not accurately rewarded for the flexibility provided. Specific meters for flexible assets can be in place when these assets are situated at large sites with highly variable demand patterns. The more aggregators and asset operators who control behind-the-meter assets participate in local flexibility markets, the stronger the case for accepting asset level metering.

In the case of a flexibility product which can be provided by aggregating different resources, the following use of metering data would be possible to measure the service delivery:

- Receive metering data at the individual resource level and let the market settlement sum the data at the aggregated area level before assessing the performance
- Receive directly the metering data aggregated by the FSP and possibly verified by the DSO

3.4.7.2 Baselining

The baseline provides a power or energy schedule with an asset's normal behaviour without flexibility activations. Its methodology is usually defined by the TSO, DSO or FSP (depending on the type of market) and approved by the regulator. Depending on the grid service the baseline can be sent in advance by the FSP on a fixed interval (e.g. for aFRR in Belgium, 60 seconds before delivery) or can be computed afterwards based on the profile before the activation (e.g. for FCR in Belgium). The granularity and window of the baseline or the application of individual or aggregated baselining, all depend on the product design.

There are different methods to calculate the baseline, all with their advantages and disadvantages. Important factors to consider are:

- Fairness and transparency, not gaming the system, see for example [142].
- Accuracy, for correctly calculating the activated flexible energy or power in settlement
- The relation with other flexibility products and the possibility to perform multiple services if the products allow doing so.
- Technologies that participate in the service: depending on the technology (e.g. distributed generation vs demand response), a specific baseline methodology might be required to allow these technologies to participate.

Although baseline methodologies have been mainly exclusively used to refer to Demand Response (DR), the diversity of resources managed by small FSP requires extending their application to a wider range of options including customers with the generation, storage, and flexible loads. The baseline is important because payments for FSPs are directly based on the difference between the baseline and actual metered demand; therefore, an optimal baseline methodology is necessary to measure the effective performance of a demand resource and to properly compensate the FSP. The selection of the methodology to be applied will depend on several factors, such as the function performed in the system by the DR, regulatory frameworks for FSP participation in the wholesale markets, and characteristics of the FSP [143]. In general, five baseline methodologies are considered: Historical Data Approach, Statistical Sampling, Maximum Base Load, Meter Before / Meter After, and Metering Generator Output.

3.4.7.2.1 Historical Data Approaches

This methodology is the most prominent in DR programs today, and it is commonly known as baseline Type-I by the North American Energy Standards Board. It incorporates frequent granular measurement across similar days resulting in a demand estimate that mimics the dynamic nature of a customer's demand curve over 24 hours [144]. The main characteristics of this methodology are: i) the baseline shape is the average load profile, ii) utilizes meter data from each site, iii) relies upon historical meter data from days immediately preceding the activation of the service, and iv) may use weather and calendar data to inform or adjust the baseline [145]. Moreover, this methodology includes the following variations:

- **Averaging methods:** create baselines by averaging recent historical load data to build estimates of load for specific time intervals. They are often called X of Y approaches and could be classified according to the relationship between X and Y. For example, High X of Y, Last Y days, or Middle X of Y.
- **Regression methods:** take an extensive data set as input and determines the relationship between a dependent and independent variable (s) through a regression model.
- **Comparable day:** identifies a representative day in the past, to be taken as a reference for the computation of the baseline, using historical meter data.
- **Rolling Average:** uses historical meter data from many days but gives a larger weight to the most recent days.

3.4.7.2.2 Statistical Sampling

This baseline uses statistical sampling to estimate the electricity consumption of an aggregated demand resource where interval metering is not available on the entire population. The statistical sampling methodology is more often used in residential DR programs, where it has been cost-prohibitive to install interval meters at every house. As the deployment of residential interval meters increases; however, the need for statistical sampling methods will likely decrease [145].

3.4.7.2.3 Maximum Base Load

Maximum Base Load methods identify the maximum energy usage expected of each customer and then set a specific level of electricity usage that is equal to the maximum level minus the committed capacity of the customer. Some of the main characteristics of this approach are: i) the baseline shape is static, ii) utilizes meter data from each site of the system, and iii) relies upon historical meter data from the previous year [145]. This method could be either coincident or non-coincident:

- A coincident baseline uses peak hours of the previous season that are chosen based on system load peaks.
- A non-coincident baseline also uses peak hours, but they are determined by individual load behaviour and not by the system load.

3.4.7.2.4 Meter Before / Meter After

The meter before / meter after (MBMA) method is a static baseline method that is usually employed for fast-response programs and reflects actual load changes in real-time, reading the meter before and after response to measure the change in demand [146].

3.4.7.2.5 Metering Generator Output

This methodology is used when a generation asset is located behind the demand resources' revenue meter, in which the demand reduction values are based on the output of the generation asset. This baseline is set as zero and measured against usage readings from behind-the-meter emergency back-up generators. This method is only applicable to facilities with an on-site generation [145].

3.4.7.3 Settlement

The settlement consists of obtaining the measurements (active and reactive power), checking service delivery and calculating payments to be made. This activity is generally performed by the DSO or by third parties (e.g. market operator). In the latter case, the DSO would need to validate the measures. The DSO, as the buyer of grid services, calculates the payments and penalties if there are mismatches from the commitments for the service delivery. To make the financial settlement when the FSP does not have individual known schedules, an agreed baseline would be needed. Furthermore, a relevant aspect for the flexibility market is the relation with final energy balance and how it affects the final imbalance settlement. This last relation would depend on the interrelation between the local market and the imbalance settlement which can be arranged in different ways but this out of the scope of this document, but very often quantities are negligible at TSO level.

3.4.8 Integration with existing markets and coordination between agents

This section summarizes the proposal of Deliverable D1.2 [147] to classify markets organisation according to the coordination between the TSO, DSO and market agents. As described in D1.2 [147], this proposal is based on previous approaches such as those from the SmartNet [148] and CoordiNet [149] projects, or the proposal from ENTSOe and associations representing DSOs (CEDEC, EDSO for smart grids, EURELECTRIC and GEODE) [28]. Refer to D1.2 for further details and a graphical representation of each market organisation type [147].

EUniversal D1.2 reviewed the main market models for TSO-DSO coordination, and how these market models are used in the different projects and initiatives reviewed to acquire the identified services [147]. This analysis generated the mapping of Table 3-19. This table provides a first insight of the DSO services which are more frequently addressed, the preferred conceptual market organisations and TSO-DSO coordination mechanisms for each type of service, and whether the products considered are energy or capacity based.

Table 3-19. Markets–Services mapping

Market Model	DSO Needs / Grid Services							
	Voltage Control		**Congestion Management**			**Service Restoration**		**Voltage Sag Mitigation**
	RP	AP	OP	ST	LT	BS	IO	FRT
M1 - Centralized flex market								
M2 - Local and global flex market	Piclo Sensible	CoordiNet EcoGrid 2.0 EMPOWER H2020 Flexiciency Interflex IREMEL Sensible	Coordinet	Coordinet EMPOWER H2020 enera FLECH-iPower Flex-DLM GOPACS-IDCONS Interflex IREMEL NODES Piclo Sensible	Coordinet De-Flex-Market EcoGrid 2.0 FLECH-iPower FlexMart Piclo		Coordinet EMPOWER H2020 Interflex	
M2/3 - Local and global flex market with balancing coordination		USEF	INTERRFACE	INTERRFACE USEF	INTERRFACE		USEF	
M3 - Local and global flex markets with shared responsibility	Coordinet EU SysFlex	Coordinet						
M4 - Common TSO-DSO flexibility market			INTERRFACE	Coordinet INTERRFACE	Coordinet INTERRFACE			
M5 - Integrated flexibility market for TSO, DSOs and BRP								

- *RP: Reactive Power Management*
- *AP – Active power management*
- *OP: Operational*
- *ST: Short-term planning (D-1 to M-1)*
- *LT: Long-term planning (>M-1 to Y-1 or more)*
- *BS: Black Start for distribution islands*
- *IO – Isolated/Islanding operation mode*
- *FRT: Fault-ride Through*

- Capacity
- Energy

Centralized flexibility market (M1):

- It is the approach closer to the current situation, where DSOs generally do not procure flexibility.
- The flexibility is procured by the TSO in a unique centralized market, where aggregated DER are also allowed to participate under certain conditions.
- A pre-qualification process of the DER can take place to guarantee that their activation does not put the DSO grid in trouble.
- If the TSO-DSO coordination is more advanced, a DSO validation could also take place, close to real-time, before the activation of the bids selected by the TSO.

Local and global flexibility markets (M2 and M2-OM)

- The flexibility offered by the DER is managed in a local DSO flexibility market.
- The DSO uses the local resources for its own flexibility needs.
- The remaining flexibility bids, not needed by the DSO, become available for the TSO (M2 case, see below for the M2-OM).
- The DSO can also validate that the bids finally selected by the TSO do not compromise its grid safe operation before the activation of the resources offered.
- The M2-MO case differs from the M2 because in M2-MO the coordination does not take place between the TSO and DSO but between the wholesale MO and the DSO to integrate DER into the commercial energy markets. The DSO can establish limitations to the DER schedules that are used by the MO to clear the day ahead and intraday markets.

Local and global flexibility markets with balancing coordination (M2/3)

- As in M2 case, a local DSO flexibility market and global TSO flexibility market coexist.
- The DSO informs the TSO about the net amount of flexibility activated in the local market for its own needs so that the TSO can take the corresponding balancing actions.
- Although the flexibility not used locally could in principle be made available to the TSO, this would be rather an M2 type with additional balancing information exchange.

Local and global flexibility markets with shared responsibility (M3)

- Similar to the M2 case, but in this case, the TSO agrees with the DSO the active or reactive power profiles needed (for balancing or for other TSO needs) at the TSO-DSO interface. In this sense, the TSO does not have direct access to the DER bids.
- The DSO is responsible for providing the agreed profile using its local market resources.
- Detailed DER location remains implicit for the TSO that only needs to know the DSO grid at which the DER is connected.

Common TSO-DSO flexibility market (M4)

- 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.
- The level of TSO/DSO coordination can vary depending on the regional grid topology.
- If resources are used to resolve grid constraints, the TSO or DSO needs their location information.

Integrated flexibility market for TSO, DSO and BRP (M5)

- Grid operators and BRP compete all together for the available flexibilities in a unique market.
- Flexibility is bought by those that are willing to pay the highest price.
- It is the responsibility of the grid operators to make the appropriate bids to guarantee the secure operation of their grids, being all in competition.
- Grid operators need to know the resources' location to use them for solving grid constraints.
- TSO/DSO could still have the possibility to validate assignments before allowing activation.

3.4.9 Benefits and challenges of local markets

Local flexibility markets can potentially fill most of the desirable criteria defined in section 2.2 for the mechanisms for acquiring flexibility services: incentivise economic efficiency, transparency, equity, customer engagement and contribute to the reliability of the network. However, as previously discussed in this section, there are significant design elements that need to be carefully chosen to properly fill those criteria. Below the main benefits and challenges of local flexibility markets are described.

3.4.9.1 Benefits

The benefits of local flexibilities markets are summarized below.

1. They can be designed as a technological neutral solution to incentivise assets from different nature to compete to provide grid services. By doing so, economic efficiency is fostered.
2. Tailor-made market solutions can be adapted to the DSO needs and FSPs characteristics. The DSO needs can be restricted to a geographical area; therefore, local markets can be adapted to it and also consider the technical constraints of flexible resources.
3. Customer engagement is favoured as there is continuous interaction with the market.
4. If well designed, local markets can contribute to maintain or improve reliability by providing services to the DSO to manage the networks safely.

3.4.9.2 Challenges

Besides the potential benefits that local flexibility markets can provide, there are many challenges related to their integration with existing markets, FSP availability and characteristics and implementation concerns that need to be carefully analysed.

1. Integration with existing markets and coordination of agents
    a. Local flexibility markets may require complex coordination with different agents and existing markets: between TSO-DSOs, DSO-FMO, DSO-DSO, DSO-FSP, FSP-BRP etc. Different coordination schemes are possible as described and they should be

carefully chosen to keep a balance among different criteria (e.g. gains on economic efficiency vs implementation costs). It is relevant to define the roles, functions and responsibilities of the different agents.
    b. In some cases, tailor-made products can reduce the liquidity from interrelated markets: energy (day-ahead, intraday), TSO markets (balancing, congestion management).
    c. The alignment between local flexibility markets with the EU market design may be challenging as they often take place in the same timeframe and coherence between market prices, activation signals, etc. should be carefully considered.
    d. The activation of local flexibility can create energy imbalances. To account for this, different alternatives are possible either to have strong coordination with the TSO to account for such imbalances or to counter-activate a bid to keep the balance unaltered. This imbalance risk could also be managed as FSP responsibility.
2. FSP characteristics and competition concerns
    a. Market competition is a concern in local flexibility markets due to network characteristics and flexible resources availability. Furthermore, the ability that FSPs can exercise market power is higher with low liquidity. When liquidity is poor, other alternatives have to be considered.
    b. Trading local flexibility from resources that do not have their schedules requires to develop and agree on a baseline methodology.
    c. Customer engagement and regulated incentives for the FSPs have to be designed with accuracy for achieving an adequate level of customer participation without introducing over remunerations and cross-subsidies.
    d. There is a trade-off between the gain in computation efficiency and accuracy on price signals. For example, to consider sudden changes in network nodes input or output creates more important non-linear responses in the network.
    e. Different resources may present rebound effects or specific technical constraints. Therefore, a balance has to be made between accounting for complex resource characteristics and a fast optimisation mechanism.
    f. The different conditions that affect the implementation of local markets evolve depending on the attributes of the needs and the potential flexibility from FSPs. These conditions are also evolving with time, and similarly, the market design should evolve.
    g. A single FSP may be able to provide different flexibility services at the same time. FSPs may have to be able to combine different revenue streams to have a solid business case and maximise the asset uses.
3. Implementation concerns
    a. Accounting for network characteristics and computation of impact factors will be key to properly remunerate the provision of grid services. Dynamic impact factors computed at short-term timeframes and possibly accounting for different network configurations would be an efficient solution but require significant computational and forecasting efforts.
    b. The definition of standards for communication systems, information exchange, activation, etc., can reduce entry barriers for flexibility providers.

3.5 Bilateral contracts, cost-based remuneration, obligations

More regulated mechanisms are alternative or complementary solutions to market-based solutions when they cannot work properly due to market failures or implementations costs. The regulated mechanisms discussed in this section are bilateral contracts, cost-based remuneration and obligations.

A bilateral contract establishes an exchange promise to perform a certain action or deliver a certain product under specified conditions in exchange for an agreed payment. In cost-based remuneration, the buyer (DSO or even the NRA) establishes the price for the service but there is an agreement or legal basis to deliver the service at specified conditions. Finally, obligations do not provide payments for delivering a service but are requirements to provide a certain volume of flexibility for system operation.

A bilateral contract can be an agreement between the DSO and an FSP where the latter might invest in certain technology (e.g. battery) to be able to provide a service (e.g. congestion management) under specific conditions. While in contrast, a cost-based remuneration is based on a determined price or price curve that the DSO sets for buying a service and potentially on an agreement with the FSP on the specified quantity.

As defined in section 2.2, economic efficiency is one of the main criteria to be considered when designing a mechanism to acquire grid services. When economic efficiency cannot be guaranteed as the conditions discussed in section 0 are not met in a large extent, the regulated options described in this section are alternatives or complementary solutions to local flexibility markets.

CEER [2] argues that administrative measures are potential solutions when the costs related to gaming (e.g. risk of exercising market power) and the risk of other increased costs for consumers are greater than the potential efficiency losses of the more regulated mechanism.

Furthermore, **mixed alternatives between markets and more regulated mechanisms** for flexibility procurement for a specific service may be possible: a market for incentivizing investments in new capacity may function but the activation of such capacity can be based on standard or negotiated activation cost.

One key aspect when implementing an administrative approach is whether **information about cost structure** and opportunity costs are known with high certainty. This could be the case for voltage control services when the providers have similar and standard technologies (e.g. wind and solar through smart inverters) and when the information about their investment, operational and opportunity costs is accessible.

Considering voltage control, the similarities in loss curves of power generators allow devising a generalised cost function for the reactive power production [150]. Accordingly, a generalised Expected Payment Function (EPF) for reactive power provision can be devised [150]–[152]. For the sake of simplicity, the piecewise linear function depicted in Figure 3-18 approximates the quadratic relationship between active power losses and reactive power output [153].

As shown in Figure 3-18, four operating regions characterised by a different reactive power generation cost can be identified [153]. The region I models the mandatory reactive power provision; the related cost can be considered as the OPEX of the active power production. The regions II and III represent the operating conditions in which the reactive power production and absorption do not require a reduction of the active power output. The losses due to the reactive power provision are greater than the minimum possible value for the related active power production, or even when active power is zero there is the active power consumption for reactive power provision (e.g. due to the consumption related to the auxiliary power consumption); therefore, the related cost might be compensated in case of reactive power provision. The regions IV and V represent the operating conditions in which the reactive power production and adsorption requires an active power reduction due to the capability limits of the generator. Therefore, in addition to the cost related to the reactive power losses, the opportunity cost due to the active power has to be accounted for.

In Figure 3-18 ${Q_A}^{min}$ and ${Q_G}^{min}$ are zero when a remuneration is conceived even for a minimum value of reactive power exchange. If a minimum level of reactive power support is required as a not paid mandatory service, the values of ${Q_A}^{min}$ and ${Q_G}^{min}$ are non-zero and equal to the value of the reactive power output that corresponds to the mandatory range.

Notice that for certain technologies getting an estimation of the opportunity cost is difficult, for instance for demand-side resources which include opportunity costs related to the loss of comfort, storage technologies or aggregation of them. Therefore, for NRA or DSOs, it becomes challenging to discover such costs without a market mechanism that contributes to price discovery.

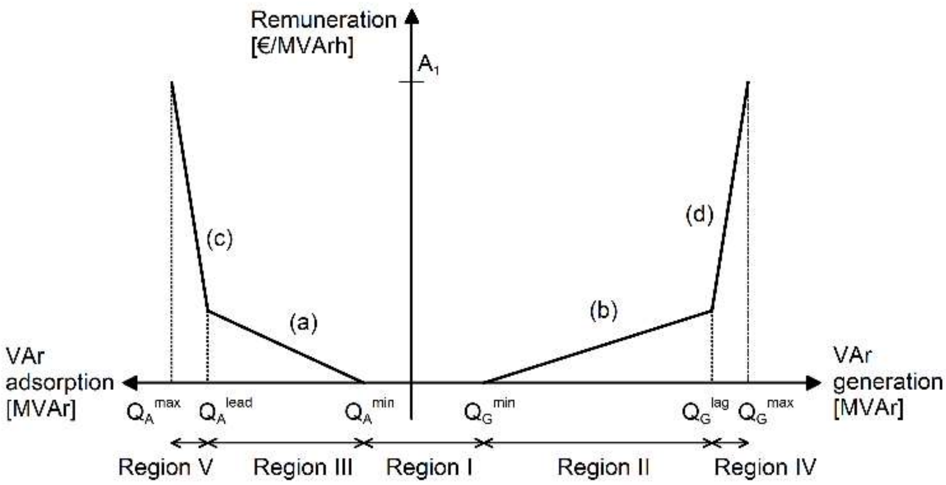

Figure 3-18. Example of cost structure and opportunity costs for voltage control provision

Source: adapted from [153]

One risk of administrative solutions is that they potentially provide inefficient incentives for investment and operation in flexible resources. This leads to under or over-compensation to FSPs, creating in the long-run higher costs for managing network constraints. **Differentiated compensation for different resources** may also become a challenge, and errors in computing those costs create inefficiencies in the dispatch of these resources.

Figure 3-19 summarizes the relevant conditions when deciding among a market or a more regulated mechanism for procuring grid services by DSOs. The conditions can go under both options but with the opposite adjective. If a certain condition is fulfilled, it shifts the balance in favour of the alternative signalled on top, if not, it favours the other alternative. For instance, if the expected liquidity is high, this favours a market implementation but, if it is low, it favours a regulated solution. The most adequate solution would have a larger balance from the conditions shown, but in some cases, this will be difficult to estimate and the conditions may evolve requiring to assess them frequently.

The implementation of a ruled-based provision through network codes and mandatory requirements may become a last alternative for providing a grid service. It is only justified when the overall costs of implementing a market or a more regulated mechanism (accounting for all the impacts) is higher than its benefits. This may be the case when providing a service which has low costs and which has to be provided throughout the network and by all resources. For instance, primary voltage control for generators and requirements for RES generators to contribute to voltage control through their inverters (at least under determined ranges [154]). Furthermore, the ruled-based solutions may be applied for a specific quantity and additional quantities can be procured through a market-based approach.

Example of mandatory flexibility provision based on opportunity costs: Redispatching of conventional generation, RES and storage in Germany [155]

The German redispatch, whose revision will be implemented by 10/2021 gives an example where all generators and storage with a capacity as from 100 kW, additionally all controllable generators, are allowed to be re-dispatched by DSOs and TSOs on a scheduled basis. Therefore, the flexibility providers must tolerate the adaption of their schedules and in return, receive compensation based on opportunity costs, including lost revenues and additional costs but also considering costs not incurred. The methodologies to assess these costs fairly are determined in a stakeholder engagement process across the NRA, TSOs, DSOs and flexibility providers.

Example of price incentives: Reduced grid tariffs for controllable loads in LV in Germany [156]

Grid users in LV with controllable loads such as EVs and heat pumps can opt for a reduced grid tariff provided that the DSO can reduce their consumption at certain times. The details of this scheme, such as the price schemes and opt-out solutions, are currently under discussion. The grid users may decide if they want to accept this grid tariff or use the normal grid tariff without giving the DSO the right to reduce the consumption.

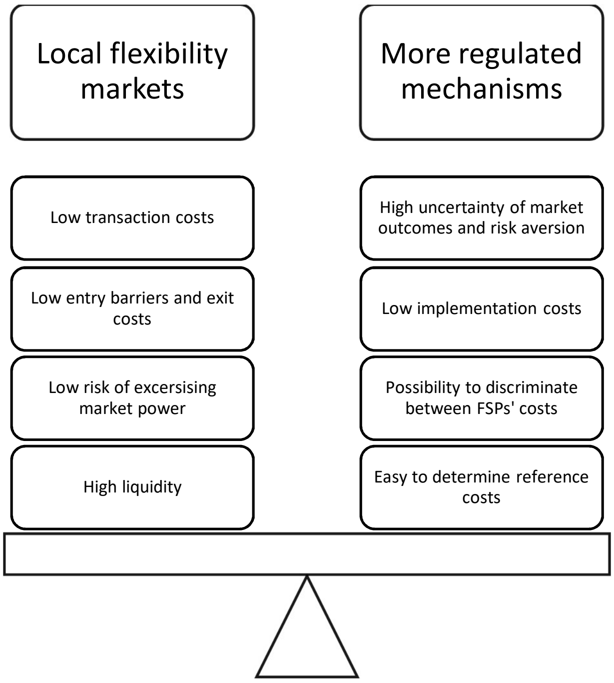

Figure 3-19. Relevant conditions when choosing among local flexibility markets and more regulated mechanisms

4 Analysis of context and needs attributes

The previous chapter presents the main design elements for each of the mechanisms for acquiring grid services. However, to obtain an efficient outcome from procuring grid services, local features - grid and FSPs characteristics - have to be adequately considered at all stages, including grid planning and operation.

In this deliverable, the exploitation of novel practices for procuring flexibility from third-party FSPs to solve congestion and voltage issues are of interest. The high-level analysis concerns a set of acquisition mechanisms of which the effectiveness depends on the context characteristics and the attributes of the system need as introduced in chapter 2.

This chapter reviews the main DSO services identified in previous project tasks. In particular, this chapter summarizes the preliminary results of EUniversal Deliverable D1.2 and Deliverable D2.1, still ongoing when writing this deliverable [147], [157].

Furthermore, this deliverable mainly focuses on congestion management and voltage control. It defines a set of general context attributes for these services and the methodology for the qualitative assessment of each market mechanism suitability.

4.1 Main DSO needs and services

Based on the results from EUniversal Deliverable 1.2 and Deliverable 2.1, the identification and classification of the main flexibility needs and associated services, based on a revision of a large set of related projects and initiatives. These grid services are presented in Table 4-1. For this deliverable, the analysis is not presented in detail for specific services but the two more general services: congestion management and voltage control. Both services are the most relevant ones for the EUniversal project.

In this classification, long-term acquisition of both congestion management and voltage control are grouped in a new network planning service. This grouping can be justified as long term planning usually tends to consider solutions to both grid problems simultaneously. Some other services, already identified in D2.1, cannot be provided using the usual corrective and predictive services for grid operation [157]. Therefore, they may have specific requirements and acquisition mechanisms, but this deliverable does not address them.

The next section focuses on the proposed values for context attributes that may be used to characterize services at a high level to assess the most suitable acquisition mechanism for the services. These context attributes have been elaborated considering the services' requirements defined in D2.1 and the feedback of relevant project partners (such as DSOs) collected through a survey [157].

Table 4-1. Services identified in EUniversal D1.2

Source: [147]

Needs/Services	Definitions
Congestion Management • Corrective (real-time) • Predictive (intraday or day ahead)	Service to mitigate congestions (a condition in which insufficient energy is provided to consumers due to physical limitations of the network) that can be caused by high power consumption during peak hours, concentrated charging of EVs or excessive power generation from DGs, among other.
Voltage Control • Corrective (real-time) • Predictive (intraday or day ahead)	Service to keep voltages within specific safe bands and restore their values to the normal range after grid disturbances occur, to minimise reactive power flows, investments and technical losses.
Support for network planning (1 to 3 years timeframe) • Voltage control (power-based) • Congestion management (capacity based)	Service to use flexibility in combination with grid investments to solve either current or forecasted physical congestions related to reduced network capacity (overload or voltage violation).
Phase balancing	Service to maintain the balance of loads among phases to reduce losses, increase the distribution network capacity, reduce the risk of failures, and improve voltage profiles.
Support for extreme events • Islanding • Blackstart • Emergency load control/ Interruptible load/DER • Backup generation capacity	Services designed to increase the resiliency of distribution networks for a quick recovery from extreme events (driven mainly by natural disasters and extreme weather, whose frequency and severity might increase as a direct impact of climate change). • Islanding: improve continuity of supply when the higher voltage source is unavailable • Blackstart: black start service provides the ability to the network to restart after a blackout, guaranteeing grid stability by making sure that the active and reactive powers are within limits. • Emergency load control: under increased demand or when the grid is affected by unplanned events (such as inclement weather), this service is to provide load reductions that lessen stress on the electric grid. • Backup generation capacity: under extreme events, this service is to make sustainable power available for islanded operation.

4.2 Context attributes, definition and relevance assessment

4.2.1 Definition of the context attributes

The particular context characteristics strongly influence the effectiveness of the acquisition mechanism that could be exploited. As already introduced in section 2.1, the context attributes are relevant for describing the need for grid services. In this section, the detailed description of each context attribute is provided.

A collaborative approach has been followed to identify the context attributes relevant for assessing the suitability of the acquisition mechanisms. A preliminary set of context attribute has been proposed to project partners. Through a questionnaire, project partners (N-SIDE, CENTRICA, NODES, Innogy/E.ON, ENERGA, and EDPD) point of view have been collected. The template of the questionnaire is available in chapter 8. Both the context attribute definition and relevance has been discussed through the questionnaire. Additionally, the partners proposed new attributes not yet present in the initial list.

A unique set of context attributes valid for both congestion management and voltage control is proposed. The aspects identified as potentially be relevant for describing the context and the need are the **voltage level, contracting timeframe, frequency of the need, the volume of the problem, network type,** and **the ratio of the volume of flexibility available by volume needed**. Moreover, **the FSP size, FSP nominal voltage, number of expected FSP participants,** and **resources types of FSP** are relevant aspects which have been considered for describing the system context. It is worth noting that the combination of the information provided by each context attribute allows describing the need for grid services.

Voltage level	• High voltage • Medium voltage • Low voltage

The **voltage level** is the nominal voltage of the grid area in which the contingency occurs. One of the most acknowledged classifications of the different power system portions is based on voltage levels [158]. Grid portions characterised by different voltage levels show relevant differences in terms of components, connected assets, and operation strategies. Therefore, the set of actions that could be taken to solve the contingency is different as the voltage level of the context of the need is different. The voltage level is considered relevant since it can limit some FSPs to be able to contribute to providing a service depending on its location (e. g. it may not be feasible to use an FSP in MV or HV for a local LV problem). The voltage level is considered relevant due to the different grid characteristics across voltage levels and the different FSPs characteristics based on the voltage level to which are connected.

Contracting timeframe	• Real-time • Short-term • Long-Term

The **contracting timeframe** is the time gap between the procurement and the delivery of flexibility. The real-time contracting timeframe is exploited for emergency measures, and the short-term contracting timeframe characterises the operational practices (e.g., day-ahead and intraday). Planning activities are covered via the mid-term (e.g. week-ahead to months ahead) or long-term (e.g. annually or longer) contracting timeframe. The exploitation of different contracting timeframes within the same market mechanism is possible since the different contracting timeframes are not mutually exclusive. To illustrate, the day-ahead market can be devoted to solving expected congestions or voltage problems while an intra-day market can be applied for further fine-tuning.

Frequency of the need	• Low • Medium • High • Very High

The attribute **frequency of the need** characterises the need in temporal terms. Considering a predefined time interval, the frequency of the need describes the number of occurrences that FSPs are required to provide the service considering a predefined time interval. A very high frequency is related to issues that occur regularly (e.g. daily); hence the system operator requires frequent corrective measures. Conversely, a low frequency indicates occasional issues (e.g. less than one time a month). Hence, corrective measures will be taken only a few times in the predefined time interval. Within these extremes, a medium (less than one time a week) and a high frequency (equals or more than one time a week) are relevant to be considered. In building the BUC for the grid service provision, the frequency of the need is relevant since it decisively determines the economic profitability for participating.

Volume of the problem	• High • Medium • Low

The **volume of the problem** characterises the need in terms of the amount of active/reactive power required to overcome the grid problem. A qualitative indicator of the volume of the problem is spread over a three-point scale (low, medium, high). The corresponding quantitative values are case-specific and therefore have to be defined according to the specific context characteristics. The formalisation of this attribute can be in relative terms. By considering the average nominal size of the resources connected to the area impacted, it is possible to have a yardstick of the problem dimension. Therefore, the definition of this attribute is case-specific.

Network topology	• Radial • Meshed

The **network topology** influences the extent to which the FSPs can contribute to solving the problems. Hence, it influences the paths that characterise the service provision. A higher level of interconnection of meshed networks enlarges potential service providers' set. Contrariwise a radial topology limits the number of potential FSPs that can effectively satisfy the system needs. The network topology information could be alternatively substituted by considering sensitivity factors. In electric networks, the influence of a bus over the others depends on network topology, network impedances, and the system's operating point. The network sensitivity analysis allows to characterize the coupling among busses and identify each generator's area of influence [153].

Beside the described attributes, the effectiveness of the service provided is influenced by power system context attributes that depend on the number and type of FSPs in the considered area.

FSP size	• Large FSP / Aggregation of small FSPs • Small FSP / No Aggregation

The **size and type of the FSPs** providing the service can be large FSPs (single units having a large size or aggregated small units) or small FSPs (single units having a small size which are not aggregated). In the context analysis, specific threshold values can be used to categorize the FSPs. The threshold values depend strongly on the voltage level and locality, i.e., several 10kWs can be a lot for an LV-feeder. Therefore, the FSP type/size information has to be related to other context information. The specific value for each FSP has to be known in any case. Furthermore, it has also relevance the location of all the aggregated small FSPs.

FSP nominal voltage	• High voltage • Medium voltage • Low voltage

The **FSP nominal voltage** is the nominal voltage of the network to which each potential FSP is connected. As introduced for the attribute Voltage level related to the need, the technical differences among voltage levels are relevant, so it is also essential to know which voltage level the flexible resources are located. This knowledge allows defining the set of available actions which could be taken to solve the contingency. To illustrate, to solve a voltage problem on a high voltage bus it could be more effective to resort to resources connected at the transmission level than to use flexibility from resources connected to the low voltage network. The information about the FSP nominal voltage has to be related to the locational information and should be exchanged upon registration. Exact values help to tackle the problem in the most efficient way possible.

Number of expected FSP participants	• Large • Medium • Small

The **number of participants** which can potentially provide support for satisfying the power system need influences the effectiveness of the mechanism which can be exploited for acquiring DSO services. The number of participants influences the expected degree of competition, the degree of market power, and service shortage. Moreover, the number of participants affects the cost of operating the acquisition mechanisms (e.g. the overall burden related to highly personalized bilateral contracts increases as the number of FSPs to be contracted increases). However, the number of participants is not an attribute relevant per se; it has to be correlated with other characteristics so that the volume of flexibility potentially available and the market liquidity can be determined. Besides the number of participants, the volume of flexibility available, the market liquidity, and the level of competition achieved are influenced by aggregators and their size.

Resources types of FSP	• Generation • DSR • Storage

Furthermore, the **resources types of potential FSPs** which can be involved influence the nature of the (market) mechanism which could be exploited. Therefore, the participation of generation, demand, and storage have to be assessed since their effectiveness and cost differ. If, in addition to generators, demand and energy storage are involved as FSPs, the set of flexible tools available to the system operator is broader; to illustrate, demand-side flexibility can be used instead of generation curtailment. In this case, solutions capable of including within the same mechanism generators, demand, and energy storage are required.

Ratio of the volume of flexibility available by volume needed	• Low • Medium • High

As a derived attribute obtainable by the composition of the ones previously described, the **ratio of the volume of flexibility available by volume needed** provides a measure of the degree of competition and liquidity. Competition and liquidity depend on the ratio of the volume of flexibility available by the volume needed and the number of independent FSPs/aggregators and the distribution of flexibility volumes (e.g. if one FSP has 90% of volume, market power is high). Therefore, this attribute provides an estimation of the feasibility of a market-based mechanism; to illustrate a high ratio would allow the use of market-based mechanisms, whereas a low ratio requires the exploitation of long-term contracts, flexible connection agreements or obligation. The thresholds values for considering this attribute are Low (ratio equals or less than 1), Medium (ratio greater than 1 but less than 3), High (ratio equals or greater than 3). However, it is worth highlighting that a value of ratio greater than 1 does not necessarily mean there would be competition.

4.3 Relevance assessment of the context attributes

The description of the context through its attributes allows a systematic analysis of the need and the related characteristics that influence identifying the most appropriate acquisition mechanism. By describing the contexts, the relevance of the different attributes is highly case-specific, making it impossible to find solutions that fit all contexts.

The project partners' point of view has been collected through an interactive survey to overcome this issue. As introduced in section 4.2, a preliminary set of context attribute has been proposed to project partners. According to the process depicted in Figure 4-1, the partners have reviewed the definition proposed for each attribute and the corresponding qualitative values. As shown in the questionnaire template in Annex I, the project partners evaluated each attribute appropriateness and the related value. If the respondent disagreed with the proposed definition, it was requested to provide suggestions and alternative definitions. The answers provided by the project partners were collected and analysed, then the outcome of the analysis was discussed in a meeting from which the final result described in this document has been obtained. The appropriateness of context attributes definition and values has been assessed independently for congestion management and voltage control. However, the answers collected are aligned, hence for the sake of conciseness, the results obtained are presented in a unified way. In addition to the context attribute appropriateness, each context attribute relevance was assessed by project partners.

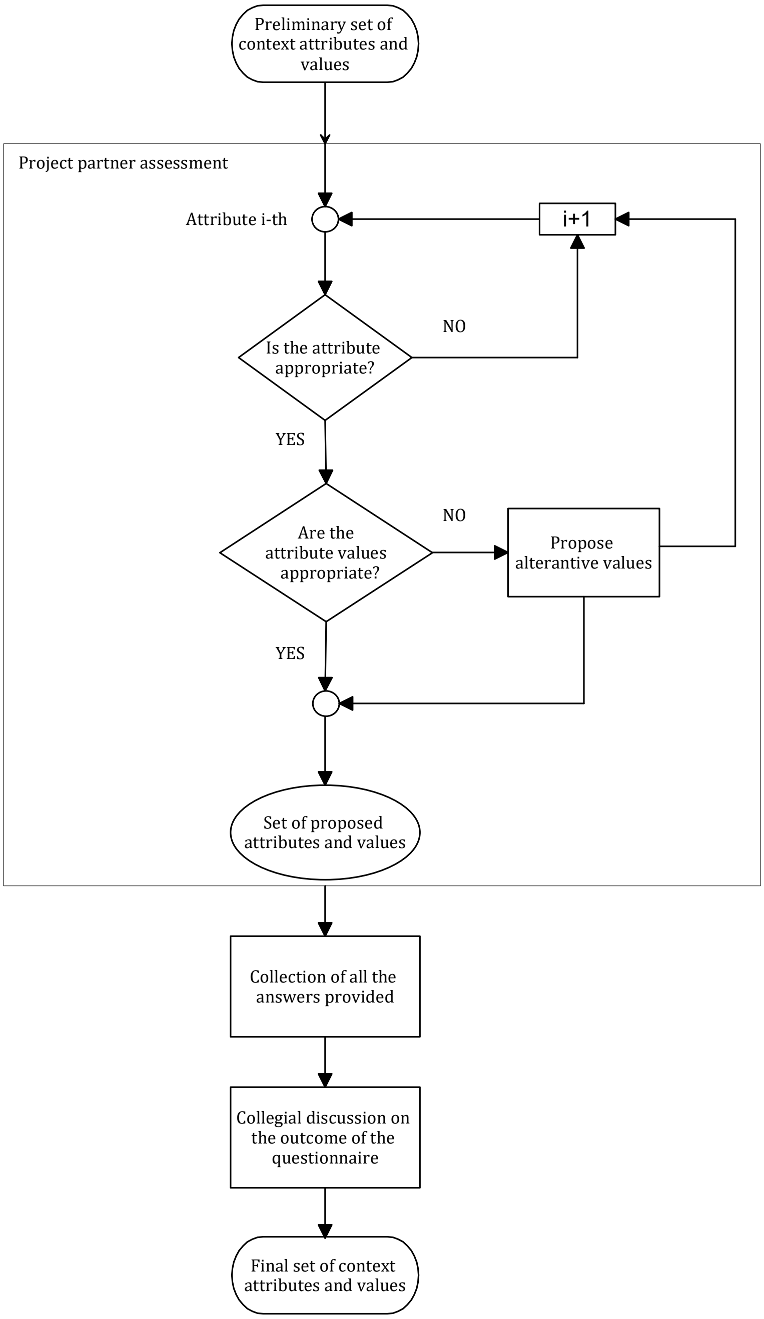

Figure 4-1. Flowchart of the procedure for the assessment of context attributes

Table 4-2 presents the outcome of the assessment of the context attribute appropriateness. The survey of project partners highlighted that a consensus among the distribution system players exists irrespective from their role. However, some conflicting opinions have been collected. It is worth to note that a consensus exists in considering the volume of the problem as an attribute for describing the context of the need. Moreover, it has been expressed the general opinion that it would be useful for introducing the "Ratio of the volume of flexibility available by volume needed" as a derived attribute.

Table 4-2. Assessment of the context attribute appropriateness

	Distribution System Operators			Flexibility Market Operators		
	DSO #1	DSO #2	DSO #3	FMO #1	FMO #2	FMO #3
Voltage level of the contingency	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute but not the values	Not appropriate	Appropriate attribute and values
Contracting timeframe	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute but not the values	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute but not the values
Frequency of the need	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute but not the values	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute but not the values
Volume of the problem	Appropriate attribute but not the values	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute but not the values	Appropriate attribute and values
Network topology	Appropriate attribute and values	Not appropriate	Appropriate attribute and values	Appropriate attribute and values	Not appropriate	Not appropriate
FSP type/size	Appropriate attribute but not the values	Appropriate attribute and values	Appropriate attribute but not the values	Appropriate attribute and values	Appropriate attribute but not the values	Not appropriate
FSP nominal voltage	Appropriate attribute and values	Not appropriate	Appropriate attribute and values	Appropriate attribute but not the values	Appropriate attribute but not the values	Appropriate attribute and values
Number of FSP	Appropriate attribute and values	Appropriate attribute and values	Not appropriate	Appropriate attribute but not the values	Appropriate attribute but not the values	Appropriate attribute but not the values
Resources types of FSP	Appropriate attribute but not the values	Appropriate attribute and values	Appropriate attribute but not the values	Appropriate attribute and values	Appropriate attribute and values	Appropriate attribute and values
Ratio of the volume of flexibility available by volume needed	New attribute suggested by the survey participants					

As a second step, the project partners evaluated the relevance of the context attributes for describing the scenario in which the mechanism for acquiring grid services has to be exploited for solving congestions or voltage problems. Each respondent had to rank the proposed context attributes in ascending order according to the perceived relevance. The collected rankings have been aggregated according to a three-step procedure. First, the rank product statistic was calculated for each attributed (i.e. the geometric mean of the position index assigned in the various rankings) [159]. A bonus is then assigned to an attribute for each time the item has been considered the most important. Each time an attribute assumes the first position in the singular ranking receives a bonus equal to 0.5. As a second step, an intermediate ranking is calculated, the rank for each attribute is calculated as the difference between the rank product statistic and the bonus values. As the last step, the final ranking s is obtaining by sorting in ascending order the context attribute considering the intermediate ranking values. For the sake of clarity, the procedure for calculating the final aggregated ranking is depicted in Figure 4-2.

Context Attributes	Rank A	Rank B	Rank C	Rank D	Rank E	Rank Product Position	Bonus	Intermediate rank	Final Ranking
Voltage level of the contingency	9	3	3	8	2	4.2	0	4.2	5
Contracting timeframe	4	6	4	1	4	3.3	0.5	2.8	3
Frequency of the need	7	9	2	3	3	4.1	0	4.1	4
Volume of the problem	1	1	1	2	9	1.8	1.5	0.3	1
Network type	8	7	5	6	9	6.9	0	6.9	9
FSP size	6	5	6	4	9	5.8	0	5.8	7
FSP nominal voltage	3	8	7	9	9	6.7	0	6.7	8
Number of FSP participants	2	4	9	5	1	3.2	0.5	2.7	2
Resources types of FSP	5	2	8	7	9	5.5	0	5.5	6

Figure 4-2. Example of the process for aggregating the individual rankings

Table 4-3 and Table 4-4 show the rankings of context attributes and the related final aggregated ranking considering, respectively, congestion management and voltage control. From these tables, it is possible to note that there are not relevant discrepancies between the point of view of DSOs and FMOs. From Table 4-3 and Table 4-4 DSOs are more concerned than FMOs for the frequency of the need, while the FMOs consider the resources types of FSP a relevant attribute for describing the context of the need.

As shown in Table 4-3 and Table 4-4, the final ranking obtained for congestion management and voltage control is quite similar. Therefore, according to the stakeholders' point of view, the same set of attributes can describe the context of the need both for congestion management and voltage control. In general, the most relevant attribute to be considered is the volume of the problem, followed by the number of participants. These two attributes can be related to the liquidity and the competition level which have been considered by the respondents the most important aspects to be considered when designing the mechanism for acquiring the grid services in each specific context.

Table 4-3. Rankings collected for congestion management

Context attribute	DSOs			FMOs			Final rank
	DSO #1	DSO #2	DSO #3	FMO #1	FMO #2	FMO #3	
Voltage level of the contingency	3	8	2	3	9	3	4
Contracting timeframe	4	1	4	6	4	6	3
Frequency of the need	2	3	3	9	7	9	6
Volume of the problem	1	2	9	1	1	1	1
Network topology	5	6	9	7	8	7	8
FSP size/type	6	4	9	5	6	5	7
FSP nominal voltage	7	9	9	8	3	8	9
Number of FSP participants	9	5	1	4	2	4	2
Resources types of FSP	8	7	9	2	5	2	5

Table 4-4. Rankings collected for voltage control

Context attribute	DSOs			FMOs			Final rank
	DSO #1	DSO #2	DSO #3	FMO #1	FMO #2	FMO #3	
Voltage level of the contingency	3	8	3	2	6	2	6
Contracting timeframe	4	1	5	9	8	9	4
Frequency of the need	2	3	4	5	7	5	5
Volume of the problem	1	2	9	3	4	3	1
Network topology	5	6	9	8	9	8	9
FSP size/type	6	4	9	6	3	6	7
FSP nominal voltage	9	9	9	4	2	4	8
Number of FSP participants	8	5	2	1	5	1	2
Resources types of FSP	7	7	9	2	1	2	3

5 Qualitative assessment of the suitability of each market mechanisms

This chapter describes the qualitative appraisal of the acquisition mechanisms for grid services. First, the suitability of the acquisition mechanisms for grid services is analysed concerning the context of the needs described in section 2.1 and chapter 4. Each acquisition mechanism is then assessed according to the evaluation criteria defined in section 2.2.

The mechanisms for acquiring grid services defined in chapter 3 are considered in isolation as a specific process for acquiring the service from the parties. More complex mechanisms can be obtained by combining their features. Each mechanism can be exploited to procure flexibility from FSPs for solving network congestion and voltage problems. However, the related applicability and effectiveness of each mechanism depend on the characteristics of the context in which it has to be employed. The qualitative analysis provided in this section studies the applicability and the potential effectiveness that each mechanism could reach. The aim is to provide general recommendations for designing the framework that has to be set up to exploit grid services from third-parties for solving congestion and voltage issues at the distribution level.

5.1 Suitability analysis of acquisition mechanisms according to context attributes and evaluation criteria

According to the context attributes defined in Table 2-1, a high-level qualitative analysis of the mechanisms for acquiring grid services concerning the context attributes is given in Table 5-1, in which the colour scale represents the suitability of each mechanism for acquiring grid services considering each attribute. The green colour represents high suitability, the yellow colour weak suitability, while red means that the mechanism for acquiring grid services is not suitable if the related attribute applies. The rows are not necessarily mutually exclusive, but they are depicted as such for the sake of simplicity. Only binary qualitative values have been used for most of the attributes.

5.1.1 General assessment of the acquisition mechanisms

The qualitative assessment in Table 5-1 can be considered valid for congestion management and voltage control. The assessment represented in Table 5-1 is part of the outcome of the survey of the project partners' point of view on the appropriateness and relevance of the context attributes. The template of the questionnaire is given in chapter 8.

Table 5-1. Suitability of the mechanisms for acquiring grid services considering the context attributes

		Flexible connection	Dynamic tariffs	Local market	Bilateral contract	Cost-based	Obligation
Voltage level	High	High	High	High	High	High	High
	Medium	High	High	High	High	High	High
	Low	High	High	High	High	High	High
Contracting time	Long-term	High	High	High	High	High	High
	Short-term	Weak	High	High	Weak	High	High
	Real-time	Low	Low	Low	Weak	High	High
Frequency of the need	High	High	High	High	Weak	High	High
	Low	High	High	Low	High	High	High
Network topology	Radial	High	High	Weak	High	High	High
	Meshed	High	High	High	High	High	High
Volume of the problem	Small	High	Weak	Weak	High	High	High
	Large	High	High	High	Low	High	High
FSP size/type	Large	High	High	High	High	High	High
	Small	High	High	Weak	Low	Low	High
FSP voltage level	High	High	High	High	High	High	High
	Medium	High	High	High	High	High	High
	Low	High	High	High	High	High	High
Number of participants	Large	Weak	High	High	Low	High	High
	Small	High	Weak	Low	High	High	High
Demand &/or energy storage	Generation	High	High	High	High	High	High
	Demand	High	High	High	High	Low	High
	Storage	High	High	High	High	Low	High
Ratio of the volume of flexibility available by the volume needed	Low	High	Low	Low	Weak	High	High
	High	High	High	High	High	High	High

Legend:

Suitability	High	Weak	Low

A priori, voltage levels do not impact the choice among the mechanisms. In general terms, all mechanisms can be applied to different voltage levels. Combining other attributes may make a mechanism preferable to others, as explained below.

The contracting timeframe attribute is related to the ability to know in advance the needs and to contract the service in advance. Flexible connection and access agreements require defining the agreement between the parties that establishes the temporal and quantity of the reduction of the grid access. Therefore, the flexible connection and access agreements mechanism are suitable if flexibility can be contracted long term ahead. Contrariwise, the flexible connection and access agreements appear less suitable for a short-time contracting timeframe and not suitable for addressing emergencies, unless the emergency intervention is concerned in the agreement signed at the connection stage. It is inconceivable that in emergencies, which require a short time to be resolved, new flexible connections are contracted for this purpose. The concerns related to the reliability of the participating FSPs make the dynamic network tariffs mechanism not suitable in the case of emergencies, as it would require a specific response from some customers and with short notice. The risk of not collecting enough participation of potential flexible providers for solving the network problem could be unacceptable for ensuring the security and quality of the electric supply to network customers. Regarding the exploitation of the local flexible markets, the short-time available for procuring the bids, the reliability and market power concern make this mechanism not suitable for handling the emergency scenarios. Bilateral contracts require to be stipulated in advance since the high information asymmetry and the complexity related to the negotiation stage. Therefore, the bilateral contract mechanism is less suitable complying with short-term and emergency needs. However, since two parties can achieve any agreement in term of volume, timeframe, and price of the grid service to be provided, specific agreements for short-term or emergency needs can be stipulated long in advance.

When a high frequency characterises the need for service provision, the suitability of a bilateral contract is low since the overall burden related to the high volume of negations would be high. Contrariwise, a local market mechanism appears not suitable in the case of a low frequency of the need as this would lead to a lack of liquidity and the underutilisation of the possibly complex market structure.

The radial topology limits the area which contains the potential FSPs to be exploited for the flexibility provision. In this case, a local market may have only a few participants, hence the risk of market power issues exits. However, as liquidity is dependent on the volume of flexibility available compared to the volume needed and the number of independent FSPs available (also considering the volumes offered per FSP), liquidity can also be high in meshed grids and low in radial grids. Therefore, the topology criterion only gives an indication.

The attribute that describes the problem volume must be related to the attributes number of participants and FSP size/type. Besides the volume of the problem, it is relevant to understand how the potential resources can participate for solving it (i.e. a large problem can be solved by only one FSP, the FSP can be a large FSPs or a set of aggregated small FSPs. If not available, it is necessary to contract a set of small independent FSPs). The attribute "ratio of the volume of flexibility available by volume needed" synthesises the information contained in the combination of the attributes volume of the problem, number of participants, and FSP size/type. A possible metric of the attribute could be the volume of the problem by mean volume of offers. However, for completeness, each of these three context attributes is also analysed independently.

Suppose the volume of the problem to be solved by resorting FSPs is small. In that case, a dynamic tariff mechanism is less suitable than other acquiring mechanisms since it would involve only a small set of localised FSPs which could or could not participate in the service provision. In the case of large volume problems, a local market mechanism is more suitable since the number of potential FSPs involved is large. Furthermore, solving a large volume problem with bilateral contracts appears unsound since a large number of negotiations would be required.

Suppose only small FSPs are involved in the mechanisms for acquiring grid services. In that case, local markets may represent a less appealing choice since the burden of participation which would be required for asset management might be too high. Furthermore, the exploitation of bilateral contracts would require negotiating a high number of contracts concerning a small volume. Similarly, a cost-based mechanism can be a considerable burden for auditing FSPs.

The voltage level of the FSPs does not impact the choice among the mechanisms; however, it is considered as a relevant attribute for designing the acquisition mechanism in the case-specific analysis. If the potential FSPs are connected to different voltage levels to the voltage level of the need, the effectiveness in contributing by providing the grid service changes. Therefore, the set of potential FSPs must be defined accordingly.

As already stated, if the number of participants is large, then the exploitation of bilateral contracts is not suitable. Similarly, the exploitation of flexible connection agreements could be less suitable; however, it has to be considered that the burden of achieving the agreements between the parties is lower than the case of bilateral contracts. On the contrary, a small number of participants makes dynamic tariffs and local markets weak and less suitable, respectively. In such a context, the exploitation of dynamic tariffs may lead to a shortage in the flexibility procured. In contrast, in local markets, significant concerns related to market power risk arise.

When demand and energy storage devices are involved as FSPs, the cost-based mechanism appears unsuitable as determining reference costs would be very complex, considering the great diversity of potential providers.

If the ratio of the volume of flexibility available by volume needed is low, dynamic tariffs and local market are not suitable mechanisms for acquiring grid services since the concerns related to reliability and market power issues. The market power issues concern also limits the suitability of the bilateral contract mechanism in the case of low values of the ratio of the volume of flexibility available by volume needed.

5.1.2 Congestion management and voltage control peculiarities

Even if the qualitative assessment in Table 5-1 has been devised for being valid for both for congestion management and voltage control, the voltage control service peculiarities require further discussion.

Congestion management is mainly characterised by the provision of active power services -i.e. active power injections and withdraws. While voltage control can be obtained considering both active and reactive power which can be generated or adsorbed by generators and loads. However, reactive power is more suitable for voltage problems since it is less expensive.

In particular, two relevant characteristics of voltage control service influence the choice of the procurement mechanism which can be exploited. Voltage control is a local activity; solving a voltage problem requires the exploitation of resources close to the need. Moreover, voltage problems generally require short-term actions; it is not possible to know long in advance the position and the extent of the voltage issue. Unless it depends on structural deficits and the known periodic behaviour of the generation or the demand. Considering these two relevant characteristics of voltage control, it is possible to conclude that not all the mechanism for acquiring grid service presented in chapter 3 fit well for voltage control:

a. Connection and access agreements: may fit, but the terms of grid service provision and the contracting timeframe have to be carefully designed.

b. Dynamic network tariffs: do not fit well since the local characteristic of voltage control and the typical price volatility [160]–[162].
c. Local flexibility markets: may be suitable if competition among providers close to the need exists.
d. Bilateral contracts: is a mechanism already used for voltage control [163]–[165].
e. Cost-based: may fit with voltage control, but it is complex to define the reference costs due to potential providers' great technological diversity.
f. Obligation: fits with voltage control, however, it does not guarantee an efficient allocation of resources, and as previously discussed, it should only be considered a last option.

Table 5-2 summarises the applicability assessment of the mechanisms for acquiring grid services concerning active power measures for congestion management and reactive power measures for voltage control. All the mechanisms described in chapter 3 can be used for congestion management, while for voltage control, bilateral contracts and obligations mechanisms fit considering this service attributes. The use of flexible connection and access agreements, local flexibility markets, and the cost-based mechanisms is case-specific and may work but considering appropriate designs. Dynamic network tariffs do not fit for voltage control.

Table 5-2. Applicability of the mechanisms for acquiring grid services

	Flexible connection and access agreements	**Dynamic network tariffs**	**Local market**	**Bilateral contract**	**Cost-based**	**Obligation**
Congestion management (Active power)						
Voltage control (Reactive power)						

Legend:

Suitability	**High**	**Weak**	**Low**

5.1.3 Assessment of combined mechanisms for acquiring grid services

The assessment in Table 5-1 is the outcome of the high-level qualitative analysis of the mechanisms for acquiring grid services. More complex results can be obtained by considering non-binary attributes for characterising the context and the need and more complex mechanism for acquiring grid services obtained by combining them. In this section, the qualitative analysis of the applicability of more complex mechanisms for acquiring grid services is described considering independently congestion management and voltage control based on the outcome of the assessment of the mechanisms reported in Table 5-2.

The combination of the mechanisms for acquiring grid services is made considering the same service and the same context in terms of network area and resources involved. Therefore, a combination of these mechanisms can, for example, be used for procuring reactive power support (the service) from all the resources connected to an area of the distribution grid. The reactive power support can be procured according to different mechanisms. Table 5-3 provides an overview of the complementarity assessment of the mechanism for acquiring grid services considering congestion management (active power). The green colour means compatibility among the mechanism, yellow weak compatibility, while red the incompatibility. The matrix in Table 5-3 is symmetrical. The comparison is made considering the parallel use of two different mechanisms for acquiring active power products for congestion management.

Table 5-3. Compatibility of the mechanisms for acquiring congestion management – active power

	Flexible connection and access agreements	Dynamic network tariffs	Local flexibility markets	Bilateral contracts	Cost-based	Obligation
Flexible connection and access agreements						
Dynamic network tariffs						
Local flexibility markets						
Bilateral contracts						
Cost-based						

The assessment in Table 5-3 shows that connection and access agreements can be exploited in parallel with dynamic network tariffs, cost-based, and obligation mechanisms. Considering the single FSP, a flexible connection cannot be combined with other mechanisms if the full resource's flexibility is already allocated. However, a combination of mechanisms is always possible considering different FSPs or needs. If flexible connection and access agreements concern connection costs and dynamic network tariffs focus on the overall network costs; the separation between both has to be determined. Combining the connection and access agreements with local flexibility markets and bilateral contracts raises the challenge about the possible limitations introduced by the flexible connection agreements and the possibility of engaging in other mechanisms. To illustrate, an FSP with a flexible connection agreement (EV charging in LV) can take part in a local flexibility market to start charging when renewable energy is abundant to integrate more RES. The offers in the local flexibility market are constrained by the restrictions of the connection agreement.

Dynamic network tariffs can work in parallel with local flexibility markets and bilateral contracts; however, the interaction between the two mechanisms has to be designed considering the constraints introduced by the voltage level, the contracting timeframe, the frequency of the need, the network topology, and the volume of the problem. Combining local flexibility markets and bilateral contracts the bids on the market (or the price which will be agreed in the bilateral contract) have to consider the impact on the network charges for the FSP (e.g. flexibility delivery could lead to higher network charges) unless certain exemptions are given during the service delivery.

Local flexibility markets and cost-reflective long-term incremental charges have the same objective, reducing future network costs, and can complement each other. Network tariffs are usually designed for large areas, being a whole country or DSO region. Local flexibility mechanisms, though, are designed for specific network components or limited areas located within those larger areas. In this way, both mechanisms are complementary in terms of geographical scope.

The suitability of different options also depends on how extensive the required customer reaction should be. For instance, system-wide reactions, caused for example by a heatwave, are better achieved by broadcasting high network tariffs for the following day during peak-use hours, while local resources to solve specific network congestions, which occur at different times and locations, can be better mobilized using local flexibility markets [166]. Also, local flexibility markets providers are committed to providing the service in response to the DSO request based on the outcome of the market process. In fact, in some cases, this response may be automatic. Hence, local flexibility markets enable DSOs to rely on flexibility for actively managing the network and to avoid grid reinforcements when planning the expansion of the grid [166].

Bilateral contracts could be exploited as a backup solution for acquiring the volume of flexibility services which has not been obtained using dynamic network tariffs. Nevertheless, bilateral contracts for the appropriate volume of grid service have to be signed with the FSP located in the appropriate location and voltage level, and with an appropriate contracting timeframe considering the activation time of the resources involved. Therefore, the combination of dynamic network tariffs with local flexibility markets and bilateral contracts has to be assessed case-by-case at the design stage. The interaction of the dynamic network tariffs and the cost-based mechanism is challenging because based on different principles, dynamic network tariffs incentivise customers to reduce network costs while cost-based mechanism aims to cover the expenses related to the service provision. In contrast, cost-based mechanisms are related to the cost of providing the service occurred by the FSPs. Therefore, in general, if cost-based mechanisms are in force, dynamic tariffs for the same group of FSPs is not valuable. Combining both options requires to assess the scope and expected results obtained from each of them. The compulsory participation at the dynamic network tariff mechanism could be devised considering the characteristics of the context.

In [167], an optimal reconfiguration-based mechanism including nodal prices (short-term marginal costs) for congestion management and line loss reduction in distribution networks with high electric vehicles penetration is presented. Their results show that the congestions under the optimal topology are further alleviated, and the distribution locational marginal prices are reduced compared to the original topology. In [168], a comprehensive scheme for day-ahead congestion management of a distribution network with high penetration of DERs is presented. In this case, the nodal prices, network reconfiguration and re-profiling products are integrated, which combines the advantages of these methods. With the utilisation of the flexibilities from various types of DERs and the advantages of the three congestion management methods, the proposed comprehensive scheme can solve the congestion more effectively, and at the same time ensures that the congestion management prices are within an acceptable level.

Local flexibility markets can be combined with bilateral contracts considering the constraints introduced by the voltage level, the contracting timeframe, the frequency of the need, the network topology, the volume of the problem, and the number of participants. For example, bilateral contracts could be used in certain network areas when competitive local flexibility market outcomes cannot be guaranteed. Local flexibility markets and cost-based mechanisms can be exploited in a combined mechanism considering different mechanisms for capacity and activation. Local markets for acquiring flexibility capacity can be used while activation may be a cost-based dispatch if representative costs can be obtained easily. Moreover, combining the local flexibility market with the obligation mechanism is possible considering the context characteristics. To illustrate, the obligation can be used to guarantee a minimum level of flexibility, obligation can be considered a technical connection requirement established in the grid code. Combining the bilateral contract and the obligation mechanism poses the same challenges as discussed for the combination of local flexibility markets and obligation.

Table 5-4 provides an overview of the complementarity assessment of the mechanism for acquiring grid services considering voltage control (reactive power). The yellow colour means weak compatibility among the mechanism, while red the incompatibility. The comparison is made considering the parallel use of two different mechanisms for acquiring reactive power products for voltage control.

The assessment in Table 5-4 shows that the flexible connection and access agreement mechanism in the context of voltage control could be combined with local flexibility markets but it raises the challenge about the possible limitations introduced in the participation in local markets by the flexible connection agreements. The combination of flexible connection and access agreements and bilateral contracts could be possible considering different timeframes and locations, but the conditions of both mechanisms have to be clearly stated. The combination of flexible connection and access agreements and the obligation mechanisms could be achieved by considering that obligations guarantee a minimum flexibility quantity and additional quantities can be guaranteed with flexible connection and access agreements.

Dynamic network tariffs are not combinable with any other mechanism since it is considered not feasible for reactive power procurement for voltage control, as described in section 5.1.2.

The combination of local flexibility markets and bilateral contracts could be introduced considering different mechanisms depending on locations and level of potential competition. Combining the local flexibility markets and the cost-based mechanisms could be achieved by considering using different capacity procurement mechanisms and activation mechanisms. For capacity, a local market can guarantee investments in new resources to provide voltage control, while for activation, a cost-based method can guarantee an efficient allocation if costs are easily known. For example, considering the similarities of loss curves of reactive power generators, a generalised cost function for reactive power production can be defined [150]–[153], [169], [170]. As illustrated in section 0, a generalised expected cost function for reactive power provision can be devised for a broad set of technologies [151]–[153]. Moreover, the combinations which include the obligation mechanism may guarantee a minimum available volume [154]. This obligation requirement can be combined with a local flexibility market or bilateral contracts, depending on whether competition is guaranteed in the former.

Table 5-4. Compatibility of the mechanisms for acquiring voltage control – reactive power

	Flexible connection and access agreements	Dynamic network tariffs	Local Flexibility markets	Bilateral contracts	Cost-based	Obligation
Flexible connection and access agreements						
Dynamic network tariffs						
Local flexibility markets						
Bilateral contracts						
Cost-based						

5.2 Relevance assessment of the evaluation criteria

As no-solution fits all and, as previously presented, each mechanism performs better in one criterion than in another, a qualitative assessment was conducted to get a sense of each criterion importance for the DSOs and MOs. Table 5-9 represents the outcome of this high-level qualitative analysis. The assessment of specific realisation of the mechanism for acquiring grid services would make possible a more detailed discussion since assessing the single features.

Moreover, in the context of a comprehensive assessment of the acquisition mechanism, each evaluation criteria relevance has to be considered. In the context of the present deliverable activities, the information on the evaluation criteria relevance in Table 5-9 has been collected from the project partners contributing to this deliverable. Through the questionnaire available in chapter 8, the respondents provided their view in terms of the relevance of each evaluation criteria and the related sub-criteria. Each respondent had to rank the evaluation criteria proposed from the most relevant to the less relevant. The rankings collected have been then composed according to the procedure described in section 4.3.

In Table 5-5, the outcome of the survey on the relevance of the general evaluation criteria is provided. Among the general criteria, the reliability of the mechanism for acquiring grid services has the utmost relevance, followed by transparency and economic efficiency. Whereas, customer engagement, implementation concerns, and equity are secondary for assessing the suitability of the acquisition mechanism. There is a general alignment between the point of view of the two groups of respondents (MOs and DSOs). However, Table 5-5 highlights that the MOs are more concerned than DSOs about transparency; conversely, implementation concerns is a criterion of higher relevance for DSOs. The general view collected through the survey is that the mechanism for procuring grid service has to guarantee first operational security since it is exploited for solving grid issues. Economic efficiency and transparency are considered important pillars for achieving an economically optimal outcome for the participants.

Table 5-5. Survey on the relevance of the general evaluation criteria

General evaluation criteria	Flexibility Market Operators			Distribution System Operators			Final ranking
	FMO #1	FMO #2	FMO #3	DSO #1	DSO #2	DSO #3	
Economic efficiency	2	1	1	3	2	3	3
Transparency	1	1	1	6	5	4	2
Equity	4	4	4	4	4	6	6
Implementation concerns	6	5	5	2	1	2	5
Customer engagement	3	1	1	3	6	7	4
Reliability	5	1	1	1	3	1	1

*1 means highly relevant and 10 non-relevant

Table 5-6 represents the survey outcome about the relevance of economic efficiency sub-criteria. Regarding economic efficiency, the most relevant aspects concern the limitation of the risk of exercising market power and information asymmetry; the reduction of entry barriers represents another important criterion according to the respondents. Table 5-7 shows that MOs are more concerned about information asymmetry while the DSOs about the issues related to the exercise of market power.

Table 5-6. Survey on the economic efficiency sub-criteria

Economic Efficiency sub-criteria	Flexibility Market Operators			Distribution System Operators			Final ranking
	FMO #1	FMO #2	FMO #3	DSO #1	DSO #2	DSO #3	
Allocative economic efficiency	3	7	7	3	1	3	6
Limit market power	5	1	1	1	4	1	1
Technology neutrality	2	1	1	5	3	4	4
Low entry barriers	4	1	1	2	2	6	3
Limited information asymmetry	1	1	1	6	5	5	2
Limited uncertainty	6	1	1	4	6	2	5

*1 means highly relevant and 10 non-relevant

Table 5-7 represents the outcome of the survey about the relevance of the equity sub-criteria. According to the respondents, the main aspect to be considered when designing a mechanism for acquiring grid services are allocative and transitional equity. However, FMOs are more concerned about allocative equity whereas DSO on transitional equity.

Table 5-7. Survey on the equity sub-criteria

Equity sub-criteria	Flexibility Market Operators			Distribution System Operators			Final ranking
	FMO #1	FMO #2	FMO #3	DSO #1	DSO #2	DSO #3	
Allocative equity	1	1	1	1	2	2	1
Distributional equity	3	1	1	3	3	3	3
Transitional equity	2	1	1	2	1	1	1

Table 5-8 represents the outcome of the survey about the relevance of the implementation concerns sub-criteria. According to the respondents, the most relevant aspects to be considered when designing a grid service mechanism are the implementation costs and the alignment with the EU market regulation. Implementation concerns are related to the achievement of a reasonable level of complexity and implementation costs while preserving the alignment with the EU market design/regulation and achieving a high level of effectiveness. The alignment with EU market design is key to facilitate the integration with the existing practices. Moreover, if the mechanism for procuring grid services is internally complex but simple from a participant point of view (and reasonable in terms of cost), it could be acceptable.

Table 5-8. Survey on the implementation concerns sub-criteria

Implementation sub-criteria	Flexibility Market Operators			Distribution System Operators			Final ranking
	FMO #1	FMO #2	FMO #3	DSO #1	DSO #2	DSO #3	
Implementation costs	2	1	1	4	2	4	1
Complexity	4	6	6	3	1	2	4
Effectiveness	3	6	6	2	3	1	3
Aligned with EU market design/regulation	1	6	6	1	4	3	2

5.3 Assessment of the acquisition mechanism according to evaluation criteria

An overview of the high-level appraisal of the acquisition mechanism considering the evaluation criteria defined in section 2.2 is provided in Table 5-9. The green colour represents a high level of performance, the yellow colour medium performance, while red means that the acquisition mechanism achieves a low level of performance considering the related criterion.

Considering allocative economic efficiency, all analysed mechanisms for acquiring grid services, if well designed, can perform well except for bilateral contracts, cost-based mechanism, and obligation. Bilateral contracts and cost-based mechanisms show a medium level of allocative efficiency since both do not incentivize cost discovery and that the resulting compensation would be equal to the marginal cost. The obligation mechanism implies a non-remunerated service provision. Therefore, it does not work for creating allocative efficiency as the costs involved are not considered.

Due to the possible lack of competition among the FSPs, the use of a local market and bilateral contracts may be unable to limit the risks related to market power. Therefore, it is of utmost importance to determine the factors influencing the market power to apply corrective measures, such as close monitoring and penalties if required or choose alternative mechanisms.

Technology neutrality can generally be a characteristic of all mechanisms for acquiring grid services except for obligation mechanisms. If an obligation mechanism is in force, the providers are not remunerated irrespective from the technology adopted. Moreover, in general, an obligation is set only for specific technologies.

Except for dynamic tariffs and local markets, all appraised mechanisms for acquiring grid services may become a means for uncertainty management. Dynamic network tariffs is a voluntary mechanism for flexible resources, and besides, there is uncertainty related to price elasticity, then the participation rate of the FSPs the provision of the grid service required is uncertain. Moreover, in local markets, only a few are already implemented; therefore, a lack of historical economic information exists. Besides, the system operator can influence the required needs by exploiting additional flexibility means such as tap changers, line reconfigurations, and by investing in owned resources. These two aspects lead to significant uncertainty for potential participants of a local flexibility market mechanism.

Table 5-9. Appraisal of the acquisition mechanism considering the evaluation criteria

General criteria	Sub-criteria	Flexible connection	Dynamic tariffs	Local market	Bilateral contract	Cost-based	Obligation
Economic efficiency	Allocative economic efficiency	High	High	High	Weak	Weak	Low
	No exercise of market power	High	High	Weak	Weak	High	High
	Technology neutrality	High	High	High	High	Weak	Weak
	Manage of uncertainty	High	Weak	Weak	High	High	High
	No entry barriers	High	High	Weak	High	Weak	Weak
	Manage information asymmetry	High	High	High	Weak	Low	High
Transparency		High	High	High	Weak	Weak	High
Equity	Allocative equity	High	High	High	Weak	High	Low
	Distributional equity	High	High	High	High	High	High
	Transitional equity	High	High	High	High	High	High
Implementation concerns	Implementation costs	Weak	Weak	Low	High	Weak	High
	Complexity	Weak	Weak	Weak	High	Weak	High
	Effectiveness	High	Weak	High	High	High	Weak
	Alignment with EU design	High	High	High	Weak	Weak	Low
Customer engagement		Weak	High	High	High	Weak	Low
Reliability		High	Low	Weak	Weak	High	High

Legend:

Performances	High	Weak	Low

Entry barriers concern local markets, cost-based, and obligation mechanisms. In the case of local markets, barriers can be related to entry costs to engage in the market; considering the cost-based mechanism, the regulatory burden of cost recovery and technological neutrality may constitute an entry barrier for new players. Moreover, a mandatory service provision without any remuneration may limit the investments in assets that can support the network needs since it may lower the profitability of investing in the core business.

Information asymmetry management is a challenge for bilateral contracts and cost-based mechanisms. In bilateral contracts, the parties are inclined to share little information to achieve the most convenient deal. In the cost-based mechanism, the FSPs have to provide enough information for auditing the incurred costs. The verification process can be extremely burdensome, and besides, the validity of the verification process could be questionable.

A transparent mechanism for acquiring grid services allows auditing the processes related to service provision and the related costs. Bilateral contracts may lack in transparency since the parties could claim confidentiality for the negotiation process. Moreover, it represents a mechanism in which the information asymmetry can be unbridgeable. The cost-based mechanism may lack in transparency since auditing the costs of the provision of grid service could be burdensome as the typology of potential providers grows. Transparency in cost-based mechanisms is even more challenging to achieve for demand-side resources where costs are not easy to audit as some of them are related to opportunity costs. Therefore, the actual price of grid service provision could end up unrevealed.

Regarding the equity principles, the obligation mechanism does not comply with allocative equity since the grid service provided is not remunerated; therefore, cost reflectivity does not subsist. Bilateral contracts and flexible connection agreements may lack in allocative equity, due to the possible market distortions, cost reflectivity is not guaranteed due to a bilateral negotiation procedure.

The infrastructures required for enabling the communication and control may have high implementation costs in the case of flexible connections, local markets, and cost-based mechanisms. Still, implementing local markets may require even higher implementation costs. For dynamic tariffs, data collection and computation may be costly, especially for locational granular tariffs. However, the actual implementation costs strictly depend on the design features of each specific mechanism.

Flexible connections, dynamic tariffs, local markets, and cost-based mechanisms are expected to be complex. Flexible connections and dynamic tariffs require to define and implement the mechanism which links the spatial and temporal features of the need with the FSPs. Besides, the complexity of the local market is related to the need for defining the market area and the trading platform. The complexity of the cost-based mechanism lies, amongst others, on procedures for auditing the declared costs. However, similarly, for the implementation costs, complexity strictly depends on the design features of each specific mechanism.

Except for dynamic tariffs and obligations, all mechanisms are expected to achieve a high procurement effectiveness level. Since dynamic tariffs rely on the response to price signals, the risk of under/over procurement exists. Obligations may under or overestimate the system's needs and, as they are specified when connecting to the grid, they cannot be continuously updated to the grid needs. An obligation is not efficient because, if obligation concerns only certain units, it may lead to under procurement. While, if all possible providers are included in obligation, it leads to over procurement.

Considering the EU market design principles, bilateral contracts and cost-based mechanism are less preferable options if other mechanisms could be employed as they are less aligned with market-based principles [1]. Furthermore, the exploitation of a mandatory service provision mechanism has to be always prevented.

A medium level of customer engagement characterises flexible connection and cost-based mechanisms since customer’s choices would be fixed and determined in the early stages of interactions with the grid. The obligation mechanism does not encompass any freedom of choice for the customers; therefore, the lowest customer engagement level is expected to be achieved.

Since dynamic tariffs rely on price signal for involving the FSPs in the service provisions, a big concern exists on the reliability of the DSO to rely on the uncertain response. Dynamic tariffs do not guarantee a level of participation that can satisfy the system need. Local markets and bilateral contracts show some reliability concerns since the liberalised negotiation framework may lead in some cases to flexibility shortage if not properly designed. Definition of penalties and conservative procurement, including security margins, may overcome reliability risks.

6 Conclusions

The energy transition implies a significant change in the electricity system. The technology development such as digitalisation gives customers the possibility to connect at distribution networks to become active participants who interact with the system. Consumers with distributed energy resources can provide electricity back to the network by installing distributed generation and different storage technologies, including electric vehicles. These technologies can provide a wide range of grid services and support grid planning and operation.

To take advantage of this potential, the European Commission in the Article 32 of the Directive (2019/944) [1] requires the Member States to create incentives for DSOs to procure grid services 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 higher congestions. This deliverable has specifically addressed this requirement to analyse different **mechanisms to acquire grid services** and assesses the suitability of each of them considering **relevant context attributes** from the DSO needs (e.g. voltage level, contracting timeframe, frequency of the need, the volume of the problem, the network type, and the ratio of the volume of flexibility available by volume needed) and FSP attributes (e.g. size, FSP nominal voltage, number of expected FSP participants, and resources types of FSP) and following a series of **evaluation criteria** (e.g. economic efficiency, transparency, equity, implementation concerns, customer engagement and reliability).

The main mechanisms analysed are **access and connection agreements, dynamic network tariffs, local flexibility markets, bilateral contracts, cost-based remuneration, and obligations**. These mechanisms are evaluated for congestion management and voltage control, two of the main services that are tested in the EUniversal demonstrators. Each of these mechanisms has different design elements that need to be carefully assessed before being implemented. Furthermore, their implementation has some benefits but also important challenges, as summarized below.

Access and connection agreements

Connection charges should promote the **efficient use of the already existing hosting capacity** of the network by sending locational signals to new connections. This is accomplished with deep and shallowish connection charges that incorporate the costs of network reinforcements needed to connect new installations.

A key element to improve efficiency are **flexible connections** or non-firm access, which give the option to the DSO to limit energy injections or withdrawals to/from the network, and it allows the deferral of network reinforcements. However, in some of the analysed countries as Portugal, Poland, and Spain this is incompatible with current national regulation. In Ireland and the UK, non-firm generator access is in the implementation phase.

The lessons learnt in the flexible connection projects show that generation curtailment can enable significant reductions in network reinforcement resulting in benefits for both, DSOs and generators. As in transmission networks, the optimal solution might be a mixed approach of network reinforcement and congestion management including curtailment options. **Curtailment compensation or agreement on predefined curtailment volumes between the DSO and the generators** can balance the risk and benefit of flexible connections. Large generators are better suited to manage these agreements in a cost-efficient manner. For small users, the connection costs are smaller, and especially at low penetration level, a simpler approach might be reasonable.

The **transparency of the connection and access process** is a relevant factor and should be as high as possible. Customers should be aware of the access and connection procedures and, in case of deep connection charges, transparency on reinforcement costs is needed for grid users to know what they are paying for.

Dynamic network tariffs

Efficient dynamic network tariffs should provide **short-term and long-term marginal costs signals** and recover the rest of the network costs through residual fixed network charges. By applying such tariffs, efficient economic signals are provided to customers to reduce short-term and long-term network costs incentivizing the development and efficient operation of new technologies such as distributed generation, demand flexibility, storage, electric vehicles, etc.

To advance on providing short-term and long-term marginal costs, energy prices and network charges need to be **highly granular in time and location**. Thanks to smart metering deployment, temporal granularity can be easier to advance, but determining the critical tariff blocks and allocating cost in each of them is not straightforward. The level of locational granularity of short-term and long-term marginal costs is challenging and there are different kind of implementation barriers such as legal (e.g. requirements that consumers should have the same price across the country or region), lack of data (e.g. network observability), high implementation costs, complexity when computing short-term and long-term costs, administrative burden, etc.

A mild approach could be to include some sort of time-of-use charges. These are simpler to implement and provide more predictability for consumers. The trade-off is that they are less accurate as they take real-time grid conditions less into account. Furthermore, price differentiation can be applied at voltage levels within a zone or even at a national level.

Finally, **residual network costs should be allocated in a non-distortive manner** to avoid interfering with efficient price signals but to ensure cost recovery and economic sustainability of the electricity system. Equity criterion should be considered to design the associated costs. There is no first best option to allocate such costs, fixed charges based on income levels, contracted capacity at peak and mid-peak hours or past energy consumption are options that fulfil the non-distortion and equity criteria but have other implementation challenges.

Local flexibility markets

Local flexibility market is generally a technological neutral solution to incentivise assets from different nature to compete to provide grid services. **Tailor-made solutions** that can be adapted to the DSO needs and FSPs characteristics. However, the implementation of these markets has many design elements and challenges to be considered.

Local flexibility markets may require **complex coordination with existing markets and different agents**: with TSO-DSOs, DSO-DSO, DSO-Aggregators, DSO-FMO, etc. As described in the document, different coordination schemes are possible and they should be carefully chosen to keep a balance among different criteria (e.g. gains on economic efficiency vs implementation costs). It is relevant to **define the roles, functions, and responsibilities** of the different agents.

These tailor-made solutions can become quite complex, on one side they can be adapted to the local characteristics, but on the other hand, the **complexity of the algorithms** and possibly the implementation costs may increase. There is a trade-off between the gain in computation efficiency and accuracy on price signals. The **grid representation and transparency** are key for accounting for network constraints; however, at lower voltage levels, lack of monitoring of the network may become a challenge. Where flexibility bids cannot be selected based on a price merit order, the selection directly by the network operators reduces technical (e.g. massive grid data exchange, duplication of IT systems) and avoids regulatory (e.g. sharing responsibilities, cost recognition) challenges. Instead, the allocation of the bid selection to DSOs fits their responsibility of operating their systems and can be combined with the selection of switching measures to find the most efficient combination of measures.

The **definition of standards for communication systems, information exchange,** activation, etc., can reduce entry barriers for flexibility providers. A balance has to be achieved on agreeing on certain standards that can be used in other markets, but on the other hand, it should not bind costly solutions.

Liquidity is a concern in local flexibility markets due to network characteristics and flexible resources availability. Furthermore, the ability that FSPs can exercise market power is higher with low liquidity. When liquidity is poor, other alternatives have to be considered. The different conditions that affect the implementation of local markets evolve depending on the attributes of the needs and the potential FSPs. These **evolving conditions** change with time, and similarly, the market mechanisms should be adapted.

The characteristics of FSP may affect the local market design. For instance, trading local flexibility from resources that do not have their schedules require to develop and agree on a **baseline methodology**. Different resources may present rebound effects or specific technical constraints. Therefore, a balance has to be made between accounting for complex resource characteristics and a fast optimisation mechanism.

Bilateral contracts, cost-based remuneration and obligations

More regulated mechanisms are alternatives when markets cannot work properly due to **market failures or implementation costs**. When one or more of the following conditions strongly impact the functioning of market-based mechanisms a more regulated option can be considered: high transaction costs, high entry or exit barriers, the exercise of market power, low liquidity, uncertainty on market development, high implementation costs. Bilateral contracts, cost-based remuneration and obligations may be alternatives that in standalone or in combination with other mechanisms can manage market failures. Furthermore, the implementation of bilateral contracts or cost-based remuneration has its challenges as the possibility to discriminate between FSP costs or determine reference costs. Finally, obligations are the last option as they do not consider the involved cost to provide the services leading to under or overprovision.

Evaluation of the mechanisms

A qualitative assessment was conducted to evaluate the different market mechanisms suitability for congestion management and voltage control. This assessment consisted of an interactive approach with the DSOs and MOs participating in EUniversal project.

According to the participants' point of view, the almost same set of context attributes can be used for describing the context for both for congestion management and voltage control services. In general, the most relevant attribute to be considered is the volume of the problem, followed by the number of participants. These two attributes can be related to the liquidity and the competition level which have been considered by the respondents the most important aspects to be considered when designing the mechanism for acquiring the grid services in each specific context.

The mechanisms for acquiring grid services were assessed following evaluation criteria. The general view collected through the survey to MOs and DSOs participating in the project is that the mechanism for procuring grid service has to guarantee first operational security since it is exploited for solving grid issues. Then, economic efficiency and transparency are considered as important pillars for achieving an economically optimal outcome for the participants.

Regarding economic efficiency, the most relevant aspects concern the limitation of the risk of exercising market power and information asymmetry; the reduction of entry barriers represents another important criterion. From the outcome of the survey about the relevance of the implementation concerns sub-criteria, the most relevant aspects are the implementation costs and the alignment with the EU market regulation. Implementation concerns are related to the achievement of a reasonable level of complexity and implementation costs while preserving the alignment with the EU market design/regulation and achieving a high level of effectiveness. The alignment with EU market design is key to facilitate the integration with the existing practices. Moreover, if the mechanism for procuring grid services is internally complex but simple from a participant point of view (and reasonable in terms of cost), it could be acceptable.

In general terms, all the analysed mechanisms could work for congestion management but considering the context attributes described above. For voltage control, due to its local nature, bilateral contracts and obligations for guaranteeing a certain level of support may fit considering the attributes of this service. The use of flexible connection and access agreements, local flexibility markets, and the cost-based mechanisms is case-specific and may work but considering appropriate designs. Dynamic network tariffs do not fit well for voltage control.

Combination of the acquisition mechanisms

The considered mechanisms can be combined to improve their performance and the reduction of short-term and long-term network costs. A certain mechanism as standalone may fail to reduce network costs because of the context attributes or evaluation criteria are not met (e.g. low liquidity and potential exercise of market power). But, the combination of the mechanisms can perform better in combination, e.g. by encouraging investments through contracts but establishing a local flexibility market for activation open to all FSPs.

For congestion management, connection and access agreements can fit with the dynamic network tariffs, cost-based, and obligation mechanisms. Flexible connection and access agreements focus mainly on connection costs and the required investment costs associated to the connection while dynamic network tariffs targets on overall network costs (e.g. as result of the increase on demand already connected to the network, improve on reliability, etc.) and the separation between both mechanisms has to be determined. The combination of the connection and access agreements with local flexibility markets and bilateral contracts raises the challenge about the possible limitations introduced by the flexible connection agreements and the possibility to engage in other mechanisms.

Dynamic network tariffs can work in parallel with local flexibility markets and bilateral contracts; however, the interaction between the two mechanisms has to be designed considering the constraints introduced by the voltage level, the contracting timeframe, the frequency of the need, the network topology, and the volume of the problem. The interaction of the dynamic network tariffs and the cost-based mechanism is challenging because based on different principles, dynamic network tariffs incentivize customers to reduce network costs while cost-based remuneration are based to the cost of providing the service occurred by the FSPs. Combining both options requires to assess the scope and expected results obtained from each of them. The compulsory participation at the dynamic network tariff mechanism could be devised considering the characteristics of the context.

Local flexibility markets can be combined with the bilateral contract mechanism considering the constraints introduced by the voltage level, the contracting timeframe, the frequency of the need, the network topology, the volume of the problem, and the number of participants. For example, bilateral contracts could be used in certain areas of the network when competitive local flexibility market outcomes cannot be guaranteed. Local flexibility markets and cost-based mechanism can be exploited in a combined mechanism considering the existence of different mechanisms for capacity and activation. Local markets for acquiring flexibility capacity can be used while activation may be a cost-based dispatch if representative costs can be obtained easily. Moreover, the combination of the local flexibility market with the obligation mechanism is possible considering the characteristics of the context where applied.

For voltage control, flexible connection and access agreement mechanism could be combined with the local flexibility markets, but it raises the challenge about the possible limitations introduced in the participation in local markets by the flexible connection agreements. The combination of flexible connection and access agreements and bilateral contracts could be possible considering different timeframes and locations, but the conditions of both mechanisms have to be clearly stated. The combination of flexible connection and access agreements and the obligation mechanisms could be achieved by considering that obligations guarantee a minimum flexibility quantity and additional quantities can be guaranteed with flexible connection and access agreements. The combination of local flexibility markets and bilateral contracts could be introduced considering different mechanisms depending on locations and level of potential competition. The combination of the local flexibility markets and the cost-based mechanisms could be achieved by considering to use different mechanisms for capacity procurement and activation. For capacity, a local market can guarantee investments on new resources to provide voltage control, while for activation, a cost-based method can guarantee an efficient allocation if costs are easily known.

7 External Documents

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8 Annex I

EUniversal T5.1 Questionnaire – Mechanisms for acquiring DSO grid services

This **survey** aims to identify the most appropriate mechanism for acquiring grid services of task T5.1 for the services to be implemented in the different EUniversal demonstrators. Therefore, the **point of view of the DSOs and market players** participating in the project is essential. The next section describes the proposed methodology to provide an understanding of the objectives of the questionnaire

8.1 Proposed Methodology

8.1.1 Introduction

The proposed methodology supports the identification of the most suitable mechanisms for acquiring grid services from third-party assets. The grid services which are considered are congestion management and voltage control. The proposed methodology considers the influence of the context on the performance of the mechanisms for acquiring grid services; hence it can be exploited for the analysis of various scenarios both in the transmission and distribution systems. Moreover, the mechanisms for acquiring grid services are evaluated according to a set of criteria for assessing compliance with some of the main general regulatory principles.

The proposed methodology consists of three main steps:

iv. The identification of the context attributes

v. The analysis of correlations between the context and the mechanisms for acquiring grid services

vi. The assessment of the compliance of the mechanisms with the main general regulatory principles

Context attributes strongly influence the effectiveness of the mechanism for acquiring grid services which could be exploited; therefore, the latter has to be chosen accordingly. To this aim, a set of attributes relevant for describing the context and the characteristic of the need is identified. These attributes include:

1. the contracting timeframe,
2. the spatial and temporal features of the need,
3. the network topology,
4. the number and type of potential FSPs (Flexibility Service Providers) involved.

Based on the context attributes, possible mechanisms for acquiring grid services are analysed qualitatively for assessing the applicability of each of them. The outcome of the qualitative analysis will become a subset of eligible acquisition for acquiring DSO services suitable for the selected context attributes. As the last step, the mechanisms in the subset are evaluated according to specified criteria to identify the most suitable ones. The **evaluation criteria** are defined according to general principles for promoting economic efficiency, transparency, reliability, customer engagement, and equity.

To obtain an effective methodology, the perspective of the stakeholders which will benefit from the outcome of the analysis has to be considered. Based on the provided feedback, the collected information allows identifying the main aspects to be considered and understand the perceived relevance.

8.1.2 Description of the procedure

8.1.2.1 Description of the mechanisms for acquiring grid services

A brief description of the mechanisms for acquiring grid services which are considered in the analysis is provided in this section. Each mechanism can be exploited to procure flexibility from FSPs for solving network congestion and voltage problems. The mechanisms described in this section are considered as standalone since more complex mechanisms can be obtained by combining their features.

g. Flexible connection

The flexible connection mechanism is an agreement between the system operator and the FSP in which the latter agrees to have the connection curtailed in some periods. Demand could be temporarily reduced during the periods of load peak demand, whereas generation could be curtailed to avoid network contingencies such as congestions or voltage issues.

h. Dynamic tariffs

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 customers are incentivized to change their consumption and/or production according to the grid operation and future network needs.

i. Local market

Local flexibility markets include long-term and/or short-term auctions. A long-term mechanism could be used in the context of planning activities to procure flexibility by contracting long in advance the potential service providers. The extension of the local market depends on the grid characteristics, i.e. the market area can encompass only a portion of the distribution network and/or transmission network. The size of the local market is site-specific. Flexibility will be utilised by the DSO based on its willingness to pay for it, but also, on the type of flexibility product required. A local flexibility market seeks to promote competition among flexibility providers.

j. Bilateral contract

A bilateral contract is a binding agreement between two parties. In the context of grid services, one side is represented by the system operator while the other is the FSP. A bilateral contract requires a negotiation process between the two parties. Differently than the flexible connection mechanism in which the agreements are signed with all third-parties that apply on a public call for the service provision, the bilateral contract mechanism refers to a customised negotiation between the DSO and each third-part provider.

k. Cost-based

A cost-based mechanism deals with the remuneration of the flexibility provided by the FSP based on the actual costs for providing the service. To illustrate, the cost-based mechanism for flexibility can determine the price of the service provided according to the opportunity cost of active power generation curtailment. The cost-based mechanism requires an acknowledged audit process of the costs incurred by the provider and financial margin that allows providers a return.

l. Obligation

The 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, the FSPs which are asked to participate in service provision are obliged to contribute with their flexibility.

8.1.2.2 Context and need attributes characterisation

For congestion management and voltage control, the aspects identified as relevant for describing the context and the need are **the contracting timeframes, the frequency of the need, the specificity of the problem, and the network topology**. Moreover, the **FSP type, the number of participants, and the involvement of energy storage devices and demand-side management** are relevant aspects which have been considered for describing the system context. In Table 8-1 an overview of the context attributes considered in the qualitative analysis described in this section is provided. For the sake of simplicity, only binary attributes are considered. But the authors acknowledge that in real-life intermediate values are possible for some of the attributes.

Table 8-1. Needs/services and grid characterisation

High-level needs attributes		
Name	**Description**	**Values**
Voltage level	The nominal voltage of the portion of the grid in which the contingency occurs	• High • Medium • Low
Contracting timeframe	The period in which the agreement between the parties is established regarding the expected moment of service provision	• Operations (real-time) • Short-term • Long-Term
Frequency of the need	Number of occurrences that FSPs are required to provide the service considering a predefined time interval	• Low • High
Specificity of the problem	The characterisation in spatial terms. A specific need represents localised particular issues, while widespread needs are issues that are commonly affecting the grid or that affect a large portion of the grid	• Specific • Widespread
Network type	Network topology	• Radial • Meshed
FSP size	Typology of potential providers in terms of size and architecture	• Large FSP / Aggregation of small FSP • Small FSP / No Aggregation
FSP nominal voltage connection	The nominal voltage of the network to which each potential FSP is connected	• High • Medium • Low

Number of expected FSP participants	Number of participants which can potentially provide the flexibility support	• Large • Small
Expected resources types of FSP		• Includes DSR • Includes DSR with storage

The **voltage level** is the nominal voltage of the portion of the grid in which the contingency occurs. Since the differences among voltage levels, the knowledge of these aspect allows defining the set of actions which could be taken for solving the contingency.

The **contracting timeframe** characterises the need in terms of the period in which the agreement between the parties is established regarding the expected moment of service provision. If the flexibility provider is contracted long in advance to the time of service delivery (i.e. at the planning stage), a long-term contracting framework is exploited. Conversely, if the flexibility provider is contracted close to the time of service delivery (i.e. intraday) a short-term contracting timeframe is exploited.

The attribute **frequency of the need** characterises the need in temporal terms. Considering a predefined time interval, the frequency of the need describes the number of occurrences that FSPs are required to provide the service considering a predefined time interval. A high frequency is related to issues that occur regularly (e.g. daily), hence the system operator requires to resort frequently corrective measures. Conversely, a low frequency indicates issues that occur occasionally (e.g. few times a year) therefore the corrective measures will be taken only a few times in the predefined time interval.

The **specificity of the problem** characterises the need in spatial terms. A specific need represents localised particular issues, while widespread needs are issues that are commonly affecting the grid or that affect a large portion of the grid. If the voltage issue concerns only one bus, the problem is considered specific; whereas, if the voltage issue concerns a large number of busses, the voltage problem is widespread. The spatial attribute of the need influences the size of the area from which potential FSPs can be contracted. In the case of widespread problems, if the frequency of the need is reasonably high, the occurrence of the problem may justify a more expensive solution.

The **network topology** influences the way according to which the FSPs contribute to solving the issues; hence, it influences the paths that characterise the service provision. A higher level of interconnection of meshed networks enlarges the set of potential service providers, contrariwise a radial topology limits the number of potential FSPs which can effectively satisfy the system need.

Beside the described attributes, the effectiveness of the service provided is influenced by power system context attributes that depends on the number and type of FSPs in the considered area.

The **size of the FSPs** involved in providing the service can be large FSPs (single units having a large size or aggregated small units) or small FSPs (single units having a small size which are not aggregated).

The **FSP nominal voltage** is the nominal voltage of the network to which each potential FSP is connected. Since the differences among voltage levels, it is relevant to know at which voltage level the resources are located to define the set of actions which could be taken for solving the contingency.

The **number of participants** which can potentially provide support for satisfying the power system need influences the effectiveness of the mechanism which can be exploited for acquiring grid services. If the number of participants is large, high levels of competition are expected; contrariwise, a small number of participants can lead to market power issues and service shortage. Moreover, the number of participants affects the cost of operating the acquisition mechanisms (i.e. the overall burden related to highly personalized bilateral contracts increases as the number of FSP to be contracted).

Furthermore, the **type of potential FSPs** which can be involved influence the nature of the (market) mechanism which could be exploited. If demand and energy storage are involved as FSPs, the set of the flexible tools available to the system operator is broaden; to illustrate, the flexibility can concern the demand curtailment. In this case, solutions capable to include within the same mechanism generators, demand, and energy storage are required.

8.1.3 Definition of the evaluation criteria

Even if the mechanism for acquiring grid services has to comply by design to the general regulatory principles, each realisation satisfies these principles differently. Therefore, it is of interest to assess the extent to which each mechanism for acquiring grid services meet regulatory expectations. In Table 8-2 an overview of the proposed evaluation criteria is provided.

Some of the main general regulatory principles for cost allocation are:

1. Economic efficiency
2. Transparency
3. Equity
4. Implementation concerns
5. Customer engagement
6. Reliability

Economic efficiency is the main guiding principle to guarantee an optimal allocation of resources. This principle can be divided into different sub-criteria:

g. Allocative (static and dynamic) economic efficiency

h. Limited exercise of market power

i. Technology neutrality

j. Low entry barriers

k. Limited information asymmetry between System Operator and third-parties

l. Limited uncertainty

The *allocative economic efficiency* measures the optimality of the static and dynamic distribution of goods or services considering the related demand. Allocative efficiency exists when the marginal cost equals the marginal utility of the good or service.

Market power is the ability of FSPs of altering the market price of a good or service and increasing it over the actual marginal cost. Market power risk has to be avoided since it introduces distortions in the allocation of costs and benefits.

Technology neutrality ensures the absence of technical barriers for participating in the service/good provision. If a mechanism is technologically neutral, the same regulatory principles are applied regardless of the technology adopted, therefore any technology can be adopted if the product or service provided is indistinguishable.

To allow the highest level of potential competition, the mechanism for acquiring grid services has to show *low entry barriers* for new providers. To illustrate, entry barriers are defined by start-up costs, regulation, switching costs. Considering grid services, product standardisation reduces entry barriers; however, ICT requirements may become an entry barrier.

The *asymmetry of information* exists when one of the parties has greater knowledge than the others. Economic efficiency is increased as the information asymmetry is reduced since a better level playing field is obtained.

Another element related to economic efficiency is the *management of the uncertainties*. Efficient market prices are achieved if all factors are known, while unknown factors produce market instability and then market uncertainty. Therefore, a mechanism for acquiring grid services capable to reduce the impact of uncertainties leads to an augmented economic efficiency.

Transparency is a general principle for designing mechanism since it allows to audit the processes related to service provision and the related costs. The higher the transparency of the mechanism for acquiring grid services, the higher the awareness of the parties and other stakeholders. Transparency can be an important factor for achieving social acceptance, a high level of transparency encourages customer participation in all the services.

A mechanism for acquiring grid services shows **equity** if it pursues fair conditions among the stakeholders. This principle can be split into specific subprinciples[15]:

a. Allocative equity
b. Distributional equity
c. Transitional equity

A*llocative equity* is a general principle that pursues that identical usages/exploitations have to be charged/paid equally. One of the main implications of allocative equity is that marginal consumption/production should be charged/paid according to the marginal cost/value it creates[16]. This can be assumed as cost reflectivity and, therefore, would conduce to a more efficient system.

According to the *distributional equity* principle, charges should be proportional to the economic capability of each user. Residual costs are those costs that have no cost driver, and cannot be recovered following economically efficient signals.

The *transitional equity* states that a transition from an old to a new scheme should be gradually implemented.

The **implementation** of each mechanism for acquiring grid services raises **concerns** which can be analysed considering:

e. Implementation costs (including transaction costs)

f. Complexity

g. Effectiveness

h. Alignment with EU market regulation.

The *implementation costs* represent all the costs required for achieving a full deployment of the mechanism for acquiring grid services. For the sake of simplicity, transaction costs are considered as included in the implementation costs as they are related to costs of implementing a particular solution.

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[16] Burger, S. P., Schneider, I., Botterud, A., & Pérez-Arriaga, I. (2019). Fair, equitable, and efficient tariffs in the presence of distributed energy resources. Academic Press.

Each mechanism for acquiring grid services is characterised by a different level of *complexity* which depends, amongst others, on the procedures adopted, the related features, the (market) algorithms used and the implementation requirements.

The *effectiveness* of a mechanism for acquiring grid services appraises the capability of the adopted procedures in procuring the required quantity of goods and services without the risk of under/over procurement.

In real contexts, the implementation of a mechanism for acquiring grid services cannot ignore compliance with the current and future regulatory frameworks. Since Europe is the focus of the project, the *alignment with the current end expected EU market regulation* is of interest.

Customer engagement provides a measure of the extent to which the customers are involved in the procedures related to the flexibility provision. **Customer engagement** strategies provide direct benefits which are related to the economic efficiency criteria. Besides, engaged customer produce externalities such as the contribution in energy efficiency measures and a higher social acceptance. Moreover, a mechanism for acquiring grid services which achieves a high level of **customer engagement** allows enhancing the penetration of renewable energy sources and the adoption of energy efficiency practices. Aware costumers are more willing to participate with an active role in the grid operation empowering the exploitation of their flexibility. A more aware use of the electric energy and more efficient use of the existing infrastructure it allows to increase the hosting capacity of the network by postponing the otherwise network reinforcements required for meeting the expected future scenarios.

The **reliability** of a mechanism for acquiring grid services measures the ability to procure a sufficient amount of service for guaranteeing a secure operation of the power system. In particular, it represents the certainty that the contracted FSPs deliver the contracted service.

Table 8-2.Overview of the evaluation criteria

Criteria	Sub-criteria	Description
Economic efficiency	Allocative economic efficiency	Optimality of the distribution of goods or services considering the related demand.
	Limited exercise of market power	The ability of FSPs of altering the market price of a good. It has to be limited.
	Technology neutrality	Absence of technical specific barriers for participating in the service/good provision.
	Low entry barriers	Entry barriers are any aspect that can discourage the participation of new players.
	Limited information asymmetry	Not fair dissemination of the information among players. It has to be limited to prevent distortions.
	Limited uncertainty	Unknown factors produce market instability. The uncertainty has to be reduced to achieve efficient market prices.
Transparency		Allowing auditing the processes related to service provision and the related costs
Equity	Allocative equity	Is a general principle that pursues that identical usages/exploitations have to be charged/paid equally
	Distributional equity	Charges should be proportional to the economic capability of each user
	Transitional equity	It states that a transition from an old to a new scheme should be gradually implemented
Implementation concerns	Implementation costs	All the costs required for achieving a full deployment of the mechanism for acquiring DSO services.
	Complexity	It assesses the complexity related to the procedures, iterations, and algorithms that are required for implementing the mechanism.
	Effectiveness	The capability of the adopted procedures in procuring the required quantity of goods and services without the risk of under/over procurement.
	Alignment with EU market regulation	A mechanism cannot ignore compliance with the current and future regulatory frameworks.
Customer engagement		It measures the extent to which the customers are involved in the procedures related to the flexibility provision.
Reliability		Ability to procure a sufficient amount of service for guaranteeing a secure operation of the power system.

8.1.4 Example of correlation analysis of context attributes

According to the context attributes defined in 8.1.2.2, a high-level qualitative analysis of the correlation with the mechanisms for acquiring grid services is depicted in Table 8-3, in which the colour scale represents the suitability of each mechanism for acquiring grid services considering each attribute. The green colour represents high suitability, the yellow colour weak suitability, while red means that the mechanism for acquiring grid services is not suitable if the related attribute subsists. The rows are not necessarily mutually exclusive but for the sake of simplicity, they are depicted as such.

Table 8-3 Suitability of the mechanisms for acquiring grid services according to context attributes

		Flexible connection	Dynamic tariffs	Local market	Bilateral contract	Cost-based	Obligation
Voltage level	High	High	High	High	High	High	High
	Medium	High	High	High	High	High	High
	Low	High	High	High	High	High	High
Contracting time	Long-term	High	Weak	High	High	High	High
	Short-term	Low	High	High	Weak	High	High
Frequency of the need	High	High	High	High	Weak	High	High
	Low	High	High	Weak	High	High	High
Network topology	Radial	High	High	Weak	High	High	High
	Meshed	High	High	High	High	High	High
Specificity of the problem	Specific	High	Weak	Weak	High	High	High
	Widespread	High	High	High	Low	High	High
FSP size	Large	High	High	High	High	High	High
	Small	High	High	Weak	Low	Low	High
FSP voltage level	High	High	High	High	High	High	High
	Medium	High	High	High	High	High	High
	Low	High	High	High	High	High	High
Number of participants	Large	High	High	High	Low	High	High
	Small	High	Weak	Low	High	High	High
Demand &/or energy storage		High	High	High	High	Low	High

Legend:

Suitability	High	Weak	Low

Considering the contracting timeframe, flexible connections are suitable if a long-term mechanism is exploited while a short-term mechanism may lead to a shortage in flexibility procurement since the short time available for contracting FSPs. Contracting the FSPs for achieving a satisfactory amount of flexible capacity is an activity which has the highest effectiveness in the planning stages. The exploitation of dynamic tariffs presents weak suitability considering a long-term contracting time since the volatility of the tariffs may lead to inaccurate forecasts for the service price. Similarly to the flexible connection mechanism, the bilateral contract mechanism seems weakly suitable for the short-term contracting time.

When the need for service provision is characterised by a high frequency the suitability of bilateral contract is low since the overall burden related to the high volume of negations which would be required would be high. Contrariwise, a local market mechanism appears less suitable in the case of a low frequency of the need since underutilisation of the possibly complex market structure.

The radial topology limits the area which contains the potential FSPs to be exploited for the flexibility provision. In this case, a local power market may have too few participants, hence the risk of market power issues exits.

If the problem to be solved by resorting FSPs is specific, then a dynamic tariff mechanism is less suitable than other acquiring mechanisms since it would involve only a small set of localised FSPs which could or could not participate in the service provision. In case of widespread problems, a local market mechanism is more suitable since the size of the area in which the potential FSPs can be large; moreover, the mechanism behind the dynamic tariff can be replicated as is to be used in more grid scenarios. Furthermore, solving a widespread problem with bilateral contracts appears unsound since a large number of negotiations would be required.

If small FSPs are involved in the mechanisms for acquiring grid services, local markets may represent a less appealing choice since the burden of participation which would be required for asset management. The exploitation of bilateral contracts would require to negotiate a high number of contracts each one concerning a small amount of service. Similarly, a cost-based mechanism would result in a considerable burden for auditing all FSPs involved.

As already stated, if the number of participants is large then the exploitation of bilateral contracts could be less suitable. On the contrary, a small number of participants makes dynamic tariffs and local markets weak and less suitable, respectively. In such a context, the exploitation of dynamic tariffs may lead to a shortage in the flexibility procured, whereas in the case of local markets big concerns related to market power risk arise.

When demand and energy storage devices are involved as FSPs, the cost-based mechanism appears unsuitable as determining reference costs would be very complex, considering the great diversity of potential providers.

The correlations in Table 8-3 are the outcome of a high-level qualitative analysis. More complex results can be obtained by considering non-binary attributes for characterising the context and the need.

8.1.5 Mechanisms complementarity

The exploitation of the methodology would require to assess the main requirements and the boundary conditions of the service delivery. Then, the set of mechanisms for acquiring DSO services of interest has to be defined and the contained options have to be assessed considering the product required.

Furthermore, in addition to the mechanism for acquiring DSO services presented in section 8.1.2.1, novel mechanisms can be obtained by considering feasible combinations and coexistence of the standalone ones. Then, the obtained mechanisms can be appraised according to the proposed evaluation criteria.

8.2 Needs/services and grid characterisation

The goal of this survey to collect the respondent perspective on the aspects which are relevant for designing the mechanism for acquiring DSO services which best fits with the local characteristics. Considering independently congestion management and voltage support the respondent has to state if the proposed attributes and the related values are relevant. Conversely, the respondent is asked to provide new attributes and values. In this case, the new proposals have to be motivated by filling the gaps below the main table.

Since the flexibility provision for congestion management and voltage support have different features and involve different assets, it is expected that the attributes to be considered for designing the mechanism for acquiring grid services would be different.

8.2.1 Congestion management and voltage control

The respondents were asked to answer this section separately for congestion management and voltage control.

The first column of Table 8-4 reports the name of the proposed attribute, while the second column provides the related definition. The third column explains the reasons which have led the proponents in considering the attribute. The fourth column reports the values of the attribute which have been considered relevant for the design of the mechanism for acquiring grid services. In the fifth, the respondent has to provide an opinion about the attribute and the related values which have been proposed. For each attribute, the respondent has to check one of the three boxes about the attribute and values appropriateness. In the sixth column, the respondent has to suggest new values for the attributes if the values proposed in column four are considered not appropriate.

Table 8-4. High-level needs and attributes survey – Congestion management

High-level needs attributes	Attribute definition	Why this attribute	Attributes values	Answers. In cases b) and c) please provide an explanation and alternatives if applicable	If values are not appropriate, please suggest new values
Voltage level of the contingency	Nominal voltage of the portion of the grid in which the contingency occurs	Since the differences among voltage levels, the knowledge of these aspect allows defining the set of actions which could be taken for solving the contingency	a. High b. Medium c. Low	• ☐ a) appropriate attribute and values • ☐ b) appropriate attribute but not the values • ☐ c) not appropriate	
Contracting timeframe	The period in which the agreement between the parties is established regarding the expected moment of service provision.	Timeframes may be relevant on the mechanism for acquiring grid services selected, since, for example, real-time may need the fast activation of previously reserved flexibility, or short-term vs long-term may differ on the possibility of grid reinforcements.	a. Operation (real-time, on an hourly basis) b. Short-term (daily or intraday) c. Long-Term (annually)	• ☐ a) appropriate attribute and values • ☐ b) appropriate attribute but not the values • ☐ c) not appropriate	Operation: _______ Short-term: ______ Long-term: _______
Frequency of the need	Considering a predefined time interval, the frequency of the need describes the number of occurrences that FSPs are required to provide the service considering a predefined time interval.	The frequency of a particular grid problem may be relevant to select more or less complex or expensive mechanisms.	a. Low (less than one time a week) b. High (equals or more than one time a week)	• ☐ a) appropriate attribute and values • ☐ b) appropriate attribute but not the values • ☐ c) not appropriate	Low: __________ High: __________

Specificity of the problem	The specificity of the problem characterises the need in spatial terms.	Grid problems can be localized in repetitive areas, or appear in a more widespread way, which might be relevant for the mechanisms for acquiring grid services.	a. Specific (less than 10 users involved or problem that occurs only in one scenario) b. Widespread (equal or more than 10 users involved or problem that occurs in more than one scenario)	• ☐ a) appropriate attribute and values • ☐ b) appropriate attribute but not the values • ☐ c) not appropriate	Specific: _________ Widespread: _______
Network type	Degree of interconnection among the FSPs.	The grid-type may influence the way flexibilities activation impact on the grid and therefore the most appropriate mechanism for acquiring DSO services.	a. Radial b. Meshed	•	
FSP size	It characterises the nature of the actors which are involved in the service provision.	The types of Flexibility Providers (FSP) may be determinant to select the appropriate mechanisms for acquiring grid services.	a. Large FSP / Aggregation of small FSP (equals or more than 10 MVA) b. Small FSP / No Aggregation (less than 10 MVA)	• ☐ a) appropriate attribute and values • ☐ b) appropriate attribute but not the values • ☐ c) not appropriate	Large FSP: _________ Small FSP: _________

FSP nominal voltage	The nominal voltage of the network to which each potential FSP is connected	Since the differences among voltage levels, it is relevant to know at which voltage level the resources are located to define the set of actions which could be taken for solving the contingency.	a. High b. Medium c. Low	• ☐ a) appropriate attribute and values • ☐ b) appropriate attribute but not the values • ☐ c) not appropriate	
Number of FSP	The expected quantity of participants on the market, able and qualified to provide flexibility.	If the number of participants is large, high levels of competition are expected; contrariwise, a small number of participants leads to market power issues and service shortage.	a. High (equals or more than 25) b. Low (less than 25)	• ☐ a) appropriate attribute and values • ☐ b) appropriate attribute but not the values • ☐ c) not appropriate	High: ___________ Low: _________
Resources types of FSP	It assesses the involvement of demand-side response and energy storage.	This attribute is relevant since the difficulty of assigning unique flexibility cost considering the great variety of assets which could participate in the service provision.	a. Includes DSR b. Includes storage c. Includes DSR d. DSR and storage not included	• ☐ a) appropriate attribute and values • ☐ b) appropriate attribute but not the values • ☐ c) not appropriate	
Other: ______________________					
Other: _______________________					

Please provide a brief description of the evaluation made:

Voltage level of the contingency

Contracting timeframe
Frequency of the need
Specificity of the problem
Network type
FSP size
FSP nominal voltage
Number of FSP participants
Resources types of FSP
Other: ____________________

8.2.2 Attribute relevance

In regards to Congestion Management, which of the following attribute is most important to you?

Please rank the following attributes considering their relevance for describing the congestion management problem in light of solving it by procuring grid services.

(Rank from 1-11 with 1 being the most important and 11 being the least important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

	1	2	3	4	5	6	7	8	9	10	11
Voltage level of the contingency	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Contracting timeframe	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Frequency of the need	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Specificity of the problem	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Network type	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
FSP size	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
FSP nominal voltage	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Number of FSP participants	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Resources types of FSP	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Other: ____________	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Other: ____________	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Please provide a brief description of the ranking:

In regards to Voltage control, which of the following attribute is most important to you?

Please rank the following attributes considering their relevance for describing the congestion management problem in light of solving it by procuring grid services.

(Rank from 1-11 with 1 being the most important and 11 being the least important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

	1	2	3	4	5	6	7	8	9	10	11
Voltage level of the contingency	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Contracting timeframe	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Frequency of the need	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Specificity of the problem	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Network type	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
FSP size	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
FSP nominal voltage	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Number of FSP participants	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Resources types of FSP	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Please provide a brief description of the ranking:

Other relevant needs/services:

According to the work in progress in task T2.1 and D2.1 what other needs/services do you think that could/should be added for a similar analysis?

Currently D2.1

- Support for network planning:
- Phase balancing:
- Support to planned/unplanned operations:
- Support to extreme events (probably needs further disaggregation)

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8.3 Acquisition mechanisms assessment

8.3.1 General evaluation criteria assessment

Which of the following evaluation criteria for acquisition mechanisms are most important to you?

Please note: some of the above criteria are disaggregated below for better characterisation.

(Rank from 1-7 with 1 being the most important and 7 being the least important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

	1	2	3	4	5	6	7
Economic efficiency	☐	☐	☐	☐	☐	☐	☐
Transparency	☐	☐	☐	☐	☐	☐	☐
Equity	☐	☐	☐	☐	☐	☐	☐
Implementation concerns	☐	☐	☐	☐	☐	☐	☐
Customer engagement	☐	☐	☐	☐	☐	☐	☐
Reliability	☐	☐	☐	☐	☐	☐	☐

Please provide a brief description of the ranking:

8.3.2 Economic Efficiency criteria assessment

In regards to Economic Efficiency, which of the following evaluation criteria are most important to you?

(Rank from 1-9 with 1 being the most important and 9 being the least important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

	1	2	3	4	5	6	7	8	9
Allocative economic efficiency	☐	☐	☐	☐	☐	☐	☐	☐	☐
Limit market power	☐	☐	☐	☐	☐	☐	☐	☐	☐
Technology neutrality	☐	☐	☐	☐	☐	☐	☐	☐	☐
Low entry barriers	☐	☐	☐	☐	☐	☐	☐	☐	☐
Limited information asymmetry	☐	☐	☐	☐	☐	☐	☐	☐	☐
Limited uncertainty	☐	☐	☐	☐	☐	☐	☐	☐	☐
Other: ________________________	☐	☐	☐	☐	☐	☐	☐	☐	☐
Other: ________________________	☐	☐	☐	☐	☐	☐	☐	☐	☐

Please provide a brief description of the ranking:

8.3.3 Equity criteria assessment

In regards to Equity, which of the following evaluation criteria are most important to you?

(Rank from 1-7 with 1 being the most important and 7 being the least important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

	1	2	3	4	5	6	7
Allocative equity	☐	☐	☐	☐	☐	☐	☐
Distributional equity	☐	☐	☐	☐	☐	☐	☐
Transitional equity	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐

Please provide a brief description of the ranking:

8.3.4 Implementation criteria assessment

In regards to Implementation, which of the following evaluation criteria are most important to you?

(Rank from 1-7 with 1 being the most important and 7 being the least important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

	1	2	3	4	5	6	7
Implementation costs	☐	☐	☐	☐	☐	☐	☐
Complexity	☐	☐	☐	☐	☐	☐	☐
Effectiveness	☐	☐	☐	☐	☐	☐	☐
Aligned with EU market design/regulation	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐
Other: ______________________	☐	☐	☐	☐	☐	☐	☐

Please provide a brief description of the ranking:

8.3.5 Costumer engagement criteria assessment

In regards to Costumer engagement, do you consider further criteria subdivision/disaggregation?

(Rank from 1-5 with 1 being the most important and 5 being the least important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

	1	2	3	4	5
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐

Please provide a brief description of the ranking:

8.3.6 Reliability criteria assessment

In regards to Reliability, do you consider further criteria subdivision/disaggregation?

(Rank from 1-5 with 1 being the most important and 5 least the most important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

	1	2	3	4	5
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐
____________________________	☐	☐	☐	☐	☐

Please provide a brief description of the ranking:

8.3.7 Additional criteria assessment

If you added any additional criteria to the 4 initially considered (Economic efficiency, Implementation, Costumer engagement, and Reliability) do you think an additional disaggregation is needed?

(Rank from 1-5 with 1 being the most important and 5 being the least important; you can add additional evaluation criteria in the lines below. Different criteria cannot have the same rank position).

New criteria: ________________________

Disaggregation proposed

	1	2	3	4	5
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐

New criteria: ___________________________

Disaggregation proposed

	1	2	3	4	5
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐
___________________________	☐	☐	☐	☐	☐

9 Annex II Questionnaire on connection and access

9.1 About the questionnaire

This questionnaire is composed of 33 questions. This questionnaire aims at understanding the current regulations and expected changes related to connection and access agreements for grid users.

Please note that the data collected here is treated anonymously and will be used for research purposes only. At the end of the questionnaire, you will have the option to leave your email for contact in case we require additional clarification. No additional personal data will be recorded for this survey.

9.2 Grid access and connection agreements

Please indicate the laws, grid codes or technical norms where the aspects are regulated. If English versions are available, please use this version. If not, reference the documents in the language available.

9.2.1 Access

9.2.1.1 Available capacity

1) Which entity is in charge of calculating the available grid capacity?

The first step in the procedure to network access for a new user is the determination of available capacity. Usually, this threshold value is established by the DSO in charge of the network, but other entities might be in charge of the calculation.

☐ DSO	☐ Regulator	☐ Other, please specify

Corresponding regulatory document/norm:

2) Which criteria are employed for the determination of available capacity?

The capacity available in a network can be determined according to different criteria. For example, the Spanish regulation limits the available capacity with the thermal capacity of the distribution line and the short-circuit power in the point of connection to the transmission network [67]. On the contrary, Engineering Recommendation G99 in the United Kingdom establishes the need for power flow analysis to be carried out for every generator applying for grid access [73].

☐ Short-circuit ratio	☐ Thermal capacity of lines	☐ Power flow analysis	☐ Other, please specify

Please quantify the limits applied.

Corresponding regulatory document/norm:

3) <u>With what type of software are these criteria evaluated?</u>

Corresponding regulatory document/norm:

4) <u>Who sets the criteria quantified in question 2?</u>

☐ Criteria defined in regulation	☐ Defined by each DSO for the corresponding network	☐ Other, please specify

Corresponding regulatory document/norm:

5) <u>How is available capacity communicated to grid users?</u>

Information transparency regarding the available grid capacity describes the fact of whether available capacity at different grid nodes is publicly accessible or determined in individual connection studies for each applicant. Publication formats include look-up tables [38] or heat maps [37].

☐ Made public on the internet for informative purposes combined with a detailed study once the access request was made.	☐ Made public on the internet and binding for access granting to new grid users.
☐ No publication, available capacity is communicated individually as a result of the connection study	☐ Other, please specify

Corresponding regulatory document/norm:

6) <u>Is this procedure equal for generation and demand and different sizes of grid users?</u>

☐ Yes	☐ Different for generation and demand	☐ Different according to the voltage level
☐ Different according to capacity	☐ Locational differences (e.g. nodal, urban/non-urban)	☐ Other (please specify)

Please specify the differences.

Corresponding regulatory document/norm:

7) <u>In case you publish available capacity on the internet, in which interval is the information updated?</u>

Please include a link to the information.

Corresponding regulatory document/norm:

8) <u>In case you publish available capacity on the internet, in which format is the information published?</u>

☐ Look-up tables	☐ Interactive maps	☐ Other, please specify

Please include a link to the information.

9) <u>How is the communication of available grid capacity regulated?</u>

☐ Common regulation that applies to all DSOs	☐ Each DSO manages the communication procedure according to own standards	☐ Other, please specify

Corresponding regulatory document/norm:

10) <u>Is capacity assigned differently for the different grid users?</u>

Due to different characteristics, it is common to define different access methodologies for demand and generation. The assignation of capacity might also vary with the size of an installation or voltage level. For example, according to Engineering Recommendation G98 [87], small distributed generation facilities do not need to apply for access.

☐ Yes, a different methodology is applied to generation and demand (please specify)	☐ Yes, distinction according to the size of the installation (please specify)	☐ Yes, distinction according to the voltage level (please specify)	☐ No

Criteria for different grid users:

Corresponding regulatory document/norm:

11) <u>According to which criteria are available capacity assigned? Does the procedure vary for different grid users (i.e. generation and demand), voltage levels or sizes?</u>

Once the available capacity has been determined, its allocation might be subject to different mechanisms. The most common methodology is **first-come-first-served**, which implies the allocation of available capacity according to the order of permission applications. In contrast to that, **batch processing** represents an approach where several applications are evaluated in a common process [75]. However, the promotion of renewable energies might include the **priority** of grid access. In this case, RES generation facilities are favoured over conventional power plants. Another mechanism is the marked-based allocation of grid capacity by employing **auctions** [5].

☐ First-come-first served	☐ Priority for RES	☐ Market-based: auctions	☐ Batch processing	☐ Other, please specify

Please indicate specifications and differences among grid users.

Corresponding regulatory document/norm:

9.2.1.2 Firmness options of grid access

12) Are any options for non-firm access employed by your company?

☐ Yes, we offer non-firm access	☐ Yes, we offer options for complementary capacity with non-firm access	☐ No (continue with question 20)	☐ Other, please specify

In case you offer complimentary non-firm access, please answer the following questions for the non-firm capacity.

Corresponding regulatory document/norm:

13) Are these options offered to all grid users?

☐ Yes	☐ Demand only	☐ Generation only	☐ RES Generation only
☐ Only for specific voltage levels		☐ Only for specific sizes	☐ Other, please specify

In case the options are not offered to all grid users, please specify the categorisation.

Corresponding regulatory document/norm:

14) In case the answer to the prior question was yes: please specify the available options for non-firm grid access. Please include a link to your webpage, if available.

☐ Temporal granularity (seasons, inter-daily, other)	☐ Regional granularity (nodes, voltage levels, feeders, other)	☐ Other, please specify

Corresponding regulatory document/norm:

15) Are DSOs obliged to offer non-firm access?

☐ DSOs are obliged to offer non-firm access	☐ DSOs are entitled to offer non-firm access	☐ Other, please specify

Corresponding regulatory document/norm:

16) Are the non-firm options mandatory for the user? Please indicate differences among different grid users, sizes or voltage levels.

☐ Users have the right to be offered a non-firm access alternative	☐ Users have the right opt for a firm access option	☐ Other, please specify

Corresponding regulatory document/norm:

17) In the case of optionality, which benefits are offered to the user? If possible, please include an example of the magnitude of these benefits.

☐ Compensation payments (please specify)	☐ Reduction of connection time	☐ Reduction of the connection cost	☐ Other, please specify

Corresponding regulatory document/norm:

18) Which are the requirements for grid users to make use of non-firm access?

☐ Economic guarantees	☐ Comply with advanced technical requirements	☐ Other, please specify

Please specify the requirements and penalties for non-compliance.

Corresponding regulatory document/norm:

19) According to which procedure is curtailment carried out? Find a more detailed description of principles of access in [81], [88], [171]

☐ Pro-rata	☐ First-in-last-out	☐ Non-RES generators first	☐ Marked-based	☐ Other, please specify

Corresponding regulatory document/norm:

20) In case you do not offer non-firm access options, have you considered its implementation?

☐ Yes, we thought about it but decided against it	☐ Yes, we are currently in the implementation process (please answer questions 11 to 19 for your draft)	☐ No

Corresponding regulatory document/norm:

21) If you discussed the implementation of non-firm access, what arguments made you decide against it? Please explain your decision.

☐ Implementation complexity	☐ Incompatibility with national law	☐ Other (please specify)

Corresponding regulatory document/norm:

9.2.1.3 Further aspects of grid access rights

22) Is it possible to change the capacity once the application was sent? Or is a new application required for upscaling or downscaling?

☐ Upscaling and downscaling are possible	☐ Only downscaling is possible	☐ Other (please specify)

Corresponding regulatory document/norm:

23) Is this option offered to all grid users?

☐ Yes	☐ Demand only	☐ Generation only	☐ RES Generation only
☐ Only for specific voltage levels		☐ Only for specific sizes	☐ Other, please specify

Corresponding regulatory document/norm:

24) Can access rights obtained for a certain point of connection be sold?

As a consequence for the permission of selling access rights, these rights turned into a speculative good in Spain and prices of up to 300 kEUR/MW have been reported [172]. The limitation of the possibility to sell access rights for immature projects (for example, allow selling only when the generation/demand facility is constructed already). might be an option to tackle speculation.

<table>
<tr><td>☐ Access rights can be sold at any instance of the connection process</td><td>☐ Access rights cannot be sold</td><td>☐ Other (please specify)</td></tr>
<tr><td colspan="3">☐ Access rights can only be sold after the project reaches a certain maturity. Please include the indicator of maturity used for the evaluation of a project.</td></tr>
</table>

Corresponding regulatory document/norm:

25) Is this option offered to all grid users?

<table>
<tr><td>☐ Yes</td><td>☐ Demand only</td><td>☐ Generation only</td><td>☐ RES Generation only</td></tr>
<tr><td colspan="2">☐ Only for specific voltage levels</td><td>☐ Only for specific sizes</td><td>☐ Other, please specify</td></tr>
</table>

Corresponding regulatory document/norm:

9.2.2 Connection

26) Which type of connection charges are employed?

Connection charges are commonly categorised depending on how connection costs are allocated between the grid operator and the new grid users. These categories are [78]:

☐ Deep	☐ Shallow	☐ Shallowish

In the case of shallowish connection charges, please indicate the specifications (for example only on the same voltage level or a pre-defined share of total reinforcement costs).

Corresponding regulatory document/norm:

27) How is the calculation methodology of connection charges regulated?

☐ Methodology determined by regulator	☐ Methodology determined by each DSO and approved by regulator	☐ Methodology determined by each DSO without the supervision of the regulator	☐ Other (please specify)

Corresponding regulatory document/norm:

28) Are connection charges different for different grid users?

☐ No	☐ Different for generation and demand	☐ Different according to the voltage level
☐ Different according to capacity	☐ Locational differences (e.g. nodal, urban/non-urban)	☐ Other (please specify)

Please specify the differences.

Corresponding regulatory document/norm:

29) In case you publish available capacity on the internet, in which format is the information published?

☐ Look-up tables	☐ Interactive maps	☐ Other, please specify

Please include the link to the information.

30) Who sets the methodology for the calculation of connection charges?

Different entities to set the magnitude of connection charges are commonly the regulator or the system operator. The regulator usually establishes a common methodology to be applied throughout the country. When the different DSOs establish connection charges for their networks, regional differences are more likely.

☐ Defined by each DSO for the corresponding network	☐ Regulator	☐ Other (please specify)

Corresponding regulatory document/norm:

31) How are connection charges communicated to the users?

Information transparency to the available grid capacity describes the fact of whether available capacity at different grid nodes is publicly accessible or determined in individual connection studies for each applicant. Publication formats include look-up tables [38] or heat maps [37].

☐ Made public on the internet for informative purposes combined with a detailed study once the connection request was made.	☐ Made public on the internet and binding for connection of new grid users.
☐ No publication, available capacity is communicated individually as a result of the connection study.	☐ Other, please specify

Corresponding regulatory document/norm:

32) Is this procedure equal for generation and demand and different sizes of grid users?

☐ Yes	☐ Different for generation and demand	☐ Different according to the voltage level
☐ Different according to capacity	☐ Locational differences (e.g. nodal, urban/non-urban)	☐ Other (please specify)

Please specify the categorisation.

Corresponding regulatory document/norm:

33) What is the average duration of connection studies? Do you see the potential of non-firm access to reduce these durations? If necessary, distinguish between grid users (generation/demand, capacity, voltage level, location at congested nodes/uncongested nodes).

If you agree, please provide your name and email to be contacted in case of clarifications of your answers.